# Abstract

This paper reports the trends and outlook for the preferred resources in California's "loading order"—energy efficiency, demand response, renewables, and distributed generation—established in 2003 by the state's principal energy agencies. The intent of the loading order is to develop and operate California's electricity system in the best, long-term interest of consumers, ratepayers, and taxpayers. The paper also identifies the barriers that must be overcome to integrate energy efficiency, demand response, renewables, and distributed generation into California's electricity system, and suggests policy options to address these barriers. In addition, the paper discusses ways to monitor and verify the state's progress in acquiring these preferred resources so that policy makers can make any necessary mid-course corrections in state policy in response to shortfalls or overages.

# Key Words

Preferred loading order, energy efficiency, demand response, renewable energy, distributed generation, measurement and verification, renewables portfolio standard, photovoltaic energy, integrating intermittent renewables, renewable energy certificates

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# EXECUTIVE SUMMARY

## Introduction

As the sixth largest economy in the world, California's demand for electricity is growing, fueled by an expanding population and a robust economy. To meet this growing demand, California's principal energy agencies—the California Energy Commission (Energy Commission), the California Public Utilities Commission, and the California Consumer Power and Conservation Financing Authority (Power Authority)—established an energy resource loading order to guide their energy decisions.

The loading order consists of decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources, and second with clean fossil-fueled generation. The loading order was adopted in the *2003 Energy Action Plan* prepared by the energy agencies and the Energy Commission's *2003 Integrated Energy Policy Report (2003 Energy Report)* used the loading order as the foundation for its recommended energy policies and decisions.

This staff report discusses the trends and outlook for the four preferred resources identified in the loading order:  energy efficiency, demand response, renewables, and distributed generation. It also presents the challenges to aggressively pursuing the preferred loading order resources and suggests policy options to counter these challenges. The report also discusses ways to monitor and verify California's progress in acquiring preferred resources so that policymakers can make necessary mid-course corrections in response to either shortfalls or overages

Among the loading order preferred resources, "energy efficiency" includes programs that require buildings and appliances to be constructed in a manner that uses less energy, that provide incentives for purchasing energy efficient equipment, and that provide information and education to encourage people to save energy. "Demand response" includes new rate designs, which provide customers lower electricity prices during most hours in exchange for higher prices during the peak hours when supply reserves are small and electricity typically costs more, and programs that provide incentives for on-peak load reductions. "Renewable resources" include forms of electricity generation that naturally replenish themselves, including energy from wind, solar, small hydroelectric, geothermal, and biomass. "Distributed generation" is electricity that is produced by the customer or utility who will use some or all of it locally. Examples include small fuel cells, rooftop photovoltaic systems, or cogeneration systems that simultaneously produce electricity and heat or steam for on-site use.

# Advantages of Loading Order Resources

Each of the loading order resources provides specific and unique benefits to California that help the state balance its electricity requirements by managing generating resources and reducing demand.

## *Energy Efficiency*

Using energy efficient buildings and equipment to decrease California's per capita electricity consumption reduces the state's need for new power plants and the associated environmental impacts. These measures also reduce the state's dependence on natural gas, thereby increasing the reliability of the electricity system.

## *Demand Response*

Demand response programs also reduce electricity consumption and are well established in California. These programs serve an important role in stabilizing the state's electrical grid. Some programs reduce or curtail electricity loads during times of high demand and emergencies. The programs include a variety of measures such as programs where the utility either shuts off specific equipment to reduce a business's electricity load, a business reduces its load to an agreed-upon level, or the utility cycles air conditioners. These reliability programs are used to stabilize the electricity system and avoid rotating outages when electricity reserves are very low.

Demand response pricing programs provide financial incentives for customers to reduce their electricity loads when the demand for electricity is high. These price-sensitive programs, like "dynamic pricing" and demand bidding, reflect more recent approaches in California to reducing demand during periods of peak load or high wholesale costs. For example, in the Demand Bidding Program, a utility offers to pay for load reduction during specific times when demand is very high. The utility names the price, and customers offer (or "bid") the amount of demand they are willing to reduce. The discussion in this paper focuses on these newer approaches and the state's efforts to expand their impacts.

## *Renewable Resources*

Renewable resources provide fuel and supply alternatives that increase the diversity of fuel options used to provide electricity. Renewable resources also enhance energy security because the fuel supplies are usually local and therefore not affected by supply interruptions from outside California or the United States. In its Renewables Portfolio Standard, California set goals for increasing the amount of electricity that renewable energy generation will provide, calling for 20 percent of the state's electricity generation from renewable energy by 2010.

### *Distributed Generation*

California has a wealth of both renewable and non-renewable distributed generation technologies. These technologies have tremendous potential to help meet California's growing energy needs as both additional generation sources and essential elements of customer choice. Benefits from distributed generation include improved reliability and power quality, reduced peak demand, and system reliability. Distributed generation also offers efficiency gains by avoiding line losses (from the transmission of power over long distances from generator to consumer) and by using waste heat for making steam or heating and/or air conditioning. These "combined heat and power" generating plants use fuel very efficiently. Because distributed generation reduces line losses, it can defer the need for new transmission and distribution infrastructure, reduce utility resource acquisition costs, and provide ancillary services such as voltage control.

## Loading Order Goals and Progress Toward Achieving Those Goals

Because each loading order resource offers unique ways to manage or reduce electricity demand, specific goals are established for each resource.

### *Energy Efficiency Goals*

In its *2003 Energy Report*, the Energy Commission recommended four goals to improve energy efficiency:

- Increase public funding for cost effective energy efficiency programs above then current levels to reduce peak electricity demand by at least an additional 1,700 megawatts and reduce total electricity used by 6,000 gigawatt hours by 2008.
- Increase funding for natural gas efficiency programs to reduce natural gas an additional 100 million therms by 2013.
- Standardize and increase the evaluation and monitoring of energy efficiency programs to ensure the delivery of savings and benefits.
- Implement appropriate mandates, incentives, and funding to maximize the energy efficiency potential of existing buildings.

The *2003 Energy Report* also concluded that the maximum achievable savings from energy efficiency programs over the next decade is 30,000 gigawatt hours. In September 2004, the California Public Utilities Commission adopted a set of aggressive energy savings goals designed to reach this potential.

As shown in Table E-1, the California Public Utility Commission goals exceed the recommendations in the *2003 Energy Report*. If these goals are met, the energy savings could represent as much as 59 percent of the investor-owned utilities' additional electricity needs between 2004 and 2013, and could increase natural gas savings by 116 percent over the next decade.

## Table E-1. Electricity and Natural Gas Program Savings Goals (All Investor-Owned Utilities)

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Annual Electricity Savings (GWh/yr) | 1,838 | 1,838 | 2,032 | 2,275 | 2,505 | 2,538 | 2,465 | 2,513 | 2,547 | 2,631 |
| Total Cumulative Savings(GWh/yr) | 1,838 | 3,677 | 5,709 | 7,984 | 10,489 | 13,027 | 15,492 | 18,005 | 20,552 | 23,183 |
| Total Peak Savings (MW) | 379 | 757 | 1,199 | 1,677 | 2,205 | 2,740 | 3,259 | 3,789 | 4,328 | 4,885 |
| Total Annual Natural Gas Savings (MMTh/yr) | 21 | 21 | 30 | 37 | 44 | 52 | 54 | 57 | 61 | 67 |
| Total Cumulative Natural Gas Savings (MMTh/yr) | 21 | 42 | 72 | 110 | 154 | 206 | 260 | 316 | 377 | 444 |

Source: CPUC Decision 04-09-060, September 23, 2004, *Interim Opinion: Energy Savings goals for Program Year 2006 and Beyond.*

The California Public Utilities Commission recognized the practical limits to increasing energy efficiency funding and increased the funding for programs to achieve the aggressive energy efficiency goals, particularly those for natural gas. The goals will be updated every three years concurrent with the new three-year energy efficiency program planning cycle.

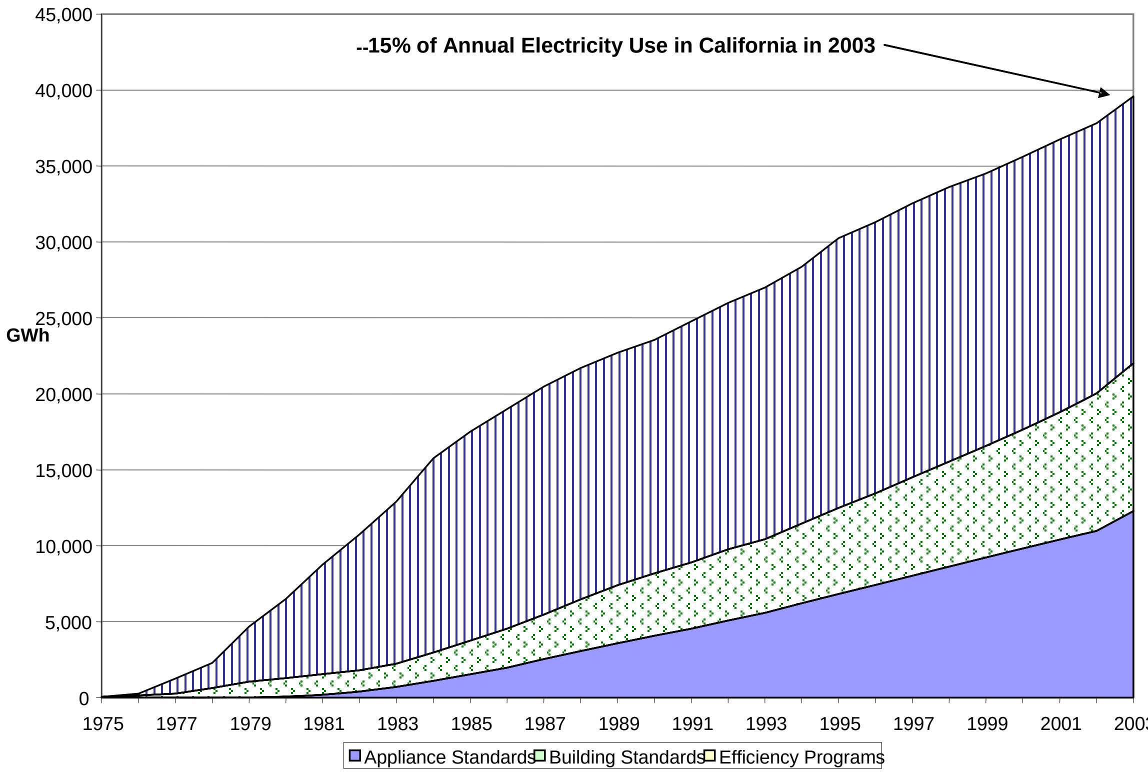
## *Progress Toward Energy Efficiency Goals*

California has a long history of supporting energy efficiency. As of 2004, the state's Building and Appliance Standards and energy efficiency incentive and education programs have cumulatively saved more than 40,000 gigawatt-hours of electricity and 12,000 megawatts of peak electricity, equivalent to 24 500-megawatt power plants. Figure E-1 shows cumulative efficiency savings from 1975 to 2003. The amount of energy saved as of 2003 is equivalent to 15 percent of the electricity used in California in that year. More than half of these savings come from the Building and Appliance Standards, with the balance resulting from programs implemented by the state's investor-owned and publicly owned utilities.

In addition to generating savings themselves, California's Building and Appliance Standards enhance energy efficiency programs by incorporating efficiency measures into long-term sustainable savings for all market sectors. The Energy Commission's 2005 Building Standards are expected to help meet energy efficiency goals by reducing growth in electricity demand by 479 gigawatt-hours and peak demand by

182 megawatts annually over the life of the measures. The standards are also expected to reduce annual natural gas use by 8.9 million therms.

## Figure E-1. Cumulative Efficiency Savings



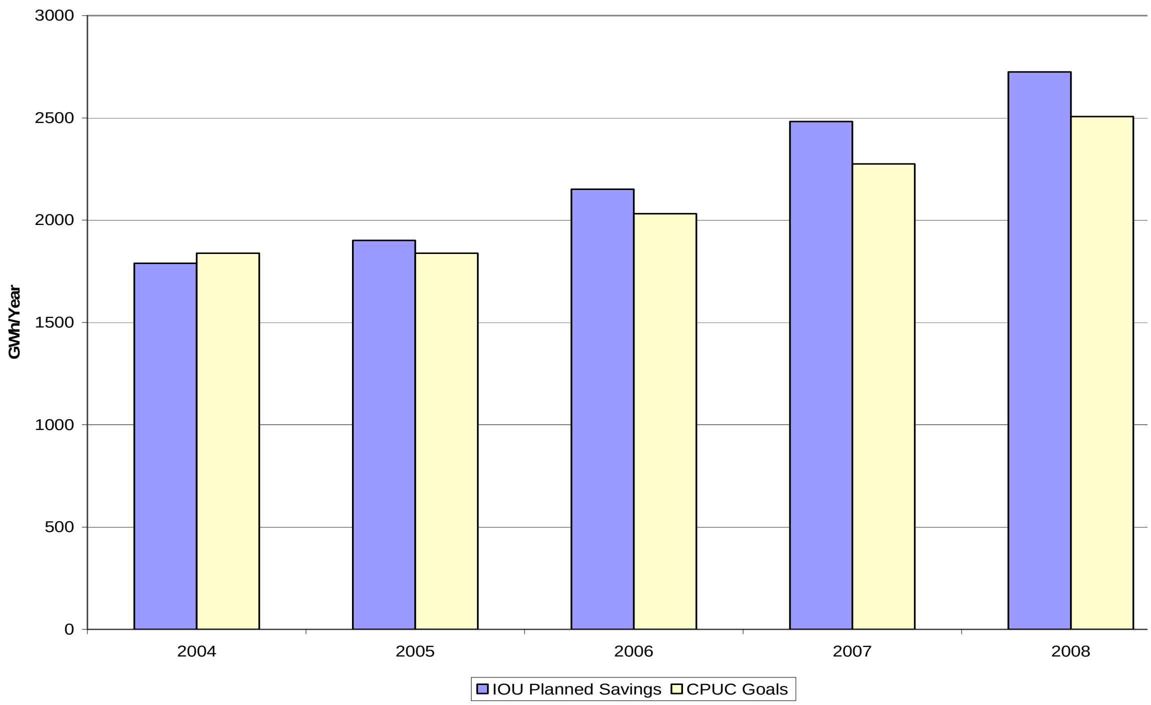

Source: Energy Commission DSM forecast model output

In 2003, the California Public Utilities Commission directed utilities to increase the amount of funding used for energy efficiency programs. Based on the utility plans, the California Public Utilities Commission authorized $245 million in additional funding for energy efficiency in California's Public Goods Charge funds. This increased overall available funding for fiscal year 2004-2005 to $823 million, a 43 percent increase over the mandated Public Goods Charge funding levels.

In June 2005, investor-owned utilities submitted their 2006-2008 energy efficiency plans to the California Public Utilities Commission. These are the first plans to use the 2004 California Public Utilities Commission's energy efficiency goals as a benchmark. Figure E-2 shows the comparison of projected savings with goals for the investor-owned utilities.

Energy Commission staff and others reviewed the utilities' mid-May versions of the portfolio plans. The reviewers concluded that the program portfolios had a good chance of meeting the California Public Utilities Commission's near-term goals for electricity and natural gas savings and reduced demand. There is more uncertainty, however, about meeting the longer-term 2009-2013 goals.

## Figure E-2. Projected Savings Compared to Goals 2006-2008




Source: 2004 savings, Energy Efficiency Annual Summaries published May 2005 for each investor-owned utility in the 2005 Annual Earnings Assessment Proceeding; 2006-2008 projected savings, June 2005 filings to CPUC for approval of 2006-2008 energy efficiency programs and budgets (A.05-06-004, PG&E; A.05-06-016, SDG&E; A.05-06-015, SCE).

Ensuring that savings from these efficiency programs are achieved is a vital component of the state's *Energy Action Plan* goals, underscoring the importance of evaluation and monitoring activities. Timely, accurate evaluation, measurement, and verification is needed to ensure that investor-owned utility intentions are translated into real energy and peak demand savings. Investor-owned utility administrators will no longer manage contracts to evaluate, measure, or verify the energy savings impacts of their programs. Instead, the California Public Utility Commission's Energy Division and the Energy Commission will cooperatively assume management and contracting responsibilities for all efficiency monitoring and verification studies.

Success of the programs fundamentally depends on consumer action. Energy efficiency actions need to be understood within the context of household or organizational energy use patterns and factors that shape a consumer's ability to act. These complex patterns change and evolve, but they can be shaped and influenced to enhance the effectiveness of energy efficiency policies and programs.

### *Demand Response Goals*

In 2003, the California Public Utilities Commission set goals for the utilities' peak demand reduction from demand response programs. These goals are shown in Table E-2.

**Table E-2. Utility Demand Response Goals (MW)**

| Year | PG&E | SCE | SDG&E | Total |
|---|---|---|---|---|
| 2003 | 150 | 150 | 30 | 330 |
| 2004 | 400 | 400 | 80 | 880 |
| 2004 (revised) | 343 | 141 | 47 | 531 |
| 2005[1] | 450 | 628 | 125 | 1,203 |
| 2006 | 4% of the annual system peak demand | | | |
| 2007 | 5% of the annual system peak demand | | | |

The challenge in meeting these goals, which have not been met to date, is two-fold. First, current programs are limited to customers with advanced meters that can track when electricity is used (about 40 percent of total investor-owned utility load). Second, the current programs are voluntary and designed to collect the same amount of money as normal rates. The programs do not provide enough incentive to enroll a sufficient number of customers to meet the goals. The California Public Utilities Commission recognized this issue and lowered the expected goals for 2004, directing the utilities to propose programs in which they would assign customers to the demand response rates unless they requested the standard rate. The California Public Utilities Commission also directed the utilities to expand the use of advanced meters to all customers.

## *Progress Toward Demand Response Goals*

The *2003 Energy Report* and the *2004 Energy Report Update* recommend moving forward on developing an advanced metering infrastructure for all customers and implementing default dynamic rates for large customers who have advanced meters in order to meet demand response megawatt goals. Although the state is behind in meeting these goals, significant progress is being made and the potential for meeting those goals in the future is growing.

The California Public Utilities Commission's demand response goal for 2004 is 880 megawatts (see Table E-2). As shown in Table E-3, the investor-owned utilities reported 556 megawatts of savings as of April 2005, which is 324 megawatts short of the goal.

As part of its demand response rulemaking, the California Public Utilities Commission established several working groups to develop incentives and rate programs to encourage increased demand response in California. The working groups developed the following programs and tariffs:

**Table E-3. Investor-Owned Utility Demand Response Report Summary as of April 2005**

| | PG&E (MW) | SCE (MW) | SDG&E (MW) | Totals (MW) |
|---|---|---|---|---|
| **Price Responsive Programs** | 370.8 | 150.3 | 34.6 | 555.7 |
| **Reliability Programs** | 334.9 | 1145.3 | 76.6 | 1556.8 |
| **Totals** | **705.7** | **1295.6** | **111.2** | **2112.5** |

- The Critical Peak Pricing tariff, a summer season program for large customers (greater than 200 kilowatts) that encourages customers to reduce energy consumption during critical peak times.
- The Demand Bidding Program, a year-round voluntary demand/energy bidding program. Under this program, a utility offers to pay for load reduction during specific times when demand is very high. The utility names the price, and customers offer (or “bid”) the amount of demand they are willing to reduce.
- The Demand Reserves Program, a year-round program that provides incentives to large customers who commit to turning off load upon request for up to an agreed amount of hours per year.
- The Statewide Pricing Pilot Program, a program for small customers (fewer than 200 kilowatts). The customers are offered different rates that charge more for electricity used during periods of peak system load.

The Statewide Pricing Pilot demonstrated that time-based rates can significantly reduce peak demand. While the existing program designs would not contribute significantly to achieving demand response goals because they are voluntary, the process of designing, marketing and implementing the programs has provided utilities with valuable experience and customer feedback. This information will help investor-owned utilities meet the California Public Utilities Commission’s requirement to implement a Critical Peak Pricing tariff for customers with demand greater than 200 kilowatts by summer 2006.

Advanced metering technologies are necessary to allow dynamic pricing, and could help utilities better meet their demand response goals. Assembly Bill 29X (Kehoe), Chapter 9, Statutes of 2001, authorized $35 million to install advanced meters for all customers with peak demand greater than 200 kilowatts. Under this program, which is managed by the Energy Commission, utilities installed 25,000 real-time energy meters in order to develop real-time pricing rate designs. These meters will allow utilities to offer their customers a variety of possible dynamic pricing and demand response programs. In fact, the state’s investor-owned utilities have filed proposals with the California Public Utilities Commission to deploy advanced meters to all of their customers over the next several years.

## Renewable Goals

California's Renewables Portfolio Standard, established in 2002, requires that retail electricity sellers, including utilities, sell more electricity from renewable energy sources. These sellers are required to increase the amount of renewable energy sales by at least one percent per year. By 2017, 20 percent of the electricity they sell should come from renewable generation, subject to certain cost constraints. The *2003 Energy Report* and the energy agencies call for accelerating that 20 percent target to 2010. In 2004, the *2004 Energy Report Update* recommended a longer-term goal of 33 percent renewable by 2020.

The law requires publicly owned municipal utilities to develop Renewables Portfolio Standard programs; however, they are not subject to the same implementation rules as the state's investor-owned utilities. Because publicly owned utilities provide 20-25 percent of the state's electricity, the *2004 Energy Report Update* also recommends requiring these utilities to comply with the accelerated and increased Renewables Portfolio Standard targets.

Governor Schwarzenegger has also set forth a renewable goal calling for solar photovoltaic development in California in his Million Solar Roofs Initiative. The initiative calls for increasing photovoltaics in California from 104 MW today to 3,000 MW over the next 13 years.

## Progress Toward Renewable Goals

Over the past two decades, California has developed one of the largest and most diverse renewable generation mixes in the world. However, 2004 electricity data indicates that the state appears to be behind schedule for meeting the goal of 20 percent of its electricity from renewable energy by 2010.

Table E-4 shows actual or planned renewable energy procurement compared to the estimated amount needed to reach 20 percent renewable by 2010.

It is not a shortage of in-state renewable generating potential that caused the slip in schedule:  California clearly has enough renewable potential to meet the Renewables Portfolio Standard targets. Undeveloped potential from biomass, biogas, geothermal, ocean, small hydroelectric, and wind totals more than 41,000 megawatts. When solar thermal and solar photovoltaic are added, the technical potential is well over one million megawatts.

The procedures for soliciting, selecting, and contracting with renewable energy developers, however, has proved to be time-consuming and cumbersome. Southern California Edison solicited for renewable generation in August 2003, but has only recently completed negotiations with bidders. The solicitation resulted in six contracts totaling 142 megawatts of capacity (643 gigawatt hours annually), with potential to expand to 428 megawatts (2,2127 gigawatt hours annually). Southern California Edison contracts are with two biomass, one geothermal, and three wind projects, with construction anticipated sometime between 2006 and 2008.

## Table E-4. Procured versus Needed Renewable Energy to Reach 20 Percent by 2010[2]

| Utilities and Year | Actual or Planned Renewable Energy Procurement (GWh/yr) | Annual Procurement Target set by CPUC | Estimated Cumulative Need (GWh/yr) |
|---|---|---|---|
| ***PG&E*** 2003 | 8,828 | 8,764 | 7,326 |
| 2004 | 8,591 | 9,475 | 8,550 |
| 2005 | 9,034 | 10,211 | 9,633 |
| 2010 | 14,790 | | 15,879 |
| ***SCE*** 2003 | 12,497 | 12,030 | 12,451 |
| 2004 | 13,246 | 12,736 | 13,637 |
| 2005 | 13,192 | 13,466 | 14,560 |
| 2010 | Redacted | | 15,934 |
| ***SDG&E*** 2003 | 547 | 150 | 501 |
| 2004 | 678 | 423 | 893 |
| 2005 | 884 | 581 | 1,285 |
| 2010 | Redacted | | 3,462 |
| ***Direct Access and Rest of State*** | | | |
| 2003 | 4,856 | n/a | 9,540 |
| 2004 | 4,676 | n/a | 11,512 |
| 2005 | | | 13,022 |
| 2010 | | | 20,885 |
| ***Total State*** | | | |
| 2003 | 26,728 | n/a | 29,818 |
| 2004 | 27,191 | n/a | 34,593 |
| 2005 | | | 38,501 |
| 2010 | | | 56,160 |

Source: IOU APT compliance reports filed with the CPUC, Gross System Power (less 7% for losses), Appendix A. Cells outlined in bold indicate cumulative procurement that is behind schedule.

In 2004, the California Public Utilities Commission ordered Pacific Gas and Electric Company and San Diego Gas and Electric Company to solicit for renewable energy. Pacific Gas and Electric Company issued its Request for Offers in July 2004, but did not complete contract negotiations with any bidders until April 2005. As a result of its 2004 Renewables Portfolio Standard solicitation, the utility has executed contracts with four wind generators totaling 194.5–233 megawatts of wind, and additional contracts may follow. San Diego Gas and Electric Company also issued its Request for Offers in July of 2004, but has not yet completed negotiations with any bidders.

For the 2005 resource procurement process, investor-owned utilities submitted their draft Renewables Portfolio Standard plans in the spring of 2005. Investor-owned utilities expect to release their Requests for Offers in late 2005.

### *Distributed Generation Goals*

There is no explicit megawatt goal for distributed generation development. Without specific goals, the state cannot measure progress toward implementing the state's preference for distributed generation and expanding the amount of energy from distributed generation sources. In developing this goal, California could look to goals established at the national level as well as those in other countries.

The United States Department of Energy, for example, has established the goal of 20 percent of new electricity generating capacity in the United States to be distributed generation. Internationally, the United Kingdom set a goal to develop 10,000 megawatts of combined heat and power distributed generation by 2010. Denmark requires that all fossil-fueled generation be natural gas-fired and used in the combined heat and power mode, mainly for district heating.

### *Progress Toward Distributed Generation Goals*

While no specific goal currently exists for distributed generation development, the state has addressed several major barriers to more customers installing distributed generation. In 2000, the California Public Utilities Commission revised its Rule 21 governing the connection of distributed generation customers to the utility grid. Since this change, customers with approximately 500 megawatts of distributed generation have connected under the revised Rule 21, bringing total installed distributed generation in California to approximately 2,500 megawatts.

The recent changes in Rule 21 have also reduced the time required for generators to interconnect by 80 percent. More importantly, Rule 21 changes saved distributed generation customers approximately $8 million for small systems and $26 million for large systems between 2001 and 2003 in interconnection costs. Based on current trends, these savings will continue to increase.

The California Public Utilities Commission has also directed investor-owned utilities to revise how distributed generation is considered in their distribution planning process. Southern California Edison began a process in late 2004 to actively solicit distributed generation for its distribution planning purposes.

Although distributed generation is not part of the investor-owned utility procurement processes, San Diego Gas and Electric has requested approval from the California Public Utilities Commission for a specific solicitation for renewable distributed generation. This would diversify its mix of generating sources and encourage local interest in renewable generation. This would be the only procurement to date to recognize the value of distributed generation being local.

In April 2005, the Energy Commission's Public Interest Energy Research Program released the *Assessment of California Combined Heat and Power Market and Policy Options For Increased Penetration.* This study determined that market potential for combined heat and power is substantial. This is despite higher natural gas prices, which make natural gas-based combined heat and power generation more expensive. In the base case, market penetration for combined heat and power is close to 2,000 megawatts; reaching this market penetration could significantly contribute to California's goals for distributed generation.

## Challenges and Options Facing Loading Order Resources

California currently faces numerous challenges to achieving the loading order resource goals and integrating them into the state's electricity system. The Energy Commission staff summarizes these key challenges here. The staff discusses the challenges and options for overcoming them in more detail in Chapter 7, and identifies possible next steps in Chapter 8.

### *Challenges to Integrating Loading Order Resources into California's Electricity System*

- Investor-owned utility efforts need state policy support to better combine efficiency and demand response programs with other loading order options to match California's future needs.
- Decision makers need more information to better understand the effect of each of the preferred loading order resources on the operation of the electricity system.
- Utilities need to provide the necessary funding and staff to implement the loading order preference.
- California needs more research on how to integrate intermittent renewables, such as wind, into the electricity system to maintain consistent and reliable service.

### *Regulatory and Legal Challenges*

- Expanding the impact of efficiency programs requires a concerted effort to improve the energy efficiency of existing buildings.
- Current law prevents residential customers from benefiting from electricity rates that change as the cost of electricity fluctuates.

- To fairly allocate the costs of electricity across all customers, California needs to enroll and maintain demand response program participation for customers with a variety of usage characteristics.
- Current voluntary demand response offerings have not enrolled sufficient load to meet the California Public Utilities Commission's demand response goals.
- The procurement process for renewable energy suppliers is slow: the utility decision-making process to select renewable resources is unclear.
- Electric service providers and community choice aggregators, while expected to include renewable energy in the mix of their supply, have no direction from the California Public Utilities Commission on how to do so.
- The complexity of administering and calculating payments for new renewable suppliers may cause delays in meeting the state's goals for accelerated renewable energy development.
- The Renewables Portfolio Standard rules require both in-state and out-of-state generators to deliver their electricity to a location that the purchasing utility specifies. Congestion in California's transmission system can interfere with the renewable developers' ability to deliver power, making it harder to achieve the state's renewables target.
- To ensure California meets its Renewables Portfolio Standard goal of 20 percent by 2010, the state needs to develop mechanisms to anticipate and mitigate the possibility of failure to produce adequate renewables.
- In the Altamont Pass area, wind turbines are responsible for killing raptors and other birds protected by domestic and international law, highlighting the need to apply the best available information on siting and best available technology to avoid and mitigate bird deaths when developing wind resources.
- The complex metering and scheduling process required to sell electricity into the wholesale market discourages combined heat and power distributed generation.
- Utilities have little incentive to promote or enable customer or utility-owned distributed generation.
- Distributed generation operators have little incentive to supply power when it is most needed.

## *Infrastructure Needs to Facilitate Loading Order Resources*

- Undertaking a broad program of demand response and dynamic rates requires the installation of specialized metering and related equipment for all customers.
- Encouraging and managing an expanded program of distributed generation in California requires a system for tracking and metering its output.
- Lack of infrastructure complicates efforts to bring sufficient renewable energy into California's utilities to meet the Renewables Portfolio Standard mandate.

- Antiquated distribution infrastructure is not compatible with the advanced loading order technologies.

### *Monitoring and Evaluation*

- State government and utilities need to provide the necessary funding and staff for evaluation, monitoring and social research that will help integrate loading order resources into electricity system planning and procurement.
- Current data reporting protocols make it difficult to track output from small distributed generation resources and measure progress toward demand response goals.
- The diverse efficiency programs that utilities are pursuing need monitoring and evaluation to provide prompt feedback on the successes of the programs.
- Disseminating information and offering financial incentives is inadequate to achieve the state's energy mandate.
- To the extent possible, public information programs should be evaluated to determine their effectiveness in encouraging people to conserve energy during peak periods and purchase energy efficient equipment.
- Demand response/dynamic rate impacts on customers vary by customer load profile. Some customers may lose under the rates while others benefit, depending upon the timing and flexibility of their electricity usage.
- The relationship between planned and actual megawatt savings from demand response programs is not well established.
- There is a need to clarify how Renewable Portfolio Standard Compliance will be determined.

# Executive Summary Endnotes

[1] 2005 goals were originally described as 3% of annual system peak, but in D.04-12-048 were converted to numeric goals for each IOU, p. 60.

[2] Actual procured in 2003 and 2004 and planned for 2005 is from IOU APT compliance reports filed with CPUC, per Appendix B of D.04-06-014. Total State is from Gross System Power less 7% for losses. Direct Access and Rest of State is the difference. IOUs are required to meet Annual Procurement Targets set by the CPUC in R. 04-04-026, with a 3-year compliance window for over- or under-procurement. Planned renewable energy procurement for 2010 is from the public version of the IOU RPS plans, using (2010 procured energy) divided by (previous year's retail sales). Estimated cumulative need is based on a projection from an estimated 2001 baseline to 20% by 2010, using staff forecast of retail sales. The baseline uses data from the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002" which was filed by each of the IOUs under Rulemaking 01-10-024. The 2001 baseline also uses data from Gross System Power and the J-11 table, less 7% for losses. PG&E plans to procure renewables in 2010 equal to 20 percent of 2009 retail sales of 73,952 GWh, citing the RPS Annual Procurement Target (APT) Methodology in Appendix B of CPUC decision 04-06-014. The Accelerated Renewable Energy Development Report Appendix A indicated that SCE procured 12,791 GWh of renewables for 2003, based on SCE's June 22, 2004, "Report to the California Energy Commission: Utility Procurement of Renewable Energy in 2003." However, both the Southern California Edison Company Renewable Procurement Plan of June 14, 2004 and the July 7, 2004 Report by the Southern California Edison Company Regarding 2004 Annual Procurement Target indicated that 12,489 GWh of renewables were procured in 2003. The March 1, 2005 Southern California Edison Company's Compliance Report Regarding Achievement of the 2004 Annual Procurement Target filed with the CPUC indicated that SCE procured 12,497 GWh of RPS-eligible renewables in 2003. SCE and SDG&E redacted the GWh/year from the public versions of the RPS procurement plans, but stated that their 2010 procurement of renewable energy would be 20 percent of 2009 retail sales, consistent with CPUC Decision 04-06-014. See Appendix A for details.

# CHAPTER 1: INTRODUCTION

In addition to presenting the trends and outlook for the preferred resources in California's loading order, this staff report identifies challenges to aggressively pursuing those preferred resources—energy efficiency, demand response, renewables, and distributed generation—for California's electricity system and suggests policy options to counter these challenges. The report also discusses ways to monitor and verify the state's progress in acquiring preferred resources so that policymakers can make necessary mid-course corrections in response to either shortfalls or overages.

In 2003, California's principal energy agencies—the California Energy Commission, the California Public Utilities Commission (CPUC), and the California Consumer Power and Conservation Financing Authority—developed a common policy on the priority order of new facilities and programs to meet California's growing electricity needs. This priority list, or "loading order," is meant to guide individual and joint energy decisions made by the agencies. The *2003 Energy Action Plan*[3] adopted the loading order. It was later cemented in the Energy Commission's *2003 Integrated Energy Policy Report (2003 Energy Report)*.

The goal of the loading order is to develop and operate California's electricity system in the best long-term interests of consumers, ratepayers, and taxpayers. The loading order calls for (1) decreasing electricity consumption by increasing energy efficiency and conservation, (2) reducing demand during peak periods through demand response and (3) meeting new generation needs first with renewable and distributed generation resources and then with clean fossil-fueled generation.

The paper is divided into eight chapters. Chapter 1 summarizes key policy issues currently facing loading order resources, followed by a brief overview of the legislative and policy backgrounds for these resources. Chapter 2 summarizes current efforts at the Energy Commission, CPUC, and elsewhere to support these preferred resources. Chapters 3 through 6 individually address issues facing energy efficiency, demand response, renewables, and distributed generation. Chapter 7 identifies options for overcoming challenges to developing these resources, and Chapter 8 identifies next steps.

## Key Policy Issues

### *Energy Efficiency*

California's electricity demand is characterized by short summer peaks when air conditioning demand pushes the need for electricity well above annual averages. The state depends heavily upon fossil-fueled generation, primarily from natural gas, to satisfy its electricity needs. Using energy efficiency measures to decrease California's per capita electricity consumption reduces the state's need for new power plants. These measures also reduce the state's dependence on natural gas, thereby increasing energy security and decreasing environmental impacts from fossil-fueled electricity generation.

Key policy issues for energy efficiency relate to ensuring that energy efficiency takes its place as a viable and tangible resource for procurement and reduction of per capita energy use in California. Achieving the energy efficiency goals in the *2003 Energy Report* will require increased public funding for both electricity and natural gas efficiency programs, as well as for efficiency standards development and enforcement. In addition, there needs to be a standardized evaluation and monitoring system to ensure that these programs deliver their desired savings and benefits. Finally, because of the huge potential for energy efficiency in existing buildings, it may be desirable to target mandates, incentives, and funding toward achieving that potential.

## *Demand Response*

Demand response programs also encourage energy efficiency and conservation during peak demand, enhancing system reliability, reducing the severity of wholesale price spikes, limiting supplier market power, and, depending upon the marginal generation that is displaced, providing environmental benefits. Rapid technological innovation in advanced metering technology, communications technology and data processing also reduce the cost of providing the required infrastructure for all customers to participate in price-sensitive demand response programs. As utilities update their metering system technologies, demand response programs will become an integral part of future electricity markets.

Addressing the discrepancy between projected levels of price-sensitive demand response in the investor-owned utility (IOU) resource plans relative to the CPUC's demand response goals is one key policy issue for demand response. Options including advanced metering, additional financial incentives for participating in demand response programs, and better marketing and customer education can help address this discrepancy. Monitoring and verifying the costs and benefits of demand response programs will also help establish the cost effectiveness of these programs and provide more reliable estimates of capacity for resource planners.

Other key policy issues for demand response include:  the regulatory process and logistical elements of building an advanced metering infrastructure, the development and implementation of fair and effective dynamic electricity tariffs, and the incorporation of price-sensitive and reliability demand response into the resource planning process.

### *Renewable Resources*

Like energy efficiency and demand response, renewable resources provide important benefits to California. Because renewable resources do not depend upon fuel markets they are not subject to fluctuating oil or natural gas prices; renewables can therefore help stabilize the electricity market, providing real economic benefit. Renewable resources also enhance energy security since the fuel supplies are usually local and therefore unaffected by control or supply interruptions from outside California or the United States.

For renewable resources, the early implementation of California's Renewables Portfolio Standard (RPS) suggests that the program needs revisions to streamline future RPS procurement cycles. Beyond the lessons learned so far from RPS implementation, one key policy issue is the clear need for development of new or upgraded transmission lines to link resource areas to load while also managing risk in renewable energy transmission development.

Another issue is the impact of intermittent renewable resources, such as wind, on both the transmission system and transmission operators. Unplanned and unexpected fluctuations in wind generator output can require system operators to call on other generators to increase or decrease output, complicating system management and transmission system operation. Another issue of note relating to wind resources is the need to apply the best available information on siting and best available technology to avoid and mitigate bird deaths from wind turbines. Finally, there is Governor Schwarzenegger's initiative to reach a million solar roofs in California over the next 13 years, and the technical and policy challenges to meeting that goal.

### *Distributed Generation*

California has a wealth of both renewable and non-renewable distributed generation (DG) technologies. These technologies have tremendous potential to help meet California's growing energy needs as both additional generation sources and essential elements of customer choice. These technologies are also strategic components of the loading order. Benefits from using DG include:  improved reliability and power quality for customers using distributed generation and customers close to distributed generation sites, customer ability to reduce system peak load, and efficiency gains from avoiding line losses. Customers with combined heat and power (CHP) installations also increase their fuel efficiency by using waste heat for heating and/or air conditioning. For utilities, DG can defer the need for new transmission and distribution infrastructure, reduce utility resource acquisition costs, and support ancillary services.

Key policy issues for DG focus on challenges to interconnection of these technologies with the grid, including the need for standardized interconnection rules and a streamlined interconnection process, and the need to minimize impacts to the state's electricity system. There is large untapped potential for CHP DG facilities due to technical, regulatory, market, and perceptual barriers.

The uncertainties faced by large CHP facilities regarding IOU renewal of their long term contracts are of particular concern. Given the many societal benefits that CHP provides and California's need for generating capacity, there needs to be easier access to wholesale electricity markets so that all CHP facilities can be sized to their thermal loads and sell their excess electricity with certainty and ease.

There is also a need to better account for the benefits of DG in utility procurement and distribution planning. Distribution planning processes need to be more transparent so that policy makers can ensure cost effective and reliable distribution services for ratepayers.

## Legislative and Policy Background

### *Energy Efficiency*

California has a long history of support for energy efficiency. In the mid-1970s, the state, through the Energy Commission, developed energy codes requiring new residential and commercial buildings and appliances to meet minimum energy-efficiency standards. The first utility-based savings programs appeared about the same time. Program spending over the subsequent twenty years exhibited a series of peaks and declines associated with wholesale energy prices and policy interest in energy efficiency.

In 1996, Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996, restructured California's electricity market. Recognizing that competitive markets often fail to provide adequate levels of public goods, AB 1890 identified four areas to be funded through a non-bypassable Public Goods Charge (PGC) on electricity consumption. These areas were energy efficiency, renewables, research, development and demonstration (RD&D), and low-income assistance. Energy efficiency funding for the IOUs during the period of 1998-2002 was $228 million per year.

In 2002, Assembly Bill 995 (Wright), Chapter 1051, Statutes of 2000, and Senate Bill 1194 (Sher) Chapter 1050, Statutes of 2000, extended the collection of funding for renewables, energy efficiency, and RD&D for 10 years, from 2002 to December 31, 2011, at the same annual funding levels adjusted for the lesser of load growth or inflation.

Based on short- and long-term procurement plans submitted by IOUs in 2003, the CPUC authorized a $245 million increase for energy efficiency programs.[4] This amount was in addition to the PGC funds, thus increasing available funding for 2004-2005 to $823 million, a 43 percent increase over statutorily authorized levels.[5]

## *Building Standards*

The Energy Commission established the nation's first Energy Efficiency Standards for Residential and Nonresidential Buildings in 1978 in response to legislation reducing California's energy consumption (Public Resources Code Section 25402, et seq.). The standards are periodically updated to reflect new energy efficiency technologies and methods. In 2000, passage of AB 970 (Ducheny), Chapter 329, Statutes of 2000, interrupted work on what became the 2005 Standards. AB 970 required the Energy Commission to adopt an emergency update of the standards to respond to California's electricity crisis. In 2001, Senate Bill 5X (Sher), Chapter 7, Statutes of 2001, required the Energy Commission to adopt energy efficiency building standards for outdoor lighting.

The Energy Commission developed the AB 970 standards by focusing on reducing peak electricity consumption by using energy efficiency measures for which there was substantial information already available. The Energy Commission adopted the 2005 Standards on November 5, 2003. The standards become effective October 1, 2005.

## *Appliance Standards*

Public Resources Code Section 25402(c) requires the Energy Commission to adopt energy efficiency standards for appliances using a significant amount of energy. The first Appliance Efficiency Regulations were adopted in 1976, and the 2005 Appliance Efficiency Regulations were adopted by the Energy Commission in April 2005.[6]

## *Peakload Reduction Efforts*

Assembly Bill 549 (Longville), Chapter 905, Statutes of 2001, requires the Energy Commission to: "...investigate options and develop a plan to decrease wasteful peakload energy consumption in existing residential and nonresidential buildings." The Energy Commission will report its findings to the Legislature by October 1, 2005.

## *Green Buildings Program*

Governor Schwarzenegger's Executive Order S-20-04 established a high priority for energy and resource-efficient high-performance buildings. The Executive Order sets a goal to reduce energy use in state-owned buildings by 20 percent by 2015 (over 2003 levels), and directs compliance with the Green Building Action Plan, which outlines steps the state will take to meet this goal.

## *Demand Response and Dynamic Rates*

Assembly Bill 29X (Kehoe), Chapter 9, Statutes of 2001, authorized $35 million for installation of advanced meters for all customers with peak demand greater than 200 kilowatts. The Energy Commission administered the funds and evaluated program impacts. This program was completed in 2003, with about 25,000 meters installed.

The Energy Commission joined the CPUC in instituting CPUC Rulemaking 02-06-001. The rulemaking's purpose is "to develop demand response as a resource to enhance electricity system reliability, reduce power purchase and individual consumer costs, and protect the environment."[7] The rulemaking focused on two activities. The first was developing dynamic rates and price-sensitive demand response programs for large customers, taking advantage of the state's investment in advanced metering. The second was conducting research and analysis necessary to evaluate the potential costs and benefits of building an advanced metering infrastructure to serve all IOU customers. Chapter 4 describes the current status of these efforts.

CPUC Decision 03-06-032[8] set target demand response goals for California's IOUs as part of the demand response rulemaking.

### *Renewable Energy Program*

In 1997, Senate Bill 90 (Sher), Chapter 905, Statutes of 1997, implemented provisions of AB 1890 and established the Energy Commission's Renewable Energy Program. The program provides a variety of incentives to renewable technologies. After AB 995 and SB 1194 extended the collection of the Public Goods Charge, Senate Bill 1038 (Sher), Chapter 515, Statutes of 2002, authorized the Energy Commission to administer the Renewable Energy Program from 2002 through 2006.

### *Renewables Portfolio Standard*

In 2002, Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002, established a Renewables Portfolio Standard (RPS) requiring retail sellers to add at least one percent of renewable energy to their supply resources per year in order to reach 20 percent by 2017, within certain cost constraints. Senate Bill 67 (Bowen), Chapter 731, Statutes of 2003, and Senate Bill 183 (Sher), Chapter 666, Statutes of 2003, revised RPS eligibility requirements for out-of-state renewable facilities. As stated in the *2003 Energy Action Plan* and *2003 Energy Report*, the state's energy agencies are working to accelerate the timetable to 20 percent by 2010.

Beyond 20 percent by 2010, the *2004 Energy Report Update* encouraged the state to embrace a longer-term goal of 33 percent renewable by 2020. This goal could also help further the Governor's plan to reduce greenhouse gas emissions, reaching 2000 levels of emissions by the year 2010, 1990 emission levels by 2020, and 80 percent below 1990 levels by 2050.[9]

The Energy Commission and the CPUC have a collaborative process to implement the RPS program for IOUs, electric service providers, and community choice aggregators. While the law sets clear tasks for each agency, the two agencies are working together closely to ensure smooth coordination of various aspects of the program. Locally elected boards oversee publicly owned utilities and implementation of their RPS programs.

### *Governor's Solar Initiative*

In August 2004, Governor Schwarzenegger announced a plan to encourage installation of solar panels on one million new homes over the next 13 years. The Energy Commission and the CPUC are working collaboratively to support a California Solar Initiative to the maximum extent under existing authority, through the CPUC's Distributed Generation Rulemaking 04-03-017. Appendix B contains a progress summary as of June 2005.

### *Distributed Generation*

The Energy Commission and the CPUC have addressed DG policy issues since 1998. Major policy decisions were adopted in 2002. In 2003, the CPUC issued Decision 03-04-030 outlining a mechanism for exempting certain DG customers from paying power surcharges known as "exit fees" or "cost responsibility surcharges." In response to this CPUC decision, the Energy Commission implemented an exemption approval process and tracking system so that the public can monitor the number of available exemptions.

In March 2004, the CPUC opened Rulemaking 04-03-017 to take a broader look at potential DG deployment. This rulemaking is designed to produce decisions representing existing economic, technical, and environmental conditions associated with DG deployment. Topics for the rulemaking include: cost-benefit analyses for customer and investor-owned utility installations, DG as a utility procurement resource, future incentives for customer-side DG, outstanding interconnection and related technical issues, and DG issues for the future.

The Energy Commission is concurrently investigating the costs and benefits of DG deployment, interconnection related issues, and research and development efforts related to the technical, economic and regulatory feasibility of future DG technologies.[10] The results of this investigation will assist the CPUC in its rule changes as well as contribute to the Energy Commission's planning process.

Other state and local agencies have active programs to support renewable and non-renewable DG technologies. For example, the Energy Commission provides support to small distributed grid-connected renewable systems through its Renewable Energy Program. The CPUC's Self-Generation Incentive Program supports a broad range of DG technologies (both renewable and non-renewable), while the Sacramento Municipal Utility District supports grid-connected photovoltaic DG systems. A number of other municipal utilities also have rebate programs for photovoltaic DG systems.

# Chapter 1 Endnotes

[3] State of California, 2003, *Energy Action Plan*. California Power Authority, California Energy Commission, and California Public Utilities Commission.
[4] Decision 03-12-060, CPUC Energy Efficiency Rulemaking 01-08-028.
[5] The CPUC approved the utilities' procurement funded programs together with their PGC-funded programs in Decision 03-012-060.
[6] California Energy Commission, April 2005, *2005 Appliance Efficiency Regulations*, CEC-400-2005-012.
[7] CPUC, Decision 03-06-032, p. 3.
[8] CPUC, Decision 03-06-032 in Rulemaking R.02-06-001, *the Interim Opinion in Phase 1 Addressing Demand Response Goals and Adopting Tariffs and Programs for Large Customers*, filed June 2003.
[9] California Office of the Governor, June 1, 2005, "Governor's Remarks at World Environment Day Conference, Wednesday, 06/01/2005 03:00 pm, [http://www.governor.ca.gov/state/govsite/gov_pressroom_main.jsp], accessed July 11, 2005.
[10] California Energy Commission, April 23, 2004, Order to Institute Investigation, Docket 04-DIST-GEN-1.

# CHAPTER 2: CURRENT EFFORTS TO SUPPORT LOADING ORDER RESOURCES

This chapter provides a brief background on current efforts at the Energy Commission, the California Public Utilities Commission (CPUC), and other agencies to support energy efficiency, demand response, renewables, and distributed generation.

## Energy Efficiency

Every day, California homeowners, factory managers, farmers, business people, and building operators make millions of decisions that greatly affect energy demand, but they rarely make those decisions from the perspective of energy efficiency. Instead, Californians are concerned about cooling their homes and producing goods or offering services. Energy efficiency and conservation programs can reduce the California economy's energy dependence, make businesses more competitive, and allow consumers to save money and live more comfortably. These programs also play major roles in increasing reliability of the electricity system and reducing the cost of meeting peak demand during periods of high temperatures and/or high prices.

Appendix D provides a summary of California's current public benefit efficiency programs. These do not include the state's appliance and building efficiency standards.

### *Historic Energy Efficiency Efforts and Impacts*

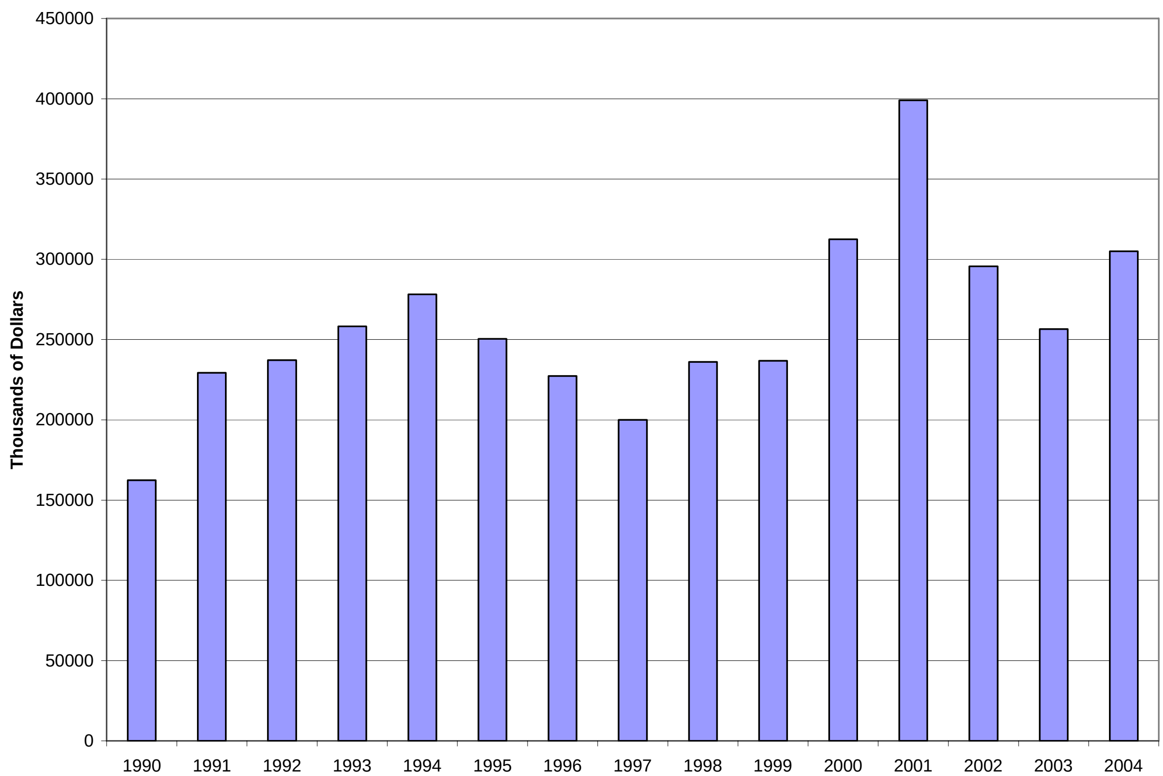
By law, every utility customer pays a small Public Goods Charge (PGC) to support public programs for energy efficiency, low-income services, renewable energy, and public interest research and development. A natural gas surcharge provides similar support on the gas side. As of 2004, investor-owned utilities are authorized to augment efficiency programs with procurement rate-based funding.

#### Expenditures

Expenditures for utility energy efficiency programs are governed by changes in both fuel prices and state energy policy emphases. Figures 1 and 2 show spending for electricity and natural gas from 1990-2004.[11] Spending by investor-owned utilities (IOUs), publicly owned utilities (POUs), and public agencies is included, with approximately 80 percent attributable to IOUs.

Over the last decade, three policy shifts affected spending on energy efficiency.[12] Until the mid-1990s, energy efficiency and other demand-side management activities were recognized as "viable cost effective alternatives to supply-side energy generation projects."[13] With restructuring, however, the energy efficiency focus shifted to market transformation activities that supported customer ability to make more informed choices about energy-using equipment and services. In 2001, increasing concern over wholesale electric prices and reliability prompted a return to resource acquisition programs that could reduce electricity consumption and achieve peak load benefits.

## Figure 1. Electricity Efficiency Program Expenditure Trends



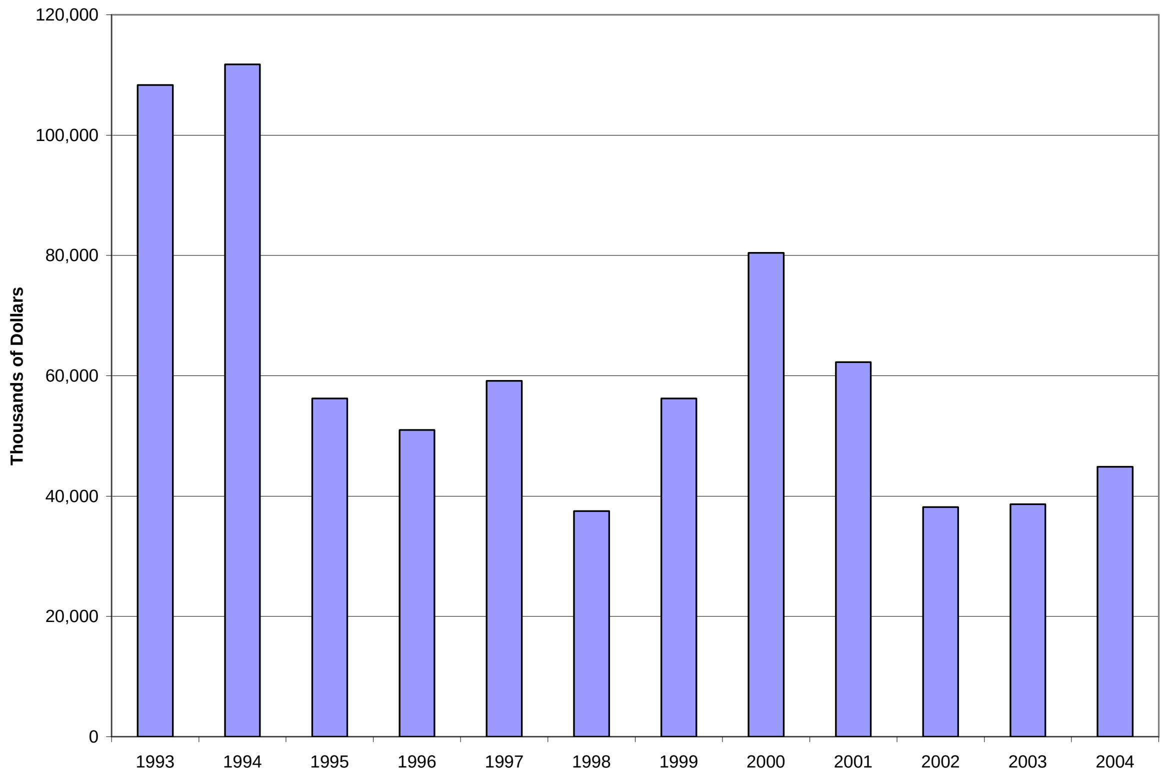

Source: California Energy Commission DSM history files derived from utility annual reports to the CPUC and Energy Information Administration, independent evaluations for municipal utility programs, and other sources. Nominal $.

Figure 1 illustrates historic trends in program spending. Spending generally increases for five to seven years, and decreases for two to three years before beginning a new upward cycle in association with policy and energy price influences. However, average annual spending on electric efficiency programs from 1990-2004 shows an upward trend of more than 20 percent.

Spending on natural gas efficiency programs shows similar ebbs and flows, due both to changes in perception about forward gas prices and shifts in state policy. The highest spending peak occurred in 1985, followed by a smaller wave of spending increases during the first half of the 1990s. Dramatic increases in natural gas prices beginning in 2003, coupled with concerns about inadequate production, led the

CPUC to authorize an additional $19.8 million in funding for 2005 natural gas efficiency programs.[14]

## Figure 2. Natural Gas Efficiency Program Expenditure Trends



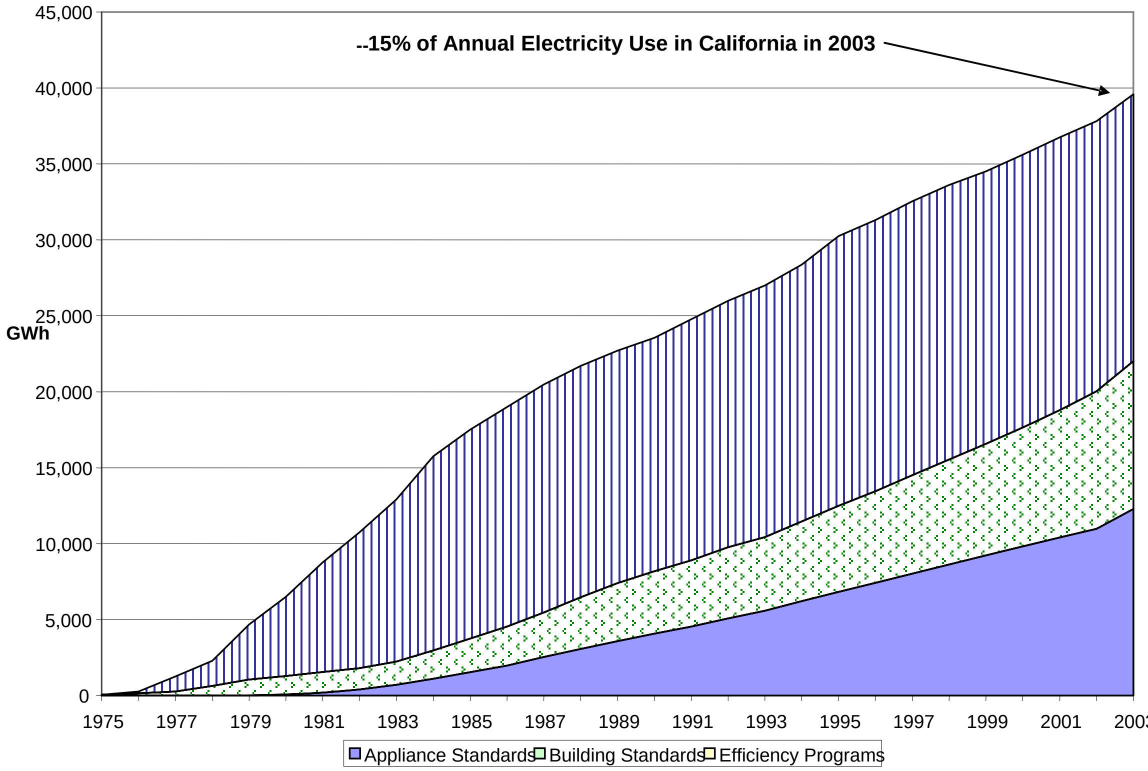

Source: California Energy Commission DSM history file. Nominal $.

For 2004 and subsequent years, the state's *Energy Action Plan (EAP)* guides the CPUC's regulatory policies for energy efficiency. The *EAP* identifies specific goals and actions to eliminate energy outages and excessive spikes in electricity and natural gas prices in California.

### Savings

As shown in Figure 3, the cumulative savings through 2003 from all of California's electricity efficiency programs, including building and appliance standards, are more than 40,000 gigawatt hours (GWh) and 12,000 megawatts (MW). The amount of energy saved as of 2003 is equivalent to 15 percent of the electricity used in California in that year. Without these savings, the state would have needed an additional twenty-four 500-MW power plants.

## Figure 3. Cumulative Efficiency Savings




Source: Energy Commission DSM forecast model output

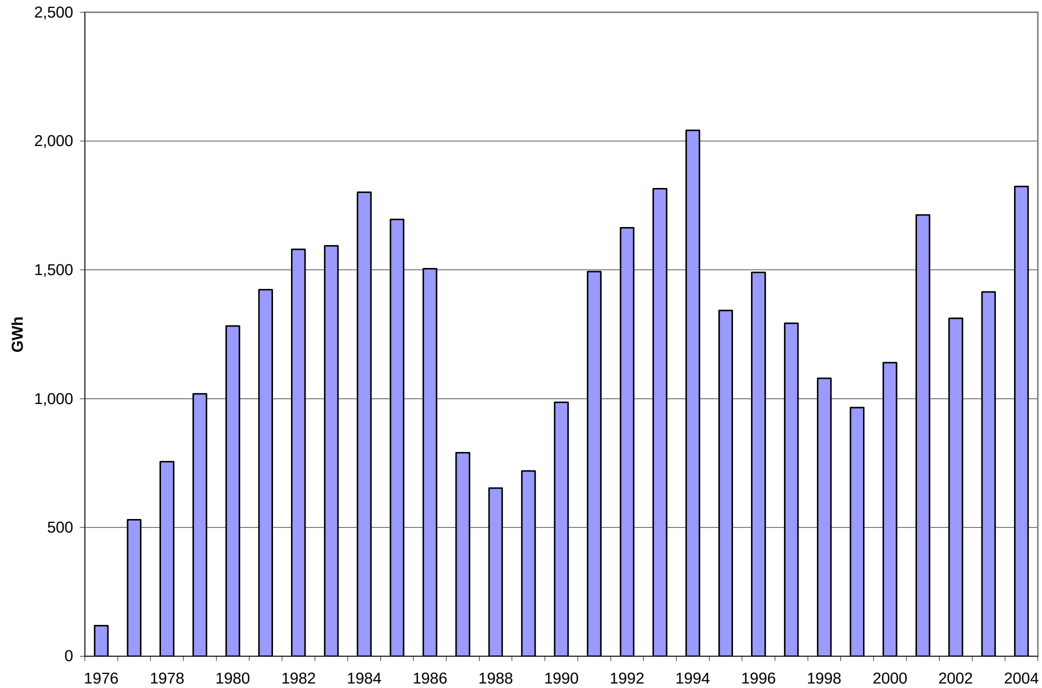
Figures 4 and 5 show the annual energy and peak demand savings from efficiency programs implemented by IOUs, municipal utilities, and other public agencies. With the exception of the 2000-2001 energy crisis period, most of the savings reported are attributable to IOUs. Building and appliance standards savings are not included in these charts.

The pattern of first-year electricity savings (shown in Figure 5) shows the result of dramatic funding increases for IOUs, municipal utilities, public agencies, and other local government or non-profit organizations for peak demand reduction during the energy crisis. As expenditures returned to more normal levels, so have energy savings.

Several lessons are evident in these patterns[15] that are useful in considering post-2005 efficiency program spending plans:

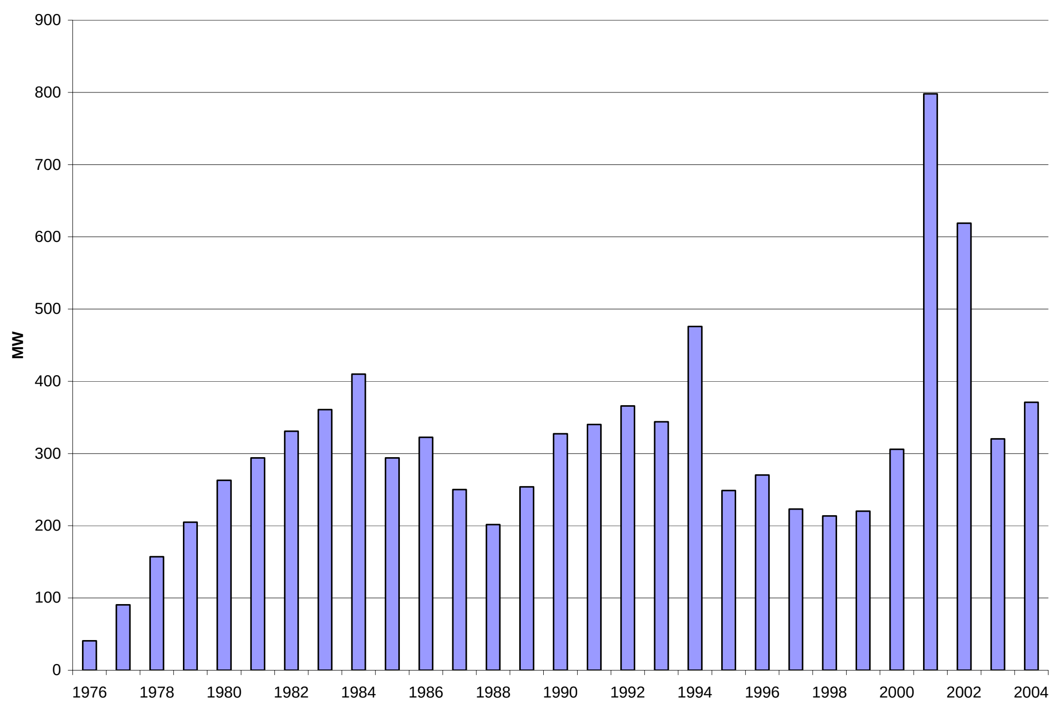
- Doubling or tripling of spending is typically spread over three to four years.
- Program administrators typically do not spend all authorized funds in ramp-up periods. Spending averaged 85 percent of the authorized level across the period.

## Figure 4. Annual Energy Savings from Efficiency Programs




Source:  California Energy Commission DSM history files

## Figure 5. Annual Peak Savings from Efficiency Programs




Source:  California Energy Commission DSM history files

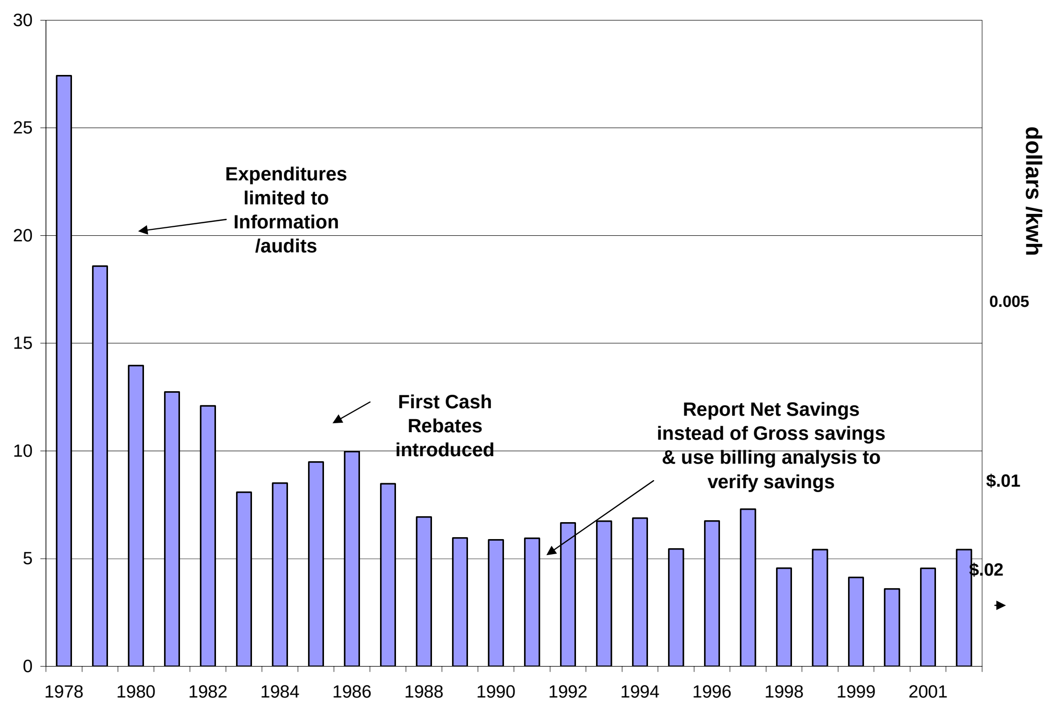
- The maximum increase in funding over a five-year period is in the range of 25-33 percent per year.
- Savings typically lag spending during ramp-up periods.
- With the exception of the energy crisis, annual first year energy and peak savings have never exceeded 2,000 GWh and 700 MW.

### Effectiveness

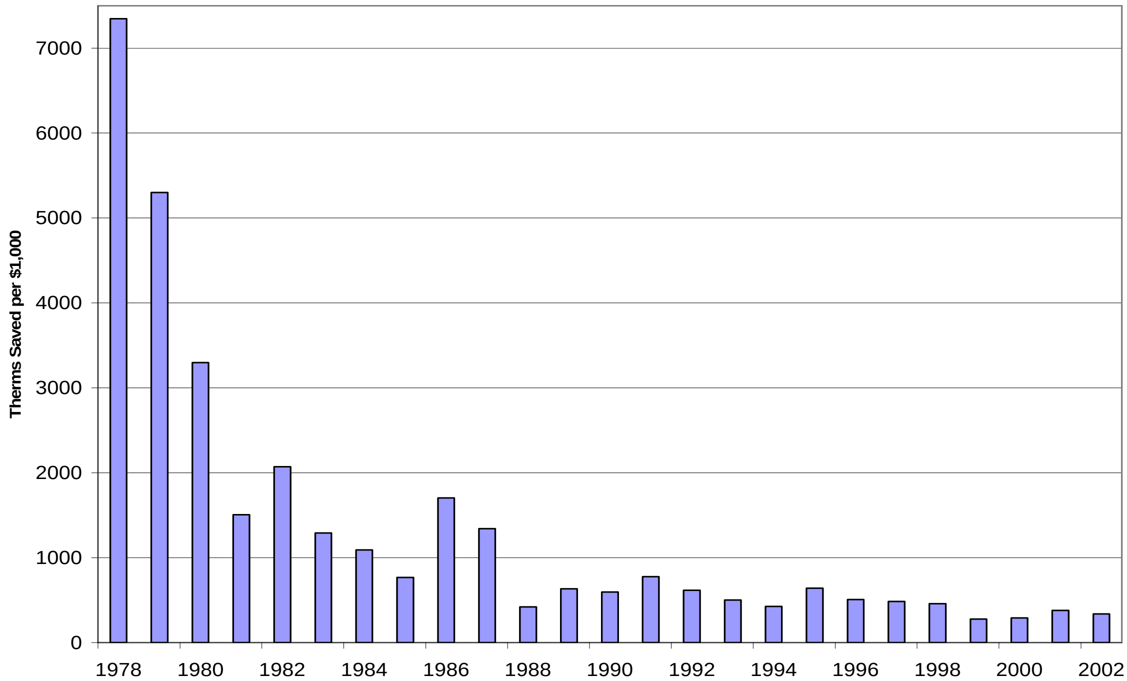
In considering energy efficiency as an alternative to supply resources, it is more important to analyze overall historic trends in program effectiveness than individual cycles in expenditures and savings. Program cost effectiveness is measured by energy savings for each dollar spent.

The *2003 Energy Report* proposed setting program goals for IOU energy efficiency savings. Beginning in late 2003, the staffs of the Energy Commission and the CPUC's Energy Division (Joint Staff) reviewed program trends to assess the feasibility of ramping up energy efficiency programs over the next decade to "bend down the curve" of per capita energy consumption, as directed by the *EAP*.[16] Figures 6 and 7 illustrate the results of the analysis of historical effectiveness of utility and public agency electric and natural gas programs.

## Figure 6. Electric Efficiency Program Effectiveness



## Figure 7. Natural Gas Efficiency Program Effectiveness




Based on these analyses, the Joint Staff recommended that the state adopt energy savings goals for both electricity and natural gas. Chapter 3 contains further information on the CPUC's adoption of both statewide and individual utility goals for 2004-2013.

Figure 6 shows megawatt-hours (MWh) saved per $1,000 of spending (in 2002 real dollars to remove the effects of inflation). The data includes program cost, including cash rebates, and electricity savings data as reported by the IOU and major municipal utility programs, along with reported savings from state agency programs in 2001 and 2002.

Since 1998, the long downward slide in electricity saved per dollar spent appears to have stabilized at an average of 4.75 kWh per dollar, or $0.021 per kWh on a levelized basis.[17] During the energy crisis, program effectiveness actually increased to 5 kWh per program dollar in 2001 and 2002 because of the infusion of additional funding and increased public receptivity to energy investments.[18]

Natural gas program effectiveness follows a similar pattern to electricity programs. The downward trend in natural gas program effectiveness resulted from factors similar to electric program factors. These factors include:

- Rebate programs decrease the yield or kWh per dollar spent.
- Periodic strengthening of the standards makes measures once promoted in programs mandatory.

- Changes in program accounting rules and the mix of program types, plus more stringent performance metrics, push the yield downward.

As shown in Figure 7, natural gas program effectiveness stabilized during the last decade at 387 therms/$1000 or $0.29/therm on a levelized basis. This compares with the most recent forecast of natural gas avoided costs at the wholesale level of $0.050/therm and the levelized cost of $0.67 at the retail level.[19]

**Publicly Owned Utilities**

POUs provide between 20-25 percent of the electricity consumed in California. POUs typically offer programs across all market sectors using information, audits, rebates and financing to promote energy efficiency technologies. Renewable energy, low-income, and research and development programs are also available. Appendix E shows a variety of residential and nonresidential programs from more than two dozen POUs.

Investment in public benefit programs by POUs is based on a legislatively mandated formula. Without publicly available data sources, it is difficult to determine how much POUs spend on efficiency or how much energy they save. The Energy Commission is pursuing ways to gather additional information on the efficiency investments made by these programs. In filings made for the 2006-2016 demand forecast, POUs reported spending $24.6 million on energy efficiency programs in 2004. The first year savings were 84 GWh and 38 MW.[20] Though the state has adopted savings goals for IOUs, POUs are not required to contribute to those goals. The Energy Commission is working to quantify individual POU goals that would contribute another 15 percent to energy and peak demand reductions.

**California's Building and Appliance Standards**

Building and appliance standards enhance the effects of efficiency programs, as well as provide substantial savings on their own, by incorporating energy efficiency measures into long-term, sustainable savings for all market sectors. The Energy Commission is responsible for establishing building and appliance standards for California.

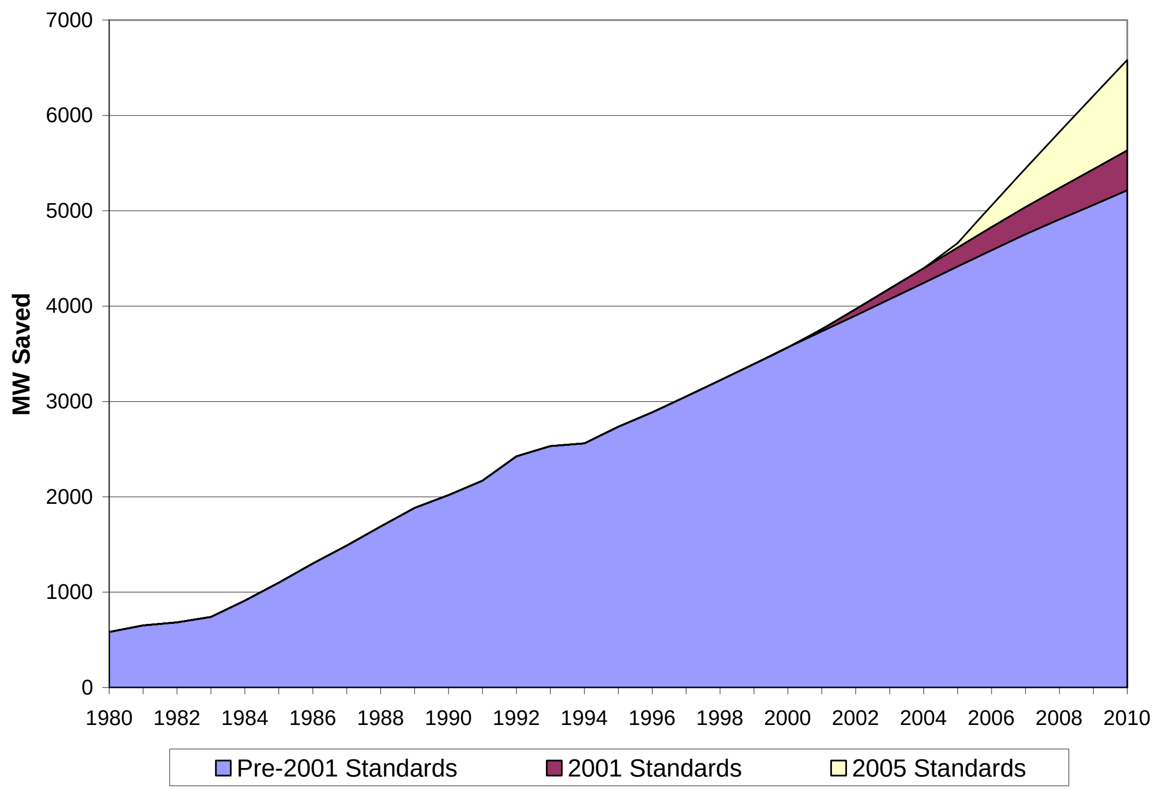
Since 2003, there have been major changes to the standards. The 2005 Building Energy Efficiency Standards (Title 24, Part 6) adopted new requirements for both existing and new residential and non-residential buildings. These 2005 changes were adopted for the following reasons:

- To reduce energy bills, increase energy delivery system reliability, and contribute to improved economic conditions for the state.
- To respond to the Senate Bill 5X (Sher), Chapter 7, Statutes of 2001, urgency legislation to adopt energy efficiency standards for outdoor lighting.

- To emphasize measures that save energy at peak periods and seasons, improve the quality of installation of energy efficiency measures, and incorporate recent publicly funded building science research.

Figure 8 shows estimated savings from the latest Building Standards updates. The Energy Commission expects that each year the proposed standards are used will reduce growth in electricity demand by 479 GWh, reduce growth in peak demand by 182 MW, and reduce natural gas use by 8.9 million therms annually. Newly constructed buildings (including outdoor lighting) account for about 55 percent of the electricity savings, 61 percent of the demand savings, and 68 percent of the gas savings. Alterations to existing buildings account for the remaining savings.

## Figure 8. Estimated Peak Savings from Building Standards




Source: Energy Commission DSM forecast model output

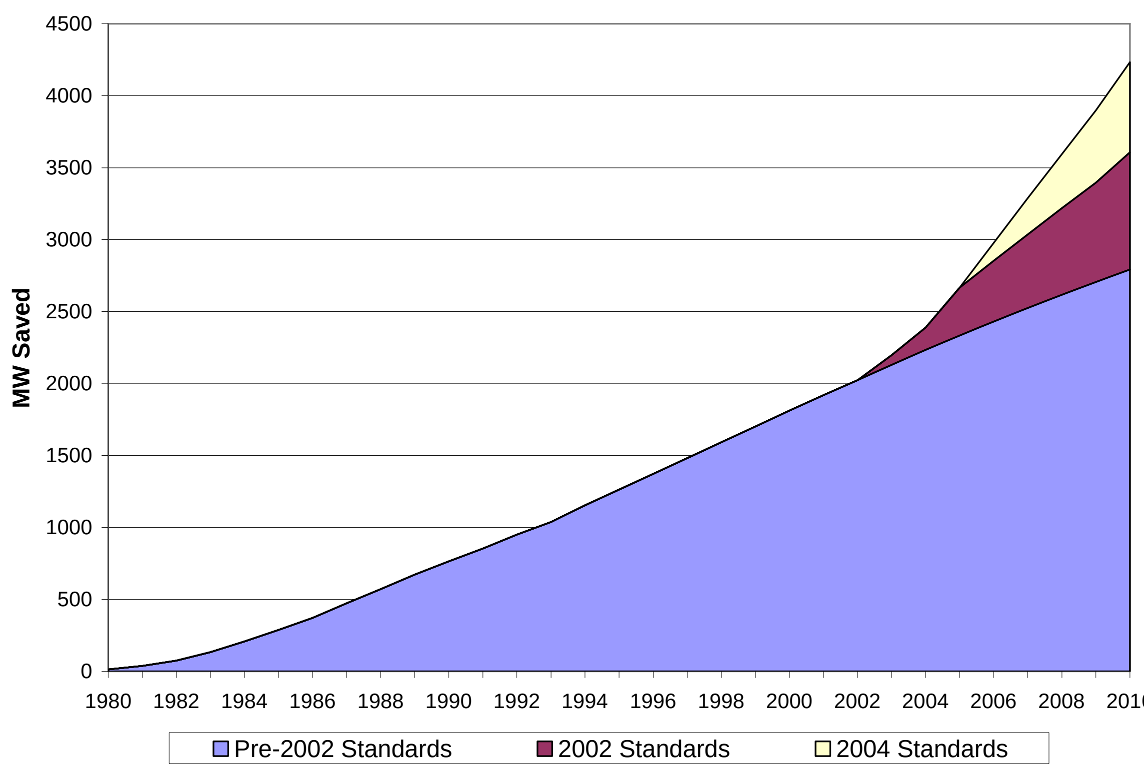
Nonresidential new construction and alterations produce most of the electricity savings. Peak demand savings are concentrated in both residential and nonresidential new construction. Gas savings are largely in residential new construction and alterations.

Utility programs will be extremely important to help extend the reach of the standards to existing building alterations because building departments often do not require building permits for such alterations. If the utilities do not provide programs to motivate customers who are making alterations to their homes, statewide savings from energy efficiency standards for these alterations (for example, duct sealing when residential air conditioners are replaced) would be at most 25 percent of total possible savings. Chapter 3 contains further discussion on the interaction between the building standards and utility efficiency programs and goals.

The Energy Commission is also responsible for setting Appliance Efficiency Standards so that all appliances sold in California meet a minimum threshold of efficiency. California law requires the Appliance Efficiency Standards to (1) apply to applications using a significant amount of energy on a state-wide basis, (2) be based on feasible and attainable efficiencies, and (3) be cost effective to consumers based on a reasonable use pattern over the design life of the appliances.

The 2004 rulemaking adopted new efficiency standards for 19 types of appliances, offering significant savings to the state. Projected annual savings for businesses are $116 million with residential customers saving $141 million. The increased cost of appliances is more than made up by lower electricity and natural gas bills. During the first 15 years they are in effect, the proposed appliance standards are expected to increase purchase costs by $1.4 billion and lower utility bills by $3.3 billion. Figure 9 shows estimated peak savings from the Appliance Standards updates.

## Figure 9. Estimated Peak Savings from Appliance Standards




Source: Energy Commission DSM forecast model output

The following types of appliances represent some of the largest energy and peak savings in the 2004 Appliance Efficiency Standards:

- Two-speed motor residential pool pumps.
- Incandescent lamps and reflector lights that are not federally regulated.
- Luminaires for metal halide lamps.
- External power supplies.
- Audio and video consumer electronics.

The Appliance Efficiency Standards are also closely connected to utility incentive programs. Chapter 3 discusses the implications of the new standards for utility programs and the statewide goals.

## *Potential for Additional Efficiency*

Future potential savings from commercially available technologies are far from exhausted. For a variety of reasons, energy-efficient equipment is not always purchased despite its cost effectiveness. These reasons include little knowledge of the product, uncertainty over equipment performance, or higher initial cost compared to less-efficient models. Certain customer segments also pose more difficult marketing challenges for utility and state efficiency programs than others.

The Energy Foundation's 2002 report, *California's Secret Energy Surplus,*[21] focused on identifying the remaining economic potential for energy efficiency programs; in other words, savings that could be achieved at a cost less than or equal to the projected cost of supply alternatives. The Energy Foundation's report and its underlying technical reports were the foundation for the Energy Commission's recommended savings goals for 2004-2013 contained in the *2003 Energy Report*. Several shortcomings in the study, however, could potentially bias any estimate of savings.[22]

In 2004, the CPUC authorized an update to the 2002 study intended to support development of the Energy Commission's *2005 Energy Report,* among other policy objectives. Key activities for this update include creating estimates for emerging technologies and disaggregating statewide potential by climate zones. Unfortunately, the study has been delayed due to technical difficulties, and no data have been made available to the Energy Commission. As a result, IOU planning for the 2006-2008 program cycle is based upon 2002 data. The lack of data from this study is significant because the 2006-2008 program cycle is the first using the CPUC's efficiency goals as a target. The update was specifically intended to help develop program designs for 2006-2008 and inform revisions to post-2008 goals.

## Demand Response

In this paper, demand response generally refers to customer load reductions in response to price signals or directions from distribution utilities, energy marketers, or system operators. Dynamic pricing, demand-bidding programs, voluntary demand response programs, emergency load curtailment programs, and direct load control are all forms of demand response. The paper focuses on price responsive programs rather than load control and interruptible service programs that have characterized demand response in the past.

In most markets, demand response happens naturally because customers respond to prices by buying less of a product or substituting an alternative when prices are high. In electricity markets in California, however, most electricity customers pay rates that do not vary by time of day but by volume of monthly consumption; the more electricity consumed, the higher the marginal price. Although there is an incentive to reduce total consumption, there is no incentive to reduce load during times when costly peaking power is brought online.

Even large customers required to take service on static time-of-use rates are charged “average” on-peak rates that do not vary with system conditions. They provide no incentive to reduce load during the few critical hours each year when high demand strains capacity and system stability is at risk. The Energy Commission’s and CPUC’s demand response activities encourage adoption of rate options allowing customers to either lower their costs by reducing load under wholesale price or system conditions, or maintaining consumption levels but assuming their fair share of the cost to both the system and other ratepayers.

Recent demand response activities in California include:

- Evaluation of the impact of the Assembly Bill 29X (Kehoe), Chapter 9, Statutes of 2001, meter installation program shows that customers moving to time-of-use (TOU) rates significantly lower their on-peak usage through a combination of load-shifting and conservation.
- In December 2004, the CPUC included price-based demand response targets for IOUs in the IOU procurement planning process (see Table E-2).
- The 2003 *Energy Report* calls for rapid deployment of advanced metering systems “if analyses show the results are favorable to the customer and will effectively decrease peak electricity use,”[23] and recommends “continued collaborative assessment with the CPUC to gain a more complete understanding of the extent to which dynamic pricing is appropriate for various types of customers.”[24] Substantial progress has been made on both recommendations and is discussed further in Chapter 4.
- Beginning in 2003, IOUs began offering voluntary demand response programs and tariffs to customers with advanced meters and with demand greater than

200 kW. Implementation of these tariffs has been accompanied by an ongoing evaluation providing both performance impact and feedback on design.

- The CPUC has directed California's IOUs to develop plans for implementing a default Critical Peak Pricing tariff for large customers (customers with demand greater than 200 kW) by summer 2006.
- A Statewide Pricing Pilot for customers with demand less than 200 kW has demonstrated that time-based rates can significantly reduce peak demand. The pilot also showed that customers almost universally prefer these rates to existing rate structures and believe they should be offered to all customers.
- Pacific Gas and Electric Company and San Diego Gas and Electric Company have filed proposals with the CPUC to deploy advanced meters to all their customers over the next few years. Southern California Edison has filed a plan for developing an advanced metering infrastructure system that will meet the specific needs of its service territory for implementation beginning in three to five years.

## Renewables

Renewable energy can promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels. Renewable energy is defined as the use of eligible renewable resources to generate grid-connected electricity for use in California. Renewable resources include: biomass, digester gas, fuel cells using renewable fuels, geothermal, landfill gas, ocean thermal, ocean wave, photovoltaic, small hydroelectric generation, solar thermal electric, tidal current energy systems, and wind.

This section provides a brief history of renewable energy programs in California and describes (1) efforts to implement the state's Renewables Portfolio Standard (RPS), (2) incentives to support distributed generation photovoltaics, and (3) technical potential for renewables.

### *Historical Renewable Energy Efforts and Impacts*

Over the past two decades, California has developed one of the largest and most diverse renewable generation mixes in the world. Much of California's renewable development arose from the federal Public Utility Regulatory Policies Act of 1978 (PURPA), which required utilities to purchase power from non-utility generators, including renewable generators, at the utilities' full avoided cost.

California implemented PURPA through "standard offer" contracts between utilities and non-utility generators. These contracts added about 5,000 MW of renewable capacity to California's electricity system between 1985 and 1990. The overwhelming response to these standard offer contracts led to their suspension in 1985-1986.

In the early 1990s, renewable energy generation in California declined, due primarily to low energy prices, the end of high fixed-energy price periods for many standard offer contracts, and the end of tax credits to stimulate development. To reverse this decline, in 1996 the Legislature included Public Goods Charge (PGC) renewables funding in its electricity restructuring bill, Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996.

In 1998, Senate Bill 90 (Sher), Chapter 905, Statutes of 1997, established the Energy Commission's Renewable Energy Program, funded by the PGC, to improve the competitiveness of eligible existing, new, and emerging renewable technologies. Since the program was established, it has supported 4,000 MW of existing renewable capacity, helped bring 429 MW of new renewable capacity on-line, and supported installation of more than 47 MW of grid-connected distributed generation in the state, mostly photovoltaics.[25] In 2004, about 29,000 GWh of renewable energy were generated in California, representing 10.6 percent of total in-state generation and imports.[26]

### *Renewables Portfolio Standard*

After California's energy crisis of 2000-2001, the Legislature passed Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002, in order to secure the benefits of renewable energy and establish the RPS.

California's RPS requires retail sellers to add at least one percent per year of renewable energy to their electricity supply mix. By 2017, at least 20 percent of the electricity the suppliers provide is to come from renewable resources. Lead decision-making authority for the RPS program is divided between the CPUC, the Energy Commission, and POUs. The CPUC and the Energy Commission are working collaboratively to implement the RPS program for IOUs, electric service providers (ESPs), and community choice aggregators (CCAs). Within that collaborative process, the Energy Commission retains lead authority over RPS eligibility, certification, supplemental energy payments, and an RPS accounting system. The CPUC has lead authority over baseline and procurement targets, flexible compliance and penalties, standard contract terms and conditions, market price referents, least-cost-best-fit criteria for IOU bid evaluation, and approval of IOU renewable procurement plans and contracts.

Several outstanding issues associated with California's RPS program include the use of renewable energy certificates for RPS compliance, requirements for deliverability of renewable energy, rules for ESP and CCA compliance, and rules for counting renewable distributed generation in the RPS.

## Renewable Energy Certificates

An important issue that could affect retail sellers' ability to meet RPS goals is the ability to sell the "greenness" of renewable energy through unbundled renewable energy certificates (RECs). California's RPS program currently does not allow the IOUs to procure unbundled RECs to meet their RPS obligations. Under a number of RPS programs in other states, however, the renewable attributes of each megawatt hour (MWh) of electricity can be sold separately from the electricity itself. Moreover, every state with competitive ESPs with the exception of California allows the use of unbundled RECs for RPS compliance, although some states require delivery into the state before the RECs are unbundled.

California has significant transmission congestion and constraints. Allowing the use of unbundled RECs to count towards the RPS could provide greater flexibility in the timing, placement, and amount of new transmission needed to support renewable development between utility service territories. This policy, however, would not eliminate the need for transmission infrastructure to access in-state renewable energy and meet RPS targets.

Potential disadvantages to counting unbundled RECs toward RPS compliance include reducing the benefits of renewable energy as a "hedge" against fossil fuel price fluctuations and potentially opening up market manipulation. Unbundled RECs from outside the state could also reduce the in-state environmental and economic development benefits of the RPS. Lower RPS compliance costs resulting from unbundled RECs could offset these potential disadvantages to some degree. The CPUC and Energy Commission continue to investigate advantages, disadvantages, and available safeguards of allowing retail sellers to use unbundled RECs to meet RPS obligations.

The Energy Commission is working with other agencies in the Western Electricity Coordinating Council (WECC) to develop a REC-based tracking system known as the Western Renewable Generation Information System (WREGIS). The Western Governors' Association, the Western Regional Air Partnership, and the Energy Commission are sponsoring WREGIS. They are designing WREGIS to track RECs, which include all environmental attributes but not associated electricity or financial transactions. As discussed in Chapter 5, electricity delivery will be tracked outside of the WREGIS.

The unbundled REC market is relatively new, and the ownership and disposition of RECs under existing "qualifying facility" (QF) contracts is still unsettled due to litigation stemming from a declaratory order issued by Federal Energy Regulatory Commission (FERC) in October 2003. Under that order the FERC found that 1) in the absence of express contract provisions, QF contracts do not convey the renewable attributes associated with generation to the purchasing utility, and 2) that the ownership of such renewable attributes is a matter of state law. Xcel Energy Services, a Colorado utility, appealed the FERC order in 2004 to the U.S. Court of

Appeals for the District of Columbia Circuit arguing that QF contracts under federal law do convey the renewable attributes associated with generation to the purchasing utility.[27] On May 17, 2005, the U.S. Court of Appeals ruled that it could not consider the merits of the case unless it was filed as an "enforcement action" and appealed.[28]

The CPUC has not specifically ruled yet on issues relating to QF RECs, though IOUs are currently counting renewable energy from these contracts as eligible under the RPS. One pending topic in the CPUC's RPS rulemaking (R.04-04-026), therefore, is how to treat QF RECs when existing contracts are silent on the issue. In December 2004, CPUC President Peevey included this topic in the scope for Phase II of the RPS proceeding.[29] The CPUC has received comments and reply comments on Phase II issues from twelve stakeholders with widely varying views.[30] As of June 2005, the CPUC has not yet issued a draft decision.

To address this issue for future contracts, the CPUC now requires IOU Requests for Offers to include specific contract terms and conditions that clearly define RECs and require renewable sellers to transfer REC ownership to the IOU along with the electricity generated.

**Rules for Electric Service Providers and Community Choice Aggregators**

The CPUC is considering RPS compliance rules for ESPs and CCAs as part of its Phase II RPS proceeding. As of June 2005, the CPUC had not yet established a schedule for developing rules for ESPs and CCAs, considering it of lesser priority than approval of the IOUs' 2005 renewable RFOs.

**Renewable Distributed Generation in the RPS**

CPUC Decision 05-05-011 clarified the RPS rules for renewable distributed generation (DG). The CPUC decided that utilities should treat eligible renewable DG facilities the same as other types of renewable generation, to the extent feasible. In addition, the owner of a renewable DG facility owns the RECs associated with generation from that facility, but the only RECs that can be counted for the RPS are those from facilities installed after October 24, 2002. RECs from DG facilities, however, cannot be counted toward the RPS until issues relating to subsidies and measurement are resolved through the CPUC's DG rulemaking (R.04-03-017).[31]

## *Distributed Generation Photovoltaics*

Since 1998, the Energy Commission has provided rebates for systems under 30 kW that use DG emerging renewable technologies, particularly photovoltaic energy (PV). The Energy Commission also provides performance-based incentives for DG PV systems of up to $400,000 through a pilot program launched earlier this year. CPUC's Self Generation Incentive Program, launched in 2001, offers rebates to PV 30 kW and larger, and other DG systems up to five megawatts (MW), although only the first one MW of the five-MW system is eligible for support. POUs also have incentive programs for DG PV energy, including the Sacramento Municipal Utility District which has supported PV since 1984. [32]

California is a leader in the United States in installing PV, but the state lags behind Japan and Germany which are world leaders. The reported amount of distributed PV installed in Japan as of 2004 ranges from approximately 900-1000 MW. Germany has installed approximately 700-750 MW as of 2004.[33]

In 2004, Governor Schwarzenegger announced an initiative to install a million solar roofs in California over the next 13 years.[34] To meet the Governor's target, total installed grid-connected DG PV in California would need to reach 3,000 MW over the next 13 years. To put this in perspective, the CA ISO peak demand in 2004 was about 45,600 MW.

Beyond programs that are currently in operation related to DG renewable energy, the Energy Commission and the CPUC are working together to develop a proposal for the Governor's Solar Roofs Initiative in CPUC R.04-03-017.[35] Appendix B contains a summary of the progress achieved as of June 2005.

## *Renewables Technical Potential*

In April 2005, the Energy Commission's Public Interest Energy Research (PIER) Renewables Program published draft resource assessments for geothermal, solar, wind, biomass, small hydropower and ocean wave energy resources in California.[36] Assessments of economic resources were published in June 2005 in support of the PIER Renewables Strategic Value Analysis (SVA), summarized later in this paper.

Table 1 shows the estimates of in-state renewable technical and economic potential published in support of the SVA.[37] Based on these estimates, renewable technical and economic potential in California is large enough to meet the state's RPS goals. However, there are many issues that will constrain development of these resources, as discussed in Chapter 5.

The estimates in Table 1 are updates of those in the Energy Commission's *2003 Renewable Resources Development Report* (RRDR).[38] The RRDR noted that out-of-state resources are also eligible to compete for RPS contracts within certain constraints, and that the technical potential for renewable energy in the Western Electricity Coordinating Council (WECC) is many times what is available within California.

## *Renewables Development Scenarios*

The RRDR estimates of technical potential formed the basis for a renewable energy deployment scenario to meet 20 percent renewable by 2017 statewide and a scenario to meet 20 percent by 2010 statewide with in-state resources. [39] The actual resource mix used to meet a statewide goal of 20 percent by 2010 and to remain constant at 20 percent through 2017, would be determined through competitive bidding. The accelerated scenario showed a total of 7,987 MW of in-state renewables added by 2017 beyond the 2001 estimated baseline (of which 6,445 MW [81 percent] were wind).

## Table 1. Estimates of California's Renewable Energy Technical and Economic Potential[40]

| Resource | Total Technical Potential (MW) | Installed MW (2003) | Undeveloped Potential (total minus installed) (MW) | Total 2010 Economic Potential (MW) |
|---|---|---|---|---|
| Biomass and Biogas | 10,700 | 930 | 9,770 | 228 |
| Geothermal | 4,732 | 1,870 | 2,862 | 1,214 |
| Ocean wave | 7,460 | N/A | 7,460 | N/A |
| Small hydro conduit | 255-278 + portion of small hydro impoundments & natural waterways | Included in small hydro impound-ments and natural water ways | 255-278 | N/A |
| Small hydro impoundments and natural water ways | 3,191 | 1,264 | 1,927 | N/A |
| Solar photovoltaic (DG) | 75,000 | 56 | 74,944 | 500 |
| Solar thermal | 1,061,361 | 350 | 1,061,011 | 1,046 |
| Wind (high speed) | 14,346 | 1,868 | 12,478 | 3,041 |
| Total | 1,108,584 | 6,338 | 1,102,246 | 6,029 |

Sources: *California Geothermal Resources-Staff Paper* (2005), *California Wind Resources-Draft Staff Paper* (2005), *California Solar Resources-Draft Staff Paper* (2005), *Biomass Resource Assessment in California-Draft Consultant Report* (2005); for these four papers see [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905]. Data on installed small hydro is from California Energy Commission, "California Power Plants Database," current as of July 1, 2004, [http://www.energy.ca.gov/database/index.html#powerplants]. Data for economic potential is from *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration, CEC-500-2005-106, June 2005;* see [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#070105].

In early 2005, the staff prepared a WECC-wide renewable development reference case. This reference case supported estimates of future natural gas demand being conducted by the Western Integrated Energy Board (WIEB). Table 2 shows the level of renewable energy development assumed for each of the Western states from utility-scale wind, geothermal, biomass, and solar resources.

The reference case projects 7,381 MW of renewable development in California by 2016, 4,800 MW (65 percent) of which would be wind.[41] The WECC-WIEB reference case assumes that 3,800 MW of wind will be developed south of Transmission Path 15 and 1,000 MW north of Path 15, the constrained transmission corridor linking

Northern and Southern California. This is a more conservative estimate of in-state wind development than the 6,445 MW of wind development included in the RRDR scenario.

**Table 2. WECC Renewable Reference Case 2005-2016 (Installed MW, Assuming Transmission Upgrades after 2010)** [42]

| State | Total (MW) | Wind Only (MW) |
|---|---:|---:|
| California | 7,381 | 4,800 |
| Arizona | 397 | 0 |
| Colorado | 1,199 | 1,006 |
| Idaho | 290 | 60 |
| Montana | 1,188 | 957 |
| New Mexico | 444 | 228 |
| Nevada | 1,224 | 338 |
| Oregon | 1,286 | 1,038 |
| Utah | 698 | 516 |
| Washington | 1,286 | 1,038 |
| Wyoming | 923 | 805 |
| Canada | 901 | 849 |
| Baja California, Mexico | 302 | 0 |
| **TOTAL** | **17,519** | **11,635** |

Source: Energy Commission staff estimate, 2005

Additional transmission lines will be needed to reach the level of renewable energy shown in Table 2 by 2016. There are at least four regional transmission study groups considering the possible export of renewable energy from different parts of the WECC to California.[43] To determine whether the current transmission system within California could accommodate these imports, a draft consultant study prepared for the Energy Commission analyzed the thermal constraints of the transmission grid. The draft study, published in April 2005, indicated that up to 220 MW of new renewable resources could be imported across all of the interconnections in aggregate limited by the California-Oregon Intertie under contingency conditions.[44]

## *Other Efforts Affecting Renewable Energy Development*

Several new efforts affecting central-station renewable energy development include the following:

- The FERC proceeding to consider new transmission products to better integrate intermittent resources.
- Southern California Edison Company's (SCE) concept of a new category of transmission lines called a "renewable trunk line." FERC denied SCE's proposal

for a Tehachapi trunk line on July 1, 2005, but parties have 30 days to file for a rehearing.

- Strategic transmission planning processes reported elsewhere in the *2005 Energy Report* proceeding.
- Analysis of IOU and statewide resource plans to identify to what extent expected electricity peak demand and energy requirements exceed resources under a variety of contingencies. This analysis is reported elsewhere in the *2005 Energy Report* proceeding and will be transmitted to the CPUC for use in its 2006 procurement cycle.[45]

These issues are discussed in more detail in Chapter 5.

## Distributed Generation

This section discusses utility interconnection, distribution planning, and procurement as they affect distributed generation technologies.

DG is the most strategic of the loading order's preferred resources because it can use a wide variety of fuels in a number of different applications. . When used in combined heat and power, DG is also a cost effective end-use efficiency strategy that has global climate change benefits. Despite these advantages, DG faces technology, regulatory, and business model challenges that affect its deployment into California's resource mix.

The CPUC and the Energy Commission have collaborated on DG issues since the CPUC's initial distributed generation rulemaking was opened in 1999.[46] This collaboration has been successful in removing several barriers to implementation of DG in California.

The most important achievement is the development of a revised Rule 21, a standardized interconnection rule for IOUs.[47] This revised rule is being voluntarily adopted by other California ESPs such as municipal utilities and irrigation districts. Another important accomplishment is the development and implementation of cost responsibility surcharge (CRS) regulations exempting departing load from paying exit fees.[48] Finally, market transformation incentive programs are increasing the number of customers using DG technologies. These programs include the CPUC's Self Generation Incentive Program and the Energy Commission's Emerging Renewables Program, among others.[49]

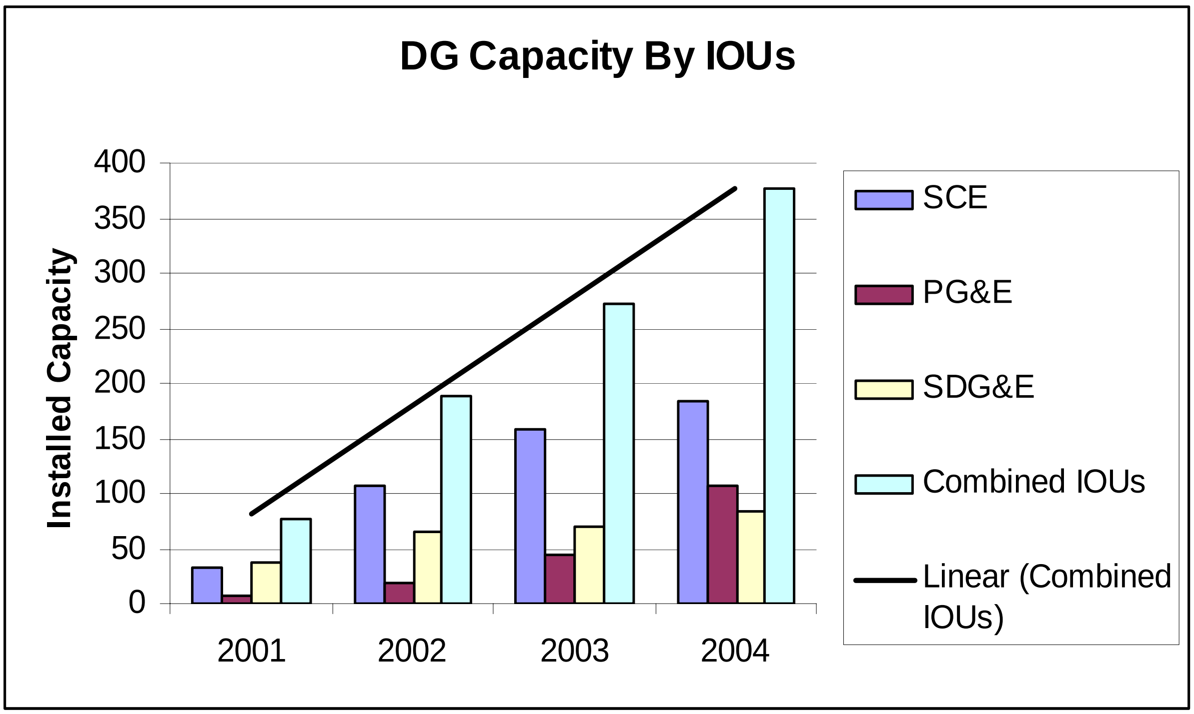
### *Utility Interconnection*

California's revised Rule 21 governs the process, schedule and fees associated with interconnecting DG customers to utility power systems. A standardized interconnection rule eliminates a major barrier to the safe and cost effective deployment of DG in California.

Since revising Rule 21 in 2000, California has significantly increased its DG capacity. IOU interconnection reporting since 2001 shows increases in DG capacity ranging from 1.2 to 4.2 megawatts (MW) per month, with cumulative installed capacity of approximately 500 MW interconnected through the revised interconnection rule.[50] There are approximately 2,500 MW installed in California today.

Figure 10 shows the growth trend in capacity for each of the IOUs. This data does not include renewable DG, which is typically able to interconnect under net metering tariffs.

**Figure 10. DG Interconnected to California IOUs**




The Energy Commission facilitates the Rule 21 Working Group through which IOUs, the DG industry and developers, government, and regulators continue to refine and implement standardized interconnection rules. The Energy Commission's Public Interest Energy Research (PIER) Program funds much of this effort. Over the past two years, the Rule 21 Working Group has improved and streamlined the interconnection process with the following products:

- A standardized interconnection application.
- A DG interconnection equipment certification program allowing manufacturer equipment eligibility for streamlined interconnection.

- An interconnection guidebook on interconnecting one or more electricity generators to the local electric utility grid in California under California Rule 21.[51]
- Supplemental Review Guidelines to assist individuals or project teams who do not qualify for simplified interconnection and are undergoing supplemental review.[52]
- Reconciliation of Rule 21 to IEEE 1547, the new national interconnection standard adopted by the Institute of Electrical and Electronics Engineers in June 2003, and continuing participation in the national standard development process.[53]

Utilities have also made progress in the last two years. Several utilities have dedicated staff resources to assist DG applicants with their interconnection applications. This has reduced confusion about whom to contact at those utilities. Some utilities provide training and workshops for potential DG customers on interconnection processes and utility practices. Other utilities have developed detailed tracking systems to better integrate DG interconnections and associated application responsibilities into their business practices.

The interconnection process is greatly improved because of the collaborative efforts of Rule 21 participants and IOU efforts to streamline their internal processes. In July 2004, Reflective Energies, the technical support contractor for Rule 21, conducted a cost effectiveness study on improvements in the interconnection process in California.[54] The study found that Rule 21 has dramatically decreased the time between when an application is submitted to the utility and when an interconnection agreement is approved.

As shown in Figure 11, there was an 80 percent reduction in the number of days to interconnect and the number of days between the applicant‘s desired interconnection date and when the DG system actually came on-line.

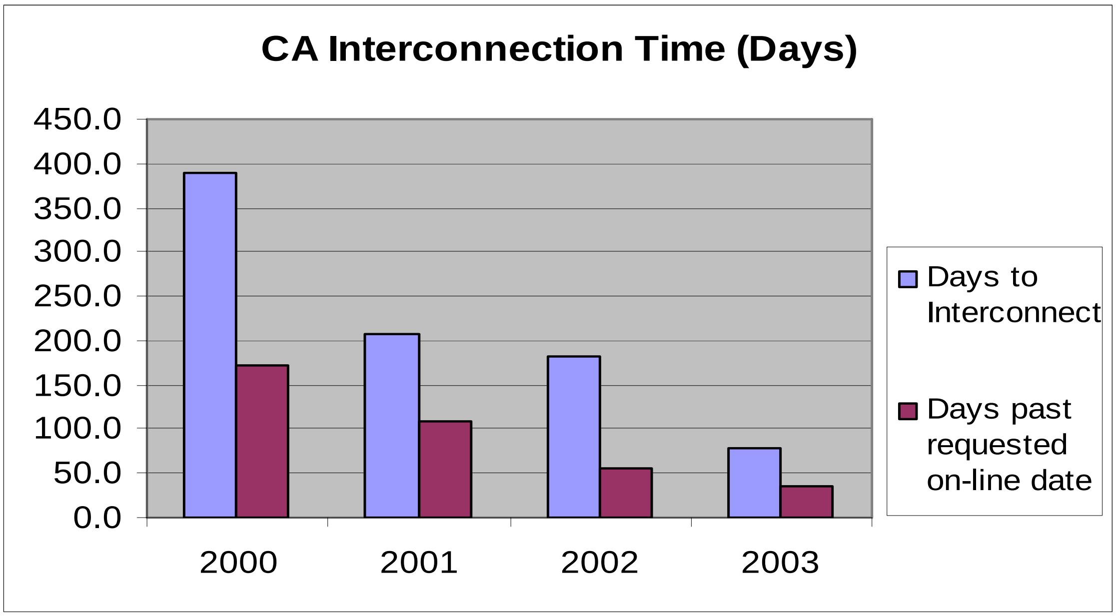
The Reflective Energies study also evaluated changes in interconnection costs since Rule 21 was revised. This evaluation looked only at costs associated with interconnection, such as the cost of the application or study, costs associated with the carrying cost of money, and the opportunity cost of delayed interconnections. The evaluation did not account for the cost or value of DG itself.

Table 3 illustrates that, as a result of revising and streamlining Rule 21, between 2001 and 2003 DG customers saved approximately $8 million for systems less than one MW and approximately $26 million for larger systems on interconnection costs. Based upon current trends, these savings will continue to increase.

**Status of Recent Interconnection Rule Changes**

On April 21, 2004, the Energy Commission began investigating a variety of issues concerning deployment of DG, including interconnection rules. On February 2, 2005, the Energy Commission adopted a report containing a set of recommended changes to California's interconnection rules.[55] These recommendations were the result of numerous Rule 21 Working Group meetings, public comments, and staff analysis relating to whether and how utility interconnection rules for DG should be changed to promote safer and more cost effective deployment of DG in California.

### Figure 11. Days Between Interconnection Application Submittal and IOU Approval




### Table 3. Interconnection-Related Cost Savings from Rule 21

| | 2001 | | 2002 | | 2003 | |
|---|---|---|---|---|---|---|
| | **<1 MW** | **1+ MW** | **<1 MW** | **1+ MW** | **<1 MW** | **1+ MW** |
| Lost Opportunity | $476,754 | $2,926,241 | $1,415,538 | $5,131,287 | $2,151,112 | $7,994,888 |
| Carrying Cost | $373,116 | $3,641,811 | $888,018 | $2,350,196 | $1,349,471 | $3,661,763 |
| Interconnection Fee | $294,400 | $179,200 | $576,000 | $121,600 | $435,200 | $150,400 |
| **TOTAL SAVINGS** | **$1,144,270** | **$6,747,252** | **$1,879,556** | **$7,603,083** | **$3,935,783** | **$11,807,051** |

The Energy Commission submitted its report to the CPUC in February 2005. The CPUC solicited comments from parties in its DG proceeding regarding the validity of the Energy Commission's recommendations, as well as implications for increased utility costs and how those costs should be allocated to utility customers. In March 2005, the CPUC reviewed comments on the Energy Commission's recommendations and the CPUC's decision is expected by the end of 2005.

## Recommended Rule 21 Changes

Recommended changes to Rule 21 focus on five key areas and are summarized below.

*Metering Issues*

- Net generation output metering shall only be required when the customer receives publicly funded incentives or tariff exemptions.
- Billing-grade or utility-owned meters are not always necessary. However, if the frequency of billing disputes increases substantially, this issue may need revisiting. Additionally, costs surrounding billing disputes will be recovered from distribution rates.

*Dispute Resolution Process*

- Modifications shall be made that incorporate mediation from the CPUC's Energy Division, tighten IOU timelines for review and resolution, and clearly identify IOU technical and process decision-makers.
- IOUs must provide more detailed technical justification to disputing parties for IOU requirements, instead of simply relying on a general assertion of the need to protect safety and ensure reliability.
- Some level of information regarding disputes and their resolution will be available to the public for purposes of learning and reducing the frequency of similar disputes in the future.

*Initial/Supplemental Interconnection Review Fees*

- No changes to the fee structure are needed at this time.
- An ongoing IOU tracking and reporting system shall be established to provide detailed data on interconnection costs and assist regulators in making informed decisions regarding the future allocation of interconnection costs. The cost of such a tracking system should be recovered through utility distribution cost mechanisms.

*Net Metering for Systems with "Combined" Technologies*

- "Combined technologies" are multiple DG systems installed at a customer's facility where some systems are eligible for net metering tariffs and others are not. Any methodology preventing export from the Net Energy Metered (NEM) generator while the non-NEM generator is operating is inappropriate. Doing so potentially reduces the economic benefit the customer might otherwise enjoy under the NEM tariff, potentially reducing the efficiency at which the non-NEM generator operates. This runs counter to the state's need for additional generation.

- Interconnection application fees and the costs associated with grid infrastructure improvements should be the responsibility of the IOU, with costs recovered through the distribution component of IOU rates.

*Interconnection Rules for Network Systems*

- The Rule 21 Working Group shall develop network interconnection rules that can be incorporated into the current framework of Rule 21, and report progress on this effort to the *Energy Report* Committee by December 2005.

## *Utility Distribution Planning*

The CPUC's DG rulemaking (R.99-010-025) clarified IOU distribution planning and the criteria DG would have to meet in order to defer traditional distribution projects. As part of that proceeding the CPUC directed IOUs to revise how they considered DG in their distribution process.[56]

The CPUC also adopted criteria for DG distribution system benefits allowing IOUs to defer upgrades or additions to distribution facilities. Under these criteria, the DG unit must be installed and operating at the right place, at the right time, at the right size. The unit must also provide real load reduction or "physical assurance" that load reduction will be realized.

There was some IOU activity after the CPUC's decision was issued in March 2003, but no significant, publicly visible efforts resulted in third-party or IOU-owned DG expansion deferrals or distribution system benefits. In late 2004 and 2005, SCE began to actively solicit DG for its distribution purposes. This effort is described in Chapter 6.

## *Utility Procurement*

Although IOUs have made an effort to solicit renewable DG through recent RPS procurements, IOU procurement processes typically do not incorporate DG. In 2004 and 2005, SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E) issued multiple RFOs for power to meet the long-term electricity needs of their customers. Even though PG&E agreed to consider offers from QFs one MW or greater, the terms and conditions of the RFOs tended to favor facilities greater than 25 MW. This offered little opportunity for smaller DG resources to successfully compete in the solicitations.

During the same period, IOUs released RFOs for renewable technologies in order to diversify their renewable portfolios and meet their RPS requirements. A wide range of renewable projects responded to these solicitations, but they are primarily large base load biomass, biogas, wind, solar and geothermal facilities.

In May 2005, SDG&E requested approval from the CPUC to amend its renewable resource plans because transmission constraints hamper its ability to meet the 20 percent renewable requirement by 2010. SDG&E proposed a specific renewable distributed generation RFO to diversify its portfolio and encourage local interest in renewable generation. The RFO will seek offers from PV and wind developers that can install these technologies at selected SDG&E facilities, with their output sold to SDG&E. This is the only RFO that incorporates and recognizes the location-specific value of DG resources in the competitive procurement process, and is a positive first step that other utilities should also consider.

## *Status of CPUC Distributed Generation Order Instituting Rulemaking*

The initial scope of the CPUC's current DG rulemaking identified four principal issues:[57] developing a cost-benefit methodology for DG, revising Rule 21 Interconnection Rules, modifying the CPUC's Self Generation Incentive Program (SGIP), and streamlining utility DG reporting requirements. Revisions to the Rule 21 Interconnection Rules were discussed earlier in the chapter.

### Cost Benefit Methodology

Energy Commission staff prepared a summary of the extensive research, analysis and studies that have been done in past years concerning the costs and benefits of DG. The CPUC used the staff paper to help frame DG cost/benefit issues. Costs and benefits were then prioritized.[58] Table 4 lists the highest priorities determined by the staff.

## Table 4. High Priority Costs and Benefits[59]

| Benefits | Costs |
|---|---|
| • Airborne or Outdoor Emissions<br>• Reliability and Power Quality (Distribution System)<br>• Enhanced Electricity Price Elasticity<br>• Avoided T&D Capacity<br>• System Losses<br>• Ancillary Services | • Utility Revenue Reduction<br>• Standby Charges<br>• Incentives for Clean Technologies<br>• Maintain System Reliability & Control Distributed Energy Resources<br>• Emissions Offsets<br>• Airborne or Outdoor Emissions<br>• Distributed Energy Resource Fuel Delivery Challenges |

To assist parties to the rulemaking in preparing their testimonies, the CPUC released an interim report from Itron describing a cost and benefit methodology being used to evaluate the SGIP.[60] This report details the main components of a potential cost and benefit methodology and includes societal, participant, and non-participant tests.

In May 2005, the CPUC held hearings to collect testimony and rebuttal testimony from parties participating in the rulemaking on proposed cost and benefit methodologies. The CPUC anticipates issuing a final decision on a standard cost and benefit methodology by the end of 2005. After issuing this decision the CPUC has indicated it will implement this methodology in utility distribution and procurement planning.

### Modifications to the Self Generation Incentive Program

The CPUC's SGIP supports a broad range of DG technologies, both renewable and non-renewable. The CPUC initiated certain load control and DG incentives on March 29, 2001, pursuant to Assembly Bill 970 (Ducheny), Chapter 329, Statutes of 2000. They authorized an annual budget of $137.8 million through 2004:  $12.8 million for load control, and $125 million for self generation. Under the SGIP adopted in D.01-03-073 and modified in D.02-09-051, certain customers qualify for incentives to install three different levels of clean and renewable DG to serve some portion of their onsite load.

The CPUC has again modified the SGIP in the current DG proceeding, R.04-03-017. In Decision 04-12-045, issued on December 16, 2004, the CPUC adopted modifications to implement the provisions of Assembly Bill 1685 (Leno), Chapter 894, Statutes of 2003, including the following:

- Reducing incentive payments for several technologies, including a reduction to $3.50 per watt for Level 1 solar projects.
- Eliminating the “maximum percentage payment limits” that caused considerable administrative complexity.
- Directing the SGIP program administrators to expand opportunities for public input in three Working Group activities:  developing a declining rebate schedule, developing an exit strategy, and adapting a data release format.

Costs associated with the SGIP continue to be included in utility distribution revenue requirements. IOUs will track these costs in the SGIP memorandum accounts created by Decision 01-03-073 for recovery in their respective general rate cases or other authorized proceedings.

### Streamlining Distributed Generation Reporting

In comments submitted to the current DG rulemaking and at a prehearing conference held in June 2004, parties questioned whether the proceeding might streamline or consolidate multiple utility reports filed each year with the CPUC and the Energy Commission. These reports provide data on interconnections, net metering installations, cost responsibility surcharge exemptions, and the SGIP. To minimize the number of reports and assure their usefulness, CPUC and Energy Commission staff are planning a public workshop in late 2005 to discuss streamlining. The Energy Commission staff will use this opportunity to address data needed from utilities to monitor and evaluate implementation of DG and its contribution to the loading order. These data issues are discussed in further detail in Chapter 6.

# Chapter 2 Endnotes

[11] A more detailed look at the most recent electricity efficiency spending, savings, and cost-effectiveness trends can be found in a separate Energy Commission staff paper, *Funding and Savings for Energy Efficiency Programs for Program Years 2000 through 2004*, Publication CEC 400-2005-042. Data is reported by program area and individual investor-owned utility.
[12] These trends are discussed in more detail in the *Public Interest Energy Strategies Report*, California Energy Commission, Publication 100-03-012F, December 2003, pp. 35-38.
[13] Office of Ratepayer Advocates, 2002, *The Public Purpose Energy Efficiency Surcharge: Trends and Patterns in the Costs and Benefits of Utility Administered Energy Efficiency Programs*., California Public Utilities Commission, p.1-1.
[14] CPUC, December 2, 2004, "Decision D.04-12-019: Order Granting Petition to Modify Decision 03-12-060," in Order Instituting Rulemaking to examine the commission's Future Energy Efficiency Policies, Administration, and Programs. Rulemaking 01-08-028, [http://www,cpuc.ca.gov/word_pdf/FINAL_DECISION/42044.pdf], accessed June 9, 2005.
[15] California Energy Commission, October 27, 2003, *Proposed Energy Savings Goals for Energy Efficiency Programs in California, Staff Report*, Publication 100-03-021, p.14-15
[16] California Energy Commission, October 27, 2003, *Proposed Energy Savings Goals for Energy Efficiency Programs in California, Staff Report*, Publication 100-03-021, p.15
[17] This assumes an average efficiency measure life of 10 years and a real discount rate of 4 percent per year.
[18] See CEC 400-2005-042 for more details on cost-effectiveness of 2000 through 2004 programs..
[19] Levelized cost = $2.39 program cost *.125 (Capital recovery factor)/therm, assuming a ten-year measure life. Costs are based on the E3 report recently adopted by the CPUC for use in procurement proceedings.
[20] Not all publicly-owned utilities reported this information. Data on efficiency programs were received from City of Glendale, Imperial Irrigation District, Turlock Irrigation District, Sacramento Metropolitan Utility District, and Silicon Valley Power.
[21] Rufo, M. and Coito, F., 2002, *California's Secret Energy Surplus: The Potential for energy Efficiency*, The Energy Foundation and The Hewlett Foundation.
[22] Factors suggesting that the Energy Foundation savings estimates may be too high include: (1) the assumption that a 100 percent increase in customer rebate levels leads to a100 percent increase in customer adoption is overly optimistic; (2) reaching and convincing the last 10-20 percent of customers may pose higher administrative costs than assumed in the study model; (3) actions taken during the energy crisis and recent changes to the Building and Appliance Standards eliminated some of the cost-effective potential. Factors suggesting these estimates may be to low include: (1) Estimates of the potential energy and peak savings associated with energy management system controls and the effects of dynamic pricing were not included; (2) estimates did not account for the recent increases in program effectiveness; and (3) no savings from the emerging technologies certain to be invented or introduced into programs over the next decade were included.
[23] 2003 *Integrated Energy Policy Report, p. vii*
[24] Ibid. p.11
[25] See California Energy Commission, April 2005, "Renewable Energy Program Summary of Activities, July – December 2004," [http://www.energy.ca.gov/renewables/quarterly_updates/updates/PROGRAM_SUMMARY.PDF], accessed June 9, 2005.
[26] "California Gross System Power for 2004," Table 2 of 2004 Net System Power Calculation, [http://www.energy.ca.gov/2005publications/CEC-300-2005-004/CEC-300-2005-004.PDF], accessed June 9, 2005.
[27] *American Ref-Fuel Co., et al.*, 105 FERC 61,004 [PDF] (2003) at page 6.
[28] *Xcel Energy Services Inc. v. FERC* D.C. Cir. No. 04-1182 (D.C. Cir. filed 6/14/2004), Order granting petition for declaratory order, finding that PURPA contracts for the sale of QF capacity do not convey renewable energy credits or similar tradable certificates to the purchasing utility. *American Ref-Fuel Co., et al.,* 105 FERC 61,004 [PDF] (2003), reh'g denied, 107 FERC 61,016 [PDF] (2004). FERC Docket No. EL03-133, Assigned to: Robert Solomon, Status: briefing; submitted without oral

argument, [http://www.ferc.gov/legal/court-cases/pend-case.asp]], accessed May 19, 2005. See also, *Xcel Energy Services Inc. v. FERC* D.C. Cir. No. 04-1182 (D.C. Cir. filed 6/14/2004), decided May 17, 2005, the court ruled that it lacks jurisdiction to consider Xcel's petition for review, stating that, "The FERC's position is reviewable by this court only after someone -- a utility, a QF, or the Commission -- brings an enforcement action in the district court and appeals therefrom. See *Industrial Cogenerators v. FERC*, 47 F.3d 1231, 1234 (D.C. Cir. 1995)," [http://caselaw.lp.findlaw.com/data2/circs/dc/041182a.pdf]], accessed May 19, 2005.

[29] California Public Utilities Commission, December 16, 2004, "Assigned Commissioner's Ruling and Scoping Memo Establishing Schedule for Phase Two of the Renewable Portfolio Standard Proceeding," in Rulemaking 04-04-026, [http://www.cpuc.ca.gov/PUBLISHED/RULINGS/42320.htm]], accessed April 30, 2005.

[30] The following parties submitted comments and/or reply comments on QF RECs: Alliance for Retail Energy Markets (AReM), Center for Energy Efficiency and Renewable Technologies (CEERT), Central California Power, City and County of San Francisco (CCSF), Green Power Institute (GPI), Independent Energy Producers Association (IEP), CPUC Office of Ratepayer Advocate (ORA), PG&E, Pacificorp, SDG&E, SCE, The Utility Reform Network (TURN), and the Union of Concerned Scientists (UCS).

[31] CPUC, May 5, 2005, "Decision 05-05-11: Opinion Clarifying Participation of Renewable Distributed Generation in the Renewable Portfolio Standards Program," in Rulemaking 04-04-026, [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/46213.pdf]], accessed May 19, 2005.

[32] For further information on publicly owned utilities' photovoltaic incentive programs, see Chapter 2 of California Energy Commission, July 30, 2004, *Accelerated Renewable Energy Development Draft Staff White Paper*, 100-04-003, [http://www.energy.ca.gov/2004_policy_update/documents/index.html#draftwhitepapers]], accessed April 11, 2005.

[33] There are conflicting reports on the cumulative amount of distributed PV installed in Japan at the end of 2003: The Japan Times reported the amount to be 640 MW; however, an update of that figure appeared in an International Energy Agency report, showing cumulative installed grid-connected distributed generation PV capacity in Japan at the end of 2003 to be more than 770 MW. A European photovoltaic newsletter reports that 280 MW of PV were added in Japan in 2004, which would bring the total to over 1,000 MW.[33] In Germany, about 120 MW was added in 2003, bringing the cumulative total to more than 350 MW of DG PV by the end of 2003. The IEA reports an even higher figure of 390 MW of cumulative grid-connected DG PV in Germany by the end of 2003. In 2004, Germany added 363 MW in 2004, three times the amount added in 2003, bringing the cumulative total to more than 750 MW. International Energy Agency Photovoltaic Power Systems Programme, September 2004, **"**Table 1 – Installed PV power in reporting IEA PVPS countries as of the end of 2003," in *Trends in photovoltaic applications. Survey report of selected IEA countries between 1992 and 2003*, [http://www.oja-services.nl/iea-pvps/isr/index.htm], accessed June 24, 2005. Observatoire des énergies renouvelables 146, April 2005, "EurObserv'ER: 2005 Photovoltaic Barometer," Press Release, [http://www.epia.org/03DataFigures/barometer/Barometer_2005_PV_EN.pdf], accessed June 24, 2005. See also Christoph Hünnekes, August 7, 2004, "Germany: Photovoltaic technology status and prospects," Projektträger Jülich (PTJ), Forschungszentrum Jülich GmbH, Annual Reports, IEA PVPS, [http://www.oja-services.nl/iea-pvps/ar03/index.htm], accessed June 24, 2005.

[34] California Office of the Governor, August 20, 2004, "Governor Schwarzenegger Calls for One Million Solar Energy Systems in California Homes," [http://www.governor.ca.gov]], accessed May 5, 2005.

[35] CPUC, November 29, 2004, *Assigned Commissioner's Ruling Soliciting Comments for Proposed Solar Roofs Initiative*, [http://www.cpuc.ca.gov/word_pdf/RULINGS/41746.doc]], accessed April 11, 2005.

[36] The *California Geothermal Resources-Staff Paper* (2005), *California Wind Resources-Draft Staff Paper* (2005), *California Solar Resources-Draft Staff Paper* (2005), *Biomass Resource Assessment in California-Draft Consultant Report* (2005), [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905]], accessed April 30, 2005.

[37] Although tidal current energy is excluded from the April 2005 scope of technical potential, it is nevertheless eligible for the RPS, with the first U.S. project submitted to the FERC for preliminary licensing on April 27, 2005. Gulf Stream Energy, Inc., Golden Gate Energy Company, April 26, 2005, "Gulf Stream Energy, Inc & Golden Energy Co's Joint Application for Preliminary Permit for the San Francisco Bay Tidal Energy Project under P-12585." FERC Docket: P-12585, [http://www.ferc.gov/docs-filing/elibrary.asp], accessed May 4, 2005. Also, see Energy Commission, August 2004, *Renewables Portfolio Standard Eligibility Guidebook*, 500-04-002F1, [http://www.energy.ca.gov/portfolio/documents/guidebooks/2004-08-20_500-04-002F1.PDF], accessed May 4, 2005.

[38] California Energy Commission, November 2003, *Renewable Resources Development Report, Commission Adopted Report*, 500-03-080F, [http://www.energy.ca.gov/renewables/02-REN-1038/documents/index.html]], accessed May 9, 2005. The RRDR used the technical potential estimates for solar prepared by Regional Economic Research, Inc. (RER).

[39] Ibid, pp. 91-98.

[40] Note that economic potential also reflects renewable generation that can be deployed into the state's electricity system with only limited new transmission capacity being added, and results in a net increase in system reliability based on a NERC N-1 contingency approach.

[41] Of the total expected WECC-wide renewable energy development indicated in Table 2, roughly two-thirds would be used to meet each state's individual RPS and integrated resource plans. The remainder (approximately 5,500 MW) could be used by the respective states or exported to other states, depending on available transmission. See California Energy Commission, April 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California From Western Electricity Coordinating Council States - Draft Consultant Report*, CEC 500-2005-064-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905], p. 5.

[42] For further details regarding the information and assumptions used in preparing this scenario, please see California Energy Commission, April 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California From Western Electricity Coordinating Council States - Draft Consultant Report*, CEC 500-2005-064-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905], pp. 3-5.

[43] For example, see Northwest Transmission Assessment Committee (NTAC) [http://www.nwpp.org/ntac/], Rocky Mountain Area Transmission Study (RMATS) [http://psc.state.wy.us/htdocs/subregional/home.htm], Southwest Transmission Expansion Plan (STEP) [http://www.caiso.com/docs/2003/01/22/2003012211380012544.pdf], Southwest Area Transmission Study (SWAT) [http://www.azpower.org/swat/]. See also California Energy Commission, April 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California From Western Electricity Coordinating Council States - Draft Consultant Report*, CEC 500-2005-064-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905], p. 7-8.

[44] California Energy Commission, April 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California From Western Electricity Coordinating Council States - Draft Consultant Report*, CEC 500-2005-064-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905], p. 45.

[45] See CPUC, March 14, 2005, "Assigned Commissioner's Ruling Detailing how the California Energy Commission 2005 Integrated Energy Policy Report Process will be Used in the California Public Utilities Commission's 2006 Procurement Proceedings and Addressing Related Procedural Details," Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning (Rulemaking 04-04-003), [http://www.cpuc.ca.gov/word_pdf/RULINGS/44509.pdf]], accessed April 15, 2005.

[46] See [http://www.cpuc.ca.gov/static/industry/electric/distributed+generation/r.99-10-025_decisions.htm].

[47] On December 21, 2000, CPUC decision D.00-12-037 approved in its entirety the Rule 21 language adopted by the California Energy Commission.

[48] On April 3, 2003, the CPUC issued Decision 03-04-030, outlining a mechanism for granting a range of DG customers from paying power surcharges known as "exit fees" or "cost responsibility

surcharges" (CRS). A customer with departing load generally refers to utility customers that leave the utility system in part or entirely to self-generate electricity. The CPUC asked the Energy Commission to assume responsibility for determining exemption eligibility. The CRS regulations adopted by the Energy Commission on October 22, 2004 became effective officially on January 30, 2004. Applications requesting an exemption from the CRS are now being accepted by PG&E, SCE, and SDG&E. Information can be found at: [http://www.energy.ca.gov/exit_fees/index.html].

[49] More information about incentive programs can be found at: [http://www.energy.ca.gov/distgen/incentives/incentives.html].

[50] Derived from IOU reported interconnection data available at: [http://www.energy.ca.gov/distgen/interconnection/rule21_stats.html] using the 20MW working definition for DG.

[51] *California Interconnection Guidebook*, California Energy Commission, Publication #500-03-083, September 2003, http://www.energy.ca.gov/distgen/interconnection/guide_book.html

[52] *California Electric Rule 21 Supplemental Review Guideline*, California Energy Commission Rule 21 Working Group, updated January 2005, [http://www.energy.ca.gov/distgen/interconnection/guideline.html]

[53] More information on IEEE 1547 and its related family of guides, best practices and standards can be found at: [http://grouper.ieee.org/groups/scc21/dr_shared/]

[54] *Making Better Connections: Cost Effectiveness Report on Interconnection of Distributed Generation in California Under the Revised Rule 21*, California Energy Commission, Publication #500-04-044F, July 2004, [http://www.energy.ca.gov/reports/2004-11-04_500-04-044.PDF]

[55] *Recommended Changes To Interconnection Rules*, California Energy Commission, Publication #CEC-100-2005-003-CTF, January 2005, [http://www.energy.ca.gov/2005publications/CEC-100-2005-003/CEC-100-2005-003-CMF.PDF]

[56] CPUC Decision D.03-02-068

[57] CPUC Scoping Ruling, August 6, 2004, http://www.cpuc.ca.gov/published/rulings/38555.htm

[58] *Distributed Generation Costs and Benefits Issue Paper*, Mark Rawson, California Energy Commission, Publication #500-04-048, July 2004 [http://www.energy.ca.gov/papers/2004-08-30_rawson.pdf]

[59] Ibid, p. i.

[60] *Self-Generation Incentive Program, Framework for Assessing the Cost-Effectiveness of the Self-Generation Incentive Program*, Itron, March 2005.

# CHAPTER 3:  ENERGY EFFICIENCY

This chapter describes the status of energy efficiency efforts in California. It covers progress toward and barriers to achieving energy efficiency goals, integrating and counting efficiency as a cost effective procurement resource, evaluating the reality of the savings and involving the public in understanding energy efficiency.

## Status of Energy Efficiency Activities in California for Investor-Owned Utilities

The institutional and organizational framework for delivering and evaluating the 2006-2008 cycle of efficiency programs for investor-owned utilities (IOUs) will be quite different from the system described in the *2003 Integrated Energy Policy Report (2003 Energy Report)*. This chapter focuses on the impact of the new IOU structure on efficiency programs, savings, and evaluation. This structure does not apply to publicly owned utilities, energy service providers, or California's Building and Appliance Standards.

The new framework supports the four goals recommended in the *2003 Energy Report* to improve energy efficiency:

- Ramping up public funding for cost effective energy efficiency programs above current levels to achieve at least an additional 1,700 MW of peak electricity demand reduction and 6,000 gigawatt hours of electricity savings by 2008.
- Increasing funding for natural gas efficiency programs to achieve an additional 100 million therms of reduction in natural gas demand by 2013.
- Standardizing and increasing the evaluation and monitoring of energy efficiency programs to ensure that savings and benefits are delivered.
- Implementing appropriate mandates, incentives, and funding to maximize the energy efficiency potential of existing buildings.

Three recent decisions from the California Public Utilities Commission's (CPUC) Energy Efficiency Rulemaking (R.01-08-028) will guide the future of IOU energy efficiency programs in California and their success in realizing energy efficiency's potential as the preferred resource at the top of the loading order.

First, Decision 04-09-060 (September 2004) adopted very aggressive energy savings goals that reflect the importance of reducing per capita energy use in California. The energy saved as a result of these goals represents as much as 59 percent of the IOUs added electricity needs between 2004 and 2013, and an increase of 116 percent in natural gas savings over the next decade.

Second, Decision 05-01-055 (January 2005) established the framework for a new administrative structure to meet the objectives of California's *Energy Action Plan* (*EAP*) and protect the public interest through an advisory group structure, competitive bidding requirements, and a ban on affiliate transactions.

Finally, Decision 05-04-051 (April 2005) established a structure for evaluation, measurement and verification that clearly separates program administrators and implementers from program evaluators. The decision also updated the policy rules that guide program portfolio development and define performance evaluation metrics for energy efficiency programs to displace or defer supply-side energy resources.

CPUC Commissioner Susan Kennedy recently commented that. "These decisions taken together—the savings goals, the administrative structure, and the EM&V structure—provide the foundation that will allow energy efficiency to take its place as a viable and tangible resource for California." [61]

Assessing whether or not these decisions will be effective in making energy efficiency a viable and tangible resource raises the following questions.

- How do the changes help realize efficiency's potential?
- What are the remaining uncertainties and risks?
- How will we know the savings are realistic?
- How could low levels of consumer awareness, knowledge, technical competence, and trust in commercial sources of expertise derail efforts to achieve significant energy savings?
- How can we increase consumer participation?

## Achieving Numeric Goals for Energy Efficiency

California's *EAP* identifies reducing per capita energy use as one of six critical actions that will ensure "adequate, reliable, and reasonably priced electrical power and natural gas supplies" that are "cost effective and environmentally sound for California's consumers and taxpayers."[62] Achieving this goal requires a set of statewide and utility-specific targets.

### *Statewide Investor-Owned Utility Efficiency Goals*

As part of the *2003 Energy Report*, Energy Commission staff prepared a statewide goals report based on a review of the economic potential for energy efficiency programs. This report became the basis for further joint staff work with the CPUC.[63] The report also considered the impact of these goals on future per capita energy usage levels, and assessed several different per capita goals and calculation methods. The report concluded that the "maximum achievable" potential from energy efficiency programs is approximately 30,000 gigawatt hours (GWh) over the next decade.

Using recommendations from work by the staff of the Energy Commission and the CPUC (Joint Staff), the CPUC adopted a set of goals to reach this target, shown in Table 5.[64] These goals far exceed the recommendations in the *2003 Energy Report*.

## Table 5. Electricity and Natural Gas Program Savings Goals (all IOUs)

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Annual Electricity Savings (GWh/yr) | 1,838 | 1,838 | 2,032 | 2,275 | 2,505 | 2,538 | 2,465 | 2,513 | 2,547 | 2,631 |
| Total Cumulative Savings(GWh/yr) | 1,838 | 3,677 | 5,709 | 7,984 | 10,489 | 13,027 | 15,492 | 18,005 | 20,552 | 23,183 |
| Total Peak Savings (MW) | 379 | 757 | 1,199 | 1,677 | 2,205 | 2,740 | 3,259 | 3,789 | 4,328 | 4,885 |
| Total Annual Natural Gas Savings (MMTh/yr) | 21 | 21 | 30 | 37 | 44 | 52 | 54 | 57 | 61 | 67 |
| Total Cumulative Natural Gas Savings (MMTh/yr) | 21 | 42 | 72 | 110 | 154 | 206 | 260 | 316 | 377 | 444 |

The goals use historic program spending, savings, and effectiveness trends as a guide for their trajectory and are bounded by the remaining potential for energy efficiency that is both economic and achievable through programs. The cumulative 2013 goal captures 91 percent of the maximum achievable potential and 68 percent of what is cost effective. Savings from energy efficiency programs funded by the electric and natural gas public benefit surcharges and procurement surcharges will contribute to these goals, including savings in the Low-Income Efficiency Program.

### *Investor-Owned Utility-Specific Efficiency Goals*

The Energy Commission staff translated the statewide goals into specific numerical goals for each of the state's four largest IOUs: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Southern California Gas Company.[65] The staff applied a baseline ratio of savings per dollar of expenditures to each utility's relative share of program funding. The IOUs' savings goals are approximately 85 percent of statewide savings goals, reflecting omission of annual savings estimates for municipal utility energy efficiency programs.

There are two ways to calculate how much these goals will lower per capita consumption over the next decade.[66] The first method looks at per capita usage relative to a forecast of future per capita usage. With this method, to meet their respective goals, PG&E would have to reduce its per capita usage by 0.6 percent annually from 2004-2013 and SCE and SDG&E would have to reduce their per capita usage by 0.8 percent and 0.93 percent. The second method uses 2003 as a base year for comparison, and shows that the goals will result in reduced per capita usage of 0.3-0.4 percent per year, culminating in 2013 when per capita usage will be about 3 percent lower than the 2003 base value.

These goals are considered aggressive "stretch goals" needed to achieve savings over a decade. The CPUC recognized that there may be practical limits to increasing funding and ramping up programs to achieve these goals, particularly for natural gas. Therefore, the goals will be updated every three years so they remain in sync with the new three-year program planning cycle. Future adjustments to the goals will be based on updated savings potential, changes to the building and appliance standards, and evaluation studies.

## Integrating Energy Efficiency as a Cost effective Procurement Resource

Recent decisions at the CPUC are dramatically changing administration of post-2005 efficiency programs, including how savings are quantified and how to evaluate, measure and verify program results. These changes aim to ensure that energy efficiency becomes the viable procurement resource envisioned in the *EAP*.

This section discusses the new administrative structure for energy efficiency programs, new policy rules for energy efficiency, the 2006-2008 program cycle, and uncertainties and risks in achieving energy efficiency goals.

### *New Administrative Structure for Efficiency*

CPUC Decision 05-01-059 returned program choice and portfolio management roles for energy efficiency to the IOUs. This change shifted program oversight away from the CPUC's Energy Division, which has been responsible for most of the day-to-day management assignments since 2000. In its decision, the CPUC directed the IOUs to design and implement a portfolio of utility and non-utility administered energy efficiency programs.

Recognizing the role played by private energy service companies, local government agencies, nonprofit organizations and other entities, at least 20 percent of the portfolio must be competitively bid to non-utility third parties, the rationale being that these entities will improve overall portfolio performance by bringing proposals that will be both innovative and targeted toward specific market needs or niches.

In contrast to previous program cycles, the new planning effort introduces a wider variety of public participation in developing the portfolio, as well as more-detailed peer review to assess overall plans, minimum third-party bidding requirement plans, and bid evaluation criteria. The purpose of this new level of public review is to ensure that each utility's portfolio will pursue the most cost effective programs to meet or exceed short- and long-term savings goals while minimizing lost opportunities. After the programs are established, public involvement and review will continue on a quarterly basis to assess program implementation, consider fund shifts, and offer input on other issues related to ongoing portfolio management. The public advisory and review groups will file annual reports on the third-party bid process and the effectiveness of the IOUs as administrators of the portfolio of programs.

Another important administrative change affects the measurement of savings. IOU administrators are no longer allowed to manage contracts to evaluate, measure, or verify the energy savings impacts of their programs. IOUs will only manage contracts that provide market information or deliver feedback on program process and cannot manage statewide studies related to establishing future savings potential or measuring cost or saving estimates.

Instead, the CPUC's Energy Division and the Energy Commission will cooperatively assume management and contracting responsibilities for all efficiency monitoring and verification studies to:

- Measure and verify energy and peak load savings for individual programs and impacts of programs at the portfolio levels (including load impacts, useful measure life, savings retention and persistence studies).
- Generate the data for savings estimates and cost effectiveness inputs.
- Measure and evaluate achievements in terms of the "performance basis" to be established.
- Evaluate if program or portfolio goals are met.[67]

This new structure establishes a clear separation between program evaluators and program administrators and implementers.

## *New Policy Rules for Efficiency*

The updated *Energy Efficiency Policy Manual for Post-2005 Programs*[68] (*Rules)* reflects the CPUC's overriding energy efficiency goal, which is "to pursue all cost effective energy efficiency opportunities over both the short- and long-term." This goal also recognizes that energy efficiency can reduce the environmental impacts from California's energy consumption.

The new *Rules* focus on "resource programs" that can serve as alternatives to more costly supply-side resource options. Cost effectiveness calculations for evaluation purposes will be at the portfolio level to encourage innovation and some risk-taking: pilot programs and adding new measures into the programs. The "performance basis," or metric, will be calculated on net resource benefits (energy savings benefits minus costs) plus attaining a minimum threshold of savings goals. This is intended to prevent program administrators from achieving energy or demand reductions regardless of the cost.

Using two cost-effectiveness tests to assess the 2006-2008 portfolio of programs is designed to prevent spending on more financial incentives or rebates than is necessary. The first test, Total Resource Cost, measures net resource benefits to all ratepayers as the avoided costs of supply side resources that will not be needed. Costs in this test include any higher costs to the customer of purchasing high efficiency equipment and costs of program administration. Two-thirds weight is given to this test. One-third weight is given to the Program Administrator test, which differs by not including the incremental customer costs. To be eligible for public funds, the entire portfolio must be cost-effective using both tests.

The cost effectiveness tests for the post-2005 program portfolios will use non-price components of the avoided costs, including environmental adders. The CPUC adopted an updated avoided cost methodology specifically to include the real cost to ratepayers that are avoided by deploying energy efficiency. [69]

Viewing energy efficiency as a viable resource alternative to supply-side investment, the CPUC rejected the use of a "societal" discount rate that is, by definition, lower than market rates. The Building and Appliance Standards use a societal rate. The Energy Commission deemed the societal rate appropriate because efficiency investments reduce societal risk and provide valuable cost savings and environmental benefits well into the future. Using a market discount rate in social cost benefit analyses can undervalue the interests of future generations; because it raises the cost effectiveness threshold, it can also reduce the number of possible measures or programs. The CPUC decided that the utility's weighted cost of capital is more comparable, and directed its use in cost effectiveness calculations for energy efficiency. The rationale is that not using a market discount rate makes comparisons with alternative investments more difficult. The weighted cost of capital currently ranges between 7.6 and 8.7 percent, depending on the utility.

The new Rules also tighten the counting conventions for energy efficiency savings. Only savings from actual installations will count toward an annual goal. Previously, annual savings counted both savings from actual installations and commitments to install. Programs such as New Construction and Standard Performance Contracting are especially vulnerable under this new rule because projects typically take several years to complete.

The *Rules* continue the convention of differentiating "resource" programs from "non-resource" programs that do not directly produce energy savings for procurement. The latter category includes audits, codes and standards advocacy, education and training, and advertising and marketing. By maintaining this distinction, the non-resource programs continue to fall under a performance basis that does not require them to produce actual savings. The performance basis instead values them within the overall portfolio for their ability to direct customers to resource programs. For example, the performance basis for advertising and marketing programs would include the reach and frequency of the activity.

In a departure from previous practices, the CPUC decision agreed to consider a performance basis for the Codes and Standards Advocacy Program, administered by the IOUs, that is tied to the estimated savings associated with proposed and implemented revisions to standards. Another non-resource program found appropriate for re-examination is the IOUs' Emerging Technologies Program. These changes would allow IOUs to count a portion of these savings toward their goals.

The CPUC foregoes policy guidelines that dictate program choice. Instead, the CPUC relies on the requirement to pursue the most cost effective programs that meet or exceed the adopted goals as motivation for IOUs to propose a mix of programs that meet California's market sector and geographic needs while avoiding lost opportunities.

### *2006-2008 Portfolio Plans*

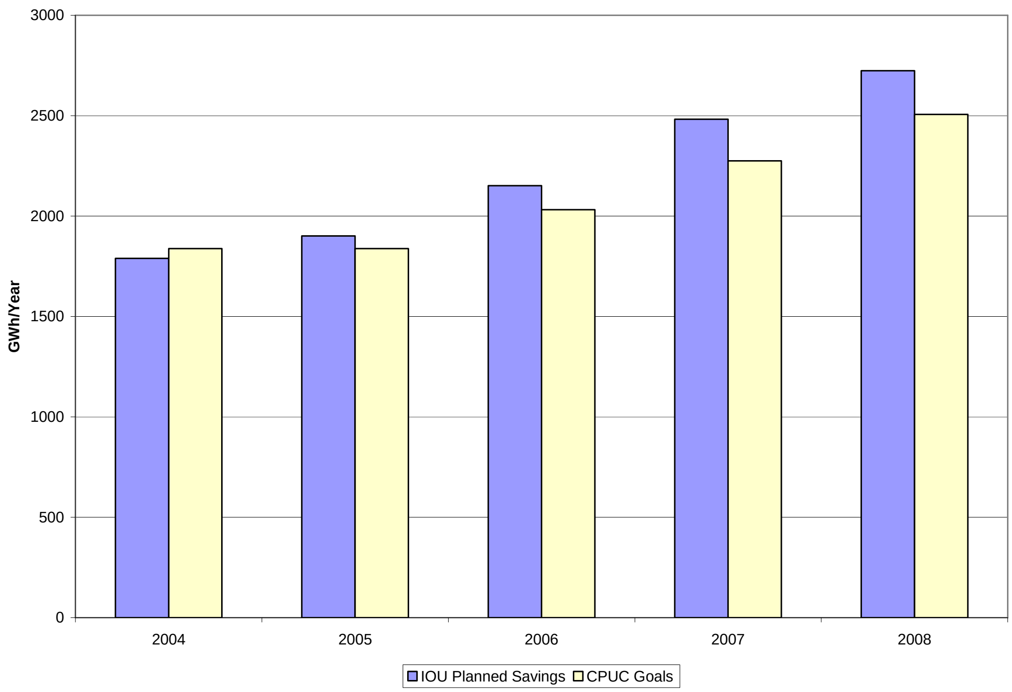
California's IOUs submitted their 2006-2008 portfolio plans to the CPUC on June 1, 2005. A preliminary assessment of the mid-May versions of the portfolio planning documents by CPUC Energy Division consultants reveals a combination of continuing tried-and-true programs with some totally new programs, market partners, and approaches.[70] The assessment concludes that the set of program portfolios "has a good chance" of meeting the CPUC's near-term goals for energy savings, demand reduction, and therm savings, although there is less certainty about the longer-term. Figure 12 shows the comparison of projected savings with goals for the IOUs.

Although energy savings declined significantly after the 2000-2001 energy crisis was over, the trend today points toward significant increases in both spending and energy savings, consistent with the policies adopted in the *EAP*.

Through procurement proceedings, ratepayer funds are once again available to fund energy efficiency beyond levels in the PGC. The IOUs have proposed large increases over their 2004-05 budgets as a result. Table 6 shows the preliminary spending proposals and the relative size of the annual increases.[71]

Though the basic approach for achieving their savings goals is very different for each of the IOUs, they have several significant features in common. In response to the Governor's Green Building Initiative, non-residential programs are receiving significant funding. Emphasis is on achieving energy savings rather than reducing peak demand. Programs are also integrating demand response, distributed generation, renewables, and water efficiency with traditional energy efficiency measures and information, but still rely on lighting for most of the savings. Finally, the IOUs face the risk of simultaneously launching many new programs with large budgets.

## Figure 12. Projected Savings Compared to Goals 2006-2008




## Table 6. Funding for 2006-2008 Programs ($000)

| | 2006 | % Diff from Previous Year | 2007 | % Diff from Previous Year | 2008 | % Diff from Previous Year |
|---|---|---|---|---|---|---|
| PG&E | $276,000 | 111% | $304,000 | 10% | $373,000 | 35% |
| SCE | $243,000 | 43% | $243,000 | 0% | $243,000 | 0% |
| SDG&E | $81,000 | 30% | $91,000 | 12% | $106,000 | 16% |
| SCG | $48,000 | 47% | $61,000 | 27% | $73,000 | 20% |

In an effort to cultivate innovative ideas, SDG&E has chosen to put a large portion of its budget into bid programs, partnerships and third-party programs. Issues that could impact savings from SDG&E's portfolio include: inadequate local infrastructure to support programs (for example, contractors and vendors), and lack of information on how well goals will be supported by reliance upon bid programs, third parties, and partnerships beyond SDG&E's direct control.

PG&E has proposed to put half of its budget into a new combined mass market approach targeting residential, multi-family residential, and small business customers. This approach has the potential for success, but a program of this magnitude is risky. PG&E projects that at least 70 percent of its expected peak savings will come from this program, so consequences will be dramatic if it fails to deliver.

SCE has put together a highly diversified portfolio of programs that fit under three umbrella programs. The CPUC's consultants were unable to judge the reasonableness of the savings estimates in SCE's portfolio. The majority of the estimated savings result from measures that are not included in the *Database of Energy Efficient Resources*, which is the source of the deemed cost and savings estimates used in calculating cost effectiveness.

Southern California Gas has planned a portfolio of traditional programs projected to meet 106 percent of the goals in 2006-2008. The major differences are in the large funding increase and reliance on third-party programs and partnerships for 30 percent of funding. This portfolio has the lowest overall cost effectiveness ratio, and, therefore, is more vulnerable to the risk of not being cost effective overall. Reliance upon previously successful and statewide programs lowers this risk.

### *Uncertainties and Risks in Achieving Energy Efficiency Goals*

While initial portfolio plans look promising, much could go wrong before 2008. Some of the uncertainties and risks are described below.

First, the amount of cost effective efficiency potential may change. The estimates of potential used in the portfolio planning data are based on analysis conducted in 2001 and 2002. The estimates do not reflect the unusual amount of conservation and efficiency actions taken during the 2000-2001 energy crisis. They also do not incorporate new equipment, measure saturation information from statewide residential and commercial end-use surveys, or account for emerging technologies that could be incorporated into programs.

Second, innovative programs are still unproven. Although innovation is needed to capture the full range of savings needed to achieve the goals, it is inherently risky. Approaching the market in completely new ways carries the risk of failure by miscalculating how the program will be received or how market conditions could prevent potential participants from taking action. As a result, needed market penetration may never be achieved.

Third, ramping up may be difficult. Programs with new implementers may take longer than expected to reach full effectiveness, slowing the effective use of program dollars. Funding for some of the established programs could also be double or triple the amount of funding from previous years. As described in Chapter 2, the historical record of program effectiveness indicates that such extreme increases may not result in more savings for expended funds.

Fourth, program delivery may not proceed as planned. No program has doubled its spending in a single year, but more typically spreads out increases over three to four years. However, sustaining multi-year increases over more than five or seven years has also historically failed. While it appears likely the near-term savings goals can be met, there is doubt about achieving savings just when efficiency would become important to resource planners. Ceding control of direct implementation to another entity, such as a partnership or a third-party implementer, reduces the amount of control that an IOU will have over the program and could put potential savings at risk.

Fifth, the program mix may not result in sustainable savings if it overemphasizes the easiest, cheapest savings at the expense of long-term market change. A comprehensive portfolio must be able to both adapt to market place changes and incorporate new approaches to capturing cost effective benefits over the long run. Portfolios need to balance “hard savings” now with a sustainable future savings stream.

## Monitoring and Verification: Evaluating the Reality of the Savings

The IOUs have stated they fully intend to follow the EAP loading order. In addition, according to their long-term resource plans and 2006-2008 program filings, they consider the savings goals as a floor rather than a ceiling in evaluating options. Timely and accurate evaluation, measurement, and verification is needed to ensure that IOU intentions are translated into real energy and peak demand savings.

### *Joint Staff Responsibilities for Evaluation, Measurement and Verification*

CPUC Decision 05-01-055 directs the staff of the Energy Commission and the CPUC’s Energy Division (Joint Staff), through a Memorandum of Understanding, to evaluate, monitor, and verify (EM&V) the energy savings and load impacts from $600 million in annual spending for energy efficiency programs.[72] Funding for this activity is approximately $48 million for the period 2006-2008, about eight percent of total program funding.[73]

This is an improvement over past approaches because it cleanly separates “those who do” from “those who evaluate.” The IOU portfolio administrators will manage market tracking studies, process evaluations, and periodic market assessments using contractors subject to Energy Division approval and input from ad-hoc technical advisory groups.

The Joint Staff will manage and contract all EM&V studies after 2005 that will be used to:

- Measure and verify energy and peak load savings for individual programs, groups of programs, and portfolios.
- Generate the data used to estimate savings and determine cost effectiveness.
- Measure and evaluate the achievements of energy efficiency programs, groups of programs and/or the portfolio in terms of the "performance basis."
- Evaluate if program or portfolio goals are met.

Ensuring that savings from these efficiency programs are achieved is a vital component of the state's *EAP* goals, underscoring the importance of evaluation and monitoring activities. Efficiency program savings "estimates" must be verified or confirmed through EM&V before those savings can be considered permanent and included in forecasts of future energy demand.

The Joint Staff are also responsible for managing statewide studies to gather information about future potential for energy savings. Examples of these studies include the *Database of Energy Efficient Resources* and the *Residential Appliance Saturation Survey*.

In April 2005, the CPUC adopted a roadmap for EM&V that was prepared by the Joint Staff for the 2006-2008 program cycle. [74] The roadmap is intended to produce:

- A standardized process for evaluating programs, reporting results and acting on results.
- Credible and objective information on program impacts and performance.
- Recommendations to improve program performance.
- Results that meet the needs of the Independent System Operator and resource planners in order to ensure energy efficiency is a viable resource.[75]

The first step was to gather information on current and ongoing EM&V projects,, identify needs, and clarify roles and responsibilities. A multi-step process is also underway to develop revised evaluation protocols for both resource and non-resource programs to conform to the new *Energy Efficiency Policy Rules* in several overlapping phases. The goal is to develop the protocols during summer 2005 and adopt them by November 1, 2005, for use in evaluation studies beginning January 1, 2006. Public workshops are scheduled throughout the process.

One phase of protocol development focuses on how the performance basis for each 2006-2008 program will be evaluated and how often to update specific performance measurement parameters, including first-year savings estimates, net-to-gross ratios, program participation levels, useful measure lives, incremental measure costs, and technical degradation factors.

Joint Staff were asked to also consider whether savings associated with the utilities' emerging technologies program and the Codes and Standards Advocacy Program might contribute toward the savings goals. If so, evaluation protocols and a performance basis will need to be developed for these programs.

Developing quality control and "how to" protocols are other aspects of the Joint Staff work. These protocols are designed to improve EM&V results by providing guidance and/or minimum requirements on collecting data for major study parameters, such as sampling techniques, confidence intervals, and verification of baseline usage...

Next, Joint Staff will develop specific plans for evaluating both the 2006-2008 programs proposed in the IOUs' June 1, 2005 filings and appropriate budgets for these programs. Evaluation plans for non-utility programs selected during the competitive bid process in the summer of 2005 will be reviewed in October and a final set of evaluation plans for all programs will be issued on November 1, 2005. The *California Evaluation Framework* will provide conceptual guidance for evaluating the programs across the three-year cycle.[76]

Budgets for studies that will provide policy oversight, such as financial audits, market tracking studies, or updates to statewide "parameter" studies, will be merged with the program-specific plans to produce an overall budget request for EM&V expenditures in December 2005.

### *Uncertainties and Risks in Evaluating the Reality of Savings*

While the new framework attempts to ensure that EM&V will be timely, unbiased, and accurate, several uncertainties could undermine these efforts. Some of the uncertainties and risks that could impact energy efficiency are discussed below.

- The current staffing level for the monitoring activities is insufficient. There are only two person-years assigned, between the Energy Commission and the CPUC, to direct activities for a $600 million dollar efficiency program. Without additional resources, most of the regulatory oversight of the efficiency programs will need to be contracted out, removing staff from direct involvement. This could lead to larger accountability problems and compromise the state's policies for energy efficiency.
- Data reporting on efficiency programs can be complicated and time-consuming. The risks include not having the right type of credible data when it is needed. Too much reporting can be as bad as too little; the focus needs to be on identifying useful data. Agreement on reporting methods, frequency and definitions, as well as access to utility program data, will be critical for state staff

to accurately assess how efficiency programs are contributing to state policy goals. This data should be publicly available.

- The evaluation process could prove too cumbersome and too expensive if every program is evaluated every year. Sequencing of evaluations based on the needs of the programs may be more valuable than a standardized schedule. Grouping similar programs into one evaluation may be another way to mitigate this risk. The value of information and the cost of obtaining it need to be defensible.
- The underlying metrics for the programs could prove unreliable over time. Inputs to the cost effectiveness tests—such as net-to-gross ratios, incremental measure cost and measure life—must be given as much attention as the program evaluations to avoid wasting public funds.
- Qualified consultants to do the evaluation work may be in short supply because consulting firms may no longer work as both program implementers and evaluators. A shortage of capable evaluation consultants could lead to work overload, delays in evaluation products, and poor quality data.
- State EM&V staff has faced significant opposition to collecting utility load and billing data, despite specific provisions in the Energy Commission's regulations authorizing collection of that data. This lack of access hampers state policy analysis of how energy efficiency impacts customers and system demand. The Energy Commission plans to take additional steps to ensure the timely provision of this confidential data to state EM&V staff.
- Larger political issues could overwhelm the process if the Joint Staff cease to cooperate for some reason. Shifts in state policy toward efficiency due to economic downturns or rising fear of blackouts could jeopardize funding for both programs and EM&V.

## Public Involvement and Understanding Related to Efficiency

Energy efficiency savings goals will not be achieved without strong public involvement and understanding. While there is extensive technical knowledge about reducing energy dependence, knowledge and analysis of the human factors that shape energy use and the flow of energy are critical.

The following sections discuss some of these factors—including psychological states, choice behavior, and knowledge—for both individuals and groups. These insights are drawn from work prepared in 2004 for the Energy Commission by Lutzenhiser Associates in support of Assembly Bill 549 (Longville), Chapter 905, Statutes of 2001, [77] and from analysis of consumer response to the 2000-2001 energy crisis.

## *Individual Behavior*

- Most consumers take energy for granted and are unaware of opportunities to conserve energy or implement energy efficiency measures.[78] Even when consumers become aware of problems, such as during an energy crisis, they are unlikely to change their behavior unless they feel some responsibility for the problem or believe their behavior will make a difference.
- Consumers have a very different view of energy than policy makers and program designers. A classic example describes how consumers view their thermostats as a valve; a significant number of people believe that the farther you turn the thermostat to the right, the hotter (or cooler) the air will be that comes out.[79]
- Most consumers have little opportunity to develop technical competence related to energy efficiency. Houses come equipped with furnaces and air conditioners, and consumers use what is already in place, relying upon the technical expertise of others.[80]
- For most consumers, decisions depend upon the quality of information rather than the quantity. There is a wide variety of message delivery vehicles in energy efficiency programs. Consumers are more likely to rely upon information that comes from a trusted source or through a social network that is specific, vivid, and personal.[81] Social attitudes and simple awareness, on the other hand, rarely predict behavior.
- Another important factor influencing consumer decisions is feedback (via meters or energy bills) that helps individuals assess if behavior changes make a difference. Because consumers often miscalculate their energy use, they may also misjudge how much their efforts have reduced energy use or cost. Without this feedback, consumers may discontinue their efforts or be unwilling to make similar efforts in the future.
- Although financial incentives do motivate some consumers to participate in energy efficiency programs or purchase energy efficient products, the initial decision to participate often results from non-financial considerations. For example, homeowners may prefer to invest in solar photovoltaic panels not because they are more energy efficient or environmentally friendly, but because the panels are highly visible.[82] Rebates and incentives are commonly used in energy efficiency programs, but there is little information available to help understand when these types of financial inducements are necessary, how large they need to be to trigger action, or whether they are simply confidence-builders (“this is a smart thing to do”).

## *Group Behavior*

- Individual decision-making does not fully explain energy use in homes, offices or factories. Examining individual attitudes and decision-making is too limited for a policy approach because households and businesses, not individuals, use energy.

- Energy efficiency policy frequently assumes that consumers use energy and efficiency technologies in similar ways. In reality, variations in energy use, status, and lifestyle affect actual savings from energy efficiency measures.
- Most energy consumption is truly the result of group decisions. In the home, energy use is built into everyday life and varies by household habits relating to comfort, convenience, and cleanliness.[83] Energy use is also affected by social considerations, such as how many people live in the house, how many "toys" they own, how often they entertain, and other considerations. In the workplace, energy use also follows patterns of behavior related to the job, the equipment, and the office building itself.
- Social expectations and cultural understandings also influence group behavior. Status considerations, for example, can influence equipment purchases. Equipment such as solar panels may be distasteful to one social group which perceives them as unattractive, while another social circle finds them desirable as symbols of concern for clean air and future generations.[84]
- One study has found that even in homes with similar or identical physical characteristics, energy use varies in a way that can only be explained by differences in occupant behavior. Recent research has shown that households with similar technological configurations and housing sizes vary in energy consumption by a ratio as large as three to one.[85]
- In addition, policy makers often assume that financial cost-benefit calculations about energy choices are primary incentives for consumers to change their energy behavior or adopt energy efficient technologies. Instead, consumers are often motivated by non-financial considerations, such as increased comfort, reduced pollution, or status display. As a result, programs that focus solely on economic considerations may have disappointing results.

## ***Conclusion***

Energy efficiency actions need to be fundamentally understood within the context of household or organizational energy use patterns and factors that shape a consumer's ability to act. These complex patterns change and evolve, but they can be shaped and influenced to enhance the effectiveness of energy efficiency policies and programs. To understand why some people practice conservation and buy energy efficient products while others do not depends on three factors: level of concern, capacity to act, and the conditions (or constraints) surrounding the action.

# Chapter 3 Endnotes

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[62] State of California, 2003, *Energy Action Plan*. California Power Authority, California Energy Commission, and California Public Utilities Commission, p.2.
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[65] California Energy Commission and California Public Utilities Commission, *California Electricity Savings Goals Report*, March 26, 2004, and California Energy Commission and California Public Utilities Commission, *Natural Gas Savings Goals Report*, March 26, 2004.
[66] See D.04-09-060 pp. 9-11 and the *California Electricity Savings Goals Report* for a discussion of the various methods.
[67] California Public Utilities Commission, Decision 05-01-055, January 27, 2005, *Interim Opinion on the Administrative Structure for Energy Efficiency: Threshold Issues* and Decision 05-04-055, April 21, 2005, *Interim Opinion: Updated Policy Rules for Post-2005 Energy Efficiency and threshold Issues Related to Evaluation, Measurement and Verification of Energy Efficiency Programs*, p. 3-4.
[68] CPUC, April 21, 2005, Decision 05-04-051, Attachment 3.
[69] CPUC, April 7, 2005, Decision 05-04-024 under Rulemaking 04-04-029.
[70] *The California 2006-2008 Energy Efficiency Portfolio, A Review of Early IOU Planning Documents*, May 27, 2005, prepared for the California Public Utilities Commission, Energy Division by TecMarket Works.
[71] These PG&E, SCE, and SCG preliminary budget estimates are taken from *The California 2006-2008 Energy Efficiency Portfolio, A Review of Early IOU Planning Documents*, pp. 16, 54, and 70; SDG&E budget estimates are from preliminary portfolio tables provided to the Peer Advisory Group on May 9, 2005.
[72] This ruling can be downloaded at [http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/eeadministrativestructure.htm/]
[73] EM&V expenditures have ranged from a high of approximately 14% over the 1993-1996 period, but has averaged approximately 4% in recent years. CPUC D.05-04-051, pp. 69-70.
[74] The ALJ Ruling and roadmap can be found at [http://www.cpuc.ca.gov/word.pdf/rulings/45673.doc]
[75] California Public Utilities Commission, January 21, 2005, *Report on Workshop #4: The EM&V Protocol Development Process*, p.5.
[76] *The California Evaluation Framework*, June 2004, prepared for the California Public Utilities Commission and the Project Advisory Group by TecMarket Works and the project Team Members.
[77] These insights are drawn from Lutzenhiser Associates., 2004, *Social Science Literature Review2, AB 549 Intervention-Relevant Work*, prepared for the California Energy Commission AB 549 Study. Full citations for all sources are provided therein.
[78] Ibid, Kempton 1982, Lutzenhiser 2002.
[79] Ibid, Kempton 1986.
[80] Ibid, Lutzenhiser 2002c.
[81] Ibid, Stern 1992.
[82] Ibid, Wilk and Wilhite 1984.
[83] Ibid, Shove and Warde 1997, Wilhite and Wilk 1987, Erickson 1997, Hackette and Lutzenhiser 1991.
[84] Ibid, Gossard 2004.
[85] Ibid, Hacket and Lutzenhiser 1991, Lutzenhiser 1992, 1993, Schipper *et al.* 1989, Shove *et al.* 1998.

# CHAPTER 4: DEMAND RESPONSE

This chapter discusses demand response activities in California, including activities at the California Public Utilities Commission (CPUC) and the California Energy Commission, utility goals and progress toward those goals, and measurement and verification efforts to ensure those goals are ultimately met.

“Demand response” refers to a wide range of programs and rate designs that provide incentives for customers to reduce their electricity loads when the demand for electricity is high. Reducing load before the distribution system reaches its capacity limits enhances the reliability of California’s electricity grid.

The umbrella term “demand response” describes both price-sensitive programs and programs to reduce load during system emergencies. Emergency load reduction programs are dispatched as needed for reliability, often by location, when reserve margins fall to a point where system stability is at risk. These programs include interruptible or curtailable tariffs, emergency back-up generation, and air conditioner cycling. In contrast, price-sensitive programs are designed to reduce demand before it reaches critical levels and reduce the subsidy of higher marginal cost on-peak energy consumption inherent in average rates.

In the short-term, reducing load lowers costs by minimizing the amount of high-priced electricity purchased in short-term markets to serve peak loads.[86] By reducing the need to expand system infrastructure or build peaking power plants, demand response measures can also lower consumer costs over the long term.

At the system level, peak load “shaving” minimizes both long- and short-term financial costs. Shifting load to periods of lower demand and lower prices increases economic efficiency by reducing costs. Reduced energy consumption also reduces the environmental costs of generation, including greenhouse gas emissions.

Well-established reliability programs in California play an important role in providing the last defense against outages. This paper, however, focuses on price-sensitive demand response programs. These programs have system impacts during the normal course of operation. They are not implemented to bolster system reserves only during times of high demand relative to resources. Price-sensitive demand response is consistent with the Energy Commission’s historical policy support of customer choice. Now that the technology to support hourly pricing is mature enough to be evaluated for viability and cost effectiveness for all customers, the efficiency gains possible from more closely aligning wholesale and retail costs are achievable.

With hourly energy prices that more closely track wholesale market prices and system conditions, customers—rather than policymakers, utilities, or system operators—are able to make their own choices about which components of their total load they want served at a particular price. The collective effect of these individual choices will lead to lower overall costs and allocate those costs more fairly.

Under the current system, on-peak usage is subsidized through average rates that are too low during peak times and too high the rest of the time. Even customers paying time-of-use rates pay higher average on-peak rates than warranted on days when supply is plentiful and system conditions are stable. Because rates remain the same during critical times, these customers have no incentive to further reduce their loads when reserve margins are low or costs are high.

Current reliability programs make implicit judgments about the load value during critical periods. Dispatchable air conditioning cycling programs that shut off cooling on hot days and interruptible programs that shut down industrial production, are crude reflections of the much more finely tuned opportunities customers have with market-based tariffs. The fundamental premise of price-sensitive demand response is allowing customers to choose when and how to use electricity in response to a price signal that both reflects actual costs and applies to all customers.

## Status of Demand Response Activities in California

### *Joint Agency Demand Response Proceeding*

The California Public Utilities Commission (CPUC) instituted Rulemaking 02-06-001 as a joint proceeding of the CPUC, the Energy Commission, and the California Consumer Power and Conservation Financing Authority (CPA). The purpose of the rulemaking is "to develop demand response as a resource to enhance electricity system reliability, reduce power purchase and individual consumer costs, and protect the environment."[87]

The Rulemaking formed working groups to manage three general areas of the proceeding.

- Working Group 1—composed of CPUC Commissioner Peevey, Energy Commission Commissioner Rosenfeld, and CPA board member McPeak—provides a forum for interagency cooperation, policy development, and proceeding direction.
- Working Group 2 is responsible for developing programs and tariffs for large customers who already have advanced meters.
- Working Group 3 addresses issues surrounding possible expansion of the advanced metering infrastructure to include all customers.

**Working Group 2 Activities**

Working Group 2 addresses large customers (with demand exceeding 200 kilowatts [kW]). Participants include staff from the Energy Commission, the CPUC, the CPA, and the California Independent System Operator (CA ISO), and representatives of large customer groups, consumer advocates, academic researchers, utility employee unions, and vendors.

Working Group 2 established a two-part strategy for demand response. First, programs and tariffs would be voluntary rather than mandatory. Second, programs and tariff designs would work within existing IOU revenue requirements set in their most recent respective General Rate Cases.

The working group proposed several program and tariff concepts, a number of which were developed by the IOUs. CPUC Decision 03-06-032 approved the following program/tariff offerings for large commercial and industrial customers:

- Critical Peak Pricing tariff.
- Hourly Pricing Option tariff for customers in San Diego Gas and Electric Company's (SDG&E) service territory.
- Demand Bidding Program for IOUs.
- Demand Reserves Program, originally under the control of the CPA and now administered by Pacific Gas and Electric Company (PG&E).

The Critical Peak Pricing tariff is a summer season program to encourage customers to reduce energy consumption during critical peak times. For up to 12 designated "critical peak" days per summer season, prices are substantially higher from 12:00 p.m. to 6:00 p.m. These prices are offset by discounted mid-peak and on-peak prices on all other weekdays. Prices on weekends and holidays remain at the lowest, off-peak rate for all hours.

The Demand Bidding Program is a voluntary web-based demand/energy bidding program offering incentives to customers for reducing energy consumption and demand during specific Demand Bidding Program event periods. The program is available year-round to bundled service customers with greater than 200 kW demand. These customers must commit to curtailing at least 10 percent of their average monthly demand, but not fewer than 100 kW, during a Demand Bidding Program event period. The Demand Bidding Program periods are called on a day-ahead basis when the CA ISO issues an Alert notice or forecasts a day-ahead peak of greater than 43,000 MW.

The Demand Reserves Program is administered by PG&E for the CPA under contract with the California Department of Water Resources. The program gives participants a reservation payment in return for a commitment to shed pre-designated amounts of load when called on to do so. Individual participants may sign up with a "Demand Reserves Provider" who aggregates load from multiple customers and is responsible for notifying customers of an impending event, verifying load reductions, and providing settlement services with the customer. Similar to IOU interruptible programs, there are limits on the frequency and an annual cap on the total number of hours load can be curtailed.

There are two incentive options available to customers participating in the Critical Peak Pricing or the Demand Reserves Partnership. The first option is the Bill Protection Incentive, which allows participating customers to pay no more for energy commodity service than if they had remained on their otherwise applicable rate. The second option is the Technical Assistance Option, which allows customers to earn a rebate for professional technical assistance enhancing the customer's ability to respond to curtailment requests for on-peak demand reductions.

#### Working Group 3 Activities

Working Group 3 focuses on small customers with demand of fewer than 200 kW. This group pursued two paths. First, participants developed and provided oversight for a Statewide Pricing Pilot to estimate potential demand response from residential, small commercial, and industrial customers.

Second, the group developed utility business cases for advanced metering infrastructure (AMI). There are substantial savings—compared with current operations—inherent in AMI systems that offset the additional costs of purchase, installation, operation, and maintenance. The purpose was to calculate those costs and savings in a parallel framework for each utility.

### *Advanced Communicating Meters*

Assembly Bill 29X (Kehoe), Chapter 9, Statutes of 2001, authorized $35 million to install advanced communicating meters for all customer accounts with peak demand greater than 200 kW. The Energy Commission administered the AB 29X funds and was responsible for program evaluation.[88] Meter installation by itself was not expected to impact customers' behavior. However, the meters could ultimately affect consumption by allowing time-based tariffs and providing detailed feedback about energy use to customers. The Energy Commission required utilities to provide web-based consumption data to customers who received the meters. Customers not already on time-of-use rates were required to switch to these rates as a condition of receiving the meter.[89]

Under the program, about 25,000 real time energy meters (RTEM) were installed in California. Nearly half (12,000) were installed in Southern California Edison's (SCE) service area, with another quarter (7,800) installed in PG&E's service territory. Because SDG&E had already received CPUC approval to install advanced meters for its customers in the 100 to 300 kW range, SDG&E used the Energy Commission funding to install about 1,400 meters for customers in the over-300 kW range.

The remaining meters were installed at publicly owned utilities, including Los Angeles Department of Water and Power, with 3,400, Sacramento Municipal Utility District, with 300, and the Southern California Public Power Authority and Northern California Power Agency who collectively received approximately 350 meters.

The initial intent of the program was to help develop real time pricing (RTP) rate designs, influence customer electricity use patterns, and encourage demand response, particularly during periods of peak demand and high wholesale costs. Although no extensive RTP programs have been approved, some pilot demand response programs have been implemented. In addition, metering infrastructure is now in place.

Laurits Christensen Associates evaluated the Energy Commission's meter installation effort and concluded that although many customers reduced their summer peak electricity consumption, there was only modest evidence that the reduction resulted from installing the RTEM or converting smaller customers to TOU energy prices.[90] The lack of hard evidence may be a consequence of the non-experimental nature of the program and the lack of a comparison period or control group.

What the evaluation did find, however, was that a number of SCE and PG&E commercial and industrial customers were already responding to peak prices, and some were able to reduce summer peak load levels by five to nearly 100 percent. These are presumably customers with flexible loads and high sensitivity to cost.

This result suggests that customers who already respond to TOU rates and energy charges can provide little additional demand response. However, these customers could benefit from a critical peak pricing product with high peak prices on days with critical resource constraint conditions and lower peak prices on lower-cost days. With this type of product, these customers could continue to provide substantial demand response on days when it is most valuable, but would not have to modify their operations the rest of the time.

A recent Working Group 2 evaluation of demand response programs found that while the accomplishments of the 2004 programs were "reasonable and in-line with experiences with similar voluntary price-responsive programs in other parts of the country", those programs were unlikely to achieve significantly more demand response either from improved participant response or from additional participation. The evaluation concluded that "the market needs stronger motivation, knowledge, and capability in order for these programs to make large contributions to the price-responsive DR goals."[91]

# Achieving Numeric Goals for Demand Response

## *Utility Goals for Demand Response*

Decision 03-06-032 under the CPUC's demand response proceeding set targets for demand response goals, as shown in Table 7. Decision 04-12-048[92] directs the IOUs to follow these target goals.[93] In April, 2004, the IOUs filed program plans requesting approval of adjustments to the large customer programs designed to increase enrollment and response. As part of these filings, they estimated the amount of demand response they would likely achieve during the summer of 2004. In the course of approving the program changes, the CPUC revised the 2004 goals to equal the IOUs' estimates.

For load reductions to count toward the targets, they must come from programs and tariffs that are categorized as "price responsive." The CPUC defines "price responsive" programs as those "in which customers choose how much load reduction they can provide based on either the electricity price or a per-kW or kWh load reduction incentive."[94]

While this definition is consistent with previous decisions in the Demand Response proceeding, Decision 05-01-056, released in January 2005, revised the definition to include MWs "from any program that provides a day-ahead demand reduction signal, whether it is based on a price, temperature, or reliability forecast, to count towards meeting the utilities' price responsive demand program goals adopted in D.03-06-032 and D.04-12-048."[95] This most recent definition draws a line between day-of and day-ahead demand response, reasoning that the purpose of day-of demand response is to support immediate system reliability. For procurement purposes, such demand response is accounted for separately.

### Table 7. Utility Demand Response Goals (MW)[96]

| Year | **PG&E** | **SCE** | **SDG&E** | **Total** |
|---|---|---|---|---|
| 2003 | 150 | 150 | 30 | 330 |
| 2004 | 400 | 400 | 80 | 880 |
| 2004 (revised) | 343 | 141 | 47 | 531 |
| 2005[97] | 450 | 628 | 125 | 1,203 |
| 2006 | 4% of the annual system peak demand | | | |
| 2007 | 5% of the annual system peak demand | | | |

### *Progress Toward Utility Goals*

Table 8 shows a summary of IOU demand response as of April 2005. The IOUs must report monthly progress toward the goals.[98] The CPUC clarified which programs' MW count toward the demand response goals, but the definition of which reported MW number to count requires additional CPUC direction.

## Table 8. IOU Demand Response Report Summary as of April 2005 (MW)[99]

| | PG&E | SCE | SDG&E | Totals |
|---|---|---|---|---|
| **Price-Sensitive Programs** | 370.8 | 150.3 | 34.6 | 555.7 |
| **Reliability Programs** | 334.9 | 1145.3 | 76.6 | 1556.8 |
| **Totals** | **705.7** | **1295.6** | **111.2** | **2112.5** |

There are three ways to report program MW: enrolled, demonstrated and expected. These methods are discussed in more detail below. Each of these methods overlaps to some extent depending on the program, and are interpreted somewhat differently within each IOU. Most monthly reports provide enrolled MW.

Enrolled MW reflects the maximum possible demand response available from customers enrolled in existing programs. IOUs assume that price-reducing tariffs will induce a 15 percent reduction in the total non-coincident peak demand of participating customers. For the Demand Bidding Program, IOU estimates reflect all customers' committed load reduction for an event. Such total participation is unlikely since bidding for any particular event is voluntary. The DRP numbers reflect the highest monthly peak load nominations from each customer.

Demonstrated MW refers to actual performance data. Current performance data, however, significantly underestimate available voluntary price responsive demand for two reasons. First, the population of participants is constantly changing and growing. Second, there have been few actual events on which to measure response. For instance, SCE reports low performance from artificial test events for the Demand Bidding Program, but estimates higher performance numbers for actual events based on customer contacts. The customers report that they are unwilling to curtail production and incur economic losses under test conditions but would curtail if needed during a system alert.

Over time, demonstrated MW will likely become the standard for forecasting demand response. Current programs, however, have been in a state of flux. In addition, a combination of design differences between programs and tariffs, untested triggering criteria, and mild weather in 2004 resulted in very little actual experience during the first summer with the new program designs.

Expected MW refers to IOU resource planners' best estimates, using a variety of input including enrollment, actual performance, and customer input. Table 9 shows expected MW savings from price-sensitive and reliability demand response programs.

## Table 9. Expected MW from IOU Demand Response Programs April 2005

| **Price Responsive Demand Programs (MW)** | | | | |
|---|---|---|---|---|
| Category | PG&E | SCE | SDG&E | Total |
| Demand Bidding | 40 | 67 | 1 | 108 |
| Critical Peak Pricing | 12 | 6 | 5 | 23 |
| Power Authority Demand Response | 200 | 31 | 5 | 236 |
| 20/20; Voluntary Programs | 0 | | 2 | 2 |
| **Total** | **252** | **104** | **13** | **369** |
| **Reliability Programs (MW)** | | | | |
| Category | PG&E | SCE | SDG&E | Total |
| Interruptible/Curtailable | 305 | 639 | 2 | 947 |
| Direct Load Control | 0 | 294 | 2 | 296 |
| Backup Generators | 0 | 0 | 17 | 17 |
| **Total** | **305** | **933** | **21** | **1260** |
| Numbers reflect demand response derated from reported enrollment/participation numbers that IOU resource planners consider reliable based on program experience, performance data, and customer self-report | | | | |

Source: Energy Commission and CPUC staff, in preparation for the *2005 Energy Report* Workshop on Resource Planning held March 21, 2005, and updated by Energy Commission staff in June 2005 to reflect the most recent IOU monthly reports.

When the CPUC revised the 2004 goals to equal the IOUs' estimates, it also directed the IOUs to procure additional resources to make up for the shortfall. Even so, the revised goals were not achieved, falling short by 24 MW.[100] In April 2005, IOUs reported 556 MW of price-sensitive demand response (enrolled MW), 324 MW short of the original collective goal of 880 MW for 2004 shown in Table 7. Discounting to the "expected" number of 368 MW reveals a 33 percent difference. However, when comparing the goals to the IOU numbers in Table 8, it is important to note that the largest component of enrolled MW in the Demand Reserves Partnership is Department of Water Resources pumping load—a resource with a long history of providing reliability services to PG&E—which is now included in a different type of program.

There is a fundamental disconnect between how IOUs report megawatts counted toward meeting their demand response goals set forth in CPUC Decision 03-06-032 and resource planners' need for measurable and reliable load reduction. Decision 04-12-048 anticipates this issue in its discussion of utility suggestions to either adjust the goals or institute an annual review process. The decision concludes that the goals should remain as they are to encourage IOUs to meet them cost effectively.

As a result of a meeting between representatives of the three IOUs and the Energy Commission and CPUC staff in May 2005, monthly reports will have an additional column of information beginning in June 2005 reflecting the IOUs' best estimates of available capacity from demand response programs.

Resource planners need unambiguous, reliable estimates of demand response capacity to accurately procure resources needed to meet demand. However, the goals set in the demand response proceeding provide an incentive for regulated utilities to take risks in developing and implementing innovative programs. Because not all programs will be successful, planners cannot reliably estimate the demand response achievable by any of those programs until IOUs and their customers gain more experience.

The Energy Commission staff expects low estimates of reliable demand response capacity from these programs, especially during the first few years. This does not indicate program failure, especially when the goals that serve as the measure of success are set high to encourage the utilities to innovate. Nor does it suggest that the goals should be lowered to "more realistic" levels. There is good reason to believe that reliable expected demand response will grow substantially over the next three years as current efforts begin to show returns.

On August 1, 2005, the IOUs will file applications to implement default critical peak pricing tariffs for large customers, beginning in summer 2006. Along with the tariff designs, the utilities will develop customer education, assistance, and incentive plans to ease the transition, and increase achievable demand response from this customer class. This will move utilities closer to their demand response goals.

### *Advanced Metering Infrastructure*

At the same time, PG&E, SDG&E and SCE have filed plans for replacing their metering systems with advanced metering and communications systems that will support time-based tariffs for all customers.

Advanced metering infrastructure (AMI) allows utilities to remotely read customer meters, support time differentiated rates and other forms of emergency reliability programs on the demand side, and increase the level of customer service provided by reducing the costs of billing, metering and outage management systems. In the last year, the IOUs completed an analysis of the costs and benefits of deploying advanced metering networks. The CPUC and Energy Commission have reviewed these analyses and encouraged the utilities to move ahead with their AMI cost applications. The CPUC expects to hold hearings on these proposals during the remainder of 2005 and issue a decision in early 2006.

PG&E and SDG&E found that the benefits of AMI deployment exceeded the anticipated costs over the next twenty years. PG&E estimates that the operational savings in reducing metering billing and system costs alone will exceed 90 percent of the $2.2 billion in expected costs of deploying the system over the next five years. Demand response benefits ranging from $200 million to $800 million are expected to fill the operational savings gap of $201 million identified by PG&E in its latest May filing.

SDG&E conducted a similar analysis. SCE's analysis showed the current generation of AMI metering and communication technologies could not provide all desired functionality. In response, SCE has filed for approval of roughly $33 million in research and development costs to jointly develop a more advanced metering system with metering vendors.

Both SDG&E and SCE have applied for CPUC authorization to recover expenses associated with pre-deployment and testing of the first wave of meters, to be ordered and installed in 2006. In addition, both companies have applied for full cost recovery for fully deploying the advanced meters over a three- to five-year period. A decision on the preliminary deployment costs is expected in September and a final decision on the full scale deployment for both utilities is expected in February 2006.

Outstanding issues from opponents of AMI investments include: the impact of the Assembly Bill 1X (Keeley), Chapter 4, Statutes of 2001, rate freeze on the CPUC's ability to introduce new rate structures, the value of peak load reductions, the bill impacts of AMI deployment on low-usage customers, and rate design issues related to removal of cross subsidies in current rates.

## Integrating Demand Response as a Cost Effective Procurement Resource

One of the barriers facing integration of price-sensitive demand response into the procurement process is uncertainty associated with measuring the cost effectiveness of the programs. Neither the cost per MW of demand response nor the avoided costs have the track record of intensive measurement and evaluation as parallel benefits and costs that are long-established in energy efficiency and renewable programs.

## Monitoring and Verifying Demand Response

Evaluation of demand response programs has followed the "large" and "small" customer divisions of the working group process. Small customers were the subject of a comprehensive experiment designed to estimate potential demand response impacts of a variety of rate designs. Large customers were offered voluntary demand response programs and tariffs, and evaluation focused on participant impacts and an exploration of non-participant characteristics, decision processes, and demand response potential.

**Small Customers**

Initially, Working Group 3 discussion in the Joint Agency Demand Response proceeding revealed a wide variety of opinion on the costs and benefits of advanced metering systems for small customers, the technological viability of currently available metering systems, the demand response potential for small customers, and the customer impact of advanced metering systems and time-based rates.

To address the customer impact issues, the Working Group and the CPUC established a Statewide Pricing Pilot (SPP) program to test the impacts of various types of time-based rates and technology options.

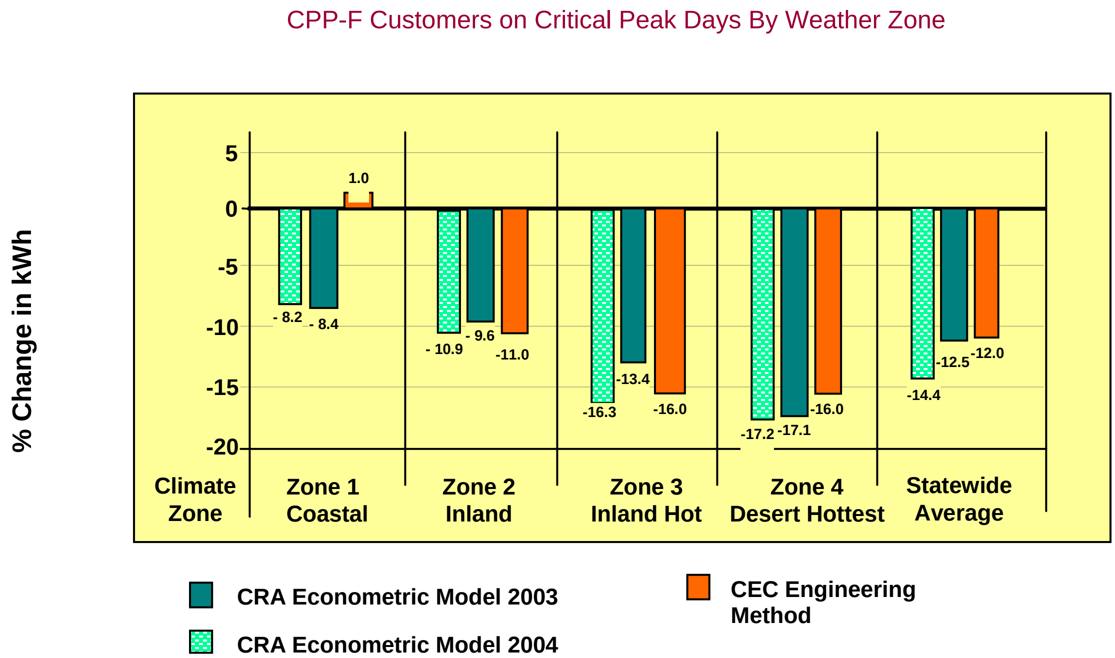
Between fall 2002 and spring 2003, the SPP and its supporting infrastructure were developed and installed. The first customers joined the program beginning in July of 2003. More than 2,500 customers tested a number of different rate structures. These included a control group, an “information only” group, groups given a traditional time-of-use rate, two types of critical peak pricing (CPP) rates—one with a fixed time period and one-day’s notice (CPP-F), and the other with a variable time period and day-of notice (CPP-V). Most of the pilot program participants were residential customers, but a sample of small commercial and industrial customers was given a variable CPP and time-of-use rate.

Figure 13 shows the price elasticity—the amount of load in kW reduced for each one cent increase in price—for residential customers on the CPP-F rates using three different calculation methods. The two “CRA Statistical” methods are designed to both account for usage differences observed within the sample and for slight differences between the sample and the general population.

Figure 14 shows the average load reduction of customers on three different types of rate treatment on a hot August day. The three categories are: customers in the control group, customers who have an automatic load reduction technology installed (but without a time-varying rate—thus a “flat” rate), and customers with a particular automatic load reduction technology (an automatic thermostat that responds to a critical peak rate signal from the utility) and a time-varying rate. The results show the largest load reductions from customers with the combined automatic technology and time-varying rate.

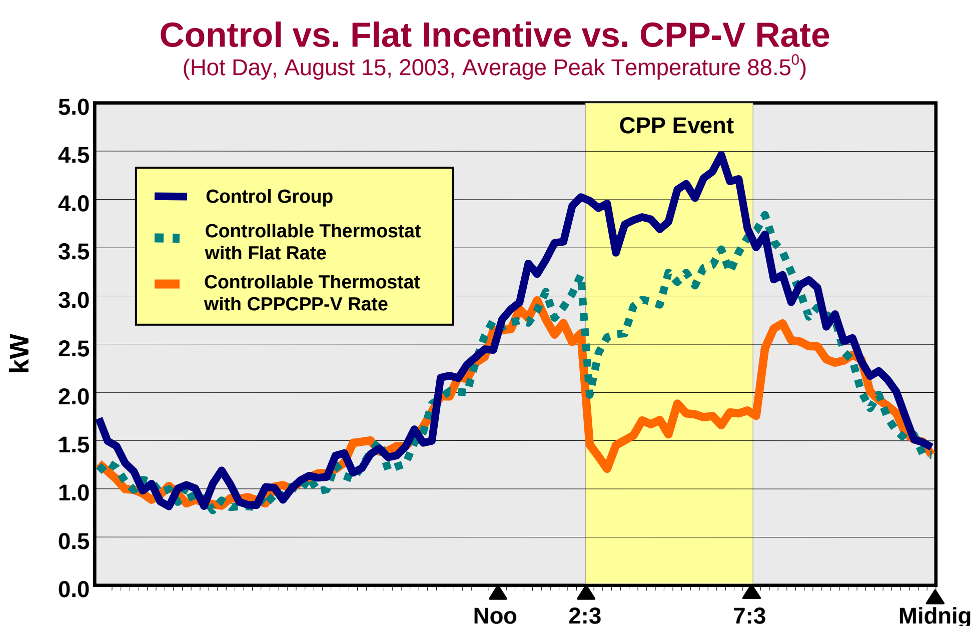
Figure 15 shows results from a survey of SPP participants on the question of making time-varying rates available to all customers. The results clearly indicate that these pilot participants had an overall positive perception of the rates after their experience.

## Figure 13. Percent Change in Peak Period Energy Use



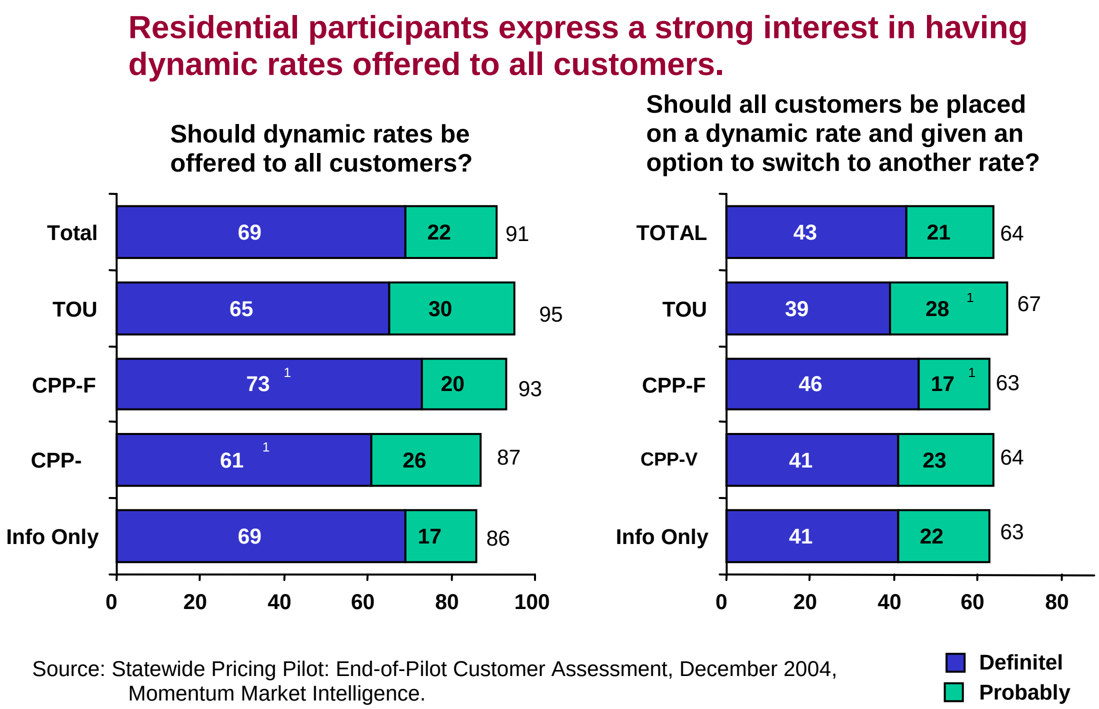

Source: Statewide Pricing Pilot, Summer 2003 Impact Analysis, Charles River Associates, August 9, 2004, Table 5-4; California's Statewide Pricing Pilot: Update of Results, Charles River Associates, January 7, 2005, Slide 4.

## Figure 14. Residential Response




Source: Response of Residential Customers to Critical Peak Pricing and Time-of-Use Rates during the Summer of 2003, September 13, 2004, CEC Report.

## Figure 15. Customer Acceptance



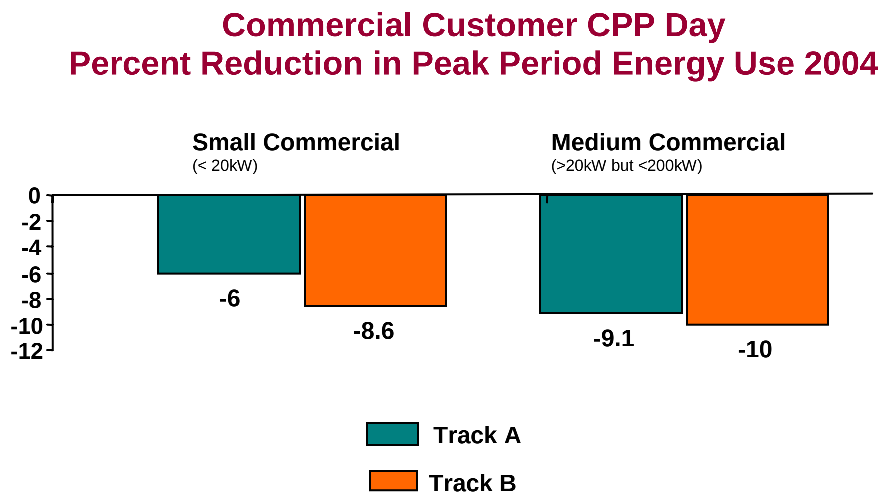

Source: Statewide Pricing Pilot: End-of-Pilot Customer Assessment, December 2004, Momentum Market Intelligence.

Commercial customers, as expected, showed less ability to reduce loads by a large magnitude than residential customers. However, as shown in Figure 16, the load reductions they do provide make a significant contribution to system stability. Customer bill impacts in 2004 are represented in Figure 17. Overall, most customers participating in the SPP saw bill reductions.

The overall impacts of the SPP show that:

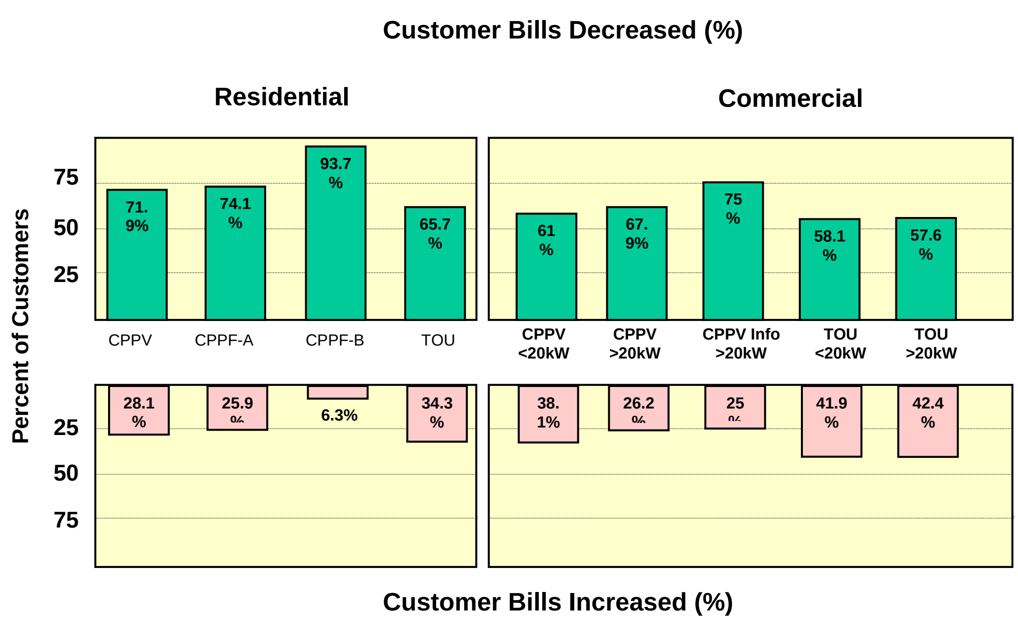
- Residential CPP-F rates reduced peak period (2:00 p.m. to 7:00 p.m.) energy use on critical peak pricing days by more than an average 14 percent. Customers opting for automatic controls reduced peak energy use by 25-35 percent.
- Pricing produces stable results:  residential peak period reductions were almost identical in summers 2003 and 2004.
- Average residential peak period impacts held steady throughout multiple-day peak pricing events usually associated with heat storms.

## Figure 16. Commercial Customer Load Impacts




Source: California's Statewide Pricing Pilot: Update of Results, Charles River Associates, January 7, 2005, Slide 13. Track A= General population with choice of smart thermostat; Track C=load reductions for customer already participating in smart thermostat program

## Figure 17. Customer Bill Impacts



**Large Customers**

Working Group 2 under the Joint Agency Demand Response proceeding identified basic objectives for a measurement and evaluation approach for large customers and set up a subcommittee to oversee that work.[101] The final research plan was developed by Quantum Consulting in cooperation with the subcommittee.

One important attribute of this work is that it was conducted on a close to real-time basis, with results coinciding with regulatory filings and decisions. The evaluation was conducted in parallel with program marketing and implementation throughout 2004 and reports were provided approximately every quarter. Though challenging, this approach provided important feedback to policy makers and program designers and contributed to a number of proposed program changes and regulatory decisions for 2005. Three reports were provided during this study, along with several presentations, each of which was timed to coincide with key regulatory deadlines and activities throughout 2004.

Key findings and conclusions from the 2004 Critical Peak Pricing (CPP) and Demand Bidding Program (DBP) Evaluation are below.

- Only one percent of eligible accounts participated in CPP in summer 2004. The program was designed so that about half of eligible customers could benefit without making any change in their load shapes. However, the level of benefit for these customers is only about one percent of their annual bill; this combined with uncertainty about the stability of the Critical Peak Pricing rate, as well as future changes in their load shapes due to weather or other factors appear to have reduced participation in 2004.

  Table 10 summarizes program penetration levels for the 2004 CPP and DBP programs.
- Across all utilities, overall estimated load reduction in the CPP was roughly eight MW. For PG&E and SDG&E, which had the vast majority of CPP participants, average percent savings ranged from a few percent up to 20 percent depending on the utility and event.
- For the DBP, only seven percent of SCE customers signed up for the program bid load for at least one of SCE's two test events. For SDG&E, 27 percent of customers bid in at least one of the three day-of events, while there were no "bidders" per se for PG&E because the IOU's 2004 DBP did not allow for actual bidding on day-of events. Survey results show that of those who did not bid, 39 percent said it was because they could not reduce load on that particular day. In general, low levels of bidding in 2004 appear to reflect lack of experience, knowledge, and capability for some customers.

## Table 10. 2004 Critical Peak Pricing and Demand Bidding Program Signups Across All Utilities

| 3 IOUs | Participant Penetration | Participant MW Penetration* | Participant GWh Penetration* | CPP Penetration | DBP Penetration |
|---|---|---|---|---|---|
| **Size** | | | | | |
| Very Small (100-200 kW) - SDG&E Only | 0.5% | 0.6% | 0.3% | 0.4% | 0.3% |
| Small (200-500 kW) | 3.2% | 3.0% | 4.1% | 0.6% | 2.7% |
| Medium (500-1000 kW) | 7.4% | 7.6% | 8.0% | 2.1% | 5.6% |
| Large (1000-2000 kW) | 10.9% | 11.0% | 11.8% | 3.1% | 8.6% |
| Extra Large (2000+ kW) | 11.1% | 10.9% | 20.4% | 1.6% | 10.1% |
| **Business Type** | | | | | |
| **Commercial and TCU** | | | | | |
| Office | 1.8% | 2.6% | 3.2% | 0.3% | 1.6% |
| Retail/Grocery | 7.6% | 6.8% | 9.0% | 0.1% | 7.5% |
| Institutional | 2.6% | 6.9% | 8.7% | 1.0% | 1.7% |
| Other Commercial | 4.5% | 7.5% | 8.1% | 1.0% | 3.7% |
| Transportation/Communication/Utility | 6.2% | 5.2% | 7.5% | 1.8% | 4.5% |
| **Industrial and Agricultural** | | | | | |
| Petroleum, Plastic, Rubber and Chemicals | 8.0% | 9.1% | 12.8% | 1.0% | 7.1% |
| Mining, Metals, Stone, Glass, Concrete | 8.2% | 23.7% | 31.9% | 0.7% | 7.8% |
| Electronic, Machinery, Fabricated Metals | 6.2% | 14.8% | 20.3% | 2.0% | 4.5% |
| Other Industrial and Agriculture | 4.1% | 8.5% | 10.8% | 1.3% | 3.1% |
| **Unclassified** | | | | | |
| Unknown | 10.5% | 5.2% | 13.4% | 4.1% | 6.7% |
| Total Accounts | 4.7% | 8.0% | 11.2% | 1.1% | 3.8% |

*Diversified customer peak demand

- Because there were very few DBP events, it is difficult to identify a reliable DBP impact estimate that can be used to forecast future expected savings. However, the evaluation did estimate overall load reduction from the DBP events to be about 27 MW across all utilities.
- The evaluation also indicated that many participating customers believe the costs of participating in the program exceeded the value of the financial incentives. In addition, customers identified several barriers to their participation in demand response programs. The number one concern was effects on products or productivity, followed by insufficient bill savings, high on-peak prices or non-performance penalties, and inadequate program information.
- To identify technical MW reduction potential, the evaluation surveyed non-participants. Although technical potential varied widely by market segment, the average technical potential reported from the market was 16 percent, or about 1,600 MW.[102]
- There is evidence that a modified technical assistance approach that includes site-specific support could provide value to participants and lead to increased demand response impacts.
- All of the utilities were successful in raising awareness about these new programs. The main source of program information came from personal contacts with the utility.

- Overall, customers were satisfied with the notification process for both the CPP and the DBP, with a lower level of satisfaction among DBP participants that may be related to their inability to curtail in the time required.
- There are significant challenges associated with achieving high levels of participation in and load reduction from the voluntary 2004 DBP and CPP programs.
- Although adoption of these programs takes time, the results of the program evaluation indicate that the 2004 CPP and DBP programs would not contribute largely to achieving demand response goals. If participation in demand response programs or tariffs remains voluntary, the market needs stronger motivation, knowledge, and capability for these programs.

# Chapter 4 Endnotes

[86] While average peak loads can be forecast with a high degree of precision, the difference between average and peak event loads in California is largely driven by weather events that lead to increasing a/c use. While the magnitude of these peaks can be predicted with precision, their timing can be forecast only as accurately, and with as much advance notice, as the weather. Procuring capacity to serve that load thus requires some combination of advance capacity purchases and short term energy purchases that balance the risk of purchasing too much (paying for unneeded capacity) or too little (purchasing in the real-time market).

[87] D.03-06-032, p. 3

[88] Evaluation of California's Real-Time Metering (RTEM) Program. California Energy Commission Consultant Report CEC-400-2005-021

[89] Most customer accounts with maximum demands greater than 500 kW already had interval meters installed in their facilities. However, many needed upgrades to install the communication equipment needed to allow remote data retrieval and posting on the website.

[90] Evaluation of California's Real-Time Metering (RTEM) Program. California Energy Commission Consultant Report CEC-400-2005-021.

[91] Working Group 2 Demand Response Program Evaluation – Program Year 2004," prepared for WG2 Measurement and Evaluation Committee, by Quantum Consulting Inc. and Summit Blue Consulting, LLC, December 2004, p. 1-1.

[92] D.04-12-048 in Rulemaking 04-04-003, the *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company's Long-Term Procurement Plans,* filed December 16, 2004.

[93] D.03-06-032 in Rulemaking R.02-06-001, *the Interim Opinion in Phase 1 Addressing Demand Response Goals and Adopting Tariffs and Programs for Large Customers*, filed June 28, 2003.

[94] D.04-12-048, p. 57

[95] D.05-01-056, in R.02-06-001, p. 8

[96] The goals were to be achieved by July 1st of each year. Goals for 2004 were revised in an Assigned Commissioner's Ruling dated June 2, 2004.

[97] 2005 goals were originally described as 3% of annual system peak, but in D.04-12-048 were converted to numeric goals for each IOU, p. 60.

[98] Monthly reports, now filed under R.02-06-001, On Interruptible Load Programs, Rotating Outage Activities, and Demand Response Programs, are filed by each IOU on a monthly basis.

[99] This table is compiled from the three IOU monthly reports on Interruptible load Programs, rotating Outage Activities, and Demand Response Programs for April 2005.

[100] R.02-06-001. *Administrative Law Judge's Ruling Approving 2004 Schedule and Plan for the Statewide Pricing Pilot Evaluation and Customer Research Activities and Extablishing Process for Evaluation of Proposed 2005 Price Responsive Demand Programs*. Filed June 2, 2004.

[101] [http://www.energy.ca.gov/demandresponse/documents/working_group_documents/2002-12-13_WG2_REPORT2.PDF]

[102] To develop very rough estimates of the DR capability that currently exists customers were asked a hypothetical question asking what percent of their normal summer afternoon peak demand their company would be willing and able to reduce for a few hours on four weekdays in the summer, provided they were notified the day before, and were given *sufficient financial motivation*. The estimates were calculated using the self-reported reduction ranges and can be considered the upper bound of the near-term technical potential since there may be a tendency with self-reports to over-estimate true ability. At the same time, because DR knowledge and automation capabilities are still relatively limited and nascent, one would expect that the longer-term DR technical potential would be higher if improvements in knowledge and controls automation increase.

# CHAPTER 5: RENEWABLE RESOURCES

This chapter discusses renewable energy resources in California, including current status, progress toward achieving numeric goals, issues surrounding integrating renewable resources into the system, and monitoring and verification efforts.

This chapter draws on publicly available information regarding renewable energy development in California, including recently published staff and consultant reports docketed in the *2005 Energy Report* proceeding, as well as a series of workshops held by the *2005 Energy Report* Committee.

## Status of Renewable Energy Development in California

California's Renewables Portfolio Standard, established in 2002, requires retail sellers of electricity to increase the amount of renewable energy, as a percentage of the electricity they sell, by at least one percent per year toward a target of 20 percent renewable by 2017, subject to certain cost constraints. In 2003, the state's energy agencies began working to accelerate the timetable to 20 percent renewables by 2010.

This section discusses progress to date on the state's RPS goals, RPS implementation issues, renewables technical potential in California, potential impacts of intermittent resources on the state's electrical grid system, and trends in long-term power procurement as they relate to renewable energy.

### *Progress toward Goals in the 2004 Integrated Energy Policy Report Update*

The *2004 Energy Report Update* recommended accelerating the 20 percent RPS goal from 2017 to 2010 and establishing a longer-term goal of 33 percent by 2020.

In addition, the report recommended legislation requiring all retail suppliers of electricity, including large publicly owned utilities (POUs), to meet accelerated and longer-term goals and to use common definitions of eligible renewable energy. Finally, the report recommended legislation allowing the California Public Utilities Commission (CPUC) to impose utility-specific targets for Southern California Edison (SCE), because SCE is already well on its way to achieving the 20 percent target.

Table 11 shows the amount of renewable procurement to date compared with the amount of renewable generation needed in 2004 for the state to stay on track to reach 20 percent by 2010, based on 2001 baseline renewable sales. Table 11 also shows the Annual Procurement Target set by the CPUC, which is calculated as 101 percent of the previous year's retail sales.[103]

## Table 11. Procured versus Needed Renewable Energy to Reach 20 Percent by 2010[104]

| Utilities and Year | Actual or Planned Renewable Energy Procurement (GWh/yr) | APT set by CPUC | Estimated Cumulative Need (GWh/yr) |
|---|---|---|---|
| ***PG&E*** 2003 | 8,828 | 8,764 | 7,326 |
| 2004 | 8,591 | 9,475 | 8,550 |
| 2005 | 9,034 | 10,211 | 9,633 |
| 2010 | 14,790 | | 15,879 |
| ***SCE*** 2003 | 12,497 | 12,030 | 12,451 |
| 2004 | 13,246 | 12,736 | 13,637 |
| 2005 | 13,192 | 13,466 | 14,560 |
| 2010 | Redacted | | 15,934 |
| ***SDG&E*** 2003 | 547 | 150 | 501 |
| 2004 | 678 | 423 | 893 |
| 2005 | 884 | 581 | 1,285 |
| 2010 | Redacted | | 3,462 |
| ***Direct Access and Rest of State*** | | | |
| 2003 | 4,856 | n/a | 9,540 |
| 2004 | 4,676 | n/a | 11,512 |
| 2005 | | | 13,022 |
| 2010 | | | 20,885 |
| ***Total State*** | | | |
| 2003 | 26,728 | n/a | 29,818 |
| 2004 | 27,191 | n/a | 34,593 |
| 2005 | | | 38,501 |
| 2010 | | | 56,160 |

Source: IOU APT compliance reports filed with the CPUC, Gross System Power (less 7% for losses), Appendix A. Cells outlined in bold indicate cumulative procurement that is behind schedule.

### Investor-Owned Utilities

In August 2003, SCE issued a solicitation for renewable energy to satisfy its RPS requirements. Although bids were due in September 2003, SCE's negotiations with short listed bidders were not completed until March 2005. SCE then submitted an Advice Letter to the CPUC asking for approval for six RPS contracts totaling 142 MW of capacity (643 gigawatt hours [GWh] annually), with potential to expand to 428 MW (2,2127 GWh annually), and including biomass, geothermal, and wind resources.[105] The CPUC approved the contracts,[106] but deliveries from these facilities will not begin in 2004 because project construction will not be completed until 2006-2008.[107] The CPUC also approved four bilateral contracts that SCE executed with wind facilities that are being repowered, anticipated to result in future deliveries of approximately 25 GWh annually.[108]

The CPUC excused SCE from conducting a renewables solicitation in 2004 partly because of SCE's progress toward meeting the 20 percent renewable target. As ordered by the CPUC, the other two investor-owned utilities (IOUs), Pacific Gas and Electric Company (PG&E) and San Diego Gas and Electric Company (SDG&E), conducted solicitations for renewable energy for 2004.

SDG&E issued its RFO July 1, 2004, with bids due August 12, 2004, and is still negotiating with bidders.

PG&E issued its Request For Offers (RFO) on July 15, 2004, with bids due August 23, 2004. In April 2005, PG&E received approval from the CPUC for three wind contracts totaling 142-158 MW from its 2004 solicitation,[109] and has requested approval of a fourth contract with a new wind facility with 52.5 MW capacity and expansion potential to 75 MW. To date, PG&E has executed RPS contracts from its 2004 solicitation totaling 194.5-233 MW of wind priced below the MPR and ineligible for supplemental energy payments from the Energy Commission. PG&E anticipates that the expected future generation from these projects will exceed 100 percent of its incremental procurement target for 2004 under the state's RPS.[110] It is important to note, however, that the amount of energy delivered in 2005 is not expected to meet PG&E's annual procurement targets.[111]

In their Requests for Offers (RFOs), the IOUs estimated the amount of time needed between the release of their solicitations and the filing of their contract advice letters with the CPUC:  four months for SCE, five months for PG&E, and nine months for SDG&E. However, the actual time has been significantly longer than anticipated. It took SCE 20 months and PG&E nine months to file their advice letters, and SDG&E is currently three months behind schedule.

The delays are largely related to negotiating contract terms and conditions. Other sources of delay include the selection process for the short list of least-cost, best-fit bidders, especially in relation to estimating transmission costs and uncertainty regarding potential federal or state regulatory changes.

For 2005 renewables procurement, the IOUs submitted their draft RPS procurement plans and draft RFOs in the spring of 2005; CPUC approval is expected in July 2005. The IOUs expect to release their 2005 renewable solicitations in mid-to-late 2005, with contracts signed by the end of 2005 or in 2006.

**Publicly Owned Utilities**

Publicly owned utilities (POUs) in California are required to develop RPS programs recognizing the intent of the Legislature to encourage renewable resource development. However, because POUs are not subject to the same implementation rules as IOUs, their RPS programs include varying targets, timelines, and eligibility standards. For example, many POUs still consider large hydroelectric projects as eligible renewable technologies. Only small hydroelectric is eligible for IOU RPS compliance. In addition, many POUs set a target of 20 percent of retail sales from renewable energy by 2017, not by 2010 as adopted by the state's energy agencies. Twenty-nine POUs have informed the Energy Commission of their adopted RPS plans, which are summarized in Table 12.[112]

### *Integrating Wind Energy into the System*

Wind generation will likely play an important role in meeting California's RPS goals. Because wind is an intermittent resource, increased wind penetration in California and the Western Electricity Coordinating Council (WECC) will have an impact on the state's electrical grid. Figure 18 shows an example of the monthly and hourly profile of wind energy generation in three California wind resource areas, based on CA ISO data for 2002.

To help address scheduling challenges for wind, the CA ISO developed the Participating Intermittent Renewables Program. As part of the program, the CA ISO uses wind forecasts to anticipate wind energy delivery and settles energy imbalance costs (charges for when delivered energy differs from the scheduled amount) with participating wind energy generators on a net monthly basis.[113] Wind generators pay a forecasting service fee of $0.1/MWh to the CA ISO to participate in the program.[114]

There are currently only 10 participants in the CA ISO's program, with a total of 450 MW capacity. This represents only 20 percent of the total wind generation available. The other 80 percent is currently covered by qualifying facility (QF) contracts with local utilities; those utilities have the responsibility to forecast and schedule that wind generation. An important goal is for all wind generators, QF or otherwise, to participate in the program. By having all wind generation participate in the program, the California ISO will be able to develop more accurate advance forecasts of wind generation, and could make more informed decisions on what generating units should run.

The Energy Commission's PIER Program also developed the Strategic Value Analysis (SVA) methodology as a research and planning tool to estimate the impact of new transmission or new generation on statewide power flow congestion.

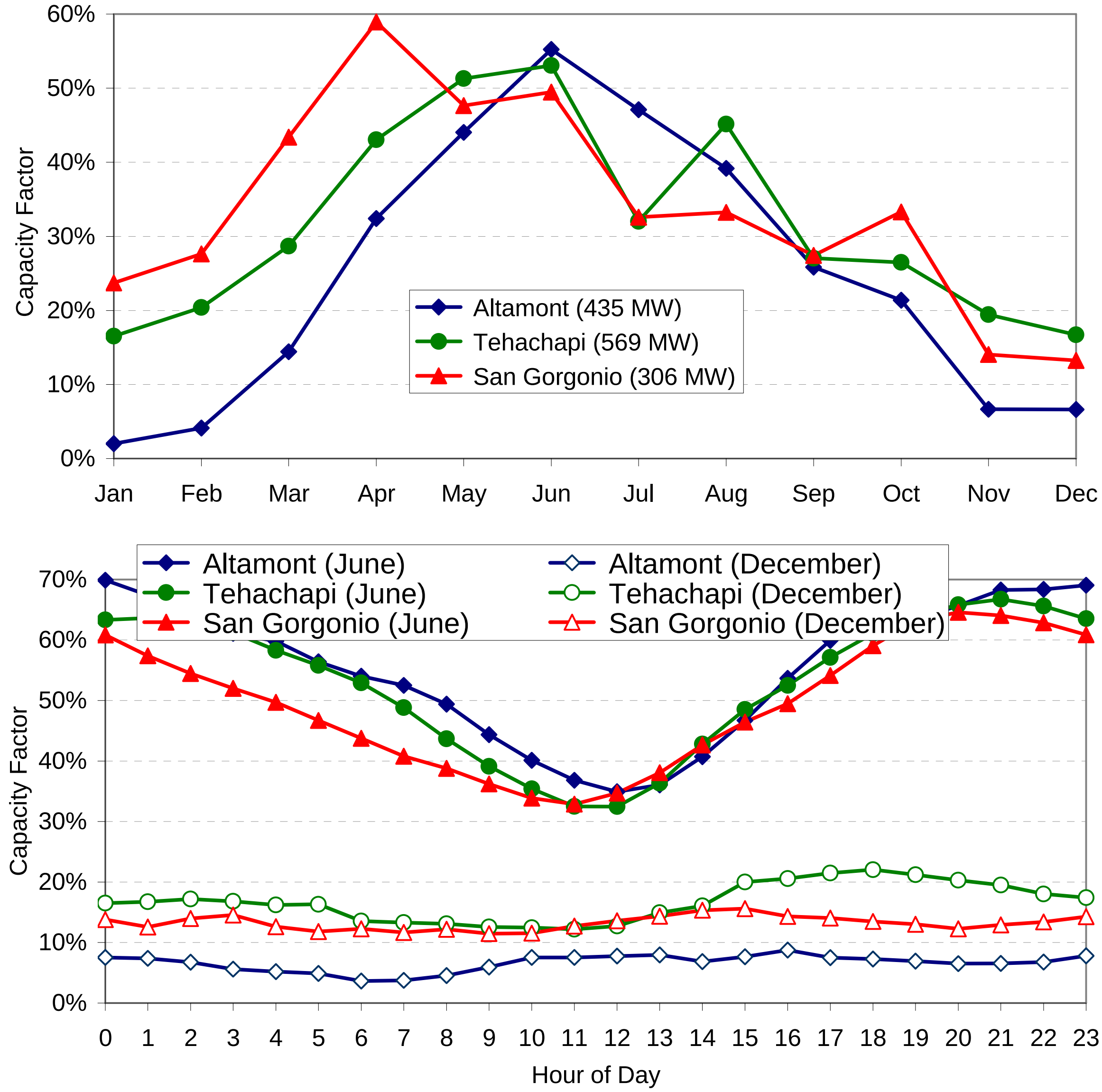
Another integration issue facing wind power is its ability to compete with non-intermittent resources in the RPS procurement process. A central component of California's RPS is a competitive least-cost-best-fit process used to select baseload, as-available, and peaking renewable products.[115] The CPUC defines "best fit" as "the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs."[116] As a result, renewable energy products that offer energy when it is not needed are likely to rank poorly against products in the same category that offer energy when demand is high and unmet by current resources, unless there is a substantial cost savings relative to other bids.

## Table 12. RPS Status for Publicly Owned Electric Utilities

| Utility | Renewable resources in utility portfolios (% of sales) "Eligible" Renewable* 2003 | "Eligible" Renewable* 2004 | Large Hydro qualifies as renewable | Target in RPS plan | Time frame for achieving the RPS target? |
|---|---|---|---|---|---|
| Alameda | 50% | | Yes | 40% | Maintain through 2020 |
| Anaheim[117] | <1% | 1% | Yes | 15% | 2017 |
| Azusa | 7% | 7% | Yes | 20% | 2017 |
| Banning | 0% | | Yes | 20% | 2017 |
| Biggs | 10% | | Yes | 20% | Unknown |
| Burbank | 1% | 1% | "if low impact" | 20% | 2017 |
| Colton | 2.2% | | Yes | 15% | 2017 |
| Glendale | 7.2% | 14% w/lg hydro | Yes | 20% | 2017 |
| Gridley | 10% | | Yes | 20% | Unknown |
| Healdsburg | 55% | | | | |
| Imperial[118] | 12% | 11% | Yes | 20% | 2007 |
| Lodi | 25% | 28% | Yes | 20% | Maintain for unspecified time |
| Lompoc | 37.3% | | Yes | 20% | Purchases limited to funds, load growth, and replacing retired resources |
| Los Angeles | 1.5% | | Undecided. | 20% | 2017 |
| Merced | 11% | 12% | no | 15% | 2012 |
| Modesto | <1% | | No | 20% | 2017 |
| Palo Alto | 7% | 5% | No | 20% | 2015 |
| Pasadena | 1.7% | | Yes | 20% | 2017 |
| Plumas-Sierra Rural Electric Cooperative | Unknown | | Yes | 20% | Unknown |
| Port of Oakland | 4% | | Yes | 20 % Goal, 40% Objective | 2017 |
| Redding | 4.8% | | Yes | 20% | 2017 |
| Riverside | 12% | 12% | Yes | 20% | 2015 |
| Roseville | 14% | 13% | yes | 20% | Maintain for unspecified time |
| Sacramento | 7% | | No | 20% | 2011 |
| Santa Clara | 26% | 24% | Yes | Continue support of renewables. | |
| Trinity | 0% | | Yes | Consider only renewables in meeting future growth as needs grow beyond that provided by the Trinity River. | |
| Truckee Donner | Unknown | | Yes | Seek to add qualifying renewables if public goods charge available | |
| Turlock | 8% | | No | 20% | 2017 |
| Ukiah | 50% | | Yes | Will seek to add qualifying renewables as demand increases. | |

Source: Electricity Resource and Transmission Data Submittals for the *2005 Energy Report* from Publicly Owned Electric Utilities (filed in March and April, 2005), California Municipal Utilities Association, and *Renewable Resources Development Report*, 2003

**Figure 18. Monthly and Hourly Wind Production in Altamont, Tehachapi, and San Gorgonio Resource Areas**




Source: CA ISO 2002 production data, as cited in Ryan H. Wiser, May 9, 2005, "Temporal Production Profiles of Wind Power Plants in California and Other Western States," presented at the Committee Workshop on Renewable Resource Potential in California and Interstate Renewable Resources, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-05-09_workshop/presentations/Ryan_Wiser_Wind_Profiles_2005-05-09.PDF], slide 7 and 8.

Determining the capacity value for wind is important both for least-cost-best-fit evaluation of bids in RPS solicitations and assessing the degree to which wind contributes to resource adequacy requirements. For RPS competitive bid processes, the CPUC adopted a wind capacity value of 24 percent, based on an analysis of the effective load carrying capability of existing wind resource areas.[119] For resource adequacy purposes, a CPUC decision on the capacity values for wind is expected this summer.

In an effort to better understand the value of wind generation based on what time it is generated, the Kema-Xenergy, Inc. Contracting Team completed a summary of wind profiles in California and other western states in February 2005.[120] Kema-Xenergy, Inc. concluded that many California wind sites show reasonably consistent patterns of high production in the spring and early summer months, with energy production highest around midnight and lowest around noon. In contrast, many wind sites elsewhere throughout the West peak in the winter months, while others have either less-pronounced seasonal variations or variations similar to those in California's wind resource areas. Based on their analysis, Kema-Xenergy, Inc. concluded that there is little evidence that wind sites located outside of California would be a significantly better match to California load or prices than in-state resources. The Kema-Xenergy, Inc. team also found that temporal wind patterns can affect wholesale market value by plus-five to minus-10 percent with the best sites performing about 15 percent better. This means that with a base wholesale price forecast of $42/MWh, the difference in wholesale market value between the best and worst wind sites could be about $6/MWh.[121]

## *Long-term Procurement and Renewable Resources*

For renewable resources, California's load serving entities (LSEs) must meet specific procurement mandates that implement current statute and policy directives. The CPUC established a long-term procurement framework for IOUs intended to integrate the results of the Energy Commission's Integrated Energy Policy Report and be consistent with the state's loading order and an accelerated RPS. The state's municipal utilities are implementing RPS programs in a variety of ways consistent with their unique long-term resource plans.

The Energy Commission directed all LSEs in California to report on their long term procurement plans for renewable resources as part of their 2005 Electricity Supply and Bulk Transmission data submittals.

### Investor Owned Utilities

The CPUC directed the state's IOUs to file long-term procurement plans (LTPPs) every two years, beginning in 2004. In its December 16, 2004 LTPP decision, [122] the CPUC stated that the loading order is the highest priority and provided specific direction to the IOUs on renewable resource procurement. The decision also stated that renewables are "the rebuttable presumption," adding that whenever an IOU issues a Request for Offers (RFO) for generation resources, it must justify its selection of fossil generation over renewable generation offers. The CPUC intends to make renewable energy development central to IOU resource plans. In the interim, the CPUC has directed IOUs to issue RPS solicitations for 2005.

Concurrent with their LTPP filings and data filings for the *2005 Energy Report*, IOUs submitted updated long-term RPS procurement plans in April 2005 and were directed to conduct RPS solicitations for 2005. The regulatory context of IOU resource procurement is further discussed in the Energy Commission staff report *Investor-Owned Utility Resource Plan Summary Assessment.*[123]

Among the 10-year resource plans developed for the *2005 Energy Report* is the reference case. This case describes each IOU's annual procurement targets (APT) as the annual amount of renewable resources the IOU should receive from generators, expressed as a percent of IOU annual retail sales. The IOUs assume that in 2010, 20 percent of all retail energy sales will match energy produced from RPS-eligible renewable resources. To ramp up and maintain this 20 percent renewable energy target, IOUs assume median hydro conditions (excluding large hydro). The IOUs cannot assume that three-year averaging rules or tradable RECs can be used to meet the targets.

To assess a longer-term RPS goal of 33 percent by 2020, the IOUs were asked to submit an Accelerated Renewables Scenario. In addition, IOUs were asked to provide an alternative or preferred resource case with resource assumptions that may differ from the reference case, but still maintain the RPS of 20 percent by 2010, retaining that percentage through 2016. In all cases, the IOUs' resource plan only generically identified the amount of renewable generation needed to meet specified APT targets.

Collectively, the long-term procurement or resource plans submitted by the IOUs in 2005 express some common concerns about achieving the state's accelerated goals for renewable energy. Transmission may be the most severe constraint to the IOUs and the state achieving renewable energy targets. The IOUs raised the following issues:

- Deliverability of eligible renewable resources from outside the service area and to load centers.
- Electric system operational and transmission reliability consequences of intermittent and non-dispatchable procurement obligations.
- Rate impacts from increased transmission costs, the potential for above-market RPS costs and whether a PGC fund can or will be necessary to fund those costs.

- Availability of an economic and balanced mix of renewable resources consistent with least-cost, best-fit criteria, given the statewide competition for RPS-eligible renewable resources.
- Availability of unbundled RECs as a compliance mechanism for meeting renewable procurement requirements.

### Energy Service Providers and Community Choice Aggregators

The CPUC has not developed RPS procurement and compliance requirements for ESPs and CCAs. However, on June 29, the CPUC issued a draft decision setting forth the basic parameters for participation by ESPs, CCAs, small and multi-jurisdictional utilities in the RPS.[124] The draft decision proposes that ESPs and CCAs which do not need any public goods charge funds to meet their RPS requirements may be excused from some of the requirements imposed on the IOUs. For example, they would be excused from submitting renewable resources plans and using the least-cost, best-fit methodology to evaluate renewable bids, but would still be required to comply with annual procurement targets, the 20 percent target, and reporting and tracking requirements. If an ESP or CCA needs public goods charge funds, then it would be subject to all the same rules that apply to the IOUs. Nonetheless, RPS obligations for these entities began on January 1, 2003, per Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002. While LSEs were asked to submit resource plan data in their *2005 Energy Report* filings, information submitted to date is largely confidential.

### Publicly Owned Utilities

California's RPS procurement targets are not being met uniformly across the state. The publicly owned utilities were expected to report their long-term resource plans, including RPS implementation plans, as part of their *2005 Energy Report* filings. The latter are summarized in the *Statewide and WECC Resource Outlook Staff Report*.

## Achieving California's Numeric Goals for Renewable Energy

To effectively implement the state's loading order and achieve California's goals for renewable energy, the state must optimize its regulatory system for renewable resources. Some of the most pressing issues affecting renewables in the loading order include:

- Lessons learned from the first two years of RPS implementation.
- Renewable transmission planning, including SCE's concept of a renewable trunk line and encouraging "clustered" renewable development near existing and planned transmission.

- Electric system modifications needed to integrate a high penetration of intermittent renewable resources into the system.
- These issues are discussed in more detail below. In addition, the Energy Commission's *Electricity Environmental Performance Report* contains information regarding bird deaths from wind turbines and other environmental issues related to electric generation from renewable resources.[125]

## *Lessons Learned from the RPS*

Wiser, Porter, and Bolinger (Wiser *et al.*) conducted a study for the Energy Commission on deliverability and lessons learned from the RPS. The study included three IOUs, 10 renewable energy developers, three developer associations, three non-profit organizations, an ESP representative, and a CCA representative. The sample and the results were dominated by renewable energy developers and developer associations active in California.[126]

Participating parties identified a number of areas needing improvement within the RPS. These include:

- The amount of time it takes to implement the RPS and develop renewable energy projects.
- The deliverability requirements.
- The complexity of RPS rules.
- The need for greater transparency in how IOUs select renewable projects for contracts.
- Application of RPS rules to ESPs, CCAs, and municipal utilities.
- The need for more aggressive support from the CPUC for ratepayer-funded transmission.

### RPS Implementation Process

The Wiser *et al.* study compared California's RPS to the nineteen other RPS programs in the United States and found that California's RPS has taken longer to implement than programs in other states. Reasons for this could be because many states are still in the early stages of their RPS programs, and California has a larger and more complex electricity market structure than many states. Regardless of the reasons for the delay, opportunities for expediting the current RPS process need to be identified and pursued.

Respondents to the study agreed that the most useful aspect of the RPS program is the overall renewable energy target. However, the Energy Commission Gross System Power Report indicates that the state was at 11 percent eligible renewables in 2002, 10.4 percent renewable in 2003, and 10.6 percent renewable in 2004. The state has not added one percent per year of renewable energy. It is also not on track to reach the state's goal of meeting 20 percent of retail sales by 2010. The flat trend shown in the Gross System Power report may, however, reflect that RPS implementation has not begun for ESPs and CCAs and individual POUs are setting their own implementation schedules.

If the 2005 round of renewable energy procurement does not result in substantial progress toward meeting the state's goal of 20 percent renewable energy by 2010, the RPS program may require greater regulatory scrutiny and standardization to ensure state goals are met. For the IOUs, the state must consider options for establishing a quicker procurement cycle. The current slow progress on the RPS raises the following questions, which we believe state policymakers and regulators should pursue:

- What actions are needed to ensure that the 2005 RPS solicitation results in signed contracts with expected future deliveries or new construction in 2005?
- Are regulatory deadlines for utility procurement cycles desirable?
- Should certain additional contract terms be standardized to encourage developer participation in solicitations, reduce negotiation delays, and possibly lower the ultimate cost of renewable energy contracts for ratepayers?
- What can be done to accelerate RPS procurement?
- Recognizing that renewable energy procured by IOUs in the general long-term procurement process will count towards the RPS, what can be done to expedite contracts and deliveries in that proceeding?
- Why is the progress reported by individual IOUs toward state RPS goals different from the state's overall progress? What can be done to reduce this difference and move the state onto a path to reach 20 percent by 2010?

A related issue is the perception by some parties that signed contracts, as opposed to renewable energy output, are sufficient to demonstrate RPS compliance. To be consistent with the intent of the RPS, it is essential over the next five years that the state remain focused on renewable energy output as the indicator of whether utilities are complying with the RPS, regardless of the CPUC's flexible compliance rules.

**Timely Development of Renewable Energy Facilities**

Stakeholders identified the following reasons for delay in the 2003/2004 Request for Offer process:

- Negotiation Timeframe: The utilities' initial schedules often underestimate both the amount of time it takes to negotiate with short-listed bidders and the uniqueness and complexity of each individual deal.

- Inadequate Contract Forms, Terms, and Conditions: There was near-universal agreement, at least among non-utility survey respondents, that contract forms were inadequate.
- Disputes Over Delivery Point: With the prospect of CA ISO market redesign, parties spent considerable time negotiating the delivery point for renewable project output.
- Utility Staffing: Several respondents close to the bid evaluation and negotiation process noted that utility staffing and staff continuity is a problem and that utility staff have not consistently received adequate support from their upper management.
- Bidder Responsiveness: Some parties submitted unresponsive bids and some developers did not respond quickly to utility requests and negotiations.
- Other items that slowed the process included: the need to develop bid evaluation protocols, risks associated with the federal production tax credit and the impact of wind turbine shortages (which led to numerous bidders dropping out of the solicitations in mid-stream), negotiations related to performance standards, development milestones, credit requirements, and wind power scheduling, and regulatory delays associated with release and revision of the MPR.

Even though RFOs have focused on securing signed contracts for renewable energy, signed contracts may fail to materialize. For example, the Wiser *et al.* (2005) study reports that a large number of renewable energy projects under contract to Nevada utilities for their RPS have either experienced construction delays or cancellations. Although California's flexible compliance mechanism allows utilities to compensate for failed contracts, the state should consider developing additional incentives to guard against this problem and ensure that utilities reach their 20 percent renewable energy goals by 2010.

One suggested option is for the CPUC to clarify that delivered energy, rather than contracted energy, is the metric to be used for compliance with the RPS, and that flexible compliance is for interim years only, not the end date. This would encourage utilities to contract for additional renewable energy, assuming an attrition rate in proposed projects.

**RPS Deliverability Requirement**

Deliverability problems cost utilities hundreds of millions of dollars each year. The CA ISO reports that congestion costs in 2004 alone were $426 million, almost triple the amount charged to utilities in 2003.[127] Recognizing the deliverability problems facing California, Governor Schwarzenegger "is seeking all opportunities to enhance and expand the transmission grid as a way to reduce congestion costs, improve reliability, and provide a path to accessing cleaner, more cost effective energy sources."[128]

Under the current RPS rules, renewable facilities or suppliers must deliver their electricity and associated RECs to the CA ISO market hub or substation that the contracting IOU specifies in the power purchase contract. This requirement is imposed to identify and mitigate deliverability problems that could interfere with the state's renewable energy goals.

Given transmission congestion in California, however, this requirement could limit the number of renewable energy facilities bidding into RPS RFOs, interfering with the ability of retail sellers to comply with RPS targets and putting upward pressure on bid prices. To prevent this, the CPUC proposes that utilities allow bids for delivery points that are outside their service territories but in the CA ISO control area.

The PG&E and SDG&E draft 2005 RPS procurement plans prompted this proposed clarification. The CPUC was particularly concerned that: "For 2005, SDG&E proposes that it will not accept proposals from areas even within its service territory that are transmission constrained. PG&E prioritizes all resources in its service territory higher than almost any outside it, and proposes changes to the RPS rules for in-state delivery as a way to avoid transmission constraints."[129]

These deliverability requirements are more stringent than those of a number of other states with RPS requirements. In the *Preliminary Stakeholder Evaluation of the Renewables Portfolio Standard*, Wiser *et al.* asked stakeholders who are active in California's RPS whether California's deliverability requirements are reasonable and support the objectives of the state's RPS.[130] Although there was no general agreement on what changes should be made, most respondents did not believe that the current deliverability requirements are serving the objectives of the RPS.

## Policy Complexity

Many stakeholders in the Wiser *et al.* study identified California's RPS complexity as one of its weakest points. Wiser *et al.* attributes some of the complexity to the market price referent (MPR)/supplemental energy payment (SEP) process and its attendant oversight requirements. They suggest that the state consider eliminating this aspect of the RPS. They propose requiring utilities to purchase renewable energy to meet the state's RPS targets, with costs recovered directly from ratepayers, as most other states do. Nearly half of study respondents indicated openness to eliminating MPRs and SEPs, although several felt that more experience with the present system is needed before making such a fundamental policy shift. In addition, with utility procurements now taking place, none of the survey respondents wished to enter into a multi-year policy design process that would further delay renewable energy contracts.

Finally, several respondents, including those from utilities, reported strong support for the current system. Utility respondents stated that the MPR is a useful benchmark for cost reasonableness, and that using SEPs to cover above-market costs is appropriate. However, utility and other respondents also noted that the MPR could potentially inflate bid prices.

**Improved Transparency**

According to ongoing work at Lawrence Berkeley Laboratory, California's RPS program is less transparent than the RPS programs of other western states. It is difficult to compare California's need for confidentiality with other states. Unlike other states, California's RPS program includes pre-approved evaluation protocols, procurement plans, and publicly funded SEP payments combined with a hybrid market design.

In the Wiser *et al.* study, a majority of respondents felt the need for greater transparency in the overall RPS process. The most frequently cited areas needing additional transparency were bid evaluation practices and renewable energy procurement plans. Though calls for greater transparency generally came from developers, developer associations, and non-profit organizations, a few developers observed that increased transparency should not be pursued if it would further slow down the contracting process. The two utility respondents cited concerns over the impact of releasing additional information on bid prices, fearing creation of a sellers' market that could disadvantage ratepayers.

**Expedite Application of the RPS to ESPs/CCAs and Municipal Utilities**

The Energy Commission staff believes that after two-and-a-half years, it is time to expedite ESP and CCA compliance with the RPS. The RPS statute requires the CPUC to determine both how the ESPs will participate in the RPS, and how they will be "subject to the same terms and conditions" as IOUs. IOU statutory requirements, such as calling for electricity delivery (rather than procurement of unbundled renewable energy certificates), long-term contracts, and CPUC procurement oversight, do not appear to fit well with typical ESP and CCA business models. Consequently, the state may need new regulatory structures for ESPs and CCAs.

One option could be to require ESPs and CCAs to comply with the RPS process established for IOUs, including submitting a procurement plan using standard contract terms and the least-cost-best-fit evaluation process. This would include applying the MPR, employing annual procurement targets and compliance rules, and seeking CPUC contract approval. ESPs and CCAs have far greater short-term and long-term percent load variability than IOUs, making it difficult to predict their RPS procurement need. They also typically lack the credit ranking needed to back long-term contracts. In addition, their load is not large enough to support a medium-sized renewable facility so their procurement has not historically been subject to CPUC oversight.

A more flexible approach would require full compliance with IOU rules only if the ESP or CCA seeks SEPs, as described in the June, 2005 CPUC draft decision on ESPs and CCAs.[131] Otherwise, ESPs and CCAs could be allowed to develop their own procurement practices to comply with the RPS, subject to compliance with CPUC annual procurement targets, flexible compliance mechanisms and, perhaps, additional regulatory requirements.

A fundamentally different option would set up a process whereby the Energy Commission, the IOUs, or some other entity acts as the procurement agent for ESPs and CCAs. For example, the Energy Commission or the Department of Water Resources could procure eligible renewable energy certificates on behalf of the ESPs and CCAs from generators through long-term agreements. The agency would then allocate renewable energy certificates on a pro-rata basis to the ESPs and CCAs toward meeting their RPS obligations. The electricity associated with the renewable energy certificates could be sold into the CA ISO real-time market or bilaterally to retail sellers. Alternatively, the IOUs or another agent could conduct solicitations on behalf of the ESPs and CCAs, with the ESPs/CCAs providing oversight and paying a fee for the service. The CPUC draft decision on ESPs and CCAs endorses the concept of using procurement entities or other intermediaries, and proposes that the utilities would be the appropriate entities but that they would not be required to do so.

The Wiser *et al.* study also noted that a private utility respondent identified the need to not only address ESPs and CCAs, but to also fold municipal utilities into the state's RPS, which would require legislative action.

**Need for More Aggressive Support from the CPUC for Ratepayer-Funded Transmission**

Transmission may be the most severe constraint to achieving the state's renewable energy targets. A wide range of respondents in the Wiser *et al.* study echo this observation. Developers expressed particular concern over a lack of integration of transmission planning in the utilities' long-term renewable energy procurement plans.

The RPS statute requires the CPUC to encourage transmission expansion necessary to support the RPS goal. However, the study results show participant frustration with the speed of the transmission expansion approval process. As described in the next section, the difficulty in siting new transmission is in part due to the mixed jurisdiction of the CPUC and FERC and the "chicken and egg" problem of expanding transmission in an area without firm developer commitments to build facilities in that area.

Several survey respondents cited the Tehachapi and Imperial Valley transmission working groups as useful operating models for needed transmission development. The CPUC and Energy Commission should explore expansion of this process to other renewable resource areas identified by stakeholders as deserving further scrutiny.

Another source of complexity in the RPS program is that the CPUC requires each utility to develop a Transmission Ranking Cost Report before issuing an RPS RFO. These reports estimate the costs of transmission expansion needed to support potential bidders. The utilities estimate transmission costs for geographic areas where clusters of renewable projects may be proposed based on data collected from renewable developers. The CPUC directs the utilities to use the cost estimates to evaluate the bids, based on their least-cost-best-fit criterion.

Although utilities in other states do consider transmission expansion costs in meeting their RPS obligations, no state other than California uses a formal process requiring regulatory approval that must be formally applied in bid evaluation. In the Wiser *et al.* study, stakeholders offered widely divergent views on the appropriateness of the current methods. The IOUs stress that the process is consistent with the CA ISO procedures. The developers argue that the process imposes a far more rigorous standard for congestion relief on renewable projects than for other generation types and is inconsistent with the state's loading order policy.

Additional regulatory expertise may be required to carry out the CPUC's responsibilities for transmission issues. More active involvement by the CA ISO may also be necessary to evaluate different views on appropriate methodologies. Parties need to explore an alternative approach to the transmission cost ranking report.

### *Renewable Energy Transmission Planning*

To meet its ambitious renewable energy goals at least cost, the state needs new or upgraded transmission access for accessing renewable resources. For example, wind resources in the Tehachapi area could be a vital component in meeting targets for renewable energy development in California. However, there are significant transmission constraints in that area that prevent new wind installations.

Traditionally, the first generator that causes the need for a transmission upgrade funds a large portion of its cost.[132] This raises a "chicken and egg" issue, whereby other generators may wait for the first generator to pay the upgrade costs before filing for interconnection themselves. This is true not only for renewables but also for other generating technologies. New transmission facility costs have a large fixed component. For large generation facilities, such as those fueled by natural gas, the cost of these transmission upgrades reflect a much smaller portion of project cost than for smaller renewable energy facilities.

Recognizing that current rules regarding cost recovery pose a barrier to transmission construction, in March 2005 SCE proposed a new category of transmission facility called a "renewable-resource trunk line." The trunk line would interconnect large concentrations of potential renewable generation resources located within a reasonable distance from the existing grid, and be operated by the CA ISO. SCE requested a federal ruling allowing the cost of developing the new line to be recovered through general transmission rates.[133]

The trunk line proposal was included in SCE's March 2005 petition to the FERC regarding recovery of the costs of transmission facilities for renewables in the Antelope Valley and Tehachapi wind resource areas. The facilities would allow as many as 1,100 MW of these resources to be used by SCE, PG&E, SDG&E, and other CA ISO grid users to help meet their RPS goals.[134] On April 14, 2005, the Energy Commission and the CPUC filed motions to intervene and submitted comments in support of SCE's petition.[135] On July 1, 2005, FERC disapproved SCE's petition, and parties have 30 days to file for rehearing. Additional analysis and coordination will be needed to address these issues.

SCE stated that its proposed transmission capacity for Antelope/Tehachapi is based on forecasted renewable energy development rather than completed interconnection agreements. This approach exposes SCE to the risk that it may be left with sizeable quantities of unused transmission, as well as liability for 50 percent of the associated "abandoned" costs.[136]

Another way to address the problem of building transmission without the certainty of renewable generation is to plan several renewable projects together, referred to as "clustering" of generation projects, which allows costs to be shared equally by multiple projects. However, clustering renewable energy projects is not allowed under current CA ISO tariff and FERC interconnection policies. The Tehachapi Collaborative Study Group recommends regulatory change to support clustered development of renewables to limit the risk of overbuilding transmission by "tying permitting and construction approvals closely to market demand."[137]

As discussed in the Wiser *et al.* study, another method of limiting the risk of overbuilding transmission is the interim "transmission cost adder" used in California's RPS program to consider indirect costs associated with transmission upgrades. As part of the RPS least-cost-best-fit evaluation, bids are grouped by interconnection location to determine the amount of generation capacity that would trigger a transmission upgrade in each cluster. The costs are then allocated to each proposal, with the cost estimate becoming an adder to the bid price for renewable power, for evaluation purposes.[138] The CPUC held a workshop in early 2005 to consider improvements to the interim methodology that elicited suggestions to impose a curtailability standard, coordinate deliverability requirements between the RPS and Resource Adequacy proceedings, or consider a new standard for transmission financing.[139] On June 21, 2005, the CPUC released a proposed decision requiring the IOUs to allow bids that have curtailability as an attribute, and released a decision on transmission issues, limiting modifications to the TRCR methodology for the 2005 RPS solicitations.[140]

Another option would be to allocate indirect transmission costs equally across all projects located near existing and anticipated renewable resource transmission upgrades, since it is their aggregate potential that drives the need for the transmission upgrade. For example, in the Antelope/Tehachapi transmission plan, the emphasis is on the region's aggregate forecasted renewable energy potential of 4,000 MW, not on individual projects in the interconnection queue.

## Integrating Renewables into the Electricity and Transmission System

The RPS process categorizes renewable energy as baseload, as-available, and peaking energy products. Integrating modest amounts of as-available or intermittent resources into the system can be accommodated with minor adjustments to the system. However, experience in Europe shows that high levels of wind (e.g., 20 percent or greater), relative to other resources on the electricity grid, can require changes in operation and equipment requirements of the transmission system.[141]

The fit between renewable energy product characteristics and the load serving entity's supply needs can be improved through changes in system operations, the use of energy storage, the use of hybrid generating facilities, and strategic placement of generation where possible. In addition, the FERC has recently adopted uniform interconnection procedures for wind and is considering imbalance provisions for intermittent resources. Both the FERC and Bonneville Power Authority (BPA) are looking into "conditional" firm transmission services for wind energy.

### Changes in System Operations

The Consortium for Electric Reliability Technology Solutions (CERTS) issued a report in April 2005 on renewable transmission integration and planning. The report identified changes in the CA ISO system operation that could be needed to support the state's goal of 20 percent renewables by 2010, using the scenario in the Energy Commission's 2003 RRDR and scaling up CA ISO 2004 loads to 2010 levels based on Energy Commission load forecasts.[142]

CERTS anticipates changes in average and maximum daily load swings. To address this concern, CERTS suggests improved day-ahead planning (including improvements in wind forecasting), changes in the renewable mix such as including more solar resources, and procuring controllable resources with the ramping capability to match anticipated system needs.

The CERTS study also found that control area operators may need to reduce generation output during high run-off and high wind periods, especially during lightly loaded early morning hours. CERTS suggests coordinating pumped storage hydro deployment to create load during early morning high run-off and high wind periods—sending clear price signals to end-use customers to shift loads to minimum load time periods—and procuring energy sources with turn-down flexibility.

CERTS suggests operating reserves with quick-start, fast-ramp, and cycling capabilities in order to meet WECC and NERC standards covering regulation requirements, non-firm imports from out of state, and the system's largest contingency.

The CERTS report noted that frequency and voltage requirements are addressed by the WECC low-voltage ride-through standard for wind, which goes into effect in March 2006. However, there is a need to address deliverability bottlenecks in the CA ISO control area. The CPUC requires IOUs to assess deliverability at annual peak demand but this does not address problems that may occur infrequently, such as minimum load problems during high run-off and peak wind production periods. CERTS suggests performing off-peak contingency analysis to address this potential problem.

In addition to suggestions for improving planning, monitoring, and operation of the CA ISO system in support of the state's accelerated RPS goals, the staff believes policymakers should seek input from POUs and IOUs regarding research, issues, or measures under consideration to integrate renewables into their control areas, as well as any issues regarding inter-system impacts or opportunities for coordination.

The Energy Commission's PIER program will examine these issues in-depth throughout 2005 and into 2006. PIER has contracted with GE Energy Consulting—who performed a wind-integration study in New York which examined the system impacts of 10 percent penetration of wind—to assess the potential system impacts of higher levels of intermittent renewables in California in 2010 and 2020.

### Energy Storage

To meet RPS goals, California is likely to increasingly rely on intermittent resources. Expanding the state's energy storage options could mitigate the integration issues associated with intermittent resources raised in the CERTS study. Energy storage could also increase the operational flexibility of the state's electric and transmission systems.

Energy storage allows electricity to be delivered when it is needed, not just when it is generated.[143] The most established energy storage systems are pumped-storage and impounded hydroelectric systems. Other options include compressed air energy storage and battery/flywheel options.

- Pumped Hydroelectric Systems: With pumped hydroelectric energy, water is pumped uphill during low-demand periods and released downhill during high-demand periods. The economics of pumped hydro depend on the difference in off-peak and on-peak electricity prices.[144] Small, modular pumped hydropower systems can range from 20-100 MW.

Many wind resources in California generate electricity during off-peak hours in the spring and summer months. Pumped storage can shift delivery of wind energy from off-peak to on-peak periods during the day, and smooth production spikes.[145]

California has more than 4,000 MW of pumped hydro storage capacity, with about 2,700 MW in the CA ISO control area.[146] The two largest pumped hydro facilities in California are Castaic (~1,500 MW), and Helms (~1,200 MW).[147] The Sacramento Municipal Utility District (SMUD) plans to build a pumped hydro storage facility in the Iowa Hill area of El Dorado County. This project would provide 400 MW of pumped-hydro storage, drawing water from SMUD's Slab Creek Reservoir down the hill from the proposed site. The project is intended to make the utility's wind energy projects dispatchable. It will also provide spinning reserve for high-demand periods.[148]

Outside of California, BPA offers a storage and shaping service that integrates and stores hourly wind energy generation into the federal Columbia River Hydroelectric System. A week after delivery to BPA, the electricity is transmitted to the purchasing customer in blocks of flat-peak and off-peak power, capped at 50 percent of nameplate capacity of the wind generation facilities.

- Compressed Air Energy Storage: Compressed air is another option for storing electricity from wind. Compressed air energy storage generation facilities usually use underground caverns or inactive mines to provide electricity during the day, re-charging at night.[149] These systems depend on having suitable geologic formations or inactive mines available for compressed storage.

  Currently, only two commercial compressed air energy storage plants have been built worldwide, a 290 MW facility in Germany and a 110 MW facility in Alabama.[150] In Iowa, more than 70 municipal utilities are exploring the feasibility of combining a 100-MW wind energy generation facility with 200 MW of compressed air energy storage generation.[151] In Texas, the Texas State Energy Conservation Office is looking into using compressed air energy storage generation with wind energy to address transmission constraints.[152]

- Battery and Flywheel Technologies: Battery and flywheel technologies focus primarily on managing short-term power quality to improve grid reliability. Power quality is particularly important to industrial and commercial customers (e.g., food processors) because a brief interruption in power can be costly.[153]

  Fairbanks, Alaska, has a 40 MW, 15-minute nickel-cadmium battery energy storage system, together with a new transmission line parallel to the existing line, which began operating in January 2004. The transmission and battery systems were designed to improve reliability of the transmission of electricity from Anchorage, 400 miles to the south.[154] In Puerto Rico, a 20 MW lead acid battery energy storage system provides system reliability and balances the system.[155]

In Castle Valley, Utah, PacifiCorp installed an electrolyte-based flow battery. Charging at night for use during peak demand, this 2 MWh battery reduced line losses by 40 kW, and postponed a $4 million transmission upgrade.[156] This technology has also been used by Hydro Tasmania on King Island, Australia since 2003. The flow battery stores wind energy that exceeds demand and wind surges that would destabilize the electric and transmission system, and releases the stored energy during periods of high demand.[157]

Another energy storage technology is the sodium-sulfur (NAS) battery. Japan has commercially available systems using this technology, with more than 50 projects greater than 500 kW each. American Electric Power in Gahanna, Ohio, also installed a demonstration NAS system in 2002. This type of battery has been used for load leveling, emergency power supply, and power quality protection for uninterruptible power supply applications.[158]

Detroit Edison Company employed a 400 kWh Zinc/Bromine energy storage system for power quality at a grain drying facility in Akron, Michigan, and for peak shaving in Lum, Michigan. Lessons learned from the program included the need to know voltage sags and surges before sizing the battery system. Detroit Edison also reports that automatic load following is required.[159]

### Hybrid Generating Facilities

Another option addressing some of the integration concerns raised by the CERTS study is to use hybrid generation systems combining more than one type of resource at a generation facility. Not all of the energy from hybrid facilities is eligible for the RPS.

The Solar Electric Generating System facility in Kramer Junction combines concentrating solar power and natural gas.[160] In accordance with FERC's QF requirements, the facility uses no more than 25 percent natural gas in a calendar year. Hybrid facilities using fossil fuels certified as QFs with FERC can count 100 percent of their energy output as RPS-eligible. Facilities not QF-certified can only count the renewable portion of their generation, and then not until the Energy Commission develops its tracking system.[161]

Another potential hybrid system combines pumped hydro with wind energy. The wind could then pump water into a storage reservoir, with the hydro facility providing energy storage and firming.[162]

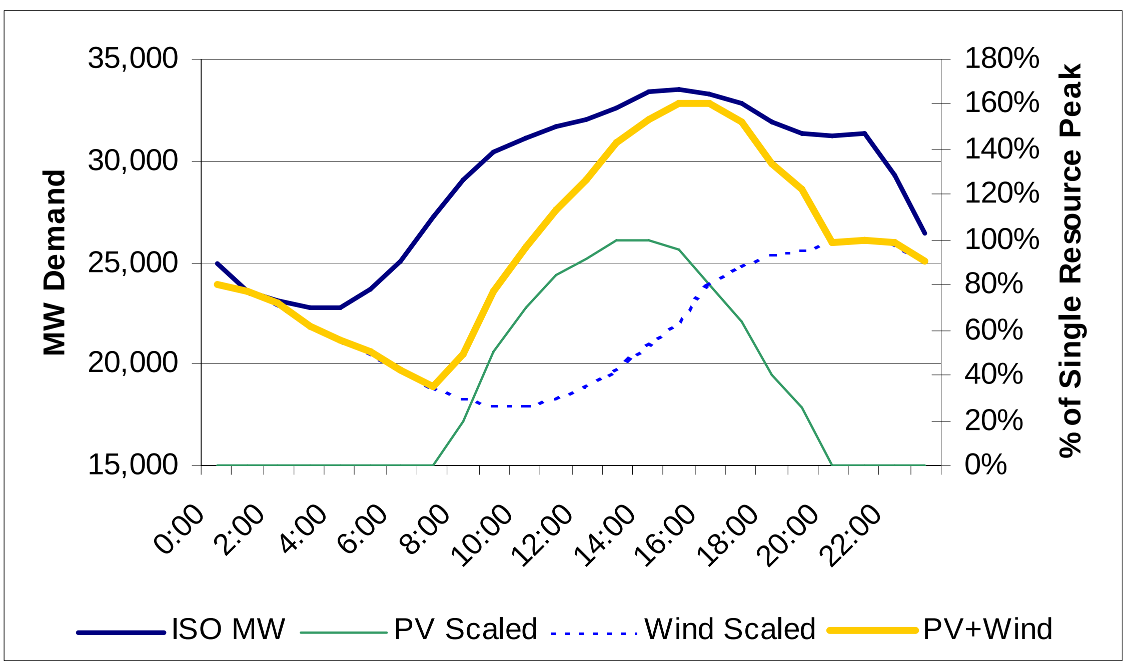
RPS eligibility for hydroelectric facilities is limited to facilities that are 30 MW or fewer, and do not require a new appropriation or diversion of water, among other requirements. Pumped hydro must meet the eligibility requirements for hydroelectric facilities, the electricity used to pump the water must be RPS eligible, and only the electricity dispatched from the facility may qualify for the RPS.[163]

A third potential combination is solar power and wind energy. As shown in Figure 19, the potential output of such a facility could provide load-following to help support system-wide needs. Additional research is needed to explore the best scaling of wind and solar.

### *Strategic Placement of Generation*

The Public Interest Energy Research (PIER) Renewables Program has developed a Strategic Value Analysis (SVA) methodology to evaluate potential benefits of renewables at specific locations throughout California. These resources may provide benefits to transmission system reliability while meeting California's RPS target renewable penetration levels. Energy Commission staff and consultant reports were published in June 2005 summarizing the SVA approach and current findings for renewable technologies.[164] The results of the SVA were also the subject of a public workshop in July 2005.[165]

**Figure 19. July Weekday Demand Versus PV Example Day and July Average California Wind Generation**




Source: Kema-Xenergy, Inc., Contracting Team, January 2005.

The SVA scenario assumed no additional major new transmission lines except for the following:

- Development of two segments of Phase 1 of the Tehachapi Transmission Plan: Antelope to Pardee and Antelope to Vincent, which, according to the model, would enable development of an additional 900 MW of high-speed wind resources in the region.[166]
- Development of transmission lines associated with Salton Sea 6 and Blythe, including Devers-Mira Loma, Devers-Valley, Devers-Serrano, and Devers to the Salton Sea—which, according to the model, would enable addition of about 1,000 MW of geothermal resources in the region.
- Other smaller transmission line additions in areas including Solano County and Medicine Lake in Siskiyou County.

In addition, minor upgrades to existing transmission lines were assumed in the approach used to develop the renewable mix scenario towards meeting the RPS while ensuring net system benefits.

Additional upgrades to the transmission system will be needed to develop other in-state renewable resources and/or import out-of-state renewables into the California system.

The PIER Renewables Program plans to work with an IOU to explore and further develop the possible contributions of the SVA to assist in energy and transmission planning in California.

### Pending FERC Proceedings Related to Intermittent Renewables

The FERC and BPA are looking at "conditional firm" transmission services for wind energy.[167] With these services, transmission customers can get firm service for most of the year (except for a certain number of hours). The hours without service are provided in advance by the transmission operator. Alternatively, the transmission operator can offer the transmission customer a long-term non-firm transmission contract, subject to curtailment. This type of contract contains no guarantee for a fixed number of curtailment hours, or even when the curtailment would occur. For further information on development of conditional-firm transmission products, see *Assessing the State of Wind Energy in Wholesale Electricity Markets*, a FERC staff report published in November 2004.[168]

The FERC has also opened two rulemakings to accommodate greater levels of wind energy in the United States: uniform interconnection procedures for wind in RM05-4-000; and imbalance provisions for intermittent resources in RM05-10-000.[169]

## *Efforts to Reduce Bird Deaths from Wind Turbines*

The Washington Department of Fish and Wildlife has developed "Wind Power Guidelines" for review and mitigation of wind project impacts, including impacts on birds, under Washington's State Environmental Policy Act.[170] Another approach is outlined in a United States Department of Interior Fish and Wildlife 2003 memorandum.[171]

More recently, the Energy Commission funded a multi-year research project that in August 2004 published recommendations to reduce bird mortality in the Altamont Pass area.[172] The *2004 Energy Report Update*, published in November 2004, recommended using the findings of this report to evaluate permits for new and re-powered wind turbine facilities. In addition, the Energy Commission published a report in December 2004 on siting new turbines in the Altamont Pass area.[173]

Additional information on bird and bat deaths from wind turbines and research exploring mitigation options is included in the Energy Commission's *Electricity Environmental Performance Report*.

To support California's ambitious renewable development goals while avoiding, minimizing, and mitigating the taking of protected wildlife, the staff suggests the following policy options:

1. Establish a standing statewide working group to develop regulatory procedures and guidelines for wind turbine projects to comply with state and federal law, including the California Environmental Quality Act (CEQA). The group should include industry, public interest groups, local permitting agencies, and state and federal agencies responsible for wildlife protection, and incorporate the latest available information on the best available practices and technologies, with periodic updates as needed.
2. Develop private-public partnerships to sponsor environmental studies of known wind resource areas to determine how to best protect birds.
3. Compile an archive of information on important wildlife migratory corridors that can be used in permitting wind facilities, based on work the Energy Commission is doing with the California Department of Fish and Game and the California Department of Forestry to incorporate data on bird migration routes into wind-mapping data sets using a geographic information system.

### *Million Solar Roofs in California*

To move from 100 MW to 3,000 MW of DG PV in California over the next 13 years, a number of technical and policy challenges must be addressed. The CPUC and the Energy Commission are working with stakeholders to develop an administrative framework in support of the Governor's proposed solar roofs initiative. The work is focusing on Self Generation Incentive Program funding levels, qualification of solar technologies to meet customer needs, time-variant rate structure and metering, incentive funding continuity, and future program administration. Stakeholder comments on these topics are summarized in Appendix B.

Currently, there is a near-term shortage in the availability of photovoltaic modules caused, in part, by rapidly growing worldwide demand. For example, in Germany there was a surge in PV demand in 2004 due to increased incentive levels; Germany installed about 120 MW in 2003, and more than 360 MW in 2004. [174]

Another factor contributing to the shortage is hesitation by PV manufacturers to make long-term commitments to suppliers of silicon, an important raw material used in many PV modules. This hesitation limits production of low-grade silicon. Although costs have declined by about five to seven percent each year over the long term, the shortage of modules has led to short-term price increases.

Other types of PV modules are under development and this may place some downward cost pressure on silicon-based modules. Adoption of the Governor's Solar Initiative, which would commit more than $1 billion toward installing 3,000 MW of DG PV in California, could reduce the risk associated with long-term investments in producing PV system equipment and other segments of the market supply and delivery chain.  In Japan, a similar level of investment has resulted in a largely self-sufficient PV market.

## Monitoring and Verifying Renewable Energy

Although the Energy Commission has a number of monitoring and verification activities underway for renewable energy, additional measures may be needed to ensure timely progress toward achieving the RPS goals. In addition, staff believes that additional data on DG PV performance is needed.

### *Renewables Portfolio Standard Program Deliverability*

To be eligible for the RPS, generation must meet specific delivery requirements developed by the Energy Commission in consultation with the CA ISO. For example, renewable generators must deliver to an IOU-designated market hub or substation within the CA ISO control area. For renewable electricity generated outside of California, delivery must be documented with a "NERC tag" from the North American Electricity Reliability Council showing the RPS certification number of the renewable energy facility. The NERC tag must show where the energy was generated, the contract or market path, where the energy will be delivered, the LSE responsible for the electricity consumption, and the facility's RPS certification number. The facility must make the NERC tag documentation available to the Energy Commission upon request; every May 2, the facility must submit an annual report to the Energy Commission showing NERC tag compliance. Until the WREGIS is operational, the facility must also submit meter readings from a third-party verifying its generation.

### *Western Renewable Energy Generation Information System*

For the RPS, the Western Renewable Energy Generation Information System (WREGIS) tracking system will track the renewable energy certificates (RECs) associated with energy generation but not the transmittal of energy to the purchasing entity. WREGIS will issue a unique REC for each MWh of renewable generation. Each certificate will contain a variety of data, including the generation date (month, year), the fuel used, and the facility from which the REC originated, along with other characteristics. The tracked information is intended to provide sufficient information to determine whether the REC is eligible for compliance with various state policies.

At this time, WREGIS is still being developed. Staff anticipates the Request for Proposals for the WREGIS tracking system will be released in the summer of 2005, with the system beginning operation in early 2007. For further information, see [http://www.westgov.org/wieb/wregis].

### *Interim RPS Contract-based Tracking System*

Until the WREGIS is operational, IOU compliance with the RPS will be verified using an interim contract-based tracking system. IOUs report annually to the Energy Commission on the amount of RPS-eligible energy they procure from each RPS-certified facility.

RPS-certified projects are required to annually submit third-party verified meter reads to the Energy Commission that show the amount of energy generated in each month of the year. When a generator submits its own application for RPS certification, the third-party verified meter data documentation is typically the invoice showing the amount of energy purchased from the generator by the utility. However, third-party verified meter data is not available from facilities that have been indirectly certified through a utility-sponsored application, and these facilities make up most of the IOU RPS procurement to date.

In response to this lack of third-party verified meter read data, the staff has been using mostly self-reported data sources to identify the amount of electricity generated per RPS-eligible facility.[175] Because these data sets were compiled for other purposes, it is difficult to know which facility in each database corresponds with a particular RPS-certified facility. For example, a single facility in one database may be equivalent to two RPS-certified facilities, or the facilities may be identified by different names under different data bases.

The Energy Commission will report the finding of its analysis and the amount of renewable energy procured by each utility to the CPUC. To determine RPS compliance, the CPUC compares the results of the Energy Commission's verification analysis with the utility's annual procurement target.

If procurement contract negotiations delay delivery of renewable energy, an IOU may fail to meet its annual procurement target (APT). To provide early warning, each IOU must submit a mid-year report to the CPUC showing actual and forecasted progress toward meeting its APT. There is no formal mechanism to respond to protracted contract negotiations or failure to demonstrate actual progress in the mid-year APT filing. To encourage IOUs to stay on track toward their goals of 20 percent by 2010, the staff suggests stronger regulatory intervention if IOUs are not meeting their APTs.

The need for clarification regarding compliance progress became apparent in PG&E's 2004 RPS compliance filing to the CPUC and its 2005 RPS procurement plan. PG&E has requested energy that is under contract to be developed in the future to count toward current year APT compliance, but this may be inconsistent with RPS enabling legislation. In the June 21, 2005 Draft "Opinion approving Procurement Plans and Requests for Offers for 2005 RPS Solicitations," Administrative Law Judge (ALJ) Simon proposed ruling that utilities must use actual deliveries of energy from eligible renewable resources as their measure of compliance with their Incremental Procurement Targets and Annual Procurement Targets.[176]

A related topic is the need to clarify compliance with the 20 percent by 2010 target. The staff believes that the Energy Action Plan (*EAP*) and SB 1078 state that the target should be measured in energy delivered no later than the end target year. The flexible compliance mechanism, allowing up to a three-year grace period for incomplete APT compliance, should be applied to interim years, but not the end date of 2010. In his draft opinion, ALJ Simon addressed this as well, stating: "We consider 2010 the date by which 20 percent of energy sold to retail end-users is to be delivered from eligible renewable resources; the utilities should, too."[177]

Finally, the staff believes that measurement and verification for RPS compliance should include a component to track progress for transmission development needed to interconnect RPS resources. As reported in the *2004 Energy Report Update*, there is a mismatch between the location and unmet RPS need among IOUs, particularly SDG&E.

### *Statewide Grid-Connected Photovoltaic*

In addition to current and planned measurement and verification activities, the staff believes there is a need to collect and publish performance data from statewide grid-connected PV. More than 14,000 grid-connected PV systems are installed in California, with more than 12,000 systems installed through the Emerging Renewables Program since 1998. These systems provide more than 100 MW of installed DG PV capacity.[178] To assess the contribution of these and future DG PV systems to meeting system load and reducing peak demand, the staff is exploring options for developing measurement and evaluation programs on an on-going basis.

Additional information on status, trends and issues related to data on DG PV performance is summarized in Appendix B.

# Future Directions

As a next step in developing future directions for renewable energy programs in California, the staff seeks stakeholder input on the following questions relating to the RPS and to renewable DG:

## *Renewables Portfolio Standard*

1. The RPS is a statewide goal that 20 percent of California's retail sales will be served with renewable energy deliveries by 2010, and 33 percent by 2020. To date, however, the program appears to be falling behind schedule. What actions are needed to correct this trend? Please prioritize the key risks to meeting these targets and recommend corrective actions.
2. Given that developing transmission to tap into remote areas where new renewable resources can be developed is a key step to meeting the statewide RPS goals, what actions should be taken to foster timely and necessary transmission to support renewable development? What milestones and target dates can be identified to measure success?
3. What actions are needed to ensure that the utilities' RPS solicitations result in deliveries that meet both the annual procurement targets set by the CPUC and reach 20 percent of retail electricity sales with delivery of renewable energy by 2010?
4. The June 29, 2005 draft decision by ALJ Simon lays out a general framework for ESP and CCA compliance with the RPS.[179] What actions are needed to ensure that ESPs and CCAs meet their RPS obligations?
5. What could be done to develop an RPS framework with a faster contracting process and improved transparency that would most assist the IOUs in meeting their RPS goals?
6. The consultant report, "*Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard*," recommends considering eliminating SEPs and the MPR as a long-term policy issue in order to ensure clearer price signals to the utilities and renewable generators, and to simplify the program requirements and implementation. Should the Energy Commission support this proposal? Under what conditions, if any, should the Energy Commission support elimination of the MPR and SEPs?
7. If SEPs and the MPR were eliminated, how should the state contain RPS program costs? If SEPs are eliminated, how should the funding collected for SEPs otherwise be used to facilitate accomplishing the state's renewable energy goals?

8. Does the Energy Commission's process to certify renewable facilities as eligible for the RPS (and eligible for the RPS and SEPs) adequately meet the program needs? Are changes needed to make the certification process more reliable, verifiable, timely, and supportive of market development? If changes are needed, please identify the problem and recommend remedies.
9. How could other Western states and programs be encouraged to participate in WREGIS?

### *Renewable Distributed Generation*

1. How should a declining rebate be structured to maximize the amount of distributed renewable energy supported by ratepayer funds while minimizing funding disruptions?
2. To what extent should installation of energy efficiency measures be required, prior to qualifying for a renewable distributed generation incentive? What criteria should be used?
3. How soon should performance-based incentives be more broadly implemented for renewable distributed generation systems? Should the incentives be overseen?
4. What steps would be needed for the Emerging Renewables Program to charge an application fee? Should it be similar to the fee implemented by the CPUC for the Self Generation Incentive Program?
5. Should the equipment and labor warranty required to qualify for a renewable distributed generation incentive be increased to 10 years?
6. How can incentives for distributed generation photovoltaic systems be changed to bring system costs in California down to levels similar to those in Germany and Japan?
7. What other criteria to qualify PV systems for California incentives, such as being produced in California, would benefit the state?
8. Should the various solar incentive programs in California (i.e., municipal utility programs, Self Generation Incentive Program, and Emerging Renewables Program) be consolidated to implement a unified strategy to create a self-sustaining solar PV market? If so, how?

# Chapter 5 Endnotes

[103] For further information on the method used to calculate the Annual Procurement Target, see Appendix B of CPUC Decision 04-06-014, "Opinion Adopting Standard Terms and Conditions," [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37401.doc], accessed July 5, 2005.

[104] Cells in bold outline indicate cumulative procurement that is behind schedule. Amounts procured in 2003 and 2004 and planned for 2005 are from IOU APT compliance reports filed with CPUC, per Appendix B of D.04-06-014. Total State is from Gross System Power less 7% for losses. Direct Access and Rest of State is the difference. IOUs are required to meet Annual Procurement Targets set by the CPUC in R. 04-04-026, with a 3-year compliance window for over- or under-procurement. Planned renewable energy procurement for 2010 is from the public version of the IOU RPS plans, using (2010 procured energy) divided by (previous year's retail sales). Estimated cumulative need is based on a projection from an estimated 2001 baseline to 20% by 2010, using staff forecast of retail sales. The baseline uses data from the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002" which was filed by each of the IOUs under Rulemaking 01-10-024. The baseline also uses data from Gross System Power and the J-11 table, less 7% for losses. PG&E plans to procure renewables in 2010 equal to 20 percent of 2009 retail sales of 73,952 GWh, citing the RPS Annual Procurement Target (APT) Methodology in Appendix B of CPUC decision 04-06-014. The Accelerated Renewable Energy Development Report Appendix A indicated that SCE procured 12,791 GWh of renewables for 2003, based on SCE's June 22, 2004, "Report to the California Energy Commission: Utility Procurement of Renewable Energy in 2003." However, both the Southern California Edison Company Renewable Procurement Plan of June 14, 2004 and the July 7, 2004 Report by the Southern California Edison Company Regarding 2004 Annual Procurement Target indicated that 12,489 GWh of renewables were procured in 2003. The March 1, 2005 Southern California Edison Company's Compliance Report Regarding Achievement of the 2004 Annual Procurement Target filed with the CPUC indicated that SCE procured 12,497 GWh of RPS-eligible renewables in 2003. SCE and SDG&E redacted the GWh/year from the public versions of the RPS procurement plans, but stated that their 2010 procurement of renewable energy would be 20 percent of 2009 retail sales, consistent with CPUC Decision 04-06-014. See Appendix A for details.

[105] Southern California Edison, March 25, 2005, "Advice 1876-E-A to Public Utilities Commission of the State of California Energy Division, Supplement to Submission of Contracts for Procurement from Renewable Resources Pursuant to California Renewables Portfolio Standard Program."

[106] CPUC, Energy Division, Resolution E-3934, June 30, 2005.

[107] Actual on-line dates range from Dec 31, 2006 to March 31, 2008. SCE, March 8, 2005, Advice Letter 1876-E to the Public Utilities Commission of the State of California, Energy Division.

[108] CPUC, Energy Division, Resolution E-3935, July 21, 2005.

[109] CPUC, Energy Division, Resolution E-3994, July 21, 2005

[110] Pacific Gas and Electric Company, Advice Letter 2678-E to the CPUC, Contract for Procurement of Renewable Energy Resources Resulting from PG&E 2004 Renewable Portfolio Standard Solicitation , June 21, 2005.

[111] PG&E, July 1, 2005 Compliance Filing of Pacific Gas and Electric Company (U 39-E) Reporting Progress Toward Achievement of Annual Procurement Target for Renewable Generation Pursuant to Renewable Portfolio Standard, R. 04-04-026, July 1, 2005.

[112] This summary is compiled from information submitted by the California Municipal Utilities Association, data submitted in compliance with the Power Source Disclosure Program (SB 1305) and work done by the Lawrence Berkeley National Laboratory. For the most part, these values were provided by cities and utilities, and were not independently verified. "Eligible Renewable" is the same definition that IOUs must comply with to meet the RPS, as described in SB 1078 and SB 1038 (which excludes hydro facilities larger than 30 MW). "Qualifying Renewable" is usually the same set of resources that IOUs use to meet the RPS, but with the probable inclusion of large hydro (larger than 30 MW).

[113] For information on Amendment 42, see "Amendment 42 Docket No. ER02-922-000 (Intermittent Resources; CT 487; Intra-zonal Congestion; and Real Time Pricing)," [http://www.caiso.com/docs/2002/02/01/200202011116576547.html]], accessed April 15, 2005. For

information on the PIRP program, see “Participating Intermittent Resource Program (PIRP) - Background/Documentation,” [http://www.caiso.com/docs/2003/01/29/2003012914271718285.html]], accessed April 15, 2005.

[114] See CA ISO Tariff Section 11.2.4.5.4 and Schedule 4 of Appendix F. [http://www.caiso.com/docs/2005/06/30/2005063008591817859.pdf], accessed July 7, 2005.

[115] See CPUC, July 8, 2004, "Opinion Adopting Criteria for the Selection [of] Least-Cost and Best-Fit Renewable Resources," part of Rulemaking 04-04-026, Decision 04-07-029, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/38287.html]], accessed April 14, 2005.

[116] CPUC, June 19, 2003, Decision 03-06-071, "Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program," p. 28, [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/27360.pdf]], accessed April 19, 2005.

[117] Anaheim predicts they will be at 6.8% renewables in 2006. Email exchange Marcie Edwards of the Anaheim and Todd Lieberg of the Energy Commission, May 19, 2005.

[117] IID established a 20 percent by 2007 RPS. IID stated that it intends to achieve its RPS with the addition of a geothermal plant by 2007. This is the Salton Sea VI project. Originally, the developer was planning to keep the greenness and sell the RECs to a third party, while IID would only receive the energy. In its written comments filed October 13, 2004 in the *2004 Energy Report Update* proceeding, IID stated that an amended contract specifically conferring the rights to the RECS to IID was approved on September 21, 2004.

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[119] See CPUC, July 8, 2004, Decision 04-07-029, “Opinion Adopting Criteria for the Selection [of] Least-Cost And Best-Fit Renewable Resources,” Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program, Rulemaking 04-04-026, [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/ 38287.doc]], accessed April 15, 2005, p. 21: “For wind resources, we adopt a capacity value that is an average of those found in the Integration Study for the existing resources in the state’s three principal wind resource areas (Altamont, San Gorgonio, and Tehachapi): 24%. While recognizing that this is a very rough approximation, we emphasize the purpose of this determination: to provide a lower bound to the capacity value a utility should impute to a wind resource bid into its RPS solicitation.” This decision references p. xi and p. 32-35 of California Wind Energy Collaborative, December 2003, *California RPS Integration Cost Analysis-Phase I: One Year Analysis of Existing Resources*, Consultant Report, Prepared for the California Energy Commission Public Interest Energy Research Program, 500-03-108C, [http://www.energy.ca.gov/reports/2004-02-05_500-03-108C.PDF]], accessed April 15, 2005.

[120] Ryan Wiser, Mark Bolinger, Kevin Porter, February 25, 2005, "Temporal Production Profiles for Wind Power Projects Located Within or Delivered to California," memorandum prepared by the XENERGY, Inc., Contracting Team, Work Authorization 25, Contract no. 500-01-036). See also, California Energy Commission, April 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California From Western Electricity Coordinating Council States - Draft Consultant Report*, CEC 500-2005-064-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905, p. 57.

[121] California Energy Commission, April 2005, *Renewable Energy and Electric Transmission Strategic Integration and Planning: Interstate Generation and Delivery of Renewable Resources Into California From Western Electricity Coordinating Council States - Draft Consultant Report*, CEC 500-2005-064-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#050905, p. 64.

[122] See CPUC, December 16, 2004, “Opinion Adopting [the IOUs] Long-Term Procurement Plans,” Rulemaking R.04-04-003, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224.htm.

[123] California Energy Commission, June 17, 2005, *Investor-Owned Utility Resource Plan Summary Assessment,* CEC-700-2005-014, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#062905].

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# CHAPTER 6:  DISTRIBUTED GENERATION

This chapter discusses challenges facing distributed generation (DG) technologies, as well as DG deployment, integration, tracking, and forecasting in California.

DG is broadly defined as electricity produced on-site or close to a load center that is also interconnected to the utility distribution system.[180] The benefits that DG technologies provide go far beyond generation. When used in combined heat and power (CHP) applications, DG can help the state achieve its energy efficiency goals. DG can also improve the efficiency of the transmission and distribution (T&D) system by reducing losses at peak delivery times. Customers can also use DG technologies as peaking resources to respond to high prices during peak periods. Finally, renewable DG helps California reach its renewable energy goals.

Because of the interconnection characteristics of the investor-owned utility (IOU) distribution system, for the purposes of this paper Energy Commission staff consider DG as no greater than 20 megawatts.[181] However, many of the issues described in this chapter also affect larger systems that are on-site or close to the load center, and these systems will be referred to in this chapter as “large DG.”

## Status of Distributed Generation in California

This section discusses the results of current assessment activities in California, as well as issues with forecasts of future DG penetration.

### *Combined Heat and Power Market and Policy Assessment*

Currently, the most energy-efficient and cost effective form of DG is combined cooling, heating and power (CCHP). Combined heat and power (CHP) is a subset of CCHP, but is a more mature and widely deployed technology because of its cost. For purposes of this paper, the term “CHP” refers generally to all heating and cooling, while “CCHP” refers exclusively to cooling and heating.

During preparation of the *2003 Energy Report*, stakeholders expressed concern that CHP was not sufficiently addressed as a key, preferred contributor to California’s energy resource mix. To address this concern, the Energy Commission recognized the need to reassess the technical and market opportunities for CHP applications and the role they could play in the state’s loading order and *Energy Action Plan* goals.

In April 2005, the Energy Commission’s Public Interest Energy Research (PIER) Distributed Energy Integration Research Program released the *Assessment of California CHP Market and Policy Options For Increased Penetration* (*CHP Assessment*), prepared by the Electric Power Research Institute (EPRI) and a project team comprised of Energy and Environmental Analysis (EEA), EPRI Solutions Primen, and Energy and Environmental Economics (E3). [182]

The *CHP Assessment* evaluates the penetration of CHP in California between today and 2020 for a base case and alternative scenarios. The base case scenario uses current regulatory structures, forecasted electricity and natural gas prices, existing incentive programs, anticipated technology cost and performance characteristics, and current utility treatment of CHP. The alternative scenarios examine the impact of different policies on CHP penetration over the next 15 years. These policies include changing incentive programs for end use adopters of CHP and for utilities, using special or modified natural gas and electric tariffs for CHP, streamlining CHP project permitting and interconnection, special CHP marketing and branding, providing special state tax incentives, imposing CHP portfolio standards, and others.[183]

In addition, the CHP Assessment conducted market research to determine what drives end-use customers' decisions whether or not to install CHP projects, and also considered research and development priorities to address barriers to CHP penetration in California.

For a more complete description of the evaluation methodology and results, please see Appendix C.

**Existing CHP Capacity in California**

The *CHP Assessment* identified 9,130 MW of active CHP projects at 776 sites in California, with nearly 90 percent of this capacity representing DG systems greater than 20 MW.

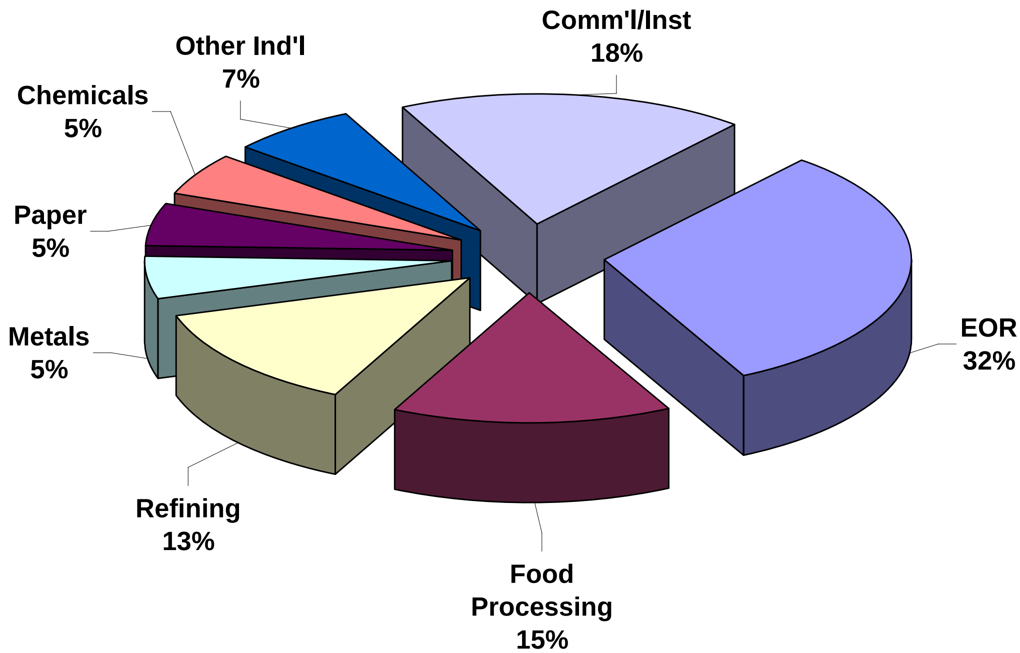
Figure 20 shows the breakdown of California CHP by application. Half of existing CHP capacity is in the industrial sector—food processing, refining, metals, paper and chemicals. About a third of existing CHP capacity is in oil fields providing steam for enhanced oil recovery (EOR); the remaining 18 percent is made up of the commercial and institutional sectors.

Systems under five MW represent only about three percent of existing CHP capacity in California, with the remaining capacity provided by large installations. In fact, systems greater than 100 MW represent nearly 40 percent of existing capacity. However, the market saturation of CHP in large facilities is higher than for smaller sites, and much of the remaining technical market potential is in smaller systems.

Natural gas is the major fuel used for CHP, representing 84 percent of the total installed capacity. Renewable fuel makes up four percent of the total capacity, mostly in the wood product, paper, and food processing industries and in wastewater treatment facilities.

With the concentration of large scale systems in the existing CHP population, the most common generators are gas turbines. In very large systems, these are often in combined-cycle configurations, while simple cycle gas turbines are used in intermediate-sized systems. In the wood, paper, food, and petrochemical industries, boilers drive steam turbines using renewable or waste fuels.

## Figure 20. California Active CHP by Application




Small systems represent only about three percent of total CHP capacity and are driven by gas-fired reciprocating engines at 64 percent of the CHP sites. Emerging technologies, such as microturbines and fuel cells, make up a small but growing fraction of systems.

### Summary of Conclusions and Options

Market potential for CHP is substantial, despite higher natural gas prices, and could significantly contribute to California's EAP goals. In the base case, market penetration for CHP is close to 2,000 MW. Because of higher natural gas price forecasts, this is about half of what was forecast in 1999. Higher natural gas prices make it difficult for CHP to compete because of longer payback periods and lower acceptance levels among potential adopters.

During the first five years of the forecast period, the *CHP Assessment* reports no market penetration of systems smaller than 20 MW in the southern part of the state. This is because reciprocating engine systems, the dominant technology in markets smaller than five MW, will be unable to meet 2007 emissions requirements until 2010. In addition, small gas turbines will require very expensive after-treatment emission control systems until that technology improves. Market penetration of emerging technologies, such as fuel cells and microturbines, will remain very low throughout the forecast period due to uncompetitive early market pricing that is not offset by payments from the CPUC's Self Generation Incentive Program.

There are 5,200 MW of untapped export potential from CHP in California today. It is difficult for CHP generators to sell their excess electricity, because the market requires scheduling exports hour-by-hour with the CA ISO. This problem could be addressed by encouraging utilities to buy electricity from CHP installations as delivered at the prevailing wholesale price, which could resemble "net metering" at the wholesale energy price. This policy could also encourage larger CHP installations in facilities that use significant amounts of thermal energy.

Energy cost savings, reliability, and security are key drivers for adoption of CHP. However, California end users indicate they want payback periods of fewer than three years, which will limit adoption of CHP. Allowing larger projects to participate in the Self Generation Incentive Program and allowing CHP owners to sell excess power to the grid could increase the likelihood of CHP projects going forward.

Encouraging CHP operation during times of high value to the system, and the local transmission and distribution system, could reduce or replace the Self Generation Incentive Program over time and reduce utility operating margin losses by increasing the system benefits of CHP. CHP owners could be paid for an operating agreement ensuring that the DG unit is running during critical peak days, times of high electricity prices, or a local transmission and distribution capacity constraint. Operating CHP to capture both owner and utility benefits could result in societal benefits.

To achieve short- and long-term goals, the state could favor a more market-based approach. Payments to CHP installations could be based on the market prices of the services they provide, such as energy and capacity or carbon dioxide reductions. Then, an incentive sufficient to encourage new CHP activity could be provided, with the incentive ramping down over time as technology cost and performance improve. This approach would reward CHP installations that provide system benefits while providing a clear exit strategy to the incentive. However, this approach would require a change to the Self Generation Incentive Program since projects that participate in that program cannot receive incentives from other programs.

Existing CHP projects are currently designed and operated to maximize energy cost savings for the CHP owner. However, incentives from the Self Generation Incentive Program are based on size, technology, and fuel type—not on output or efficiency. By creating the right operating agreements with CHP units, the state can integrate its investment in CHP into its resource planning.

One way to increase the rate of CHP adoption is to increase incentives through the Self Generation Incentive Program or some other mechanism, such as a production tax credit or capital cost credit. However, if incentives are not linked to CHP performance, they will not change the fundamental CHP market and will reduce funding for other uses. Also, increasing incentives across the board could result in higher than necessary payments to some CHP installations.

From a research and development (R&D) perspective, R&D technologies for the commercial sector could be most effective because of high technical potential in this sector. In the near-term, R&D could focus on making low-emission gas turbines and internal combustion engines available in the marketplace. In the longer-term, R&D could focus on reducing the capital cost of smaller CHP systems—such as microturbines and high temperature fuel cells—to reach acceptable payback periods for commercial and light industrial end users.

## *Public Comment on Combined Heat and Power Workshop*

On April 28, 2005, the Integrated Energy Policy Report Committee held a workshop to discuss market potential in California for CHP and DG and policy options that would affect market penetration, including those identified in the *CHP Assessment*.

### End-User Comments

In general, end-users contend that IOUs base their decisions solely on cost, ignoring non-price attributes such as carbon dioxide reductions, more efficient use of natural gas resources, reduced criteria pollutant emissions, energy security, and enhanced utility system reliability. According to end users, when these non-price attributes are considered, CHP has greater societal benefits than traditional central plant power generation.

Many larger end-users express concern and frustration with the IOUs' apparent unwillingness to renew long-term QF contracts. One company stated that because it could not extend its long-term contract, it was forced to abandon additional CHP installation and instead install traditional boilers to meet its heat demands.

Without utility contracts for their excess electricity, CHP owners have little choice. Some owners have tried to sell their excess electricity to the wholesale market, but complying with CA ISO metering tariff requirements is difficult and expensive compared with the value of selling the wholesale electricity. Stakeholders claim that if long-term contracts with utilities or access to wholesale markets can be addressed, the remaining 5,270 MW of technical potential identified in the *CHP Assessment* for larger CHP owners could be tapped.

Another issue raised by CHP owners is new standby rates. One operator stated that SCE's new standby rate requires a CHP facility to operate all the time, and that a 15-minute down period in a given month negates their savings of facility-related demand charges. This facility typically experiences one to four outages per month, all the result of utility-induced disturbances. The utility interruptions take the system offline for a minimum of one hour. Although the operator accepts that the utility has a right to insist that a CHP facility be reliable and available, the operator suggests that

90-95 percent of the time is more reasonable, similar to requirements for a large independent power producer subject to a long-term power purchase agreement.

Many of these end users believe that CHP is the most efficient DG application, more efficient than central power plants, and should therefore be a priority resource in the state's loading order on a par with renewables and DG. To accomplish this, several proponents recommend a Cogeneration Portfolio Standard and integrating cogeneration into the RPS. Another suggested option would be "Qualified Energy Recovery" as an eligible resource within the RPS. Qualified Energy Recovery is conversion to electricity of otherwise lost energy from engine exhaust stacks, manufacturing or industrial processes, and water and natural gas pressure let-down facilities. Proponents point out that such energy resources accomplish the policy objectives of the RPS by reducing dependence on fossil fuels for electricity production, as well as associated emissions from those fuels.

**Utility Comments**

Utility concerns focus on protecting ratepayers from increases in electricity rates. The utilities strongly suggest that the Energy Commission not pursue any policies until a definitive cost and benefit methodology has been adopted in the CPUC's current DG proceeding, and that the state should avoid policy options that simply result in cost shifting. They state that although the *CHP Assessment* is a useful tool in determining the future direction of DG, it is premature for the state to make any policy changes based on that assessment until all input values have been fully evaluated. In addition, SCE stated that the *CHP Assessment* does not consider the perspectives of non-DG participants such as utilities, regulators, and ratepayer groups.

PG&E warned that policy makers must be careful about recommending new DG subsidies and that the Energy Commission should clearly identify its goals. PG&E also recommended that the Energy Commission thoroughly evaluate the costs and benefits of new subsidies—as well as other alternative ways to meet the state's policy objectives. PG&E contends that any proposed action must address whether DG will have a positive or negative affect on utility procurement.

In response to specific comments made by CHP proponents during a workshop, PG&E stated that QFs should not receive a set-aside, as proposed by representatives of the Cogeneration Association of California /Energy Producers and Users Coalition. In PG&E's opinion, set-asides could be uneconomic and crowd out renewable energy purchases or purchases of more efficient resources on the wholesale electricity market, and the IOU recommends that these issues be dealt with in the current QF proceeding at the CPUC.

PG&E also took exception with providing wholesale net metering for CHP. They stated that net metering is a subsidy paid for by non-participating ratepayers. PG&E pointed out that the Legislature has implemented net metering for a narrow set of technologies with clear societal benefits such as non-fossil fuel use and zero emissions.

PG&E also disagreed with RealEnergy's position that the efficiency requirement for cogeneration QFs is "bogus." PG&E believes that the efficiency requirement promotes real CHP projects and attains the benefits of more efficient forms of generation. PG&E contended that cogeneration facilities receive many incentives in the form of reduced interconnection costs, reduced natural gas transportation rates, exemptions from some non-bypassable charges, and waivers of standby charges. PG&E also claimed that some purported CHP facilities vent heat to various non-productive uses simply to qualify for these incentives.

### *Forecasting Future DG Penetration*

As a key component of the *2005 Energy Report*, the Energy Commission is assessing the data used by load serving entities and transmission owners in their forecasts of electricity supply and demand in California. These assessments will provide the foundation for recommendations in the *2005 Energy Report*, including progress toward energy efficiency, demand response, and renewable energy goals.

One of the initial difficulties in the Energy Commission's assessment of this data as it applies to DG was determining how exactly the IOUs define DG—including how they differentiate between renewable and non-renewable DG. This issue was also raised in the CPUC's current DG proceeding (R.03-04-017). In future data requests of load serving entities, the Energy Commission needs to ensure that a common definition is used for DG and that renewable and non-renewable DG are clearly differentiated.

Another difficulty has been in identifying the IOUs assumptions regarding which DG applications reduce their peak demand and which do not. DG availability varies by technology or application; availability and installed capacity affect energy delivered. For example, natural gas-fired internal combustion engines (ICE) or microturbines (MTG) can provide peaking power but can also be used as baseload in CHP applications providing electric and thermal loads. ICEs using methane from wastewater treatment can do the same, as can biogas ICEs and MTGs in agricultural applications. Larger applications can also rely on gas turbines as either electrical peakers or as baseload units supplying both electricity and heat.

To fully assess the transparency, coherence, consistency, and plausibility of future IOU forecasts, the Energy Commission needs to request more detailed information regarding types of DG technologies included by the IOUs, how those technologies will be applied, and their assumed availabilities.

## Achieving Numeric Goals for Distributed Generation

The state has not established any explicit MW goal for non-renewable DG. However, state energy policy prefers DG over traditional central station, transmission, and distribution resources. This policy is articulated in legislation, previous Integrated Energy Policy Reports (IEPR), the Energy Commission's DG Strategic Plan, and various CPUC regulations, as well as the EAP, which contains the specific goal of promoting customer and utility-owned DG.

CHP is the most energy efficient and cost effective form of DG and provides numerous benefits to California, including more efficient fuel use, reduced energy costs, fewer environmental impacts, improved reliability and power quality, and support of utility T&D systems. Using CHP systems in commercial, industrial, institutional and multifamily residential applications can increase energy efficiency by displacing boilers and marginal, predominantly natural gas-fired, sources of electricity generation.

In 1999, the Energy Commission estimated 12 gigawatts (GW) (12,000 MW) of CHP technical potential in California.[184] Today, California has not fully tapped this potential and only nine GW have been installed. Regulatory uncertainty, natural gas prices, utility tariffs, emissions standards and other drivers continue to delay implementation of CHP in California.

Energy Commission staff believe that progress toward attaining the state's DG preferences cannot be measured without having a specific goal. However, selection of a DG goal should be done carefully because of potential impacts to both utility ratepayers and the state.

DG and CHP goals have been established at the national level, as well as in other countries. In September 2000, the United States Department of Energy (DOE) released its *Strategic Plan for Distributed Energy Resources*, outlining principal objectives of the federal government through 2020. DOE's plan contains the following vision statement: "The United States will have the cleanest, most efficient, and reliable energy system in the world by maximizing the use of affordable distributed energy resources." To support the vision, DOE will lead a national effort to develop "next generation" DG technologies, document their environmental benefits, and implement deployment strategies.[185]

As part of their strategic plan, DOE has established a 2010 mid-term goal to reduce costs and emissions while increasing the efficiency and reliability of DG so that 20 percent of new electric capacity additions in the United States can be met with DG. Preliminary analysis based on data from the Energy Information Administration found approximately 53 GW of installed DG in the United States in 1998, including installations of up to 50 MW. DOE calculates that to achieve the goal of 20 percent by 2010, 26.5 GW of additional DG capacity will need to be added, equivalent to an increase of four percent per year.

Based upon the *CHP Assessment* and specifically the policy scenarios, the Aggressive Market Scenario would be an attainable goal to pursue, equating to roughly 5,400 MW of CHP over the next 15 years. Since 2001, California has averaged about 100 MW new DG capacity per year; under this scenario, this would increase to 360 MW per year.

To attain this goal under the Aggressive Market Scenario, California will need to provide access to wholesale markets for CHP operators so that excess electricity (generated as a result of systems being sized to meet thermal loads) can be readily sold. Establishing transmission and distribution capacity payments for CHP systems fewer than 20 MW in size that are operated to alleviate utility system peaks would also be necessary. California would need to also implement a global warming incentive in the form of a payment for $CO_2$ reductions. Lastly, mechanisms will need to be implemented to address utility loss of revenue, such as Earning Rate Adjustment Mechanisms used in energy efficiency or other programs.

## Integrating Resources into the System

This section discusses integration issues that continue to be central barriers to the successful deployment of DG and CHP in California, including air quality impacts, electrical interconnection and integration with utility distribution system operations and planning, and incorporation of utility tariffs and other markets. This discussion is followed by an overview of Denmark's experience with high levels of DG integration and accompanying system impacts.

### *Air Quality Impacts of CHP*

At the April 28, 2005 DG workshop, the University of California at Irvine presented results of a PIER-funded research study on air quality impacts from DG deployment in California.[186] This study used state-of-the-art modeling techniques and DG deployment scenarios to assess how different types of DG would affect the South Coast Air Quality Management District (SCAQMD) air basin in the year 2010.

This seminal study used geographic information systems and land use data to develop DG implementation scenarios representing DG technologies most likely to be adopted by energy end-use sectors. The result was a temporal and spatial assessment of how DG contributes to the air quality in the SCAQMD air basin during episodic air quality events.

The study evaluated 26 different DG deployment scenarios, one of which was aimed specifically at CHP. (For more information about the specific assumptions in the scenarios, please see *Air Quality Impacts of Distributed Generation,* publication number CEC-500-2005-069-D, April 2005).

The study presented several principal findings relative to DG and CHP deployment in the SCAQMD in 2010:

- Use of CHP can provide significant reductions in some criteria pollutant and carbon dioxide emissions.

- Under realistic DG penetration scenarios, the total contribution of DG to total emissions in the basin is less than half of one percent of emissions from all other stationary and mobile sources.
- Large DG is most likely to be concentrated near industrial zones due to relatively high adoption of DG.
- Slightly less than two-thirds of total DG will be in the industrial sector, with the remaining one-third in the commercial-institutional sector.
- Nearly half of the DG market is met by gas turbines, followed by internal combustion engines (17 percent), microturbine generators (15 percent), fuel cells (10 percent), photovoltaic (5 percent), and gas turbine-fuel cell hybrids (4 percent).

### *Utility Distribution Planning and the Role of DG*

Distribution systems in California are increasingly constrained because utility financial stress, slow or uncertain load growth, fallout from the 2000-2001 energy crisis, and other drivers have delayed additions to those systems. Traditional utility distribution planning processes were adequate in the past, but new alternatives such as DG, demand response, and research into the utility system benefits they provide, require a reassessment of how utilities make distribution planning and investment decisions.

The *2003 Energy Report* recommended a more transparent distribution planning process so that policy makers can ensure cost effective and reliable distribution services and costs for ratepayers. To support this recommendation, policy discussion and supporting PIER research has focused on answering three key questions:

1. What lessons can be learned from utilities that have embraced and incorporated DG and demand response into their distribution planning and operations?
2. Do the new tools developed through PIER enable new approaches for utilities?
3. Should the planning process be changed to ensure that distribution investments result in cost effective and reliable distribution systems for ratepayers?

On April 29, 2005, the *Energy Report* Committee conducted a public workshop to investigate the role of DG and demand response in distribution planning and understand typical distribution planning processes as well as new approaches. In addition, the workshop highlighted several important PIER-funded research projects that are investigating distribution planning processes and practices, as well as tools and methods for understanding how DG and demand response can be integrated into engineering analysis of distribution problems. These tools were discussed against the backdrop of how utilities traditionally conduct distribution studies and plan for distribution projects. A representative from Detroit Edison also presented more visionary distribution planning practices that embrace DG as a distribution asset.

The traditional utility distribution planning process is fairly uniform among utilities, with minor deviations specific to a particular utility's practices. There are seven main steps in the planning process:

1. Defining the planning area.
2. Modeling the distribution system and understanding the loads.
3. Forecasting load growth.
4. Normalizing for weather conditions.
5. Applying planning criteria.
6. Identifying different solution alternatives.
7. Gaining necessary approvals.

Generally, utilities forecast over a 10-year planning horizon to identify distribution system delivery deficiencies. By understanding distribution system abilities and limitations, a utility can develop a set of recommended projects required over a specified time period to address those system deficiencies. The process also identifies necessary financial requirements, lead time to obtain project materials, right-of-ways and permits, and community or state involvement.[187]

Distribution planners are typically assigned to a particular planning area within a utility's system. They are responsible for understanding that area's capacity, potential load growth, operation, and reliability. Planners model their portion of the system including inherent equipment, protection schemes, connectivity to other parts of the utility system, and tie points within that part of a distribution system.[188]

Challenges for distribution planners identified during the workshop are shown in Table 13. DG and demand response, along with new planning tools and approaches, could potentially remedy these challenges if utilities are willing to embrace new ideas and strategies.

There are two planning tools being developed through the Energy Commission's PIER program. The first is a methodology to assess the benefits of distributed generation and demand response for utility T&D systems. The second is a joint engineering and economic tool for utility evaluation of renewable DG.

## Table 13. Challenges to the Distribution Planner

<table>
<tr><th colspan="2">Planning Challenges</th></tr>
<tr><td>

- Accurate load forecasting
- Having accurate data to model the system
- Adjusting for normal configuration
- Adjusting for weather normalization
- Gathering accurate load information
- Keeping circuits balanced
- Ensuring coordination of protective devices
- Designing ties for contingency switching
- Aligning load forecasts
- Coordination with substation and transmission upgrades
- Limits for duct availability
- Challenges to securing Right-of-Ways
- Resistance from community
- Limitations for securing outages to construct
- Ensuring completion by peak load season
- Communicating
  - The funding plan
  - The plan for accurate engineering and construction
  - System risk associated with not expanding

</td><td>

- Constraints to exit substations
- Substations are limited for additional sources
- Automated switching deployment
- Contingency analysis for un-funded upgrade projects
- Adjusting to incorporate local load shedding
- Incorporating localized generation
- Having systems to accommodate interconnections
- Relay changes to accommodate generation addition
- Internal coordination for technology deployment
- Settings
- Installation Coordination
- Operations training to utilize according to the criteria
- Interface with SCADA
- Crew acceptance
- Battery maintenance and on-going testing
- Fast track load additions that impact the existing plan
- Changing characteristics of existing load

</td></tr>
<tr><th colspan="2">Operational Challenges</th></tr>
<tr><td>

- Maintaining configuration during peak loads
- Gathering load data (if not available automatically)
- Scheduling switching to provide outages for construction

</td><td>

- Operating using planning assumptions
- Entering information for system additions
- Dispatching to minimize outage duration

</td></tr>
</table>

### Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits[189]

The overall goal of this research is a tool to identify where Distributed Energy Resources (DER) can provide specific benefits, as well as the value of those benefits in engineering and economic terms. In this research, DER is broadly defined as DG, demand response, and localized reactive power sources.

The methodology determines which characteristics of DER projects enhance the performance of the T&D system by improving power quality and reliability and relieving congestion. The methodology will provide a suggested set of financial and non-financial incentives for DER projects, including value-sharing rather than cost-shifting incentives that benefit operation of the T&D network.[190]

The first phase of this project, using Silicon Valley Power's (SVP) T&D system as a case study, showed that DER projects in the right locations and with the right characteristics and operating profiles can improve the performance of a given network by reducing real power losses, VAR flow and consumption, distribution system voltage variability, and system stress. In addition, these projects can eliminate low- and high-voltage buses, increase load-serving capability, and avoid or defer T&D improvements.[191]

Results presented at the *Energy Report* Committee's April 29 workshop showed that for the 2005 summer peak case, a majority of 422 SVP customers could implement DG and demand response that would provide varying degrees of utility system benefits, as shown in Table 14. The optimal portfolio is comprised of smaller DG systems, on average fewer than 160 kW

## Table 14. Benefits to SVP from Optimal Portfolio Implementation for 2005 Summer Peak Case[192]

| | |
|---|---|
| DER Portfolio Projects: | |
| Demand Response | 389 sites; 10.5 MW (2.6% of load on-peak) |
| DG | 380 sites; 54.9 MW on-peak (13.8% of peak load).<br>160 kW average, 8.9 MW largest |
| | |
| Network Benefits: | |
| Loss reduction | Total of 6.7 MW, 85.4 MVAR on peak<br>33 - 39% reduction in local real power losses.<br>28 - 45% reduction in local reactive power losses. |
| Increased load-serving capability | 117.6 MW |
| Incremental peak capacity | 60.3 MW |
| Eliminated all low-voltage buses | |
| Reduced voltage variability | |
| | |
| **Network benefits occur under Winter Peak and Minimum Load conditions (i.e., not limited to Knee Peak and 1% highest hour Summer Peak).** | |
| | |
| **Estimated value of network benefits:**<br>~$450 per kW of year-round dispatchable DER if capacity is included. | |

In this optimal portfolio, 60 percent of DG projects would not need to vary MW output to provide the observed system benefits.[193] This is a very important finding for two reasons. First, it refutes utilities' claims that they need to control a customer's DG system to realize system benefits. For CHP and other baseload applications at a customer's site, the utility system and nonparticipating ratepayers on the system will capture the benefit as long as the DG system has high availability. Second, it means that an expensive communications and controls infrastructure to dispatch these DG systems in a more real-time manner (comparable to the CA ISO metering systems for independent power producers) is probably not needed.

Another key finding: "As with DR, the ranking of DG capacity additions is largely independent of the customer size or customer class, and DG at the transmission-level customer locations received among the lowest ranks in terms of per-unit network benefit."[194]

Based upon the Phase 1 findings, the PIER program partnered with SCE to conduct a Phase 2 study using this approach. Phase 2 will analyze a portion of SCE's system roughly 15 times larger, more heavily loaded, and more complex than SVP's. Phase 2 will expand the available DER devices to include storage and changeability distribution topologies (e.g., automated switching), and also expand system performance measures to include value of service, reliability and operator planning objectives. In addition, Phase 2 will use a common cost benefit evaluation for DER and traditional utility measures to allow an apples-to-apples comparison of options.[195]

### Renewable Distributed Generation Assessment

A second tool to help distribution planners was also presented at the *Energy Report* Committee's April 29 workshop on distribution planning. This project developed a joint engineering and economic tool for utility evaluation of renewable DG. The research was performed by Energy & Environmental Economics and involved four California municipal utilities: Alameda Power and Telecom, City of Palo Alto Utilities, Sacramento Municipal Utility District, and San Francisco Public Utility Commission-Hetch Hetchy.

The main objectives of this project were to: (1) analyze local system impacts and benefits that accrue directly to a municipal utility in a localized network; (2) expand the evaluation methodology to evaluate the impacts on local system reliability, including the value to both the customers and the utility; and (3) incorporate load growth and generator system performance uncertainty in weather assumptions.[196]

There were several key conclusions from the case studies with each of the participating municipal utilities. First, it is difficult to identify cost effective renewable DG on a net direct-benefit basis because avoided costs are too low and renewable DG capital costs too high. This means that the indirect benefit value (e.g., environmental values, locational value, etc.) needs to be high to make up the gap in cost effectiveness. Second, cost effective technologies tend to be larger CHP applications. Finally, if sited in the best location, renewable DG provides substantial benefits to distribution systems in terms of capacity release and peak load loss reduction.[197]

The study also found that there are effective ways for utilities to plan for contingencies when using intermittent renewables such as PV and wind. Traditional utility planning practices don't lend themselves well to intermittent sources. However, due to its distributed nature, renewable DG—and DG in general for that matter—can be effectively incorporated into contingencies for reliability purposes.

The basic methodology to acquire equivalent reliability with DG and renewable DG is comprised of three main steps described below.[198]

1. Use the load forecast to set the required capacity to serve the study area.
2. Compute the probability that the integrated plan provides "equivalent" reliability to the traditional system.
    a. Estimate the availability of each transmission path and its load carrying capability.
    b. Define the reliability of the combined resources to serve the area (e.g., 99.999%).
    c. Estimate the availability of each individual resource (e.g., DG is 95%, Demand Response is 75%).
    d. Use a Markov chain model to determine the states that provide enough capability and their probability.
3. Compute the nameplate capacity of additional resources required to match "equivalent" reliability of traditional solution based on existing engineering criteria.

An example is provided in Table 15, showing that in order to meet the four MW firm capacity shortfall in 2001, more than four MW of installed capacity of DG units will be required to ensure reliability through redundancy. For example, 20 250-kW DG units, or five MW of DG capacity, would need to be installed to achieve equivalent reliability of four MW. This assumes that four of the 250 kW DG units (or one MW) are non-firm units and thus one MW of installed capacity is redundant. This level of redundancy yields an *installed* capacity of 125 percent of the required *firm* capacity required.

As the DG units increase in size, greater installed capacity is needed to meet the four MW firm capacity shortfall. In the case of 2,000 kW DG units, two redundant units are required; therefore, total installed capacity of eight MW is needed to reliably meet the four MW shortfall.

### *DG as a Distribution Asset*

Despite new tools and methods for determining where and how DG can provide benefits to utility T&D systems, DG will continue to face barriers to integration into utility planning and operations practices until utilities wholly embrace this technology. In other parts of the United States, some utilities have done so and are finding the DG can be a valuable asset in their traditional toolbox of solutions.

## Table 15. Examples Results with Redundancy[199]

| Required Installed Capacity for "Equivalent Reliability" | | | |
|---|---|---|---|
| | Year<br>Firm Capacity Shortfall | | |
| **kW/unit** | **2001**<br>**4 MW** | **2002**<br>**14 MW** | **2003**<br>**19 MW** |
| 30 | 4.38 MW, 110% | 14.46 MW, 103% | 19.59 MW, 103% |
| 250 | 5 MW, 125% | 16 MW, 114% | 21.25 MW, 112% |
| 500 | 5.5 MW, 138% | 16.5 MW, 118% | 22 MW, 116% |
| 1000 | 6 MW, 150% | 18 MW, 129% | 23 MW, 121% |
| 2000 | 8 MW, 200% | 20 MW, 143% | 26 MW, 137% |
| 5000 | 15 MW, 375% | 25 MW, 179% | 30 MW, 158% |

**Detroit Edison Experience**

Detroit Edison and its parent company, DTE Energy, have committed to DG, as illustrated in the following quote by DTE's chairman and CEO, Anthony F. Earley, Jr.:[200]

> Several years ago the leadership at DTE tried to envision what the electric utility business would look like in a decade. One of our conclusions was that this industry would go through the same transformation that the computer business has experienced. There, mainframe computers gave way to desktops which gave way to laptops.
>
> In the electric industry, the day of large central station power plants has already given way to modular, combined cycle gas powered plants. We envisioned a day when the next step, distributed (or personal) generation would play a major role. In fact utilities may be among the first real-world, large scale users of distributed generation. Distributed generation will increasingly become a cost effective alternative to the expansion and reinforcement of T&D infrastructure.

At the April 29 Committee workshop, Detroit Edison made a presentation on its experience with integrating DG into its system.[201] Detroit Edison and DTE Energy are rethinking the role of DG in their business practices. Their vision for DG is a hybrid system of the traditional system and DG. Detroit Edison has therefore formed a DG Planning Group to integrate DG into the regulated utility's planning and operation processes. This group serves as a champion for DG within the utility, and provides a range of important services to other business units. These services include:  DG system design, control and communication, interconnection protection issues, community relations, manage utility DG installations, and operations.

Detroit Edison's experience in installing and operating DG on its system dispelled several utility myths about DG. First, there is a common misconception that DG is too expensive. Detroit Edison found this to be untrue when DG was compared with peaker plants, or when there were free fuels. Second, there is a perception that it is unsafe to parallel DG systems with the utility system. Detroit Edison disagrees, as long as the protection system is designed properly. Third, regarding the belief that customers will not allow a utility to control the DG or that the utility "hates" DG, Detroit Edison learned that as long as the customer or utility gets something out of DG, this is not a problem.

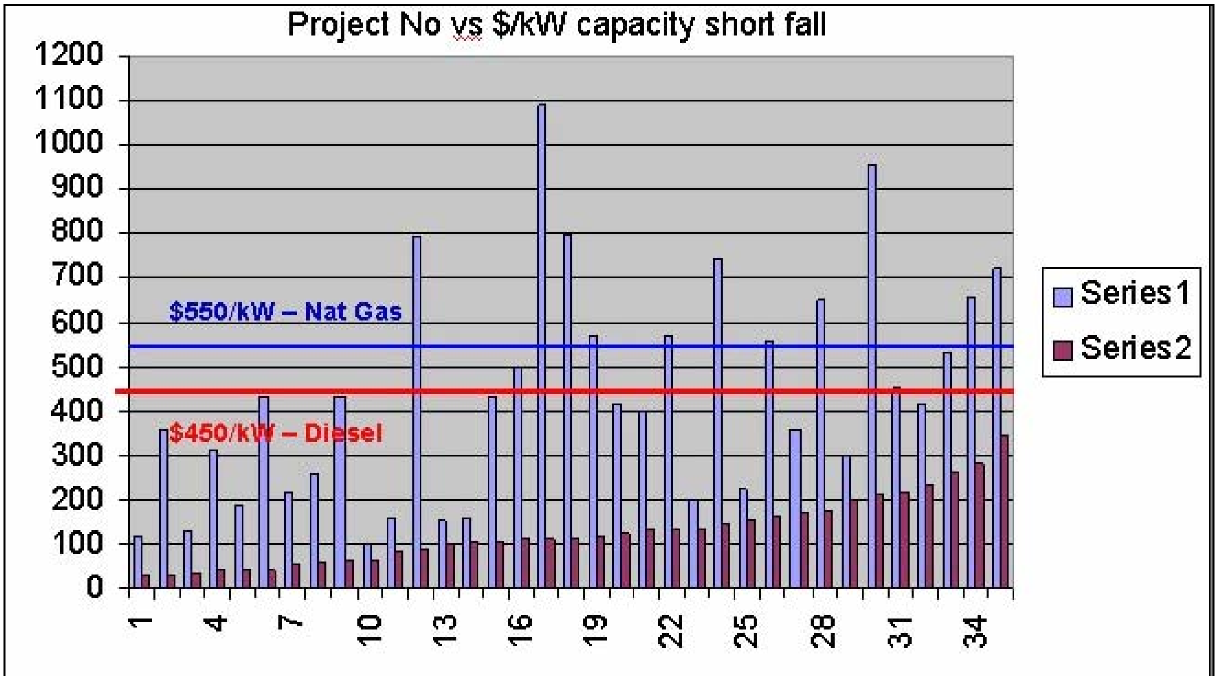
Detroit Edison sees continued constraints on capital budgets while utility customer expectations increase. Utilities are faced with the daunting task of balancing the need for new distribution while maintaining existing distribution systems. The reality of this situation is that utilities "can no longer afford to solve every one MVA problem with [the] traditional T&D 30 MVA solution," because problems may only exist for a few hours out of the year, or the large amount of additional capacity may no be fully utilized for several years.[202] Detroit Edison has found that "DG is one way of delivering just-in-time and right sized capacity [additions] to resolve smaller short falls while minimizing the initial capital outlay." This allows limited capital project budgets to focus on higher priority reliability and maintenance projects.

Figure 21 shows Detroit Edison's 2003 DG Integration Review. This figure illustrates that for some distribution projects, natural gas or diesel fueled DG alternatives can be more cost effective on a dollars-per-kW basis. In many cases, however, the traditional utility wires solution is more cost effective.

Detroit Edison uses DG in three principal situations:  emergency, temporary and permanent. Emergency applications are where DG is installed to provide immediate relief of an emergency problem using Detroit Edison's own portable DG units or a standard leased unit. Detroit Edison also relies on that particular distribution circuit's embedded interruptible loads to help manage loading under emergencies. A key consideration for the utility is also to explore customer-owned generation on the circuit that could provide emergency help.

Temporary relief applications use DG to relieve a problem using leased or purchased DG to return loading levels to within distribution planning criteria. These types of applications should typically last from one to four years. Again, DG, as well as circuit specific interruptible loads, is used to manage the loading level. The utility strives to partner with customers for siting of DG, and also explores whether known customer generation on that circuit can provide help.

## Figure 21. 2003 DER Integration Review




Note: Vertical axis is $/kW and horizontal axis is distribution project number[203]

Permanent applications are those in which DG is used to return circuit loading to below distribution planning criteria for an estimated five-year period.

For all of these applications, Detroit Edison makes a concerted effort to educate communities, customers, and regulators that electricity is an essential service and that utilities have a mandate to serve. They impress upon key stakeholders that the emergency and temporary installations are special circumstances that should be given different treatment, and at a minimum should get faster consideration. Detroit Edison makes an effort to communicate with a common voice and to enlist the support of other state utilities. They also offer references to affected customers and potential DG site owners of past DG site owners or communities.

Detroit Edison's public relations efforts have been effective. Over the past several years, Detroit Edison has installed more than 1,400 MW of DG on their system, representing 12 percent of system peak load. (For a description of eight projects installed by Detroit Edison to serve as emergency and temporary installations, refer to the Energy Commission's website at [http://www.energy.ca.gov/distgen_oii/documents/2005-04-29_workshop/SEGUIN_DTE.PDF].)

California utilities have contended that two-thirds of Detroit Edison's distribution is made up of 4.8 kV circuits, where DG systems of the sizes mentioned are more beneficial. However, Detroit Edison has successfully used DG on both 4.8 kV and 13.2 kV circuits. Utilities and others in California have claimed that Detroit Edison's approach is not feasible in California because diesel-fueled DG cannot meet California's stringent air quality rules. However, Detroit Edison uses both natural gas and diesel-fueled DG.

The real concern is whether internal combustion engines similar to what Detroit Edison uses can meet the California Air Resources Board's 2007 Air Quality Standards for DG. The Energy Commission currently supports a significant amount of research to make DG systems meet these standards.

Detroit Edison typically operates their DG systems whenever the ambient temperature rises above 90°F. In a comparison of five DG installations that Detroit Edison uses for distribution support, the hours of operation were modest. In 2002, the average per-unit operation time for the entire year was fewer than 108 hours. In 2003, the average was 30 hours, and in 2004, the average was 58 hours. In addition, three of five installations used natural gas and the remaining two used diesel. In comparison, in California air districts often permit backup emergency generators to operate for up to 200 hours per year for maintenance purposes. The vast majority of California's 3,000 MW of emergency backup generators are diesel-fired, and some units are up to 30 years old with less than optimal emissions profiles.

Another key conclusion from the five cases discussed is that the cost of the DG solution was cheaper than the traditional utility wires solution for four of the five cases. In one exception, Detroit Edison calculates that the DG project would have been more cost effective had they bought the DG system outright, as opposed to leasing it, which they later did. Based upon Detroit Edison's experience, however, it appears their approach could work in California.

In general, Detroit Edison's corporate commitment and development of a dedicated DG Planning Group has moved them considerably up the learning curve on how to integrate DG into their planning and operations practices. Their operators now have DG assets along with customer interruptible loads readily available to dispatch during contingencies or other distribution system loading constraints. With over 1,400 MW of utility installed/leased and operated DG serving their system as a distribution asset, Detroit Edison has made significant progress for a utility serving only 2.1 million customers. California's three IOUs serve more than 30 million customers and don't own, lease or contract for even a fraction of Detroit Edison's DG capacity.

However, since the CPUC's rulemaking ordering incorporation of DG into distribution planning processes, the Energy Commission has seen some limited noteworthy progress. SCE has had the most publicly visible activities in distribution planning and has been working collaboratively with the DG industry to solicit DG projects for deferment of distribution projects.

**Southern California Edison Distributed Generation Activities**

To comply with the CPUC's order in the last DG rulemaking, SCE originally planned to issue solicitations by November 2004 to solicit DG as a way to defer additional transmission and distribution infrastructure. SCE hoped to have DG projects under contract to meet the 2006 summer peak. SCE had followed the unsuccessful attempts of pilot programs in New York, where feedback from the DG industry suggested the New York utilities did not understand how DG projects should work.

SCE decided that a more collaborative approach with the DG industry could result in better participation in their DG solicitation. In early 2004, SCE enlisted the Electricity Innovation Institute to assist them in facilitating a collaborative with the DG industry to define SCE's solicitation. This effort was funded in large part by the Energy Commission's PIER Program.[204]

Between May and October of 2004, SCE and the industry worked out the structure and details of a deferment pilot program to be implemented in 2005. Because of related changes to SCE's distribution planning cycle and their desire for CPUC approval of their model agreement for the deferment program, SCE delayed the program; results of that effort are not yet known.

However, of note are three key findings that directly resulted from SCE's collaborative work with the DG industry to implement this pilot program. First, the CPUC decision specified that the DG units provide physical assurance to SCE. Through the collaborative workshops and meetings, the amount of reliability required for physical assurance was made more flexible. Instead of requiring load reduction or "demand limitation" at all times when DG is not operating, which can create real burdens for customers otherwise willing to help the utility, SCE will limit the requirement to 200 to 400 hours per year, with a daily limitation. SCE will also make allowances for customer maintenance outages.

Second, DG customers and third-party providers need to know whether responding to a utility DG solicitation is worth the considerable time and expense it requires. SCE's starting point was that no price or value would be included in its RFP, and proposals would be sealed bids, to take or leave. Based on the collaborator's input, SCE has now agreed to include a "market reference price" to guide customers, and to negotiate the final agreement with successful bidders.

Third, the model agreement was originally designed so that the utility would take virtually none of the risk. Through the collaborative discussions, SCE was persuaded to rewrite the agreement to share more of the risks, and collaborative participants are now satisfied that it meets many of the needs of prospective bidders.

Other issues identified included focusing on sources of value by capturing value streams to all stakeholders, simplifying the process that utilities use to procure DG, adopting long-term perspectives by improving forecasting methods for local distribution systems, and providing economic incentives to utilities to use the most cost effective resources (including customer-side DG) to serve all customers.

**United States Department of Energy's Future Grid Research**

According to the Gas Technology Institute, recent studies by the United States Department of Energy (DOE) indicate that California may have another choice. DOE's Future Grid studies demonstrate that targeted deployment of energy efficiency, CHP, and renewables on constrained circuits could fundamentally change the electricity load shape; significantly reducing peak demand and eliminating the need for new distribution, as well as, supporting transmission and generation.[205]

The studies identify several innovative policies that can direct the deployment of load shaping technologies by influencing private investment. Policies include:

- Waiving standby charges for constrained areas of the system.
- Focusing incentives on constrained areas.
- Stepped demand charges or time of use rates that increase as load increases during the day.

According to the Gas Technology Institute, all of the above policies are in use in some form in the United States; these policies improve the rate of return for private investment in CHP, energy efficiency and renewables. DOE, with support from the Gas Technology Institute, has developed modeling tools allowing regulators to design time of use rates; these rates improve the rate of return on private investment in technologies, thereby slowing peak load growth without impacting growth in intermediate and base-load consumption. The end result is increased energy efficiency, improved grid utilization, lower cost electricity for California consumers, and lower transmission and distribution costs for utilities.

The Gas Technology Institute has been working with the DOE and several major utilities for over two years addressing five specific goals through case study modeling of utility circuits. The goals are to:

1. Increase the use of clean energy sources
2. Improve grid utilization and relieve constrained areas
3. Slow or eliminate peak load growth
4. Improve system reliability
5. Attract private investment

The case studies, which include circuits in Detroit Edison Service territory, have shown that the five goals above can be met through strategic deployment of energy efficiency, CHP, and renewables.

## *International Perspectives on DG Integration*

In December 2004, Energy Commission staff participated in the First International Conference on Integration of Renewable Energy Resources and Distributed Energy Resources held in Brussels, Belgium.[206] The staff made a presentation to European member states outlining California's DG activities, including research and development, policy and regulations. The staff also identifies strategies and goals from the DG experience of the United Kingdom, Germany, and Denmark that provide useful input to California's consideration of DG goals.

### United Kingdom

The United Kingdom (UK) has been proactive in dealing with regulatory barriers preventing the successful implementation of DG. Their regulator is the Office of Gas and Electricity Markets (OFGEM). OFGEM is working with the UK's Department of Trade and Industry and the utility and DER industry through the DG Coordinating Group to address these barriers.

The UK government has set some challenging environmental targets to meet its obligations under the Kyoto climate change protocol. By 2010, their goal is to generate 10 percent of UK electricity supplies from renewable sources and to develop 10,000 MW of installed CHP capacity. Meeting these targets will involve adding some 8,000 MW of renewable capacity and 5,500 MW of CHP capacity to the network.[207] This could increase the number of generators on a Distribution Network Operator's (DNO) network from 300 total generators to 300 generators at every substation—a significant challenge. To accomplish this, OFGEM is presently implementing utility incentives to promote innovation in embracing DG implementation.

### Germany

Germany continues to lead Europe in implementing wind and solar technologies, with more than 16,000 MW of wind capacity installed to date. Germany presently has about 12.5 percent of its energy provided by renewables, with a goal of 21 percent by 2010. The main drivers for pursuing renewables and CHP are climate change, sustainability and security of supplies.

Germany currently employs more than 120,000 people to support renewable energy production, which accounts for over $10 billion Euro ($13.5 billion US dollars). Germany has identified the following requirements to successfully implement renewables:

- Integrating intermittency of renewables and dealing with system voltage stability issues.
- Making renewables technically and economically feasible.
- Addressing the traditional utility infrastructure changeover.
- Dealing with constrained transmission systems across Europe.
- Relying on energy efficiency.
- Continuing to pursue market deregulation.

**Denmark**

Denmark has a large portfolio of wind and CHP DG capacity installed presently. While small compared with California standards, this amount of capacity is quite impressive. Denmark has over 7,500 MW of total installed capacity, of which distributed wind constitutes more than 2,300 MW and distributed CHP constitutes 1,600 MW. All the remaining capacity is central-scale, but is used in CHP applications as well as to provide district heating. By law, Denmark requires all fossil-fueled generation to be natural gas-fired and used in CHP mode, again predominantly for district heating.

## *A Glimpse of a Potential Future*

As California continues to promote renewable and nonrenewable DG, the state must consider how the utility system will be affected by this technology. Today's distribution systems are designed for one-way power flow; that is, power flows from the substation down the distribution feeders to individual customer loads. As more and more DG is interconnected to the utilities' systems, normal distribution system design and operation must be modernized to deal with these embedded generation sources.

The Energy Commission's PIER program has invested more than $40 million in research for integrating DG into today's distribution system. However, in the future, as DG penetration levels and generation capacity become higher than the loads being served on any given distribution feeder or substation, problems will arise. New research is beginning to look at the technical challenges this kind of future will hold.

Today, Denmark is dealing with these very issues while trying to maintain the reliability and security of its power system.[208] Denmark's power system evolved from a central-generation paradigm to a DG-dominated paradigm over a 20-year period. DG currently represents more than 50 percent of total generation capacity. The main policy drivers for this change were the energy crisis of the 1970's and the Kyoto Protocols. The latter influenced Denmark to increase its wind resources to roughly 31 percent of the country's generating capacity.

Denmark is a major transmission conduit between Germany and the Netherlands, and between Sweden and Finland. Many of these countries use the vast hydroelectric resources of Sweden and Finland to firm up their wind resources. However, this creates large transmission constraints for Denmark and the Netherlands. Denmark's peak load is only about 3.8 GW, but the country produces more than 7.5 GW, which is then exported to other countries.

During concurrent high wind and high thermal load periods, Denmark experiences critical transmission and distribution system conditions. The high electricity production from the distributed CHP and wind generators results in power flows out of their distribution system and into their transmission system. These flows create equipment safety and system operational issues in the transmission and distribution system.

These problems are exacerbated by the fact that the transmission system operator only has control of the transmission scale generation systems, meaning the operator cannot change the dispatch of the distributed CHP or wind, cannot maintain N-1 reliability, or easily restore the system following faults.

To remedy these problems, Denmark is working to change the architecture of its transmission and distribution system so that DG can contribute to system balance and security. In the short term, Denmark is requiring all DG to be dispatchable, and local distribution companies to maintain supply and demand locally. In addition, distribution companies must internally control reactive power and voltages, shed local load and DG during emergencies, and restore local grids after failures including local start after blackout. In the long term, Denmark is looking to implement better communications and controls in its transmission and distribution systems to better understand its real-time conditions. They are evaluating advanced distribution system operation approaches being developed by EPRI under the auspices of the Intelligrid Program and United States Department of Energy's Gridwise program. Through these short- and long-term approaches, Denmark hopes to technically improve its transmission and distribution system so that the high penetration of DG and wind can be best utilized to meet the country's environmental goals.

California can learn from Denmark's experience of considering a DG-dominant path. Large penetrations of a 21$^{st}$ century technology such as DG into a 20$^{th}$ century transmission and distribution system will exacerbate California's energy problems. To truly reap the benefits of DG, California must ensure that the state's transmission and distribution system is modernized as DG is added to the system.

If California is going to pursue a large role for DG, it is noteworthy to consider Denmark's challenges as a way to anticipate a future where DG plays a significant role. In this way, California can ensure the power system is built in a DG-friendly manner.

## Monitoring and Verifying Distributed Generation for Effective Planning

To monitor the progress of DG deployment in California and ensure that DG and loading order goals are being met, the state needs to improve DG tracking mechanisms. Today, it is extremely difficult to track the increase in installed capacity and energy production of DG. This is principally because data reporting requirements and regulations have not focused specifically on small generation.

As discussed in Chapter 2, the IOUs are currently required to submit a number of reports on DG activities to the CPUC and Energy Commission. These reports include providing data on interconnections, net metering installations, cost responsibility surcharge exemptions, and the SGIP. In the data reporting required for the *2005 Energy Report*, utilities also provide long-range forecasts to the Energy Commission. Energy Commission staff already has identified several needs for improved data reporting in that process.

Finally, in current interconnection rule revisions, the Energy Commission has recommended that the CPUC require IOUs to develop a more thorough interconnection data tracking system. These recommendations are expected to be decided upon by the CPUC by the end of 2005.

The Energy Commission and CPUC staff is addressing these and other data reporting needs in the CPUC's current DG rulemaking. Through this public process, the two agencies expect to develop sufficient data reporting requirements that will improve state government's ability to monitor the progression of DG deployment.

# Chapter 6 Endnotes

[180] This is a working definition for DG that is used in various policy activities at the California Energy Commission and California Public Utilities Commission.
[181] In California, IOU substations and feeders vary in voltage level, current carrying capacity, and total capacity. For example, Southern California Edison's distribution system voltages are 33, 16, 12, and 4 kV (nominal). Furthermore, Southern California Edison typically designs their 12 and 16 kV circuits or feeders to carry about 400 amps, or 9 and 12 MW, respectively. In emergencies, 12 and 16 kV feeders can carry up to 600 amps, or 13 and 17 MW, respectively. Their distribution substations consist of multiple 28 MVA transformers. DG larger than 20 MW would likely be interconnected at transmission voltages and not distribution voltages based on these typical substation and feeder ratings and capacities for Southern California Edison's distribution system.
[182] *Assessment of California CHP Market and Policy Options For Increased Penetration*, California Energy Commission, Publication #CEC-2005-060-D, April 2005.
[183] *CHP Assessment*, Appendix H.
[184] *Market Assessment of Combined Hear and Power in the State of California*, California Energy Commission, Publication #P700-00-009, July 1999.
[185] Strategic Plan for Distributed Energy Resources, U.S. DOE, September 2000, p. 2.
[186] *Air Quality Impacts of Distributed Generation*, California Energy Commission, Publication #CEC-500-2005-069-D, April 2005
[187] Presentation by Judd Putnamm, IEPR Distribution Planning Workshop, April 29, 2005, p. 3
[188] *Ibid*, p. 5
[189] *Optimal Portfolio Methodology for Assessing Distributed Energy Resources for the EnergyNet[SM]* , California Energy Commission, Publication #CEC-500-2005-061-D, April 2005, [http://www.energy.ca.gov/2005publications/CEC-500-2005-061/CEC-500-2005-061-D.PDF]
[190] Ibid, p. 14
[191] Ibid, p. 7
[192] Presentation by Peter Evans, New Power Technologies, IEPR Distribution Planning Workshop, April 29, 2005, p. 20
[193] Ibid, p. 24
[194] *Optimal Portfolio Methodology for Assessing Distributed Energy Resources for the EnergyNet[SM]* , California Energy Commission, Publication #CEC-500-2005-061-D, April 2005, p. 40
[195] Presentation by Peter Evans, New Power Technologies, IEPR Distribution Planning Workshop, April 29, 2005, p 26
[196] Presentation by Snuller Price, E3, IEPR Distribution Planning Workshop, April 29, 2005, p. 20
[197] Ibid. p. 21
[198] Ibid, p. 39
[199] Ibid, p. 42
[200] Presentation by Richard Seguin, Detroit Edison, IEPR Distribution Planning Workshop, April 29, 2005, p. 5
[201] Ibid, p. 5
[202] Ibid, p. 11
[203] Ibid, p. 13
[204] Full details of the SCE/DG Industry partnership can be found in *Shaping a California Distributed Energy Resources Procurement*, California Energy Commission, Publication #CEC-500-2005-062-D, April 2005.
[205] Written comments by John Kelly, Gas Technology Institute, IEPR Distribution Planning Workshop, April 29, 2005.
[206] Presentations from the conference can be found at: [http://www.conference-on-integration.com].
[207] Electric Distribution Price Control Review, Regulatory Impact Assessment for Registered Power Zones and the Innovation Funding Incentive, United Kingdom Office of Gas and Electricity Markets, March 2004, p. 9.
[208] Presentation on the Operational Impacts from Large Penetrations of CHP/DG, Paul-Frederick Bach, Eltra – Independent System Operator for Denmark, IEPR CHP Workshop, April 28, 2005.

# CHAPTER 7: OVERCOMING CHALLENGES FACING LOADING ORDER RESOURCES

This chapter discusses key issues highlighted in Chapters 3 through 6 and options to better implement California's loading order. Chapter 8 lists the options to address these challenges that the Energy Commission staff believes should be pursued first.

California needs to address challenges facing loading order resources in order to rely more heavily on these resources in the future. Although energy efficiency, demand response, renewables, and distributed generation face unique challenges, policy makers increasingly recognize the benefits of a more integrative approach to the loading order. The more quickly policy makers accelerate the state's reliance on these resources, however, the more quickly the state must act to address these challenges.

The challenges identified in this paper fall into several broad categories that are discussed in more detail below.

## Integrating Loading Order Resources

***Investor-owned utility (IOU) efforts need state policy support to better combine efficiency and demand response programs with other loading order options to match their future needs.***

Outside the Energy Commission's *Integrated Energy Policy Report* proceeding and the California Public Utilities Commission's (CPUC) long-term procurement proceeding, both agencies consider efficiency, demand response, renewable energy procurement, and distributed generation in separate proceedings. Applying the loading order preference to all proceedings would assure consistency and continuity toward reaching the state's goal.

The 2006-2008 energy efficiency program portfolios now incorporate self-generation, demand response, and, to some degree, renewables, in their program offerings. The Energy Commission and the CPUC should encourage and coordinate these activities. To further such coordination, the CPUC could clarify eligibility and prioritize use of combined or "bundled" mixes of loading order resources in utility procurement. The CPUC could also develop options for third parties, such as energy services companies, to provide "bundling" services combining incentives and program opportunities and allowing customers to benefit from multiple types of resources.

***Decision makers need more information to better understand the effect of each of the preferred loading order resources on the operation of the electricity system.***

Recent studies by the United States Department of Energy indicate that a blend of loading order resources could address problems of constrained circuits and reliability in California's electricity system. These studies demonstrate that targeted deployment of energy efficiency, combined heat and power, and renewables on constrained circuits could fundamentally change the electricity load shape. By doing so, these resources can significantly reduce peak demand and eliminate the need for new transmission and distribution infrastructure while providing additional generation.

The studies identified several innovative policies that could influence private investment and direct deployment of load-shaping technologies. These policies include:  waiving standby charges for constrained areas, focusing incentives on constrained areas, and using stepped-demand charges or time-of-use rates that increase along with load increases throughout the day.

The Energy Commission's Public Interest Energy Research Program has conducted research on the impact of integrating loading order resources. The tools and methods developed in this research need to be validated and vetted by utilities and regulators, and then utilized so that loading order resources can be optimally implemented to best meet the state's needs.

***Utilities need to provide the necessary funding and staff to implement the loading order preference.***

Fully incorporating loading order resources into California's electricity system requires changes in electricity system planning, operation, and design, as well as additional capital investment in transmission, metering, and communications. Utilities, both investor- and publicly owned, need to provide the additional resources needed to make these changes.

***California needs more research on how to integrate intermittent renewables, such as wind, into the electricity system to maintain consistent and reliable service.***

Given the low cost of wind energy relative to other renewables, the Energy Commission anticipates significant wind power development to meet the Renewables Portfolio Standard (RPS). The Energy Commission has sponsored research to identify potentially necessary changes in system operations to effectively integrate increasing penetration of intermittent renewable resources. At low levels of penetration, integration costs are also low. At higher levels of penetration, such as those seen in Europe, research indicates that system operation changes may be necessary.

Wind generation presents a unique challenge to system schedulers because wind itself determines when electricity generation occurs. This requires system schedulers to use wind forecasting models to predict wind supply. In general, California's three major wind resource areas tend to produce the most energy during summer evenings, rather than on summer days when peak demand occurs. When significant amounts of wind energy are available during hours of low demand, the system can encounter minimum load problems resulting in turning away inexpensive power already purchased from baseload plants. Sudden changes in the amount of electricity provided by wind generators can also pose challenges for grid operators, particularly if reserves are low when the wind drops off or high when extra wind energy becomes available.

The Energy Commission is researching options for accommodation of high penetrations of wind energy. Options include: improved wind forecasting, coordinating operation of power plants and pumped hydropower so that they can quickly ramp up or down with changes in wind speeds, using energy storage options, capping the amount of wind accepted during low load periods, and encouraging shaped or hybrid wind energy products.

Some of these options would add to the capital cost of wind generation, but would also make wind energy more valuable to the system. The staff suggests the following as next steps in integrating intermittent energy into the state's electricity system:

1. Conduct research on reduced integration costs for high penetrations of intermittent renewables resulting from energy storage, hybrid generation, technical and operational changes to the electric and transmission systems, and/or use of conditional firm transmission contracts.
2. Based on research results, develop updated capacity values for a range of wind-related energy products to use in RPS procurement, subject to CPUC review and adoption.

## Regulatory and Legal Challenges

***Expanding the impact of efficiency programs will require a concerted effort to improve efficiency of existing buildings.***

While the Title 24 Building Efficiency Standards ensure that new buildings, additions, and alterations to existing buildings include energy efficiency in their design, there is no coordinated effort to upgrade the energy efficiency of existing buildings unless those buildings are significantly renovated. Consequently, there is a large potential for efficiency improvements in older buildings within California. The state needs to capture this potential to achieve the state's efficiency goals.

The Energy Commission is currently developing a report to the Legislature in response to Assembly Bill 549 (Longville), Chapter 905, Statutes of 2001, outlining options to upgrade existing buildings. Options including requiring efficiency inspections when buildings are sold could be useful. These options could benefit from new utility pilot programs, such as on-bill financing and building commissioning and retro-commissioning. Close coordination with the benchmarking effort of the Green Buildings Initiative will also extend the possibilities for upgrading existing buildings.

***Current law prevents residential customers from benefiting from electricity rates that change as the cost of electricity rises and falls.***

Following the 2000-2001 energy crisis, the Governor approved Assembly Bill 1X (Keeley), Chapter 4, Statutes of 2001, which contained provisions protecting the first 130 percent of baseline residential usage from price increases associated with the Department of Water Resources long-term procurement contracts. The goal of these provisions was to allow residential customers to purchase at least some power without facing much higher costs. Unfortunately, this aspect of the bill severely limits the ability of the IOUs to provide time-varying rates to residential customers, even if those rates would result in lower bills for most low-usage customers.

To allow the CPUC to develop such dynamic rates, new legislation must be enacted to amend the provisions of AB1X that freeze the tariff at which the first 130 percent of baseline usage is sold and develop different mechanisms for protecting vulnerable customers.

***To fairly allocate the costs of electricity across all customers, California needs to enroll and maintain demand response program participation for customers with a variety of usage characteristics.***

Dynamic rates reduce electricity system costs when customers reduce their electricity use during hours in which electricity is expensive. Voluntary demand response programs and dynamic tariffs only attract customers who save without changing their usage. This does not reduce the overall cost of providing electricity. Expanding enrollment to a broader group of customers is necessary to reduce electricity costs. If programs are voluntary, with “opt-in” design, incentives are necessary to attract more customers. This raises program costs for all ratepayers, reducing savings. Requiring customers to accept service under a cost-based dynamic tariff with the freedom to “opt-out” to standard rate options will reduce the current subsidy of on-peak consumption by all ratepayers, reducing overall costs and fairly allocating those higher costs.

***Current voluntary demand response offerings have not enrolled sufficient load to meet the demand response goals set in D.03-06-032 and D.04-12-042.***

The current voluntary price-sensitive demand response program and tariff offerings have limited appeal to customers for a number of reasons. First, the perceived costs of participation are high. Second, altering energy use patterns, especially for the smaller majority of large customers (those with between 200 kW and 500 kW of demand), requires expertise and investment to plan and implement. Third, the compensation levels may be insufficient to overcome both the perceived and actual costs.

These programs could be subsidized to create larger incentives that would increase enrollment. However, doing so would increase costs, work against the long term goal of moving toward rates that reflect the time-varying cost of supplying and procuring electricity, and create a constituency of customers who depend on rate subsidies. Even with increased incentives, the customers driving on-peak costs are unlikely to participate.

An effective option could address the fundamental limits of voluntary demand response by placing all customers with the metering capability on a default Critical Peak Pricing tariff. This price structure would shift the risk for high-cost peak energy from the utility to the customer. Properly designed, the default tariff would have lower prices than the non-dynamic TOU tariff. The CPUC directed the IOU to file applications to implement these tariffs for summer 2006. Although the tariffs are not voluntary, the results should provide significant benefits to the electricity system.

***The procurement process for renewable energy suppliers is complex and slow: the utility decision-making process to select renewable sources is unclear.***

Stakeholders, most of whom were renewable energy developers, identified the following reasons for delay in the 2003 and 2004 RPS procurements: utilities underestimate the time needed for contract negotiations, contract forms, terms, and conditions are inadequate, negotiations stall with disputes over whether to deliver electricity to the power plant busbar where it enters the utility's system or the utility load aggregation point, utility staffing and management are inadequately focused on the RPS negotiations, and a number of other items, including risks associated with the federal production tax credit and the impact of wind turbine shortages.

One option to reduce the required time to develop contracts is for the CPUC to develop a standard-offer approach, with flexible pricing and standard contract terms. This could eliminate much of the uncertainty and delay in the bidding process. Other options include imposing regulatory deadlines for utility procurement cycles or expediting RPS-eligible contracts in the CPUC's long-term procurement proceeding.

To evaluate the advantages and disadvantages of these options, the Energy Commission staff seeks input on the following questions:

- What actions are needed to ensure that the 2005 RPS solicitation results in both signed contracts with expected future deliveries and new construction, starting in 2005?
- Are regulatory deadlines desirable for utility procurement cycles?
- Should certain additional contract terms be standardized to encourage developer participation in solicitations, reduce negotiation delays, and possibly lower the ultimate cost of renewable energy contracts for ratepayers?
- What can be done to accelerate RPS procurement?
- Recognizing that renewable energy procured by IOUs in the general long-term procurement process will count towards the RPS, what can be done to expedite contracts and deliveries in that proceeding?
- Why is progress reported by individual IOUs toward state RPS goals different from overall state progress? What can be done to reduce the difference and move the state onto the path to reach 20 percent renewable by 2010?

***Electric service providers (ESPs) and community choice aggregators (CCAs), while expected to include renewable energy in the mix of their supply, have no direction from the CPUC on how to do so.***

The challenge here is to meet the statutory requirement in light of inherent differences between ESPs/CCAs and IOUs. ESPs and CCAs have far greater variability in their short-term and long-term expectations of sales than the IOUs. As a result, it is difficult for them to predict the amount of renewable energy they will have to purchase to meet their RPS obligations in the long-run. They typically lack the credit ranking needed to back long-term contracts. In addition, their load is not large enough to support a medium-sized renewable facility, and their procurement has not historically been subject to CPUC oversight.

One option could be to require ESPs and CCA's to comply with the RPS process established for IOUs, including submitting a procurement plan, using standard contract terms and the least-cost-best-fit evaluation process, applying the market price referent (MPR), employing annual procurement targets and compliance rules, and seeking CPUC contract approval.

A more flexible approach would be to require full compliance with IOU rules only if the ESP or CCA is seeking Supplemental Energy Payments from the Renewable Resource Trust Fund. The ESPs and CCAs could otherwise be allowed to develop their own procurement practices to comply with the RPS, subject to compliance with CPUC annual procurement targets, flexible compliance mechanisms and, perhaps, additional regulatory requirements.

***The complexity of administering and calculating payments for new renewable suppliers may cause delays in meeting the state's goals for accelerated renewable energy development.***

Many stakeholders in the Wiser *et al.* study identified California's RPS complexity as one of its weakest points. The study authors attribute some of the complexity to the market price referent (MPR)/supplemental energy payment (SEP) process and its attendant oversight requirements. The current approach to the RPS allows utilities to pay for renewable energy using two sources of funds. The utilities use the normal cost recovery mechanisms to pay an amount for renewable energy that is close to the cost of non-renewable power. If renewable energy costs more than this, the additional cost is paid from the Renewable Resource Trust Fund. This structure is designed to limit ratepayers' financial risk from renewable resource bids. Any cost of a renewable project above that of a "normal" resource may be eligible for SEPs, subject to certain cost constraints. Administering the Market Price Referent and SEPs requires significant oversight and adds administrative complexity to RPS implementation.

One option to reduce the complexity of the IOU RPS program would be to eliminate the division of payments entirely. This may involve paying for renewable energy using the same mechanisms as electricity from non-renewable sources.

***The Renewables Portfolio Standard rules require both in-state and out-of-state generators to deliver their electricity to a location that the purchasing utility specifies. Congestion in California's transmission system can interfere with the renewable developers' ability to deliver power, making it harder to achieve the state's renewables target.***

California's electricity system has numerous congested areas. As a result, this delivery location requirement is likely to limit the number of renewable energy facilities that are able to bid to supply utilities with renewable energy. This could interfere with the retail sellers' ability to comply with RPS targets and could also place upward price pressure on bids. Draft legislation is pending that would revise RPS deliverability requirements for both in-state and out-of-state generators.

There are several options for addressing the possibility of delayed RPS compliance from deliverability constraints. Although the Energy Commission and CPUC RPS collaborative staff should work together to implement these options, the primary decision-making responsibility for the first three options resides with the CPUC.

The first option is to clarify whether utilities can take delivery of renewable electricity for the RPS at in-state hubs located outside of their service territories using utility swaps, trade between scheduling coordinators, or remarketing of the electricity to balance comparable amounts of electricity with load.

A second possibility is allowing “shaped” and “firmed” products for renewable energy. This option places remarketing and congestion risks on the renewable energy developer, while allowing the developer to deliver a shaped product to a utility that could eliminate the need for costly transmission additions between utility service territories.

A third option is to consider standardized contract terms and conditions for the generation delivery point in the event of market redesign, reportedly a significant factor in the contracting delays experienced during 2003/2004 RPS solicitations.

***To ensure California meets its RPS goals of 20 percent renewables by 2010, the state needs to develop mechanisms to anticipate and mitigate the possibility of failure to produce adequate renewables.***

Even though the utility Requests for Offers (RFOs) have focused on getting signed contracts for renewable energy, those signed contracts may fail to materialize. A large number of renewable energy projects under contract to Nevada utilities for their RPS, for example, have experienced construction delays or cancellation.

Although the flexible compliance mechanism of the RPS allows utilities to compensate for failed contracts in earlier or later procurements, the state should consider developing additional incentives to guard against this problem and ensure utilities reach 20 percent by 2010.

One suggested option is for the CPUC to direct that delivered energy, rather than contracted energy, be the metric used for compliance with the RPS. The CPUC could further direct that flexible compliance be for interim years only—not the end date.

***In the Altamont Pass area, wind turbines are responsible for killing raptors and other birds protected by domestic and international law, highlighting the need to apply the best available information on siting and best available technology to avoid and mitigate bird deaths when developing wind resources.***

In the Altamont Pass Wind Resource Area, wind turbines have killed raptors protected under federal and international law. In support of recommendations in the *2004 Energy Report Update*, the staff suggests the following three options for reducing the number of protected raptors killed by existing, repowered, and new wind energy generation used to meet California’s RPS:

1. Establish a standing statewide working group to develop regulatory procedures and guidelines for wind projects to comply with state and federal law, including CEQA. The group should include industry, public interest groups, local permitting agencies, and state and federal agencies responsible for wildlife protection, and incorporate the latest available information on best-

available practices and technologies, with periodic updates as needed.

2. Develop private-public partnerships to sponsor environmental studies of known wind resource areas to determine how best to protect birds.

3. Compile an archive on important wildlife migratory corridors to be used in permitting wind facilities. This archive should be based on work the Energy Commission is doing with the California Department of Fish and Game and the California Department of Forestry to incorporate data on bird migration routes into wind-mapping data sets, using a geographic information system.

***The complex metering and scheduling process required to sell excess power into the wholesale market discourages combined heat and power (CHP) distributed generation (DG).***

It is difficult for CHP generators to fulfill requirements to sell their excess electricity. There are 5,200 MW of untapped export potential from existing CHP DG in California. Current rules require the DG developer to find an electricity buyer and to schedule exports hour-by-hour with the CA ISO.

This problem could be addressed by encouraging utilities to buy electricity from CHP installations in their service territories at the prevailing wholesale price. If utilities arranged to purchase the power at the plant, rather than a delivery point further away in the system, it would reduce complexities posed by scheduling power with the CA ISO. Even though some CHP facilities need a lot of heat, justifying a larger generator, those facilities install smaller generating equipment that just meets their internal electricity load. Simplifying these facilities' ability to sell excess power would encourage them to install larger generating equipment.

Energy cost savings, reliability, and security are key drivers for adoption of CHP. However, California end users indicate they want payback periods of fewer than three years, which will limit adoption of CHP. Allowing larger projects to participate in the Self Generation Incentive Program and allowing CHP owners to sell excess power to the grid could increase the likelihood of CHP project success.

***Utilities have little incentive to promote or enable customer- or utility-owned DG.***

Use of DG and CHP is typically not embraced by utilities because they see it primarily as a revenue reducer. Policy scenario and cost effectiveness analysis has shown in all instances that implementing distributed generation results in costs to the utilities, despite benefits to distributed generation customers and society as a whole. When evaluated from all stakeholders' perspectives, certain types of distributed generation provide net benefits. Therefore, policies and regulations need to be developed to keep utilities whole while promoting clean, efficient distributed generation installations. One option to address this could be something like shareholder incentives that have been effective in efficiency programs. Decoupling revenue and sales benefited efficiency programs by making them revenue neutral; however, there is currently neither an incentive for program administrators to exceed the adopted efficiency goals nor any penalty if goals are not met.

***DG operators have little incentive to supply power when it is most needed by the grid.***

DG and CHP owners could be paid for operating agreements ensuring that units run during critical peak days, times of high electricity prices, or a local transmission and distribution capacity constraint. Operating CHP to capture both owner and utility benefits would also result in higher societal benefits. Encouraging DG and CHP operation during times of high value to the system and the local transmission and distribution network could reduce or replace the CPUC's Self Generation Incentive Program over time, and could also reduce utility operating margin losses by increasing the system benefits of CHP. In the long-term, incentive programs should be replaced with markets that pay DG and CHP customers for all the value they provide, whether it is capacity, energy, transmission and distribution congestion relief, ancillary services, greenhouse gas reductions, or emission reductions.

## Infrastructure Needs to Facilitate Loading Order Resources

***Undertaking a broad program of demand response and dynamic rates requires installation of specialized metering and related equipment for all customers.***

To expand demand response to all customers, utilities must install advanced meters needed to support time-based rates for all customers, and update their system management, customer service, and billing systems to fully use the new information provided by the advanced metering infrastructure. The business case for advanced metering relies on the substantial operational benefits available from advanced metering that can only be achieved with full deployment. The demand response benefits accrue in addition to the operational savings. This is particularly an issue for the non-IOUs.

For IOU customers, these activities are discussed as part of the CPUC's Demand Response Proceeding (R.02-06-001). Utilities have provided business cases analyses that justify the expenditures necessary to allow advanced metering to be deployed for some IOU customers by 2008.

There is, however, no similar effort for non-IOU customers. The Energy Commission could conduct research to evaluate whether advanced meters would be cost effective for municipal utility customers.

***Encouraging and managing an expanded program of distributed generation in California requires a system for metering and tracking output from distributed resources.***

Advanced metering and reporting equipment can also benefit DG resources. Currently, it is extremely difficult to track increases in installed capacity and energy production from DG. This is principally because data reporting requirements and regulations have not focused specifically on small generation.

This equipment is necessary for real-time tracking of distributed generation output, as well as for billing producers and encouraging their participation. It will be extremely important to improve tracking mechanisms for DG if California is to effectively monitor the progression of DG deployment and ultimately verify that DG and loading order goals are met.

***Lack of infrastructure complicates efforts to bring sufficient renewable energy into California's utilities to meet the RPS mandate.***

To meet its ambitious renewable energy goals, the state needs new or upgraded transmission to open access for renewable resources where they must be located. One key issue for renewable energy transmission is the problem of expanding transmission in a resource area in the absence of firm developer commitment to build facilities in that area.

The Energy Commission and the CPUC support SCE's proposed "renewable trunk line" concept, which would reduce SCE's regulatory risk of building transmission to meet projected rather than actual renewable energy development. On July 1, 2005, FERC disapproved SCE's petition, and parties have 30 days to file for rehearing. Additional analysis and coordination will be needed to address this concept. Other options include:

- Encouraging the FERC to allow the CA ISO to tie permitting and construction approvals closely to market demand in support of clustered development of renewables.
- Encouraging the CPUC to revise the transmission ranking cost report methodology to encourage full utilization of transmission planned for construction in areas of high renewable energy potential**,** recognizing it is the aggregate potential, not the individual projects, that drives the need for transmission upgrades.

***Antiquated distribution infrastructure is not compatible with the advanced loading order technologies.***

As California continues to promote renewable and nonrenewable DG, the state must consider how the utility system will be affected by this technology. Large penetrations of a 21$^{st}$ century technology such as DG into a 20$^{th}$ century transmission and distribution system will exacerbate California's energy problems. Today's distribution systems are designed for one-way power flow; power flows from the substation down the distribution feeders to individual customer loads. However, as more and more DG is interconnected to utility systems, normal distribution system design and operation must be modernized to deal with these embedded generation sources. Future distribution systems must be able to incorporate demand response technologies.

California can learn from Denmark's experience and upgrade its distribution system before high levels of DG penetration are realized. To complement this objective, California could study the United Kingdom, where regulatory incentives encourage utilities to develop innovative transmission and distribution designs and programs to promote renewable and DG integration. Finally, utility planning practices need to be more transparent and consider cost effective loading order resources as an alternative to traditional utility solutions.

## Monitoring and Evaluation

***State government and utilities need to provide the necessary funding and staff for evaluation, monitoring and social research that will help integrate loading order resources into electricity system planning and procurement.***

Current resources allocated to monitoring and verifying are inadequate to effectively evaluate the impacts of higher penetration of loading order resources upon the state's electric market. A renewed social science research effort focused on consumer decision-making could improve program effectiveness. The CPUC, the Energy Commission, and IOUs need to allocate additional resources to this effort.

***Current data reporting protocols make it difficult to track the output from small DG resources and progress toward demand response goals.***

As discussed in Chapter 2, IOUs must currently submit various reports to the CPUC and Energy Commission. For DG resources, these reports include data on interconnections, net metering installations, cost responsibility surcharge exemptions, and the Self Generation Incentive Program. Now, with the *2005 Energy Report* data reporting requirements, utilities must also report long-range forecasts to the Energy Commission.

In its revisions to the current interconnection rule, the Energy Commission recommends that the CPUC require IOUs to develop a more thorough interconnection data tracking system. The Energy Commission expects the CPUC to act upon this recommendation, among others, by the end of 2005.

The Energy Commission and CPUC staff will address these and other data reporting needs in the CPUC's current DG rulemaking. Through this public process, the two agencies will develop data reporting requirements to ensure that California effectively monitors the progression of DG deployment.

To be used effectively in resource planning, demand response programs and DG both need useful data reporting and management systems. These resources, by their natures, require dispersed resources to provide system benefits. For more effective planning, the state needs reporting systems that track the contribution of these resources over time while providing real-time information on program impacts.

***The diverse efficiency programs that utilities are pursuing need monitoring and evaluation to provide prompt feedback on the successes of the programs.***

Early feedback on program results is needed to reduce the risk of shortfalls or overcommitment of resources. Clearer methods for reporting evaluation results and efficiency trends to policy makers should be explored.

It will be important to track the progress and impact of new approaches to energy efficiency. One option is to evaluate and verify results early in the operation of the programs to provide early feedback that signals a need for change. This option reduces the risk of needing to address shortfalls with other resources, or of over-commitment to resources if efficiency impacts exceed expectations.

As part of this option, annual summaries of process and impact evaluation results will be critical for policy makers to determine the long-term effects. New methods for conveying the outcomes of the state's efficiency programs to a variety of audiences should be explored, such as illustrating trends in customer end-use load shapes for equipment targeted by efficiency programs, or relationships between increased efficiency spending and customer bills.

***Disseminating information and offering financial incentives will not be enough to achieve the state's energy mandate. Some consumers are reluctant to try new products or services because the risk of failure is too high, while for others, environmental benefits matter more than saving money.***

Reducing consumer uncertainty would improve program success. Incorporating social science research into program planning and policy development could reduce uncertainties that hamper consumer action. Lack of trust is one of the key reasons for consumer inaction. Research is needed on program approaches including warranties, labeling, and consumer use of information. Little research has been done on the effectiveness of mixing different modes of information, bill stuffers, point of purchase, Internet, and other methods and vehicles. Social science research, particularly in areas like behavioral economics, has much to offer program design and policy development.

Shifting education and marketing efforts from energy savings alone to a broader range of potential non-energy benefits, and using incentives other than rebates, could broaden the spectrum of customers participating in programs. The key will be to get the right kinds of incentives in front of the right customers by accounting for individual and group concerns, capacity to act, and situational conditions of households and organizations.

***To the extent possible, information programs must be evaluated to determine their effectiveness in encouraging people to conserve energy and purchase energy efficient equipment.***

During the 2000-2001 energy crisis when California needed rapid results from the education campaign, the state's Flex Your Power campaign along with general media coverage yielded impressive results. The Flex Your Power campaign has continued to spend more than $40 million a year to promote energy efficiency public awareness. The CPUC and the Energy Commission could evaluate this public awareness effort and consider broadening this statewide marketing strategy to all aspects of the loading order.

***Demand response/dynamic rates impacts on customers vary by customer load profiles. Some customers may lose under the rates while others benefit through timing and flexibility of electric usage.***

The goal of undertaking demand response programs is more efficient use of electricity. These programs offer price signals to customers, who could save money by shifting energy use to off-peak hours or reducing or interrupting their energy use during emergencies. Changing customer rate structures does result in "winners" and "losers." It would be useful to better understand the volume of expected winners, the volume of expected losers, and identify characteristics that typify both groups.

While demand response programs are being developed, California should identify options to help customers reduce their electricity use when costs are high. Efforts such as home designs that require little or no air conditioning while remaining comfortable would allow customers to benefit from demand response rates. Public Interest Energy Research has shown that with minimal investment and customer difficulty, existing energy management systems can be automated to respond to price signals in a cost effective manner while attaining significant load reduction.

***The relationship between planned and actual megawatt savings from demand response programs is not well established.***

There is little question that resource planners need unambiguous, reliable estimates of demand response capacity to effectively procure resources to meet demand. The goals set in the Demand Response proceeding provide an incentive for IOUs to take risks in developing and implementing innovative programs. The CPUC and the Energy Commission could work together with IOUs to develop a tracking system that better evaluates the likely amount of energy savings resulting from demand response programs. This information could provide resource planners with the estimates of the demand response capacity they need to accurately procure resources to meet demand.

***There is a need to clarify how RPS compliance will be determined.***

In PG&E's 2004 RPS compliance filing to the CPUC and its 2005 RPS procurement plan, the utility requested that energy under contract to be developed in the future count toward PG&E's current annual procurement target compliance. In addition, there may be some confusion about how to measure compliance with the 2010 target of 20 percent. Finally, because there is a mismatch between the location of undeveloped renewable resources and unmet RPS need among IOUs, particularly SDG&E, there may be a need to track the progress of transmission needed to interconnect RPS resources.

While the CPUC's flexible compliance rules in the RPS allow up to a three-year grace period for incomplete annual procurement target (APT) compliance, the Energy Commission staff believe utility APTs should be satisfied by energy delivered, not energy contracted for. This belief was echoed in the recent draft opinion by California Public Utilities Commission Administrative Law Judge Simon proposing that utilities use actual deliveries of energy from eligible renewable resources as their measure of compliance with both incremental and annual procurement targets.

The Energy Commission staff also believes that the *Energy Action Plan* and Senate Bill 1078 require that the target be measured in energy delivered no later than the end target year. The flexible compliance mechanism should be interpreted to apply to interim years, but not to the end date of 2010. Regarding transmission development, the staff believes that measurement and verification for RPS compliance should include a component to track progress for the transmission development needed to interconnect RPS resources.

# CHAPTER 8: NEXT STEPS

The state's *Energy Action Plan* calls for a groundbreaking shift in focus on new resources that utilities should acquire in the future, but regulatory progress on a shift in priorities has been slow. California has been trying to launch demand response programs since the energy crisis of 2000-2001. Five years later there have been pilot efforts, but a larger program planned for summer of 2005 has been postponed until 2006. Distributed generation has been available to California's utilities for years, but consideration of rules to govern expansion of this well-understood resource continues to languish.

California has also encouraged development of renewable resources for years, with strategies ranging from favorably viewing geothermal generation plants in siting policies to recommending "set asides" for renewable generation in biennial electricity reports to providing financial incentives for renewable generators. Yet, as the state adopts more aggressive Renewables Portfolio Standard (RPS) targets, contract negotiations to purchase RPS-eligible energy drag on beyond expected timeframes. Regulators, investor-owned utilities (IOUs), and developers struggle with a split payment system in a partially regulated market. Participants strive to achieve careful oversight to control costs behind a veil of confidentiality intended to keep competitors from knowing too much about each other.

Chapter 7 listed challenges and options for expanding the use of preferred loading order resources in California. The following options to address those challenges are those that the Energy Commission staff believes should be pursued first. In some cases, challenges have only recently been developed or recognized. As the Energy Commission better understands these challenges, future cycles of the *Integrated Energy Policy Report* will address them in greater detail.

## Regulatory Changes

- The Energy Commission should update its Title 20 data regulations to strengthen its enforcement provisions for the receipt of utility interval meter and billing data. These data will be crucial in the ongoing efforts to evaluate how the loading order resources are impacting California's electricity and natural gas demand. Without them, we cannot conduct analyses to document how and when Californians are using energy and the ways in which these uses are changing.

### *Contracting and Payment Issues*

- The state needs to shorten contract development and agreement processes by developing standardized contracts and time limits for contract negotiations. This would accelerate the use of loading order resources and allow them to fully participate in California's market. IOU contracting processes are too slow. It takes too long for utilities to even pursue contracts, and in many cases contract negotiations are incomplete.

- The California Public Utilities Commission (CPUC) should eliminate the “market price referent” (MPR) in the RPS Program unless the MPR and all supporting information are public. Instead, the cost of purchasing or contracting with renewable resources should be included in customer rates, separate from the Public Goods Charge.
- The CPUC should require IOUs to buy electricity from combined heat and power (CHP) plants in their service territories, as delivered at prevailing wholesale prices, to promote development of distributed CHP generation. The prices should reflect the varying value of energy by time, encouraging generators to provide energy and capacity during peak hours; this could resemble “net metering” at the wholesale energy price. As part of this approach, the CPUC should also allow larger self-generation projects to participate in the Self Generation Incentive Program and allow CHP owners to sell excess power to the grid.

### *Expanding Infrastructure*

- The CPUC should continue to consider IOU business cases for installing advanced metering and “real time” communications and data collection systems. This infrastructure improvement is essential so that demand response programs and dynamic rates become broadly available and effective in reducing peak loads. The state should also pursue more sophisticated metering and data collection systems to maximize benefits of combined heat and power generation facilities, as well as other distributed generation resources.
- The CPUC should address the issue of upgrading distribution infrastructure to better accommodate distributed generation. Both distributed renewable generation and combined heat and power options would benefit from more flexible distribution system designs.
- The CPUC and the Energy Commission need to coordinate their efforts at the Federal Energy Regulatory Commission (FERC) in support of clustered development of renewable facilities. The FERC should allow the California Independent System Operator to tie permitting and construction approval of transmission projects to market demand.
- When valuing potential transmission projects, the CPUC should view the aggregate potential of the line to serve renewable and other supply projects, instead of only considering current, individual projects prompting the need for the upgrade. Because loading order resources are typically smaller than central station fossil-fired generating plants, this change requires a shift in the criteria used to estimate the value of certain infrastructure projects. One single renewable project might not justify building a large transmission line, but there may be the opportunity to develop more resources around that line once it is built.

- The CPUC, in conjunction with the Energy Commission, should accelerate development of distributed generation metering and reporting protocols. Properly done, this will provide data on the impact of DG on system loads.

## *Monitoring and Evaluation*

- Changes in efficiency program monitoring and evaluation are underway. The Joint CPUC/Energy Commission staff effort to develop new protocols for measuring impacts and improving programs is a key effort. As part of this process, it will be critical for parties to propose, and the CPUC to consider, options to make those results quickly available. This issue also applies to demand response program activities. Achieving the goals set for these loading order resources will require rapid feedback to allow mid-course corrections and keep resource development on track. Timely access to this information and the ability to adjust program efforts in response are essential for the success of these loading order resources.
- The CPUC, Energy Commission, and utilities should begin a process to clarify criteria for compliance with California's RPS. The Energy Commission staff believes that only actual energy generated, not energy under contract, should count toward an IOU's annual procurement target. In addition, the staff believes that the three-year flexible compliance window does not apply to the 2010 20 percent renewable energy target end-date.
- The Energy Commission should continue efforts to develop more complete documentation of efficiency efforts by publicly owned utilities.

## *Demand Response Program Needs*

- The CPUC needs to develop dynamic electricity tariffs. Without these tariffs, the need for advanced metering and related infrastructure is moot, and investments being made by the state in this area are questionable.
- The CPUC and the Energy Commission should continue to collaboratively develop demand response program policies. The agencies need to resolve significant issues relating to developing a customer base for these programs, as well as determining their impacts, so that these programs play a large role in California's electricity system. Developing a large customer base will probably require a mix of default rates and financial incentives to blunt the possibility of large increases in customer bills. Program design must encourage participation or acceptance of mandatory change without unduly burdening the customer or making the program uneconomic for the electricity system.
- Default dynamic rates should be accompanied by significant customer education and technical support to facilitate customer acceptance and to enhance demand response. The IOUs included draft plans for customer education and support along with their default CPP proposals for large customers on January 20, 2005. CPUC Decision 05-04-043 acknowledged customer concerns raised during the

proceeding that customers would not be prepared for default rates by summer 2005 and directed the IOUs to submit new default CPP proposals on August 1, 2005 that would propose a schedule for implementing default CPP for summer 2006 and would include proposals for customer education and support.

## Legislative Changes

The staff believes that legislation may be needed to encourage broader purchase and use of advanced meters. This will allow more of California's population, including those served by publicly owned utilities, to participate in load shifting in response to costs reflecting market prices.

- Existing provisions of Assembly Bill 1X (Keeley), Chapter 4, Statutes of 2001, freeze residential tariffs for the first 130 percent of baseline kWh usage. If these provisions were removed, the CPUC could approve time-varying electricity rates that encourage demand response during peak periods but provide lower prices the rest of the time.
- Requiring municipal utilities to buy electricity from CHP plants in their service territories at prevailing wholesale prices, similar to earlier recommendations for CHP plants in IOU service territories, would also require new legislation.

## Research and Development Priorities

Research opportunities exist to help individual loading order resources meet their development targets. However, the Energy Commission staff believes that additional research should be coordinated in an effort to determine how loading order resources can provide "synergistic" benefits. Because the state intends to make significant investments in these resources, it is appropriate to determine how to reap the greatest benefits from this effort for the people of California.

Research is needed on the following issues affecting one or more of the loading order resources:

- How existing combined heat and power generation contributes to the state's electricity system.
- How the load enrolled in demand response programs translates to load reduction during peak periods.
- How well installed energy efficiency measures, distributed generation systems, and energy conservation activities are actually performing.
- How renewable energy procured for the RPS impacts system operations and dependable peak capacity as projects come on line.
- How and to what extent energy storage, hybridization with other generation or demand response measures, or unbundled renewable energy certificates can improve the fit of renewable energy procured for the RPS.

- How having different discount rates for efficiency standards and programs affects our ability to capture savings.

- How we can better “see through the customers’ eyes.”

Pivotal research is underway to understand the utility system impacts of distributed generation, demand response, and renewables. Additional research is needed on the combined impact of these resources on system operations and reliability. Findings from this research will affect the design of regulatory structures that encourage the best loading order resources at least cost.

Research is needed on the following “synergistic” issues:

- Which renewable resource characteristics are most important to evaluate in “least cost-best fit” analyses.
- What options are available for energy products that reduce the net impact of intermittent renewable energy on the state’s electricity and transmission system.
- What are the peak and minimum load impacts and value of alternative demand response programs for scenarios with high penetrations of intermittent wind versus shaped renewable products, among others.
- Which efficiency impacts have greatest value to the electricity system, including using scenarios that assume different resource mixes for achieving the state’s goals for demand response, renewables, and distributed generation.
- How desirable are alternative distribution system configurations (e.g., strategic placement of generation or demand reduction) in encouraging development of loading order resources.
- What kind of energy-focused information technology could provide better feedback for investment, utilization, and price-response decisions.

## Public Input Priorities

- The *2004 Energy Report Update* encouraged repowering of California’s older wind sites, particularly the Altamont wind resource area, consistent with best available science to avoid and mitigate bird deaths from wind turbines. In addition to removal of current problem turbines, the Energy Commission staff believes that further efforts are needed to avoid and mitigate the killing of raptors protected by domestic and international law, and suggests that the state establish a standing statewide working group to develop regulatory procedures and guidelines for wind turbine projects to comply with state and federal law, including the California Environmental Quality Act. The group should include industry, public interest groups, local permitting agencies, and state and federal agencies responsible for wildlife protection, and incorporate the latest available information on the best available practices and technologies, with periodic updates as needed.

# ACRONYMS

| | | |
|---|---|---|
| AB | — | Assembly Bill |
| ACR | — | Assigned Commissioner Ruling |
| AMI | — | Advanced metering infrastructure |
| APT | — | Annual procurement target |
| ARED | — | Accelerated Renewable Energy Development Draft Staff White Paper |
| ATC | — | Available transfer capacity |
| BPA | — | Bonneville Power Administration |
| Btu | — | British thermal units |
| CA ISO | — | California Independent System Operator |
| CCA | — | Community choice aggregator |
| CCHP | — | Combined cooling, heating and power |
| CEQA | — | California Environmental Quality Act |
| CERTS | — | Consortium for Electric Reliability Technology Solutions |
| CF | — | Capacity factor |
| CHP | — | Combined heat and power |
| CPA | — | California Consumer Power and Conservation Financing Authority |
| CPP | — | Critical Peak Pricing |
| CPUC | — | California Public Utilities Commission |
| CRS | — | Cost responsibility surcharge |
| DBP | — | Demand Bidding Program |
| DER | — | Distributed energy resources |
| DG | — | Distributed generation |
| DNO | — | Distribution Network Operator |
| DOE | — | United States Department of Energy |
| DR | — | Demand response |
| DRP | — | Demand Reserves Program |
| DWR | — | California Department of Water Resources |
| E3 | — | Energy and Environmental Economics |
| EAP | — | Energy Action Plan |
| EEA | — | Energy and Environmental Analysis |
| EIS | — | Environmental impact statement |
| EM&V | — | Evaluation, measurement, and verification |
| EOR | — | Enhanced oil recovery |
| EPRI | — | Electric Power Research Institute |
| ERP | — | Emerging Renewables Program |
| ESP | — | Electric service provider |
| FERC | — | Federal Energy Regulatory Commission |
| GIS | — | Geographic information system |
| GW | — | Gigawatt |
| GWh | — | Gigawatt-hour |
| ICE | — | Internal combustion engine |
| IEEE | — | Institute of Electrical and Electronics Engineers |
| IEPR | — | Integrated Energy Policy Report |
| IOU | — | Investor-owned utility |

| | | |
|---|---|---|
| kW | — | Kilowatt |
| kWh | — | Kilowatt-hour |
| | | |
| LADWP | — | Los Angeles Department of Water and Power |
| LSE | — | Load serving entity |
| LTTP | — | Long term procurement plan |
| | | |
| MBTA | — | Migratory Bird Treaty Act |
| MPR | — | Market price referent |
| MTG | — | Microturbine generators |
| MW | — | Megawatt |
| MWh | — | Megawatt-hour |
| | | |
| NCPA | — | Northern California Power Agency |
| NEM | — | Net-energy metered |
| NEPA | — | National Environmental Protection Act |
| NERC | — | North American Electricity Reliability Council |
| | | |
| OFGEM | — | Office of Gas and Electricity Markets |
| | | |
| PG&E | — | Pacific Gas and Electric Company |
| PGC | — | Public goods charge |
| PIER | — | Public Interest Energy Research |
| PIRP | — | Participating Intermittent Renewables Program |
| POU | — | Publicly owned utility |
| PURPA | — | Public Utility Regulatory Policies Act |
| PV | — | Photovoltaic |
| | | |
| QF | — | Qualifying facility |
| | | |
| R&D | — | Research and development |
| RD&D | — | Research, development and demonstration |
| RECs | — | Renewable Energy Certificates |
| RFO | — | Request for Offers |
| RFP | — | Request for Proposals |
| RPS | — | Renewables Portfolio Standard |
| RRDR | — | Renewable Resources Development Report |
| RTEM | — | Real-time energy meters |
| RTP | — | Real-time pricing |
| | | |
| SB | — | Senate Bill |
| SCAQMD | — | South Coast Air Quality Management District |
| SCE | — | Southern California Edison Company |
| SCPPA | — | Southern California Public Power Authority |
| SDG&E | — | San Diego Gas and Electric Company |
| SEPs | — | Supplemental Energy Payments |
| SGIP | — | Self Generation Incentive Program |
| SMUD | — | Sacramento Municipal Utility District |
| SPP | — | Statewide Pricing Pilot |
| SRI | — | Solar Roofs Initiative |
| SVA | — | Strategic Value Analysis |
| SVP | — | Silicon Valley Power |
| | | |
| T&D | — | Transmission and distribution |
| TOU | — | Time of use |

| | | |
|---|---|---|
| UK | — | United Kingdom |
| USFWS | — | United States Fish and Wildlife Service |
| | | |
| WECC | — | Western Electricity Coordinating Council |
| WIEB | — | Western Integrated Energy Board |
| WREGIS | — | Western Renewable Generation Information System |

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# APPENDIX A: ESTIMATED ENERGY REQUIREMENTS TO MEET CALIFORNIA'S RENEWABLE ENERGY GOALS

Using reported 2001 baseline retail sales and renewable procurement as a starting point, Appendix A estimates the growth in renewable procurement necessary to reach California's RPS goals.

Historical data that has been updated from previous published versions of Appendix A in the *Accelerated Renewable Energy Development Draft Staff White Paper* and the *Renewable Resources Development Report* are outlined in bold (Sections 1 and 2). Also, the amounts of cumulative renewable energy needed by the target dates are outlined in bold (Section 7), as are the amounts needed by the target dates beyond the 2001 baseline (Section 9).

There are three tables in Appendix A:

- Table 1: growth needed to reach 20 percent by 2010, maintaining 20 percent through 2017;
- Table 2: growth needed to reach 20 percent by 2017; and
- Table 3: forecasted retail sales.

**Table 1:**

Sections 1 through 6 of Table 1 lay the groundwork for Section 7, which estimates the total renewable procurement needed to achieve 20 percent by 2010 and maintain 20 percent through 2017. For example, Section 7 indicates that the amount of total renewable procurement needed statewide to achieve 20 percent by 2010 is estimated to be 56,160 GWh/year.

For comparison, the table also lists publicly available information on actual procurements for 2002 through June 2005 (Sections 10-17). Using this information, the table shows that to remain on track to reach 20 percent by 2010, the IOUs should have procured about 14 percent of retail sales from renewable energy in 2004 (Section 6). To increase certainty regarding each year's target, the CPUC allows IOUs to measure compliance by their actual reported sales for the prior year. Dividing 2004 actual IOU procurement by 2003 reported retail sales, the IOUs appear to have procured about 14 percent renewables (Section 13). Dividing by 2004 reported retail sales, also yields about 14 percent IOU renewables (Section 14).

Table 1 suggests that SDG&E must increase renewable energy purchases more rapidly than SCE or PG&E (Section 6), given the small amount of renewable energy they procured in 2001 (Section 2). SDG&E's progress as of the end of 2004 is more than a percentage point behind the schedule (Section 14 compared to Section 6). However, SDG&E procured more than the minimum amount of renewables required in 2004 by the CPUC (Section 12). Looking to the future, SDG&E's next installment of renewable procurement growth is not yet in place: SDG&E is still negotiating with bidders from its 2004 solicitation. SCE 's renewable procurements in 2004 were about one-half a percent behind the schedule (Section 14 compared to Section 6), although SCE procured more than the minimum required by the CPUC (Section 12).

PG&E's delivered renewable energy in 2004 (Section 10) was less than its APT for 2004 (Section 12). Although the table does not show planned procurement until after each year is completed, it is important to note that the amount of energy delivered in 2005 is not expected to meet PG&E's annual procurement targets [*FN: PG&E, July 1, 2005 Compliance Filing of Pacific Gas and Electric Company (U 39-E) Reporting Progress Toward Achievement of Annual Procurement Target for Renewable Generation Pursuant to Renewable Portfolio Standard, R. 04-04-026, July 1, 2005*].

Statewide, the table A indicates that almost 34,600 GWh/year of renewables were needed in 2004 to keep the state on track to reaching 20 percent by 2010 (Section 7). However, the actual amount of renewable generation used to meet California load in 2004 is reported to be 29,238 GWh/year (Section 15). Subtracting seven percent for losses, leaves 27,191 GWh/year, indicating that statewide progress is slipping behind schedule considerably.

Further details explaining the sources and calculations are shown in shaded cells at the beginning of each section.

**Table 2:**

The structure of Table 2 is parallel to that of Table 1, and shows the growth needed to reach 20 percent renewable by 2017.

TABLE 1

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 retail sales forecast for California, taken from the Energy Commission Draft Staff Report entitled, "California Energy Demand 2006-2016 Staff Energy Demand Forecast" (Publication Number CEC-400-2004-034-SD). This information appears in this report as Form 1.c. which is entitled, "Statewide California Energy Demand 2006-2016 Staff Forecast Retail Sales by Utility (GWh)." The methodology for preparing Form 1.c. can be found in the Energy Commission's Staff Report entitled, "Energy Demand Forecast Methods Report: Companion Report to the California Energy Demand 2006-2016 Staff Energy Demand Forecast Report" (Publication Number CEC-400-2005-036.) To calculate the 2017 retail sales numbers, staff averaged the forecasted annual sales growth between 2006 and 2016 and used that growth rate as the growth in retail sales from 2016 to 2017. | | | | | | | | | | | | | | | | | | **Average Annual Growth Rate 2006-2016** |
| 2 | | | | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | |
| 3 | **1** | Sales (GWh) | **PG&E** | 75,319 | 68,445 | 71,084 | 73,137 | 73,671 | 74,891 | 76,030 | 77,075 | 78,191 | 79,397 | 80,766 | 81,920 | 83,248 | 84,318 | 85,422 | 86,467 | 87,719 | **1.45%** |
| 4 | | | **SCE** | 68,387 | 68,431 | 70,677 | 73,254 | 74,224 | 75,116 | 76,196 | 77,342 | 78,565 | 79,669 | 80,727 | 81,896 | 82,958 | 84,130 | 85,281 | 86,254 | 87,455 | **1.39%** |
| 5 | | | **SDG&E** | 14,919 | 14,364 | 14,930 | 15,585 | 15,846 | 16,123 | 16,397 | 16,732 | 17,026 | 17,312 | 17,595 | 17,882 | 18,167 | 18,450 | 18,732 | 19,007 | 19,322 | **1.66%** |
| 6 | | | **Total** | 158,625 | 151,240 | 156,691 | 161,976 | 163,740 | 166,129 | 168,623 | 171,149 | 173,782 | 176,378 | 179,088 | 181,698 | 184,373 | 186,898 | 189,435 | 191,727 | 194,495 | |
| 7 | | | | | | | | | | | | | | | | | | | | | |
| 8 | | | Grand Total Statewide Sales | 241,384 | 247,527 | 253,690 | 260,955 | 263,697 | 266,954 | 270,295 | 273,718 | 277,286 | 280,802 | 284,427 | 287,938 | 291,548 | 294,961 | 298,317 | 301,348 | 305,023 | **1.22%** |
| 9 | | | DA and Rest of State | 82,759 | 96,287 | 97,000 | 98,979 | 99,957 | 100,825 | 101,672 | 102,569 | 103,504 | 104,424 | 105,339 | 106,240 | 107,175 | 108,062 | 108,882 | 109,621 | 110,527 | **0.84%** |
| 10 | | | **PG&E DA** | 2,952 | 9,820 | 9,127 | 9,283 | 9,357 | 9,421 | 9,478 | 9,568 | 9,643 | 9,716 | 9,783 | 9,855 | 9,927 | 9,997 | 10,053 | 10,104 | 10,175 | **0.70%** |
| 11 | | | **SCE DA** | 10,103 | 11,228 | 11,571 | 11,731 | 11,797 | 11,846 | 11,905 | 11,967 | 12,039 | 12,097 | 12,154 | 12,222 | 12,281 | 12,351 | 12,413 | 12,456 | 12,518 | **0.50%** |
| 12 | | | **SDG&E DA** | 2,444 | 3,405 | 3,467 | 3,553 | 3,580 | 3,611 | 3,637 | 3,673 | 3,702 | 3,731 | 3,758 | 3,786 | 3,813 | 3,840 | 3,864 | 3,887 | 3,915 | **0.74%** |
| 13 | | | **Total DA** | 15,499 | 24,453 | 24,166 | 24,566 | 24,733 | 24,877 | 25,020 | 25,208 | 25,383 | 25,544 | 25,695 | 25,862 | 26,021 | 26,188 | 26,330 | 26,446 | 26,608 | **0.61%** |
| 14 | | | **Total Rest of State** | 67,260 | 71,834 | 72,834 | 74,414 | 75,224 | 75,948 | 76,652 | 77,361 | 78,121 | 78,880 | 79,644 | 80,378 | 81,155 | 81,875 | 82,552 | 83,175 | 83,919 | **0.91%** |
| 15 | | | **DA % of Diff** | 18.73% | 25.40% | 24.91% | 24.82% | 24.74% | 24.67% | 24.61% | 24.58% | 24.52% | 24.46% | 24.39% | 24.34% | 24.28% | 24.23% | 24.18% | 24.13% | 24.07% | |
| 16 | | | **Rest of State % of Diff** | 81.27% | 74.60% | 75.09% | 75.18% | 75.26% | 75.33% | 75.39% | 75.42% | 75.48% | 75.54% | 75.61% | 75.66% | 75.72% | 75.77% | 75.82% | 75.87% | 75.93% | |
| 17 | | | | | | | | | | | | | | | | | | | | | |
| 18 | | | Percent IOU sales | 65.71% | 61.10% | 61.76% | 62.07% | 62.09% | 62.23% | 62.38% | 62.53% | 62.67% | 62.81% | 62.96% | 63.10% | 63.24% | 63.36% | 63.50% | 63.62% | 63.76% | |
| 19 | | | Percent DA | 6.42% | 9.88% | 9.53% | 9.41% | 9.38% | 9.32% | 9.26% | 9.21% | 9.15% | 9.10% | 9.03% | 8.98% | 8.92% | 8.88% | 8.83% | 8.78% | 8.72% | |
| 20 | | | Percent Rest of State | 27.86% | 29.02% | 28.71% | 28.52% | 28.53% | 28.45% | 28.36% | 28.26% | 28.17% | 28.09% | 28.00% | 27.91% | 27.84% | 27.76% | 27.67% | 27.60% | 27.51% | |
| 21 | | | | | | | | | | | | | | | | | | | | | |
| 22 | **2** | **2001 Baseline** | | The baseline data for IOUs is from the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002," which was filed by each of the IOUs under Rulemaking 01-10-024. For total state renewable procurement, small hydro generation data from Gross System Power was added to geothermal, organic waste, wind, and solar from from the J-11 table, less 7% for losses. See Energy Commission, Updated August 6, 2004, "California Electrial Energy Generation, 1983 to 2003, Total Production by Resource Type," (J-11 table), http://www.energy.ca.gov/electricity/ELECTRICITY_GEN_1983-2003.XLS, accessed June 28, 2005. To calculate the direct access percent of renewable energy, the staff used total renewable energy sales for customer credits that received payment from the Energy Commission in 2001, which was 745 GWh/year. This was divided by total direct access retail sales for 2001. The resulting percentage was assumed for each IOU. | | | | | | | | | | | | | | | | | |
| 23 | | | | 2001 GWh (Baseline) | 2001 as % of Sales | | | | | | | | | | | | | | | | |
| 24 | | | **PG&E** | 6,719 | 8.921% | | | | | | | | | | | | | | | | |
| 25 | | | **SCE** | 11,364 | 16.617% | | | | | | | | | | | | | | | | |
| 26 | | | **SDG&E** | 146 | 0.977% | | | | | | | | | | | | | | | | |
| 27 | | | **Total** | 18,229 | 11.492% | | | | | | | | | | | | | | | | |
| 28 | | | | | | | | | | | | | | | | | | | | | |
| 29 | | 4.81% | **PG&E DA** | 142 | 4.81% | | | | | | | | | | | | | | | | |
| 30 | | | **SCE DA** | 486 | 4.81% | | | | | | | | | | | | | | | | |
| 31 | | | **SDG&E** | 117 | 4.81% | | | | | | | | | | | | | | | | |
| 32 | | | **Total DA** | 745 | 4.81% | | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | | | | | | | |
| 34 | | | **Total DA and IOU Baseline** | 18,974 | | | | | | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | | | | | | | | | |
| 36 | | | **Total Rest of State** | 6,842 | 10.17% | | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | | | | | | |
| 38 | | | **Statewide Total (J-11 Adjusted)** | 25,816 | | | | | | | | | | | | | | | | | |
| 39 | | | | | | | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | | | | | | |
| 41 | | | | | | | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | | | | | | | |

Shading with text is explanatory. Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

TABLE 1

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 | |
| 43 | 3 | **1% Minimum Percentage Point Growth (capped) as percent** | | [% shown in (Section 2)] + [1%] up to [20%]. | | | | | | | | | | | | | | | | | |
| 44 | | | **PG&E** | | | 9.92% | 10.92% | 11.92% | 12.92% | 13.92% | 14.92% | 15.92% | 16.92% | | | | | | | | |
| 45 | | | **SCE** | | | 17.62% | 18.62% | 19.62% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | | | | | | | | |
| 46 | | | **SDG&E** | | | 1.98% | 2.98% | 3.98% | 4.98% | 5.98% | 6.98% | 7.98% | 8.98% | | | | | | | | |
| 47 | | | **Total** | | | | | | | | | | | | | | | | | | |
| 48 | | | | | | | | | | | | | | | | | | | | | |
| 49 | | | **PG&E DA** | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | | | | | | | | |
| 50 | | | **SCE DA** | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | | | | | | | | |
| 51 | | | **SDG&E DA** | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | | | | | | | | |
| 52 | | | **Total DA** | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | | | | | | | | |
| 53 | | | | | | | | | | | | | | | | | | | | | |
| 54 | | | **Total Rest of State** | | | 11.17% | 12.17% | 13.17% | 14.17% | 15.17% | 16.17% | 17.17% | 18.17% | | | | | | | | |
| 55 | | | | | | | | | | | | | | | | | | | | | |
| 56 | 4 | **1% Minimum Percentage Point Growth (capped) as GWh** | | (Section 3) * (Section 1). | | | | | | | | | | | | | | | | | |
| 57 | | | **PG&E** | | | 7,052 | 7,988 | 8,783 | 9,677 | 10,584 | 11,501 | 12,449 | 13,435 | | | | | | | | |
| 58 | | | **SCE** | | | 12,451 | 13,637 | 14,560 | 15,023 | 15,239 | 15,468 | 15,713 | 15,934 | | | | | | | | |
| 59 | | | **SDG&E** | | | 295 | 464 | 630 | 802 | 980 | 1,167 | 1,358 | 1,554 | | | | | | | | |
| 60 | | | **Total** | | | 19,798 | 22,089 | 23,973 | 25,502 | 26,804 | 28,137 | 29,520 | 30,923 | | | | | | | | |
| 61 | | | | | | | | | | | | | | | | | | | | | |
| 62 | | | **PG&E DA** | | | 530 | 632 | 730 | 830 | 929 | 1,034 | 1,139 | 1,244 | | | | | | | | |
| 63 | | | **SCE DA** | | | 672 | 798 | 921 | 1,043 | 1,168 | 1,293 | 1,421 | 1,549 | | | | | | | | |
| 64 | | | **SDG&E DA** | | | 201 | 242 | 279 | 318 | 357 | 397 | 437 | 478 | | | | | | | | |
| 65 | | | **Total DA** | | | 1,403 | 1,672 | 1,931 | 2,191 | 2,454 | 2,724 | 2,997 | 3,271 | | | | | | | | |
| 66 | | | | | | | | | | | | | | | | | | | | | |
| 67 | | | **Total Rest of State** | | | 8,137 | 9,058 | 9,909 | 10,764 | 11,630 | 12,511 | 13,415 | 14,335 | | | | | | | | |
| 68 | | | | | | | | | | | | | | | | | | | | | |
| 69 | 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) | | | | | | | | | | | | | | | | | |
| 70 | | | **PG&E** | | | 333 | 935 | 795 | 894 | 908 | 916 | 948 | 986 | | | | | | | | |
| 71 | | | **SCE** | | | 1,087 | 1,187 | 923 | 463 | 216 | 229 | 245 | 221 | | | | | | | | |
| 72 | | | **SDG&E** | | | 149 | 169 | 166 | 172 | 178 | 187 | 191 | 196 | | | | | | | | |
| 73 | | | **Total** | | | 1,570 | 2,290 | 1,884 | 1,530 | 1,301 | 1,333 | 1,384 | 1,403 | | | | | | | | |
| 74 | | | | | | | | | | | | | | | | | | | | | |
| 75 | | | **PG&E DA** | | | 388 | 102 | 99 | 99 | 100 | 105 | 105 | 106 | | | | | | | | |
| 76 | | | **SCE DA** | | | 186 | 127 | 122 | 122 | 124 | 126 | 128 | 128 | | | | | | | | |
| 77 | | | **SDG&E DA** | | | 84 | 40 | 38 | 39 | 39 | 40 | 40 | 41 | | | | | | | | |
| 78 | | | **Total DA** | | | 658 | 269 | 259 | 260 | 263 | 271 | 273 | 274 | | | | | | | | |
| 79 | | | | | | | | | | | | | | | | | | | | | |
| 80 | | | **Total Rest of State** | | | 1,295 | 921 | 851 | 855 | 866 | 881 | 904 | 919 | | | | | | | | |
| 81 | | | | | | | | | | | | | | | | | | | | | |
| 82 | 6 | **Needed Growth- percent (total) - if NOT at 20% by 2010 with simple 1 % growth** | | If not at 20% by (Section 3) method, grow at annual average percent to reach 20% by 2010. | | | | | | | | | | Annual Avg. Growth Rate if not at 20% by 2010 at 1% | | | | | | | |
| 83 | | | **PG&E** | | | 10.31% | 11.69% | 13.08% | 14.46% | 15.85% | 17.23% | 18.62% | 20.00% | 1.38% | | | | | | | |
| 84 | | | **SCE** | | | 17.62% | 18.62% | 19.62% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 0.00% | | | | | | | |
| 85 | | | **SDG&E** | | | 3.35% | 5.73% | 8.11% | 10.49% | 12.87% | 15.24% | 17.62% | 20.00% | 2.38% | | | | | | | |
| 86 | | | **Total** | | | 12.94% | 14.25% | 15.56% | 16.58% | 17.43% | 18.29% | 19.14% | 20.00% | | | | | | | | |
| 87 | | | | | | | | | | | | | | | | | | | | | |
| 88 | | | **PG&E DA** | | | 6.71% | 8.61% | 10.50% | 12.40% | 14.30% | 16.20% | 18.10% | 20.00% | 1.90% | | | | | | | |
| 89 | | | **SCE DA** | | | 6.71% | 8.61% | 10.50% | 12.40% | 14.30% | 16.20% | 18.10% | 20.00% | 1.90% | | | | | | | |
| 90 | | | **SDG&E DA** | | | 6.71% | 8.61% | 10.50% | 12.40% | 14.30% | 16.20% | 18.10% | 20.00% | 1.90% | | | | | | | |
| 91 | | | **Total** | | | 6.71% | 8.61% | 10.50% | 12.40% | 14.30% | 16.20% | 18.10% | 20.00% | 1.90% | | | | | | | |
| 92 | | | | | | | | | | | | | | | | | | | | | |
| 93 | | | **Total Rest of State** | | | 11.40% | 12.63% | 13.86% | 15.09% | 16.31% | 17.54% | 18.77% | 20.00% | 1.23% | | | | | | | |
| 94 | | | | | | | | | | | | | | | | | | | | | |
| 95 | 7 | **Needed Growth - GWh (total) - if NOT at 20% by 2010 with simple 1 % growth** | | (Section 6) * (Section 1). The 2011-2017 values here are being held at 20%. | | | | | | | | | | | | | | | | | |
| 96 | | | **PG&E** | - | | 7,326 | 8,550 | 9,633 | 10,830 | 12,047 | 13,280 | 14,555 | 15,879 | 16,153 | 16,384 | 16,650 | 16,864 | 17,084 | 17,293 | 17,544 | |
| 97 | | | **SCE** | - | | 12,451 | 13,637 | 14,560 | 15,023 | 15,239 | 15,468 | 15,713 | 15,934 | 16,145 | 16,379 | 16,592 | 16,826 | 17,056 | 17,251 | 17,491 | |
| 98 | | | **SDG&E** | - | | 501 | 893 | 1,285 | 1,691 | 2,110 | 2,551 | 3,000 | 3,462 | 3,519 | 3,576 | 3,633 | 3,690 | 3,746 | 3,801 | 3,864 | |
| 99 | | | **Total** | - | | 20,278 | 23,081 | 25,478 | 27,544 | 29,396 | 31,299 | 33,269 | 35,276 | 35,818 | 36,340 | 36,875 | 37,380 | 37,887 | 38,345 | 38,899 | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 101 | | | **PG&E DA** | - | | 612 | 799 | 983 | 1,168 | 1,356 | 1,550 | 1,745 | 1,943 | 1,957 | 1,971 | 1,985 | 1,999 | 2,011 | 2,021 | 2,035 | |
| 102 | | | **SCE DA** | - | | 776 | 1,009 | 1,239 | 1,469 | 1,703 | 1,939 | 2,179 | 2,419 | 2,431 | 2,444 | 2,456 | 2,470 | 2,483 | 2,491 | 2,504 | |
| 103 | | | **SDG&E DA** | - | | 233 | 306 | 376 | 448 | 520 | 595 | 670 | 746 | 752 | 757 | 763 | 768 | 773 | 777 | 783 | |
| 104 | | | **Total DA** | - | | 1,621 | 2,114 | 2,598 | 3,086 | 3,578 | 4,084 | 4,595 | 5,109 | 5,139 | 5,172 | 5,204 | 5,238 | 5,266 | 5,289 | 5,322 | |
| 105 | | | | | | | | | | | | | | | | | | | | | |
| 106 | | | **Total DA and IOU** | | | 21,898 | 25,195 | 28,076 | 30,629 | 32,975 | 35,384 | 37,863 | 40,384 | 40,957 | 41,512 | 42,079 | 42,617 | 43,153 | 43,635 | 44,221 | |
| 107 | | | | | | | | | | | | | | | | | | | | | |
| 108 | | | **Total Rest of State** | - | | 8,304 | 9,398 | 10,424 | 11,458 | 12,506 | 13,572 | 14,664 | 15,776 | 15,929 | 16,076 | 16,231 | 16,375 | 16,510 | 16,635 | 16,784 | |
| 109 | | | **Statewide** | | | 30,202 | 34,593 | 38,501 | 42,087 | 45,480 | 48,955 | 52,528 | 56,160 | 56,885 | 57,588 | 58,310 | 58,992 | 59,663 | 60,270 | 61,005 | |
| 110 | | | | | | | | | | | | | | | | | | | | | |

Shading with text is explanatory. Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

TABLE 1

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** | | | 607 | 1,224 | 1,083 | 1,197 | 1,218 | 1,233 | 1,275 | 1,324 | 274 | 231 | 266 | 214 | 221 | 209 | 250 | |
| 113 | | | **SCE** | | | 1,087 | 1,187 | 923 | 463 | 216 | 229 | 245 | 221 | 212 | 234 | 212 | 234 | 230 | 195 | 240 | |
| 114 | | | **SDG&E** | | | 355 | 393 | 392 | 406 | 419 | 441 | 450 | 462 | 57 | 57 | 57 | 57 | 56 | 55 | 63 | |
| 115 | | | **Total** | | - | 2,049 | 2,804 | 2,397 | 2,065 | 1,852 | 1,903 | 1,969 | 2,007 | 542 | 522 | 535 | 505 | 507 | 459 | 554 | |
| 116 | | | | | | | | | | | | | | | | | | | | | |
| 117 | | | **Cumulative MW with 50% CF** | | | 468 | 640 | 547 | 472 | 423 | 435 | 450 | 458 | 124 | 119 | 122 | 115 | 116 | 105 | 126 | |
| 118 | | | | | | | | | | | | | | | | | | | | | |
| 119 | | | **PG&E DA** | | | 470 | 187 | 184 | 186 | 187 | 195 | 195 | 198 | 13 | 14 | 14 | 14 | 11 | 10 | 14 | |
| 120 | | | **SCE DA** | | | 290 | 233 | 230 | 230 | 233 | 236 | 240 | 240 | 11 | 14 | 12 | 14 | 12 | 9 | 13 | |
| 121 | | | **SDG&E DA** | | | 115 | 73 | 70 | 72 | 72 | 75 | 75 | 76 | 5 | 6 | 5 | 5 | 5 | 5 | 6 | |
| 122 | | | **Total DA** | | | 876 | 493 | 484 | 488 | 493 | 506 | 510 | 514 | 30 | 33 | 32 | 33 | 28 | 23 | 32 | |
| 123 | | | | | | | | | | | | | | | | | | | | | |
| 124 | | | **Cumulative MW with 50% CF** | | | 200 | 113 | 111 | 111 | 113 | 115 | 117 | 117 | 7 | 8 | 7 | 8 | 7 | 5 | 7 | |
| 125 | | | | | | | | | | | | | | | | | | | | | |
| 126 | | | **Total Rest of State** | - | | 1,462 | 1,094 | 1,026 | 1,033 | 1,048 | 1,066 | 1,093 | 1,112 | 153 | 147 | 155 | 144 | 136 | 125 | 149 | |
| 127 | | | | | | | | | | | | | | | | | | | | | |
| 128 | | | **Cumulative MW with 50% CF** | | | 334 | 250 | 234 | 236 | 239 | 243 | 250 | 254 | 35 | 34 | 35 | 33 | 31 | 28 | 34 | |
| 129 | | | **DA and IOU** | | | 2,925 | 3,297 | 2,881 | 2,553 | 2,345 | 2,409 | 2,480 | 2,521 | 572 | 555 | 567 | 539 | 536 | 482 | 586 | |
| 130 | | | | | | | | | | | | | | | | | | | | | |
| 131 | **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) | | | | | | | | | | | | | | | | | |
| 132 | | | **PG&E** | | | 607 | 1,831 | 2,914 | 4,110 | 5,328 | 6,561 | 7,836 | 9,160 | 9,434 | 9,664 | 9,930 | 10,144 | 10,365 | 10,574 | 10,824 | |
| 133 | | | **SCE** | | | 1,087 | 2,274 | 3,197 | 3,660 | 3,876 | 4,105 | 4,349 | 4,570 | 4,782 | 5,016 | 5,228 | 5,462 | 5,693 | 5,887 | 6,127 | |
| 134 | | | **SDG&E** | | | 355 | 748 | 1,139 | 1,545 | 1,964 | 2,405 | 2,855 | 3,317 | 3,373 | 3,431 | 3,488 | 3,544 | 3,601 | 3,656 | 3,719 | |
| 135 | | | **Total** | | | 2,049 | 4,853 | 7,250 | 9,315 | 11,167 | 13,071 | 15,040 | 17,047 | 17,589 | 18,111 | 18,646 | 19,151 | 19,658 | 20,117 | 20,670 | |
| 136 | | | | | | | | | | | | | | | | | | | | | |
| 137 | | | **Cumulative MW with 50% CF** | | | 468 | 1,108 | 1,655 | 2,127 | 2,550 | 2,984 | 3,434 | 3,892 | 4,016 | 4,135 | 4,257 | 4,372 | 4,488 | 4,593 | 4,719 | |
| 138 | | | | | | | | | | | | | | | | | | | | | |
| 139 | | | **PG&E DA** | | | 470 | 657 | 841 | 1,027 | 1,214 | 1,408 | 1,604 | 1,801 | 1,815 | 1,829 | 1,843 | 1,857 | 1,869 | 1,879 | 1,893 | |
| 140 | | | **SCE DA** | | | 290 | 524 | 754 | 984 | 1,217 | 1,453 | 1,693 | 1,934 | 1,945 | 1,959 | 1,970 | 1,985 | 1,997 | 2,005 | 2,018 | |
| 141 | | | **SDG&E DA** | | | 115 | 188 | 259 | 330 | 403 | 478 | 553 | 629 | 634 | 640 | 645 | 650 | 655 | 660 | 666 | |
| 142 | | | **Total DA** | | | 876 | 1,369 | 1,853 | 2,341 | 2,833 | 3,339 | 3,850 | 4,364 | 4,394 | 4,427 | 4,459 | 4,493 | 4,521 | 4,544 | 4,577 | |
| 143 | | | | | | | | | | | | | | | | | | | | | |
| 144 | | | **Cumulative MW with 50% CF** | | | 200 | 313 | 423 | 534 | 647 | 762 | 879 | 996 | 1,003 | 1,011 | 1,018 | 1,026 | 1,032 | 1,037 | 1,045 | |
| 145 | | | | | | | | | | | | | | | | | | | | | |
| 146 | | | **Total Rest of State** | | | 1,462 | 2,556 | 3,582 | 4,616 | 5,664 | 6,729 | 7,822 | 8,934 | 9,087 | 9,233 | 9,389 | 9,533 | 9,668 | 9,793 | 9,942 | |
| 147 | | | | | | | | | | | | | | | | | | | | | |
| 148 | | | **Cumulative MW with 50% CF** | | | 334 | 584 | 818 | 1,054 | 1,293 | 1,536 | 1,786 | 2,040 | 2,075 | 2,108 | 2,144 | 2,176 | 2,207 | 2,236 | 2,270 | |
| 149 | | | | | | | | | | | | | | | | | | | | | |

Shading with text is explanatory. Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

TABLE 1

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** | |
| 150 | **10** | **Actual Renewable Procurement by IOU (in GWh/year)** | | For 2001 and 2002, total renewable procurement was reported in the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002" which was filed by each of the IOUs under Rulemaking 01-10-024. For 2003 and 2004, renewable procurement was reported in the IOU APT compliance reports filed with the CPUC in Rulemaking 04-04-026. | | | | | | | | | | | | | | | | | |
| 151 | | | **PG&E** | 6,719 | 7,392 | 8,828 | 8,591 | | | | | | | | | | | | | | |
| 152 | | | **SCE** | 11,364 | 11,658 | 12,497 | 13,246 | | | | | | | | | | | | | | |
| 153 | | | **SDG&E** | 146 | 141 | 547 | 678 | | | | | | | | | | | | | | |
| 154 | | | **Total** | 18,229 | 19,191 | 21,872 | 22,515 | | | | | | | | | | | | | | |
| 155 | | | | | | | | | | | | | | | | | | | | | |
| 156 | **11** | **Annual Retail Sales Reported by the IOUs to the PUC (in GWh/year)** | | For 2001 and 2002, total retail sales were reported in the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002" which was filed by each of the IOUs under Rulemaking 01-10-024. For 2003 and 2004, retail sales were reported in the IOU APT compliance reports filed with the CPUC in Rulemaking 04-04-026. There are discrepancies between some of the retail sales numbers reported in Section 1 and Section 11. The retail sales numbers reported in Section 11 are taken from the latest available filings to the Public Utilities Commission. | | | | | | | | | | | | | | | | | |
| 157 | | | **PG&E** | 75,320 | 70,797 | 71,099 | 73,616 | | | | | | | | | | | | | | |
| 158 | | | **SCE** | 74,807 | 68,462 | 70,617 | 72,964 | | | | | | | | | | | | | | |
| 159 | | | **SDG&E** | 14,999 | 14,301 | 15,044 | 15,534 | | | | | | | | | | | | | | |
| 160 | | | **Total** | 165,126 | 153,560 | 156,760 | 162,114 | | | | | | | | | | | | | | |
| 161 | | | | | | | | | | | | | | | | | | | | | |
| 162 | **12** | **Annual Procurement Target (APT) in GWh/year** | | Annual Procurement Targets (APT) are listed in IOU APT compliance reports filed with the CPUC in Rulemaking 04-04-26. | | | | | | | | | | | | | | | | | |
| 163 | | | **PG&E** | | | 8,764 | 9,475 | 10,211 | | | | | | | | | | | | | |
| 164 | | | **SCE** | | | 12,030 | 12,736 | 13,466 | | | | | | | | | | | | | |
| 165 | | | **SDG&E** | | | 150 | 423 | 581 | | | | | | | | | | | | | |
| 166 | | | **Total** | | | 20,944 | 22,634 | 24,258 | | | | | | | | | | | | | |
| 167 | | | | | | | | | | | | | | | | | | | | | |
| 168 | **13** | **Percent renewable of prior year retail sales (per CPUC method)** | | (Section 10)/(Section 11). To calculate the percent renewable per year, divide the current year's renewable procurement into the previous year's retail sales. See Appendix B of CPUC D.04-06-014 for a description of the CPUC's method for calculating RPS compliance. According to CPUC D.02-10-062, the IPT for 2003 is calculated based on 1% of 2001 retail sales for the IOUs. | | | | | | | | | | | | | | | | | |
| 169 | | | **PG&E** | 8.92% | 9.81% | 11.72% | 12.08% | | | | | | | | | | | | | | |
| 170 | | | **SCE** | 15.19% | 15.58% | 16.71% | 18.76% | | | | | | | | | | | | | | |
| 171 | | | **SDG&E** | 0.97% | 0.94% | 3.65% | 4.51% | | | | | | | | | | | | | | |
| 172 | | | **Total** | 11.04% | 11.62% | 13.25% | 14.36% | | | | | | | | | | | | | | |
| 173 | | | | | | | | | | | | | | | | | | | | | |
| 174 | **14** | **Percent renewable of current year retail sales (IOU only)** | | (Section 10)/(Section 1). In this section, percent reenwable is calculated by dividing the GWh/Year reported in the IOU's APT compliance reports into the Retail Sales Numbers compiled by the Energy Commission's Demand Analysis Office. | | | | | | | | | | | | | | | | | |
| 175 | | | **PG&E** | 8.92% | 10.80% | 12.42% | 11.75% | | | | | | | | | | | | | | |
| 176 | | | **SCE** | 16.62% | 17.04% | 17.68% | 18.08% | | | | | | | | | | | | | | |
| 177 | | | **SDG&E** | 0.98% | 0.98% | 3.66% | 4.35% | | | | | | | | | | | | | | |
| 178 | | | **Total** | 11.49% | 12.69% | 13.96% | 13.90% | | | | | | | | | | | | | | |
| 179 | | | | | | | | | | | | | | | | | | | | | |
| 180 | **15** | **Annual Renewable Generation Available to California Electricity Customers (GWh/Year)** | | For 2001-2003, all of the renewables totals except for small hydro see Energy Commission, Updated August 6, 2004, "California Electrial Energy Generation, 1983 t 2003, Total Production by Resource Type," (J-11 table), http://www.energy.ca.gov/electricity/ELECTRICITY_GEN_1983-2003.XLS, accessed June 28, 2005. Since Small Hydro is not itemized in the Energy Commission's J-11 table, those totals are taken from the Energy Commission's Gross System Power totals which are calculated in order to publish the annual Net System Power reports. The Small Hydro totals are then added to the Renewables totals published in the Energy Commission's J-11 table. The Net System Power reports utilized to extract 2001-2003 small hydro data are the following: "2001 Net System Power Calculation" (No Publication Number Assigned), "2002 Net System Power Calculation" (Publication No. 300-03-002), and "2003 Net System Power Calculation" (Publication No. 300-04-001R). The 2004 totals come from the Energy Commission Report entitled "2004 Net System Power Calculation" (Publication No. CEC-300-2005-004). | | | | | | | | | | | | | | | | | |
| 181 | | | | 27,759 | 28,908 | 28,927 | 29,238 | | | | | | | | | | | | | | |
| 182 | | | | | | | | | | | | | | | | | | | | | |
| 183 | **16** | **Total Annual Generation Available to California Electricity Customers (GWh/Year)** | | For 2001-2003, these totals are extracted from the Energy Commission's J-11 table, which is annually submitted to the California Department of Finance which could be found at the following URL: http://www.energy.ca.gov/electricity/electricity_generation.html. The 2004 totals come from the Energy Commission Report entitled "2004 Net System Power Calculation" (Publication No. CEC-300-2005-004). | | | | | | | | | | | | | | | | | |
| 184 | | | | 265,059 | 272,509 | 276,700 | 275,447 | | | | | | | | | | | | | | |
| 185 | | | | | | | | | | | | | | | | | | | | | |
| 186 | **17** | **Percent renewable of current year generation. (Statewide)** | | (Section 15)/(Section 16) | | | | | | | | | | | | | | | | | |
| 187 | | | | 10.47% | 10.61% | 10.45% | 10.61% | | | | | | | | | | | | | | |

Shading with text is explanatory. Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

**TABLE 2**

**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 - Retail Sales by Utility (GWh). The retail sales and demand forecast totals by utility were taken from the Energy Commission Draft Staff Report entitled, "California Energy Demand 2006-2016 Staff Energy Demand Forecast" (Publication Number CEC-400-2004-034-SD). This information appears in this report as Form 1.c. which is entitled, "Statewide California Energy Demand 2006-2016 Staff Forecast Retail Sales by Utility (GWh)." The methodology for preparing Form 1.c. can be found in the Energy Commission's Staff Report entitled, "Energy Demand Forecast Methods Report: Companion Report to the California Energy Demand 2006-2016 Staff Energy Demand Forecast Report" (Publication Number CEC-400-2005-036.) To calculate the 2017 retail sales numbers, staff averaged the forecasted annual sales growth between 2006 and 2016 and used that growth rate as the growth in retail sales from 2016 to 2017. | | | | | | | | | | | | | | | | | | **Average Annual Growth Rate 2006-2016** |
| 2 | | | | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | |
| 3 | **1** | **Sales (GWh)** | **PG&E** | 75,319 | 68,445 | 71,084 | 73,137 | 73,671 | 74,891 | 76,030 | 77,075 | 78,191 | 79,397 | 80,766 | 81,920 | 83,248 | 84,318 | 85,422 | 86,467 | 87,719 | **1.45%** |
| 4 | | | **SCE** | 68,387 | 68,431 | 70,677 | 73,254 | 74,224 | 75,116 | 76,196 | 77,342 | 78,565 | 79,669 | 80,727 | 81,896 | 82,958 | 84,130 | 85,281 | 86,254 | 87,455 | **1.39%** |
| 5 | | | **SDG&E** | 14,919 | 14,364 | 14,930 | 15,585 | 15,846 | 16,123 | 16,397 | 16,732 | 17,026 | 17,312 | 17,595 | 17,882 | 18,167 | 18,450 | 18,732 | 19,007 | 19,322 | **1.66%** |
| 6 | | | **Total** | 158,625 | 151,240 | 156,691 | 161,976 | 163,740 | 166,129 | 168,623 | 171,149 | 173,782 | 176,378 | 179,088 | 181,698 | 184,373 | 186,898 | 189,435 | 191,727 | 194,495 | **1.44%** |
| 7 | | | | | | | | | | | | | | | | | | | | | |
| 8 | | | Grand Total Statewide Sales | 241,384 | 247,527 | 253,690 | 260,955 | 263,697 | 266,954 | 270,295 | 273,718 | 277,286 | 280,802 | 284,427 | 287,938 | 291,548 | 294,961 | 298,317 | 301,348 | 305,023 | **1.22%** |
| 9 | | | DA and Rest of State | 82,759 | 96,287 | 97,000 | 98,979 | 99,957 | 100,825 | 101,672 | 102,569 | 103,504 | 104,424 | 105,339 | 106,240 | 107,175 | 108,062 | 108,882 | 109,621 | 110,527 | **0.84%** |
| 10 | | | **PG&E DA** | 2,952 | 9,820 | 9,127 | 9,283 | 9,357 | 9,421 | 9,478 | 9,568 | 9,643 | 9,716 | 9,783 | 9,855 | 9,927 | 9,997 | 10,053 | 10,104 | 10,175 | **0.70%** |
| 11 | | | **SCE DA** | 10,103 | 11,228 | 11,571 | 11,731 | 11,797 | 11,846 | 11,905 | 11,967 | 12,039 | 12,097 | 12,154 | 12,222 | 12,281 | 12,351 | 12,413 | 12,456 | 12,518 | **0.50%** |
| 12 | | | **SDG&E** | 2,444 | 3,405 | 3,467 | 3,553 | 3,580 | 3,611 | 3,637 | 3,673 | 3,702 | 3,731 | 3,758 | 3,786 | 3,813 | 3,840 | 3,864 | 3,887 | 3,915 | **0.74%** |
| 13 | | | **Total DA** | 15,499 | 24,453 | 24,166 | 24,566 | 24,733 | 24,877 | 25,020 | 25,208 | 25,383 | 25,544 | 25,695 | 25,862 | 26,021 | 26,188 | 26,330 | 26,446 | 26,608 | **0.61%** |
| 14 | | | **Total Rest of State** | 67,260 | 71,834 | 72,834 | 74,414 | 75,224 | 75,948 | 76,652 | 77,361 | 78,121 | 78,880 | 79,644 | 80,378 | 81,155 | 81,875 | 82,552 | 83,175 | 83,919 | **0.91%** |
| 15 | | | **DA % of non IOU** | 18.73% | 25.40% | 24.91% | 24.82% | 24.74% | 24.67% | 24.61% | 24.58% | 24.52% | 24.46% | 24.39% | 24.34% | 24.28% | 24.23% | 24.18% | 24.13% | 24.07% | |
| 16 | | | **Rest of State % of non IOU** | 81.27% | 74.60% | 75.09% | 75.18% | 75.26% | 75.33% | 75.39% | 75.42% | 75.48% | 75.54% | 75.61% | 75.66% | 75.72% | 75.77% | 75.82% | 75.87% | 75.93% | |
| 17 | | | | | | | | | | | | | | | | | | | | | |
| 18 | | | Percent IOU sales | 65.71% | 61.10% | 61.76% | 62.07% | 62.09% | 62.23% | 62.38% | 62.53% | 62.67% | 62.81% | 62.96% | 63.10% | 63.24% | 63.36% | 63.50% | 63.62% | 63.76% | |
| 19 | | | Percent DA | 6.42% | 9.88% | 9.53% | 9.41% | 9.38% | 9.32% | 9.26% | 9.21% | 9.15% | 9.10% | 9.03% | 8.98% | 8.92% | 8.88% | 8.83% | 8.78% | 8.72% | |
| 20 | | | Percent Rest | 27.86% | 29.02% | 28.71% | 28.52% | 28.53% | 28.45% | 28.36% | 28.26% | 28.17% | 28.09% | 28.00% | 27.91% | 27.84% | 27.76% | 27.67% | 27.60% | 27.51% | |
| 21 | | | | | | | | | | | | | | | | | | | | | |
| 22 | **2** | | **2001 Baseline** | The baseline data for IOUs is from the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002," which was filed by each of the IOUs under Rulemaking 01-10-024. For total state renewable procurement, small hydro generation data from Gross System Power was added to geothermal, organic waste, wind, and solar from from the J-11 table, less 7% for losses. See Energy Commission, Updated August 6, 2004, "California Electrial Energy Generation, 1983 to 2003, Total Production by Resource Type," (J-11 table), http://www.energy.ca.gov/electricity/ELECTRICITY_GEN_1983-2003.XLS, accessed June 28, 2005. To calculate the direct access percent of renewable energy, the staff used total renewable energy sales for customer credits that received payment from the Energy Commission in 2001, which was 745 GWh/year. This was divided by total direct access retail sales for 2001. The resulting percentage was assumed for each IOU. | | | | | | | | | | | | | | | | | |
| 23 | | | | 2001 GWh (Baseline) | 2001 as % of Sales | | | | | | | | | | | | | | | | |
| 24 | | | **PG&E** | 6,719 | 8.92% | | | | | | | | | | | | | | | | |
| 25 | | | **SCE** | 11,364 | 16.62% | | | | | | | | | | | | | | | | |
| 26 | | | **SDG&E** | 146 | 0.98% | | | | | | | | | | | | | | | | |
| 27 | | | **Total** | 18,229 | 11.49% | | | | | | | | | | | | | | | | |
| 28 | | | | | | | | | | | | | | | | | | | | | |
| 29 | | 4.81% | **PG&E DA** | 142 | 4.81% | | | | | | | | | | | | | | | | |
| 30 | | | **SCE DA** | 486 | 4.81% | | | | | | | | | | | | | | | | |
| 31 | | | **SDG&E** | 117 | 4.81% | | | | | | | | | | | | | | | | |
| 32 | | | **Total DA** | 745 | 4.81% | | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | | | | | | | |
| 34 | | | **Total DA and IOU Baseline** | 18,974 | | | | | | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | | | | | | | | | |
| 36 | | | **Total Rest of State** | 6,842 | 10.17% | | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | | | | | | |
| 38 | | | **Statewide Total (J-11 Adjusted)** | 25,816 | | | | | | | | | | | | | | | | | |
| 39 | | | | | | | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | | | | | | |
| 41 | | | | | | | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | | | | | | | |
| 43 | **3** | **1% Minimum Percentage Point Growth (capped) as percent** | | [% shown in (Section 2)] + [1%] up to [20%]. | | | | | | | | | | | | | | | | | |

Shading with text is explanatory.

**TABLE 2**

**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 | |
| 44 | | | PG&E | | | 9.92% | 10.92% | 11.92% | 12.92% | 13.92% | 14.92% | 15.92% | 16.92% | 17.92% | 18.92% | 19.92% | 20.00% | 20.00% | 20.00% | 20.00% | |
| 45 | | | SCE | | | 17.62% | 18.62% | 19.62% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | |
| 46 | | | SDG&E | | | 1.98% | 2.98% | 3.98% | 4.98% | 5.98% | 6.98% | 7.98% | 8.98% | 9.98% | 10.98% | 11.98% | 12.98% | 13.98% | 14.98% | 15.98% | |
| 47 | | | Total | | | 12.64% | 13.64% | 14.64% | 15.35% | 15.90% | 16.44% | 16.99% | 17.53% | 18.08% | 18.63% | 19.17% | 19.31% | 19.40% | 19.50% | 19.60% | |
| 48 | | | | | | | | | | | | | | | | | | | | | |
| 49 | | | PG&E DA | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | 13.81% | 14.81% | 15.81% | 16.81% | 17.81% | 18.81% | 19.81% | |
| 50 | | | SCE DA | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | 13.81% | 14.81% | 15.81% | 16.81% | 17.81% | 18.81% | 19.81% | |
| 51 | | | SDG&E | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | 13.81% | 14.81% | 15.81% | 16.81% | 17.81% | 18.81% | 19.81% | |
| 52 | | | Total DA | | | 5.81% | 6.81% | 7.81% | 8.81% | 9.81% | 10.81% | 11.81% | 12.81% | 13.81% | 14.81% | 15.81% | 16.81% | 17.81% | 18.81% | 19.81% | |
| 53 | | | | | | | | | | | | | | | | | | | | | |
| 54 | | | Total Rest of State | | | 11.17% | 12.17% | 13.17% | 14.17% | 15.17% | 16.17% | 17.17% | 18.17% | 19.17% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | |
| 55 | | | | | | | | | | | | | | | | | | | | | |
| 56 | 4 | 1% Minimum Percentage Point Growth (capped) as GWh | | (Section 3) * (Section 1). | | | | | | | | | | | | | | | | | |
| 57 | | | PG&E | | | 7,052 | 7,988 | 8,783 | 9,677 | 10,584 | 11,501 | 12,449 | 13,435 | 14,474 | 15,500 | 16,584 | 16,864 | 17,084 | 17,293 | 17,544 | |
| 58 | | | SCE | | | 12,451 | 13,637 | 14,560 | 15,023 | 15,239 | 15,468 | 15,713 | 15,934 | 16,145 | 16,379 | 16,592 | 16,826 | 17,056 | 17,251 | 17,491 | |
| 59 | | | SDG&E | | | 295 | 464 | 630 | 802 | 980 | 1,167 | 1,358 | 1,554 | 1,755 | 1,963 | 2,176 | 2,394 | 2,618 | 2,847 | 3,087 | |
| 60 | | | Total | | | 19,798 | 22,089 | 23,973 | 25,502 | 26,804 | 28,137 | 29,520 | 30,923 | 32,375 | 33,842 | 35,352 | 36,084 | 36,759 | 37,391 | 38,122 | |
| 61 | | | | | | | | | | | | | | | | | | | | | |
| 62 | | | PG&E DA | | | 530 | 632 | 730 | 830 | 929 | 1,034 | 1,139 | 1,244 | 1,351 | 1,459 | 1,569 | 1,680 | 1,790 | 1,900 | 2,015 | |
| 63 | | | SCE DA | | | 672 | 798 | 921 | 1,043 | 1,168 | 1,293 | 1,421 | 1,549 | 1,678 | 1,810 | 1,941 | 2,076 | 2,210 | 2,342 | 2,479 | |
| 64 | | | SDG&E | | | 201 | 242 | 279 | 318 | 357 | 397 | 437 | 478 | 519 | 561 | 603 | 645 | 688 | 731 | 776 | |
| 65 | | | Total DA | | | 1,403 | 1,672 | 1,931 | 2,191 | 2,454 | 2,724 | 2,997 | 3,271 | 3,548 | 3,829 | 4,113 | 4,401 | 4,689 | 4,974 | 5,270 | |
| 66 | | | | | | | | | | | | | | | | | | | | | |
| 67 | | | Total Rest of State | | | 8,137 | 9,058 | 9,909 | 10,764 | 11,630 | 12,511 | 13,415 | 14,335 | 15,270 | 16,076 | 16,231 | 16,375 | 16,510 | 16,635 | 16,784 | |
| 68 | | | | | | | | | | | | | | | | | | | | | |
| 69 | 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 Energy |
| 70 | | | PG&E | | | 333 | 935 | 795 | 894 | 908 | 916 | 948 | 986 | 1,039 | 1,026 | 1,084 | 280 | 221 | 209 | 250 | 10,824 |
| 71 | | | SCE | | | 1,087 | 1,187 | 923 | 463 | 216 | 229 | 245 | 221 | 212 | 234 | 212 | 234 | 230 | 195 | 240 | 6,127 |
| 72 | | | SDG&E | | | 149 | 169 | 166 | 172 | 178 | 187 | 191 | 196 | 201 | 207 | 213 | 218 | 224 | 228 | 240 | 2,941 |
| 73 | | | Total | | | 1,570 | 2,290 | 1,884 | 1,530 | 1,301 | 1,333 | 1,384 | 1,403 | 1,452 | 1,467 | 1,509 | 732 | 675 | 632 | 731 | 19,893 |
| 74 | | | | | | | | | | | | | | | | | | | | | |
| 75 | | | PG&E DA | | | 388 | 102 | 99 | 99 | 100 | 105 | 105 | 106 | 106 | 108 | 110 | 111 | 110 | 110 | 115 | 1,873 |
| 76 | | | SCE DA | | | 186 | 127 | 122 | 122 | 124 | 126 | 128 | 128 | 129 | 132 | 132 | 135 | 134 | 132 | 137 | 1,994 |
| 77 | | | SDG&E | | | 84 | 40 | 38 | 39 | 39 | 40 | 40 | 41 | 41 | 42 | 42 | 43 | 43 | 43 | 45 | 658 |
| 78 | | | Total DA | | | 658 | 269 | 259 | 260 | 263 | 271 | 273 | 274 | 276 | 282 | 284 | 288 | 287 | 285 | 297 | 4,525 |
| 79 | | | | | | | | | | | | | | | | | | | | | |
| 80 | | | Total Rest of State | | | 1,295 | 921 | 851 | 855 | 866 | 881 | 904 | 919 | 935 | 806 | 155 | 144 | 136 | 125 | 149 | 9,942 |
| 81 | | | | | | | | | | | | | | | | | | | | | |
| 82 | 6 | Needed Growth - percent (total) - if NOT at 20% by 2017 with simple 1 % growth | | If not at 20% by (Section 3) method, grow at annual average percent to reach 20% by 2017. | | | | | | | | | | | | | | | | | Annual Avg. Growth Rate if not at 20% by 2017 at 1% |
| 83 | | | PG&E | | | 9.92% | 10.92% | 11.92% | 12.92% | 13.92% | 14.92% | 15.92% | 16.92% | 17.92% | 18.92% | 19.92% | 20.00% | 20.00% | 20.00% | 20.00% | 0.00% |
| 84 | | | SCE | | | 17.62% | 18.62% | 19.62% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 0.00% |
| 85 | | | SDG&E | | | 2.25% | 3.51% | 4.78% | 6.05% | 7.32% | 8.59% | 9.85% | 11.12% | 12.39% | 13.66% | 14.93% | 16.20% | 17.46% | 18.73% | 20.00% | 1.27% |
| 86 | | | Total | | | 11.49% | 13.69% | 14.72% | 15.46% | 16.03% | 16.60% | 17.17% | 17.74% | 18.31% | 18.89% | 19.46% | 19.62% | 19.75% | 19.87% | 20.00% | |
| 87 | | | | | | | | | | | | | | | | | | | | | |
| 88 | | | PG&E DA | | | 5.82% | 6.83% | 7.85% | 8.86% | 9.87% | 10.88% | 11.90% | 12.91% | 13.92% | 14.94% | 15.95% | 16.96% | 17.97% | 18.99% | 20.00% | 1.01% |
| 89 | | | SCE DA | | | 5.82% | 6.83% | 7.85% | 8.86% | 9.87% | 10.88% | 11.90% | 12.91% | 13.92% | 14.94% | 15.95% | 16.96% | 17.97% | 18.99% | 20.00% | 1.01% |
| 90 | | | SDG&E | | | 5.82% | 6.83% | 7.85% | 8.86% | 9.87% | 10.88% | 11.90% | 12.91% | 13.92% | 14.94% | 15.95% | 16.96% | 17.97% | 18.99% | 20.00% | 1.01% |
| 91 | | | Total DA | | | 5.82% | 6.83% | 7.85% | 8.86% | 9.87% | 10.88% | 11.90% | 12.91% | 13.92% | 14.94% | 15.95% | 16.96% | 17.97% | 18.99% | 20.00% | 1.01% |
| 92 | | | | | | | | | | | | | | | | | | | | | |
| 93 | | | Total Rest of State | | | 11.17% | 12.17% | 13.17% | 14.17% | 15.17% | 16.17% | 17.17% | 18.17% | 19.17% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 20.00% | 0.00% |
| 94 | | | | | | | | | | | | | | | | | | | | | |
| 95 | 7 | Needed Growth - GWh (total) - if NOT at 20% by 2017 with simple 1 % growth | | (Section 6) * (Section 1). | | | | | | | | | | | | | | | | | |
| 96 | | | PG&E | | | 7,052 | 7,988 | 8,783 | 9,677 | 10,584 | 11,501 | 12,449 | 13,435 | 14,474 | 15,500 | 16,584 | 16,864 | 17,084 | 17,293 | 17,544 | |
| 97 | | | SCE | | | 12,451 | 13,637 | 14,560 | 15,023 | 15,239 | 15,468 | 15,713 | 15,934 | 16,145 | 16,379 | 16,592 | 16,826 | 17,056 | 17,251 | 17,491 | |
| 98 | | | SDG&E | | | 335 | 548 | 758 | 975 | 1,200 | 1,437 | 1,678 | 1,926 | 2,180 | 2,442 | 2,712 | 2,988 | 3,271 | 3,560 | 3,864 | |

Shading with text is explanatory.

**TABLE 2**

**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 | |
| 99 | | | Total | | | 19,839 | 22,173 | 24,100 | 25,675 | 27,024 | 28,406 | 29,840 | 31,294 | 32,800 | 34,322 | 35,888 | 36,678 | 37,412 | 38,104 | 38,899 | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 101 | | | PG&E DA | | | 531 | 634 | 734 | 835 | 936 | 1,041 | 1,147 | 1,254 | 1,362 | 1,472 | 1,583 | 1,696 | 1,807 | 1,918 | 2,035 | |
| 102 | | | SCE DA | | | 673 | 802 | 926 | 1,049 | 1,175 | 1,303 | 1,432 | 1,562 | 1,692 | 1,825 | 1,959 | 2,095 | 2,231 | 2,365 | 2,504 | |
| 103 | | | SDG&E | | | 202 | 243 | 281 | 320 | 359 | 400 | 440 | 482 | 523 | 565 | 608 | 651 | 695 | 738 | 783 | |
| 104 | | | Total DA | | | 1,406 | 1,678 | 1,940 | 2,204 | 2,470 | 2,744 | 3,020 | 3,298 | 3,577 | 3,863 | 4,150 | 4,442 | 4,733 | 5,021 | 5,322 | |
| 105 | | | | | | | | | | | | | | | | | | | | | |
| 106 | | | Total DA and IOU | | | 21,245 | 23,851 | 26,041 | 27,879 | 29,493 | 31,149 | 32,860 | 34,592 | 36,377 | 38,185 | 40,037 | 41,120 | 42,144 | 43,126 | 44,221 | |
| 107 | | | | | | | | | | | | | | | | | | | | | |
| 108 | | | Total Rest of State | | | 8,137 | 9,058 | 9,909 | 10,764 | 11,630 | 12,511 | 13,415 | 14,335 | 15,270 | 16,076 | 16,231 | 16,375 | 16,510 | 16,635 | 16,784 | |
| 109 | | | Statewide | | | 29,382 | 32,909 | 35,950 | 38,643 | 41,123 | 43,661 | 46,275 | 48,927 | 51,647 | 54,260 | 56,268 | 57,494 | 58,655 | 59,761 | 61,005 | |
| 110 | | | | | | | | | | | | | | | | | | | | | |
| 111 | 8 | Additional Energy (GWh) Per Year on top of 2001 est. Baseline | | For 2003, (Section 7) - (Section 2). For other years, (Section 7 current year) - (Section 7 prior year) | | | | | | | | | | | | | | | | | Total Add'tl Energy |
| 112 | | | PG&E | | | 333 | 935 | 795 | 894 | 908 | 916 | 948 | 986 | 1,039 | 1,026 | 1,084 | 280 | 221 | 209 | 250 | 10,824 |
| 113 | | | SCE | | | 1,087 | 1,187 | 923 | 463 | 216 | 229 | 245 | 221 | 212 | 234 | 212 | 234 | 230 | 195 | 240 | 6,127 |
| 114 | | | SDG&E | | | 189 | 212 | 210 | 218 | 224 | 237 | 241 | 248 | 255 | 262 | 269 | 276 | 283 | 289 | 304 | 3,719 |
| 115 | | | Total | | | 1,610 | 2,334 | 1,928 | 1,575 | 1,348 | 1,382 | 1,434 | 1,455 | 1,506 | 1,522 | 1,565 | 790 | 734 | 693 | 795 | 20,670 |
| 116 | | | | | | | | | | | | | | | | | | | | | |
| 117 | | | MW/Year with 50% CF | | | 368 | 533 | 440 | 360 | 308 | 316 | 327 | 332 | 344 | 348 | 357 | 180 | 168 | 158 | 181 | 4,719 |
| 118 | | | | | | | | | | | | | | | | | | | | | |
| 119 | | | PG&E DA | | | 389 | 103 | 100 | 100 | 101 | 106 | 106 | 107 | 108 | 110 | 111 | 112 | 111 | 111 | 117 | 1,893 |
| 120 | | | SCE DA | | | 188 | 128 | 124 | 124 | 126 | 127 | 130 | 130 | 130 | 133 | 133 | 136 | 136 | 134 | 139 | 2,018 |
| 121 | | | SDG&E | | | 84 | 41 | 38 | 39 | 39 | 41 | 41 | 41 | 42 | 42 | 43 | 43 | 43 | 43 | 45 | 666 |
| 122 | | | Total DA | | | 661 | 272 | 262 | 263 | 266 | 274 | 276 | 278 | 280 | 285 | 287 | 292 | 291 | 289 | 300 | 4,577 |
| 123 | | | | | | | | | | | | | | | | | | | | | |
| 124 | | | MW/Year with 50% CF | | | 151 | 62 | 60 | 60 | 61 | 63 | 63 | 63 | 64 | 65 | 66 | 67 | 66 | 66 | 69 | 1,045 |
| 125 | | | | | | | | | | | | | | | | | | | | | |
| 126 | | | Total Rest of State | | | 1,295 | 921 | 851 | 855 | 866 | 881 | 904 | 919 | 935 | 806 | 155 | 144 | 136 | 125 | 149 | 9,942 |
| 127 | | | | | | | | | | | | | | | | | | | | | |
| 128 | | | MW/Year with 50% CF | | | 296 | 210 | 194 | 195 | 198 | 201 | 206 | 210 | 214 | 184 | 35 | 33 | 31 | 28 | 34 | 2,270 |
| 129 | | | DA and IOU | | | 2,271 | 2,606 | 2,190 | 1,838 | 1,614 | 1,656 | 1,710 | 1,732 | 1,785 | 1,807 | 1,853 | 1,082 | 1,025 | 981 | 1,095 | |
| 130 | | | | | | | | | | | | | | | | | | | | | |
| 131 | 9 | Cumulative Energy (GWh) Per Year on top of 2001 est. Baseline | | For 2003, (Section 8). For other years, (Section 8 current year) + (Section 9 prior year) | | | | | | | | | | | | | | | | | |
| 132 | | | PG&E | | | 333 | 1,268 | 2,063 | 2,957 | 3,865 | 4,781 | 5,730 | 6,716 | 7,755 | 8,781 | 9,865 | 10,144 | 10,365 | 10,574 | 10,824 | |
| 133 | | | SCE | | | 1,087 | 2,274 | 3,197 | 3,660 | 3,876 | 4,105 | 4,349 | 4,570 | 4,782 | 5,016 | 5,228 | 5,462 | 5,693 | 5,887 | 6,127 | |
| 134 | | | SDG&E | | | 189 | 402 | 612 | 830 | 1,054 | 1,291 | 1,532 | 1,780 | 2,034 | 2,297 | 2,566 | 2,842 | 3,125 | 3,415 | 3,719 | |
| 135 | | | Total | | | 1,610 | 3,944 | 5,872 | 7,447 | 8,795 | 10,177 | 11,611 | 13,066 | 14,571 | 16,093 | 17,659 | 18,449 | 19,183 | 19,876 | 20,670 | |
| 136 | | | | | | | | | | | | | | | | | | | | | |
| 137 | | | Cumulative MW with 50% CF | | | 368 | 900 | 1,341 | 1,700 | 2,008 | 2,324 | 2,651 | 2,983 | 3,327 | 3,674 | 4,032 | 4,212 | 4,380 | 4,538 | 4,719 | |
| 138 | | | | | | | | | | | | | | | | | | | | | |
| 139 | | | PG&E DA | | | 389 | 492 | 592 | 693 | 794 | 900 | 1,005 | 1,112 | 1,220 | 1,330 | 1,441 | 1,554 | 1,665 | 1,777 | 1,893 | |
| 140 | | | SCE DA | | | 188 | 316 | 440 | 564 | 690 | 817 | 947 | 1,076 | 1,207 | 1,340 | 1,473 | 1,609 | 1,745 | 1,879 | 2,018 | |
| 141 | | | SDG&E | | | 84 | 125 | 163 | 202 | 242 | 282 | 323 | 364 | 406 | 448 | 491 | 534 | 577 | 621 | 666 | |
| 142 | | | Total DA | | | 661 | 933 | 1,195 | 1,459 | 1,725 | 1,999 | 2,275 | 2,553 | 2,832 | 3,118 | 3,405 | 3,697 | 3,988 | 4,276 | 4,577 | |
| 143 | | | | | | | | | | | | | | | | | | | | | |
| 144 | | | Cumulative MW with 50% CF | | | 151 | 213 | 273 | 333 | 394 | 456 | 519 | 583 | 647 | 712 | 777 | 844 | 910 | 976 | 1,045 | |
| 145 | | | | | | | | | | | | | | | | | | | | | |
| 146 | | | Total Rest of State | | | 1,295 | 2,216 | 3,067 | 3,922 | 4,788 | 5,669 | 6,573 | 7,492 | 8,428 | 9,233 | 9,389 | 9,533 | 9,668 | 9,793 | 9,942 | |
| 147 | | | | | | | | | | | | | | | | | | | | | |
| 148 | | | Cumulative MW with 50% CF | | | 296 | 506 | 700 | 895 | 1,093 | 1,294 | 1,501 | 1,711 | 1,924 | 2,108 | 2,144 | 2,176 | 2,207 | 2,236 | 2,270 | |
| 149 | | | | | | | | | | | | | | | | | | | | | |
| 150 | 10 | Actual Renewable Procurement by IOU (in GWh/year) | | For 2001 and 2002, total renewable procurement was reported in the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002" which was filed by each of the IOUs under Rulemaking 01-10-024. For 2003 and 2004, renewable procurement was reported in the IOU APT compliance reports filed with the CPUC in Rulemaking 04-04-026. | | | | | | | | | | | | | | | | | |
| 151 | | | PG&E | 6,719 | 7,392 | 8,828 | 8,591 | | | | | | | | | | | | | | |
| 152 | | | SCE | 11,364 | 11,658 | 12,497 | 13,246 | | | | | | | | | | | | | | |
| 153 | | | SDG&E | 146 | 141 | 547 | 678 | | | | | | | | | | | | | | |
| 154 | | | Total | 18,229 | 19,191 | 21,872 | 22,515 | | | | | | | | | | | | | | |
| 155 | | | | | | | | | | | | | | | | | | | | | |

Shading with text is explanatory.

**TABLE 2**

**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 | |
| 156 | 11 | Annual Retail Sales Reported by the IOUs to the PUC (in GWh/year) | | For 2001 and 2002, total retail sales were reported in the "Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy-2001 and 2002" which was filed by each of the IOUs under Rulemaking 01-10-024. For 2003 and 2004, retail sales were reported in the IOU APT compliance reports filed with the CPUC in Rulemaking 04-04-026. There are discrepancies between some of the retail sales numbers reported in Section 1 and Section 11. The retail sales numbers reported in Section 11 are taken from the latest available filings to the Public Utilities Commission. | | | | | | | | | | | | | | | | | |
| 157 | | | PG&E | 75,320 | 70,797 | 71,099 | 73,616 | | | | | | | | | | | | | | |
| 158 | | | SCE | 74,807 | 68,462 | 70,617 | 72,964 | | | | | | | | | | | | | | |
| 159 | | | SDG&E | 14,999 | 14,301 | 15,044 | 15,534 | | | | | | | | | | | | | | |
| 160 | | | Total | 165,126 | 153,560 | 156,760 | 162,114 | | | | | | | | | | | | | | |
| 161 | | | | | | | | | | | | | | | | | | | | | |
| 162 | 12 | Annual Procurement Target (APT) in GWh/year | | Annual Procurement Targets (APT) are listed in IOU APT compliance reports filed with the CPUC in Rulemaking 04-04-26. | | | | | | | | | | | | | | | | | |
| 163 | | | PG&E | | | 8,764 | 9,475 | 10,211 | | | | | | | | | | | | | |
| 164 | | | SCE | | | 12,030 | 12,736 | 13,466 | | | | | | | | | | | | | |
| 165 | | | SDG&E | | | 150 | 423 | 581 | | | | | | | | | | | | | |
| 166 | | | Total | | | 20,944 | 22,634 | 24,258 | | | | | | | | | | | | | |
| 167 | | | | | | | | | | | | | | | | | | | | | |
| 168 | 13 | Percent renewable of prior year retail sales (per CPUC method) | | (Section 10)/(Section 11). To calculate the percent renewable per year, divide the current year's renewable procurement into the previous year's retail sales. See Appendix B of CPUC D.04-06-014 for a description of the CPUC's method for calculating RPS compliance. According to CPUC D.02-10-062, the IPT for 2003 is calculated based on 1% of 2001 retail sales for the IOUs. | | | | | | | | | | | | | | | | | |
| 169 | | | PG&E | 8.92% | 9.81% | 11.72% | 12.08% | | | | | | | | | | | | | | |
| 170 | | | SCE | 15.19% | 15.58% | 16.71% | 18.76% | | | | | | | | | | | | | | |
| 171 | | | SDG&E | 0.97% | 0.94% | 3.65% | 4.51% | | | | | | | | | | | | | | |
| 172 | | | Total | 11.04% | 11.62% | 13.25% | 14.36% | | | | | | | | | | | | | | |
| 173 | | | | | | | | | | | | | | | | | | | | | |
| 174 | 14 | Percent renewable of current year retail sales (IOU only) | | (Section 10)/(Section 1). In this section, percent reenwable is calculated by dividing the GWh/Year reported in the IOU's APT compliance reports into the Retail Sales Numbers compiled by the Energy Commission's Demand Analysis Office. | | | | | | | | | | | | | | | | | |
| 175 | | | PG&E | 8.92% | 10.80% | 12.42% | 11.75% | | | | | | | | | | | | | | |
| 176 | | | SCE | 16.62% | 17.04% | 17.68% | 18.08% | | | | | | | | | | | | | | |
| 177 | | | SDG&E | 0.98% | 0.98% | 3.66% | 4.35% | | | | | | | | | | | | | | |
| 178 | | | Total | 11.49% | 12.69% | 13.96% | 13.90% | | | | | | | | | | | | | | |
| 179 | | | | | | | | | | | | | | | | | | | | | |
| 180 | 15 | Annual Renewable Generation Available to California Electricity Customers (GWh/Year) | | For 2001-2003, all of the renewables totals except for small hydro see Energy Commission, Updated August 6, 2004, "California Electrial Energy Generation, 1983 to 2003, Total Production by Resource Type," (J-11 table), http://www.energy.ca.gov/electricity/ELECTRICITY_GEN_1983-2003.XLS, accessed June 28, 2005. Since Small Hydro is not itemized in the Energy Commission's J-11 table, those totals are taken from the Energy Commission's Gross System Power totals which are calculated in order to publish the annual Net System Power reports. The Small Hydro totals are then added to the Renewables totals published in the Energy Commission's J-11 table. The Net System Power reports utilized to extract 2001-2003 small hydro data are the following: "2001 Net System Power Calculation" (No Publication Number Assigned), "2002 Net System Power Calculation" (Publication No. 300-03-002), and "2003 Net System Power Calculation" (Publication No. 300-04-001R). The 2004 totals come from the Energy Commission Report entitled "2004 Net System Power Calculation" (Publication No. CEC-300-2005-004). | | | | | | | | | | | | | | | | | |
| 181 | | | | 27,759 | 28,908 | 28,927 | 29,238 | | | | | | | | | | | | | | |
| 182 | | | | | | | | | | | | | | | | | | | | | |
| 183 | 16 | Total Annual Generation Available to California Electricity Customers (GWh/Year) | | For 2001-2003, these totals are extracted from the Energy Commission's J-11 table, which is annually submitted to the California Department of Finance which could be found at the following URL: http://www.energy.ca.gov/electricity/electricity_generation.html. The 2004 totals come from the Energy Commission Report entitled "2004 Net System Power Calculation" (Publication No. CEC-300-2005-004). | | | | | | | | | | | | | | | | | |
| 184 | | | | 265,059 | 272,509 | 276,700 | 275,447 | | | | | | | | | | | | | | |
| 185 | | | | | | | | | | | | | | | | | | | | | |
| 186 | 17 | Percent renewable of current year generation. (Statewide) | | (Section 15)/(Section 16) | | | | | | | | | | | | | | | | | |
| 187 | | | | 10.47% | 10.61% | 10.45% | 10.61% | | | | | | | | | | | | | | |
| 188 | | | | | | | | | | | | | | | | | | | | | |

Shading with text is explanatory.

## APPENDIX A, TABLE 3

### Form 1.c. Statewide

### California Energy Demand 2006-2016 Staff Forecast

### Retail Sales by Utility (GWh)

| | PG&E Planning Area | | | | | SMUD | SCE Planning Area | | | | | LADWP | SDGE Planning Area | | | BGP | OTHER | DWR | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Bundled Customers | Direct Access Sales | PG&E Service Area Total | Public Utility Sales | Total Planning Area | Service Area | Bundled Customers | Direct Access Sales | SCE Service Area Total | Public Utility Sales | Total Planning Area | | Bundled Customers | Direct Access Sales | Total Planning Area | | | | |
| 1990 | 69,445 | 0 | 69,445 | 13,369 | 82,814 | 8,358 | 70,370 | 0 | 70,370 | 7,901 | 78,271 | 22,244 | 14,460 | 0 | 14,460 | 2,955 | 3,310 | 8,171 | 220,583 |
| 1991 | 69,571 | 0 | 69,571 | 13,214 | 82,785 | 8,349 | 68,996 | 0 | 68,996 | 7,787 | 76,783 | 21,417 | 14,294 | 0 | 14,294 | 2,762 | 3,323 | 4,400 | 214,113 |
| 1992 | 70,671 | 0 | 70,671 | 13,467 | 84,138 | 8,496 | 70,936 | 0 | 70,936 | 7,545 | 78,482 | 22,145 | 15,218 | 0 | 15,218 | 2,934 | 3,513 | 4,088 | 219,014 |
| 1993 | 70,654 | 0 | 70,654 | 13,382 | 84,036 | 8,435 | 69,876 | 0 | 69,876 | 7,654 | 77,529 | 21,498 | 15,134 | 0 | 15,134 | 2,996 | 3,602 | 4,372 | 217,602 |
| 1994 | 70,733 | 0 | 70,733 | 13,350 | 84,084 | 8,418 | 71,117 | 0 | 71,117 | 7,952 | 79,069 | 20,308 | 15,381 | 0 | 15,381 | 3,007 | 3,758 | 4,946 | 218,970 |
| 1995 | 71,797 | 0 | 71,797 | 13,467 | 85,264 | 8,458 | 71,548 | 0 | 71,548 | 7,577 | 79,124 | 20,939 | 15,524 | 0 | 15,524 | 3,089 | 3,819 | 3,562 | 219,779 |
| 1996 | 73,273 | 0 | 73,273 | 13,746 | 87,019 | 8,805 | 73,766 | 0 | 73,766 | 8,029 | 81,795 | 21,228 | 16,046 | 0 | 16,046 | 3,160 | 3,989 | 5,146 | 227,187 |
| 1997 | 76,241 | 0 | 76,241 | 14,327 | 90,568 | 9,006 | 76,057 | 0 | 76,057 | 8,300 | 84,356 | 21,605 | 16,698 | 0 | 16,698 | 3,243 | 3,980 | 5,504 | 234,960 |
| 1998 | 70,121 | 5,559 | 75,680 | 14,364 | 90,044 | 9,123 | 76,613 | 6,161 | 82,774 | 8,215 | 90,988 | 21,412 | 13,609 | 3,641 | 17,249 | 3,307 | 3,919 | 3,421 | 239,463 |
| 1999 | 71,251 | 7,958 | 79,209 | 14,564 | 93,773 | 9,326 | 74,350 | 8,819 | 83,169 | 8,588 | 91,756 | 21,434 | 12,719 | 5,211 | 17,931 | 3,249 | 4,017 | 5,490 | 246,976 |
| 2000 | 73,387 | 8,396 | 81,783 | 15,039 | 96,822 | 9,491 | 76,468 | 9,304 | 85,772 | 6,770 | 92,543 | 22,146 | 13,430 | 5,498 | 18,928 | 3,331 | 4,236 | 5,490 | 252,987 |
| 2001 | 75,319 | 2,952 | 78,271 | 14,013 | 92,283 | 9,070 | 68,387 | 10,103 | 78,490 | 8,757 | 87,246 | 21,404 | 14,919 | 2,444 | 17,363 | 3,268 | 4,399 | 6,349 | 241,384 |
| 2002 | 68,445 | 9,820 | 78,265 | 15,358 | 93,623 | 9,383 | 68,431 | 11,228 | 79,659 | 8,876 | 88,536 | 22,290 | 14,364 | 3,405 | 17,769 | 3,189 | 4,556 | 8,181 | 247,527 |
| 2003 | 71,084 | 9,127 | 80,211 | 15,427 | 95,638 | 9,924 | 70,677 | 11,571 | 82,248 | 7,797 | 90,045 | 23,044 | 14,930 | 3,467 | 18,398 | 3,283 | 4,494 | 8,865 | 253,690 |
| 2004 | 73,137 | 9,283 | 82,420 | 15,727 | 98,146 | 10,156 | 73,254 | 11,731 | 84,985 | 8,304 | 93,288 | 23,472 | 15,585 | 3,553 | 19,137 | 3,308 | 4,582 | 8,865 | 260,955 |
| 2005 | 73,671 | 9,357 | 83,027 | 15,894 | 98,922 | 10,345 | 74,224 | 11,797 | 86,021 | 8,413 | 94,433 | 23,761 | 15,846 | 3,580 | 19,426 | 3,303 | 4,642 | 8,865 | 263,697 |
| 2006 | 74,891 | 9,421 | 84,311 | 16,143 | 100,454 | 10,562 | 75,116 | 11,846 | 86,961 | 8,521 | 95,482 | 23,860 | 16,123 | 3,611 | 19,734 | 3,287 | 4,710 | 8,865 | 266,954 |
| 2007 | 76,030 | 9,478 | 85,508 | 16,366 | 101,874 | 10,785 | 76,196 | 11,905 | 88,101 | 8,644 | 96,744 | 23,945 | 16,397 | 3,637 | 20,033 | 3,271 | 4,776 | 8,865 | 270,295 |
| 2008 | 77,075 | 9,568 | 86,643 | 16,536 | 103,180 | 11,035 | 77,342 | 11,967 | 89,309 | 8,779 | 98,088 | 24,055 | 16,732 | 3,673 | 20,405 | 3,257 | 4,833 | 8,865 | 273,718 |
| 2009 | 78,191 | 9,643 | 87,834 | 16,738 | 104,571 | 11,291 | 78,565 | 12,039 | 90,604 | 8,923 | 99,527 | 24,161 | 17,026 | 3,702 | 20,728 | 3,250 | 4,892 | 8,865 | 277,286 |
| 2010 | 79,397 | 9,716 | 89,113 | 16,961 | 106,074 | 11,545 | 79,669 | 12,097 | 91,767 | 9,054 | 100,821 | 24,263 | 17,312 | 3,731 | 21,042 | 3,235 | 4,955 | 8,865 | 280,802 |
| 2011 | 80,766 | 9,783 | 90,549 | 17,195 | 107,744 | 11,828 | 80,727 | 12,154 | 92,881 | 9,175 | 102,056 | 24,341 | 17,595 | 3,758 | 21,353 | 3,219 | 5,021 | 8,865 | 284,427 |
| 2012 | 81,920 | 9,855 | 91,774 | 17,370 | 109,145 | 12,122 | 81,896 | 12,222 | 94,118 | 9,310 | 103,428 | 24,428 | 17,882 | 3,786 | 21,668 | 3,204 | 5,078 | 8,865 | 287,938 |
| 2013 | 83,248 | 9,927 | 93,175 | 17,595 | 110,769 | 12,420 | 82,958 | 12,281 | 95,238 | 9,431 | 104,670 | 24,511 | 18,167 | 3,813 | 21,981 | 3,189 | 5,143 | 8,865 | 291,548 |
| 2014 | 84,318 | 9,997 | 94,315 | 17,752 | 112,067 | 12,723 | 84,130 | 12,351 | 96,481 | 9,563 | 106,044 | 24,598 | 18,450 | 3,840 | 22,290 | 3,175 | 5,199 | 8,865 | 294,961 |
| 2015 | 85,422 | 10,053 | 95,475 | 17,907 | 113,382 | 13,001 | 85,281 | 12,413 | 97,694 | 9,688 | 107,382 | 24,669 | 18,732 | 3,864 | 22,596 | 3,161 | 5,262 | 8,865 | 298,317 |
| 2016 | 86,467 | 10,104 | 96,571 | 18,043 | 114,614 | 13,275 | 86,254 | 12,456 | 98,710 | 9,791 | 108,500 | 24,728 | 19,007 | 3,887 | 22,893 | 3,146 | 5,326 | 8,865 | 301,348 |
| **Annual Growth Rates (%)** | | | | | | | | | | | | | | | | | | | |
| 1990-2000 | 0.6 | | 1.2 | | 1.6 | 1.3 | 0.8 | | 2.0 | -1.5 | 1.7 | 0.0 | -0.7 | #DIV/0! | 2.7 | 1.2 | 2.5 | -3.9 | 1.4 |
| 2000-2003 | -1.1 | | 0.9 | 2.8 | -0.4 | 1.5 | -2.6 | 7.5 | -1.4 | 4.8 | -0.9 | 1.3 | 3.6 | -14.2 | -0.9 | -0.5 | 2.0 | 17.3 | 0.1 |
| 2003-2008 | 1.6 | | 1.4 | 0.9 | 1.5 | 2.1 | 1.8 | 0.7 | 1.7 | 2.4 | 1.7 | 0.9 | 2.3 | 1.2 | 2.1 | -0.2 | 1.5 | 0.0 | 1.5 |
| 2008-2016 | 1.4 | | 1.1 | 0.7 | 1.3 | 2.3 | 1.4 | 0.5 | 1.3 | 1.4 | 1.3 | 0.3 | 1.6 | 0.7 | 1.4 | -0.4 | 1.2 | 0.0 | 1.2 |
| 2003-2016 | 1.5 | | 1.2 | 0.8 | 1.4 | 2.3 | 1.5 | 0.6 | 1.4 | 1.8 | 1.4 | 0.5 | 1.9 | 0.9 | 1.7 | -0.3 | 1.3 | 0.0 | 1.3 |

May 25, 2005

Retail Sales = Total Electricity Consumption - Self generation; it does not include transmission or distribution losses.

# APPENDIX B. SCOPE AND STATUS OF THE SOLAR ROOFS INITIATIVE, PV PERFORMANCE DATA, AND AVAILABILITY OF PV MODULES

The Energy Commission and the CPUC are working collaboratively to develop the Solar Roofs Initiative through R.04-03-017. A summary of the progress achieved as of June 2005 is reported in this appendix, as well as a review of the availability of PV performance data and PV modules.

## *Solar Roofs Initiative*

In January 2004, Governor Schwarzenegger announced that he was going to encourage builders to build homes using partial solar power.[1] On August 20, 2004, the Governor announced a plan to encourage installation of solar panel systems on one million new homes.[2] On October 20, 2004, Terry Taminen, Secretary of the California Environmental Protection Agency, was the keynote speaker at the evening banquet of the Solar Power 2004 conference, where he called on the industry to help bring the idea of a million solar roofs in California into reality.[3]

In November 2004, the Energy Commission explored the topic in its *2004 Integrated Energy Policy Report* proceeding, and recommended the following list of principles for further development of the initiative:

- Establishing a comprehensive solar program that includes new and existing homes and businesses.
- Leveraging energy efficiency improvements for new and existing buildings.
- Addressing peak demand challenges by linking PV installations with price responsive tariffs and advanced metering.
- Targeting PV deployment to climate zones with high peak demands and where they can provide distribution system benefits.
- Providing long-term declining incentives to promote a sustainable, competitive PV market.
- Exploring a business role in PV deployment for utilities and developing a professional inspection capability.

On November 29, 2004, CPUC President Peevey issued an *Assigned Commissioner's Ruling Soliciting Comments for Proposed Solar Roofs Initiative* (Solar ACR).[4] In the Solar ACR, President Peevey noted that the CPUC may use funds from the CPUC's Self-Generation Incentive Program and the Energy Commission may use funds from the Emerging Renewables Program to support the Governor's Solar Roofs Initiative, although the focus of the ACR was to solicit comments on ways to use the existing CPUC Self-Generation Incentive Program to support the Governor's policy objectives. The Solar ACR listed the Governor's objectives as:

> "the installation of one million solar roofs by 2017 on new and existing homes and businesses; the inclusion of solar thermal systems, to offset the increasing demand for natural gas; the inclusion of advanced metering in solar applications; and the creation of a funding source which can provide rebates over ten years through a declining incentive schedule."
> (Solar ACR, p. 1).

Specifically, the Solar ACR asked for comments on questions related to the SGIP funding level, qualifying solar technologies to accommodate customer needs, time-variant rate structure and metering, incentive funding continuity, and future program administration.

The CPUC issued a second ACR on March 7, 2005 directing Energy Commission and CPUC staff to prepare a collaborative staff report that incorporated the comments filed in response to the November ACR.[5] The collaborative staff solar report was issued in June 2005 and proposes the following actions:

- Consolidate residential and commercial solar incentives into one program, a "one-stop-solar-shop," by June 2006.
- Include photovoltaics, solar-thermal electric, and solar hot water heaters as eligible technologies, installed to offset customer load on site.
- Initially continue a size limit on incentives for electricity-generating installations of up to 1 MW.
- Initially continue but consolidate day-to-day administration of the program through Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), and the San Diego Regional Energy Office (SDREO).
- Fund the program through 2016 via gas and electric distribution rates. Tariff and metering requirements will be coordinated with the CPUC's demand response and distributed generation proceedings.
- Encourage publicly owned utilities to develop a similar program for non-IOU customers and to coordinate their efforts with our proposed program to create a statewide program, as much as possible.
- Create an incentive structure that promotes high energy efficient buildings and that supports the installation of solar in affordable housing applications.

Comments on the joint staff report were due on July 14, 2005.

### *Availability of Photovoltaic System Performance Data*

Most of the 14,000 grid-connected DG PV systems in California do not provide publicly available data regarding the generation of energy. Table B-1 summarizes the characteristics of data that are currently collected regarding energy generated from installed DG PV systems in California.

## Table B-1. DG PV Performance Data Currently Collected in California

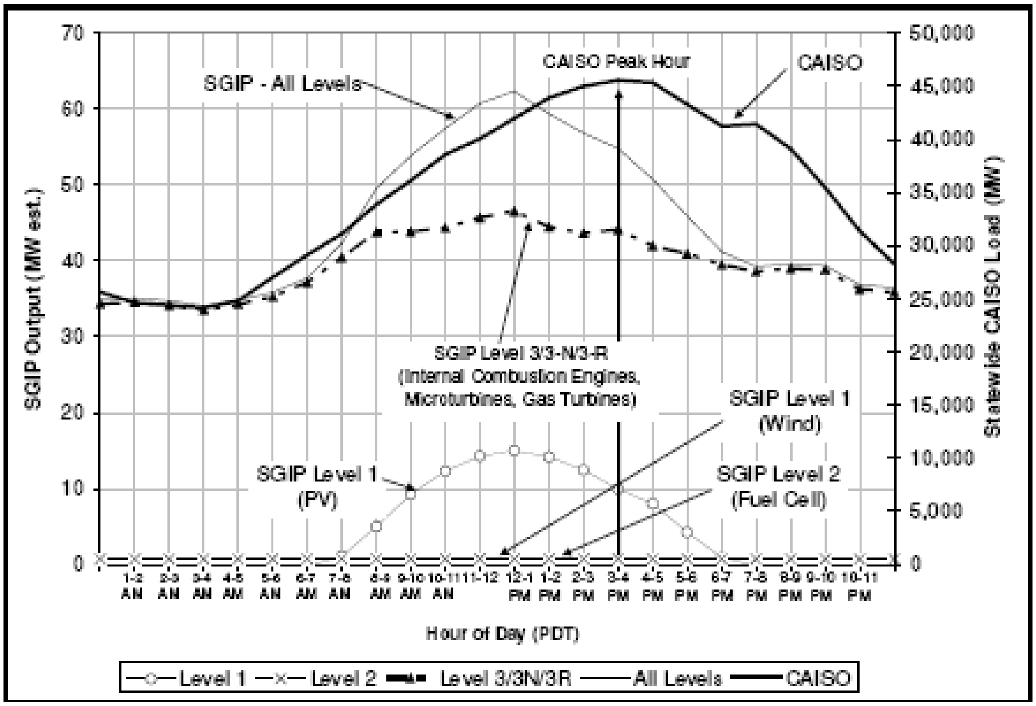
| Organization | Type of Data | Number of Sites | System Size (kW) | Orientation info? | Years of Data |
|---|---|---|---|---|---|
| RWE Schott | 15-min | 35 | 1-500 | some | 1995-2004 |
| CEC ERP Study | 15-min | 19 | 1-12 | yes | 2000-2002 |
| Selfgen | 15-min | 100+ | 30-1000 | some | 2002-2004 |
| Fat Spaniel | 15-min | 100+ | 1-1000 | some-schools in particular | 2002-2004 |
| PowerLight | 15-min | 35 | 10-1000 | yes | 1998-2004 |
| SMUD | monthly energy | 1000+ | 1-200 | some | 1995-2004 |
| PIER-Commonwealth | 15-min | 15 | 2-20 | yes | 2004-2005 |

Source: KEMA-XENERGY, Inc. June 2005

A research contract is in place through the Energy Commission's Public Interest Energy Research program to obtain SMUD data and analysis. In addition, the Renewable Energy Program is exploring possibilities for obtaining other data sets for analysis.

To date, the most comprehensive analysis of grid-connected DG PV in California is the *CPUC Self-Generation Incentive Program Fourth-Year Impact Report*, prepared by Itron, Inc. for Southern California Edison and the Self-Generation Incentive Program Working Group, and filed under CPUC Rulemakings 04-03-017 and 98-07-037. The report contained performance information on 235 DG PV systems that had received SGIP funding, using metered data for about 100 systems and estimates for the remainder. The data were compared to the 2004 CA ISO peak coincident demand, which occurred on September 8 from 3:00 to 4:00 pm. The Itron report states that energy production from the PV systems peaked at 1 pm, before the hour when their contribution would be most valuable.[6]

## Figure B-1. CA ISO 2004 Peak Day Loads and Estimated Total Self-Generation Incentive Program Generation



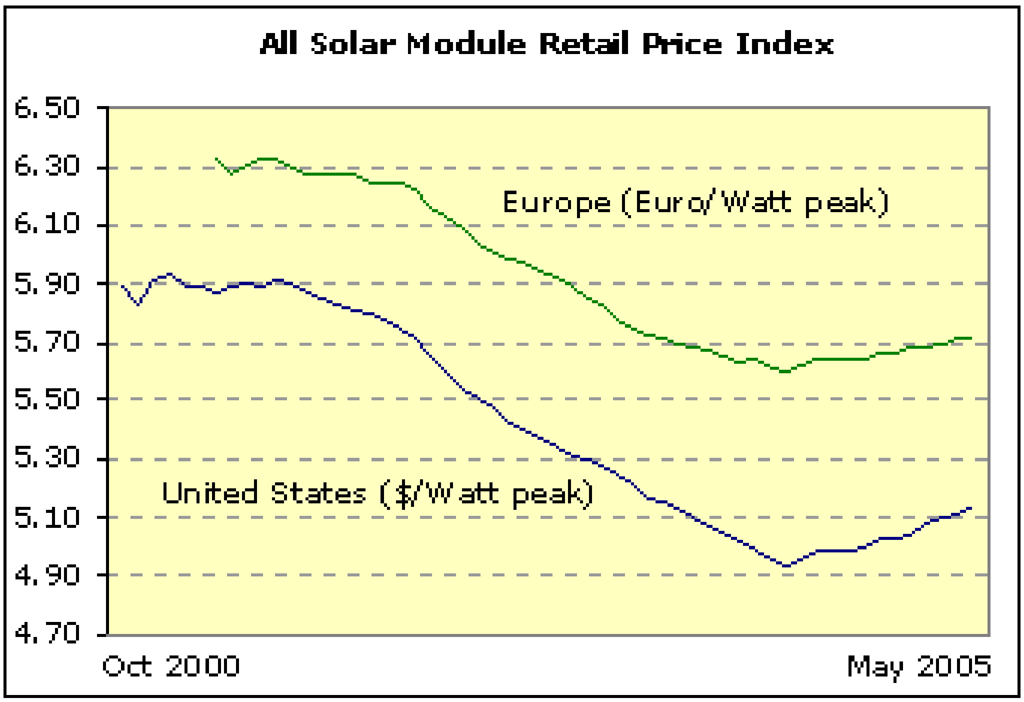

Source: Itron, Inc. April 15, 2005, *CPUC Self-Generation Incentive Program Fourth-Year Impact Report,* prepared for Southern California Edison and the Self-Generation Incentive Program Working Group, and filed under CPUC Rulemakings 04-03-017 and 98-07-037, Figure 10-3, page 10-4.

### *Availability of Photovoltaic Panels*

Long term trends in PV module prices show a 5 percent to 7 percent decline in retail prices of PV modules; however, prices have been increasing recently. Figure B-2 shows retail prices for PV modules from October 2000. Since May 2004 the downward price trend has reversed and through May 2005, retail prices in the United States have increased about 20 cents per Watt.

In California, price trends appear to be influenced by changes in rebate policy as well as availability of panels. Figure B-3 shows an apparent correlation between declining rebate levels and declining median system price levels ($/Watt PTC) by quarter.[7] The top graph of Figure B-3 shows median eligible system prices versus incentive levels for completed PV systems approved for rebates from the Emerging Renewables Program from June 1998 through May 2005. The blue line shows the average price for purchase of a single module ($/Watt Peak) in the United States from October 2000 through June 2005, according to a survey conducted by SolarBuzz. Because retailers usually purchase modules in large orders for a discounted price, the price data should be viewed as indicative of trends rather than actual prices paid for the PV modules installed with support from the ERP or SGIP. To explore whether the trend was consistent across size categories, staff disaggregated the data into three size categories (0 kW-10 kW, 10 kW-20 kW, and 20 kW – 30 kW) and calculated the medians for each quarter. The disaggregated data also indicate declining median system prices for each size category.

## Figure B-2. PV Module Prices in Europe and the United States

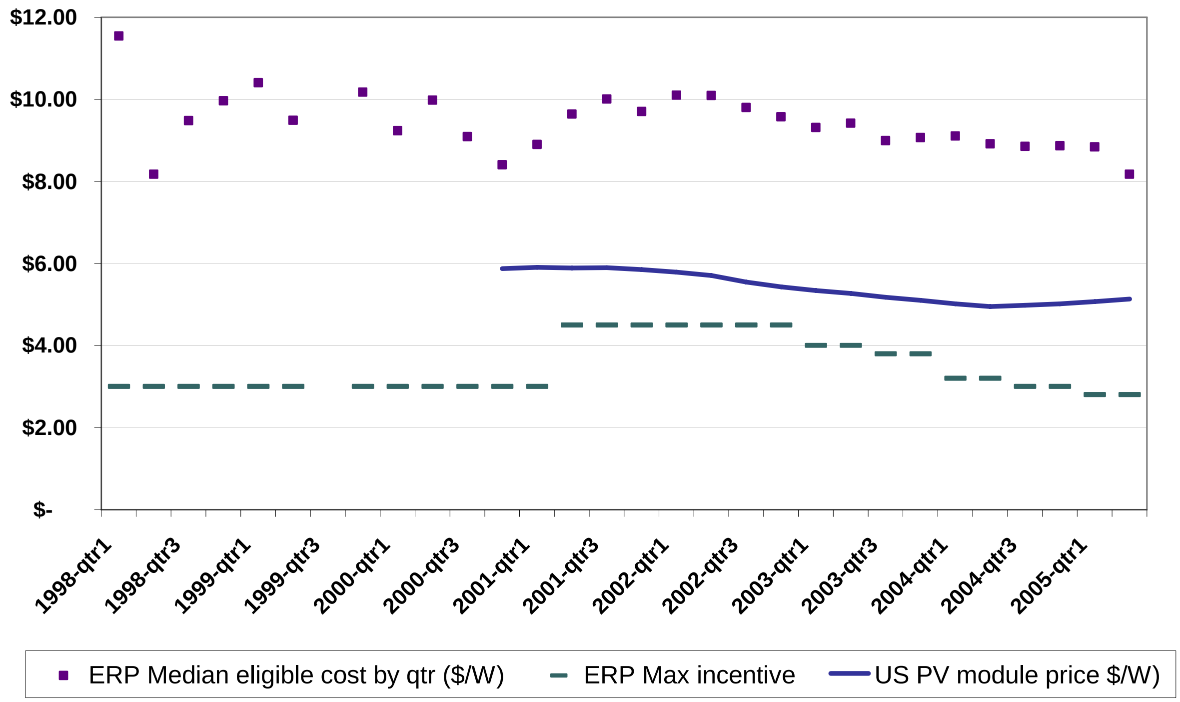


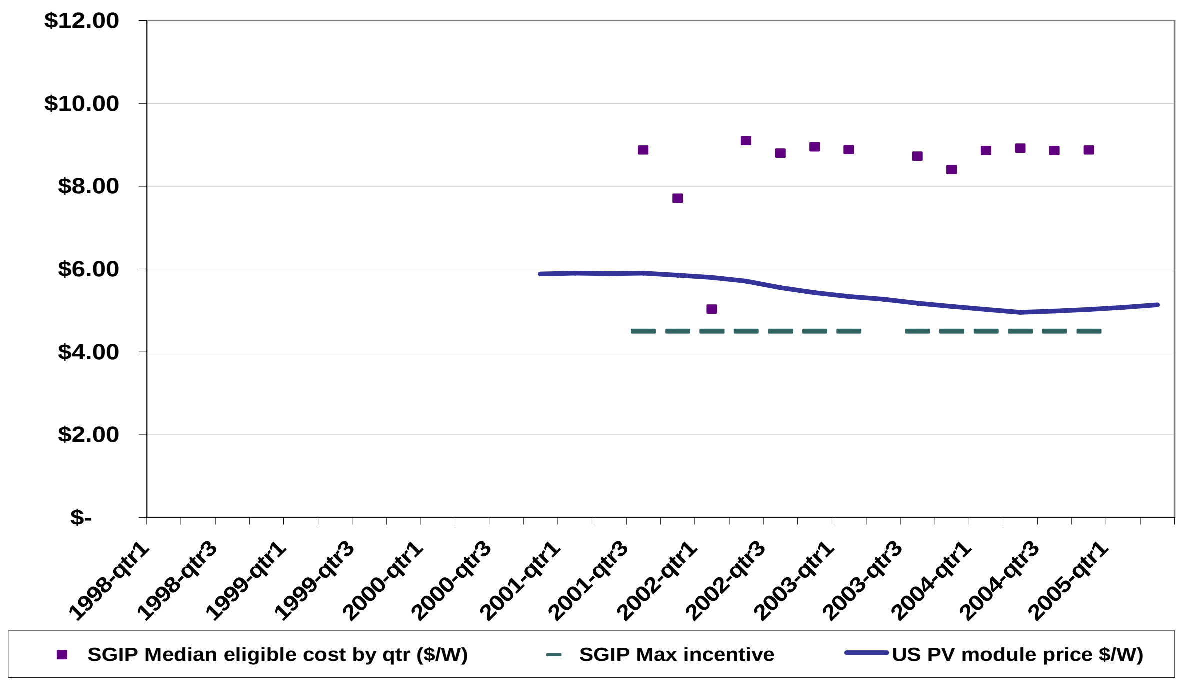

Source:  Solarbuzz, Inc., [http://www.solarbuzz.com/], May 2005.

The bottom graph shows the same information for completed PV systems approved for rebates through the Self-Generation Incentive Program from September 2001 to October 2004. The median eligible system prices in the ERP program tended to rise and fall over time, apparently correlated with the incentive level. In contrast, the median system prices in the SGIP program tended to remain constant, apparently correlated with the constant incentive level, except for a number of projects built in first quarter of 2002 discussed below. Breaking the data into 30 kW – 200 kW and 200 kW – 1 MW shows the same trend.

The SGIP median eligible system price data for the first quarter of 2002 stands out from the other SGIP data points. This reflects the unusually low prices of 12 of the 22 PV systems approved for SGIP rebates at that time:  the average system price for these 12 systems was less than $5 per watt and the sizes ranged from 30 kW to about 400 kW. Furthermore, because the purchaser was a public entity, it was not eligible for state or federal tax credits and depreciation available to commercial

## Figure B-3. Rebate Levels and PV System Prices in California




Source: Emerging Renewables Program Database, Self-Generation Incentive Program, and San Diego Regional Energy Office entities, which can amount to about 50 percent of net system costs. If the low price for these systems could be emulated more broadly across California, the PV market would likely be self-sustaining without the need for further incentive programs. For further information on the California fairground PV systems, see http://www.californiasolarcenter.org/pdfs/forum/2003.11.20-SolarForum_Baker-CalFairs.pdf.

Table B-2 shows changes in median prices from 2001 to 2004 by size of system. The jump between the cost for systems in the ERP program relative to the SGIP program indicates the impact of rebate levels in California on total system cost. For most of this period, the SGIP offered a rebate of $4.50 per watt or 50 percent of system costs, dropping to $3.50 per watt or 50% of system costs in December 2004. The ERP rebate level was $3.00 per watt from the beginning of the program through May 16, 2001 for systems under 10 kW. By 2001, the rebate for all systems was $4.50 per watt or 50 percent of system costs. This rebate level continued through 2002. The rebate was $4.00 per watt in the first half of 2003, $3.80 in the second half of 2003, $3.20 in the first half of 2004, and $3.00 in the second half of 2004.

## Table B-2. PV System Prices for Systems for Completed and with Active Reservations 2001 to 2004

| System Size | Program | Number | Median Price |
|---|---|---|---|
| 0 to 5 kW | ERP | 13,682 | $9.20 |
| 5 to 10 kW | ERP | 3,391 | $8.61 |
| 10 to 15 kW | ERP | 524 | $8.42 |
| 15 to 20 kW | ERP | 176 | $8.26 |
| 20 to 25 kW | ERP | 105 | $8.12 |
| 25 to 30 kW | ERP | 170 | $8.04 |
| 30 to 35 kW | SGIP | 126 | $9.00 |
| 35 to 40 kW | SGIP | 34 | $8.99 |
| 40 to 45 kW | SGIP | 28 | $9.00 |
| 45 to 50 kW | SGIP | 41 | $8.63 |
| 50 to 100 kW | SGIP | 143 | $8.98 |
| 100 to 200 kW | SGIP | 119 | $8.80 |
| 200 to 500 kW | SGIP | 97 | $8.06 |
| 500 to 1000 kW | SGIP | 130 | $7.63 |

At the 2005 incentive level for Level 1 technologies, only the first 10 percent of applications received rebates. All but a few percent of the Level 1 funding has gone to PV systems.[8] To make more funds available, the CPUC issued a decision recommending that program administrators immediately borrow funds from 2006 and 2007.[9] In effect, this would commit another $230 million in rebates, representing an additional 65 MW for photovoltaic system in less than 1 month. This unexpected increase in demand would represent about 10 percent of world module production.

Many manufacturers were already sold out of their 2005 factory production at the time this CPUC decision was issued.

Manufacturing capacity expansions to meet global demand for PV modules is increasing demand for raw materials, which are going up in price. Some manufacturers are encountering difficulty securing raw material (solar grade silicon) to expand PV module manufacturing capacity.[10] The Photon International survey (October 2004) of silicon prices showed solar grade silicon prices in September 2004 were $35 per kg without long term commitments and 10 percent to 20 percent lower with long-term commitments.[11] The limited availability of solar-grade silicon may cause a 2 to 3 percent annual increase in PV system prices for the next two years. Reportedly, PV manufacturers are looking to further increase their manufacturing capacity, but have been unable to secure additional solar grade silicon without a 10-year commitment. To make such a commitment to silicon suppliers, PV manufacturers need to see a long-term market growth strategy from California.[12]

# Appendix B Endnotes

[1] California Office of the Governor, January 6, 2004, "Governor Schwarzenegger's State of the State Address," [http://www.governor.ca.gov/state/govsite/gov_homepage.jsp], accessed April 28, 2005.]
[2] California Office of the Governor, August 20, 2004, "Governor Schwarzenegger Calls for One Million Solar Energy Systems in California Homes," [http://www.governor.ca.gov]], accessed May 5, 2005.
[3] San Francisco Public Utilities Commission, October 22, 2004, "Successful S.F. Solar Power Conference Is Nation's Largest Ever," [http://sfwater.org/detail.cfm/MC_ID/7/MSC_ID/64/MTO_ID/NULL/C_ID/2179]], accessed May 5, 2005.
[4] California Public Utilities Commission, November 29, 2004, Assigned Commissioner's Ruling Soliciting Comments for Proposed Solar Roofs Initiative, [http://www.cpuc.ca.gov/word_pdf/RULINGS/41746.doc]], accessed April 11, 2005.
[5] CPUC, March 7, 2005, "Assigned Commissioner's Ruling Addressing Funding Shortfalls and Setting Hearings on Cost-Benefit Methodologies," in CPUC Rulemaking 04-03-017, [http://www.cpuc.ca.gov/word_pdf/RULINGS/44300.doc], accessed July 12, 2005.
[6] Itron, Inc., April 15, 2005, *CPUC Self-Generation Incentive Program Fourth-Year Impact Report*, prepared for Southern California Edison and the Self-Generation Incentive Program Working Group, and filed under CPUC Rulemakings 04-03-017 and 98-07-037, [http://www.cpuc.ca.gov/static/industry/electric/distributed+generation/itron+sgip2004+impacts+final+report.pdf]], accessed May 13, 2005 (1.9 MB), pp. 8-2, 10-1, 10-4.
[7] The staff excluded systems prices that were below $2/Watt PTC or above $15/Watt PTC.
[8] Itron, Inc., April 15, 2005, *CPUC Self-Generation Incentive Program Fourth-Year Impact Report*, prepared for Southern California Edison and the Self-Generation Incentive Program Working Group, and filed under CPUC Rulemakings 04-03-017 and 98-07-037, [http://www.cpuc.ca.gov/static/industry/electric/distributed+generation/itron+sgip2004+impacts+final+report.pdf]], accessed May 13, 2005 (1.9 MB), page 10-2.
[9] CPUC, March 7, 2005, Assigned Commissioner's Ruling Addressing Funding Shortfalls and Setting Hearings On Cost-Benefit Methodologies, Rulemaking 04-03-017, [http://www.cpuc.ca.gov/word_pdf/RULINGS/44300.pdf]], accessed May 13, 2005.
[10] Georgina Prodhan, April 13, 2005, "Solar Firms Say Silicon Shortage Will Stall Growth," Reuters, http://today.reuters.co.uk/news/default.aspx
[11] See Photon International: The Photovoltaic Magazine, [http://www.photon-magazine.com/]. The importance of long-term contracts for solar grade silicone was also raised in the following article: William P. Hirshman, Michael Schmela, March 2005, "REC's plans for a 75-percent stake in silicon producer ASiMI won't help PV this year," *PHOTON International*, [http://www.photon-magazine.com/news/news_05-03_am_feat_ASIMI.htm]], accessed May 13, 2005.
[12] Personal communication, Tony Brasil, Emerging Renewables Program manager, California Energy Commission, June 10, 2005.

# APPENDIX C: ASSESSMENT OF THE COMBINED HEAT AND POWER MARKET AND POLICY OPTIONS FOR INCREASED PENETRATION

In April 2005, the Energy Commission's Public Interest Energy Research Distributed Energy Integration Research Program released the *Assessment of California [Combined Heat and Power] CHP Market and Policy Options For Increased Penetration* (*CHP Assessment*),[221] prepared by the Electric Power Research Institute (EPRI) and a project team comprised of Energy and Environmental Analysis (EEA), EPRI Solutions Primen, and Energy and Environmental Economics (E3).

The *CHP Assessment* evaluates the penetration of CHP in California between today and 2020 for a base case and alternative scenarios. The base case scenario uses current regulatory structures, forecasted electricity and natural gas prices, existing incentive programs, anticipated technology cost and performance characteristics, and current utility treatment of CHP. The alternative scenarios examine the impact of different policies on CHP penetration over the next 15 years. These policies included changing incentive programs for end use adopters of CHP and for utilities, using special or modified natural gas and electric tariffs for CHP, streamlining CHP project permitting and interconnection, special CHP marketing and branding, providing special state tax incentives, imposing CHP portfolio standards, and others.[222]

In addition, the CHP Assessment conducted market research to ascertain what drives end-use customers' decisions whether or not to install CHP projects, and also considered research and development priorities to address barriers to CHP penetration in California.

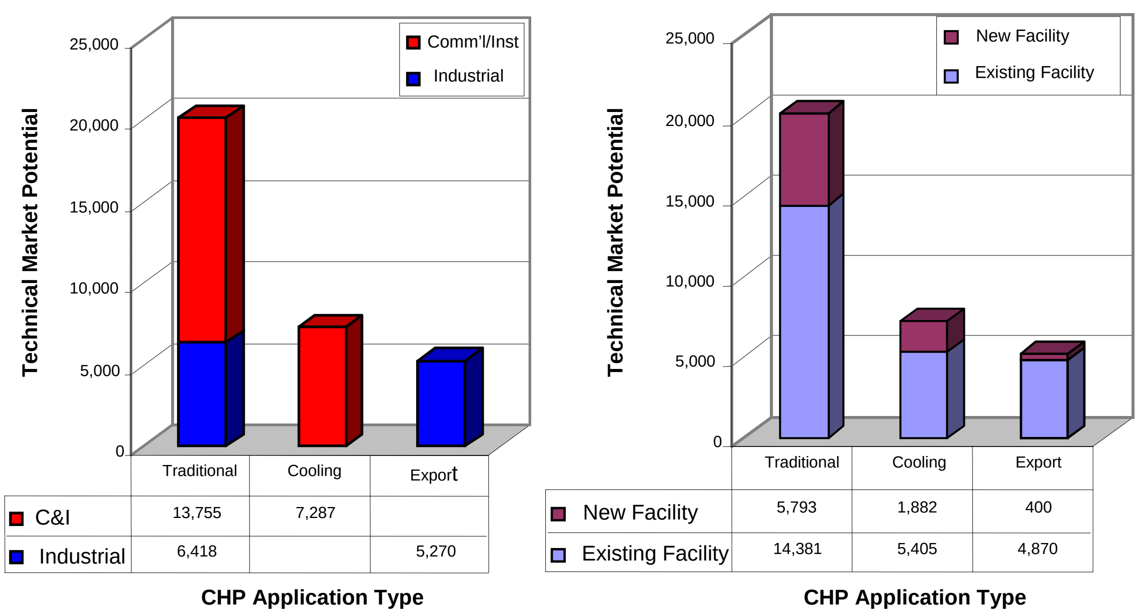
## Existing California CHP Market and Base Case Scenario Results

The assessment found that there are already 9,130 MW of active CHP projects in California at 776 sites. Nearly 90 percent of this capacity is comprised of large DG systems with site capacities over 20 MW. Furthermore, the base case analysis determined that the largest share of existing CHP capacity is located in oil fields to provide steam for enhanced oil recovery (EOR).

After identifying existing CHP in California, the analysis team then evaluated the remaining CHP technical and economic potential that could be developed over the next 15 years in the base case scenario. The team examined three potential CHP markets. First they looked at remaining technical potential and unserved thermal load at existing facilities.[223] Next, they considered combined cooling, heating, and power (CCHP) technologies for additional and incremental applications.[224] Finally, they assessed potential additional capacity if large CHP systems could be sized to meet all onsite thermal loads, with the excess electricity exported to wholesale electricity markets.[225]

Figure C-1 shows the total remaining technical potential in California for each of the different markets. The traditional CHP market has a total potential of 20,174 MW, roughly two-thirds of which is in the commercial/institutional sector. Within this sector, the greatest potential is in educational facilities, offices buildings, health care facilities, and hotels. The CCHP market has a technical potential of 5,405 MW, which is comprised of 1,846 MW additional capacity potential and 3,559 MW incremental potential. The export market technical potential is 5,270 MW from a handful of very large refineries, chemical plants, and food processors.

## Figure C-1. Total Remaining Technical Market Potential in California




Source: Presentation by Ken Darrow, EEA, IEPR CHP Workshop, April 28, 2005, p. 8.

The technical potential in these three different markets adds up to roughly 30,000 MW, and represents the universe of CHP potential that could be developed under specific market conditions. However, this technical potential does not represent real economic potential after considering regulatory, natural gas and electricity price forecasts, and other drivers. Once these drivers were considered, the analysis team came up with an estimated economic market penetration of just under 2,000 MW. Of this, about 600 MW is for CHCP systems, which save an additional 70-90 MW of peak electric capacity by displacing electrically driven air conditioning.

Figure C-2 shows the economic market penetration by CHP market type. Market potential is evenly split between Northern and Southern California, as shown in Table C-1, and opportunities for systems larger than five MW is somewhat limited because of the already-high saturation in this sector. Market penetration in the Los Angeles Department of Water and Power service territory is much lower than in other regions due to a combination of slightly lower rates and rates that reduce the portion of a customer's bill that can be saved by self generation.

## Figure C-2. Economic Market Potential of Base Case Over Forecast Period

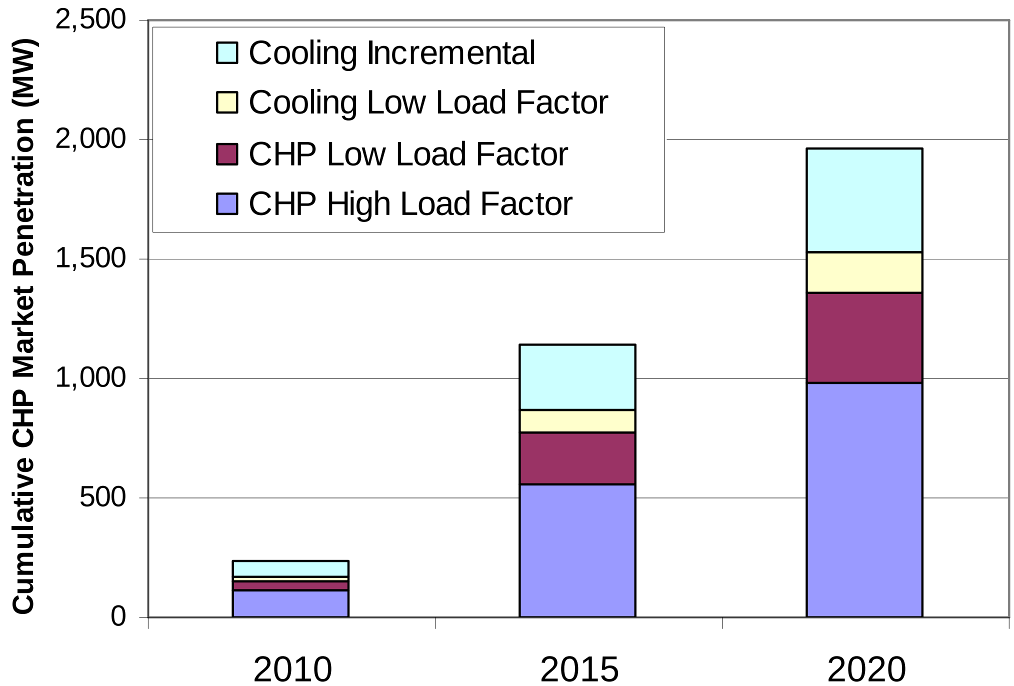


**Table C-1. Base Case: 2020 Cumulative Market Penetration - All Markets by Region and Utility (MW)**

| Region | Utility | SYSTEM SIZE | | | | | |
|---|---|---|---|---|---|---|---|
| | | 50-500 kW | 500-1,000 kW | 1-5 MW | 5-20 MW | >20 MW | All Sizes |
| North | PG&E | 167 | 239 | 286 | 72 | 74 | 839 |
| | SMUD | 8 | 14 | 18 | 5 | - | 45 |
| | Other | 2 | 3 | 3 | - | - | 8 |
| North Total | | 178 | 256 | 306 | 77 | 74 | 891 |
| South | LADWP | 7 | 5 | 14 | 5 | 15 | 47 |
| | SCE | 155 | 181 | 318 | 60 | 133 | 847 |
| | SDG&E | 28 | 39 | 63 | 6 | 18 | 155 |
| | Other | 6 | 6 | 11 | 4 | - | 27 |
| South Total | | 196 | 231 | 406 | 76 | 167 | 1,075 |
| **Statewide Total** | | **373** | **487** | **713** | **153** | **241** | **1,966** |

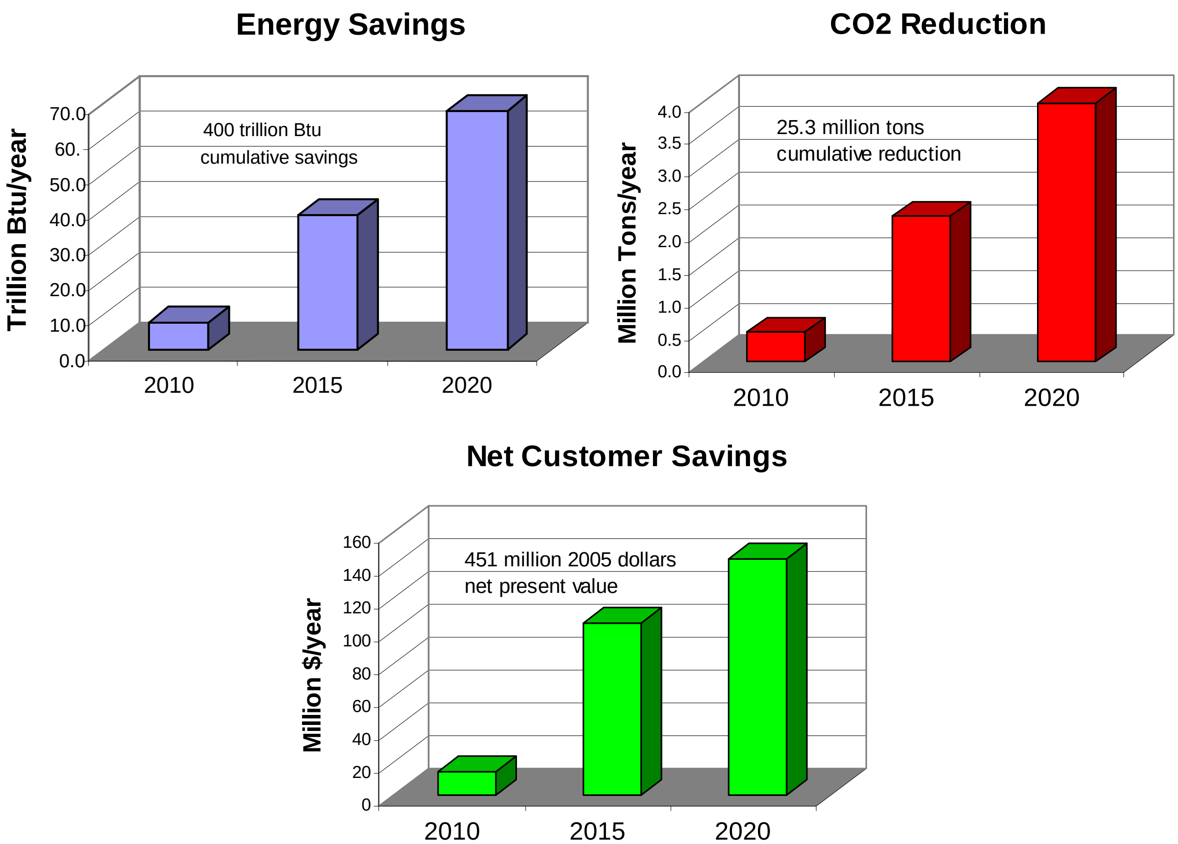
As shown in Figure C-3, the benefits under the base case scenario over the 15-year forecast period include energy savings of 400 trillion Btu, reduced facility operating costs of nearly $1 billion, and reduced carbon dioxide emissions of 23 million tons.

## *Results of Alternative Policy Scenarios*

The CHP Assessment developed eight alternative scenarios to consider various policy options and their respective effects on CHP adoption in California. Policy options included changing CHP incentive programs for end-users and for utilities, establishing special or modified natural gas and electric tariffs for CHP, streamlining CHP project permitting and interconnection, developing special CHP marketing and branding approaches, imposing special state tax incentives, developing CHP portfolio standards, and others. The assessment team then modeled the MW implications of these policy scenarios in 2020.

Table C-2 shows the respective MW penetrations for each scenario, along with a brief description of each scenario. Detailed descriptions of each scenario, their key assumptions and results can be found in Appendix G of the *CHP Assessment*.

## Figure C-3. Base Case Benefits Over Forecast Period




Source: Presentation by Ken Darrow, EEA, IEPR CHP Workshop, April 28.

The most significant effect on CHP market penetration is gained by providing access to wholesale markets for sale of excess electricity by CHP systems whose thermal loads are larger than their electrical loads. Scenarios that include this market change are the Moderate and Aggressive Market Access scenarios, and the High Deployment Case scenario. These scenarios result in penetration levels higher than the Base Case by 122%, 173% and 273% respectively.

In addition to identifying potential MW under these different policy scenarios, the assessment also evaluated the costs and benefits of the policy scenarios to the CHP owner/user, electric utilities and their customers, and society as a whole. The evaluation indicates that to be successful, policy options should first meet stakeholder goals. These include efficient use of California’s energy resources, providing a positive impact on the environment, and minimizing the impact on utility rates and cost-shifting. In addition, policy options should promote the best projects that meet stakeholders’ goals, be relatively easy to implement, require low incentive payments, and have a realistic exit strategy.

## Table C-2. Results of Alternative Forecast Scenarios

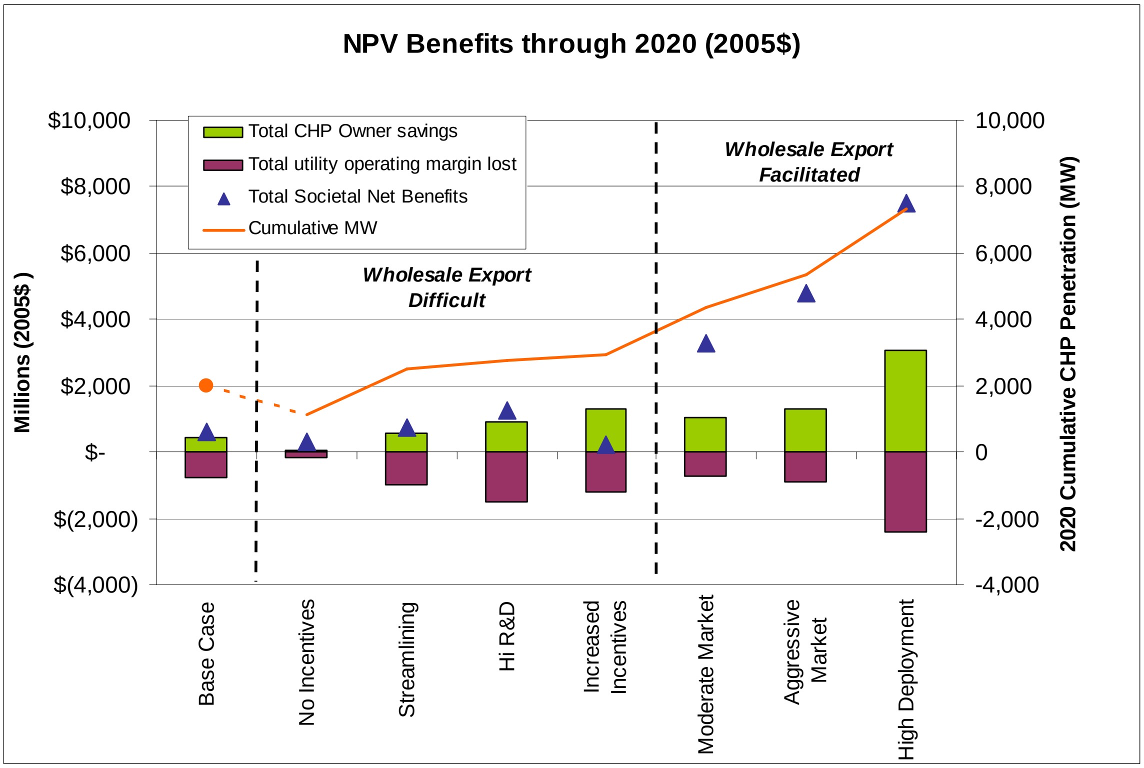
| Scenario | Onsite CHP (MW) | Export CHP (MW) | Total Market Penetration (MW) | Description |
|---|---|---|---|---|
| Base Case | 1,966 | 0 | 1,966 | Expected future conditions with existing incentives |
| No Incentives | 1,141 | 0 | 1,141 | Remove SGIP, CHP incentive gas price, and CHP CRS exemptions |
| Moderate Market Access | 1,966 | 2,410 | 4,376 | Facilitate wholesale generation export |
| Aggressive Market Access | 2,479 | 2,869 | 5,348 | $40/kW year T&D capacity payments for projects <20 MW, global warming incentive, and wholesale export |
| Increased (Alternative) Incentives | 2,942 | 0 | 2,942 | Extended SGIP incentives on first 5 MW for projects <20 MW, $0.01/kWh CHP production tax credit |
| Streamlining | 2,489 | 0 | 2,489 | Customer behavior changes of higher response to payback levels and greater share of market that will consider CHP |
| High R&D on Base Case | 2,764 | 0 | 2,764 | Rate of technology improvement accelerated 5 years |
| High Deployment Case | 4,471 | 2,869 | 7,340 | Accelerated technology improvement with aggressive market access and streamlining to improve customer attitudes and response |

Figure C-4 illustrates the results for each scenario of the stakeholder policy analysis and the associated penetration impacts.

As shown in the figure, the scenarios that enable access to wholesale electricity markets have the greatest effect on market penetrations because these projects tend to be very large. These scenarios also provide the highest societal benefits because large CHP facilities have higher efficiency and reduced carbon dioxide emissions than central station plants.

Another important finding is that in all policy options, including the base case, electric utility revenue losses are higher than the corresponding savings. Utility losses are somewhat mitigated in market access portfolios with policies that encourage participation in energy and capacity markets and transmission and distribution capacity. However, losses would need to be compensated for either with rate increases, increased utility value from CHP installations, or both.

## Figure C-4. Stakeholder Net Benefits and CHP Penetration Levels in 2020




The results of the evaluation show that for the increased incentives scenario, most of the societal benefits from CHP installations are simply transferred to the CHP owner through a production tax credit and are not captured by society as a whole.

One policy scenario, the concept of a portfolio standard for CHP, was not modeled in the cost/benefit model or the CHP penetration analysis because this type of approach relies on mandate rather than on market forces. In this scenario, a market penetration level would be established rather than determined by the marketplace. The evaluation considered two approaches for implementing such a portfolio standard. The first approach would set a target for CHP and then adjust various incentives until that target is met, while the second approach would establish a process similar to the Renewables Portfolio Standard, in which utilities would be responsible for achieving targets and payments to encourage new CHP installations would be set by competitive means.

## End User Market Research

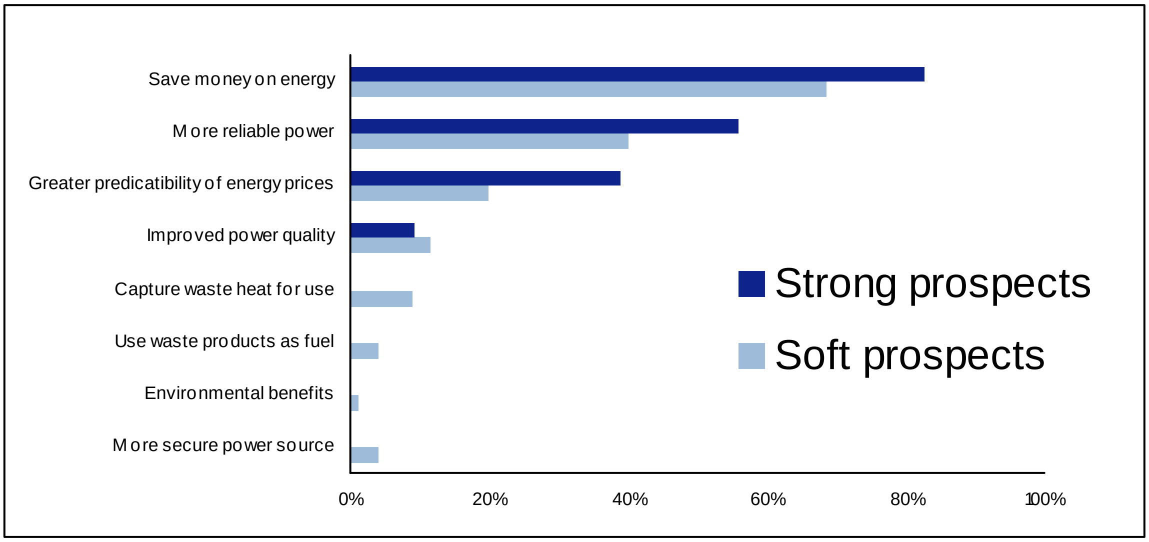
Another key component the *CHP Assessment* and the public workshop on CHP was to investigate what drives the end-use customer's decision making process on installing CHP projects.[226] EPRI Solutions Primen assessed end-users' receptiveness to CHP under different policies. This assessment relied on previous extensive national market research and 20 in-depth interviews with California energy users who adopted or considered adopting CHP. Based on these interviews, the assessment team made the following findings:

- End users value CHP for the energy cost savings and for the perceived enhanced reliability from CHP.
- Less than half of the establishments say that a payback period of two years is acceptable, a rate similar to national averages.
- There are significant barriers to adopting CHP, including longer-than-acceptable paybacks (resulting from high capital costs, natural gas prices, and interconnection charges) and low prioritization from upper management.
- End users favor new government policies that would address project economics, including an expansion of the Self Generation Incentive Program to include projects up to 20 MW and incentives for up to 5 MW of each project and measures to allow CHP owners to sell power back to the grid.

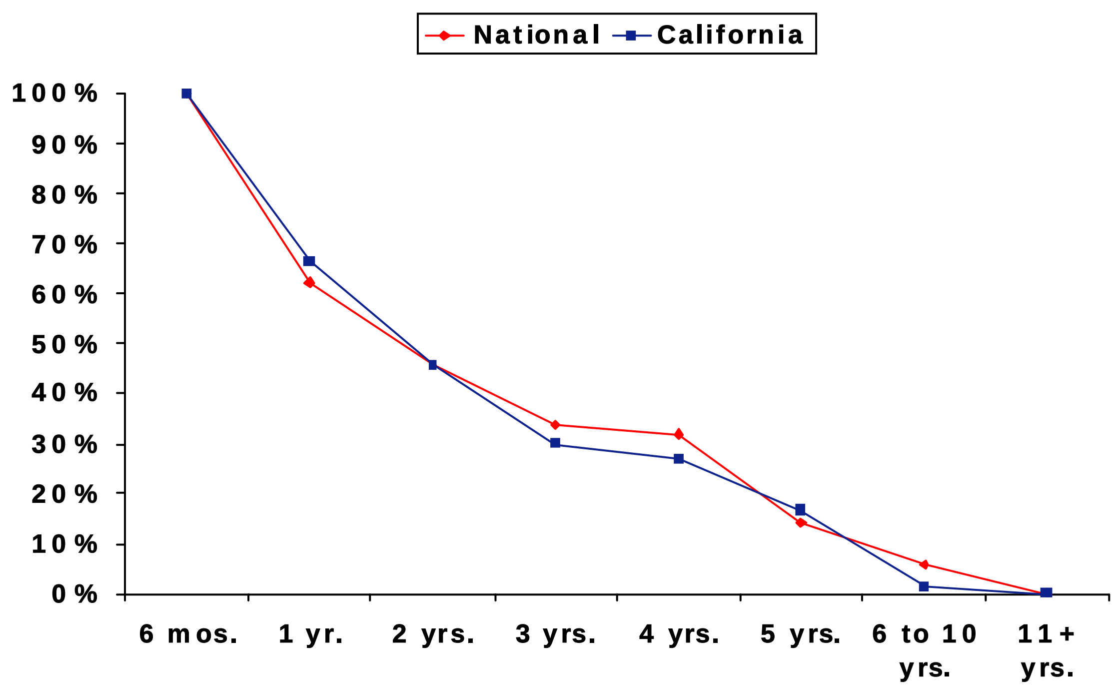
The assessment team also found from national surveys that the three top drivers for DG were energy cost savings, improved power reliability and greater predictability of future energy prices. Figure C-5 illustrates how these top drivers compare to other drivers.

The assessment also looked into what payback period is acceptable to end users to invest in DG. Figure C-6 shows that more than half of establishments find a two-year payback unacceptable. When looking at acceptance rates by business type, it was found that government and educational establishments were more willing to accept longer payback periods (about four years), probably because their capital expenditures are typically funded through bond programs that enable them to spread costs out over longer periods.

## Figure C-5. Nationwide Drivers for On-site Generation




## Figure C-6. Payback Acceptance in California and Nationwide



Most barriers that dissuaded end users from adopting DG were related to the underlying economic and payback for CHP projects. More specifically, respondents mentioned the capital cost of the equipment, the cost of natural gas, and the interconnection charges.

Survey respondents were also asked to react to potential policy initiatives that could be pursued to encourage CHP in California. When asked about one single policy option the state should adopt to encourage CHP, respondents most commonly mentioned two options. The first option was allowing end-users to sell excess power back to the grid, while the second option was modifying the Self Generation Incentive Program to apply to projects as large as 20 MW and to increase the incentive from the current 1 MW cap.

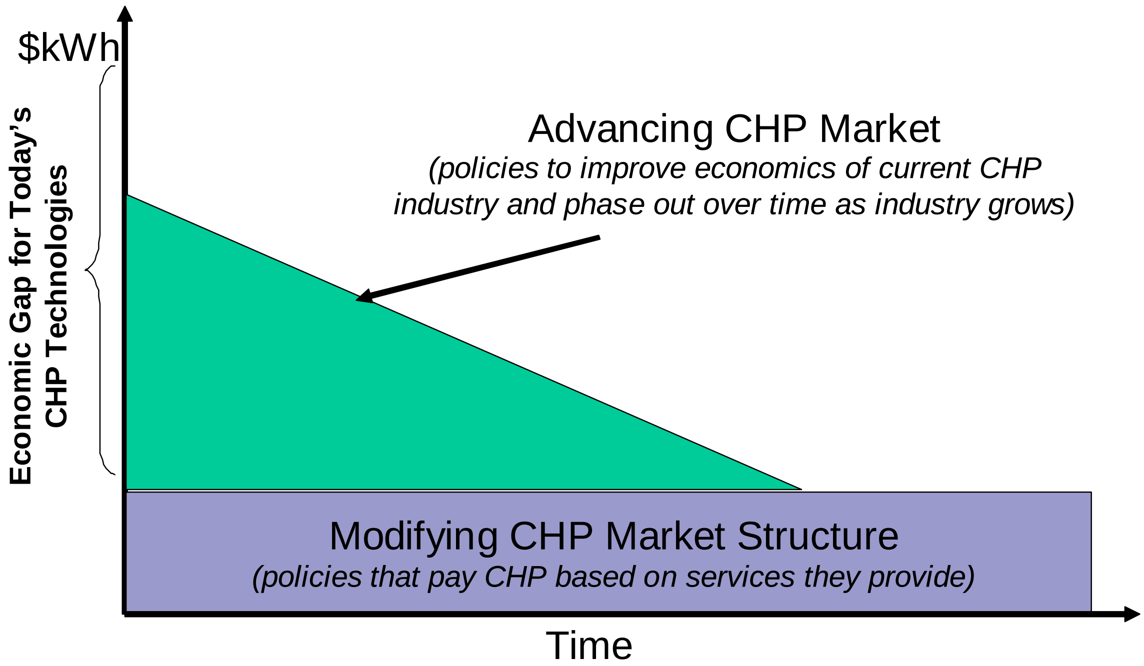
Other policy options that were identified as less valuable included:

- Vendor certification lists from the local utility or the state
- Availability of state financing
- Availability of low cost financing
- A faster, more streamlined permitting process

All of the observations from the market research were endorsed or echoed during the Integrated Energy Policy Report Committee's April 28, 2005 workshop by end users who have implemented or considered CHP at some point. These observations are of critical importance when one considers what types of policy scenarios were determined to have the greatest impact on market penetration of CHP discussed above in the modeling/forecasting results – namely those that enable wholesale electricity export.

In summarizing the alternative policy scenarios, the assessment team made several recommendations relative to exit strategies for incentives and combining of the policy scenarios. They suggested combining policy scenarios to achieve short- and long-term Energy Commission goals. Figure C-7 illustrates these concepts.

**Figure C-7. Combining Policy Scenarios and Exit Strategies[227]**



# Appendix C Endnotes

[221] *Assessment of California CHP Market and Policy Options For Increased Penetration*, California Energy Commission, Publication #CEC-2005-060-D, April 2005.
[222] *CHP Assessment*, Appendix H.
[223] They considered traditional steam and hot water CHP applications that could be characterized at high load factor (>7,500 hours per year) and low load factor (~4,500 hours per year)..
[224] "All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months."
[225] "Within large industrial process facilities, there is typically an excess of steam demand that could support CHP with significant quantities of export electricity to the wholesale power system. The incremental export value of power from these facilities was quantified and evaluated as a separate market."
[226] An IEPR Committee Workshop was held on April 28, 2005 to discuss CHP issues affecting California. See [http://www.energy.ca.gov/distgen_oii/documents/index.html] for information on agenda, presentations, and workshop transcripts.
[227] *Ibid*, p. 4-27

# APPENDIX D: SUMMARY OF PUBLIC BENEFIT ENERGY EFFICIENCY PROGRAMS IN CALIFORNIA

Source: [http://www.fypower.org/pdf/04-05_PGC_Programs.pdf], accessed July 1, 2005

| This list includes only the programs offered in the investor-owned utility service areas | | | | | | |
|---|---|---|---|---|---|---|
| RESIDENTIAL ENERGY EFFICIENCY PROGRAMS | | | | | | |
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | | √ | √ | Appliance Recycling | Incentives to dispose of operable refrigerators and freezers | PG&E, SCE, SDG&E |
| √ | √ | √ | √ | Home Energy Efficiency Surveys | Online audit service provides customers with information specific to home energy usage. Provides energy-saving ideas to help manage energy costs. Available in various languages depending on service territory. | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | Single Family Rebates | Rebates to purchase specific new, energy-efficient products | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | MultiFamily Rebates | Rebates for the installation of qualifying energy-efficient improvements in multifamily dwellings | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | California Energy Star New Home Construction | Incentives, design assistance and training to encourage the construction of single family and multifamily buildings that exceed AB 970 Title 24 residential building standards | PG&E, SCE, SDG&E, SCG |
| √ | | | | Hard To Reach Lighting Turn In | Exchange of inefficient halogen torchiere fixtures, and incandescent bulbs for ENERGY STAR® qualified torchiere fixtures and compact fluorescent lamps at no cost | SDG&E |
| | √ | √ | | Comprehensive Hard-to-Reach Mobile Home Program | Provides education and no cost installation of the following measures to hard-to-reach residential customers in mobile homes: (a) air conditioning tune-ups; (b) compact fluorescent lamps (CFL) and hard wired CFL fixtures; (c) low-flow showerheads, aerators, and water heater temperature setback; (d) set back thermostats; (e) water heater timers; and (f) enhanced duct sealing | American Synergy Corp |
| | | | √ | Community Energy Efficiency Program | Builders who submit subdivision plans that demonstrate the subdivision exceeds California ENERGY STAR® requirements (15% above Title 24) receive faster plan review, expedited field inspections, reduced fees and recognition | Building Industry Institute |
| | | | √ | Moderate Income Comprehensive Attic Program | Provides an array of cost-effective measures to the target audience, including: attic insulation, attic vents, duct seals, AC diagnostics, torchiere lamps, low-flow shower heads, aerators, water heater blankets, water heater pipe wrap, compact fluorescent lighting, programmable thermostats and energy education | Bo Enterprises |

| RESIDENTIAL ENERGY EFFICIENCY PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| | | | √ | California Retrofit Home Performance Program | Trains residential specialty contractors in "whole house contracting," in which all energy efficiency deficiencies (and related problems such as combustion safety, moisture, comfort and air contaminants) are identified through extensive testing and remedied, typically including both HVAC system equipment and building shell improvements | California Building Performance Contractors Association |
| | | | √ | California Youth Energy Services | Trains youths in Berkeley, Oakland, Albany, Emeryville, Richmond, and El Cerrito to perform energy audits and low cost energy efficiency upgrades in low to moderate income single-family residences in their neighborhoods. | City of Berkeley |
| | | | √ | Yolo Energy Efficiency Project-1 | Hardware-incentive program will serve residential, multifamily, and commercial customers and will address lighting, cooling, and building envelope needs. | City of Davis |
| | | | √ | Yolo Energy Efficiency Project-2 | Services residential, multifamily and commercial customers and addresses lighting, cooling and building envelope needs, as well as energy use in agricultural pumping. Will complement Yolo Energy Efficiency Project-1 with an information-only/market transformation program which will involve intensive and broad outreach to the public through training sessions, tabling, canvassing, mailers through local governments, and special promotions. | City of Davis |
| √ | | | | Residential Duct Services Program | Incentive program for duct repair and advanced heating, ventilation and HVAC and diagnostic tune ups and contractor training | Energy Analysis Technologies |
| √ | | | √ | HEED Home Energy Efficient Design | Provides an easy-to-use energy design tool that shows California's residential customers the energy cost savings of remodel, repair and redesign decisions for their homes | Energy Design Tools Group, UCLA |
| | | | √ | Green Building Technical Support Services | Trains custom builders, remodelers and affordable housing developers on Green Building techniques. It also provides education on Green Building techniques | Frontier Associates |
| | | √ | | Performance4 Home Certification and Whole House Energy System Services | Offers no cost energy audits and financial incentives for energy efficiency measures for residential single family homes | H&L Energy Savers |
| √ | √ | √ | √ | Designed for Comfort, Efficient Affordable Housing | Incentive based program that works with housing authorities and building owners to promote installation of energy efficiency measures. | Heschong Mahone Group |
| | | | √ | Partnership for Energy Affordability in Multi-family Housing | Technical assistance to multifamily building owners and promotion of energy efficiency programs | ICF Consulting |
| | √ | | | Gas Only Multifamily Program – South | Provides for comprehensive residential energy efficiency renovations and retrofits by offering cash incentives and services to apartment tenants and owner/operators for the installation of all energy efficiency measures | SESCO |

| NONRESIDENTIAL ENERGY EFFICIENCY PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | | √ | √ | Standard Performance Contract Program | Incentives for custom-designed energy savings retrofits of existing business facilities | PG&E, SCE, SDG&E |
| √ | √ | √ | √ | Express Efficiency Program | Rebates program for retrofit with qualifying energy efficient electric or gas equipment | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | Nonresidential Energy Audit | Energy audits to all size nonresidential customer facilities. Audits can be on-site, phone, mail-in or CD ROM | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | Building Operator Certification and Training | Certification program designed to educate building operators on every major operating system in their facilities with an emphasis on energy efficiency and building operations and maintenance | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | Savings By Design | Project-specific design assistance and incentives to building owners and design teams that exceed Title 24 requirements by 10% or more. Education, training and design tools through the integrated Energy Design Resources program component. | PG&E, SCE, SDG&E, SCG |
| √ | | √ | √ | Upstream HVAC and Motors Rebate Program | Upstream rebate program that provides financial incentives to distributors to stock and sell qualifying high efficiency products | PG&E, SCE, SDG&E |
| | | | √ | Food Service Technology Center | Provides nonresidential customers with food service operations, with impartial, reliable and useful information that stimulates the energy-efficient design and operation of commercial food service facilities. | PG&E |
| √ | | | | Small Business Energy Efficiency | Energy-efficient lighting measures are installed at no cost to eligible customers | SDG&E |
| √ | | | | Energy Savers | Financial incentives for energy efficient refrigerators, software plug load sensor, and torchieres. | SDG&E |
| √ | | | | Customer Energy Savings Bid | Competitive bidding solicitation of innovative and cost-effective energy efficiency program proposals especially customers having difficulty participating in other PGC funded nonresidential rebate programs | SDG&E |
| √ | | | | Sustainable Communities Program | Promotes sustainable growth by showcasing energy efficiency design and building practices. | |
| | | √ | | Pump Tests and Hydraulic Services Program | Information on energy efficiency measures specific to the agricultural businesses, water districts, and other high water usage businesses. | SCE |
| | | √ | | Local Small Nonresidential Hard to Reach Program | Hardware/incentive program that provides no-cost energy efficiency lighting retrofits to very small business customers. | SCE |
| | √ | | | Nonresidential Financial Incentives Program | Rebates for installation of specific energy efficient products; “kind for kind” replacement of old and inefficient equipment; and incentives to implement specific commercial building envelope or industrial process changes. | SCG |
| √ | √ | √ | | Mobile Energy Clinic | Improved energy efficiency for small HTR businesses by (10 implementing no-cost/low-cost measures and (2) providing diagnostics of energy-using equipment. | ADM Associates, Inc. |

| NONRESIDENTIAL ENERGY EFFICIENCY PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | | | | San Diego Green Schools Program | Provides a wide range of instructional materials and tools that are correlated to the California Standard of Learning in science, math, language, arts and High School Exit Exam. | Alliance to Save Energy |
| | | | √ | Northern California Local Government Energy Partnership | Provides technical assistance and information services to small to medium sized cities, counties, and special districts to complete energy efficiency projects in public facilities and to promote energy efficiency within their communities. | Association of Bay Area Governments |
| | | √ | | Energy Savers Program | Offers financial incentives for efficient lighting, programmable thermostats, energy-efficient package unit air conditioners, and tune-ups for air-cooled package units and refrigeration systems. It also provides recommendations for energy efficient practices specific to lighting, air conditioning, and refrigeration systems and other measures. | ASW Engineering Management Consultants |
| | √ | √ | √ | Agriculture Pumping Efficiency Program | Provides technical support and financial assistance in order to encourage the agricultural industry to adopt more energy efficient pumping systems, maintenance and operation. Incentives will be provided for equipment testing, repair and retrofitting. | California State University Fresno |
| | √ | | √ | Pre-rinse Spray Head Installation Program | Replaced high water use pre-rinse spray valves with ore efficient models at food service facilities:  restaurants, cafeterias, institutional kitchens and food preparation companies. | California Urban Water Conservation Council |
| | | | √ | Marin Public Facilities Energy Management Team | Information program that provides audits, walkthroughs and other activities at schools and public buildings in Marin County. | County of Marin |
| √ | | √ | √ | Statewide School Energy Efficiency Program | Expertise and resources to assist school districts in implementing energy efficient retrofits and energy education. | D&R International |
| | | | √ | RightLights (Monterey Bay Area Efficient Lighting Program) | Installs comprehensive, turnkey lighting retrofits, as well as pre-rinse spray nozzles (food service only) and information-only resources on refrigeration, HVAC, and motors efficiency measures to nonresidential customers with less than 500 kW demand. | Ecology Action |
| | | √ | √ | California Multi Measure Farm Program | Promotes the installation of energy efficient measures with cash incentives to dairy producers | EnSave Energy Performance, Inc. |
| | | √ | | Emerging Communities energy Efficiency Program | Provides target businesses with no-cost energy audits as well as direct install services for lighting and HVAC tune-up measures. | FCI Management Consultants |
| | | | √ | California Agri-Food Energy Efficiency Program | Assists rural farmers to become more energy efficient and productive. | Global Energy Partners |
| | | √ | √ | EEGOV Business Energy Services Team Program | Creates partnerships with cities with a relatively large nonresidential HTR population to expand and strengthen local government programs and promote energy efficiency among small and very small businesses in the community. | KEMA-Xenergy |
| | | √ | √ | Enhanced Automation Initiative | Promotes enhanced automation and more efficient energy management systems in large non-residential customers. | KEMA-Xenergy |

| NONRESIDENTIAL ENERGY EFFICIENCY PROGRAMS | | | | | | | |
|---|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| | | √ | | Long Beach Business Energy Services Team Program | A turnkey marketing and implementation process that takes customers from interest and intent to actual installation of targeted measures. | KEMA-Xenergy |
| | | | √ | Positive Energy Loan Fund | Provides below-market rate loans through local banks as incentive to finance the implementation of cost effective energy efficiency projects targeting hard to reach commercial and industrial customers. | KEMA-Xenergy |
| | | √ | √ | Prototype Community Energy Efficiency Programs | Assists local county and city governments to identify, select, and implement programs and policies to promote and achieve aggressive energy efficiency programs. | Navigant Consulting, Inc. |
| √ | | √ | √ | EnergySmart Grocer | Provides grocers and food-handling businesses with audits and information to encourage investment in energy-efficient equipment. | Portland Energy Conservation, Inc. |
| √ | | | | Retrocommissioning Program | Provides technical guidance and oversight, training and incentives for building retrocommissioning. | Portland Energy Conservation, Inc. |
| | | √ | √ | Building Tune-Up Program | Identifies and implements changes in building operations and related hardware to reduce energy use. The tune-ups involve use of specific test procedures. | Quantum Consulting, Inc. |
| √ | | | √ | California Wastewater Process Optimization Program | Conducts audits of wastewater treatment facilities, install “hard” monitoring, control, and equipment measures, and train staff in facilities optimization to bring about energy savings at energy inefficient wastewater treatment facilities. | Quantum Consulting, Inc. |
| | | | √ | Small Nonresidential Energy Fitness Program | Provides direct installation of cost-effective energy conservation measures (lighting, thermostats) at no cost to the target customers. For the 2004-2005 program, RHA will also add air conditioning and tune up operation and maintenance measures. | Richard Heath & Associates, Inc. |
| | | | √ | Energy Savers Program | Provides energy audits and efficiency measures for very small, small, and some medium-sized businesses. | RLW Analytics |
| | | | √ | Compressed Air Management Program | Offers free measurement-based performance assessment of compressed air systems. The assessment provides specific recommendations to plant operators and technical follow-up support to help motivate adoption of these recommendations. | SBW Consulting, Inc. |
| √ | | | | San Diego Local Government Energy Efficiency Program | Provides rebates for energy efficiency upgrades to city and county owned government buildings in San Diego County. | San Diego Regional Energy Office |
| √ | | | | San Diego Regional Green Building Education and Technical Assistance | Provides training, design assistance, and technical support for public and private sector green building projects. The program promotes long-term sustainable energy use and peak demand savings by supplementing existing municipal green building program implementation efforts. | San Diego Regional Energy Partnership |

| NONRESIDENTIAL ENERGY EFFICIENCY PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | | | | B.E.S.T. | Provides "turnkey" services that include marketing, energy education, site-specific energy analysis, financial incentives, equipment procurement and installation. | San Diego Regional Energy Partnership |
| √ | | | | San Diego Region Technical Assistance Program | Provides technical assistance to local businesses and government agencies interested in implementing energy efficiency upgrades in their facilities. The technical assistance will include development of energy management strategies, facilities audits and energy management staff education. | San Diego Regional Energy Partnership |
| √ | √ | √ | √ | IOU/UC/CSU Partnership | Energy efficiency improvements and training at UC and CSU campuses. | PG&E, SCE, SCG, SDG&E, UC and CSU |
| √ | | | | San Diego City Schools Retrofit and Partnership Program | Provides comprehensive energy audits and energy efficiency equipment installation in targeted San Diego schools. | San Diego City Schools and SDG&E |
| CROSS CUTTING ENERGY EFFICIENCY PROGRAMS | | | | | | |
| √ | √ | √ | √ | Education & Training | Energy efficiency education and training is provided to contractors, retailers, manufacturers, and distributors of energy efficiency products. | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | Emerging Technologies | Promotes the development and commercialization of new technologies through collaboration between IOUs and the Energy Commission (ETCC and PIER). | PG&E, SCE, SDG&E, SCG |
| √ | √ | √ | √ | Codes & Standards | Training and other information to code implementers and other professionals affected by Codes. Works with other interested parties on the development of state and federal standards through participation in standards organizations. Advocates for improvements in Title 24 requirements in cooperation with the Energy Commission. | PG&E, SCE, SDG&E, SCG |
| | | | √ | Energenius | Energy efficiency information and education program for grades 1-8 | PG&E |
| | | | √ | Long-Term Procurement Plan | Residential and nonresidential programs and measures aimed at reducing critical load. | PG&E |
| | | | √ | School Resources Program | Energy efficiency information, benchmarking and education services to participating school districts | PG&E |
| | | | √ | Pacific Energy Center | Information and education to local government regarding self sustaining energy efficiency partnerships. | PG&E |
| | | √ | | Local Government Initiative | Offers energy efficiency information and education, hardware upgrades, and subsidized energy efficiency improvements to small and medium business owners, lower to moderate income residential customers, single and multifamily existing residential consumers, and residential and small commercial builders. | SCE |
| | | √ | | Innovative Designs for Energy Efficiency Activities | Annual competitive bidding solicitation of innovative and cost-effective energy efficiency program proposals across all market and customer segments. | SCE |

| CROSS CUTTING ENERGY EFFICIENCY PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | | √ | √ | Green Campus Pilot Program | Develops student led campus energy efficiency outreach programs designed to provide university students as well as administrators, faculty and systems' managers energy efficiency education | Alliance to Save Energy |
| | | √ | √ | Green Schools Program | Focuses on saving energy in schools and helping students understand the link between energy and the environment through behavior modification, operational changes, and retrofits in school buildings. | Alliance to Save Energy |
| √ | | √ | √ | Building Energy Code Training | Trains production builders and local governments (building departments) in the proper implementation of the California Residential Energy Efficiency Standards (Title 24) methods and programs to exceed these Standards, and upcoming changes to the residential 2005 Title 24 Standards proposed for implementation in 2006. | Building Industry Institute |
| √ | √ | √ | √ | Nonresidential Fenestration certification Initiative | Facilitates and encourages conformance with the California Energy Commission emergency Title 24 standards of 2001 and 2005 through a comprehensive program of outreach, tailored trainings, and precisions technical assistance efforts. | CSU Chico |
| | | | √ | Lightwash | Provides incentives for installing energy and water efficient commercial washers in non-single family residential properties and for lighting and boiler systems incentives in coin laundry stores (e.g., Laundromats) | Energy Solutions |
| | √ | √ | √ | Chinese Language Efficiency Outreach Statewide | Information, audit and education targeting the residential and small commercial Chinese speaking population. | Global Energy Services, Inc. |
| | | | √ | San Joaquin County Comprehensive Energy Efficiency Program | Comprehensive energy efficiency program support including audits and education | Intergy Corporation |
| | | | √ | Redwood Coast Regional Comprehensive Information | Provides comprehensive energy efficiency education services and training tailored to local industry and needs. | Redwood Coast Energy Authority |
| √ | | √ | √ | RCA Verification Program for New Air Conditioners | Provides in-field training and upstream incentives to air conditioner contractors. The program includes computer diagnostic software that quickly determines whether or not there is a problem with RCA and then provides expert recommendations for correcting problems. | Robert Mowris & Associates |
| √ | | | | San Diego Energy Resource Center | Provides energy information to residential and nonresidential market segments and acts as a conduit for all entities that offer public purpose programs. | San Diego Regional Energy Partnership |
| √ | | | | San Diego Green Action | Works with local high school students teaching them the importance of energy conservation and the societal impacts from greenhouse gas emissions. The program consists of energy education workshops, energy audit training, direct implementation of energy audits and a youth forum. | San Diego Regional Energy Partnership |

| CROSS CUTTING ENERGY EFFICIENCY PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | | | | San Diego Regional Cool Communities Shade Tree Program | The primary objective of this program is to plant 17,000 trees throughout San Diego County by the end of 2005. | San Diego Regional Energy Partnership |
| | | | √ | Efficiency on Wheels | Installs occupancy sensors, vending misers, programmable thermostats and other energy saving items as needed depending on each individual case. Also educates communities on energy efficiency options for homes and businesses. | San Francisco Community Power Cooperative |
| | √ | √ | √ | Bakersfield Energy Watch | Energy audits and direct installation of measures to residential and small businesses. Also technical and financial assistance to city and county government buildings and other education and training. | City of Bakersfield, County of Kern, Staples/Hutchinson, SCE, SCG, & PG&E |
| | | | √ | PG&E/Silicon Valley Energy Partnership | Education and outreach, direct install services to small businesses, energy audits and targeted Savings by Design to municipal construction. | City of San Jose and PG&E |
| | | | √ | PG&E Local Government Partnership: East Bay | Building tune up, energy efficiency audits, and various other incentives and information. | PG&E |
| | | | √ | PG&E Local Government Partnership: City of Fresno | Various residential and nonresidential direct install measures and energy audits. | PG&E |
| | | | √ | PG&E Local Government Partnership: City of Stockton | Various residential and nonresidential direct install measures and energy audits. | PG&E |
| | | | √ | PG&E Local Government Partnership: City of West Sacramento | Marketing, education and outreach, special assistance to local businesses and local training | PG&E |
| | | | √ | PG&E Local Government Partnership: El Dorado County | Various residential and nonresidential direct install measures and energy audits. | PG&E |
| | √ | √ | | The Energy Coalition: Community Energy Partnership | Direct installation of energy efficiency measures and education to raise awareness of energy management. | Energy Coalition, SCG, SCE |
| | √ | √ | | South Bay Cities Energy Efficiency Center | Development of community based resource for energy information, training and materials to assist the member agencies, businesses and citizens to best utilize the resources available to them through the wide variety of statewide and local energy efficiency programs. | South Bay Cities Council of Government, SCE, SCG |
| | √ | √ | | Ventura County Regional Energy Efficiency Center and Comprehensive Public Sector Program | Develop and implement local energy policy and programs, complete the development of its Energy Resource Center, and implement a targeted public sector energy savings program for public agencies throughout Ventura County | Ventura County Regional Energy Alliance, SCE, and SCG |
| | √ | √ | | LA County SCE/SCG Partnership | Various residential and non residential direct install measures and energy audits targeting county facilities and multi family complexes. | County of Los Angeles, SCE & SCG |
| | | √ | | City of Pomona and SCE Partnership for Energy Efficiency | Various energy efficiency upgrades to hard-to-reach residential and nonresidential City of Pomona facilities. | City of Pomona and SCE |

| STATEWIDE MARKETING AND OUTREACH PROGRAMS | | | | | | |
|---|---|---|---|---|---|---|
| CUSTOMERS SERVED BY: | | | | Program Title | Description | Implementers |
| SDG&E | SCG | SCE | PG&E | | | |
| √ | √ | √ | √ | Flex Your Power Marketing and Outreach Program | Marketing and education programs that capitalize on the "Flex Your Power" campaign through TV, newspaper, radio and targeting English and Asian-speaking consumers. | McGuire and Company (aka Efficiency Partnership) |
| √ | √ | √ | √ | Univision Television Energy Efficiency Marketing Program | Marketing and outreach to Spanish-speaking communities, using televised marketing and information. | Univision Television Group and Staples Hutchinson & Associates, Inc. |
| | | | | Reach for the Stars Statewide Energy Efficiency Marketing and Outreach | Marketing and outreach energy efficiency communications program directed to customers in rural communities primarily through radio and printed materials. | Runyon Saltzman & Einhorn |

# APPENDIX E:  MUNICIPAL UTILITY ENERGY EFFICIENCY PROGRAMS

| | Residential | | | | | | | | | | | | | Commercial | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Air Conditioner/HVAC Rebates | Cool Roof | Energy Audit | Energy Star Rebates | Free Shade Trees | Heat Pump Rebates | Lighting Savings / Rebates | Pool Pumps | Refrigerator/Freezer Recycling Rebates | Refrigerator Purchase Rebates | Solar / Photovoltaic | Weatherization | | Air Conditioner/HVAC Rebates | Cool Roof | Energy Audit | Energy Efficient Exit Signs | Energy Star Rebates | Free Shade Trees | Heat Pump Rebates | Lighting Savings / Rebates | New Construction Incentives | Refrigerator/Freezer Recycling Rebates | Refrigerator Purchase Rebates | Solar / Photovoltaic | Weatherization |
| Alameda Power & Telecom | | | X | | | | X | | X | | X | X | | X | | X | | | | | X | | | | | |
| Anaheim Public Utilities | | | X | X | X | | X | | | | X | X | | | | X | X | X | X | X | X | X | | | X | |
| Anza Electric Cooperatives, Inc. | | | X | | | | | | | | | | | | | | | | | | | | | | | |
| Azusa Light & Water | X | | X | | | | | | | X | | X | | | | | | | | | | | | | | |
| City of Banning - Utility | X | | X | X | | | | | X | X | | | | | | | | | | | | | | | | |
| Burbank Water & Power | X | | X | X | X | | | X | | X | X | | | X | X | | | | X | | X | | | | X | |
| Colton Public Utilities | | | X | | | | | | | | | | | | | X | | | | | X | | | | | |
| Glendale Water & Power | X | | X | | X | | | | X | X | X | X | | X | | X | | | | | X | | | | | X |
| Imperial Irrigation District | X | | | X | | | X | | | X | X | X | | X | | | | X | | | X | | | | X | |
| Lassen Municipal Utility District (LMUD) | | | | X | | | | | | | | | | | | | | | | | | | | | | |
| Lodi Electric Utility | X | | X | X | | | | | | | | X | | X | | | | | | | X | | | | | X |
| Lompoc Utility Services | | | | X | | | | | X | X | | | | | | | X | | | | X | | | | | |
| LADWP | X | | X | X | X | | X | X | X | X | X | | | X | | | | | | | X | | | | X | |
| Merced Irrigation District | | | X | | | | | | | | | | | | | X | | | | | | | | | | |
| Modesto Irrigation District | X | | X | | | | | | | | | | | X | | X | | | | | X | | | | | |
| City of Palo Alto Utilities | | | X | | | | | | | X | X | | | X | | | | | | | X | | | | X | |
| Pasadena Water & Power | X` | | X | X | X | | | | X | | X | | | | | X | | | | | | | | | | |
| Plumas-Sierra Electricity | | | | X | | | | | | | | | | | | | | | | | | | | | | |
| Redding Electric Utility | X | | X | X | | | X | | | | X | X | | X | | | X | X | | X | X | | | | X | X |
| Riverside Public Utilities | X | | X | X | X | | | X | X | | | X | | | | | | | | | | | | | | |
| Roseville Electric | X | | X | X | X | | | X | | X | | X | | X | | | | | | | X | | X | | | |
| SMUD | X | | X | X | X | | | X | | | X | X | | X | X | X | | | | | X | | X | | | |
| Silicon Valley Power (Santa Clara) | | | X | X | | | | | | X | X | | | X | X | | | X | | | X | X | | | | |
| Surprise Valley Electrification Corp.(SVEC) | | | X | | | | | | | | | | | | | | X | | | | | | | | | |
| Truckee-Donner Public Utilities | | | | X | | X | | | | X | | X | | | | | | | | | | | | | | |
| Turlock Irrigation District | X | | | X | | | | | | X | | | | X | | | | X | | | | | | X | | |
| Ukiah Public Utilities | | | | | | | | | | | X | | | | | | | | | | | | | | X | |
| Woodland (Yolo Energy Efficiency Project) | | | | | | | X | | | | | | | | | | | | | | X | | | | | |