California Renewable Technology Market and Benefits Assessment

Technical Report

EPRI

pier

California Renewable Technology Market and Benefits Assessment

1001193

Final Report, November 2001

California Energy Commission
1516 9th Street, MS-43
Sacramento, CA 95814

Principal Investigator
G. Simons

EPRI Project Manager
T. Peterson

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Global Energy Concepts, LLC

ORDERING INFORMATION

Requests for copies of this report should be directed to EPRI Customer Fulfillment, 1355 Willow Way, Suite 278, Concord, CA 94520, (800) 313-3774, press 2.

Electric Power Research Institute and EPRI are registered service marks of the Electric Power Research Institute, Inc. EPRI. ELECTRIFY THE WORLD is a service mark of the Electric Power Research Institute, Inc.

Copyright © 2001 Electric Power Research Institute, Inc. All rights reserved.

CITATIONS

This report was prepared by

EPRI
3412 Hilview Avenue
Palo Alto, CA 94304

Principal Investigator
T. Peterson

Global Energy Concepts, LLC
5729 Lakeview Drive NE, Suite 100
Kirkland, WA 98033

Principal Investigator
R. Poore

This report describes research sponsored by California Energy Commission.

The report is a corporate document that should be cited in the literature in the following manner:

California Renewable Technology Market and Benefits Assessment, EPRI, Palo Alto, CA, and California Energy Commission, Sacramento, CA: 2001. 1001193.

REPORT SUMMARY

The renewable-energy market in California is substantial, with large numbers of companies providing a wide variety of goods and services to the market. This report characterizes the status and prospects of each renewable-energy resource in the state and estimates the current and potential economic and environmental benefits they provide. The overall objective is to provide information useful in formulating renewable-energy research strategies that can make California's electricity more reliable, affordable, and cleaner.

Background

To support research, development, and demonstration of renewable-energy technologies in the State of California, it is important to understand the current status of renewable-energy technologies located in the State, the markets for these technologies, and benefits provided by further development of renewable-energy resources.

Objective

To characterize the status and prospects of renewable-energy resources in California; to identify opportunities for research, development, and demonstration of renewable energy that will make the State's electricity more reliable, affordable, and cleaner.

Approach

In work cosponsored by California Energy Commission's (CEC) Public Interest Energy Research (PIER) program, the project team gathered information on the technological and economic status of renewable energy sources in the state of California—Wind Energy, Geothermal, Biomass, Solar Thermal, Photovoltaics, and Small Hydro (less than 30 MW). They estimated economic and environmental benefits currently provided by renewable-energy facilities in California and from further development of renewable energy, identifying the market needs of each technology from the perspective of project developers and equipment manufacturers. Finally, the team identified key unresolved issues and opportunities for future research.

Results

The renewable-energy market in California supplies approximately 5,500 MW of capacity. The only technologies that have significant new capacity planned are geothermal and wind, with over 1,100 MW planned between them. Approximately one quarter of the planned wind-energy projects will be re-powering existing capacity. The schedule on which planned projects are actually completed will depend heavily on energy market conditions in the State and the status of the Federal Production Tax Credit (PTC).

The markets for new renewable-energy technologies are taking shape as the California energy markets are deregulated. Issues limiting new participation in the markets have generally centered

on relatively low prices for energy. Recent significant increases in the price of energy have shifted the focus to the volatility of the market and uncertainty of future prices. The uncertainty of future prices is particularly challenging for renewables whose "fuel" is usually free or very low cost, but whose capital costs are a substantial percentage of the delivered cost of energy. Investors in the projects demand relatively high degree of certainty that the price paid for the energy in the future will be sufficient to provide an acceptable return on their investment. For technologies with an intermittent resource or long project-development times, the existing market structure creates significant financing problems. In particular, the absence of long-term power contracts and uncertainly with regard to possible penalties for undelivered power from intermittent sources have precluded development of many potential renewables projects in the State.

The report examines additional contributions in energy production, air-emissions reductions, and economic benefits that renewable-energy resources could make to the California energy supply over the next ten years. In the absence of an industry consensus on the growth of renewables in the State over the next ten years, three "effective price" scenarios were considered. In the most favorable scenario, California's "green power" sources could cost-effectively contribute up to 20% of the State's electrical energy demand, create over 18,000 jobs, and produce over $4.8 billion in State revenues within 11 years. In terms of energy alone, this is more than double the present relative contribution of renewables and nearly triple their present capacity.

EPRI Perspective

The study leading to this report was conducted in the latter half of 2000, at a time when it had become apparent that significant, but unpredictable, adjustments to California's recently deregulated electricity market would soon be required. Therefore, this report necessarily refers to market structures and practices, such as the Power Exchange and market-clearing prices, that were current throughout the first three years of the deregulated market but will likely not be preserved beyond 2001. Nevertheless, the report provides an accurate picture of California's renewable-energy industry; and the issues and development prospects it describes will remain relevant to the State's electricity supply in the coming decade, regardless of how the market structure may change.

Keywords

Renewable generation
Wind
Geothermal
Biomass
Solar thermal
Photovoltaics

CONTENTS

1 INTRODUCTION 1-1

Objective and Scope 1-1

Report Organization 1-2

Summary of Findings 1-2

2 WIND 2-1

Introduction 2-1

Technology Characterization 2-2

Utility-Scale Wind Systems 2-2

Small Wind Systems 2-4

Market Information 2-6

Utility-Scale Wind Systems 2-6

Small Wind Systems 2-9

Historical Market 2-9

Grid-Connected 2-9

Off-Grid Residential 2-9

Off-Grid Telecom 2-9

Current Market 2-9

Grid-Connected 2-9

Off-Grid Residential 2-10

Off-Grid Telecom 2-10

Future Market 2-11

Grid-Connected 2-11

Off-Grid Residential 2-11

Off-Grid Telecom 2-11

Operating Experience 2-11

Utility Scale 2-11

Small Wind Systems 2-12

Cost and Benefits 2-13
Utility-Scale Wind Systems 2-13
Capital Costs 2-13
Operations and Maintenance Costs 2-14
Energy Production 2-15
Financing Costs 2-15
Small-Wind Systems 2-15
Research Needs and Recommendations 2-17
Utility Scale 2-17
Small Wind Systems 2-18

***3* GEOTHERMAL 3-1**
Introduction 3-1
Technology Characterization 3-2
Market Information 3-5
Operating Experience 3-7
Cost and Benefits 3-8
Economics 3-8
Benefit of Out-of-State Sales 3-9
Benefits of Geothermal Energy 3-10
Research Needs and Recommendations 3-10

***4* BIOMASS 4-1**
Introduction 4-1
Technology Characterization 4-2
Market Information 4-4
Operating Experience 4-6
Cost and Benefits 4-6
Economics 4-7
Benefit of Out-of-State Sales 4-9
Benefits of Biomass Energy 4-9
Methane Avoidance by Biogas Power Generation 4-11
System Benefits of Biomass Energy 4-12
Research Needs and Recommendations 4-12

5 SOLAR THERMAL 5-1
Introduction 5-1
Technology Characterization 5-1
Parabolic Trough Electric Plants 5-1
Central Receiver Electric Plants 5-4
Parabolic Dish with Stirling Engine 5-5
Market Information 5-7
Parabolic Trough Electric Plants 5-8
Power Tower Electric Plants 5-9
Parabolic Dish with Stirling Engine 5-9
Operating Experience 5-10
Cost and Benefits 5-12
Parabolic Trough Electric Plants 5-12
Central Receiver Electric Plants 5-13
Parabolic Dish with Stirling Engine 5-14
Research Needs and Recommendations 5-15
Parabolic Trough Electric Plants 5-15
Power Tower Electric Plants 5-15
Parabolic Dish with Stirling Engine 5-15

6 PHOTOVOLTAICS 6-1
Introduction 6-1
Technology Characterization 6-2
Market Information 6-6
Suppliers of PV Technology 6-6
Markets for PV 6-6
PV Market Trends 6-8
PV Market Barriers 6-8
Operating Experience 6-10
Cost and Benefits 6-10
Research Needs and Recommendations 6-12

7 SMALL HYDRO 7-1
Introduction 7-1
Technology Characterization 7-2

Market Information 7-3
Operating Experience 7-5
Cost and Benefits 7-5
Research Needs and Recommendations 7-6

8 POTENTIAL CONTRIBUTION OF RENEWABLES TO CALIFORNIA 8-1
Introduction 8-1
Scenario Development 8-1
Wind 8-3
Geothermal 8-4
Biomass 8-5
Solar Thermal 8-7
Photovoltaics 8-8
Small Hydro 8-9
Total Renewable-Energy Capacity 8-10
Electricity Generation Emissions Reduction 8-10
Property- and Income-Tax Benefits 8-12
Special Solid-Fuel Biomass Benefits 8-12
Summary of Benefits by Technology 8-13

A PROJECT LISTS BY TECHNOLOGY A-1
Wind Project Data A-2
Geothermal Project Data A-9
Biomass Project Data A-11
Solar-thermal Project Data A-31
Photovoltaic Project Data A-32
Hydro Project Data A-52

B RENEWABLE TECHNOLOGY KEY COMPANIES B-1
Wind Key Companies B-1
Geothermal Key Companies B-2
Biomass Key Companies B-3
Solar-thermal Key Companies B-5
Photovoltaic Key Companies B-6
Hydropower Key Companies B-7

C **AIR-EMISSIONS REDUCTIONS AND ECONOMIC BENEFITS OF RENEWABLE ENERGY C-1**

Introduction C-1

Atmospheric Emissions Reductions C-1

Details on Emissions Calculations C-1

Taxes paid to State and local governments C-3

Technology Properties C-3

Driver and Fuel Costs for Solid-Fuel Biomass and Geothermal Truck Transportation C-4

Other Benefits C-7

Detailed Benefits Calculation Results C-8

LIST OF FIGURES

Figure 2-1 Typical Wind Power Installation 2-2
Figure 2-2 Small Wind Turbine Installation 2-4
Figure 2-3 Grid Intertied Small Wind Turbine 2-5
Figure 2-4 Intertie + Back-up 2-5
Figure 2-5 Off-Grid 2-6
Figure 3-1 Typical Direct-Steam Plant at The Geysers 3-2
Figure 3-2 Typical Flash Steam Cycle 3-3
Figure 3-3 Typical Flash Plant at Coso Hot Springs 3-3
Figure 3-4 Typical Binary Cycle 3-4
Figure 3-5 Geothermal vs. Fossil Fuel Emissions 3-5
Figure 4-1 50-MW Biomass Power Plant in Anderson, CA 4-2
Figure 5-1 Five 30-MW Parabolic Trough Plants at Kramer Junction, CA 5-2
Figure 5-2 Close-Up of Parabolic Trough Power Plant 5-2
Figure 5-3 10-MW Solar Two Demonstration Project in Daggett, CA 5-4
Figure 5-4 Schematic of a Molten-Salt Global-Receiver Plant 5-5
Figure 5-5 Two Parabolic-Dish Units at the Boeing/SES Huntington Beach Site 5-6
Figure 5-6 Kramer Junction Solar Field Availability 5-10
Figure 5-7 Kramer Junction Solar Production 5-11
Figure 5-8 KramerJunction On-Peak Generation 5-11
Figure 6-1 PV Block Diagram 6-3
Figure 6-2 Central-Station PV with Nuclear in Background 6-4
Figure 6-3 Residential PV 6-4
Figure 6-4 Telecommunications PV 6-5
Figure 8-1 Total Renewable Energy Capacity in Different Scenarios 8-10

LIST OF TABLES

Table 1-1 Renewable Energy Capacity in California 1-3
Table 1-2 Summary of Estimated Renewables Capacity Growth..... 1-5
Table 1-3 Estimated Annual Values of Renewable Energy Deployments 1-6
Table 2-1 Wind Capacity by Location 2-1
Table 2-2 Typical Project Capital Cost Elements.....2-14
Table 3-1 Geothermal Capacity by Location 3-1
Table 4-1 Biomass Capacity by Fuel Type 4-1
Table 5-1 Solar Thermal Companies..... 5-7
Table 5-2 Solar Thermal Cost Summary 5-13
Table 6-1 Summary of Grid-Connected Project Data for PV Technology 6-2
Table 7-1 Number of Small Hydroelectric Projects by Size 7-1
Table 8-1 Scenario Summary..... 8-2
Table 8-2 Wind Energy Development Scenarios 8-4
Table 8-3 Geothermal Development Scenarios..... 8-5
Table 8-4 Biomass (Solid Fuels) Development Scenarios..... 8-6
Table 8-5 Biogas (Landfill and Digester Gas) Development Scenarios 8-7
Table 8-6 Solar Thermal Development Scenarios 8-8
Table 8-7 Photovoltaics Development Scenarios 8-9
Table 8-8 California Renewable Energy Emissions Reductions 8-11
Table 8-9 California Renewable Energy Tax and Employment Benefits.....8-12
Table 8-10 California Solid-Fuel Biomass Benefits.....8-13
Table 8-11 Economic Value to California of Renewable Energy Deployments 8-13
Table C-1 Conversion Factors and Market Values for Avoided Air Emissions.....C-2
Table C-2 Technology Properties for Benefits Calculations.....C-5
Table C-3 Payroll, Taxes, and Other Values C-6
Table C-4 Truck Transportation Costs, Payroll, and Taxes C-7
Table C-5 Other Benefits of Solid-Fuel Biomass Power Generation.....C-8
Table C-6 Wind Scenario A1 .....C-9
Table C-7 Wind Scenario A2.....C-10
Table C-8 Wind Scenario B.....C-11
Table C-9 Wind Scenario C.....C-12
Table C-10 Geothermal Scenario A C-13

Table C-11 Geothermal Scenario B C-14
Table C-12 Geothermal Scenario C C-15
Table C-13 Solid-Fuel Biomass Scenario A C-16
Table C-14 Solid-Fuel Biomass Scenario B C-17
Table C-15 Solid-Fuel Biomass Scenario C C-18
Table C-16 Biogas Scenario A C-19
Table C-17 Biogas Scenario B C-20
Table C-18 Biogas Scenario C C-21
Table C-19 Solar Thermal Scenario A C-22
Table C-20 Solar Thermal Scenario B C-23
Table C-21 Solar Thermal Scenario C C-24
Table C-22 Photovoltaics Scenario A C-25
Table C-23 Photovoltaics Scenario B C-26
Table C-24 Photovoltaics Scenario C C-27
Table C-25 Small Hydro Scenarios A, B, & C C-28
Table C-26 All Renewables Scenario A1 ..... C-29
Table C-27 All Renewables Scenario A2 ..... C-30
Table C-28 All Renewables Scenario B C-31
Table C-29 All Renewables Scenario C C-32

1
INTRODUCTION

One of the goals of the California Energy Commission's (CEC) Public Interest Energy Research (PIER) program is to support research, development and demonstration of renewable-energy technologies in the State of California. To effectively utilize PIER program resources, the CEC believes it is important to understand the current status of renewable-energy technologies located in the State, the markets for these technologies, and benefits provided by further development of renewable-energy resources. This information will support the process of identifying opportunities for research, development and demonstration of renewable energy. As a result, the CEC contracted with the Electric Power Research Institute (EPRI) to research and report on the renewable-energy marketplace. EPRI, in turn, retained Global Energy Concepts (GEC) to support it in this effort.

The study leading to this report was conducted in the latter half of 2000, at a time when it had become apparent that significant, but unpredictable, adjustments to California's recently deregulated electricity market would soon be required. Therefore, this report necessarily refers to market structures and practices, such as the Power Exchange (PX) and market-clearing prices, that were current throughout the first three years of the deregulated market, but will likely not be preserved beyond 2001. Nevertheless, the status portrayed in this report of California's renewable-energy industry is still accurate, and that industry's important issues and development prospects described herein will be relevant to the State's electricity supply in the coming decade, regardless of how the market structure may change.

Objective and Scope

The overall objective of this project is to provide information useful in formulating renewable-energy research strategies that make California's electricity more reliable, more affordable, cleaner, and secure. This report helps to achieve that objective by characterizing the technology status of each renewable-energy resource, cataloguing the existing and planned projects in California, and identifying the market needs of each technology from the perspective of project developers and equipment manufacturers. In addition this report estimates benefits currently provided by renewable-energy facilities in California and from further development of renewable energy. This project addresses the following renewable-energy technologies:

- Wind Energy
- Geothermal
- Biomass
- Solar Thermal

- Photovoltaics
- Small Hydro (less than 30 MW)

Report Organization

The report is organized into eight sections. Following this introduction are six chapters devoted to the individual renewable-energy technologies discussed in the report. The final chapter describes three scenarios of future renewable-energy deployments in California and summarizes the benefits to the State of those potential deployments. Each technology chapter includes the following sections:

- Introduction
- Technology Characterization
- Market Information
- Operating Experience
- Costs and Benefits
- Research Needs and Recommendations

Appendix A provides detailed listings of individual projects in California for each technology area, while Appendix B comprises lists of the major participants in each of the renewable-energy technology markets. Finally, Appendix C gives details on the methods used to derive the benefits described in Section VIII, shows the general connection between Section VIII's assumed scenario prices and expected renewable energy technology costs, and provides more detailed results than those in Section VIII.

Summary of Findings

The renewable-energy market in California is substantial, with large numbers of companies providing a wide variety of goods and services to the market. Table 1-1 summarizes the installed renewable-energy capacity in the State, over 5,500 MW in all. Appendix A provides a detailed listing of these installments.

Table 1-1
Renewable Energy Capacity in California

Technology Type	Existing MW	% of Total	Planned MW
Wind	1,646	29.7	850
Geothermal	1,754	31.7	297
Biomass	1061	19.2	49
Solar Thermal	364	6.6	0
Photovoltaics	11	0.2	<4
Small Hydro (<30MW)	700-1000	12.6*	<1
TOTAL:	5,536		1,150

*Percentage based on low-end value.

Most of the renewable-energy facilities built in the State have remained in service and are operational. However, several biomass facilities are not currently operating due to high fuel costs or shortages of appropriate fuel stocks and the status of several geothermal facilities is uncertain, some of these are likely not in service.

The vast majority of the renewable-energy capacity in California was installed prior to 1995. Approximately 230 MW of wind-energy facilities have been re-powered since 1995, significantly increasing their energy output. These have not been counted as new facilities.

The only technologies that have significant new capacity planned are geothermal and wind, with over 1,100 MW planned between them. Approximately one quarter of the planned wind-energy projects will be re-powering existing capacity. The schedule on which planned projects are actually completed will depend heavily on energy market conditions in the State and the status of the Federal Production Tax Credit (PTC).

Appendix B lists the major participants in the renewable-energy business in California. There are several hundred organizations listed, providing equipment and services to the industry.

The markets for new renewable-energy technologies are taking shape as the California energy markets are deregulated. Issues limiting new participation in the markets have generally centered on the relatively low prices that were being paid in the energy markets. Recent significant increases in the price of energy have shifted the focus to the volatility of the market and uncertainty of future prices. The uncertainty of future prices is particularly challenging for renewables whose “fuel” is usually free or very low cost, but whose capital costs are a substantial percentage of the delivered cost of energy. Investors in the projects demand relatively high degree of certainty that the price paid for the energy in the future will be sufficient to provide an acceptable return on their investment. For technologies with an intermittent resource or long project-development times, the existing market structure creates significant financing problems. In particular the absence of long term power contracts, and

uncertainly with regard to whether intermittent resources would have to pay a penalty if they are not able to deliver energy to the Power Exchange when they expected to, have precluded development of many potential renewables projects in the State.

The industry's perception of the size of the renewable-energy market in California over the next 5–10 years varies widely across technologies and organizations. In general, established technologies such as wind, biomass, hydro and photovoltaics feel that they are well positioned to compete if the available market reflects the unique needs and attributes of their technology. Unfortunately, many of the participants in California do not believe that this is now the case, but most are optimistic that appropriate changes will be made. Costs and permitting problems continue to be a significant concern to most renewable technologies. Although recent increases in natural-gas prices are encouraging, the industry expects added fossil-fuel-fired capacity to soon bring relative stability to California electricity prices again. This will mean that the environmental and resource-diversification attributes of renewable technologies will have to be more fully reflected by the markets for them to compete.

Research opportunities vary significantly across the various technologies, however several common themes emerge. These are:

- Reductions of costs through reducing the costs of obtaining the renewable resource (geothermal and biomass)
- Developing means by which renewable energy may receive the full value that it provides to the marketplace
- Continued research into reducing project environmental impacts
- Reductions in costs through technology advancements

Individual technologies also have unique issues of particular concern. These include:

- Developing a market mechanism that provides a long-term high-confidence market for wind energy and other intermittent technologies
- Improving transmission from established wind and geothermal resource areas
- Demonstration of automated controls and new low-head and hydrokinetic technologies to assist hydro facilities to increase generation and further reduce environmental impacts
- Demonstrating solar-thermal dish technology
- Decreasing resource assessment time requirements for wind energy
- Demonstrating innovative biopower technologies such as ethanol production coupled with cogeneration or cofiring a natural-gas power plant

While the preceding reflects the view of a wide range of industry participants, there is also a portion of the renewable industry that does not see the need for additional CEC support of renewables research and development. They would rather see State resources applied to providing firm markets and "buying down" the cost of current technologies. Under this view, the companies providing the equipment will provide all of the necessary R&D. Those in the industry who believe CEC spending on R&D is appropriate note that not all of the issues needing

additional research are topics that apply to equipment suppliers (improving transmission, developing market mechanisms) and many could be applied to various manufacturers (reducing environmental impacts). In addition, the it is noted that the State has an interest in developing more advanced technologies, to reduce costs, and therefore reduce the subsidies required to achieve a more diverse, more environmentally benign, energy supply for the State. It is also noted that many of the organization engaged in the renewable industry are relatively small and do not have focused R&D programs.

The additional contributions in energy production, air-emissions reductions, and economic benefits that renewable-energy resources could make to the California energy supply over the next ten years were also examined. The absence of an industry consensus on the growth of renewables in the State over the next ten years precluded using an industry-based projection for this analysis. Instead, three "effective price" scenarios were considered. The lowest-price scenario assumes prices received by renewable energy project developers effectively will average 4.1¢/kWh through a combination of actual market prices and incentives. The second scenario assumes effective prices will average 6.8¢/kWh; and the third, 9.1¢/kWh. The contribution that renewables can make within a decade is limited by the supply of identified cost-effective resources, the time required to develop new facilities, and the high present prices of some technologies. Table 1-2 summarizes the capacity growths foreseen in the analysis.

Table 1-2
Summary of Estimated Renewables Capacity Growth

	Estimated Additional Capacity (MW)			**Resulting Cumulative Contribution to California Electricity Generation**		
Technology	Scenario A (4.1¢/kWh)	Scenario B (6.8¢/kWh)	Scenario C (9.1¢/kWh)	Scenario A	Scenario B	Scenario C
Wind	325–650	3,600	5,100	1–2%	4%	6%
Geothermal	200	480	1,200	5%	5%	7%
Biomass	136	360	1,460–3,000	2%	2%	4–6%
Solar Thermal	0	0	200	<1%	<1%	<1%
Photovoltaics	30	30	220	<1%	<1%	<1%
Small Hydro	0	n/a	n/a	1%	1%	1%
Total	691–1,016	4,470	8,180–9,720	10%	14%	19–21%

In terms of air emissions, the renewable-energy penetrations achieved by 2010 in Scenario C would result in at least 16% reductions of all electricity generation-related emissions of California Air Resources Board-monitored pollutants as compared to CARB forecast[1]. Scenario

[1] http://www.arb.ca.gov/emisinv/emsmain/emsmain.htm

C also produces a 30% reduction in greenhouse-gas carbon dioxide and 44% reduction in NO_X versus filling all needs for capacity addition with natural-gas generation over the next decade. At present market rates for California air-emissions trading, the cumulative value of the avoided emissions estimated in Scenario C exceeds $2.3 billion by 2010.

Table 1-3
Estimated Annual Values of Renewable Energy Deployments

Year	2000	2010		
	Current	Scenario A	Scenario B	Scenario C
Market value of avoided emissions (millions)	$160	$177	$253	$320
State and local taxes (millions)	$93	$102	$141	$195
Other biomas benefits (millions)	$69	$81	$82	$168
Total (millions)	$322	$360	$476	$683

This analysis shows that California's "green power" sources ("qualifying renewables" under AB1890) could cost-effectively contribute up to 20% of the State's electrical energy demand, create over 18,000 jobs, and produce over $4.8 billion in State revenues within 11 years. In terms of energy alone, this is more than double their present relative contribution and nearly triple their present capacity.

Together, the technological potential of renewable energy and California's vast renewable resources, hold the promise of eventually providing a major fraction of the State's electricity generation. Combined with suitable energy storage technologies, that fraction could even approach 100%—albeit, this could not happen within the next decade! However, in a more distant time, a portfolio of renewable-energy technologies could reduce the State's atmospheric emissions and water pollution or consumption due to electricity production to near zero. The associated costs will depend on the success of research and development programs designed to reduce the costs of both renewable-energy and energy-storage technologies.

2
WIND

Introduction

From the late 1970s through the early 1990s, California was the worldwide leader in installed wind-energy capacity. In the last decade, wind energy has become globally the fastest growing energy technology. However, the major markets for new projects have shifted overseas, mostly in Europe, or more recently, in the Midwestern United States. Nevertheless, California continues to be an important location for the wind industry. Several key industry players are based, or have satellite offices, in the State; and there is much activity in both large- and small-scale wind-energy communities. A representative sample of major companies in the wind industry, their business focus, and contact information is provided in Appendix B.

Approximately 1,700 MW of utility-scale wind-energy projects have been installed in California, representing 30% of all AB1890 "qualifying renewables." Table 2-1 breaks down the installed capacity by the three major wind development areas in the State. In recent years, outdated technology has been replaced with newer turbine models at a number of project sites. This "re-powering" effort could continue in the near term with approximately 227 MW of proposed re-powered wind projects in the planning processes. In addition, 651 MW of new capacity is also planned for California. There are however significant market related impediments to the completion of both additional re-powers and new projects. Appendix A provides additional project-specific details on the existing and planned projects. This database includes project names, locations, owners, developers, turbine types and sizes, and other relevant information.

Table 2-1
Wind Capacity by Location

	Existing		Planned New		Planned Repower	
Location	MW	% Total	MW	% Total	MW	% Total
Tehachapi	598	36	293	45	72	32
San Gorgonio	419	25	212	33	20	9
Altamont	548	33	0	0	136	60
Other	81	5	146	22	0	0
TOTAL	1646		651		227	

In the small-turbine market (i.e. wind turbines of less than 50 kW), the majority of the activity has historically been in off-grid applications. Several thousand small turbines have been sold in California for either off-grid residential or telecommunication use. The market for grid-connected small wind turbines is currently increasing as a result of the CEC buy-down program and other favorable legislation such as net metering.

Technology Characterization

Utility-Scale Wind Systems

Since its beginnings in the late 1970s, modern utility-scale wind-energy technology has seen tremendous improvements in cost-effectiveness, equipment reliability and resource prediction capabilities. Today, the industry is a multibillion-dollar-per-year international industry.

A typical modern wind power plant is shown in Figure 2-1. Utility-scale wind systems generally consist of multiple wind turbines, each larger than 50 kW, with combined total nameplate ratings ranging from a few megawatts up to about 100 MW. The utility-scale systems in California are connected to the transmission grid via substations that step up the voltage to the transmission voltage. Outside California, there are several small distributed utility-scale wind generation systems that consist of one to three wind turbines and deliver wind energy directly to the distribution line without a substation. Depending on when the wind facility was installed, the individual wind turbine nameplate ratings range from 50–100 kW each for wind plants installed during the 1980s to 500–1,700 kW today.

Figure 2-1
Typical Wind Power Installation

The overall footprint of a wind power plant is approximately 5% of the total land encompassing a wind farm. The remaining area can generally continue to be used for its original purpose. Figure 2-1 illustrates the continued agricultural use of the land adjacent to the turbines.

Wind power plants are not dispatchable, due to the intermittent nature of the wind. In addition, wind forecasting is not yet sufficiently reliable to permit high-confidence predictions of the timing and magnitude of energy deliveries from a wind power plant. However, on a seasonal and diurnal basis, general trends and patterns can be reliably identified and quantified.

Wind energy is generally an environmentally benign technology with zero emissions and no hazardous materials used in the energy-conversion process. The industry has however recognized that there is potential for wind turbines to have an adverse impact on avian species in the vicinity of wind power plants, and project construction can result in erosion problems if not properly addressed. As is the case with many energy-production technologies, the visual and acoustic impacts of the facilities are also issues that must be addressed.

Typically, wind power plants are highly modular and can be built relatively quickly. They can also be built in a range of sizes from single-turbine installations to 100-MW power plants. This modularity provides the opportunity for the technology to support distributed-generation initiatives to the extent that adequate wind resources are available.

The basic technology in the wind-energy industry is relatively mature, but innovative improvements are occurring regularly. Although there is a trend toward ever-increasing machine sizes, it is still unclear if the economic advantage offered by larger turbines is sufficient to outweigh the increased risk associated with larger turbine sizes. Larger turbines are riskier because they have seen less operating experience, are more challenging to erect in complex terrain and adverse weather conditions, and a single-turbine breakdown removes a larger portion of a plant's capacity from service. Different manufacturers offer different perspectives on the issue of whether larger machines are truly more competitive for on-shore applications, and independent analyses of the issue are highly dependent on the assumptions used concerning financing, land cost and availability, resource characteristics, and many other factors. It is highly probable that the industry will find that there is no single optimum machine size and that turbines in a wide range of sizes and configurations can meet various aspects of the overall wind-energy market.

Wind resource assessments conducted in California in the mid-1980s estimated that the State had about 7,000 MW of potential wind capacity. Currently, there are three regions where major wind-energy developments have occurred within California. These are the Altamont Pass to the east of Livermore, the Tehachapi Pass between Bakersfield and Mojave, and San Gorgonio pass in the vicinity of Palm Springs. While concerns about visual impacts, noise, avian, flora/fauna, and erosion are similar in each of these areas; the degree to which each is an issue varies by region.

In Altamont Pass, the issues associated with avian mortality have caused numerous project delays and cancellations. The pass is home to a variety of predatory birds that are hit and killed by the turbine blades. The Tehachapi Pass area has historically had significant concerns with noise emissions and erosion caused by facility maintenance roads. In the San Gorgonio Pass, noise, endangered flora/fauna, and visual impact have been significant issues. In general, none

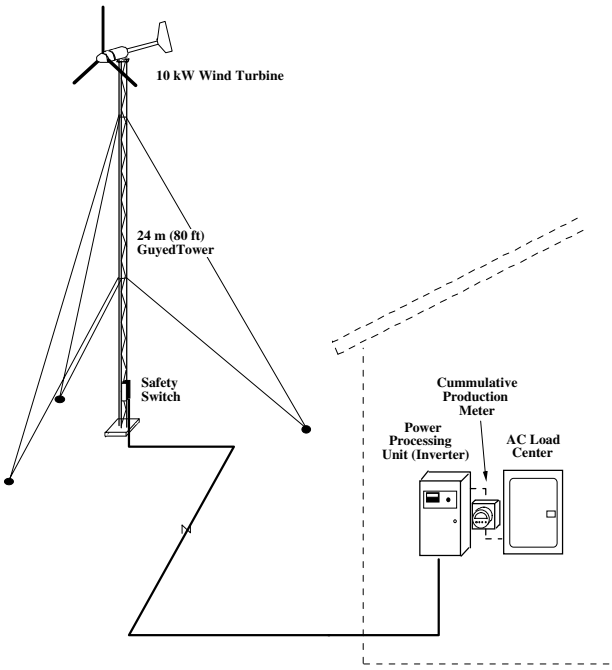
of these issues are serious impediments to wind-energy development although they may prevent, delay, or otherwise impact specific projects.

Small Wind Systems

Small wind-energy technology is generally considered to include wind turbines rated below 50 kW in capacity. These can be used in either on- or off-grid applications. Most of the wind turbines in this size range generate electricity at variable voltage and frequency. This energy is then conditioned using an electronic power inverter to supply ac power for the grid or dc power for a battery storage system. Small wind systems generally consist of one or more wind turbines. On-grid applications are generally residential or commercial and may include net-metering arrangements. Small wind systems that are connected to the distribution grid include controls and inverters to supply 60-Hz ac power to the customers' electrical circuits. The unused wind power flows into the distribution grid through the meter. Small wind turbines can be used in conjunction with photovoltaics, batteries, and other energy sources as part of hybrid systems for off-grid applications. Other off-grid applications include telecommunications, navigation, water pumping, catholic protection, and residences. Figure 2-2 shows a typical on-grid residential small wind turbine installation.

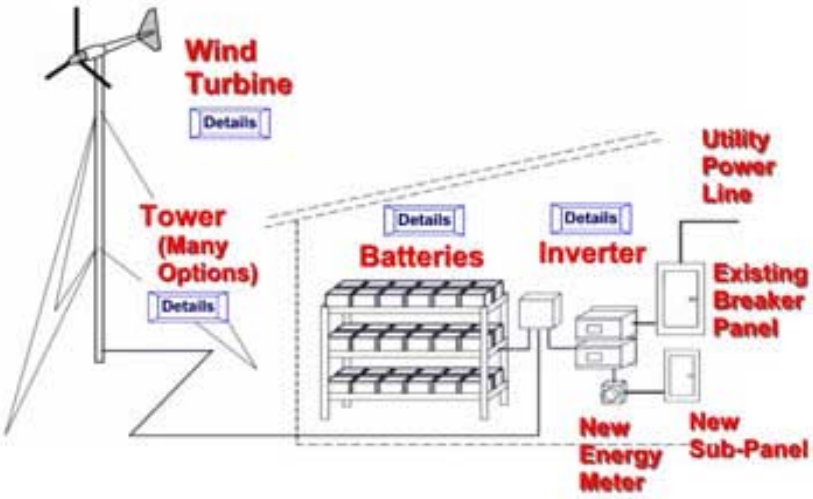
Figure 2-2
Small Wind Turbine Installation

Figure 2-3 through Figure 2-5 show schematic diagrams of typical grid-connected, battery-charging and hybrid-system applications, respectively.



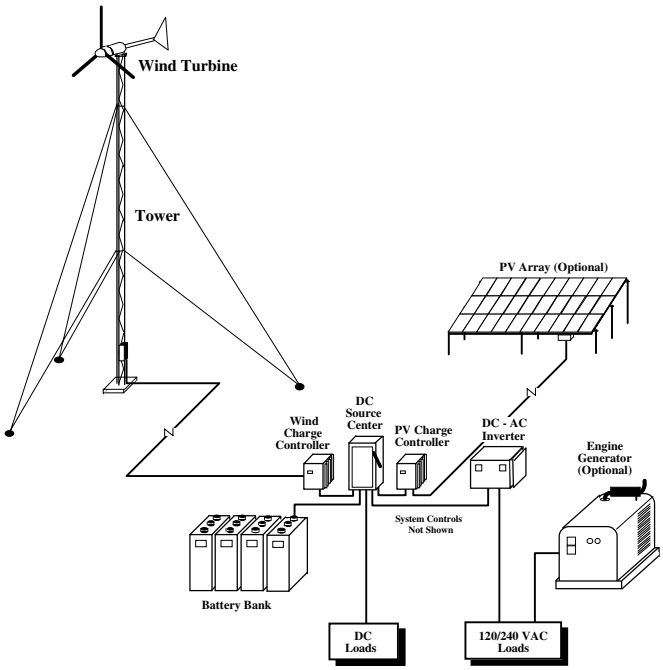
[Diagram Courtesy of Bergey WindPower]

Figure 2-3
Grid Intertied Small Wind Turbine



[Diagram Courtesy of Bergey WindPower]

Figure 2-4
Intertie + Back-up



[Diagram Courtesy of Bergey WindPower]

Figure 2-5
Off-Grid

Market Information

Utility-Scale Wind Systems

The international utility-scale wind-energy market is growing dramatically with annual growth rates averaging 40% per year for the past five years. In the United States, the market is also growing with 735 MW of new capacity installed and 173 MW added through re-powering, for a total of over 900 MW in 1999. The primary factors contributing to the growth of the U.S. market are:

- Federal Production Tax Credit
- State policies mandating the use of renewable-energy technologies
- “Green power” markets

The goal of the U.S. Department of Energy’s (DOE) Wind Powering America Program is to generating 5% of the United States electricity from wind by the year 2020. This would require installing about 80 GW of U.S. wind capacity beyond the 2.5 GW installed through 1999. California ranks 17th among U.S. states in wind generation potential, with an established wind energy support infrastructure and utilities used to integrating the technology into their systems. This combination indicates California could play a significant role in meeting the DOE’s objectives.

Private developers and independent power producers operate almost all of the wind plants in California and most of the wind energy is sold to the utilities under long-term contracts. The utilities, in turn, schedule the delivery of the wind energy and energy from other sources to the grid with the State Power Exchange (PX) or the private Automated Power Exchange (APX). There are also several "merchant" wind projects in operation and under development that sell wind energy directly to the open market. Wind energy sold directly by private operators and merchant plants can be sold through either the PX or APX, which serve as the scheduler. The APX also operates a "green ticket" system that issues a green ticket to the generator for each unit of wind energy generated and allows energy suppliers to purchase green energy by buying the green tickets from the generators.

Within California, there was significant re-powering of established facilities in 1999, but there have been less than 30 MW of totally new wind projects developed since 1998. The limited growth of new projects can be attributed to multiple factors; however, the most compelling is the absence of a market that the industry can sell into competitively. The established PX generally requires power-plant operators to commit at least a day in advance for energy deliveries and charges penalties for unmet commitments. The intermittent nature of wind and the industry's inability to accurately forecast resources a day ahead make it very difficult to finance wind-energy projects planning to sell power to the PX.

Of the 262 MW of wind-energy projects that were granted awards from the New Renewable Resources Account, established by California State Assembly Bill 1890, less than 20 MW have been built. There are a variety of reasons for this lack of development; however, the dominant ones are:

- Difficult financing due to lack of a defined market
- Limited transmission capacity out of the Tehachapi wind-resource area
- Projects rendered uneconomic by the costs of new transmission

Utility-scale wind-energy technology in California has traditionally served as a supplier to Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE). In the developing deregulated market, there are a number of new potential customers. These include:

- Green-power marketers
- Municipalities interested in becoming green-power consumers
- State and federal government agencies
- Private entities for whom the use of renewable energy is important

While these customers are all interested in wind energy's "green" attributes, the cost of the energy is still an important consideration. The costs of wind energy are very heavily dependent on capital costs of the equipment and the financing that can be obtained. Capital costs are decreasing as the industry matures and the benefits of volume production are realized. In addition, technological advances are contributing to a reduction in capital costs. The most significant factors in the costs of financing are the creditworthiness of the energy buyer and the

degree of future energy-price certainty. The more creditworthy the buyer and the longer-term the price certainty, the better the financing terms (interest rate, loan term, etc.) will be.

A significant amount of installed capacity in California has been replaced with new equipment. And in this process the energy production of the re-powered projects has increased substantially, typically between 50% and 100%. Many of the remaining projects could similarly increase production by re-powering. However, the potential for this is seriously limited by language in the federal production tax credit (PTC) extension of 1999, which prevents its application to some of the re-powered facility's output if it operates under an existing power-purchase agreement. This dramatically reduces the number of re-powering projects that can be financed.

Three-bladed, upwind turbines mounted on freestanding tubular towers generally dominate the wind-turbine market. This is the traditional configuration: well demonstrated, understood by project operators, and proven to be reliable. Except for the lattice towers offered by some manufactures, it is, for practical purposes, the only turbine configuration available in the industry today. However, at least one U.S. Company is developing a two-bladed, downwind configuration, and several European companies are examining alternative configurations. But none of these products are now on the market. The major criteria on which alternative configurations will be judged are reliability, acoustic signature, and cost of energy relative to the existing technology. Other factors will be the commercial experience and financial strength of organizations offering the technology.

As manufacturers work to reduce turbine costs there is a definite trend toward lighter, more-flexible blades and towers. This trend increases the difficulty of predicting the dynamic response of the machine and thus increases the importance of field experience in a range of environments to demonstrate the adequacy of a new turbine design. Another technical area with significant potential for reducing turbine costs is the use of higher rotor-tip speeds. Higher tip speeds allow the drive train to spin faster and reduce its torque a specific power level. Lower torque-per-unit-power results in a lower-cost drive train. The noise associated with higher tip speeds has limited the use of this effect.

Appendix B provides a representative list of the major players in the California utility-scale wind-energy market. Interviews with some of these organizations showed that there is a wide range of perceptions concerning the size of the California wind-energy market in the next 5-10 years. All participants agreed the market could be growing more rapidly, but it is limited by transmission-related constraints and the treatment of intermittent generation in the marketplace. Despite these concerns, several of the organizations expected to be developing 100-200 MW/year for the next 5 years (assuming a continuation of the Federal PTC). Others, far more pessimistic, pointed out that relatively little truly new wind capacity has been added in California in the past 5 years. The different outlooks appear to come from different opinions regarding favorable resolution of the transmission and market issues facing wind technology. In essence, they feel that the size of the market will depend significantly on the ability of the regulators to create a market structure that fosters the technology.

Small Wind Systems

Historical Market

Grid-Connected

From 1980 until the beginning of California's small wind-turbine buy-down program, the market for grid-connected small wind turbines was modest. Approximately 100 machines, ranging from 1 to 10 kW, were sold over the entire period.[1]

Off-Grid Residential

From 1972 through 1998, the California market for residential off-grid small wind turbines was modest, although it expanded significantly with the introduction of inexpensive, small (300- and 400-watt) machines in the 1990s. Approximately 2,000 turbines were purchased during this period.

Off-Grid Telecom

From 1980 through 1998, the California market for off-grid small wind turbines for telecommunications applications was modest. Less than 80 turbines were purchased during the period. Most of these machines are still in operation today.

Current Market

Grid-Connected

The current market for grid-connected small turbines can best be determined by analyzing the results of the CEC-implemented small-turbine buy-down program.[2] The CEC reports that requests for buy-down incentives were as follows:[3]

- In 1998, 5 turbines, ranging from 1,425 to 9,600 watts.
- In the first 6 months of 1999, 12 turbines, ranging from 285 to 2,357 watts.
- In the second 6 months of 1999, 26 turbines, ranging from 448 to 9,600 watts.

---

1 These figures do not include sales of machines from Jacobs, which were unavailable at the time of this writing.

2 Note that inclusion of wind-energy systems in the CA net-metering law has played an important role in increasing the economic viability of small wind installations.

3 These figures include the wind-energy systems that were completed; approved, but not yet completed; and reservation received, but not yet approved. These are probably the best figures to determine customer interest and market size.

This indicates a clear trend of increasing sales over time; however, this market has evolved slower than many anticipated. This can be attributed to the following factors (in decreasing order of importance):

- Slow development of satisfactory inverter technology — One significant manufacturer of small wind turbines did not have an inverter suitable for the California market available until January 2000. A second manufacturer is still dissatisfied with current inverter technology.
- Poor customer awareness — Generally, consumers are not familiar with small wind-turbine technology or how they could utilize it.
- Lack of customer interest — One manufacturer stated that it is very difficult to get customers thinking about the benefits of using renewable technology. People simply have higher priorities. A consumer-awareness and -education campaign could overcome this factor.
- Local zoning requirements — Local zoning requirements have stalled or halted numerous sales of small wind turbines.

Despite these obstacles, manufacturers are bringing qualifying products to market and sales of those products are increasing steadily. The effective use of consumer-education funds could significantly increase sales of small turbines. Since California allows for net metering, the customer receives a credit for the excess power at the same rate paid for the power received from the grid. This net metering enhances the economics of small turbines relative to a market without net metering. Small wind systems do not typically sell power through the California PX or the APX.

Off-Grid Residential

For remote off-grid applications, the small wind systems are often integrated with PV panels, batteries, and perhaps a backup generator fueled by propane or diesel fuel. These off-grid systems either supply dc power directly for lighting and other uses or they supply 60-Hz ac power through an inverter.

The current market for off-grid wind systems is steadily expanding, particularly for systems under 500 watts. Current estimates are that approximately 800 of these small systems were sold in 1999, along with approximately 75 machines in the 1–10 kW range.

Off-Grid Telecom

The current market for telecommunications off-grid wind turbines is expanding slowly. Current estimates are that approximately 75 machines, most under 1 kW, were sold into this market. The impediments to greater use of the technology are generally the same as for off-grid residential markets.

The off-grid market for both residential and telecommunications small wind systems has been impeded primarily by their high costs. The California buy-down program applies to only grid-connected systems, leaving off-grid system prices unchanged. The issues of poor customer

awareness, lack of customer interest, and local zoning requirements are also significant market impediments.

Future Market

The market for small wind-turbine component sales and services is likely to accelerate both inside and outside of California, especially if the evolving deregulation of the industry results in the kind of rate spikes that have dramatically increased electric bills received by customers in San Diego during 2000. Customers faced with skyrocketing electricity bills are actively investigating and purchasing equipment and services to install small wind systems, rooftop PV panels, and other distributed-generation technology at their homes and businesses to reduce their monthly electricity bills. It is likely that this will be a growing trend in the future, especially in California, while the State buys down the cost of PV and wind systems under the terms of the deregulation bill.

Estimates of future markets are extremely difficult. Markets for small wind technologies will be heavily influenced by future public policies and unpredictable energy prices. Buy-down programs and favorable net-metering terms will continue to be important sales drivers, as will be the success of State-supported consumer education. Difficulties with local zoning laws will continue to impede the market.

Grid-Connected

Over the next several years, until the buy-down program funds are exhausted, the industry anticipates sales of 300–500 turbines per year, ranging in size from 400 watts to 10 kW.

Off-Grid Residential

Sales of small turbines for off-grid residential applications will continue to grow over the next several years. Based on historical data, sales of 250–400 turbines per year, mostly 400 W, appear reasonable.

Off-Grid Telecom

Sales of small turbines for off-grid telecommunications applications will also continue to grow over the next several years. Based on historical trends, the same projection as for off-grid residential systems appears reasonable.

Operating Experience

Utility Scale

For practical purposes there have been three different development cycles in the history of the California wind industry. In the early 1980s, hundreds of megawatts of new capacity was

installed using turbines with little or no operating experience in the California environment. These turbines generally ranged in size between 40 and 120 kW. In the late 1980s and very early 1990s several hundred additional megawatts were installed using larger turbines rated between 200 and 300 kW; and in the late 1990s, numerous projects were re-powered using turbines rated between 600 and 800 kW. After each of these cycles, the recently installed turbines experienced mechanical breakdowns. In response, the owner/operators worked to develop solutions to the problems to ensure the turbines achieved availabilities over 95%. The problems following the installations in the early 1980s were highly publicized and were coupled with a significant under performance of the projects due to inaccurate energy projections and poor availability resulting from the mechanical problems. The problems with the turbines installed during the early 1990s were less widely publicized and did not have the same impact on turbine availability. This was due partly to lessons learned in the early 1980s. But the fact that the turbine manufacturers, owners, and operators were better capitalized, and therefore better able to implement repairs in a timely manner, was also important. The most recent problems have received some publicity, particularly the gearing-related ones. However, once again, turbine availability has generally been only marginally impacted, due to the response of operators and manufacturers. As a result, the majority of the projects operating in California are typically achieving availabilities over 95%. Re-powered projects are experiencing capacity factors of 35% to 45%, while the capacity factors for older facilities are generally in the 20% to 35% range. The increase in capacity factors can be attributed to improved turbine technology as well as improved ability to identify the high wind resource areas and utilize them efficiently by using larger turbines.

The majority of downtime is attributed to electrical and controller-related problems, but most of these are normal maintenance items for equipment that is over ten years old. Newer projects are experiencing problems with gearboxes and other components. To date, these have not caused substantial downtime and the turbine manufacturers are responding to correct the problems.

Small Wind Systems

The operating experience of small wind turbines can best be summarized by the number that are in operation relative to the number installed.

Most of the grid-connected small wind systems installed in California prior to the CEC buy-down program are no longer in operation for a variety of reasons, including (in decreasing order of importance):

- Poor product design by some manufacturers[4]
- Failure of inverters
- Lack of proper maintenance
- Installation at location with inadequate wind resource.

4 Some manufacturers had much higher failure rates than others. It would be incorrect to conclude that product design was a major contributor to lack of operation for all manufacturers.

Most of the off-grid turbines installed in the 1990s are still in operation although only about 50% of the machines installed in the 1970s and 1980s are in operation today. Reasons for turbine failure include:

- Lack of proper maintenance
- Poor product design by some manufacturers[4]
- Owner moved and dismantled turbine
- Owner using PV instead
- Installation at location with inadequate wind resource (primarily machines under 1 kW)

The relative success of off-grid systems compared to on-grid systems appears to be related to the maintenance activities. Owners of on-grid systems were more inclined to allow the systems to remain out-of-service thus not incurring or delaying repair expenses. This approach could be applied because access to energy from the grid was readily available. Whereas owners of off-grid systems had to implement repairs since no other source of energy was available. In addition they were more concerned about preventative maintenance and system reliability, thus improving the success of off-grid systems. It should be noted that a competitor has acquired at least one of the companies selling turbines in California during the 1970s and 1980s and relatively unreliable products are being eliminated from their product line.

Cost and Benefits

Utility-Scale Wind Systems

The cost of wind energy consists of the cost of servicing the capital investment, including debt service, return paid to equity investors, depreciation, income taxes, property tax and insurance; operation and maintenance expense; periodic component replacement; and land-lease expense; less the Federal Production Tax Credit, if eligible. The long-term power sales contract is usually structured to cover the project costs and provide an acceptable return to the equity investors over the life of the project. For large projects constructed since 1998, the power-sales contracts are typically in the range of 3–5¢/kWh with the Production Tax Credit, and 5–7.0¢/kWh without it.

Capital Costs

The costs of installed utility scale wind power plants varies substantially depending on a variety of factors including:

- Project size
- Financing structure
- Strength of the dollar (the majority of turbines are manufactured in Europe)
- Terrain and other site conditions
- Construction market conditions

- Tower height
- Other factors

For this reason, it is unrealistic to use a single dollar-per-kilowatt value to represent the installed cost of a wind power plant. The EPRI Technical Assessment Guide (TAG) identifies a range from $1,600/kW for a single turbine project to $1,000/kW for projects over 50 MW as being typical. Recent project costs in the U.S. are generally toward the lower end of this range and divided among the various cost elements as shown in Table 2-2.

Table 2-2
Typical Project Capital Cost Elements

Turbines, FOB USA	49%
Construction	22%
Towers (tubular steel)	10%
Interest During Construction	4%
Interconnect/Substation	4%
Development Activity	4%
Financing & Legal Fees	3%
Design & Engineering	2%
Land Transportation	2%

Operations and Maintenance Costs

Operations and Maintenance is a cost category that is frequently used to describe a variety of costs. Cost elements that can be include in this category include:

- Land leases
- On turbine labor
- Supervisory labor
- Clerical labor
- Parts and Equipment
- Taxes
- Insurance
- Project management
- Office expenses

The extent to which these costs are incurred by, and attributed to, a project depends on the project structure. Operations and maintenance can be further broken down into preventive or scheduled maintenance, repair of random failures and reinvestments as turbine components wear out. The extent to which these are considered depends on the age of the turbine and the accounting methods used for operations and maintenance costs.

EPRI Technical Assessment Guide suggests a range of O&M costs of from $32.71/kW for a 1 MW plant to $19.32/kW for a 200 MW plant. At a 35% capacity factor these are equivalent to 1.0¢/kWh and 0.63¢/kWh.

Energy Production

The performance of a wind power plant is dependant on the wind resource as well as the spacing of the turbines, the turbine's power curve and losses such blade soiling and turbine availability. Generally the most significant factor is the wind resource. At the present time, the economics of wind energy projects in the United States require capacity factors greater than 30 percent to be economically viable. Wind speeds in excess of 7.5 m/s are generally required to achieve these capacity factors after considering losses.[5] This may change as the cost of energy increases and the cost of turbines declines.

Financing Costs

The financing structure of wind power plants has a significant impact on their economics due to the capital-intensive nature of the technology. Some developers have been internally financing projects; however, most rely on a combination of debt and equity financing in a classical project-finance arrangement. The terms of this financing vary with the economic climate, the confidence in the wind resource assessment and turbine technology and other factors. Generally, debt costs 2–3 percentage points above the prime rate and equity participants have been requiring 12–16% returns.

The principal economic and public benefits of utility-scale wind systems include the direct avoidance of the acid-gas (SO_2 and NO_X), toxic-metal, and greenhouse-gas (CO_2) emissions of the fossil-fuel generation they replace; reduced dependence upon on native and imported fossil fuels; creation of jobs for wind-turbine component manufacturing, maintenance, and operation; and generation of sales-, income-, and property-tax revenues for State and local government. Strictly speaking, the environmental benefits should make utility-scale wind systems more valuable than an otherwise-equivalent fossil-fueled plant, but such "externalities" are not generally accounted for in present-day electricity markets. Many of these benefits are quantified in Section VIII of this report.

Small-Wind Systems

The cost of energy from small wind-energy systems depends on the system capital costs; the costs of financing the system and the energy production form the system. Capital cost components include the small wind-turbine equipment, controls, and power inverter. Additional costs may include shipping, taxes, permit costs, foundation and anchoring, wire run, electrical hook-up, and inspection fees. Depending on the application, the system may require the battery

5 EPRI Report, *Renewable Energy Technical Assessment Guide—TAG-RE: 2000* (1000574) 2001. Assuming 10% losses.

banks, dc power center, and the equipment needed for a hybrid system, such as PV array, mounting and additional wiring and controls.

Installing a small wind system may cost as little as $3,000 or as much as $100,000 with costs per kilowatt of turbine rating in the $1,500 to $4,000 range. These costs vary depending on the size, installation and application. Several manufacturers provide turn-key packages (ready-to-use) that include installation costs, maintenance agreements, and product warranties. Factory direct purchasing and self-installation offers significant savings and provides the benefit of hands-on-understanding of the equipment.

Smaller systems used primarily for back-up power and utility-bill reduction may only be 1–2 kW in size, providing approximately 60–400 kWh per month, depending on the wind resource. These systems cost between $2,500 and $8,500 with additional fees ranging $500-$4,000, so the owner could expect to pay between $3,000 and $12,500. Low costs reflect self-installation and high costs include additional customer support. Depending on the resource and financing assumptions, the cost of energy from these systems ranges from approximately $0.25 to $1.25/kWh.

The average home uses 9,400 kWh/year, 780 kWh/month, which could be met with a 10 kW wind turbine. This system would cost $24,000-$27,000, with additional fees $2,500-$8,000, resulting in overall costs ranging between $24,500-$35,000. Depending on the wind resource and financing assumptions, the cost of energy for these systems ranges from 13¢ to 76¢ per kilowatt-hour. Off-grid and hybrid applications could increase the overall costs to $61,500-$87,000 and the cost of energy from 30¢/kWh to $2.00/kWh.

A small wind system containing one or two turbines with a rated nameplate capacity of 50 kW is a more substantial investment. For average wind speeds of 5–10 m/s, net annual energy output ranges between 75,000–275,000 kWh, approximately 6,000–23,000 kWh per month. For residential, commercial, or other applications, a system connected to the distribution grid would cost approximately $70,000 with additional fees bringing the overall cost to $85,000–$100,000. The cost of energy would range from 5¢ to 28¢/kWh.

Similar to utility-scale wind systems, the principal economic and public benefits of small wind systems include the direct avoidance of the acid-gas (SO_2 and NO_X), toxic-metal, and greenhouse-gas (CO_2) emissions of the fossil-fuel generation they replace. A typical 10 kW wind turbine is estimated to offset 1.2 tons of air pollutants and 250 tons of greenhouse gas in its 30-year lifespan. Small wind systems reduce dependence upon native and imported fossil fuels; create jobs for small wind-turbine component manufacturing, maintenance, operation, and servicing; and generation of sales-, income-, and property-tax revenues for State and local government. In addition, the small wind systems provide an alternative to distribution grid electricity or a reduction in the electricity bills for the owner.

Research Needs and Recommendations

Utility Scale

The wind-energy industry has demonstrated the ability to rapidly develop projects in California, giving required consideration to the concerns of the environmental community, local landowners and municipalities. There are ample documented wind resources in the State. The two factors most responsible for the relatively slow recent growth of the market in California are the lack of a financial contract or market tailored for wind energy and limited or costly transmission access from the best wind-resource areas.

Conversations with multiple participants in the California wind-energy market indicated there are significantly different opinions regarding the usefulness of various areas of research. However, all participants agreed that the current market structure makes it very difficult for intermittent generation to compete and that transmission access is increasingly an impediment. There appears to be a consensus that one investor-owned utility is heavily biased against wind energy. As a result, contract negotiations, transmission-access issues and other transactions with that utility are believed to be overly time consuming, expensive and inconsistent with the industry's rapid expansion. Many wind-industry insiders appear to believe that, given market access that recognizes wind's intermittency, the existing technology is adequate and manufacturers will develop needed innovations without R&D support from the CEC or others. This is in marked contrast to some of the energy service providers, who strongly encouraged the development of more cost-effective advanced technologies. U.S.-based turbine manufactures also supported additional technology research and development as did those who believe that failure to maintain the country's technical expertise through government-supported research and development will ultimately cede the industry to the Europeans and others. It was also noted that the current competitive position of wind is significantly improved by the federal production tax credit. Without the tax credit, which is currently scheduled to expire in December 2001, the price of wind energy would increase substantially. Advanced technology is expected to keep the true costs of wind energy declining over the next five years.

Areas where at least some industry participants believe the market would benefit from additional research include:

- Creation of a reliable, predictable, long-term market for wind energy. Some ideas for this include: requiring that intermittent renewable technologies be treated as changes in system load, the use of industry support funds to offset any premium that wind energy would cost State agencies or other entities willing to sign up for long-term power-purchase contracts, and providing a tax credit to consumers of renewable energy.
- Resolution of the transmission constraints from the Tehachapi area.
- Forecasting wind resources to improve the industry's ability to operate in power exchange markets.
- A better understanding of the mechanisms that drive the green premium-power markets.
- Innovative policies that result in a green premium commensurate with the value offered by green energy.

- Development of advanced turbine concepts using innovative rotor and drive-train technologies to reduce cost of electricity.
- Development of cost-effective storage technologies that would allow wind energy to be treated as a dispatchable resource.
- Improved wind-turbine component monitoring and maintenance procedures to reduce forced outages, especially during the high wind season.
- Development of resource assessment tools that reduce the costs and time required for high quality resource assessment.

Small Wind Systems

Small turbine manufacturers and distributors differ in their views of the markets research needs; however, several common themes were apparent from discussions with industry participants. The most recurring theme was that consumers do not understand the technology, so consumer-education and -awareness programs are needed. There was also consensus that zoning regulations to accommodate small wind-energy systems would greatly improve their market acceptance. In addition, the small wind-energy industry felt that the small wind-turbine market in California would benefit from research in the following areas:

- Resource Assessment — Additional resource assessment work could help define the areas where the technology should be promoted.
- Interface Devices — Inverters currently available in the marketplace are generally designed to receive a constant voltage. Small wind turbines generate a variable voltage that is difficult for these inverters to process. Research into highly reliable, cost-effective inverter technology specifically suited to small wind turbines would promote the industry.
- Advanced Manufacturing Techniques — The small wind-turbine industry is poorly tooled for mass production. Manufacturing costs need to be reduced to lower costs and increase sales. In the face of a limited and uncertain market, the costs to develop the required tooling are difficult to justify for the small companies manufacturing and selling small wind turbines.

3
GEOTHERMAL

Introduction

Geothermal power plants have been operating in California for over 40 years and represent nearly one half of the State's installed non-hydro renewable capacity. Located on the tectonic "Pacific Ring of Fire," California's geothermal resources are internationally known and actively exploited. Although the focus of this report is on using geothermal energy for electric power production, which is geothermal's major use today, there are also other applications that use the earth's heat directly at numerous sites in California. Representative major US companies in the geothermal industry, their business focus, and contact information are provided in Appendix B.

Approximately 1,754 MW of geothermal power plants are currently operating in California, and six new projects, totaling 297 MW, are under development. An additional 150–200 MW are under consideration for Imperial Valley, but not officially announced. Table 3-1 breaks down the operating capacity by County. Appendix A provides additional project-specific detail on the existing and planned projects, including project name, location, owner type, completion date, and other relevant information.

Table 3-1
Geothermal Capacity by Location

	Current Operating Capacity		Planned New Capacity	
Location	MW	% of Total	MW	% of Total
Imperial	421	24%	59	20%
Inyo	240	14%	0	0%
Lake	435	25%	55	19%
Modoc	3	0%	0	0%
Mono	27	2%	0	0%
Siskiyou	0	0%	98	33%
Sonoma	628	36%	85	28%
TOTAL	1,754		297	

Technology Characterization

Geothermal power production is now a mature technology with a worldwide operating capacity of approximately 8,000 MW. In California, power is produced from geothermal fields using direct steam, flashed steam or binary heat-exchanger processes. The type of conversion process used depends on the state of the fluid (whether steam or water) and its temperature.

Steam – Dry-steam power plants draw from underground reservoirs of steam. Conventional steam turbines are used with hydrothermal fluids that are wholly or primarily steam. The steam is gathered from wells and routed directly to the turbine, which drives an electric generator. Figure 3-1 illustrates a typical steam power plant located at The Geysers, one of California's major geothermal resources.

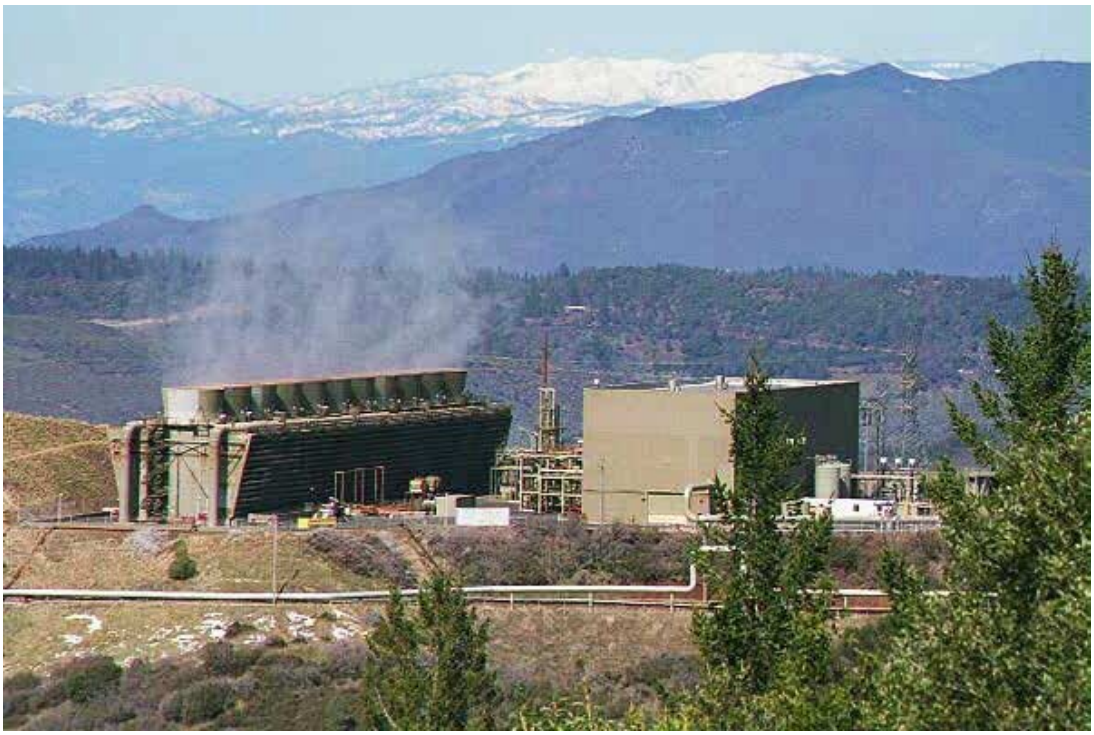


Figure 3-1
Typical Direct-Steam Plant at The Geysers

- Flash Steam – For hydrothermal fluids above 360ºF (182ºC) that are primarily water, flash-steam technology is usually employed. This uses very hot water that flows up through wells in the ground under its own pressure. The water is sprayed into a tank held at a much lower pressure than the fluid, causing some of the fluid to vaporize rapidly, or 'flash' to steam. The produced steam is then used in a conventional turbine-generator. The remaining water and condensed steam are injected through a well, back into the geothermal reservoir.
- Figure 3-2 illustrates the flash-steam power-plant cycle and Figure 3-3 illustrates a typical flash-steam power plant.

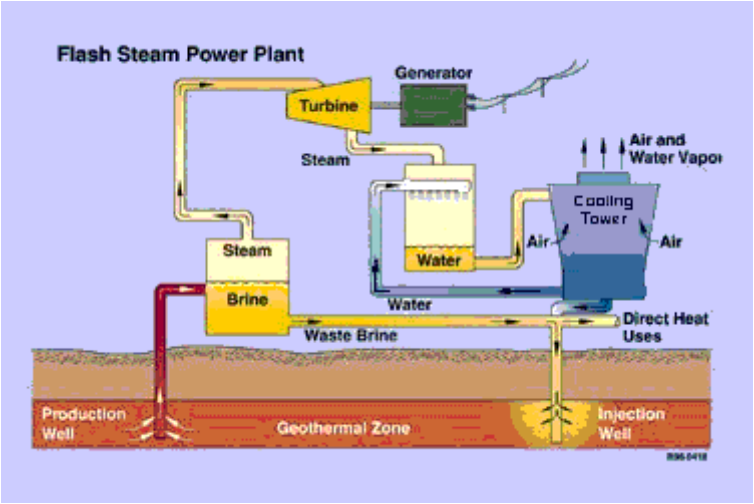


Figure 3-2
Typical Flash Steam Cycle

Figure 3-3
Typical Flash Plant at Coso Hot Springs

Binary Cycle – For hydrothermal fluids with temperatures less than 360ºF (182ºC), binary-cycle technology is generally most cost-effective. In-well pumps bring the hot hydrothermal fluid to the surface, where it is passed through a heat exchanger and vaporizes a secondary fluid[1] that drives a special-design turbine. The water, having given up its heat, is returned to the geothermal reservoir using a deep well. The water and the working fluid are confined to separate closed loops during the whole process, so there are little or no air emissions. Figure 3-4 illustrates a typical binary-cycle plant.

1 Usually an organic compound with a low boiling point

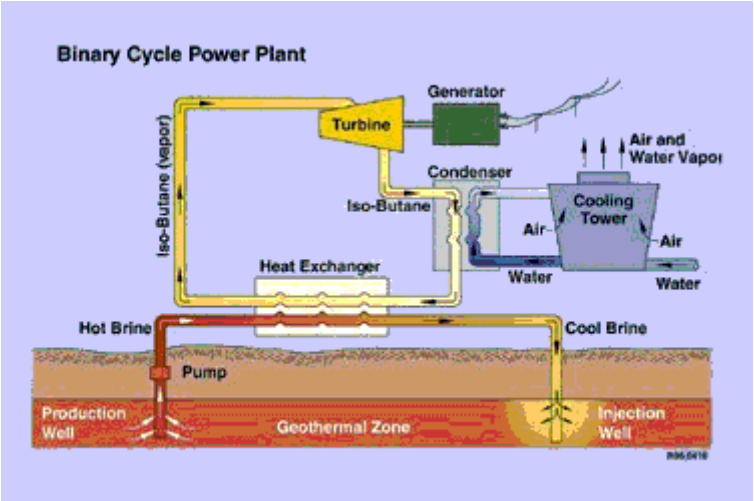


Figure 3-4
Typical Binary Cycle

Geothermal power plants are sized according to the volume, temperature, and chemistry of the geothermal reservoir underlying the project. Typical sizes are from 10 to 50 MW, although some 130-MW power plants are in operation.

Land-use patterns for geothermal power plants vary with site design and type of installation. The well field may cover 100 to 200 acres (40–80 hectares), but the heat is tapped by drilling slant wells from a single above ground location. A typical 50-MW plant and well sites may occupy one or two acres (0.4–0.8 hectare). In some cases, multiple wellhead locations are required for a single plant. In this case above-ground lines carry the resource to the power plant.

Geothermal plants are dispatchable. Ramp rates of at least 5 MW/hour are typical. Energy production is not affected by daily or seasonal resource-supply fluctuations.

Geothermal's "renewable" classification arises from its use of naturally replenished heat from below the earth's surface. However, economically attractive uses for power generation generally require that the hot water or steam be extracted faster than the natural flows of heat and water in the underground reservoir of fractured rock can replenish. Reinjection of the used, cooled fluid into the ground where it flows gradually back into the hot zone of the reservoir and counteracts the depletion of the hot fluid does not always eliminate resource depletion.

Geothermal energy's environmental concerns include land-use issues, gaseous emissions, and certain chemicals that may be entrained in the steam and must be captured and processed. The land-use issues are similar to those experienced by conventional power plants, and the industry has developed various methods to mitigate chemical concerns. As shown in Figure 3-5, geothermal power-plant sulfur and carbon dioxide emissions are significantly lower than conventional fossil-fuel-fired plants.

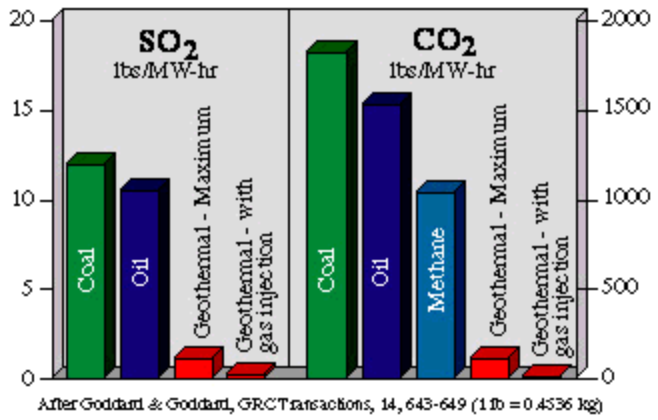


Figure 3-5
Geothermal vs. Fossil Fuel Emissions

Direct use of geothermal fluids is another way to utilize a geothermal resource. Generally used for lower temperature resources, direct-use geothermal applications include aquaculture, greenhouses, vegetable drying, and building heating.

Geothermal Heat Pumps (GHP) are used to heat or cool homes and large buildings. GHPs exchange heat by means of shallow wells (100 feet or 30 meters) drilled into rock or soil. GHPs take advantage of the constant temperature that exists at these shallow depths. Heat pumps differ from basic geothermal technology because they do not extract heat from the earth's core. Sometimes called ground-source heat pumps, GHPs operate best in climates with extreme temperature changes between summer and winter.

Market Information

As a mature technology with a demonstrated track record of reliable operation, geothermal power plants are a viable energy source for the near term in California. Recently, geothermal development has been slow, with only a single 40-MW plant commissioned in the past five years.[2] The two factors most frequently cited for the limited development are permitting problems and the high costs of resource exploration and development. Several proposed projects have been severely delayed in permitting, and market prices have not been sufficient to encourage more vigorous project development.

Geothermal power development is also limited by the availability of economically feasible resource sites near transmission lines. While market participants do not generally cite transmission constraints as a restriction on development, the U.S. Forest Service's denial of permits for transmission lines and the high costs of alternate routing have delayed several planned projects. In addition, the transmission capacity out of the Imperial Valley resource area is approaching saturation, potentially restricting further utilization of this established resource.

2 Excluding two facilities currently in the startup phase.

Without significant changes in the costs of development and/or the permitting process, geothermal market participants generally see limited potential for utilizing additional geothermal resources in California. Some participants believe that the renewables market is fully saturated by the existing facilities. As a result, they expect the renewables price premium to be relatively low and geothermal plants will have to operate in the PX markets. While PX prices have been attractive recently, industry participants expect prices to stabilize as new gas-fired capacity comes on line. In addition, the permitting-delay experiences have caused market participants to question the feasibility of making the investments needed for additional development. These factors have caused the industry to consider further development of existing plants to be the most viable way to increase California's geothermal capacity in the near term.

The actual installed capacity at The Geysers geothermal field is over 600 MW greater than the present operating capacity. This is because the steam pressure has declined as the projects have operated to a point where the most economical approach to operating the facilities is to de-rate them. Considerable effort is going into restoring the resource through the use of wastewater injection and drilling additional wells.

There is also significant new geothermal resource in California that could be developed if market conditions were able to justify the development costs.

Resources sufficient to add another 500–1000 MW of flash-process capacity in California have been identified. The two most promising sites for further development of this type are Imperial Valley in the south and Siskiyou County in the north. Of the two, the Imperial Valley, which includes more than one geothermal field, has a much larger near-term potential to expand. The largest limiting factors to exploiting these resources are (1) opposition to new or expanded projects by local residents (substantially less evident in Imperial County than in the north), and (2) economic viability. Although the recent dramatic upswing in energy prices may encourage new projects, the industry must continue to focus on ways to reduce the cost of finding and developing geothermal energy.

A recent study of geothermal resources identified 271 collocated cities and communities in the 10 western states that could potentially use geothermal energy in some way. Seventy of these communities are in California. Very few of these sites have been evaluated, much less developed, because of poor economic viability and lack of interest in developing small (<10 MW) resources. Some of these sites may be ideal candidates for small geothermal power projects where treated wastewater from nearby communities could be injected deep into the reservoir to make additional power. The injection technology is presently being evaluated and developed at The Geysers using wastewater from Lake County. In addition, there are plans to inject wastewater from Santa Rosa into the Geysers resource. As the injection technology matures, it may be applied to some of the collocated resources. It is expected that binary-cycle systems will play a significant role in development of these resources because they are generally low temperature.

The binary process is not yet widely applied in California. Most of the candidate sites are small with little prospect of economic viability at today's energy prices. The technology lends itself to hydrothermal reservoirs at temperatures between 200 and 360 degrees Fahrenheit (93–182ºC).

Several government programs support the geothermal industry in California. The California Energy Commission (CEC) solicits proposals for co-funding geothermal research and feasibility

studies through the Geothermal Resource Development Account (GRDA) and through the PIER Renewables Program. The CEC currently funds portions of a project to inject treated wastewater from the Santa Rosa area into The Geysers reservoir to make additional steam and electricity. The CEC expects to solicit more GRDA projects in 2000. In addition, the U.S. Department of Energy has initiated a program, "Geopowering the West", to solicit proposals from the industry to develop additional power from geothermal resources. This program is expected to increase the use of geothermal energy in California and other western states. Early studies have uncovered 58 potential sites in California where geothermal potential has been observed. Some of these sites may be candidates for injection of wastewater from some population centers.

Direct use of geothermal fluids is ongoing at several sites in California. Aquaculture, green houses and vegetable-drying projects were developed during the energy crisis of the 1970s. District-heating projects are being tested in a few locations. There are a few new projects in the proposal stage, and if energy prices continue to rise, more new projects will evolve.

The use of GHPs in California has been growing slowly but steadily. The market for these units is adversely affected by high initial cost, but they can be competitive with conventional heating/-cooling units in the long run.

In summary, the geothermal market in California is being driven by several factors:

- The market price for electricity has risen to unprecedented levels this year. While the industry expects these prices to subside as new, high-efficiency gas-powered plants come on line, the outlook for sustained high gas prices provides sufficient incentive to expand existing projects where reservoir capacity is reasonably well understood. The industry informally estimates this potential at 400–500 MW.
- Permitting problems and high costs are limiting development of totally new resources. While exploration costs do not emerge as a high-cost item in a project's life-cycle cost, they are high enough to be a front-end barrier to starting and expanding a project, especially in the light of uncertain competitive prospects in a deregulated market.
- The U.S. DOE program, "GeoPowering the West", is providing industry with an incentive to explore for useable heat at some smaller identified sites where surface conditions suggest the existence of a geothermal resource.
- The CEC's existing programs are supporting advances in geothermal technology. State legislators and regulators have been meeting with key industry officials to determine the industry's potential for expansion, and what incentives for expansion should be considered. Industry representatives are encouraged by the possibility of continued incentives through an extension of the CEC's current programs.
- There is a limited market for direct-use and ground-source heat pumps in California due to the relatively high costs of utilizing these technologies.

Operating Experience

Geothermal power plants are dispatchable except during planned and unplanned maintenance. Experience has led to longer periods between major overhauls, with many operators planning

5-year intervals. Because of the strong economic incentive to stay online, plant operators minimize unplanned outages by using highly reliable equipment and by keeping adequate spare-parts inventories. Such strategies help them to achieve capacity factors of 85–95 percent.

Geothermal operators prefer to run their plants baseload because the fixed operating costs far exceed variable costs. The exception to this preference occurs when the (steam) fuel supply is inadequate for the power plant's capacity. In that case, the plant will operate at or near full capacity during the peak-use period (with the highest price for electricity) and then back down in off-peak periods to allow the steam supply to recuperate. As mentioned, this is the situation at The Geysers where the now-limited steam supply forces a de-rating of approximately 40%, even on peak. Aside from steam resource limitations, California geothermal plants operate with capacity factors and availabilities both averaging over 90%.

Cost and Benefits

The results presented in this section use a simple annual capital-recovery model that is in close agreement with the levelized-capital-charge approach used in the EPRI TAG. The resulting costs are in 1999 (not constant) dollars, and the 21%/year capital recovery corresponds to an assumed 4% real annual inflation.[3]

Economics

Geothermal power plants generate electricity for as little as 2–3¢/kWh (from existing plants with no capital cost to pay off) up to as much as 6–10¢/kWh. These are *total costs*, including both fixed and variable expenses. The *marginal cost*, which determines the price at which incremental kilowatt-hours can be sold profitably, is near *zero* for a geothermal plant. This is because the main operating cost is its fixed capital cost—the cost of constructing the geothermal field and generating plant—and there is no fuel cost. Also, most of the labor cost is fixed, so the cost of operating an added hour is very small. This means that a geothermal plant can improve its economic performance by selling into power-exchange markets even at times when the price falls to a very low level, perhaps even below 1¢/kWh, for example. But if the plant is to meet all expenses, the fixed costs must be recovered sometime over the course of the year, so the average cost recovered must be in the 3–10¢/kWh range.

---

3 EPRI and other design studies provide performance and cost numbers at the level of conceptual, feasibility studies. Specifying major components provides for a buildup of capital costs. These details are in the 1997 DOE-EPRI report, *Renewable Energy Technology Characterizations* (TR-109496). Using TAG methods or their simplified equivalents, the capital-, operating-, maintenance-, and fuel-cost components are calculated separately and added to give the total generating cost.

Specifically, the BIOPOWER model, based on TAG and used in TR-109496 and in the 1993 EPRI report, *Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation* (TR-102773), was used to see what simple factor for annual capital recovery would give the same current-dollar result for an inflation rate of 4% as did the levelized capital recovery in BIOPOWER for constant-dollar calculations. The factor that gave that result (21%/year—essentially equal to simple-payback in 5 years) was used for capital costs in the cases in this market assessment.

To cover an operating staff of 40, averaging $70,000 each in annual fully-loaded salary, a 50-MW plant generating the equivalent of 7900 full-load hours/year (about 90% capacity factor) must raise an additional 40 × $70,000 or $2,800,000 per year. This requires an average of $7/MWh.

For an existing plant with its capital charges fully amortized, there will still be substantial fixed costs of maintenance and repair. The largest of these fixed costs will probably be the cost to add new wells as the field declines in performance, i.e., less flow of hot water or steam from the existing wells and/or lower temperature fluid from those wells. Allowing for a 10% annual decline from the original wells, the replacement costs in the field part of the plant will be 10% of the $300–$700/kW spent on the field originally. This gives a cost range from $30–$70/kW-yr, or an annual $1.5–$3.5M for a 50-MW operation. For the powerhouse, an allowance of 5%/year to maintain the $700–$1400/kW original investment in that part of the plant adds another $1.75–$3.5M/year. Total maintenance costs then range from $3.25M to $7.0M per year for 50 MW at 90% capacity factor. These give a range from $8/MWh to $18/MWh. Adding the $7/MWh for the fixed cost of the operating staff gives a total for the low-cost case of $15–$25/MWh.

The high-cost cases arise when a new plant must be built. For a 50-MW project, the capital cost is approximately $1400/kW. At 21%/year capital recovery and 90% capacity factor, this is $40/MWh for capital. A 7%/year allowance for maintenance—an average of 5% on the powerhouse and 10% on the field—adds another $13/MWh. The total for a 50-MW project is then (40 capital + 13 maintenance + 7 operation) $60/MWh.

The costs for a smaller 10-MW plant would be higher. First, because its higher capital cost, $2000/kW, gives $57/MWh with the same 90% capacity factor. Second, its staff of 35 is proportionately larger, and therefore, more expensive, even at the same $70,000 labor rate: $30/MWh, rather than $7/MWh. Thus the total for the 10-MW plant is (57 capital + 13 maintenance + 30 operation) $100/MWh.

Benefit of Out-of-State Sales

California already has the dominant share of U.S. geothermal power deployment. Also, California is well endowed in individuals' expertise and active companies in geothermal power. An expansion of U.S. geothermal generating capacity will favor California because of that endowment and its good resource base. California-based companies are well placed for business abroad. Therefore, the prospect for leadership and economic benefit to California from out-of-state sales is good.

The State can give manufacturers an incentive to locate operations in California by providing the best opportunity to prove and improve their products through operations at the many resource sites in California. State actions to encourage this can include facilitating geothermal power-plant permitting and continued financial assistance to existing, new, and emerging geothermal projects and technologies. Both EPRI and the CEC have investigated hybrids of geothermal with natural gas in the past and this approach may prove helpful in assuring geothermal's participation in the next wave of natural gas-based power-plant construction.

Benefits of Geothermal Energy

The benefits of geothermal electricity generation in California have been quantified in projects and brochures done for the U.S. DOE by NREL and in CEC assessments. The largest benefits—not counting greenhouse gas reduction benefits, which are potentially very large but currently have no regulatory basis or consensus as to dollar value—are found to be from the avoidance of air emissions due to geothermal's having no combustion. Sulfur emissions from geothermal are hydrogen sulfide, not sulfur dioxide, and are small compared to the sulfur dioxide emitted in coal- and oil-fired power plants.[4] Avoiding NO_X-control costs is the greatest single quantifiable benefit. NGCC power plants in California will have to use expensive "selective catalytic reduction" (SCR) of NO_X, to reduce some emissions from 0.10 lb NO_2/MBtu to 0.05 lb. The cost is in the range from $500 to $2000 per ton of NO_2 removed. With the expected future NGCC heat rate of 7000 Btu/kWh, a 1000-MW expansion of geothermal capacity operating 7900 hours per year will replace 7.9 million MWh, equaling 55.3 trillion Btu of NGCC combustion. The savings resulting from not having to remove the corresponding (0.05 lb/MBtu × 55.3 million MBtu × 1 ton/2000 lb) 1400 tons of NO_2 will be $0.7M to $2.8M annually.

Research Needs and Recommendations

While geothermal is looked upon as a mature technology, there are many opportunities for improvement through research and development. Geothermal projects are very capital-intensive. Discussions with industry leaders suggest that that future geothermal R&D programs should focus on reducing the cost of finding and developing new geothermal resources.

The industry consensus is that characterizing the commercial potential of identified geothermal reservoirs in California is a high priority. Techniques such as fracture mapping, more accurate thermal-gradient wells, and other, untested methods should be evaluated and refined, if appropriate. The objective is to be able to measure the temperature, fluid characteristics, and permeability of the resource prior to committing to expensive production wells and generation equipment.

Industry comments suggest that structured, integrated tests and experiments by industry in collaboration with the California Energy Commission and the US Department of Energy are essential to ensure further development of commercial geothermal power in California. In the near term this work should focus on the following areas:

- Reducing life-cycle costs of electrical power generation
- Improving geothermal-facility efficiencies
- Finding techniques to more cost-effectively define resources
- Supporting funding to reduce production-drilling costs and develop direct-use demonstration and commercial projects

4 The emitted hydrogen sulfide eventually does become sulfur dioxide in the atmosphere. The special odor control required at some sites—when the hot water or steam contains significant hydrogen sulfide and the power cycle is not the closed-loop binary option—has been developed and is ready to apply when needed.

- Improving technology and technical support for geothermal direct-use projects
- Reducing Geothermal Heat Pumps (GHP) initial costs
- Improving professional training and consumer education campaigns for GHP
- Supporting financing programs for residential applications for GHP
- Understanding and improving waste-water injection
- Improving public awareness about the benefits of geothermal power, direct-use, and GHP

A long-term development concept called Enhanced Geothermal Systems (EGS)[5] involves injecting water into deep hot-rock formations that have been fractured by high-pressure pumping. The water is heated as it flows through the fractures, so it can be flashed to steam and generate power. The worldwide energy potential for this technology exceeds by orders of magnitude the world's foreseeable energy use. The technical challenges to be overcome before realizing that potential are: deep drilling (Wells must be 2–3 miles deep) and *in-situ* rock fracturing. A major EGS research program underway in Europe has yielded encouraging results. However, readiness for commercial application of this technology is thought to be at least 10 years away.

5 EGS is also known as "hot dry rock" or HDR geothermal resource.

4
BIOMASS

Introduction

Over 1,200 MW of biomass electric generating capacity has been installed in California, with fuel sources including wood, landfill gas, agricultural wastes, and digester gas from sewage treatment facilities and farms. Table 4-1 shows a breakdown of the California projects by fuel type. Of the 1,200 MW of installed capacity, 136 MW, approximately 11%, are currently in a shutdown or standby mode due to a variety of reasons related to their power-purchase terms and the cost and availability of the fuel source. The only has new projects proposed or planned are fueled by landfill gas. Appendix A provides additional project-specific details on the existing and planned projects, including project name, location, owner, developer, fuel type, technology employed, ability to dispatch, and other relevant information. Representative major companies in the biomass electric industry, their business focus, and contact information are provided in Appendix B.

Table 4-1
Biomass Capacity by Fuel Type

	Operational		Shut Down		Planned or Under Construction	
Fuel Type	**MW**	**% of Total**	**MW**	**% of Total**	**MW**	**% of Total**
Agricultural waste	126	12%	51	37%	0	0%
Biogas from wood or other gasification	8	1%	0	0%	0	0%
Digester gas (sewage sludge gas)	35	3%	0	0%	0	0%
Landfill gas	255	24%	3	3%	49	100%
Manure fuel	0	0%	18	13%	0	0%
Refuse (unprocessed municipal solid waste)	45	4%	1	1%	0	0%
Unspecified biomass	5	0%	0	0%	0	0%
Wood or wood-waste fuel	587	55%	63	46%	0	0%
TOTAL	1061		136		49	

Technology Characterization

Biomass fuels are diverse, ranging from urban-area and manufacturing wood residues to captured biogas from landfills or manure/sewage digesters. Likewise diverse are the technologies employed to convert biomass fuels to electricity and useful heat. Figure 4-1 shows the 50-megawatt (MW) Wheelabrator Shasta Plant in Anderson, CA. This plant is typical of today's direct-fired biomass power plants that are fueled by solid forms of biomass. Regardless of the type of boiler used, the primary means of obtaining electricity from traditional biomass is the same. [1] A biomass fuel is converted to heat energy in a highly controlled reactor (boiler or gasifier). The heat is used to convert water into high-pressure steam. The steam is fed into a steam turbine, causing it to rotate. The turbine spins a generator that produces electricity.

Figure 4-1
50-MW Biomass Power Plant in Anderson, CA

The majority of today's solid-fueled biopower generation comes from direct-fired facilities, but the most economical near-term option for introducing new biomass power generation is cofiring. Cofiring involves substituting biomass for a portion of the fossil fuel in an existing power plant furnace. Unfortunately for the immediate growth in use of biomass fuels for power in California, the State does not have coal-fired generation within its borders and, therefore, cannot expand via biomass cofiring with coal. However, natural gas can be cofired with biomass, either supplementally at an existing biomass-fueled power plant or with a gasified-biomass supplement at a natural-gas plant. Although the natural gas use in a biomass plant increases overall fuel costs, benefits of natural gas cofiring can include expanded fuel supply and diversity, slightly increased generation capacity ability to provide a small amount of peaking capacity and reduced air

1 Virtually all of today's solid fuel biomass boilers used to generate power in California are stoker-grate type or fluidized bed (FBC) and the biomass used 90% to 95% of the time is a woody or wood-based fuel.

emissions (CO, NO_x, and particulates).[2] In the future, perhaps soon, biomass gasification will enable the use of more advanced power-generation cycles that employ gas turbines or fuel cells. This may also allow cofiring biomass fuels at natural gas- and oil-fired power plants, even those based on combustion turbines, such as the natural gas combined-cycle (NGCC) plants that are expected to dominate new additions to generation capacity in California.

Currently, biomass residue sources account for 100% of the solid fuel direct-fired for biomass power production. For the U.S. as a whole, about 90% of that is wood waste and the remainder is agricultural residue. But as Table 1 indicates, more than 10% of California's biomass capacity is at plants that can fire agricultural residues, as well as wood. Much of this residue may be woody material, such as orchard clearing/thinning residues. In the past 5 years, a few researchers and a group of power generators in the Midwest, South, and Northeast have been testing the use of locally grown energy crops as a supplemental fuel source for power generation via cofiring and gasification. These early attempts to integrate crops with residue supplies represent the first steps to a sustainable large-scale supply of bioenergy. Bioenergy crops combined with residues and high-efficiency conversion systems foreshadow the future of biopower development.

Today's operating direct-fired solid fuel biomass power plants typically range from 10 MW to about 50 MW, with an average of about 20 MW. These units usually operate to supply base- or intermediate-load power and must have access to inexpensive sources of biomass to be competitive.

In contrast to direct combustion of solid biomass fuels, much solid and wet biomass, including municipal waste and sewage can—often, must—be biologically converted into "biogas," a combustible mixture of about equal parts methane and carbon dioxide. Biogas from landfills is often called "landfill gas"; and that from sewage or manure, "digester gas" or simply "biogas." Both landfill-gas and biogas systems currently have some generation capacity in California—the landfill-gas share being the more significant at 255 out of 1061 MW. (See Table 4-1, Biomass Capacity by Fuel Type.) Both landfill gas and biogas have substantial potential for capacity expansion. Generators operating on landfill gas or farm-manure biogas are smaller than the typical solid-fueled systems. This is because landfill and biogas operations are primarily installed for waste-management purposes rather than for generating electricity. These systems typically use internal-combustion engines or gas turbines, which are quite convenient for converting relatively small quantities of biogas energy into electricity and heat. A very few, larger commercially operating landfill-gas systems use boilers and steam turbines, and several tests are under way using fuel cells. The typical capacity at individual sites is between 1 and about 5 MWe for landfill gas systems and from 0.1 to about 1.0 MWe for manure- and sewage-digester operations.

There are several environmental impacts associated with biopower facilities. Water is needed for cooling (except with landfill gas and biogas), and effluents of treated water, combustion-process

2 Cofiring with natural gas at an existing biomass fueled power plant could be an attractive technology option for California. This would offer environmental and operational benefits at existing biomass power plants, while maintaining most of the fuel cost and solid residue disposal benefits of using low cost biomass fuels. In addition, once natural gas is available at the power plant it may be possible to add new higher-efficiency gas-fired generation systems at the site to expand overall generation capacity.

air emissions, and ash are generated. Each of these items requires careful monitoring and/or treatment to minimize negative environmental impacts and to comply with solid-, liquid-, and gaseous-effluent regulations. Some environmental groups are cautious in their support of biomass technologies. Their concerns include:

- Hazardous materials entering the fuel stream and resulting in hazardous emissions
- Power-plant demand for biomass materials leading to unsustainable harvesting or biomass diversion from environmentally preferred recycling operations
- Gaseous plant emissions unacceptably impacting air quality

An inescapable result of the combustion process is that there will be emissions that adversely impact the environment. Biopower proponents note, however, that a well-managed facility can minimize or eliminate these potential negative impacts while creating significant environmental benefits. Biopower provides a productive outlet for clean biomass residues, avoiding landfilling, open burning, or natural decomposition emissions. Forest materials removed from overgrown regions can also reduce the risk of wildfires and the associated losses in property and life. Biomass resources can also bring added value in co-products, local environmental preservation (soil and water conservation and wildlife biodiversity), and global climate-change insurance benefits (sequestering carbon).

Biomass power plants are relatively compact; on-site land requirements are slightly larger than those of a similarly rated coal-fired power plant. Depending on the fuel source, significant off-site acreage may be required to grow a biopower facility's fuel. Several research and demonstration efforts are under way in the U.S. to grow energy crops for future biopower facilities. These crops will require about 800 acres (300 hectares) per megawatt of power generation capacity. Present research goals include reducing this land requirement to 400 acres (150 hectares) per megawatt via a combination of higher-yield crops and more efficient conversion technology.

Market Information

Biomass power markets in California have gone through tremendous changes in the past decade. Power contracts issued under the Public Utilities Regulatory Policy Act of 1978 (PURPA) stimulated development of almost 60 biomass power projects in the State. The peak year for capacity, which approached 800 MW, was 1990. Since 1990, biomass power capacity has declined significantly. Of the 43 plants that were in operation in 1994, only 29 are currently producing electricity (not including biomass plants operating off of landfill gas, sewage sludge, or digester gas). Approximately a dozen of these are available to come back into service, if power prices become more favorable. This decline is freely attributed to closeout or buyout of the PURPA contracts in tandem with the restructuring of the electricity market in which lowest-priced power is the primary driver of customer choices. Although biomass is an abundant California resource, the costs of gathering and delivering the solid biomass fuels combined with the costs of building and owning biomass power plants have driven marginally economic plants out of the power market. Solid biomass power plants require a relatively large investment in solid fuel handling and processing equipment (compared with natural gas). They are also not generally as efficient as modern fossil-fuel plants, due to relatively small unit size and high moisture content of the fuel. The small unit size—50 MWe for a large biomass power plant versus 300 to

900 MWe for a fossil-fueled boiler—also makes operating costs relatively high, because the staff of 40 required for operating a 50-MW biomass plant could also be enough for a 300-MW natural-gas-fired boiler or a 600-MW NGCC power plant. These factors make it difficult for the current biomass power plants to compete with conventional sources of energy in a competitive market, even if low-cost fuels are available.

Many in the industry now believe that most of the relatively low-cost solid biomass fuel sources have been identified and are being utilized. As a result, relativity low energy prices (until recently, at least) have limited growth of biopower facilities. The industry is focused on keeping existing facilities operating in a difficult market environment. Some landfill-gas developers are considering project expansion in the wake of recent energy price increases.

Solid-Fuel Resources. According to an Oak Ridge National Laboratory analysis, about 1.6-million dry tons per year of solid biomass (almost exclusively made up of urban residues) is currently available in California at delivered costs of less than $20/dry ton ($1.18/MBtu). Given today's newest biopower facilities' typical 24% efficiency (14,000 Btu/kWh) and an average capacity factor of 80%, these fuel supplies could support about 275 MW of additional capacity in California. Use of other sources, such as forest thinnings and agricultural residues, could increase the available fuel supply to as much as 11.3 million dry tons, but at greatly increased costs. These could support approximately 1,900 MW of additional generation capacity.

To date, there has been little or no effort to develop energy crops in California despite favorable climate and soil conditions that should allow successful cultivation if suitable economic conditions arise. However, irrigation costs may more than offset the favorable climate. Another underused option, but one requiring technological advance to overcome other serious barriers such as ash slagging, is disposal of problematic farm residues, such as rice straw.

The near absence of coal-burning power plants in California reduces the potential for biomass cofiring with coal. However, the State's heavy reliance on natural gas for electricity production provides opportunities for cofiring solid-fuel biomass and natural gas.

Landfill Gas and Biogas Resources. According to estimates by the U.S. EPA, more than 290 MW of additional generation capacity could be economically fueled by landfill gas in California. Other estimates, including those of the CEC, are for over 400 MWe of additional potential particularly with advances in technology. Also, according to USDA, Southern California has one of the highest concentrations of recoverable animal manure in the U.S., mostly from dairy, poultry, and beef farming operations. An estimated 350 MW of electric generation may be developed from these cost-effectively.[3] Digesters are suitable for manure collected from confined beef and dairy operations, and direct combustion or gasification systems are effective in converting poultry litter to useful heat and electricity. An added benefit of manure-fueled bioenergy systems is that it diverts to energy production, manure presently being over-applied to land as a fertilizer or a disposal method, thereby reducing phosphorus and nitrogen loading on soils and in local water bodies.

[3] Personal communication with John Sheffield at ORNL in 2000, Evan Hughes obtained an estimate for USA biogas power from manures in animal confinement industries such as feedlots and dairies of 2800 MWe. Very conservatively estimating California's share of this at 1/8, the potential is 350 MWe.

Distributed Biomass Generation Resources. One of the outcomes of restructuring the electricity industry may be the development of distributed-power resources to serve customers in remote areas where other ratepayers had subsidized the cost of providing central-station generation. This is likely to be true in many developing countries as privatization goes forward. Small-scale biopower units using local resources may have a role to play in this market.

General. Other market factors that may facilitate the greater use of biomass resources include:

- Aging chemical-recovery boilers in the pulp and paper industry may be re-powered and/or reconfigured with biomass-integrated gasification combined-cycle (IGCC) systems, where biomass can be uniquely used as fuel in combined heat and power applications.
- Increases in the market price of energy may make biomass-fueled facilities competitive with natural gas. In the future, $1.50 per million Btu (MBtu) biomass fuel could be in competition with natural gas priced at $4.00/MBtu or more. However, just after the peaking of solid fuel biomass at 800 MW in 1990-92, high demand and shrinking supply from forest harvesting made the fuel-price situation much worse than $1.50. Biomass fuel prices to the power industry were $2.00/MMBtu, at least, and sometimes even $3.00/MMBtu.
- Biomass/natural-gas hybrid systems may offer independent power producers a way to make their natural-gas-based projects especially attractive as low-cost ways to increase renewable biomass electricity generation in California.
- Developing a local bioenergy market and providing reliable electricity will stimulate rural economic development and help sustain biomass industry growth.
- Developing an improved base of public and regulatory support for cleaner new-generation plants and their environmental benefits.

Operating Experience

Biomass technologies in commercial operation have proven to be highly reliable, with typical plants achieving well over 90% availability. Capacity factors have been much more variable due to the variation in fuel supply. The national average capacity factor for biogas-fueled power plants is about 65%. California plants have a higher average, with typical facilities operating at 70–90% capacity factor. The smaller commercial biogas power systems typically range from 100-kW to 6-MW capacity and often have very high capacity factors (up to 90%) because their supply of biogas is often relatively constant. The technology is generally mature, with scheduled maintenance accounting for significant portions of the unavailable time. Variability or decline in the biogas fuel supply is typically the largest operational concern for biomass plants. (A supply decline, of course, reduces plant capacity factor, which is calculated on the basis of the nominal installed capacity)

Cost and Benefits

The results presented in this section use a simple annual capital-recovery model that is in close agreement with the levelized-capital-charge approach used in the EPRI TAG. The resulting costs are in 1999 (not constant) dollars, and the 21%/year capital recovery factor corresponds to an

assumed 4% real annual inflation.[4] This simple calculation procedure may also be used to approximate a constant-dollar (zero inflation) analysis by using a 12% annual capital recovery factor instead of 21%.

Economics

Solid-Fuel Biomass Power. Dedicated 100%-biomass (not cofired) solid-fuel power plants can generate electricity at a cost of 4–10¢/kWh. The low end of that range represents an amortized existing plant; and the high end, a newly constructed one (assuming that it does not benefit from expected advances of R&D in power-conversion and fuel-supply technologies). The marginal biomass power cost is essentially set by fuel cost and plant heat rate (Btu of fuel consumed per kilowatt-hour generated). At 22% efficiency (HHV basis), which is typical of good existing plants, the heat rate is 15,000 Btu/kWh. Then if the fuel costs $30 per dry ton (approximately $2.00/Mbtu), the marginal power cost is 3¢/kWh. Assuming an operating staff of 40 with an average annual cost of $70,000 per employee, the plant must raise an additional $2,800,000 per year. For a 50-MW plant, generating 7000 hours/year (about 80% capacity factor), or 350,000 MWh/year, this equals an operating labor cost of $8/MWh. So the cost for fuel plus fixed labor is 3.8¢/kWh. Allowing another $700,000/year to cover maintenance and repair costs, completes the 4¢/kWh low-end case.

For an example of the high-cost case, consider a new plant with capital cost of $1500/kW. At 21%/year capital recovery and 7000 hours' operation, this equals $45/MWh for capital. Then a 3%/yr allowance for maintenance adds another $7/MWh. These two items add $52/MWh, or 5.2¢/kWh, to the previously calculated 3.8¢/kWh for fuel and operating labor, giving 9¢/kWh total. For a smaller plant of 20 MW, rather than 50, the labor cost might be $18/MWh instead of $8. And the total cost per megawatt hour is then $30 (fuel) + $45 (capital) + $18 (operators) + $7 (maintenance) = $100—10¢/kWh.

In the 10-year timeframe of this market assessment, the low cost-case for solid-fuel biomass in a dedicated 100%-biomass plant would be a direct-combustion steam cycle, not a gasification technology. The boiler would probably be a fluidized bed or an advanced grate-type unit. The best heat rate possible would probably be 12,000 Btu/kWh; and the capital cost for such an efficient plant, $1500/kW. With fuel cost cut to $1.50/MBtu, 40 employees per 50-MWe unit, 3%/year maintenance-and-repair allowance, and the same 80% capacity factor, the low-cost case

---

4 EPRI and other design studies provide performance and cost numbers at the level of conceptual, feasibility studies. Specifying major components provides for a buildup of capital costs. These details are in the 1997 DOE-EPRI report, *Renewable Energy Technology Characterizations* (TR-109496) and in the cofiring design studies and demonstration facilities being built in the DOE-EPRI-utility biomass cofiring test program. Using TAG methods or their simplified equivalents, the capital-, operating-, maintenance-, and fuel-cost components are calculated separately and added to give the total generating cost.

Specifically, the BIOPOWER model, based on TAG and used in TR-109496 and in the 1993 EPRI report, *Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation* (TR-102773), was used to see what simple factor for annual capital recovery would give the same current-dollar result for an inflation rate of 4% as did the levelized capital recovery in BIOPOWER for constant-dollar calculations. The factor that gave that result (21%/year—essentially equal to simple-payback in 5 years) was used for capital costs in the cases in this market assessment, but was rounded to 20% in Section VIII and Appendix C.

would reach 7.5¢/kWh. With more time, or faster than anticipated R&D success, a gasification combined-cycle power plant at goal technology specifications could achieve $1100/kW capital cost, 9000 Btu/kWh heat rate, 40 employees running a 100 MWe unit, and 3% annual maintenance-and-repair allowance, with a resulting electricity approaching 5¢/kWh ($53.06/MWh), assuming again 80% capacity factor. An alternative technology that could reach the same cost goal, perhaps sooner, would be an advanced direct-combustion high-temperature and -pressure steam cycle such as Whole Tree Energy or a slagging combustion technology.

LFG and Biogas Power. For the "biogas" power technologies of landfill gas (LFG) and biogas from digestion of animal wastes or wastewater-sludge in sewage treatment plants, the estimated per-kilowatt-hour costs are comparable those of solid-biomass fuels: 5–10¢. Note that these do not include purchase of NO_X offsets for the internal-combustion engines used at many landfill-gas and biogas facilities. These NO_X offsets can add 1–4¢/kWh to the cost of energy from these facilities.

Landfill gas power generators have succeeded with power-sales contracts in the 4–6¢/kWh range. With most of the large-scale sites exploited already, the typical size of a new landfill-gas operation will be approximately 2 MWe. At a capital cost of $1300/kW and 2 full-time-equivalent employees to operate the plant (one-half person per shift) the cost of generation can be approximately 7¢/kWh. This is based on a 70% annual capacity factor, $0.50/MBtu for the gas supply (This pays only the cleanup costs for gas that is collected at the expense of the landfill, not the power plant), 3% of capital cost per annum for maintenance and repair, and 11,000-Btu/kWh heat rate. A low-cost case would comprise: capital cost reduced to $900/kW, number of operating staff cut in half by automation and consolidation with other LFG operations, and 9000-Btu/kWh heat rate through use of a better engine or combustion turbine. This case would generate power at about 5¢/kWh.

Biogas generators—here meaning primarily those using gas supplied by a digestion system installed for odor and wastewater pollution control, such as at animal feedlots or dairies—can be built in a manner similar to LFG plants, but in most cases, at smaller capacities. The costs for energy based on animal manures are higher than those from landfill gas. However, biogas power applications are clearly practical in some cases. One example, now having run for about ten years, is the hog-waste digester lagoon at Royal Farms in Tulare County.

Costs are rather specific to the site and circumstances, however. Much digester gas becomes competitive as a fuel source when delivered natural gas prices rise to the $5–$8/MBtu range.[5] Translated into cost of electricity terms, this is in the 6–10¢/kWh range. The high-cost case would include: $1650/kW capital cost, 200-kW unit size, one employee to operate five such 200-kW units, 5%/year allowance for maintenance and repair, 70% capacity factor, and no cost for the fuel. There is no fuel cost because the power-system capital costs include some of the gas-collection and -cleaning costs and because other costs are born by the animal-operation owner for odor and wastewater control. Lower costs may be achieved through R&D results, economies of scale, or other means, such as cost sharing and co-product sales. The low-cost case would include: capital costs cut to $1250/kW, 4% annual maintenance and repair, and operating costs at

[5] Personal communication from Fred Varani, Golden CO, to Don Augenstein, I E M, Palo Alto, CA 94306.

40% of the high-cost case, probably by a larger unit size such as 1 MWe with operating staff of only one full-time equivalent. This would equal 6¢/kWh.

Cofiring. Biomass cofiring offers lower costs for new installations of biomass power. In these situations biomass firing capability as a fraction of the energy input is added to a coal- or natural gas-fired power plant. The biomass fraction would likely be in the 5% to 15% range of the generator's heat input. The coal- or gas-fired plant can be either a new one with the biomass modification designed-in from the start or an existing plant with retrofitting. The preliminary results from the CEC-EPRI assessment of biomass cofiring with natural gas show that, at a size too small for full economies of scale (perhaps 20 MW), clean electricity from biomass can be generated at costs that would add $0.50–$1.00/MWh to the cost of energy from the facility (assuming a 20-MW biomass fraction in a 400-MW NGCC plant.) The biomass-generated electricity portion would cost $10–$20/MWh more than that which could be generated by adding natural gas capacity to the same plant, assuming the biomass and natural gas fuel costs are $1.50/MBtu and $2.50, respectively. Selling these biomass megawatt-hours in the California green-power market presents a potential market opportunity for biomass energy in the State.

Benefit of Out-of-State Sales

California can give manufacturers an incentive to locate their operations in the State by providing them opportunities to prove and improve their products at relatively small scale by integrating them as cofiring operations in gas-fired power plants. Large, 400-MW-scale natural gas combined-cycle (NGCC) plants are in the pipeline to come on line during the 2001 to 2004 timeframe and beyond. By favoring and co-funding testing and demonstration of putting 20 MW of biomass-based power into such plants, the State can become the most attractive proving ground, and add a new export industry to its industrial and engineering base, namely, modern biomass power—both combustion- and gasification-based. The result could be an industry that learns its lessons and gains its advantage through California experience and then uses that advantage to sell elsewhere and bring jobs and income into its California operations.

Benefits of Biomass Energy

Solid-fuel biomass benefits. The benefits of biomass electricity generation in California have been quantified in projects done for the CEC, the Integrated Solid Waste Management Board, and the U.S. DOE Western Regional Biomass Energy Program (WRBEP). Appel Consultants managed the WRBEP project for EPRI and WRBEP and the data gathering and benefits quantification were performed by NRSS in Sacramento. The largest benefits—not counting greenhouse-gas reduction benefits, which are the largest in some studies not specific to California, but which also have no current regulatory basis or consensus as to dollar value—were from additions to needy tax bases, avoided open burning of agricultural residues, brush clearing to prevent disastrous wildfires, reduced cost due to extending the lives of sanitary landfills, and improved forest health.

Here, as reported in EPRI draft report TR-102107-V4, March 1997, is a summary of the benefits calculated in the California biomass benefits assessment named above:

$26,736,000	Open-burning emission reductions
$29,703,000	Wildfire emission reductions
$1,046,000	Greenhouse gas emission replacement
$20,624,000	Extended landfill life
$990,000	Wildfire risk reduction
$404,000	Forest health improvement
$30,312,000	Disposal alternative to open burning
$67,654,000	Tax base impacts
$177,469,000	Total estimated benefits

NOTE: The above numbers were derived for the 1990–92 solid-fuel (not including landfill-gas or biogas) biomass power industry in California at the 800-MW peak of its generating capacity, when its overall efficiency and capacity factor led to the consumption of 7 million dry tons per year.

Adding 1000 MW of new biomass generating capacity (an amount that is practical by 2010 under the Scenario C considered in Section VIII) operated at 73% capacity factor (6400 hours per year equivalent full capacity) would generate an additional (6400 hours × 10^3 MW) 6.4 million MWh. Assuming an efficient 10,000-Btu/kWh heat rate (34% HHV thermal efficiency) and using the typical 16 million Btu per dry ton, the industry's new 1000 MW would be making renewable power from approximately 4 million dry tons of biomass fuel. If that fuel came in equal parts from each of the following four sources, the estimated benefits would be:

1. One-million dry tons of wood and trimmings displaced from landfills

   Displaces 1.4 million as-received tons of 30%-moisture biomass wastes going into landfills assumed to charge $40/ton. (Note that woody biomass does not decompose to biogas in landfills and therefore will not be capable of appreciable power generation if placed in a landfill.) *Value: $56 million*

2. One-million dry tons of agriculture and orchard residues, avoiding open burning

   The heat content of these is 16×10^{12} Btu, and the NO_X emission factor of open-field burning is about 20 times greater than the 0.15 lbs of NO_X/MBtu required of good solid-fuel combustion; i.e., 3 lbs/MBtu. This is 24,000 tons of NO_X per year. At $4000 per ton of NO_X this gives a benefit of $98M per year. Avoided particulate emissions are worth a fourth of this, or $24M per year. *Value: $122 million*

3. One-million dry tons of forest and brush thinning for wildfire risk reduction

   The benefits corresponding to these in the above table came from an 800-MW industry that was using about 7 million dry tons per year of biomass fuel, of which an estimated 1 million dry tons may have been from forest and brush thinnings. Hence, this benefit is estimated at about the same dollar value: $30 M in air-emissions-reduction benefits and $1.0 M in wildfire risk-reduction benefits. *Value: $31 million*

4. One-million dry tons of additional landfill-avoidance at lower value than Item 1

   As in Item 1, but in landfills where the avoided cost or life extension is only $15/ton. Result is 15/40×$56M. *Value: $21 million*

Thus the total estimated benefit of a 1000-MW addition to the solid-fuel part of California's biomass power industry may approach $230 million per year. Spread over the 6.4 million MWh assumed from this addition to the industry, the benefit is over $30/MWh. A credit to the biomass energy companies of this amount would contribute significantly to obtaining the effective prices required produce significant new development in the California biomass-energy industry (See Section VIII).

Landfill gas and biogas benefits. Another study originally performed for WRBEP, in 1995, estimated implicit values of environmental "externalities" if landfill gas and biogas is used. These included: (a) $10–$20/ton "carbon tax" on the CO_2-equivalent emissions avoided (By comparison, one country, Norway has a $27/US ton tax), (b) typical costs of abating air pollutants at $1–$5/lb VOCs in California, and (c) other benefits.[6] Based on a "carbon tax" with greenhouse-gas abatement of $10–$20/US ton of CO_2 and pollutant-abatement valuation at costs typical in the California emission-offset markets, the value added in the, form of environmental benefits or "externalities" of landfill-gas and biogas use could be 1–5¢/kWh.[6] This sort of analysis results in some large benefit-value estimates. With potential capacity additions ranging from 290 to 600 MW, valuing these biogas externalities at 1¢/kWh or more leads to benefits easily worth $50 million/year or more. However, the conservative approach adopted in Section VIII of this report does not assign any dollar value to greenhouse-gas emission avoidance. Therefore, much smaller estimated values are given there for the emission-reduction benefits of biomass electricity generation.

Methane Avoidance by Biogas Power Generation

Another point to bear in mind is that Section VIII not only assigns no dollar value for greenhouse-gas avoidance, but it also bases its estimates only on the fossil CO_2 avoided and not on the much larger CO_2-equivalent of the methane emission avoided by using landfill or biogas methane as fuel. On a per-unit-weight (or mass) basis, CH_4 has 21 times the greenhouse warming effect of CO_2, over a 100-year time scale. At shorter times it has higher relative strength, and less at longer times. The time-scale effect is due to the natural, slow oxidation of CH_4 to CO_2 in the earth's

[6] Augenstein, D. 1997. Economics, Externalities and Landfill Gas Energy. Proceedings, Sixth Annual Landfill Gas Symposium, Cagliari, Sardinia, Italy

atmosphere. When converted to a per-molecule basis, the effectiveness ratio becomes 7.6 (21 times the ratio of CH_4 to CO_2 molecular weights). The California Air Resources Board (CARB) reports that nearly all landfill gas is controlled for odor emissions by being burned ("flared") to CO_2. Therefore, the assessment of benefits in Section VIII does not credit California landfill-gas energy projects with any avoided emission of greenhouse gas. Also, the biogas (i.e., digester gas from animal wastes and/or sewage treatment plants) capacity is not credited for reducing methane emissions. However, this is a real greenhouse-gas reduction benefit of biogas combustion that should be considered in evaluating new biogas facilities, especially if emissions-trading markets begin assigning a monetary value to CO_2 and methane abatement.

System Benefits of Biomass Energy

There are also other benefits that are site-, time- and location-specific. These benefits are inherently difficult to quantify. In terms of distribution of generation sites, and, thereby, benefits to grid operation, solid-fueled biomass plants tend mostly to be well distributed in the grid. "End of line" plants reduce long-distance transmission losses to remote locations. Landfill-gas and solid-waste-combustion plants, tend to be very well distributed, mostly located very near (within 5–50 miles) the generators of waste, who also use the electricity. None of these benefits are quantified in this report.

Research Needs and Recommendations

Participants in the biopower market believe that California must take measures simply to maintain its existing industry, and increasing capacity will be even more difficult in the absence of significant changes in the price of energy. Most of the low-cost biomass in California is already being utilized. Significant additional residues are available from agriculture, forest thinning, urban sources, and mill residues, but these remaining sources are generally more expensive than the biomass fuels being used in California today. Some or all of the following research areas would be helpful in California:

- Determining the most appropriate incentives for utilizing the more expensive residues like agricultural and forest residues, or as-yet unsegregated or unutilized urban wood waste.
- Understanding the true costs and benefits of using low-grade forest thinnings to control fire and supply biomass facilities.
- Locating areas of restricted transmission and distribution that also have large supplies of inexpensive biomass.
- Reducing the cost of advanced biopower technologies that promise increased efficiency and, therefore, more power from the same biomass supply.
- Developing methods to create an integrated industry in which biomass plants are closely tied to other industrial facilities that supply fuel and purchase steam or electricity. Increased byproducts or value-added contributions from the biomass facilities would add revenues to the operation. Examples of potentially valuable byproducts and benefits include ash and liquefied carbon dioxide. Value-added benefits could include growing hydroponic fruits and vegetables in greenhouses enriched by stack-gas carbon dioxide and moisture. For biogas, there is odor

abatement, water-quality control, and power generation—all three resulting from biogas energy systems at confined-animal production sites.

- Supporting RD&D efforts on biomass/natural gas hybrid systems.
- Supporting demonstration plants that combine direct combustion with ethanol production or gasification to improve overall economics.
- Reducing the costs of the infrastructure required to supply fuel to biomass facilities. A goal of the biomass power industry in California has been "zero-cost fuel." One way to get to this would break out as follows: (1) collection cost $0.50/MBtu; (2) fuel-handling cost $0.50/MBtu; (3) transportation cost $0.50/MBtu; and (4) some credit for the external benefits of biomass power to offset this total of $1.50/MBtu and give a net fuel-cost of zero. At the potential 10,000-Btu/kWh efficiency of future biomass-gasification or advanced-combustion power plants, the credit would only have to be 1.5¢/kWh. But at the 15,000 Btu/kWh heat rate of the best current solid-fuel biomass power plants, it would have to be 2.25¢/kWh.
- Supporting the development of small-scale modular systems that can be economically co-located with the fuel supply and would require minimal transmission system upgrades.
- Means to inexpensively reduce combustion emissions from landfill gas powered engines. Especially needed is low-cost NO_X control.
- Automation of landfill gas engine operations to the extent that minimal operator attention and cost is needed, reducing labor cost component by 0.3–1¢/kWh
- Advances in "bioreactor" landfill gas technology, where the design of the landfill itself can be done in a way that enhances the rate of methane generation at least two-fold and thereby improves the economics appreciably.

Processes such as biomass-power development, which have multiple benefits and debits and inherently cut across regulatory and political jurisdictions, are among the more difficult with respect to assigning their public value, mustering support for, and then implementing them. It remains difficult to develop support for such crosscutting technology and to establish unified policies and efforts, and to create favorable conditions for its growth. There is always the question of who should "share the cost." However, the benefit—whatever its exact value—is potentially large.

5
SOLAR THERMAL

Introduction

With over 360 MW of operating power plants, California leads the world in solar-thermal electric power generation. The great majority of these facilities are parabolic-trough electric plants installed in the 1980s in the Mojave Desert. Although this represents over 6% of California's renewable generation resources, no new projects of this type are under development at this time. Appendix A provides project-specific detail on the existing projects. Major players in the solar-thermal industry are listed in Appendix B.

Technology Characterization

Solar thermal electric power plants utilize one of three primary technologies. These are Parabolic Troughs, Central Receivers (or Power Towers), and Parabolic Dish with Stirling Engine. Each of these is characterized below.

Parabolic Trough Electric Plants

These facilities utilize single-axis tracking parabolic-trough collector fields as the primary energy source. The solar system is essentially a steam producer, using the collector field, high temperature oil heat transport system and an oil-to-water/steam heat exchanger set to generate superheated steam. The steam is then used in a conventional steam turbine power generation process. While the steam is used in a steam plant at the Mojave facilities, the focus of current feasibility assessments is to use the steam as additional input to a gas-fired combined-cycle plant to take advantage of the higher thermal efficiencies possible in that configuration on both the solar and power block sides. Figure 5-1 and Figure 5-2 show the five 30-MW plants at Kramer Junction and a close-up of a trough solar field, respectively.

Figure 5-1
Five 30-MW Parabolic Trough Plants at Kramer Junction, CA

Figure 5-2
Close-Up of Parabolic Trough Power Plant

Trough fields are typically sized for full power output during a clear midday in April or May. In the summer when the solar resource is higher a small portion of the solar field is stowed to maintain the design maximum capacity. On a clear day, the plant will produce full power during most of the day, typically about 0700 hours to 1900 hours in summer. In arid or semi-arid areas the output is reasonably predictable during the dry season.

Thermal storage can be used to increase the operational flexibility of a solar thermal facility. By storing hot thermal energy delivered from the solar field, steam can be produced at will to meet

later peaks, such as evening. Also, thermal storage can assist during intermittent disruptions in the solar resource, such as clouds, or can be used to provide a more uniform output over time. There is limited experience in California with thermal storage. The only thermal storage at the SEGS plants was in SEGS I, which used a 2-tank (hot and cold) storage system utilizing the solar field heat transfer fluid (Caloria). The tanks were approximately 950,000 gallons each, and had an electrical capacity of about 43 MWh. Daytime solar energy was stored and used to produce electricity in the evening, initially during the winter evening peak. This storage system was destroyed by fire in 1999. Subsequent SEGS plants used solar/gas hybrid operation with supplemental boiler steam to provide dispatchable power.

Many areas in the world have late afternoon or evening peak periods. The use of storage systems enables solar thermal plants to supply these peaks. A recent evaluation by private companies examining the business showed that thermal storage systems based on lower temperature molten nitrate salts were commercially practical (based on Sandia work and Solar Two experience) and marginally cost-effective (it depends on the time-of-use value of the electricity). Several teams are ready to install thermal storage systems based on molten salt when appropriate contracts can be developed.

The plant capacities in California range from 14 to 80 MW net. Facilities as large as 200 MW have been proposed however, solar steam systems integrated with combined-cycle plants are constrained in capacity by the need to ensure that the addition of a solar system has a net positive effect on the annual performance of the combined-cycle plant. Analyses to date indicate that for typical combined-cycle projects solar fields with an equivalent 30–40 MW capacity are of the most interest.

Modern solar thermal electric plants using trough collectors require approximately 4–5 acres/MW (1.6–2 hectares/MW) in good solar areas. This value depends on both the level of insolation and the efficiency of the power cycle. The 80 MWe, net SEGS plant built in 1991 at Harper Lake utilized 5.2 acres/MWe (2.1 hectares/MWe), net (or 4.8 acres/MWe, [2 hectare/MWe] gross). The higher solar field performance possible today, higher annual insolation, or a lower solar field sizing criteria would drive that value down. Conversely, in a region with a lower insolation or by using a more conservative design approach for solar field sizing, the ratio would rise.

In most regards the technology is environmentally benign. High land use is the major environmental characteristic, with its associated impacts on scenery, flora, and fauna. The significance of these impacts depends on the particular site. A moderate environmental concern with current trough solar fields is the use of semi-hazardous synthetic oil as the heat transport fluid. While spills from broken pipes have been minimized or eliminated in the existing plants, this possibility still exists. Some current development work has been directed at replacing the current fluid with a more environmentally benign selection. Water usage at this type of plant is dominated by the heat rejection and steam condensate makeup requirements, which is not solar related, but also includes a need for water for mirror washing to maintain a high reflectivity. In general, mirror washing adds from 5–10% to the total annual water use.

Central Receiver Electric Plants

These facilities utilize central receivers and two-axis tracking heliostat reflector fields to collect direct beam solar energy at high temperatures and generate steam for a conventional steam turbine. The technology is in a development stage, with no commercial projects in operation. The 10-MW Solar Two Demonstration Project in Daggett, California is shown in Figure 5-3. This project completed testing in April 1999 and is the prototype for further U.S. development and commercialization.

Figure 5-3
10-MW Solar Two Demonstration Project in Daggett, CA

The solar system is essentially a steam producer to supply a steam turbine power plant, or augment the steam turbine side of a combined-cycle power plant. Flat mirror panels, or heliostats, track the sun in two axes and direct the sun's beams to a receiver on a central tower. Tower heights vary from 290 feet (88 m) for a 30-MW plant to 640 feet (195 m) for a 200-MW plant. In Solar Two, a molten nitrate eutectic salt flows through the receiver and into a hot storage tank, as shown in Figure 5-4. When steam generation is desired, the salt is pumped through a steam generator and returns to the cold tank. Because the heated salt is at such a high temperature, the steam can be produced at high pressures and temperatures. Internationally, central-receiver development with steam-water receivers and air receivers (for use with Rankine [steam] or Brayton cycles) is under review. Commercial plant capacities from 30 to 200 MW are anticipated.

While central-receiver systems could be configured as hybrid solar/fossil fuel plants similar to the parabolic-trough plants, the current intent in the U.S. is to utilize thermal storage to provide dispatchability. The thermal storage is provided by the molten-salt working fluid as shown in Figure 5-5.

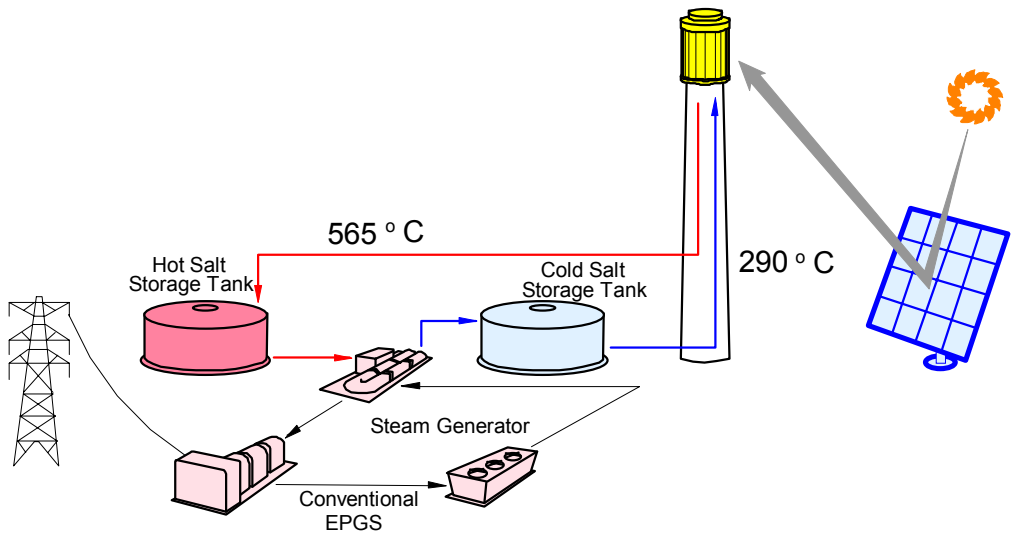


Figure 5-4
Schematic of a Molten-Salt Global-Receiver Plant

Solar thermal electric plants using central-receiver technology require about 5–6 acres/MW (2–2.4 hectares/MW) in good solar areas based on economic optimizations which trade-off the cost of heliostat spacing with the cost of land area. This value depends on both the level of insolation and the efficiency of the power cycle. In most regards the technology is environmentally benign. High land use is the major environmental impact, with its associated impacts on scenery, flora, and fauna. The degree to which this is a concern is project specific. The nitrate salts used in power towers are environmentally benign consisting of the primary ingredients in common fertilizers. Water usage at this type of plant is dominated by the heat rejection and steam condensate makeup requirements, which are not solar related, but also includes a need for water for mirror washing to maintain a high reflectivity. In general mirror washing adds from 5–10% to the total annual water use.

Parabolic Dish with Stirling Engine

A parabolic-dish electric power unit converts direct-beam insolation to electricity by supplying thermal energy to power an engine located at the focal point. The dish is pointed directly at the sun's rays by a dual-axis tracking system consisting of a drive motor, gearing and controls. The parabolic shape of the reflective surface, which can be mirrored glass, mirrored film or a polished metal, such as aluminum, focuses the radiation onto the receiver aperture at the engine. For a 25-kW unit, a typical dish diameter would be 35–40 feet (10–12 m), focusing into a receiver aperture of approximately 1.5 feet (0.5 m) diameter, with a focal point about 24 feet (7.3 m) from the dish vertex. Total unit height is on the order of 40–45 feet (12–14 m). Sun concentration ratios are 600 or more at the receiver (1000 at the focal point), providing the ability to reach very high temperatures in the working fluid. The type of engine favored in current developments is a Stirling engine with hydrogen as the internal working fluid. Thermal-to-electric efficiencies of Stirling engine-generator unit are on the order of 38–42%. Combined

with two-axis solar tracking, overall unit solar-to-electric efficiencies at 1000 W/m^2 can approach at 29–30%, with future targets of 32–36%.

Power units utilizing two-axis tracking parabolic dishes with Stirling engine-driven generators are in a commercial prototype phase. Two leading U.S. manufacturers exist – Stirling Energy Systems (Phoenix) and the SAIC/Stirling Thermal Motors team (San Diego/Ann Arbor). SES is currently operating units at a Boeing facility in Huntington Beach. Both companies are anticipating future installations in California.

Unit capacities that have been under development range from 5 kW to 25 kW electrical output. Current developments, including the Huntington Beach facility in California, are focused on 10–25 kW units, though projects have also been started in the 1–2 kW range. Annual capacity factors in the mid-20 percent range are expected, depending on the solar resource at a given site. At a good solar site capacity factors should reach 26% or slightly higher. Land requirements in commercial installations are yet to be demonstrated, but it appears that about 4–5 acres (1.6–2 hectares) per megawatt will be required.

Figure 5-5 shows the two parabolic-dish units operating at the Boeing/SES Huntington Beach site.

Figure 5-5
Two Parabolic-Dish Units at the Boeing/SES Huntington Beach Site

The engine unit can be designed as a dual-fuel system, whereby thermal energy input to the working fluid can be supplied either by solar energy or a combustion fuel – either natural gas or biomass. In this type of operation full dispatchability of electrical output is possible. In the solar-only mode, the electrical output is dependent on the direct-normal insolation level. On a clear day, the unit will produce full power during midday when the insolation peaks.

In most regards parabolic-dish technology is environmentally benign with high land use being the major environmental characteristic, with its associated impacts on scenery, flora, and fauna. The extent to which these are of concern depends on the particular site.

In a distributed-generation scenario, dish Stirling units are compatible with some existing land uses such as agriculture and grazing. The small capacity of the units makes them suitable for a number of applications for distributed-generation or remote operation. While planned for unattended remote operation, long-term reliability of dish Stirling units with respect to controls and mechanical integrity are yet to be proven in operation. Indeed, demonstrating efficient and reliable operation of a low-cost Stirling engine is the major technical hurdle remaining for this technology.

Market Information

There are a limited number of participants in the Solar Thermal market at this time. The key participants in the industry are shown in Appendix B and summarized in Table 5-1 below.

Table 5-1
Solar Thermal Companies

Technology	Category/Business	Notes
Parabolic Trough	**Active in California**	
	FPL Energy	Operate Harper Lake site: 2 80MW SEGS
	KJC Operating Co.	Operate Kramer Junction site: 5 30 MW SEGS; also interested in selling O&M services in Calif., U.S. and internationally
	Sunray Energy Inc.	Operate Daggett site: 44 MW total
	Duke Solar Energy	North Carolina base; solar steam system supplier; concentrating solar technology manuf.
	Industrial Solar Technology	Denver base; solar hot water system supplier
	Seeking business in California	
	Flabeg Solar Intrnl.	Germany; system engr. and mirror supply
	Solel Solar Energy	Israel; detailed engr. and receiver supply
	Fichtner Solar	Germany; A&E firm
	Inabensa,	Spain; solar system supplier
	Solar Millennium	Germany; green developer
Power Tower	**Active in California**	
	Nexant (Bechtel)	Initial project development; system and project engineering; thermal storage system engineering; also interested in troughs
	Boeing	Tower receiver supplier
Dish Engine	**Active in California**	
	Stirling Energy Systems (SES)	Dish engine system developer and supplier (with active Boeing support)
	SAIC	Dish project developer and concentrator supplier
	STM Power Inc.	Stirling engine supplier

International markets for solar thermal technology are quite active. Four Global Environmental Facility (GEF) sponsored projects are each approved for approximately $50M grants, located in India, Morocco, Egypt and Mexico. All consist of solar fields integrated with fossil-fired combined cycle plants. The solar fields in each will contribute steam to produce 30–40 MWe output. In brief, the status of each is:

India – Applications submitted for qualification to bid. Government-owned project. RFP due by mid-2001. Slated to be trough solar field. Many of the companies named above have submitted qualifications. Duke Solar teamed with Solel to supply solar field, and to work with a large Indian A&E on full plant. European teams also submitted qualifications. Nextant teamed with several to supply solar thermal storage system if included in design.

Morocco – Engineering firm selected to prepare RFP. Open to troughs and power towers. No request for qualifications yet on the street.

Egypt – Engineering firm to prepare RFP not yet selected. Appears to be open to troughs and towers.

Mexico – Feasibility study completed in 2000. IPP project. Next step slowed by change of government. Schedule unclear. Slated for parabolic trough solar field.

The most active non-GEF developments are going on in Spain and Italy:

Spain – As noted above, Nextant leading team to develop 15 MWe, gross power tower plant. European team also pursuing two trough plant developments in 30–50 MWe range.

Italy – Italy has recently announced a large development program for solar thermal technology, particularly troughs. A 30–50-MW power plant in Sicily has been identified to be one focus of the activity.

Completion of these projects will benefit California as they will utilize the newest technology and will re-establish solar-unique aspects of the infrastructure in design, manufacturing and construction. These developments should increase confidence in the technology and thus facilitate financing new projects in California.

Parabolic Trough Electric Plants

The target markets for the technology have traditionally been large electric grids. However, integration of solar technologies with power cycle technologies developed for geothermal resources may allow smaller modular solar thermal plants (approximately 1–10-MW capacity) to be deployed cost-effectively for distributed and remote power applications. Many of the industrial players in the geothermal industry are moving forward on the development of modular systems (ORMAT, Exergy, Bib & Associates, and Barber Nichols). Until these technologies have been commercially demonstrated, it is difficult to determine the costs at which they will be

able to produce power. Historically, the costs of parabolic-trough systems have been significantly above the market price for energy, making the systems un-economic. As energy prices rise, or the value of distributed generation increases, small- to medium-size parabolic-trough systems may become competitive as distributed-generation and central-plant sources of energy.

Duke Solar Energy is very active in seeking to develop a new parabolic trough project either in California, other southwestern states or internationally. Their interests range from large megawatt-scale to much smaller power or heat projects using different solar thermal collector designs with concentration. Duke Solar is jointly owned by Duke Engineering & Services and a group of private investors. Duke Solar has responded to GEF project solicitations for qualified bidders for large integrated solar/combined-cycle projects in Egypt and India (30–40-MWe solar fields), and is pursuing possible 50-MW project opportunities in California and Nevada.

Power Tower Electric Plants

Power-tower systems in the U.S. have evolved from programs involving the national labs, primarily Sandia National Laboratory in Albuquerque, sponsoring utilities and agencies, and a few suppliers. Currently, Bechtel (Nexant) and Boeing are the key U.S. players in this area. The technology is reasonably well developed at the commercial prototype stage, with the primary need being to reduce costs without sacrificing performance. The target market for this technology has traditionally been for grid-connected, central power-station applications. There is little evidence that other markets will develop or make economic sense.

At this time, relatively high costs are limiting the market for the technology. Economic studies indicate that an advanced, 200-MW solar-only plant operating in California with a 65% annual capacity factor and 13 hours of energy storage is economically competitive with a gas-fired combined-cycle plant of similar size when the price of natural gas is $3.50/MBtu[1] or higher. While present natural-gas prices are above this level, they are fluctuating rapidly and the assumptions made in the economic analysis have not been demonstrated.

Nexant (a Bechtel company), teaming with a Spanish company and supported by the Boeing solar group, is vigorously pursuing a 15-MWe power-tower project ('Solar Tres') in Spain in response to a new Spanish Renewable Energy law and incentives related to solar thermal, and is seeking other opportunities related to GEF projects. Nexant also proclaims a strong interest in parabolic trough plants, if appropriate to a site or project opportunity.

Parabolic Dish with Stirling Engine

The major developers of this technology, SAIC and SES, both view California as a major market for the technology. SAIC is based in California and SES is using Boeing (California) as a major subcontractor.

---

1 Kolb, Gregory J., "Economic Evaluation of Solar-Only and Hybrid Power Towers Using Molten-Salt Technology," Solar Energy, Volume 62, No.1, pp. 51–61, 1998.

Market definition is in the initial stages for both companies. Current emphasis is on prototype operation for transition into the commercial market. Commercial sales will require adequate demonstration of reliability, good operation and acceptable maintenance requirements. The primary market is believed to be distributed-generation applications. In addition to distributed and small-scale applications, at least one developer is interested in megawatt-scale electric grid installations.

SES, SAIC and STM continue to be engaged in prototype testing in anticipation of commercial entry opportunities. A 1 MW demonstration project in Las Vegas is now in active planning.

Operating Experience

No commercial dish Stirling or power-tower solar electric plants are in operation. All of the existing parabolic-trough facilities in California are located in the Mojave Desert in the general area of Barstow. These Solar Energy Generating Station (SEGS) plants, installed over the years 1984 through 1990, are all currently in operation.

For the commercial parabolic-trough plants, the best available data are from the Kramer Junction SEGS. Over their lifetime the SEGS plants have produced on the order of 4000 GWh of solar output. The solar fields in these plants are typically operating at an availability of 99% and at capacity factors between 20 and 30 percent. Solar output has improved over the last twelve years of operation as operating methods and experience built up, and as failed components have been replaced subsequent to a decline following the bankruptcy of Luz the original developer. Figure 5-6 through Figure 5-8 provide additional operating data on these facilities.

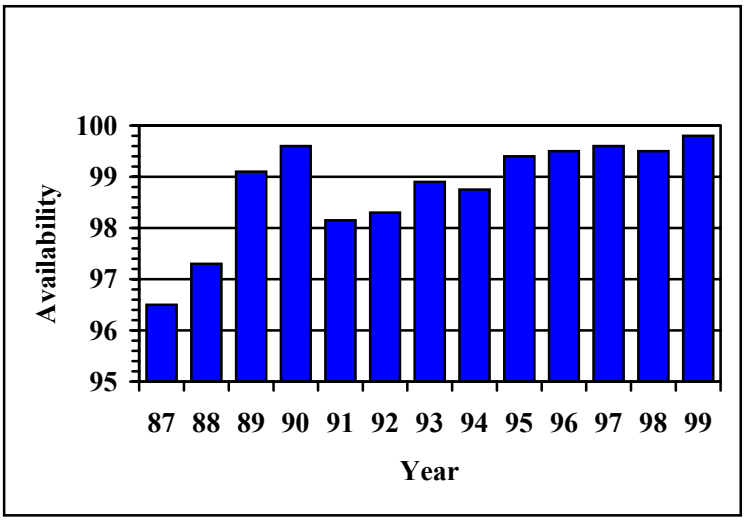


Figure 5-6
Kramer Junction Solar Field Availability

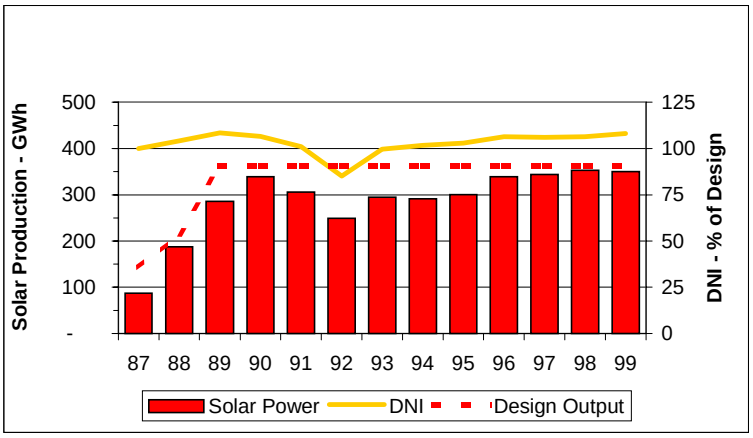


Figure 5-7
Kramer Junction Solar Production

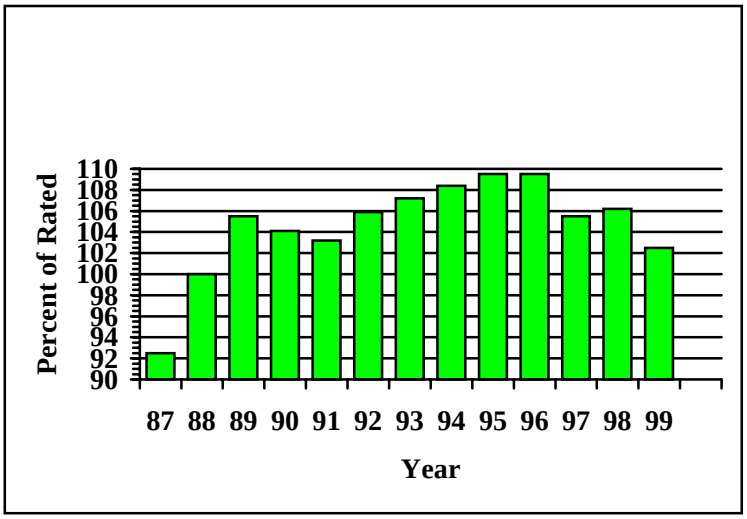


Figure 5-8
Kramer Junction On-Peak Generation

Approximately 60% of the annual revenues of the SEC's plants are derived from operation during the on-peak period that occurs on weekday afternoons from June through September. Note that the Kramer Junction plants have generated electricity in excess of nominal capacity

during this time.[2] The excess generation has been lowered in recent years because energy processes have not warranted such high capacity factors.

For periods when plant performance does not meet design levels, the main issues are component reliability of the evacuated receiver tubes, minor mirror breakage, and collector alignment related to sun focusing. O&M costs for the Kramer Junction SEGS plants are now at the 3.5–4¢/kWh level. The Kramer Junction facilities are hybrid plants, having the ability to produce steam independently using fossil fuel (specifically natural gas in this case) via a boiler or transport oil heater. With this configuration, the plants are dispatchable, i.e., can produce electricity as needed. This capability is primarily used for peak power production for the Southern California Edison grid during summer afternoons and evenings. It is noted that during summer afternoons the additional electricity supplied using natural gas is on the order of 10%, with the rest coming from solar energy.

Cost and Benefits

Parabolic Trough Electric Plants

The natural scale of parabolic-trough solar-thermal electric plants appears to be in the range of tens to hundreds of megawatts or higher. The lower limit is a result of both the physical principles of their operation, which dictate that smaller plants would be much less efficient, and the fact that the basic power plant needs a level of maintenance similar to that required by traditional fossil-fueled plants, which makes smaller plants impractically expensive to run.[3] The upper limit is less clear. Larger generating stations can clearly be constructed by building multiple modular plants on adjoining sites. This scale places such plants in the competitive space of conventional central-station power.

The costs of various Solar Thermal technologies are summarized in Table 5-2.

[2] This operation was in the hybrid mode, where natural gas fuel supplemented solar operation; the solar contribution was approximately 90% of the total output during the peak periods.

[3] The solar field will add approximately $0.005 to $0.015 per kilowatt-hour to the operations and maintenance costs based on an analysis of existing SEGS plant data adjusted for technology improvements.

Table 5-2
Solar Thermal Cost Summary

Technology	Configuration	Needed electricity cost	Build time**	Best capacity
Troughs	Rankine cycle*	10–15¢/kWh w/o grant	18–24 mo	•100 MW
	ISCCS cycle	8–10¢/kWh w/o grant		30–40 MW solar in 300+MW CC
Towers	Rankine cycle	Possibly same as troughs, but likely at the high end of the range	24–30 mo	•100MW, preferably 200 MW
Dish engine	Stirling engine	NA	NA	25 kW per unit; much lower costs in megawatt-scale systems

*Hybrid operation, like SEGS plants; at high end of this range for solar-only operation

**From contract signing

The cost of energy shown in Table 13 for Rankine cycle troughs assume that lessons learned from the operation of the existing LUZ plants and advances that have been made in collector materials and designs over the past decade are incorporated in the plant design. Incorporating these improvements will reduce the operations and maintenance costs of the facilities significantly and result in the overall costs of energy shown. As a central-station technology, the calculation methods and the factors that determine costs of generated electricity from parabolic-trough plants are very similar to those encountered in traditional generating plants. Indeed, existing trough plants incorporate a traditional gas-fired generator as part of their design. The major difference is that the solar collector increases the initial capital cost and decreases the operating (fuel) cost of the plant. That difference is highly significant, however, because it dramatically increases the impact of plant financing on generation cost. Fixed-charge rate hardly matters to the cost of electricity from a combustion-turbine generator, but it directly affects that of a solar plant.

The overall economic and public benefits of parabolic-trough generating plants stem from their reduced emissions and lowered dependence upon imported fossil fuels. Strictly speaking, these attributes, which do advantage the local economy, should make parabolic-trough solar electricity more valuable than that from an otherwise-equivalent fossil-fueled plant, but such “externalities” are not generally accounted for in present-day electricity markets.

Central Receiver Electric Plants

The natural scale of power-tower solar-thermal electric plants appears to be hundreds of mega-watts or more. This lower limit is mainly a result of the physical principles of their operation, which dictate that smaller plants are much less efficient, but is also driven to some extent by the fact that they have much complex machinery and therefore need to operate on a scale that can support a full-time maintenance crew. This scale places power-tower plants in competition with conventional central-station power that presently trades through the California PX.

Unlike the situation with parabolic-trough plants, there is no actual commercial experience with central-receiver plants. Therefore, estimates of whether or not they can realize cost-effective performance must rely upon capital-cost and O&M projections based on experience with precommercial demonstration plants, such as Solar Two, and hypothetical design exercises.

As a central-station technology, the calculation methods and the factors that determine costs of generated electricity from power-tower plants are very similar to those encountered in traditional generating plants. The major difference is that the solar collector increases the initial capital cost and decreases the operating cost of the plant by eliminating the fuel cost. As for the parabolic-trough plants, that difference is key because it dramatically increases the impact of plant financing charges on the overall cost of energy from the factories.

Also similar to parabolic troughs, the overall economic and public benefits of power-tower generating plants come from reduced emissions and lack of dependence upon imported fossil fuels. "Externality" benefits such as these are not counted in present-day markets.

Parabolic Dish with Stirling Engine

Unlike parabolic-trough and power-tower solar-thermal electric plants, the natural scale of parabolic-dish/Stirling-engine plants appears to be in the tens- to hundreds-of-kilowatt range, placing them squarely in the distributed-generation regime. This conclusion, although widely held, is crucially dependent upon the yet-to-be-demonstrated fact that these plants can be made to operate with little O&M cost. Dish/Stirling plants comprise rather complex machinery, so demonstration of low actual O&M experience is a key need if they are to become serious contenders for distributed-generation applications.

As with central-receiver plants, there is no commercial experience with dish/Stirling systems. Furthermore, although there have been several small-scale prototype experiments, there has not been a long-term demonstration similar to the power-tower's Solar Two experiment. Therefore, cost estimates of capital and O&M requirements for dish/Stirling plants must extrapolate further beyond actual experience.

The calculation methods and cost-determining factors for dish/Stirling-generated electricity are similar to those of power-tower plants, because both rely upon high-precision solar-tracking hardware for high sunlight concentration. Otherwise, the main difference between the dish and the other two is that the Stirling engine and its attendant heat-transfer equipment are rather exotic and have collectively rather stringent requirements for low cost and low maintenance. As with the other solar-thermal plants, dish/Stirling initial capital cost is key because financing it dramatically impacts the cost of the power output.

There are two primary economic and public benefits of dish/Stirling generating plants, as compared to traditional central-station fossil-fueled electricity plants. First are those derived from the attributes it shares with other solar-thermal generation, reduced emissions and lack of dependence upon imported fossil fuel. Second are the potential distributed-resource benefits of more efficient power use through elimination of transmission/distribution losses and the increased reliability of onsite power.

Research Needs and Recommendations

Parabolic Trough Electric Plants

Discussions with industry participants indicated that significant opportunities exist for additional research and development to advance the commercialization of parabolic-trough electric plants. These include:

- Research to reduce cost and improve reliability of the solar collection system. The current collector designs are mature but not yet optimized. Cost reductions with modest performance improvements via evolutionary steps are the primary goal of ongoing research. Several opportunities for technology-driven cost reductions have been identified, largely focusing on component improvements in the four major collector subsystems: structure, reflective surface, drive system, and receiver. In particular, receiver reliability deserves attention to increase lifetimes and maintain design performance levels.
- Research into thermal energy storage for trough systems. This would permit shifting of electrical generation to peak periods, or to raise the capacity factor when operating on solar alone. There are important technical and cost issues leading to the use of a molten salt for this application. A tertiary nitrate salt, similar to that utilized for thermal storage in the Solar Two power-tower project, may be quite suitable for a trough system.
- Development and operation of a demonstration power plant using the latest technology to validate the industry's projections of reduced costs relative to the currently operating plants. Partnering with some of the GEF sponsored projects would leverage available resources while obtaining valuable information concerning modern project design, performance and costs.
- Development of smaller-scale systems for distributed-generation applications.

Power Tower Electric Plants

To compete in California, the cost of power-tower plants must be reduced relative to both current fossil-fired plants and to other renewable resources. The major technical barriers associated with molten-salt power towers were addressed during Solar Two. Recent developments have focused on improving reliability and reducing the cost of key components. A number of opportunities for technology-driven cost reductions have been identified, largely focusing on improvements in the four major subsystems of the solar steam system: heliostats, tower receiver, molten-salt thermal-storage system, and steam generator. Goals include both lower investment cost and higher long-term reliability. Reliable heat tracing of the molten-salt system is an important design requirement, as is the need to minimize the parasitic power for this need. In particular the reliability and costs of molten-salt piping and valves needs further research.

Parabolic Dish with Stirling Engine

Initial cost, engine long-term reliability, and acceptable O&M requirements are major obstacles to cost-effective utilization of this technology. Specific suggestions made by industry participants for research to address these issues included:

- Development of inexpensive, durable reflective surfaces.
- Development of more efficient heat-pipe receivers.
- Research into the root cause of the technology's reliability problems and identification of solutions.
- Construction of demonstration units to obtain reliable O&M data. It is felt that if successful demonstration units can be built, the investments needed to support further development of the technology will be easier to obtain.
- Development of higher-temperature materials for engines.

6
PHOTOVOLTAICS

Introduction

Solar photovoltaic (PV) applications include both grid-connected and off-grid uses in California. Table 6-1 summarizes the number of installations and installed capacity for grid-connected projects by time period. Appendix A provides some additional details on the grid-connected systems including the name, location, type, installation date, and other relevant information. Note that the total in Table 6-1 does not show approximately 3 MW of additional PV capacity that may exist. This is because the data were developed from multiple sources containing approximately 3 MW of possibly duplicate listings. These are not included in the database at this time, and could add up to 3 MW to the total.

Some major projects are planned that can make a significant impact on the installed PV capacity in California. One is the Pleasanton Power Park, where 340 kW of PV is planned for an industrial park, as part of a distributed energy installation. Second, a dealer in San Diego country hopes to install up to 3 MW of PV at a housing development over the next few years. However, the restriction that each meter be limited to 10 kW may limit the overall size of this installation. Third, Powerlight and Green Mountain Energy plan to install up to 100 kW on Powerlight's Berkeley manufacturing plant in response to consumer demand for Green Mountain's retail PV energy product. In addition, there are several smaller projects, in the planning stages.

Accurate estimates for off-grid deployment of PV systems are difficult to obtain, but a total of 6 to 8 MW appears reasonable. Although the total PV capacity in California to date is relatively small compared to other renewable technologies, the number of projects and visibility of the technology to consumers is very high.

PV's modularity and siting flexibility, coupled with the solar resource available in California, ensure that PV can make a more significant contribution to the State's electricity supply when grid-interfacing barriers have been lowered, PV costs have been reduced further, and consumer awareness of PV benefits has grown. Appendix B provides a representative list of the major players in the PV industry, their business focus, and contact information.

Table 6-1
Summary of Grid-Connected Project Data for PV Technology

Year(s) Installed	Operational Installations	Total MW Installed
1980 – 1985	24	1.3
1986 – 1990	23	1.4
1991 – 1995	36	2.7
1996	11	0.8
1997	11	0.6
1998	82	0.9
1999	199	2.7
2000 (YTD)	36	0.2
Unknown	8	0.2
Total	430	10.8

Technology Characterization

The key components of a typical PV installation are: (1) the photovoltaic modules, which contain photovoltaic cells that convert sunlight directly into electrical energy; and (2) the inverter that converts the dc energy into ac energy for feeding the power into the grid or for on-site powering of ac loads. Some off-grid systems use the dc power directly to power dc loads, avoiding the use of an inverter. Other installations may also have backup batteries that are charged by the system to provide power when the grid is down (for on-grid systems) or insufficient solar insolation is available (for off-grid systems). Figure 6-1 shows a block diagram of a typical system.

Typical residential installations range from 1 kW to 4 kW in size. For grid-connected systems, installers attempt to size the system such its output will be slightly less than the electrical needs of the residence. This maximizes the value of net-metering contracts with the utility, assuming the homeowner receives full retail credit for every kilowatt-hour (kWh) the PV system produces. Roof-mounted residential systems require approximately 100 square feet (10 square meters) of south-facing roof for every kilowatt of modules to be installed.

Typical commercial installations, designed to serve the electrical needs of a commercial building, range from 6 to 100 kW or more. These are usually placed on the roof of the building, and require the same 100 square-feet (10 square-meters) per kilowatt of installed modules. Off-

grid commercial applications include telecommunications, cathodic protection and water pumping.

Central-station photovoltaic installations are usually no smaller than 100 kW and can be as large as 500 kW or more. These installations can be located at utility substations as a distributed-generation application as well as in large PV central stations. These larger installations require approximately one acre (0.4 hectare) per 100 kW installed.

Pictures of typical central station, residential, and telecommunications installations are shown in Figure 6-2 through Figure 6-4.

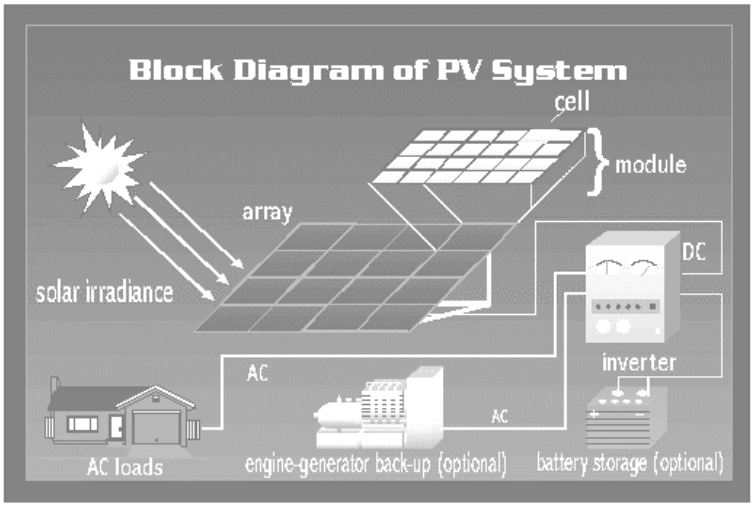


Figure 6-1
PV Block Diagram

Figure 6-2
Central-Station PV with Nuclear in Background

Figure 6-3
Residential PV

Figure 6-4
Telecommunications PV

Solar cells are special types of semiconductor devices that convert solar radiation into electrical energy. The entire process is solid state and self-contained, and requires no moving parts. There are two main types of photovoltaic modules, those based on single-crystalline or polycrystalline silicon cells and those based on thin films of other semiconductors. Silicon-cell modules have the highest output, to date, and are used for large applications or where space is at a premium. Thin-film technology has lower demonstrated conversion efficiency, and as a result requires more space, but shows promise to greatly reduce PV costs and achieve nearly equivalent efficiency in the future.

PV is a very modular technology. A system can start out small to meet basic electrical needs and then be expanded as needed. PV can also be combined with battery storage systems to provide backup power in remote locations when the sun is not shining. A grid-connected system can be sized to deliver excess electricity to the grid during the day and use grid (or battery) power at night.

The main environmental impacts of PV development are land use and visual impact. The extent to which these are concerns is project specific. Utilizing roof areas minimizes the land impact, and larger developments are sometimes sited at utility substations or on unused land near power plants. The visual impact of PV systems installed on residential and commercial buildings can be a serious impediment to their use, although newer 'building-integrated' designs can be very unobtrusive.

Market Information

Suppliers of PV Technology

Appendix B lists representatives involved in the California PV market. The industry is consolidating. For example, in 1999, IDACORP Technologies' subsidiary Applied Power Corporation acquired Ascension Technologies, Alternative Energy Engineering, and Solar Electric Specialties. Kyocera acquired Photocomm, which previously had acquired Utility Power Group (UPG). And BP Amoco purchased Enron's share of Amoco/Enron Solar to form BP Solarex, now renamed BP Solar. This acquisition made BP Solar the largest photovoltaic company in the world.

Markets for PV

The on-grid residential market is a significant one for PV systems. This market currently consists mostly of more affluent people who install systems because they feel that they are doing something positive for the environment and they are not concerned about the economics.

While wealthier individuals have historically fueled the residential PV market, the impact of high utility costs has many other people and organizations looking for ways to control their electricity costs. Middle-income homeowners and small-business people are increasingly interested in PV systems as a way to limit their exposure to high utility bills. A dealer in San Diego said that he has started getting 150 to 200 calls a day from people concerned about their electric bills. About a third of these people are looking for an alternative so they can be independent of SDG&E. People appear interested in choices that allow them to become more independent of the utility company.

Despite the high costs, hundreds of grid-connected systems have been installed in California in recent years; and therefore, it is clear that some consumers value PV electricity far higher than grid electricity, today. Additional value includes both intangibles, such as the knowledge that the system is reducing global atmospheric emissions and the ability to operate independently from the grid, and tangible—but hard to evaluate—benefits, such as increased power reliability. Presumably, the number of consumers who will find PV a compelling purchase will rise as its cost decreases and as understanding of its benefits becomes more commonplace.

Another opportunity for the photovoltaic market is the restructuring of the electric utility industry. As customers choose energy service providers that provide a portion of their offerings from solar plants, demand for additional PV installations may increase. For example, Green Mountain Energy agreed to purchase the output from a new 132-kW PV plant located in Hopland, CA. Additionally, states incorporating incentives for the use of renewables through renewable portfolio standards or subsidy programs may provide a boost to the renewables industry in which PV may also benefit.

Another on-grid market that has potential is distributed-generation applications by utilities. Several demonstrations of this application have been built in California. Some of PV's attributes—relative cost insensitivity to scale, extreme modularity, and siting ease—position the

technology well to take advantage of the fact that the value of grid-connected electricity varies greatly, depending upon how close the generator is to the point of consumption. Positioning generators close to their loads reduces the costs associated with transmission and distribution of the energy. When the costs of building the transmission system are included these costs, the value of distributed generation, close to the loads becomes apparent. In such cases, the relevant comparison metric is "retail" electricity—a higher-valued product that includes both bus-bar energy cost and the costs of transportation from central-station generator to the load. Today, California retail electricity prices typically range roughly from $100 to $150/MWh. As with the wholesale prices, there are places and times when the retail price greatly exceeds the typical range, but such situations are too unpredictable to form the basis of an economic plan to build a plant.

The market is growing for people who install PV systems for reliable back up during power outages. As businesses become increasingly reliant on computer systems, reliable electrical service is necessary. With the summer of 2000's rolling blackouts in California, the need has become even more acute. Dealers expect this market to grow in the future.

Building-integrated photovoltaic (BIPV) systems are another approach to reaching the residential and small commercial markets. Integrating the solar cells or modules directly into roofing or siding materials provides an opportunity to reduce balance-of-system costs as well as to improve the aesthetics of the installation. Many manufacturers are now offering BIPV packages to appeal to this growing market.

The off-grid market continues to develop, with applications for remote homes, telecommunication sites, highway call boxes, cathodic protection, and lighting. However, dealers are unwilling to share information as to how many of these systems they install, so the total installed capacity is difficult to estimate, as is the size of the future market.

To address the retail electricity market economically, PV technology has two key needs. First is that its net capital cost must be such that generated electricity is in the ten-¢/kWh range. This may be realized by reducing the total system hardware costs to about $1000/kW. (See the discussion of the relationship between capital and energy costs later in this section) Alternatively, the PV system may be integrated into a structure (e.g., roofing, windows, building facades, etc.) that provides the system owner sufficient additional value that the total system cost is justified, considering all of its benefits.

The tens-of-thousands-of-megawatts potential retail electricity market in California is enormous compared to today's approximately 200-MW annual worldwide PV module production. However, in California the retail value of grid-based electricity is only about 10¢/kWh, whereas billions of people outside of the U.S. live in markets where the only (potentially) available electricity costs upwards of 50¢/kWh, because there is no existing transmission/distribution system. For this reason primarily, more than half of present U.S. PV module production is shipped overseas, and that fraction has been rising as PV manufacturers continue to improve their international marketing organizations. The overseas demand for premium-priced PV products can be expected to grow steadily for the foreseeable future.

PV Market Trends

The overall revenue for PV worldwide is growing at a rate of 15% per year. This modest-appearing figure results from the compounding of very high rates of growth (20%–40% per year) in PV module megawatt capacity and ongoing price reductions that have averaged about 9% per year.

The market for photovoltaic systems accelerated in 1999 as many people purchased systems for Y2K backup. One dealer remarked that the market in 1999 was 300% of 1998's market because of this surge in sales. Manufacturers reported increases up to 50% in module demand. Sales in early 2000 subsequently declined by over 50% as the rush for PV backup systems has decreased. However, later in 2000, robust sales were again apparent and the year ended up with the industry setting a new megawatt-shipment growth record of 44% over 1999's banner sales.

Although most dealers applauded the CEC's buy-down program, all were aware that only 350+ systems had been installed as a result of the program by the end of 2000. Some dealers/distributors commented that the majority of modules are going overseas to Japan and Germany. One commented that the Germans and Japanese were willing to pay $5/watt, whereas domestic customers are only willing to pay $3.50/watt. Others noted that LADWP has a buy-down program where they are willing to pay $5/watt, again attracting more attention than other areas where the buy-down rates are lower.

The U.S. DOE's Million Solar Roof Initiative (MSRI) is encouraging utilities to promote the use of solar in their service territories by installing solar facilities themselves, developing customer education packages for PV awareness, adopting uniform PV interconnection standards, and registering installations on the Million Solar Roofs registry. The MSRI looks for partners that will commit to installing solar energy systems. DOE provides access to various financing options, training, and technical assistance, as well as links to other solar energy businesses and related industries that can help.

PV Market Barriers

Cost competitiveness remains a major element limiting the use of PV in California. Grid-connected systems, such as on residential rooftops, produce electricity at over twice the cost of conventional grid power. Sustained growth in PV production capacity, as well as improved technologies and manufacturing techniques, are needed to reduce the consumer's cost.

Another market barrier is PV's inability to provide electricity upon demand. This situation may be addressed by using either, or both of, the commercial electricity grid or on-site energy storage as a backup power source. The main advantage of using the grid, especially if it is already installed, is that it is relatively low cost. The main advantage of using on-site storage is that it is relatively more reliable. The economic balance between these two backup sources depends upon the relative value to the system owner of the security afforded by the more-expensive on-site storage. In the near term, these two means, often combined, are adequate for addressing the market need. However, better energy storage technologies will be needed in the longer term, when the aggregated size of on-site generation becomes a significant fraction of total

generation—especially if a major portion of the on-site generation is nondispatchable, such as PV.

While cost may not be an issue for the wealthy, there are other people who want to install PV systems, but cannot justify the expense unless the payback is less than five years. PV system dealers are receiving inquiries from many people who are suffering from the dramatic electricity price increases in San Diego and would like to have a PV system, but cannot afford the high initial expense. Having a tax credit does not substantially help these people, as their income is not high enough to take advantage of tax credits. Thus higher buy-down levels or state-backed interest-free loan programs would assist these potential buyers. The California Solar Bank could help people finance their systems if there was more publicity about this option.

Time-of-use meters and net metering significantly help the economics of PV. However, the market participants expressed frustration with the utilities lack of cooperation when customers want to pursue these options. Some of the utilities' resistance is due to the lack of standardized interfaces for PV systems.

Education remains another major stumbling block to increasing the use of PV. Education is needed in three different forms: (1) advertising and publicity, to let consumers know that PV systems are an option for them and how to find qualified installation support; (2) technical information so that consumers who choose to purchase PV have realistic expectations; and (3) training for building inspectors, so dealers don't have to educate each inspector with each new installation.

Even after a customer has decided to explore purchasing a PV system, dealers find that they must spend much time educating that customer about how much power a PV system will produce, why the costs are what they are, and who can install their system. Informational materials that dealers can use for that education would be helpful in setting accurate expectations. Some people expect their utility bills to fall to zero, and they may be disappointed if it doesn't.

The custom nature of the industry is also an impediment to reduced costs, increased reliability and growth. Each installation ends up being a custom job, making it difficult for dealers to be profitable. Standardized components and interfacing requirements would improve this situation.

Another challenge for the industry is working with the local building inspectors. Each building inspector is different, and most are unfamiliar with PV systems. Hence the installers must spend time educating the building inspectors, which further increases the cost of the system.

Some dealers also have a difficult time finding qualified employees. It is difficult to find C-10 licensed electricians that know anything about installing PV systems. Since the work is somewhat seasonal, it can be tough to maintain an organization when there might be a need to lay off people in the slower winter season.

Some larger companies are aware of the possibility of extracting additional revenues from PV installations by selling the energy into the grid and selling the "renewable attribute" into an exchange. Some hurdles that need to be overcome are the relatively small amounts of attributes generated from a PV system compared to the cost of installing the metering to participate in these markets. The CEC has been discussing these options with the industry and exploring how

its guidelines might apply so that PV systems can potentially benefit from becoming active in these markets.

Operating Experience

Average capacity factors are about 18% to 20% for PV systems in California. Another common metric used for PV systems is the 'performance index,' which equals the actual ac output divided by the expected ac output based on the solar irradiance received by the system. For systems that have been monitored in California the performance index averages close to 90%. Measurements taken on systems monitored under the UPVG program confirm these capacity factors and performance indices. This indicates that PV systems are generally reliable but progress can be made in improving reliability to increase the performance index closer to 100%.

Most PV system failures are associated with the power-conditioning equipment, not with the modules themselves. The lack of standardization in this equipment makes achieving extremely high reliabilities difficult.

PV systems generally have shown a slow decrease in production over time, averaging about 1% per year in actual field experience. This means that, until this degradation rate is slowed, they are limited to about a 20-year lifetime, if end-of-life is defined as the time at which performance reaches 80% of initial.

Variable operation and maintenance (O&M) costs for early EPRI-monitored PV field tests typically ranged from 0.5¢/kWh to 1¢/kWh, which was already a small O&M compared to some other generation technologies. Today, larger commercial/industrial PV systems' O&M costs run about 0.2¢/kWh.

Cost and Benefits

As with other generation sources, the cost of PV-generated electricity is a decreasing function of the size of the generating plant. However, PV generation costs do not vary with plant scale as rapidly as do some other types. For example, per-kilowatt capital cost of PV plants decreases by only about a factor of two when changing plant size from 1 kilowatt to 1 megawatt; whereas, over a similar 1000-fold scale change, from 25 kW to 25 MW, natural-gas turbine systems vary by a factor of three or more. Unlike many sources, PV generators may be built at very small sizes—even down to the few-watt level—to meet the needs of individual loads. Finally, PV plants have no significant emissions—gaseous or sonic—so they are easier to site than other types of generators.

Electric generating plant costs are usually expressed in terms of an installed, or "turnkey", capital cost plus an annual operating and maintenance (O&M) cost per unit of capacity. In that context, PV capital costs are often expressed in terms of the total installed system cost per peak watt ($\$/W_P$), where "peak" refers to the plant's output at 25°C module temperature and 1-kW/m^2 insolation. This cost includes the cost of the PV modules, balance-of-system components, and installation. Such a calculation for a 75-MW utility-scale installation, today, gives a hypothetical

cost per installed kilowatt of over $4,300.[1] Expressing costs in this way is useful for those who want to compare PV with other central-station generating options; however, it does not directly help a consumer who wants to compare PV cost with the kilowatt-hour price of utility power.

The equivalent kilowatt-hour cost of electricity from a PV plant depends not only upon the installed system and O&M costs, but also upon a number of site-specific technical details and the economic assumptions of the plant's owner. Site-specific factors that directly affect the net capital cost per unit of plant output include the amount of annual sunlight, the area's land cost, and whether or not there is a capital credit for multipurpose PV building materials. The owner's economic assumptions may also vary considerably. Using typical utility economic conditions, for example, would generally require that about 20% of the plant's total cost is recovered in each year of operation. However, a merchant-plant owner using commercial credit might well require a higher payback ratio, while a self-generating homeowner using mortgage financing could tolerate a smaller one.

Taking, as a typical homeowner example, a 2-kW_P (ac) residential rooftop system with net $5/$W_P$ subsidized turnkey cost and $15/kW annual O&M on a site with 2000 hours annually of peak-sun equivalent insolation, results in an equivalent cost of 25.75¢/kWh, assuming a 10-year simple payback.[2] This assumes that the homeowner does not recover any financing costs and ascribes neither a cost to lease the PV array's site nor a credit for avoided roofing costs that a building-integrated array might afford.

From this example, it is clear that PV system costs need to fall another factor of 2 to 3 before residential rooftop systems can compete on a strictly economic basis with grid-supplied electricity at 10¢/kWh. The lower end of this range may be appropriate for systems where some components also serve a building function such as roofing material. Clearly, wider deployment of on-grid PV generation within the State can be realized only if present-day costs to consumers are decreased at least 2-fold and production levels increased by orders of magnitude from today's few-hundred megawatts. Until those conditions are met, the on-grid PV market in California will not only be strictly non-economic, but also will compete for PV products at a disadvantage with overseas markets that place intrinsically higher values on PV-generated electricity.

PV technology benefits California and its residents in the following respects. First, it reduces emissions from electricity generation, as quantified in Section VIII. Second, PV sales in California attract PV manufacturers to build or expand California PV production, which provides high-tech employment and economic development. In addition, sales and installation of the systems creates a broad range of jobs.

Research Needs and Recommendations

The primary challenges for the PV industry in expanding the California market are to bring down costs and increase consumer awareness of the value offered by PV systems. The industry feels that the CEC PIER program can contribute in both of these areas.

---

1 EPRI Report, *Greenhouse Gas Reduction with Renewables*, (TR-113785), December 2000.

2 ($5,000/kW ÷ 10 years + $15/kW/year) ÷ 2,000 hr/year

International public and private research activities are focusing on increasing the efficiencies of thin-film technologies and building large-scale manufacturing plants. Although significant resources have been committed worldwide to these efforts, additional funding within California would accelerate overall progress as well as help to ensure continued success of the State's PV manufacturing, installation, and research enterprises. Research is also focusing on balance-of-system costs and reliability, including reducing the cost and improving reliability of dc-ac inverters. Modules with built-in inverters to directly produce ac power are also under development. All of these areas could benefit from PIER program attention and funding to leverage existing research programs and boost in-State development.

Specifically, the CEC could:

- Join the U.S. DOE Thin-Film PV Partnership program to accelerate fundamental understanding of PV materials. State-government participation would enhance access of California researchers and research institutions to the federal program and broaden the range of talents focused on its issues.
- Partner with the U.S. DOE-funded Solar Electric Power Association (formerly, Utility PhotoVoltaic Group) TEAM-UP PV deployment program to further understanding of PV system performance and installation. Closer alliance with SEPA would enhance California's PV deployment program by making better use of the significant experience SEPA has gained nationally.
- Leverage the U.S. DOE PV-MaT program by partnering in PV-MaT projects within California to enhance competitiveness of California-based PV manufacturing.

In the area of increasing consumer awareness and removing market infrastructure barriers, several specific industry recommendations for CEC actions follow:

- Perform market research on how best to inform California utility customers about the advantages of installing a PV system on their homes or businesses. The most important messages are describing how PV works and how it can help to control utility costs. This can be followed up with a widespread publicity campaign that implements the market research findings.
- Provide training for C-10 electricians and building inspectors on PV-system hardware and proper installation.
- Develop and implement a zero- or very low-interest loan program for PV systems, either through the State or in support of the California Solar Bank, to mitigate the initial-investment barrier to PV ownership.
- Develop ways to aggregate PV installations simply, so that PV owners can profit from selling renewable attributes ("green tags") into the power-exchange market.
- Provide incentives that will encourage utilities to cooperate more fully with time-of-use and net metering.
- Work on standardizing components and interfacing in the PV industry, so that systems require less custom design.

7
SMALL HYDRO

Introduction

There are currently more than 260 projects included in the Federal Energy Regulatory Commission (FERC) hydroelectric listings for California. Of these, over 225 are rated less than 30 MW. In aggregate these provide approximately 700 MW of installed generating capacity. Only these projects are addressed in this report.

These projects vary in size from less than 1 kW to 30 MW. Table 7-1 breaks down the projects addressed in this report by size. Additional project-specific details on these facilities are included in Appendix A, including project name, river, dispatchability, capacity, and other relevant information.

The FERC listing only includes projects in its jurisdiction, meaning that they meet several criteria, including the following: (1) located on a navigable river; (2) subject the Federal Power Act of 1935 (constructed or modernized after 1935); and (3) involved in interstate commerce (tied to an interstate electrical grid). Thus, there are likely some other hydroelectric facilities, especially smaller ones, in the State that are not in the table or appendix.

California's current criteria designate hydroelectric facilities of less than 30 MW as renewable or "green power." However, there are several other proposed systems for certifying the environmental friendliness of hydroelectric facilities, including the Low Impact Hydropower Institute criteria and the Life Cycle Impact Assessment (ISO 14042) used by Scientific Certification Systems. To date, none of these has achieved wide acceptance in the industry or in State rules.

Table 7-1
Number of Small Hydroelectric Projects by Size

Range	# of Projects
< 1 MW	118
1 - 2 MW	30
2 - 5 MW	42
5 - 10 MW	15
10- 20 MW	12
20 – 30 MW	9

Appendix B lists representative key participants in the hydroelectric industry and includes contact information and business focus for each company.

Technology Characterization

Hydropower is a mature technology. Dams and water wheels have served mankind for thousands of years. Mechanical water wheels and turbines used in mills date back to the 17th century, and hydroelectric turbines are among the oldest of modern electrical technologies, dating to the late 19th century.

A typical hydropower installation involves a dam or weir to direct flow into a penstock or turbine intake, a spillway to pass excess water, a generator connected to the turbine, plus equipment to regulate plant operation and transfer electricity onto the grid safely and reliably.

Some hydropower installations are meant to store energy for short or long periods by accumulating water in a storage reservoir. The stored water can be released through the plant's turbines hours, months, or even years later, depending upon the reservoir capacity relative to the rate of inflow. Projects that can convert this potential energy at specific times, including peaking plants and pumped-storage facilities, are distinct from run-of-river plants. The latter operate where reservoir inflow is exactly balanced by hydro-plant outflow within a short time.

While the land use for large hydroelectric projects with storage can be substantial, the impact of smaller projects can be quite limited. Generally smaller projects are diversion projects as opposed to ones with impoundments, thus typical hydropower installations of less than 5 MW might occupy less than 5 acres (2 hectares) of land Some owners hold extensive tracts of land around their hydroelectric projects due to other business interests, including water supply, timber lands, reservation lands, etc. These may be included within the project boundary to protect land use and water quality making them subject to associated FERC and State hydro license related regulations. These additional lands are not strictly necessary to the hydro operation.

The ability to dispatch hydropower on short notice is one of its important benefits. Most small hydro projects are run as base load or short-term (daily or hourly) peaking plants based on their storage capacity. During the storage cycle when a plant is not generating, it is often run in "condense" or "spinning reserve" mode, where it runs as a motor rather than as a generator. In this mode the plants add reactive power ("VARs") to the transmission system aiding its stability. Under such conditions, the operating system or operator is able to bring the plant on line in relatively short order (fractions of seconds to minutes, depending on the installation) to help stabilize a transmission grid or follow load. Such operations have been primarily the responsibility of large hydropower systems like the Federal Columbia River Power System where 22,000 MW of hydropower operate in a coordinated system. However, even small isolated systems and units can be run in condense or spinning reserve as needed to help stabilize the local system.

Like most mature, dispatchable generation technologies, hydroelectric plants are highly reliable. In general, hydropower plants achieve annual availabilities in excess of 90%. However, the nameplate capacity may be available for half of the year or less, depending on seasonal flows in

the river system and how much storage is available. The available capacity is a function of both water availability and the plant's mechanical condition.

While hydroelectric power produces no emissions they do have environmental impacts. The primary environmental impacts of hydropower installations are their impacts on fish and water quality. For new installations, the conversion of a free-flowing section of river into a pooled river causes biotic changes and inundation. For existing water projects that do not have hydroelectric power, adding a generating unit may have little environmental effect because it has already incurred the primary impacts. Typical existing projects include dams, drop structures, pipelines, canals, and conduits. These hydraulic structures are used for multiple purposes besides power, including irrigation, flood control, water supply, and recreation. For example, one project used the fish-attraction water in a fish ladder at McNary Dam on the Columbia River. A 10-MW plant added to the system used energy from the water needed to attract salmon into the large fish ladder. Previously, that energy was dissipated through a diffusion grating and lost.

DOE, along with industry support though EPRI and the Hydro Research Foundation, is investigating new turbine designs, which would have less impact on fish. The DOE has also recently issued a solicitation for "Testing Fish Passage Characteristics For Low Power and Low Head Hydropower Turbine Technology." These studies are intended to further help the hydroelectric industry reduce impacts to the environment.

Market Information

The Public Utilities Reform Policy Act of 1978 spurred small hydro development in California and other states, in the late 1970s through the mid-1980s. During that period, most of the potential small hydro sites were identified; and the most economically attractive ones, developed. While some undeveloped sites still exist, their economics and/or permitting concerns have precluded their use.

The increasing environmental awareness of the past decade has brought attention to the impacts of hydroelectric facilities on fish and of land inundation on wildlife. This has made project permitting more difficult and increased costs. These circumstances, coupled with the relatively low price of energy in California for the past decade, have resulted in very few new projects being developed. The increased environmental awareness has also expanded FERC's role in balancing all the uses of the resource. The Energy Policy Act of 1992 requires that FERC take into consideration all impacts as part of their relicensing program. This, combined with mandatory provisions of the Clean Water Act, has also added to the cost of new developments. Depending on the extent of development, incremental power increases at existing sites may be less impacted by the regulatory requirements, facilitating their development.

The time required for development of a new hydropower project can be 3–5 years, or more. The risks associated with obtaining permits and the high costs of initial development activities combine with uncertainty regarding market prices 3–5 years in the future combine to make such projects difficult to finance in a deregulated marketplace. Adding incremental power to existing sites would potentially require shorter development timelines. The Department of Energy has identified over 1,300 MW existing project sites with the potential to add 30 MW within California. Approximately 130 of these megawatts are at sites where generation is currently

installed and approximately 600 MW is at sites with existing diversion structures but no generation installed.[1]

Responding to environmental concerns, turbine manufactures are focusing their efforts on "fish friendly" turbine designs that can pass virtually any fish unharmed. Another environmental-protection industry focal point is improved fish-passage technology to get fish up- or downstream without harm or delay. Also under development are turbines that can operate over wide ranges of head, without dams, and that incorporate portable components to minimize civil or structural site work, for smaller installations.

Environmentally acceptable certification would improve hydropower's acceptance in the renewable-energy market. At present, however, there is no one universally accepted standard for assessing hydropower's impact. Life Cycle Impact Assessment (ISO 14042) offers measurement of impacts from initial construction through the life of operations. Low Impact Hydro Institute (LIHI) criteria measure a facility's performance against a set of criteria. Certification costs, coupled with low energy prices, have restrained owners from using the ISO 14042 criteria. Concerns about ability and cost to comply, coupled with certification cost and low energy prices have restrained facilities from approaching LIHI. Specific requirements such as buffer zone set asides to compensate for inundation areas, LIHI's yet to be developed standard for water-quality monitoring and a provision for changes in conditions relevant to the certification have made the majority of hydro operators reluctant to seek certification. The recent increase in energy prices is expected to increase activity in this area, but like other renewable-industry participants, the hydroelectric-market participants expect prices to stabilize and retreat as new gas-fired capacity comes on line. Expanding the LIHI definition of renewable generation to include incremental increases of less than 30 MW at existing facilities would also serve to offset some of this uncertainty.

There is a limited customer base for hydropower technology. Most developers contract with traditional electric utilities or the new centralized markets for electricity in deregulated states. With the challenges of permitting new projects, the industry has looked to adding hydropower to existing structures, which are easier to permit than all new installations. Most of the environmental impacts and capital costs have already occurred at existing water supply, irrigation, flood-control, or similar structures.

Hydropower plant automation and upgrades are becoming increasingly important because labor has historically been the largest component of operations and maintenance costs. Automation can also contribute to plant reliability. Modernization of existing facilities includes improved automation and communications equipment, newer-design turbines, more-reliable peripheral equipment, and machine-condition monitoring equipment to reduce outage and maintenance.

There is limited opportunity for off-grid and distributed-generation hydroelectricity. Micro-hydro systems can sometimes be installed for these applications, but the market is restricted by the need for the load to be close to a hydro resource, such as a river.

---

[1] U.S Hydropower Resource Assessment for California, DOE/ID-10430(CA)

Operating Experience

Using mature technology, hydroelectric plants have generally operated reliably, with availabilities over 90%. The primary causes of unscheduled outages are control- and power-system related. Scheduled outages for routine maintenance and equipment upgrades also contribute to downtime. The average capacity factor for Californian facilities for which data was available was approximately 52%. This value is the result of both equipment and flow limitations.

The introduction of automated controls to existing power plants has helped to keep operating costs down and increased their competitiveness. It has also improved their abilities to monitor river conditions and adjust operations to minimize environmental impacts.

The California hydroelectric resource is highly seasonal, with peak energy production in the winter, spring, and early summer. During the summer and fall dry seasons, production falls as river snow-melt-driven flows decline.

Cost and Benefits

The cost of hydroelectricity consists of the cost of servicing the capital investment, including debt service, return paid to equity investors, depreciation, income and property taxes, and insurance; operation and maintenance expense; periodic component replacement; and land-lease expense. The long-term power sales contract is usually structured to cover the project costs and provide an acceptable return to the equity investors over the life of the project. Capital costs can vary widely, ranging from$1,500–$5,000/kW. The range of costs reflects the wide range of construction and permitting conditions faced in the industry.

Numerous existing hydro plants produce energy at a cost less than 2–3 cents per kilowatt-hour. Cost of energy production at independent hydro projects would likely be significantly higher. Projects have recently been proposed elsewhere in the country at energy prices of approximately 6¢/kWh.

The principal economic and public benefits of hydroelectric generation include the direct avoidance of the acid-gas (SO_2 and NO_X), toxic-metal, and greenhouse-gas (CO_2) emissions of the fossil-fueled generation they replace; reduced dependence upon on native and imported fossil fuels; provision of low-cost power; creation of jobs for hydroelectric equipment and dam maintenance and operation, environmental and ecological studies; and generation of sales, income, and property-tax revenues for State and local government. Other public benefits include flood protection; stable water supply; and public recreation facilities for camping, swimming, fishing, flat-water boating, and white-water rafting. Strictly speaking, the environmental and recreational benefits should make hydroelectric systems more valuable than otherwise-equivalent fossil-fueled plants, but such “externalities” are not generally accounted for in present-day electricity markets.

Research Needs and Recommendations

The basic technologies for hydroelectric energy conversion are well known. Although hydroelectric is regarded as a mature technology there are several areas where the technology could benefit from addition R&D efforts. These include:

- Variable speed turbine/generators
- High-voltage generators
- Ancillary services analysis
- Advanced Hydropower Turbine Systems (AHTS) R&D
- Equipment effects of operational changes for system support
- Low/ultra low-head micro turbines
- Kinetic-energy free-flow turbines
- Improved numerical analysis techniques
- Improved absolute and relative flow requirements in rivers, through units
- Small-scale power at existing dams
- Generating equipment hardware systems improvement
- Materials issues unique to hydropower systems

In addition, opportunities exist for research on using technology to further mitigate hydropower's environmental impacts.

- Downstream thermal regimes
- Environmental impacts of micro hydropower
- Design of environmental flow requirements
- Sediment issues (transport, removal, management, etc.)
- Fish passage through reservoirs
- Measure mitigation efforts
- Develop biological criteria for assessing equipment

These R&D efforts would improve the economic viability of hydro in addition to reducing its environmental impacts. The effects for small hydro, particularly low head and free flow, would be to make sites not currently considered economic to develop more viable with lessened environmental impacts.

Technology can help to both communicate and control whether river conditions are environmentally friendly or not. Technology can monitor water conditions and automatically change power-plant operations to minimize environmental impacts. Appropriate actions could

be to assist fish passage, change flow regime, initiate voluntary spill, or even stop generating at specific periods to improve water quality, temperature, dissolved gas, or dewatering habitat.

Work in these technical areas should coordinate with and enhance current U.S. Department of Energy programs funding advanced-turbine and control-technology research.

Also, CEC assistance is needed to design and implement an energy market that better meets the needs of the hydroelectric industry. Specific suggestions included:

- Energy contracts that provide for long-term power produced at controlled prices
- Support for initial project activities to mitigate the risk associated with the 3- to 5-year development cycle
- Streamlining of licensing processes and coordination of conditions imposed by regulatory authorities
- Designating incremental hydrogenation of 30 MW or less as renewable energy and developing clear criteria for what constitutes environmentally acceptable hydroelectric development.

The industry is highly capital intensive for initial project development, but offers relatively low, constant cost of energy for the long term. It also improves grid-system stability, in addition to providing other public benefits, including flood protection, stable water supply, and public recreation facilities for camping, swimming, fishing, flat-water boating, and white-water rafting. Market structures that provide incentives commensurate with the capital risks and the full range of hydropower's benefits are needed for hydroelectric technology to grow in California.

8
POTENTIAL CONTRIBUTION OF RENEWABLES TO CALIFORNIA

Introduction

This section addresses the potential contribution that renewable-energy technologies can make to California within the next decade, in terms of electricity generation, reduction in air emissions related to electricity production, and other benefits to the State's economy. The ability of renewable-energy technologies to contribute to the California energy supply—and thereby contribute the other benefits described in this section—is dependent on a wide range of factors, including:

- market structures
- market prices
- government incentives
- transmission access
- transmission upgrades near resource areas
- permitting restrictions

Given the wide range of uncertainty in these factors over the next ten years, it is impossible to predict certainly and precisely the amounts that renewable energy will contribute to the State's energy supply within that time. Therefore, the benefits that derive from those renewable-energy deployments are also uncertain. However, it is possible to create reasonable deployment scenarios and estimate the contributions that renewables could make if those scenarios develop.

Scenario Development

As a point of departure for scenario creation, the following characteristics of the California Energy market were identified or assumed:

- 2000 peak load — 48,380 MW[1]
- Anticipated load growth — CEC load forecast[1]

[1] Market Clearing Prices Under Alternative Resource Scenarios – 2000-2010, California Energy Commission P300-00-001

- Baseline market prices — CEC Optimistic Development Scenario[1]
- 1999 electric energy generation — 275,792 GWh[2]
- Future electric energy consumption — Assumed proportional to peak load

The recent upheavals in the market have shown that, in the short term, the CEC market-clearing price forecasts are significantly in error, illustrating the challenge of energy-price forecasting.

In addition to market price uncertainties, the renewables markets are heavily influenced by State and Federal government incentives, which are similarly uncertain. To address the combined uncertainties in market prices and incentives, the CEC price forecasts were increased by 50, 150, and 250 percent to generate three scenarios designated A, B, and C respectively. This resulted in a range of prices that bracket the expected average prices in California (including effects of possible government incentives) after the current crisis has subsided.

Finally, as described in the technology sections of this report, there are many non-cost barriers to renewable-energy development, including permitting delays, emissions constraints in some cases, transmission constraints, and financing bottlenecks. For the present purpose, these were combined with the market and government incentives by dividing Scenario A into A1 and A2, and assuming favorable resolution of all non-cost barriers for all scenarios except A1. The resulting scenarios and associated energy prices are shown in Table 8-1.

Table 8-1
Scenario Summary

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Load (MW)	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104
Generation (GWh)	276,000	280,233	285,356	290,154	294,866	294,090	297,861	303,235	308,888	314,491	320,064

	Scenario Prices ($/MWh)											Avg.
A	42.75	45.75	37.20	35.55	36.90	39.15	40.35	39.75	41.40	43.65	49.35	41.07
B	71.25	76.25	62.00	59.25	61.50	65.25	67.25	66.25	69.00	72.75	82.25	68.45
C	99.75	106.75	86.80	82.95	86.10	91.35	94.15	92.75	96.60	101.85	115.15	95.84

To estimate the likely development of renewable resources under each scenario, the status of the technology and industry, as well as the availability of resources, needs to be considered. These factors were gauged from the information in the technology sections of this report.

The market in California at the present time is highly uncertain. Until some of the uncertainty is resolved, it is highly unlikely that new projects will be initiated. Given that most new projects require several years of development and construction activity, it was assumed that no developments beyond those already announced would occur in the next couple of years.

[2] California Energy Commission website, http://www.energy.ca.gov/electricity/electricitygen.html

After the next couple of years, it was assumed that developers can have reasonable certainty of the prices shown for each scenario, or their equivalent in government support. The equivalence could be provided through incentives or other mechanisms in the event market prices are lower than shown in the assumptions.

The following sections discuss the specific approaches and highlights of results for the technologies examined in this work under each of the assumed scenarios. Appendix C presents the detailed assumptions and methods used in deriving the overall benefits of each of the deployment scenarios, and it also provides technology cost illustrations to show general consistency with the scenarios of this section.

Wind

Scenario A — Under this scenario, prices are such that development is not likely to occur because most of the best wind resource areas with easy transmission access have already been developed. New sites will generally either have lower-quality resources or significant transmission issues. The past several years have shown that price is not the only barrier to wind energy development in California. Market structures, transmission access limitations and permitting challenges have delayed the implementation of many projects awarded support in the CEC's 1998 renewables auction. Whether these factors will ultimately prevent project completion remains to be seen. Given these challenges and relatively low market prices, it was assumed that between 50% and 100% of the currently announced new capacity would be built and no other development would occur in this scenario. (This assumes no extension of the new resource auctions or Federal production tax credit, which would raise the effective price) This results in total new capacity over ten years of 326 MW (Scenario A1) to 650 MW (Scenario A2).

Scenario B — Under this scenario, prices are high enough to provide an acceptable return to investors and projects are likely to be developed as a result. Based on interviews with industry participants, current project plans, and other factors, it was estimated that the industry would install 75% of the current planned capacity, plus grow 15% annually, starting in 2003 (for production in 2004). This results in total new capacity over 10 years of 3,600 MW, generating approximately 4.5% of California's electrical energy requirements at the end of the decade.

Scenario C — This scenario would provide attractive returns to investors and permit development of projects with more marginal wind resources or significant transmission upgrade requirements. This scenario is similar to Scenario B until 2004, but then the industry would grow 25% annually. The total new capacity estimated under this scenario is 5,100 MW, and at the end of the ten-year period, wind would generate approximately 6% of California's electricity requirements.

Comparing these scenarios to wind power development over the past five years in Germany, Denmark, and Spain, indicates they are reasonable. In 1999, Germany installed 1,571 MW of new capacity and in 2000 they installed nearly 1,000 MW. Under Scenario C, the maximum California capacity installed in a single year is approximately 1,160 MW (in year ten). The 5,100 installed capacity equals, at 33% capacity factor, approximately 1,700 average megawatts, which is 22% of the estimated growth in peak demand. As mentioned previously, except for Scenario A1, these scenarios assume that the market-structure, transmission, and permitting

issues that have recently been limiting development are resolved favorably. Table 8-2 shows the installed capacity, energy production and other data for the scenarios considered.

Table 8-2
Wind Energy Development Scenarios

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Scenario A1 Capacity (MW)	1,646	1,646	1,809	1,972	1,972	1,972	1,972	1,972	1,972	1,972	1,972
Capacity Factor	24%	24%	26%	27%	27%	27%	27%	27%	27%	27%	27%
Percent of Peak Load	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Generation (GWh)	3,500	3,500	4,054	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601
Percent of Generation	1.3%	1.2%	1.4%	1.6%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%
Scenario A2 Capacity (MW)	1,646	1,646	1,971	2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296
Capacity Factor	24%	24%	27%	28%	28%	28%	28%	28%	28%	28%	28%
Percent of Peak Load	3%	3%	4%	5%	4%	4%	4%	4%	4%	4%	4%
Generation (GWh)	3,500	3,500	4,604	5,685	5,685	5,685	5,685	5,685	5,685	5,685	5,685
Percent of Generation	1.3%	1.2%	1.6%	2.0%	1.9%	1.9%	1.9%	1.9%	1.8%	1.8%	1.8%
Scenario B Capacity (MW)	1,646	1,646	1,890	2,134	2,415	2,737	3,108	3,535	4,026	4,590	5,239
Capacity Factor	24%	24%	26%	27%	28%	29%	30%	30%	31%	32%	32%
Percent of Peak Load	3%	3%	4%	4%	5%	5%	6%	7%	7%	8%	9%
Generation (GWh)	3,500	3,500	4,329	5,143	6,004	6,994	8,133	9,442	10,948	12,680	14,671
Percent of Generation	1.3%	1.2%	1.5%	1.8%	2.0%	2.4%	2.7%	3.1%	3.5%	4.0%	4.6%
Scenario C Capacity (MW)	1,646	1,646	1,890	2,134	2,439	2,820	3,297	3,893	4,637	5,568	6,731
Capacity Factor	24%	24%	26%	27%	28%	29%	30%	31%	32%	32%	33%
Percent of Peak Load	3%	3%	4%	4%	5%	5%	6%	7%	9%	10%	12%
Generation (GWh)	3,500	3,500	4,329	5,143	6,079	7,249	8,711	10,539	12,823	15,679	19,249
Percent of Generation	1.3%	1.2%	1.5%	1.8%	2.1%	2.5%	2.9%	3.5%	4.2%	5.0%	6.0%

Geothermal

Scenario A — The approximately 200 MW of planned new capacity in Imperial, Lake, and Sonoma counties, discussed in Section III, could get built under this scenario. These projects are expected on line in the next couple of years. The developments planned for Siskiyou County are probably not economical at Scenario A prices, and further developments would be highly unlikely. Therefore, no further additional capacity is foreseen.

Scenario B — Higher prices make further developments of exiting resources and some of the planned resources potentially economical. This scenario is the same as Scenario A through 2003; however, after that approximately 300 MW of new capacity could be added. These additions were assumed to occur with a 10% annual growth rate. They occur primarily through expansion of existing projects and development of some of the Siskiyou County resource discussed in Section III. The total estimated new capacity over 10 years under this scenario is approximately 500 MW.

Scenario C — At these prices significant additional resources become economic (assuming that planned Federal support for exploration materializes). However, the project-development cycle is such that none of this capacity is likely to be on-line for five years. Therefore, the

development over the first five years was assumed to be the same as Scenario B, but then an additional 1,000 MW was estimated to be economical. This was assumed to be installed at a growth rate of 20% per year. The total new capacity over the ten-year period under this scenario is approximately 1,200 MW, in which case geothermal energy would account for approximately 7% of the State's electricity needs.

Table 8-3 illustrates these scenarios. Note that significant limiting factors on the development of new geothermal resources are the costs and time required for identification and development of the resource and the relative scarcity of high-temperature, clean resources that can be developed at the effective energy prices covered by these scenarios. In the event of higher effective prices, substantially more geothermal development would be possible.

Table 8-3
Geothermal Development Scenarios

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Scenario A Capacity (MW)	1,754	1,754	1,813	1,953	1,953	1,953	1,953	1,953	1,953	1,953	1,953
Capacity Factor	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
Percent of Peak Load	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%
Generation (GWh)	13,250	13,223	13,668	14,723	14,723	14,723	14,723	14,723	14,723	14,723	14,723
Percent of Generation	4.8%	4.7%	4.8%	5.1%	5.0%	5.0%	4.9%	4.9%	4.8%	4.7%	4.6%
Scenario B Capacity (MW)	1,754	1,754	1,813	1,953	1,983	2,015	2,051	2,090	2,133	2,181	2,233
Capacity Factor	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
Percent of Peak Load	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Generation (GWh)	13,223	13,223	13,668	14,723	14,946	15,190	15,459	15,755	16,081	16,439	16,833
Percent of Generation	4.8%	4.7%	4.8%	5.1%	5.1%	5.2%	5.2%	5.2%	5.2%	5.2%	5.3%
Scenario C Capacity (MW)	1754	1754	1813	1953	1983	2015	2140	2290	2470	2686	2945
Capacity Factor	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
Percent of Peak Load	4%	4%	4%	4%	4%	4%	4%	4%	5%	5%	5%
Generation (GWh)	13,223	13,223	13,668	14,723	14,946	15,190	16,133	17,263	18,620	20,249	22,203
Percent of Generation	4.8%	4.7%	4.8%	5.1%	5.1%	5.2%	5.4%	5.7%	6.0%	6.4%	6.9%

Biomass

Scenario A — Prices under this scenario are potentially high enough to justify operating the 136 MW of biomass capacity that is currently not running for lack of a cost-effective fuel supply. It has been assumed that all of this capacity would restart under this scenario; however, that may overstate what would actually happen. Under this scenario, biomass would continue to contribute approximately 2% of the State's electricity supply. For landfill gas and biogas, no new capacity is considered because it is believed that the cost effective resources at these prices have been developed.

Scenario B — Under this scenario, it was estimated that no projects would be developed for three years due to project development-time requirements. After that, approximately 50% of the readily usable municipal solid waste and landfill-gas capacity identified in Section IV was assumed to be built, divided equally between solid and gaseous fuels, together with 80 MW of feedlot-manure-fueled generation. The new capacity was spread over the remaining seven years

by assuming a 15% annual growth rate. With this assumption, the total new capacity over 10 years is approximately 360 MW. Under this scenario, biomass would provide approximately 2.6% of the State's electrical energy in ten years. If 100% of the readily available material were utilized, the new capacity would be approximately 560 MW and biomass would contribute approximately 3% of the State's electrical energy consumption.

Scenario C — Section IV of this report identifies approximately 1,900 MW of additional, but more costly, fuel supplies in the State. Under Scenario C, it is believed that these less-economic forest thinnings and agricultural residues become competitive. Therefore, for this scenario, it was assumed that in addition to the developments of Scenario B, approximately 50% of this more costly material would be utilized and an additional 100 MW of landfill gas and 40 MW of feedlot-manure-fueled generation is installed. This growth was spread across the years assuming a 20% growth rate. Under this scenario, the total new capacity in ten years is approximately 1,450 MW and biomass contributes 4.6% of the State's electrical energy needs. If 100% of these higher-cost fuels were utilized, the potential increases to approximately 3,000 MW added capacity and 7% of the State's electricity needs. Table 8-4 provides details for solid-fuel biomass; and Table 8-5, those for landfill and digester gas in these scenarios.

Table 8-4
Biomass (Solid Fuels) Development Scenarios

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Scenario A Capacity (MW)	771	771	907	907	907	907	907	907	907	907	907
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	1.6%	1.6%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%
Generation (GWh)	5,663	4,483	5,274	5,274	5,274	5,274	5,274	5,274	5,274	5,274	5,274
Percent of Generation	2.1%	1.6%	1.8%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%
Scenario B Capacity (MW)	771	771	771	781	793	807	822	840	861	884	912
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	1.6%	1.6%	1.5%	1.5%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Generation (GWh)	5,663	4,483	4,483	4,543	4,611	4,690	4,781	4,885	5,005	5,143	5,301
Percent of Generation	2.1%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.7%
Scenario C Capacity (MW)	771	771	771	838	917	1,013	1,128	1,266	1,431	1,630	1,868
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	1.6%	1.6%	1.5%	1.6%	1.8%	2.0%	2.2%	2.4%	2.6%	3.0%	3.3%
Generation (GWh)	5,663	4,483	4,483	4,870	5,334	5,890	6,559	7,360	8,323	9,477	10,863
Percent of Generation	2.1%	1.6%	1.6%	1.7%	1.8%	2.0%	2.2%	2.4%	2.7%	3.0%	3.4%

Table 8-5
Biogas (Landfill and Digester Gas) Development Scenarios

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Scenario A Capacity (MW)	290	290	290	290	290	290	290	290	290	290	290
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%
Generation (GWh)	5,663	1,686	1,686	1,686	1,686	1,686	1,686	1,686	1,686	1,686	1,686
Percent of Generation	2.1%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%
Scenario B Capacity (MW)	290	290	290	306	324	346	370	398	430	467	510
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.7%	0.8%	0.8%	0.9%
Generation (GWh)	1,678	1,678	1,678	1,770	1,877	1,999	2,140	2,302	2,488	2,702	2,948
Percent of Generation	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.8%	0.9%	0.9%
Scenario C Capacity (MW)	290	290	290	312	338	369	407	452	506	572	650
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.9%	0.9%	1.0%	1.2%
Generation (GWh)	1,678	1,678	1,678	1,804	1,955	2,137	2,355	2,616	2,930	3,307	3,759
Percent of Generation	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.9%	0.9%	1.1%	1.2%

There are several factors that could help to make the effective price such that Scenario C would be realized. These include: (1) efforts by the State waste board to shift some of the costs of biomass use to those who benefit from its waste-disposal and emissions-reductions benefits and (2) success in cofiring biomass with natural gas (3) Advancing "bioreactor" landfill technology for substantially more California power. This may be driven by factors such as major climate benefits. While these factors will encourage the development of landfill gas to energy projects, none of these events are expected to make manure fuels cost competitive under scenario C.

Solar Thermal

In the absence of a commercial manufacturer of solar-thermal electric power plants, and given the relatively high expected costs of such plants in the near term, it does not appear that solar thermal technologies can make a significant contribution to the California energy markets in the next ten years under either Scenarios A or B. Under Scenario C, it is possible that the use of some parabolic-trough collectors in conjunction with combined-cycle gas-fired generation could be economically viable. This has not yet been demonstrated, but several projects are under consideration. For Scenario C it was assumed that it would be five years before potential developers gained sufficient confidence in the technology's pricing and performance to start construction. Development could begin with a plant that combined 40 MW of solar collector and 300 MW of combined-cycle gas. If this were replicated annually, it would add 200 MW of new solar-thermal capacity to California's energy supply, increasing the total to approximately 560 MW and supplying less than 1% of California's electrical energy.

California has vast solar energy resources, so technology improvements that reduce costs, or effective energy prices higher than used for Scenario C, would greatly increase the contribution solar-thermal technology could make to California's energy supply.

Table 8-6
Solar Thermal Development Scenarios

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Scenario A Capacity (MW)	360	360	360	360	360	360	360	360	360	360	360
Capacity Factor	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Percent of Peak Load	0.74%	0.73%	0.72%	0.71%	0.70%	0.70%	0.69%	0.68%	0.66%	0.65%	0.64%
Generation (GWh)	947	947	947	947	947	947	947	947	947	947	947
Percent of Generation	0.34%	0.34%	0.33%	0.33%	0.32%	0.32%	0.32%	0.31%	0.31%	0.30%	0.30%
Scenario B Capacity (MW)	360	360	360	360	360	360	360	360	360	360	360
Capacity Factor	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Percent of Peak Load	0.74%	0.73%	0.72%	0.71%	0.70%	0.70%	0.69%	0.68%	0.66%	0.65%	0.64%
Generation (GWh)	947	947	947	947	947	947	947	947	947	947	947
Percent of Generation	0.34%	0.34%	0.33%	0.33%	0.32%	0.32%	0.32%	0.31%	0.31%	0.30%	0.30%
Scenario C Capacity (MW)	360	360	360	360	360	360	400	440	480	520	560
Capacity Factor	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Percent of Peak Load	0.74%	0.73%	0.72%	0.71%	0.70%	0.70%	0.77%	0.83%	0.89%	0.94%	1.00%
Generation (GWh)	947	947	947	947	947	947	1,052	1,157	1,262	1,367	1,473
Percent of Generation	0.34%	0.34%	0.33%	0.33%	0.32%	0.32%	0.35%	0.38%	0.41%	0.43%	0.46%

Photovoltaics

For photovoltaics, a somewhat different approach was taken. The costs of PV today are such that there would be very few sales if purchased on purely economic grounds. However, because PV addresses unique markets there are noneconomic factors now in play. For Scenarios A and B, it was assumed that the forces that resulted in 3 MW of new capacity being installed in California in 1999 would continue for the next ten years. This results in 30 MW of new PV capacity over the next ten years. For Scenario C, a 35% annual growth rate (equivalent to the global growth rate of grid-connected PV systems) was assumed. This produces 221 MW of new PV capacity in the next ten years. Table 8-7 summarizes the results for all three scenarios.

Table 8-7
Photovoltaics Development Scenarios

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Scenario A Capacity (MW)	14	17	20	23	26	29	32	35	38	41	44
Capacity Factor	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Percent of Peak Load	0.03%	0.03%	0.04%	0.05%	0.05%	0.06%	0.06%	0.07%	0.07%	0.07%	0.08%
Generation (GWh)	29	36	42	48	55	61	67	74	80	86	93
Percent of Generation	0.01%	0.01%	0.01%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%
Scenario B Capacity (MW)	14	17	20	23	26	29	32	35	38	41	44
Capacity Factor	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Percent of Peak Load	0.03%	0.03%	0.04%	0.05%	0.05%	0.06%	0.06%	0.07%	0.07%	0.07%	0.08%
Generation (GWh)	29	36	42	48	55	61	67	74	80	86	93
Percent of Generation	0.01%	0.01%	0.01%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%
Scenario C Capacity (MW)	14	18	24	31	41	54	72	97	130	175	235
Capacity Factor	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Percent of Peak Load	0.03%	0.04%	0.05%	0.06%	0.08%	0.11%	0.14%	0.18%	0.24%	0.32%	0.42%
Generation (GWh)	29	38	49	65	86	114	152	204	274	368	495
Percent of Generation	0.01%	0.01%	0.02%	0.02%	0.03%	0.04%	0.05%	0.07%	0.09%	0.12%	0.15%

Note that the details of the assumed growth in PV systems over the next ten years are not particularly important, because its present installed capacity is too small for credible growth rates to make significant impacts on the overall energy market within a decade. Thus, even the relatively aggressive growth envisioned in Scenario C results in a total capacity after 10 years equivalent to less than 0.2% of the State's electricity demand. However, if the Scenario C growth continues, the resulting PV capacity within the next decade would surpass today's capacity of all California's non-hydro renewables. Therefore, as in the case of solar-thermal generation, the vastness of California's solar resource means that PV can ultimately make a very large contribution to the State's energy budget and security.

Small Hydro

Small hydroelectric development within ten years in California will be difficult due to limited resource availability and environmental restrictions. It is estimated that permitting alone would be a five-year process. With no new facilities under serious consideration at this time, new developments in the next five years are not expected under any of the pricing scenarios. After that time, no new developments are expected under Scenario A due to the low energy price relative to the costs of new or upgraded hydro facilities. Under Scenarios B and C, some installations may be possible in the second half decade. The amounts are difficult to gauge because of the uncertainties in the regulatory environment. There is between 700 and 1,000 MW of hydroelectric capacity in the State that is within the 30-MW size limit for "qualifying renewable" designation under AB1890. This capacity operates approximately 50% of the time, contributing some 3,100 GWh to California's energy supply. This is slightly over 1% of the State's electricity use.

The Department of Energy has identified approximately 1,800 MW of additional projects under 30 MW in capacity that could be developed. They have also examined the various restrictions on project development associated with these projects and concluded that less than half is likely to be developable.[3] This would make the developable hydropower project capacity for projects under 30 MW approximately the same as the existing generation. Under either Scenario B or C, the additional development is expected to be considerably less than this, indicating that small hydro facilities will have a minimal incremental effect on California energy supplies within the next ten years.

Total Renewable-Energy Capacity

Figure 8-1 shows the result of summing all of the renewable-energy capacities in each of the four scenarios discussed in the previous paragraphs.

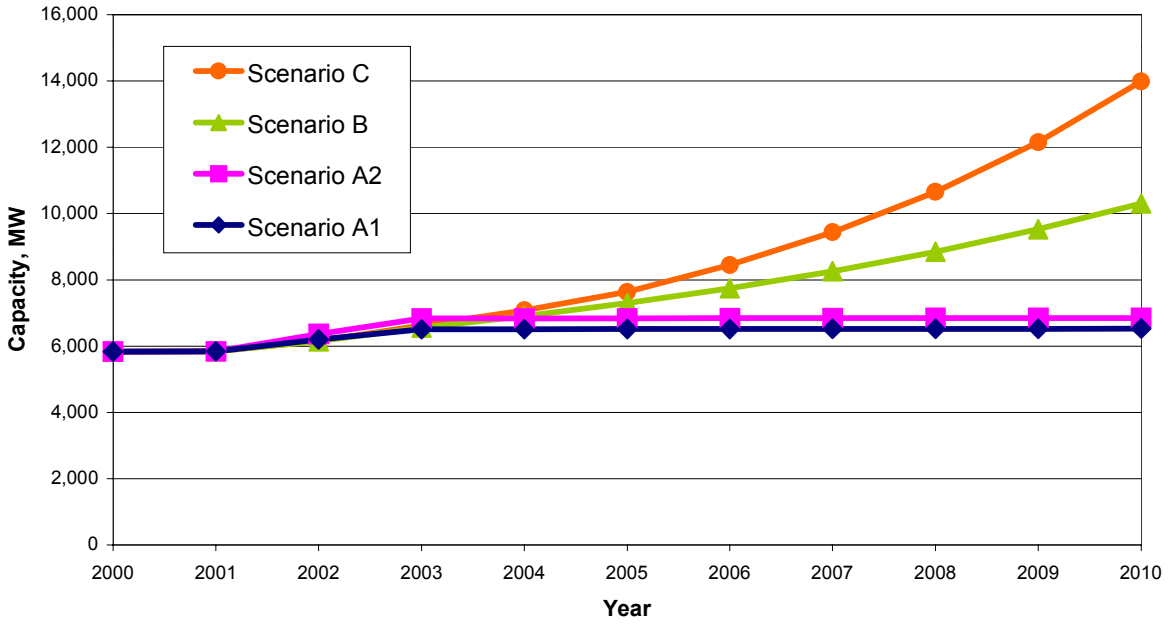


Figure 8-1
Total Renewable Energy Capacity in Different Scenarios

Electricity Generation Emissions Reduction

Using the estimates of renewable-energy generation capacity developed in Scenarios A, B, and C, it is possible to estimate approximately how much these technologies can contribute to reducing the air emissions that would occur if these additions were not made and to derive a market value for some of the avoided emissions. Table 8-8 shows present-day and year-2010 estimates for amounts of the greenhouse-gas carbon dioxide (CO_2) from fossil carbon as well as for the seven "criteria pollutants" monitored by the California Air Resources Board (CARB):

[3] U.S Hydropower Resource Assessment for California, DOE/ID-10430(CA)

oxides of nitrogen (NO_X), oxides of sulfur (SO_X), carbon monoxide (CO), total organic gases (TOG), reactive organic gases (ROG, which is essentially TOG minus methane), total airborne particulates (PM), and particulates less than 10 micrometers diameter (PM10).

Appendix C describes the details of deriving these emissions estimates. Briefly, the method assumes that the existing renewable-resource capacity displaces only fossil-fueled generation from the present system mix. However, all future additional renewable-resource generation is assumed to displace relatively clean-burning advanced natural-gas sources. The data on present criteria pollutants and generation mix were obtained from CARB and CEC estimates.[4] And the CO_2 emissions of advanced natural-gas generation were estimated from EPRI data.[5]. These assumptions are reasonable for the next decade, but they likely underestimate longer-term impacts, especially if present plans are carried out to replace retiring nuclear capacity with natural-gas and even advanced-coal generation.

Table 8-8
California Renewable Energy Emissions Reductions

Year	2000	2010		
Emission Type	**Current**	**Scenario A1**	**Scenario B**	**Scenario C**
CO_2 (Tonne/day)	55,539	60,509	74,091	92,961
NO_X (Tonne/day)	13.31	14.88	22.08	28.51
SO_X (Tonne/day)	1.12	1.12	1.12	1.12
CO (Tonne/day)	11.82	13.22	19.61	25.32
TOG (Tonne/day)	9.73	9.73	9.73	9.73
ROG (Tonne/day)	1.57	1.57	1.57	1.57
PM (Tonne/day)	1.73	1.73	1.73	1.73
PM10 (Tonne/day)	1.56	1.56	1.56	1.56
Total market value of avoided emissions (millions)	**$160**	**$184**	**$253**	**$320**

Biomass was treated very conservatively for these estimates. Specifically, biomass sources were given credit for reducing fossil CO_2 because their emitted CO_2 comes from non-fossil carbon. Biomass also got partial credit for reducing SO_X because biofuels are largely sulfur free. But it was not credited for reducing any of the other criteria pollutants. This approach likely underestimates biomass' beneficial impacts on emissions, but it was taken because biomass combustion generally is no cleaner than that in the natural gas-fired generators assumed to be the alternative source. Furthermore, since any form of biogas (LFG or digester gas) combustion reduces emissions of the very powerful greenhouse gas methane, biogas-fired electricity generation should actually receive credit for avoiding methane emissions. However, all but a trivial amount of present-day California landfill gas is already captured and burned, with or without an attached generator. Therefore, no methane emission (TOG) credit is given to LFG generation in this case, even though it does eliminate methane while producing electricity.

[4] Found respectively at http://www.arb.ca.gov/emisinv/emsmain/emsmain.htm and http://www.energy.ca.gov/electricity/electricitygen.html.

[5] Table 5-3 of TR-113785,*Greenhouse Gas Reduction with Renewables*, EPRI, December 2000.

Finally, to simplify calculations, the methane avoidance due to the assumed additions of other biogas generation was ignored because of the relatively small quantities involved.

The market values cited in Table 8-8 come from assuming the average year-2000 trading-credit values cited by the California Air Resources Board[6], which are: $21,289/tonne of NO_X, $12,615/tonne of SO_X, $8,536/tonne of CO, $7,224/tonne of ROG, and $18,763/tonne of PM10.

Finally, it should be noted that greenhouse-gas CO_2 emissions were not credited in the market value of the avoided emissions in Table 8-8 because there is no accepted value for them. However, if a "carbon tax" of as little as $25/tonne (equivalent to $7/tonne of CO_2, or about 0.1% of ROG's present market value) were implemented, it would add $142 million to the current annual value of the presently avoided emissions (nearly doubling them) and $236 million to the value of those in 2010 Scenario C.

Property- and Income-Tax Benefits

The benefits to State and local governments due to property taxes and payroll income taxes were estimated by the procedure described in Appendix C, which also presents detailed results for each of the major renewable-energy technologies.

Table 8-9
California Renewable Energy Tax and Employment Benefits

Year:	2000	2010		
	Current	**Scenario A1**	**Scenario B**	**Scenario C**
Employment (#)	6,467	7,126	11,196	18,489
State and local taxes (millions)	$93	$102	$141	$195

Special Solid-Fuel Biomass Benefits

As described in Section IV on biomass, there are unique benefits derived from solid-fueled biomass generation for such things as avoidance of landfill expansion and wildfire losses. These were estimated for the present scenarios from the results of an EPRI-managed study done in 1996 for the U.S. DOE Western Regional Biomass Energy Program (WRBEP). That study derived $111 million in such benefits from the 800-MW California biomass-power industry in 1992, when biomass power generation from solid fuels was at a peak. Table 8-10 shows the corresponding values for the present-day 771-MW solid-fuel industry as well as for the scenarios developed in this section.

[6] Prices Paid in Dollars Per Ton for Offsets (Table 1) in "Emission Reduction Offsets Transaction Cost Summary Report for 2000" <http://www.arb.ca.gov/erco/erco.htm>

Table 8-10
California Solid-Fuel Biomass Benefits

Year:	2000	2010		
	Current	**Scenario A1**	**Scenario B**	**Scenario C**
Other biomass benefits (millions)	$69	$81	$82	$168

Summary of Benefits by Technology

Adding together the three value components from above, Table 8-11 summarizes the total expected monetary and employment benefits of each renewable-energy technology for deployments in California. As detailed in Appendix C, the cumulative monetary benefits range from a total of over $3.8 billion in Scenario A1 to over $4.8 billion in Scenario C for the eleven years covered in the present study.

Table 8-11
Economic Value to California of Renewable Energy Deployments

Year	2000		2010					
	Current		**Scenario A1**		**Scenario B**		**Scenario C**	
Technology	**Jobs**	**Total Benefit ($M)**	**Jobs**	**Total Benefit ($M)**	**Jobs**	**Total Benefit ($M)**	**Jobs**	**Total Benefit ($M)**
Wind	475	$40	569	$50	3,181	$143	4,934	$186
Geothermal	2,928	$123	3,261	$136	3,937	$154	5,954	$199
Biomass	1,178	$84	1,386	$98	1,510	$99	3,875	$202
Biogas	661	$5	661	$5	1,319	$8	1,770	$10
Solar Thermal	80	$14	80	$14	80	$14	353	$21
PV	2	$1	27	$2	27	$2	459	$9
Small Hydro	1,143	$56	1,143	$56	1,143	$56	1,143	$56
Total	6,467	$322	7,126	$360	11,196	$475	18,489	$683

A
PROJECT LISTS BY TECHNOLOGY

Wind Project Data

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
Painted Hills B & C	San Gorgonio	Southern California Edison	Enron Wind Corp.	Zond Systems	Vestas	65	Completed	1981-1995	3.965	23%	8108
Painted Hills B & C	San Gorgonio	Southern California Edison	Enron Wind Corp.	Zond Systems	Vestas	90	Completed	1981-1995	15.300	22%	29185
Zond-PanAero Windsystems	San Gorgonio	Southern California Edison	Enron Wind Corp.	Zond Systems & Mesa Wind	Vestas	65	Completed	1981-1995	29.900	25%	64926
Dutch Wind	San Gorgonio	Southern California Edison		DutchWind	NedWind	500	Completed	1994	10.000		
Karen Avenue (San Gorg. Farms)	San Gorgonio	Southern California Edison	San Gorgonio Farms	San Gorgonio Farms	Vestas	500	Completed - Repower	1995	3.000	30%	7804
East Winds	San Gorgonio	Southern California Edison	Nichimen America	Nichimen America	NEG Micon	700	Completed - Repower	1997	4.200		
Enron Earth Smart/ Merchant Plant	San Gorgonio	Enron Energy Corp	Enron Wind Corp.	Enron Wind Corp.	Zond	750	Completed	1999	16.500		
Cabazon	San Gorgonio	Southern California Edison	Enron	Enron Wind Corp.	Zond	750	Completed - Repower	1999	39.750		
Energy Unlimited (EUI Management)	San Gorgonio	Southern California Edison	Energy Unlimited	Energy Unlimited	Nordex	1000	Completed	1999	10.000		
Pacific West I	San Gorgonio	Southern California Edison/PacifiCorp & GreenMountain.com	PacifiCorp	Venture Pacific (SeaWest)	NEG Micon	700	Completed	1999	2.100		
Westwind	San Gorgonio	Southern California Edison	Cinergy and Caithness	SeaWest Energy Group	NEG Micon	700	Completed - Repower	1999	47.250		
Westwind - PacifiCorp	San Gorgonio	SCE/ Pacificorp/ GMER	Pacificorp/ GMER	SeaWest Energy Group	NEG Micon	750	Completed - Repower	1999	1.500		
Painted Hills Wind Developers	San Gorgonio	SCE	Enron		Zond	750	Proposed - Repower	2001	19.500		
TBD	San Gorgonio	Southern California Edison		Whitewater Energy			Proposed - New	2000	60.720		
Alta Mesa Phase IV	San Gorgonio	Southern California Edison		Mark Technologies/FORAS Energy Inc.	Vestas	600	Proposed - New	2000	40.000	25.2	

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
Christensen/Lazar Project	San Gorgonio	SCE	Enron		Zond	750	Proposed - New	2001	23.250		
TBD	San Gorgonio	Southern California Edison		Venture Pacific (SeaWest)			Proposed - New	2000-2001	20.000		
Mountain View Partners	San Gorgonio	Southern California Edison		Sea West	Mitsubishi	600	Proposed - New	2001	44.400		
Energy Unlimited (EUI Management)	San Gorgonio			Energy Unlimited			Proposed - New	2001	16.900		
Wintec Energy #1	San Gorgonio			Wintec Energy			Proposed - New	2001	3.000		
Wintec Energy #2	San Gorgonio			Wintec Energy			Proposed - New	2001	3.750		
San Gorgonio Farms	San Gorgonio	Southern California Edison			Vestas	500	Completed	< 1995	2.000	30%	5203
Energy Unlimited (EUI)	San Gorgonio	Southern California Edison			Bonus Bonus Delta Micon Bonus	120 65 150 108 250	Completed	< 1995	14.483	26%	32480
San Jacinto Power	San Gorgonio	Southern California Edison			Vanguard Windmatic	95 65	Completed	< 1995	5.000		
Difwind, Ltd	San Gorgonio	Southern California Edison			Micon Micon	108 65	Completed	< 1995	14.955	22%	28662
So. Cal. Sunbelt	San Gorgonio	Southern California Edison			Windmatic Windmatic	65 95	Completed	< 1995	10.465	17%	15860
Difwind V	San Gorgonio	Southern California Edison			Micon	108	Completed	< 1995	7.884	24%	16440
Alta Mesa	San Gorgonio	Southern California Edison		SeaWest Energy Group	Danwin Vestas	160 225	Completed	< 1995	28.170	20%	48724
Altech Energy III	San Gorgonio	Southern California Edison		SeaWest Energy Group	Micon	108	Completed	< 1995	21.708	21%	40840

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
Meridan Trust	San Gorgonio	Southern California Edison			USW56-100 Bonus	100 150	Completed	< 1995	7.550	29%	19415
Kenetech (various)	San Gorgonio	Southern California Edison			33M-VS	300	Completed	< 1995	30.300	42%	111320
Westwind Trust	San Gorgonio	Southern California Edison			Micon Micon Nordtank Wincon Wincon	108 65 65 108 110	Completed	< 1995	15.657	22%	30320
Kenetech/ Wintec	San Gorgonio	Southern California Edison			Micon Carter Nordtank Micon	55 25 65 55	Completed	< 1995	7.265	26%	16701
San Gorgonio Farms (I)	San Gorgonio	Southern California Edison			DWT Bonus Micon Bonus Bonus	400 120 65 65 450	Completed	< 1995	26.100		
San Gorgonio Farms (II)	San Gorgonio	Southern California Edison			Bonus Micon	65 65	Completed	< 1995	3.185		
Section 28 Trust	San Gorgonio	Southern California Edison			Windmatic Windmatic Sumitomo Micon Windtech	95 65 180 108 80	Completed	< 1995	26.191		
Altech 3	San Gorgonio			Sea West	NEG Micon	65	Completed	< 1995	3.300		
Edom Hill	San Gorgonio			Sea West	Vanguard Windmatic	65, 95	Completed	< 1995	11.000		
Mojave 16, 17, & 18	Tehachapi	Southern California Edison	Tomen/FPL	SeaWest Energy Group	Mitsubishi	250	Completed	1981-1995	85.000	19%	141215
Mojave 3, 4, & 5	Tehachapi	Southern California Edison	Tomen/FPL	SeaWest Energy Group	Mitsubishi	250	Completed	1981-1995	75.000	31%	201921
Various Names - Tehachapi	Tehachapi	Southern California Edison	Enron Wind Corp.	Zond Systems, Inc.	Vestas	65	Completed	1982-87	23.990	15%	31191

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
Various Names - Tehachapi	Tehachapi	Southern California Edison	Enron Wind Corp.	Zond Systems, Inc.	Vestas	90	Completed	1982-87	64.000	19%	108544
Windland (Boxcar II)	Tehachapi	Southern California Edison	Windland, Inc.	Windland, Inc.	Carter	250	Completed	Mid-80s	14.280	21%	25156
					Carter	25					
					Bonus	120					
					Bonus	65					
					Carter	300					
					Storm Master	40					
					Vestas	500					
					Vestas	200					
					Enertec	40					
					Vestas	200					
					Vestas	225					
Various Names - Tehachapi	Tehachapi	Southern California Edison	Enron Wind Corp.	Zond Systems, Inc.	Vestas	200	Completed	1986	0.200	12%	208
Victory Gardens Phase IV	Tehachapi	Southern California Edison	FPL	Zond Systems, Inc.	Vestas	225	Completed	1990	22.050	26%	50001
Sky River	Tehachapi	Southern California Edison	FPL	Zond Systems, Inc.	Vestas	225	Completed	1993	76.950	26%	173367
Oak Creek Phase 1 (ON-Energy)	Tehachapi	Southern California Edison	Oak Creek Nichimen	Oak Creek	NEG Micon	600	Completed - Repower	1997	4.200		
Cameron Ridge	Tehachapi	Southern California Edison	FPL	FPL Energy	NEG Micon	700	Completed - Repower	1999	56.000		
Oak Creek Wind Power Phase 2	Tehachapi	Southern California Edison	Oak Creek M&N	Oak Creek	NEG Micon	700	Completed - Repower	1999	23.100		
Oak Creek-Phase 2A	Tehachapi	Southern California Edison	Oak Creek Energy Systems	Oak Creek	NEG Micon	800	Completed - Repower	1999	0.800		
Pacific Crest	Tehachapi	Southern California Edison	FPL	FPL Energy	Vestas	660	Completed - Repower	1999	45.540		
Victory Gardens	Tehachapi	Southern California Edison	Enron Wind Corp.	Enron Wind Corp.	Zond	750	Completed - Repower	1999	6.750		
Mojave/ Morowind	Tehachapi	Southern California Edison	Tomen	Tomen	Mitsubishi	600	Under Development - Repower	2000	33.600		

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
TBD	Tehachapi	Southern California Edison	Cal Wind Resources	CalWind Resources			Proposed - Repower	2001	8.400		
TBD	Tehachapi	Southern California Edison		Windland, Inc.			Proposed - New	2001	19.800		
Southern Sierra Power	Tehachapi	Southern California Edison		FLP Energy	Enron	1500	Proposed - New	2001	273.000		
Coram Energy Group	Tehachapi	Southern California Edison		Coram Energy Group (1995)	Aeroman	40	Completed	<= 1995	1.880	16%	2620
CTV, Coram Energy Group	Tehachapi	Southern California Edison		Coram Energy Group (1995)	Aeroman Tacke	40 600	Completed	<= 1995 1996	6.800	17%	6443
Energy Conversion Technology, Coram Energy Group	Tehachapi	Southern California Edison		Coram Energy Group (1995)	Aeroman	40	Completed	<= 1995	4.000	19%	6482
Calwind Resources	Tehachapi	Southern California Edison		Calwind Resources Inc. (1995)	Nordtank	65	Completed	<= 1995	8.710	19%	14180
AB Energy, Inc.	Tehachapi	Southern California Edison		AB Energy (1995)	Vestas	225	Completed	<= 1995	6.975	32%	19537
Ridgetop Energy	Tehachapi	Southern California Edison			Nordtank Nordtank Micon Micon	75 150 250 108	Completed	<= 1995	32.624	19%	54569
Cannon	Tehachapi	Southern California Edison			Micon Vestas	108 450	Completed	<= 1995	13.464	37%	43401
Calwind	Tehachapi	Southern California Edison		Calwind	Bonus	65	Completed	<= 1995	14.105	20%	24593
Victory Gardens I & IV	Tehachapi	Southern California Edison		Zond Systems, Inc.	Vestas	500	Completed	<= 1995	1.000	27%	2369
Mogul Energy	Tehachapi	Southern California Edison		Mogul Energy	Mitsubishi	500	Completed	<= 1995	4.000		
Cannon (various)	Tehachapi	Southern California Edison			Micon	108	Completed	<= 1995	4.536	27%	10880
Windridge	Tehachapi	Southern California Edison		Windridge	Windmatic	65	Completed	<= 1995	2.340		

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
Victory Garden Repower	Tehachapi	SCE	Enron		Zond	750	Proposed - Repower	2001	30.000		
1985 Zond Windsystem Partners Series 85C	Altamont Pass	Pacific Gas & Electric	Enron Wind Corp.	Zond Systems	Vestas	90	Completed	1985	18.000	18%	28868
Altech Energy, Ltd.	Altamont Pass	Pacific Gas & Electric	SeaWest Energy Group	SeaWest Energy Group	Enertech	40	Completed	1981-1995	5.760	10%	5094
C.W.E.S.	Altamont Pass	Pacific Gas & Electric	SeaWest Energy Group	SeaWest Energy Group	Enertech Enertech	60 40	Completed	1981-1995	1.320		
SeaWest Energy Group	Altamont Pass	Pacific Gas & Electric	SeaWest Energy Group	SeaWest Energy Group	Micon	65	Completed	1981-1995	0.065	13%	74
Viking Energy 83	Altamont Pass	Pacific Gas & Electric	SeaWest Energy Group	SeaWest Energy Group	Micon	65	Completed	1981-1995	1.690	15%	2192
SeaWest Energy Group	Altamont Pass	Pacific Gas & Electric	SeaWest Energy Group	SeaWest Energy Group	Micon	65	Completed	1981-1995	0.975	11%	902
SeaWest Windfarms, Inc.	Altamont Pass	Pacific Gas & Electric	SeaWest Energy Group	SeaWest Energy Group	Micon	65	Completed	1981-1995	11.570	11%	10899
Patterson Pass	Altamont Pass	Pacific Gas & Electric	International Wind Companies		Nordtank Bonus	65	Completed	1981-1995	21.840	11%	21424
Tres Vaqueros	Altamont Pass	Pacific Gas & Electric	International Wind Companies		Howden Howden	330 750	Completed	1981-1995	28.800	16%	41569
Buena Vista	Altamont Pass	Pacific Gas & Electric	International Wind Companies		Windmaster	175	Completed	1981-1995	36.925	9%	27770
Flowind Properties	Altamont Pass	Pacific Gas & Electric			Flowind		Completed	1981-1995	28.920		
Various Names	Altamont Pass	Pacific Gas & Electric	Various Owners	Various Developers	Various		Completed	1981-1995	61.260		
Venture Wind (old Los Vaqueros)	Altamont Pass	Pacific Gas & Electric	SeaWest Energy	American Diversified	Polenko Windmatic	100 65	Completed	Mid-1980s	2.890		

Project Name	Location	Utility	Owner	Developer	Turbine Vendor	Turbine Rating (kW)	Status	Year Completed	Current Capacity (MW)	Project Capacity Factor	Average Annual Production (MWh)
Venture Pacific	Altamont Pass	Pacific Gas & Electric		SeaWest Energy Group	Mitsubishi		Proposed - Repower	2000	25.600		
Green Ridge Power LLC	Altamont Pass	Pacific Gas & Electric		FPL Energy (Kenetech/Flowind repower)	NEG Micon	700	Under Development - Repower	2001	110.000		
Wind Power Partners / Green Ridge Power	Altamont Pass	Pacific Gas & Electric	FPL	Kenetech	KCS-56-100 KVS-33 Kenetech	100 300 100	Completed	1989-1994	328.300	20%	570873
Gorman	Tejon Pass near Gorman	Southern California Edison		Enron Wind Corp.	Zond	750	Proposed - New	2000	39.750		
International Turbine Research	Pacheco Pass	Pacific Gas & Electric		ITR	Wincon, Nordtank, Vestas	0	Completed	Mid-80s	16.000	15%	21187
San Clemente Island	San Clemente Island	U.S. Navy	U.S. Navy	Pacific Industrial Electric	NEG Micon	225	Completed	1998	0.675		
San Clemente Island	San Clemente Island	U.S. Navy	U.S. Navy	Pacific Industrial Electric	NEG Micon	225	Under Development - New	2001	0.750		
SMUD	Solano County	SMUD	SMUD	EnXco	Vestas	660	Completed	1999	0.660		
TBD	Solano County (PG&E)	Pacific Gas & Electric		Kenetech Windpower	US Wind Power	100	Completed	1985	60.000	19%	98231
TBD	Solano County (SMUD)	SMUD	SMUD	Kenetech Windpower	Kenetech	300	Completed	1994	3.600	29%	9243
Windridge LLC				FPL Energy			Proposed - New	2001	30.000		
Alexander 4				SeaWest Energy Group			Proposed - New	2001	3.500		
Catellus 6							Proposed - New	2001	1.800		
High Winds LLC				FPL Energy			Proposed - New	2001	70.000		

Geothermal Project Data

Project Name	Location	Utility	Owner	Operator	Type	Status	1st Year	Installed Capacity	Current Capacity (MW)	1999 Annual Production (MWh)	1999 Capacity Factor
Amedee	Modoc	PG&E	TPG/USEC	TPG	Binary	Operating	1988	1.6	1.6	7565	54%
Wineagle	Modoc	PG&E	Wineagle	Wineagle	Binary		1985	0.7	0.7	N.A.	
Honey Lake	Modoc	PG&E	HL Power	HL Power	Hybrid		1989	0.3	0.3	N.A.	
Mammoth-Pacific -I	Mono	SCE	M-P	M-P	Binary	Operating	1984	7	7	33913	55%
Mammoth-Pacific -II	Mono	SCE	Pacific Energy	M-P	Binary	Operating	1990	10	10	92657	106%
PLES-I	Mono	SCE	Pacific Energy	M-P	Binary	Operating	1990	10	10	104308	119%
Navy 1:Unit 1	Inyo	SCE	CECI	CECI	Double Flash	Operating	1987	30	30	736633	105%
Navy 1:Unit 2	Inyo	SCE	CECI	CECI	Double Flash	Operating	1988	25	25		
Navy 1:Unit 3	Inyo	SCE	CECI	CECI	Double Flash	Operating	1988	25	25		
Navy 2:Unit 4	Inyo	SCE	CECI	CECI	Double Flash	Operating	1989	28	28	677035	92%
Navy 2:Unit 5	Inyo	SCE	CECI	CECI	Double Flash	Operating	1989	28	28		
Navy 2:Unit 6	Inyo	SCE	CECI	CECI	Double Flash	Operating	1989	28	28		
BLM 1: Unit 7	Inyo	SCE	CECI	CECI	Double Flash	Operating	1988	24	24	781317	117%
BLM 1: Unit 8	Inyo	SCE	CECI	CECI	Double Flash	Operating	1988	24	24		
BLM 1: Unit 9	Inyo	SCE	CECI	CECI	Double Flash	Operating	1989	28	28		
Salton Sea #1	Imperial	SCE	Cal Energy	CE	Single Flash	Operating	1982	10	10	83883	96%
Salton Sea #2	Imperial	SCE	Cal Energy	CE	Double Flash	Operating	1990	20	20	155213	89%
Salton Sea #3	Imperial	SCE	Cal Energy	CE	Double Flash	Operating	1989	50	50	389451	89%
Salton Sea #4	Imperial	P-X/SCE	Cal Energy	CE	Double Flash	Operating	1996	40	40	333217	95%
C-E Turbo LLC	Imperial	P-X	Cal Energy	CE	Single Flash	Start-up	2000	10	10	N.A.	
Salton Sea #5	Imperial	P-X/Others	Cal Energy	CE	Double Flash	Start-up	2000	49	49	N.A.	
Vulcan	Imperial	SCE	Cal Energy	CE	Double Flash	Operating	1986	40	40	315428	90%
A.W. Hoch	Imperial	SCE	Cal Energy	CE	Double Flash	Operating	1989	42	42	343588	93%
J.J. Elmore	Imperial	SCE	Cal Energy	CE	Double Flash	Operating	1989	42	42	N.A.	
J.M. Leathers	Imperial	SCE	Cal Energy	CE	Double Flash	Operating	1990	42	42	350861	95%
Ormesa Geothermal I	Imperial	SCE	OESI	OESI	Binary	Operating	1987	32	32	255374	91%
Ormesa Geothermal II	Imperial	SCE	OESI	OESI	Binary	Operating	1989	23	23	126615	63%

Project Name	Location	Utility	Owner	Operator	Type	Status	1st Year	Installed Capacity	Current Capacity (MW)	1999 Annual Production (MWh)	1999 Capacity Factor
Heber	Imperial	SCE	Heber Geothermal Co.		Dual-Flash	Operating	1985	47	47	316061	77%
Second Imperial	Imperial	SCE	SIGC	SIGC	Binary	Operating	1993	33	33	317308	110%
Aidlin	Sonoma	PG&E	Calpine	Calpine	Dry Steam	Operating	1989	20	20	156982	90%
Bear Canyon	Lake	PG&E	Calpine	Calpine	Dry Steam	Operating	1988	20	20	146199	83%
Sonoma	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1983	72	72	N.A.	
West Ford Flat	Lake	PG&E	Calpine	Calpine	Dry Steam	Operating	1988	27	27	192955	82%
McCabe	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1971	110	80	N.A.	
Ridge Line	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1972	110	76	N.A.	
Fumarole	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1973	110	66	N.A.	
Eagle Rock	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1975	110	58	N.A.	
Cobb Creek	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1979	110	40	N.A.	
Big Geysers	Lake	P-X	Calpine	Calpine	Dry Steam	Operating	1980	137	80	N.A.	
Sulfur Springs	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1980	114	63	N.A.	
Quicksilver	Lake	P-X	Calpine	Calpine	Dry Steam	Operating	1985	119	72	N.A.	
Lake View	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1982	119	48	N.A.	
Socrates	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1983	119	60	N.A.	
Calistoga	Lake	PG&E	Calpine	Calpine	Dry Steam	Operating	1984	85	80	608748	87%
Grant	Sonoma	P-X	Calpine	Calpine	Dry Steam	Operating	1985	119	45	N.A.	
NCPA #1	Lake	NCPA	NCPA	NCPA	Dry Steam	Operating	1983	55	39	N.A.	
NCPA #2	Lake	NCPA	NCPA	NCPA	Dry Steam	Operating	1983	55	39	N.A.	
NCPA #3	Lake	NCPA	NCPA	NCPA	Dry Steam	Operating	1985	55	39	N.A.	
NCPA #4	Lake	NCPA	NCPA	NCPA	Dry Steam	Operating	1985	55	39	N.A.	
Fourmile Hill	Siskiyou	P-X	Calpine	Calpine	Dual Flash	Permitting	2003	49	NA		
Telephone Flat	Siskiyou		Cal Energy	Cal Energy	Dual Flash	Planned		49	NA		
Geysers Wastewater	Sonoma	P-X	Calpine	Calpine	Dry Steam	Construction	2002	85	NA		
Geysers Expansion	Lake	P-X	Calpine	Calpine	Dry Steam	Permitting	2002	55	NA		

Biomass Project Data

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
DIAMOND S RANCH	WATERFORD / N/A		DIAMOND S RANCH	DIAMOND S RANCH	2	Steam turbine with steam sendout	Completed, In commercial operation	1984	0.1	Intermediate	12 to 48	100% of full
PORK PALACE	OAKDALE / N/A	Pacific Gas & Electric	PORK PALACE	PORK PALACE	2	Steam turbine	Completed, In commercial operation	1985	0.1	Intermediate	12 to 48	100% of full
BUTTONWILLOW A	BUTTONWILLOW / N/A		FARMERS COOPERATIVE GINS	FARMERS COOPERATIVE GINS	2	Steam turbine with steam sendout	Completed, In commercial operation	1989	1.7	Intermediate	12 to 48	100% of full
IMPERIAL BIOMASS	Imperial / N/A	San Diego Gas & Electric	CMS GENERATION CO	CMS GENERATION CO	2	Traveling-grate stoker, Steam turbine with steam sendout	Completed, In commercial operation	1990	15.0	Intermediate	12 to 48	100% of full
MENDOTA	Mendota / N/A	Pacific Gas & Electric	THERMO ECOTEK CORP	THERMO ECOTEK CORP	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, In commercial operation	1989	25.0	Intermediate	12 to 48	100% of full
DELANO THERMO	N/A / Kern		THERMO ECOTEK CORP	THERMO ECOTEK CORP	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, In commercial operation	1993	26.0	Intermediate	12 to 48	100% of full
FLOYD MYERS MARSH	WILLIAMS / Colusa	Pacific Gas & Electric	UNITED AMER ENERGY CORP	UNITED AMER ENERGY CORP	2	Steam turbine with steam sendout	Completed, In commercial operation	1989	26.5	Intermediate	12 to 48	100% of full
DELANO THERMO	N/A / Kern		THERMO ECOTEK CORP	THERMO ECOTEK CORP	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, In commercial operation	1990	32.0	Intermediate	12 to 48	100% of full
M&M DAIRY	GONZALES / Monterey	Pacific Gas & Electric	M&M DAIRY	M&M DAIRY	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	0.1	Intermediate	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
GRANT AMEN DAIRY	REDDING / Shasta	Pacific Gas & Electric	GRANT AMEN DAIRY	GRANT AMEN DAIRY	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1984	0.1	Intermediate	1	100% of full
MILLBRAE WWTP	MILLBRAE / N/A	Company Unknown	TOWN OF MILLBRAE	TOWN OF MILLBRAE	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation		0.1	Intermediate	1	100% of full
LANGERWERF DAIRY	DURHAM / N/A		LANGERWERF DAIRY	LANGERWERF DAIRY	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1982	0.1	Intermediate	1	100% of full
BURSON	BURSON / N/A		BURSON LIVESTOCK & POWER	BURSON LIVESTOCK & POWER	3	Internal combustion engine with heat recovery	Completed, In commercial operation	1985	0.1	Intermediate	1	100% of full
LODI (CA) LUIZ	LODI / N/A	Municipal Systems	LUIZ & SONS DAIRY INC	LUIZ & SONS DAIRY INC	3	Internal combustion engine with heat recovery	Completed, In commercial operation	1985	0.1	Intermediate	1	100% of full
PLEASANTON WWTP	PLEASANTON / Pleasanton	Company Unknown	DUBLIN-SAN RAMON SEW TRT	DUBLIN-SAN RAMON SEW TRT	3	Steam turbine	Completed, In commercial operation	1984	0.4	Intermediate	1	100% of full
ATWATER ATLAS	ATWATER / Merced	Pacific Gas & Electric	JR WOOD INC	JR WOOD INC	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1982	1.1	Intermediate	1	100% of full
MARINA BIOGAS	MARINA / N/A	Pacific Gas & Electric	MONTEREY REG WATER CNTRL	MONTEREY REG WATER CNTRL	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1989	1.7	Intermediate	1	100% of full
OAKLAND EAST BAY	Oakland / Alameda	Pacific Gas & Electric	EAST BAY MUNI UTIL	EAST BAY MUNI UTIL	3	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1991	4.0	Intermediate	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
PINOLE-HERCULES WWTP	PINOLE / N/A	Pacific Gas & Electric	CITY OF PINOLE	CITY OF PINOLE	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation		0.1	Base	1	100% of full
BENICIA WASTEWATER	BENICIA / Benicia	Company Unknown	CITY OF BENICIA	CITY OF BENICIA	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation		0.1	Base	1	100% of full
DAVIS WWTP	DAVIS / Davis	Company Unknown	CITY OF DAVIS	CITY OF DAVIS	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation		0.1	Base	1	100% of full
LAS GALLINAS VALLEY	SAN RAFAEL / N/A	Company Unknown	LAS GALLINAS VALLEY SWAGE	LAS GALLINAS VALLEY SWAGE	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation		0.1	Base	1	100% of full
CHICO WWTP	CHICO / N/A	Company Unknown	CHICO SEWAGE DISPOSAL	CHICO SEWAGE DISPOSAL	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1984	0.1	Base	1	100% of full
PALM SPRINGS MUNICIPAL IC	PALM SPRINGS / N/A	Southern California Edison Company	CITY OF PALM SPRINGS	CITY OF PALM SPRINGS	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1983	0.3	Base	1	100% of full
CHIQUITA WATER REC PLANT	N/A / N/A	San Diego Gas & Electric	CHIQUITA WATER REC PLANT	CHIQUITA WATER REC PLANT	5	Internal combustion engine with heat recovery	Completed, In commercial operation	1988	0.3	Base	1	100% of full
OXNARD WWTP	OXNARD / Oxnard	Southern California Edison Co.	CITY OF OXNARD	CITY OF OXNARD	5	Internal combustion engine with heat recovery	Completed, In commercial operation	1982	0.5	Base	1	100% of full
OXNARD WWTP	OXNARD / Oxnard	Southern California Edison Co.	CITY OF OXNARD	CITY OF OXNARD	5	Internal combustion engine with heat recovery	Completed, In commercial operation	1982	0.5	Base	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
OXNARD WWTP	OXNARD / Oxnard	Southern California Edison Co.	CITY OF OXNARD	CITY OF OXNARD	5	Internal combustion engine with heat recovery	Completed, In commercial operation	1982	0.5	Base	1	100% of full
CHINO BASIN	N/A / San Bernardino	Southern California Edison Company	CHINO BASIN MWD	CHINO BASIN MWD	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1992	0.6	Base	1	100% of full
ORANGE COUNTY (CA) MWD	N/A / N/A		ORANGE COUNTY MWD	ORANGE COUNTY MWD	5	Internal combustion engine with heat recovery	Completed, In commercial operation	1992	0.6	Base	1	100% of full
HAYWARD WASTEWATER	HAYWARD / N/A	Company Unknown	CITY OF HAYWARD	CITY OF HAYWARD	5	Internal combustion engine with heat recovery	Completed, In commercial operation	1983	0.7	Base	1	100% of full
EL TORO ALISO	EL TORO / Orange	Southern California Edison Co.	ALISO WATER MGMT AGENCY	ALISO WATER MGMT AGENCY	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1983	1.2	Base	1	100% of full
FRESNO CITY	FRESNO / N/A	Company Unknown	CITY OF FRESNO	CITY OF FRESNO	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1986	1.3	Base	1	100% of full
POINT LOMA SEWAGE	SAN DIEGO / N/A	San Diego Gas & Electric	CITY OF SAN DIEGO	CITY OF SAN DIEGO	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	1.4	Base	1	100% of full
POINT LOMA SEWAGE	SAN DIEGO / N/A	San Diego Gas & Electric	CITY OF SAN DIEGO	CITY OF SAN DIEGO	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	1.4	Base	1	100% of full
HYPERION	PLAYA DEL MAR / N/A		COMBUSTION POWER CO	COMBUSTION POWER CO	5	Gas turbine in combined-cycle	Completed, In commercial operation	1987	3.5	Base	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
HYPERION	PLAYA DEL MAR / N/A		COMBUSTION POWER CO	COMBUSTION POWER CO	5	Gas turbine in combined-cycle	Completed, In commercial operation	1987	3.5	Base	1	100% of full
HYPERION	PLAYA DEL MAR / N/A		COMBUSTION POWER CO	COMBUSTION POWER CO	5	Gas turbine in combined-cycle	Completed, In commercial operation	1987	3.5	Base	1	100% of full
HYPERION	PLAYA DEL MAR / N/A		COMBUSTION POWER CO	COMBUSTION POWER CO	5	Gas turbine in combined-cycle	Completed, In commercial operation	1987	3.5	Base	1	100% of full
HUNTINGTON TREATMENT 2	Huntington Beach / Orange County	Southern California Edison Co.	ORANGE COUNTY SAN DIST	ORANGE COUNTY SAN DIST	5	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1993	11.2	Base	1	100% of full
LA ESTANCIA HOTEL	N/A / N/A		LA ESTANCIA HOTEL	LA ESTANCIA HOTEL	1	Internal combustion engine with heat recovery	Completed, In commercial operation	1987	0.0	Base	1	100% of full
NAPA SEWAGE WORKS	NAPA / N/A	Pacific Gas & Electric	NAPA SANITATION DISTRICT	NAPA SANITATION DISTRICT	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1986	0.1	Base	1	100% of full
CARUTHERS SHARP	CARUTHERS / N/A		SHARP LEROY B	SHARP LEROY B	1	Internal combustion engine with heat recovery	Completed, In commercial operation	1991	0.1	Base	1	100% of full
DALY CITY	DALY CITY / Daly City	Company Unknown	NORTH SAN MATEO SAN DIST	NORTH SAN MATEO SAN DIST	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1983	0.4	Base	1	100% of full
DUARTE LANDFILL	Duarte / N/A	Southern California Edison Company	COGENERATION CORP OF AMERICA	COGENERATION CORP OF AMERICA	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1987	0.6	Base	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
DUARTE LANDFILL	Duarte / N/A	Southern California Edison Company	COGENERATION CORP OF AMERICA	COGENERATION CORP OF AMERICA	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1987	0.6	Base	1	100% of full
DUARTE LANDFILL	Duarte / N/A	Southern California Edison Company	COGENERATION CORP OF AMERICA	COGENERATION CORP OF AMERICA	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1987	0.6	Base	1	100% of full
DUARTE LANDFILL	Duarte / N/A	Southern California Edison Company	COGENERATION CORP OF AMERICA	COGENERATION CORP OF AMERICA	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1987	0.6	Base	1	100% of full
PALOS VERDES LACSD	Rolling Hills Estate / N/A	Southern California Edison Company	LOS ANGELES CNTY SAN DIST	LOS ANGELES CNTY SAN DIST	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1983	0.7	Base	1	100% of full
SANTA CRUZ CITY SLF	Santa Cruz / Santa Cruz	Pacific Gas & Electric	GAS RECOVERY SYS	GAS RECOVERY SYS	1	Gas/combustion turbine	Completed, In commercial operation	1989	0.7	Base	1	100% of full
AUSTIN ROAD LANDFILL	Stockton / San Joaquin	Pacific Gas & Electric	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	0.8	Base	1	100% of full
PALO ALTO LANDFILL	Palo Alto / Santa Clara	Pacific Gas & Electric	INTERNATIONAL POWER TECH	INTERNATIONAL POWER TECH	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1990	1.0	Base	1	100% of full
PALO ALTO LANDFILL	Palo Alto / Santa Clara	Pacific Gas & Electric	INTERNATIONAL POWER TECH	INTERNATIONAL POWER TECH	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1990	1.0	Base	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
AMERICAN CANYON	Fremont / N/A	Pacific Gas & Electric	GAS RECOVERY SYS	GAS RECOVERY SYS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	1.5	Base	1	100% of full
CARSON BIOGAS	CARSON / N/A	Southern California Edison Co.	WATSON BIOGAS SYSTEMS	WATSON BIOGAS SYSTEMS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1991	1.7	Base	1	100% of full
BAKERSFIELD PLES	Bakersfield / N/A	Pacific Gas & Electric	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	1.9	Base	1	100% of full
MARSH ROAD LANDFILL	Fremont / N/A	Pacific Gas & Electric	GAS RECOVERY SYS	GAS RECOVERY SYS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1982	2.0	Base	1	100% of full
GUADALUPE DISPOSAL SITE	San Jose / N/A	Pacific Gas & Electric	GAS RECOVERY SYS	GAS RECOVERY SYS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1984	2.5	Base	1	100% of full
MONTEREY PENINSULA SLF	Marina / Monterey	Pacific Gas & Electric	MONTEREY REG WASTE MGMT	MONTEREY REG WASTE MGMT	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1983	2.8	Base	1	100% of full
WEST CONTRA COSTA LF	ANTIOCH / Contra Costa	Pacific Gas & Electric	CONTRA COSTA CNTY SAN DIS	CONTRA COSTA CNTY SAN DIS	1	Gas/combustion turbine	Completed, In commercial operation	1985	3.0	Base	1	100% of full
CENTRAL LF (SONOMA) PHASE 1	Petaluma / N/A	Pacific Gas & Electric	Landfill Energy Systems	Landfill Energy Systems	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1993	3.2	Base	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
OTAY LANDFILL	Chula Vista / San Diego	San Diego Gas & Electric	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1986	3.7	Base	1	100% of full
PUENTE HILLS	Whittier / N/A	Southern California Edison Company	LOS ANGELES CNTY SAN DIST	LOS ANGELES CNTY SAN DIST	1	Gas/combustion turbine	Completed, In commercial operation	1983	4.0	Base	1	100% of full
NEWBY ISLAND	Milpitas / N/A	Pacific Gas & Electric	GAS RECOVERY SYS	GAS RECOVERY SYS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1989	5.3	Base	1	100% of full
SANTA CLARA LF	Oxnard / N/A	Southern California Edison Company	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	5.6	Base	1	100% of full
OLINDA ALPHA SLF	Brea / Orange	Southern California Edison Company	GSF ENERGY INC	GSF ENERGY INC	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1984	5.7	Base	1	100% of full
PRIMA DESHECHA LANDFILL	SAN JUAN CAPISTRANO / N/A	Southern California Edison Company	CAMBRIAN ENERGY SYSTEMS	CAMBRIAN ENERGY SYSTEMS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1999	6.0	Base	1	100% of full
LOPEZ CANYON LANDFILL	Lake View Terrace / N/A	Los Angeles Dept. of Water /Power	CAMBRIAN ENERGY SYSTEMS	CAMBRIAN ENERGY SYSTEMS	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1998	6.1	Base	1	100% of full
MIRAMAR NAS LANDFILL	SAN DIEGO / N/A	San Diego Gas & Electric	MINNESOTA METHANE LLC	MINNESOTA METHANE LLC	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1997	6.5	Base	1	100% of full
ALTAMONT LANDFILL	Livermore / San Joaquin	Pacific Gas & Electric	BIO-ENERGY PARTNERS	BIO-ENERGY PARTNERS	1	Gas/combustion turbine	Completed, In commercial operation	1989	6.6	Base	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
PALOS VERDES LACSD	Rolling Hills Estate / Los Angeles	Southern California Edison Company	LOS ANGELES CNTY SAN DIST	LOS ANGELES CNTY SAN DIST	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1988	9.0	Base	1	100% of full
KIEFER LANDFILL	Sacramento / Sacramento	Municipal Util Dist	SACRAMENTO MUN UTIL DIST	SACRAMENTO MUN UTIL DIST	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation		9.1	Non-dispatchable	n/a	n/a
PENROSE LANDFILL	Sun Valley / Los Angeles	Southern California Edison Company	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	9.3	Base	1	100% of full
COYOTE CANYON	Irvine / Orange County	Southern California Edison Co.	GAS RECOVERY SYS	GAS RECOVERY SYS	1	Steam turbine	Completed, In commercial operation	1989	20.0	Base	1	100% of full
PUENTE HILLS	Whittier / N/A	Southern California Edison co.	LOS ANGELES CNTY SAN DIST	LOS ANGELES CNTY SAN DIST	1	Steam turbine	Completed, In commercial operation	1986	50.0	Base	1	100% of full
TEMESCAL ROAD LF	Corona/ N/A		NEO	City of Corona	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1986	0.6		n/a	n/a
WOODVILLE DISPOSAL SITE	Woodville/ N/A		NEO	Tulare County	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1999	0.6		n/a	n/a
POTRERO HILLS SLF	Fairfield		Nove Investments	Potrero Hills Landfill, Inc.	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	2000	1.0		n/a	n/a
CITY OF SANTA CLARA	Santa Clara/ N/A		OGDEN ENERGY GROUP	City of Santa Clara	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	1.4		n/a	n/a

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
CRAZY HORSE SLF	Prunedale		OGDEN ENERGY GROUP	Salinas Valley Solid Waste Authority	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1986	1.4		n/a	n/a
SAN MARCOS LF	San Marcos		GAS RECOVERY SYS	San Diego County	1	Gas/combustion turbine	Completed, In commercial operation	1989	1.5		n/a	n/a
SYCAMORE SLF	Santee		GAS RECOVERY SYS	Sycamore Landfill, Inc.	1	Gas/combustion turbine	Completed, In commercial operation	1989	1.5		n/a	n/a
SUNNYVALE LF	Sunnyvale		City of Sunnyvale	City of Sunnyvale	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1998	1.6		n/a	n/a
VISALIA DISPOSAL SITE	Visalia		NEO	Tulare County	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1998	1.6		n/a	n/a
YOLO COUNTY CENTRAL LF	Davis		NEO	Yolo County Public Works	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1997	2.8		n/a	n/a
TAJIGUAS SLF	Santa Barbara		NEO	Santa Barbara	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	2000	3.0		n/a	n/a
CENTRAL LF (SONOMA) PHASE 2	Petaluma / N/A		LES/DTE Biomass	Sonoma County Department of Public Works	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1996	3.2		n/a	n/a
BAILARD LF	Oxnard / N/A		OGDEN ENERGY GROUP	Ventura Regional Sanitation District	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	3.3		n/a	n/a

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
MIRAMAR SLF	SAN DIEGO / N/A		NEO	City of San Diego	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1999	3.8		n/a	n/a
SHELDON-ARLETA LF	Sun Valley / Los Angeles		OGDEN ENERGY GROUP	LOS ANGELES CNTY SAN DIST	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1988	4.1		n/a	n/a
BKK LANDFILL PHASE II	West Covina		NEO	BKK Corporation	1	Gas/combustion turbine	Completed, In commercial operation	1999	5.2		n/a	n/a
MOUNTAINGATE LF	Los Angeles		GSF ENERGY INC	Barclay Hollander/ American Golf Corp.	1	Steam turbine	Completed, In commercial operation	1994	7.5		n/a	n/a
TOYON CANYON LF	Los Angeles		OGDEN ENERGY GROUP	City of Los Angeles	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	9.0		n/a	n/a
SPADRA LF	Pomona		LACSD	LA County Sanitation District	1	Steam turbine	Completed, In commercial operation	1990	9.6		n/a	n/a
BKK LANDFILL PHASE I	West Covina		NEO	BKK Corporation	1	Steam turbine	Completed, In commercial operation	1993	10.0		n/a	n/a
CALABASSAS SLF	Agour Hills		LACSD	LA County Sanitation District	1	Internal combustion (reciprocating engine or diesel engine)	Completed, In commercial operation	1985	10.0		n/a	n/a
ACME LF	Martinez		Acme Fill/ GSF Energy	Acme Fill Corporation	1	Boiler	Completed, In commercial operation	1982			n/a	n/a

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
BRADLEY AVENUE WEST SLF	Los Angeles		WMI	WMI	1	Direct Thermal	Completed, In commercial operation	1981			n/a	n/a
DAVIS STREET LF	San Leandro		GSF ENERGY INC	WMI	1	Direct Thermal	Completed, In commercial operation	1984			n/a	n/a
FRANK R. BOWERMAN SLF	Irvine / Orange County		Ecogas	Orange County IWMD	1	Liquefied Natural Gas	Completed, In commercial operation	1999			n/a	n/a
INDUSTRY HILLS SHERATON RESORT	Industrial Hills		City of Industry	City of Industry	1	Boiler	Completed, In commercial operation	1981			n/a	n/a
PUENTE HILLS LF	Whittier / N/A		LACSD		1		Completed, In commercial operation				n/a	n/a
PUENTE HILLS LF	Whittier / N/A		LACSD		1		Completed, In commercial operation				n/a	n/a
REDWOOD SLF	Novato		RECO		1		Completed, In commercial operation				n/a	n/a
SACRAMENTO CITY LF	Sacramento / Sacramento		GAS RECOVERY SYS		1		Completed, In commercial operation				n/a	n/a
SCHOLL CANYON SLF	GLENDALE / N/A		Palmer Capital Corporation		1		Completed, In commercial operation				n/a	n/a
COMMERCE WTE	Commerce / COMMERCE	Southern California Edison Co.	LOS ANGELES CNTY SAN DIST	LOS ANGELES CNTY SAN DIST	6	Reciprocating-grate stoker, Steam turbine	Completed, In commercial operation	1987	10.5	Base	12 to 48	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
CITY OF LONG BEACH	N/A / Los Angeles	Southern California Edison Co.	SOUTHEAST RR AUTHORITY	CITY OF LONG BEACH	6		Completed, In commercial operation	1988	34.6			
MODESTO REDWOOD FOOD	MODESTO / Stanislaus	Pacific Gas & Electric	REDWOOD FOOD PKG CO	REDWOOD FOOD PKG CO	4	Steam turbine with steam sendout	Completed, In commercial operation	1980	4.5	Intermediate	12 to 48	100% of full
ANDERSON BUNYAN	ANDERSON / N/A	Pacific Gas & Electric	PAUL BUNYAN LUMBER CO	PAUL BUNYAN LUMBER CO	7	Steam turbine	Completed, In commercial operation	1980	3.0	Intermediate	12 to 48	100% of full
ANDERSON ROSEBURG	Anderson / N/A	Pacific Gas & Electric	ROSEBURG LUMBER	ROSEBURG LUMBER	7	Steam turbine	Completed, In commercial operation	1980	3.0	Intermediate	12 to 48	100% of full
BIEBER BIG VALLEY	BIEBER / Lassen	Pacific Gas & Electric Co.	BIG VALLEY LUMBER CO	BIG VALLEY LUMBER CO	7	Steam turbine with steam sendout	Completed, In commercial operation	1983	5.0	Intermediate	12 to 48	100% of full
ANDERSON HUDSON	Anderson / N/A	Pacific Gas & Electric	WHEELABRATOR ENV SYSTEMS	WHEELABRATOR ENV SYSTEMS	7	Steam turbine	Completed, In commercial operation	1982	6.0	Intermediate	12 to 48	100% of full
NORTH FORK DINUBA	NORTH FORK / N/A		DINUBA TIMBER CO	DINUBA TIMBER CO	7	Steam turbine	Completed, In commercial operation	1987	6.0	Intermediate	12 to 48	100% of full
AUBERRY	Auberry / N/A		AUBERRY ENERGY INC	AUBERRY ENERGY INC	7	Atmospheric fluidized bed boiler, Steam turbine with steam sendout	Completed, In commercial operation	1986	7.5	Intermediate	12 to 48	100% of full
HAYFORK SIERRA	HAYFORK / N/A		SIERRA PACIFIC INDUSTRIES	SIERRA PACIFIC INDUSTRIES	7	Fixed grate boiler, Steam turbine	Completed, In commercial operation	1985	7.5	Intermediate	12 to 48	100% of full
LINCOLN BOHEMIA	LINCOLN / LINCOLN	PACIFIC GAS & ELECTRIC CO.	BOHEMIA INC	BOHEMIA INC	7	Steam turbine with steam sendout	Completed, In commercial operation	1986	7.5	Intermediate	12 to 48	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
LOYALTON	LOYALTON / N/A	Sierra Pacific Power Company	SIERRA PACIFIC INDUSTRIES	SIERRA PACIFIC INDUSTRIES	7	Steam turbine	Completed, In commercial operation	1989	9.5	Intermediate	12 to 48	100% of full
BURNEY MOUNTAIN	Burney / N/A		OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	7	Spreader stoker, Steam turbine	Completed, In commercial operation	1984	9.8	Intermediate	12 to 48	100% of full
MT LASSEN	Westwood / Lassen	Pacific Gas & Electric Company	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	7	Spreader stoker, Steam turbine	Completed, In commercial operation	1984	11.4	Intermediate	12 to 48	100% of full
DINUBA ENERGY	DINUBA / N/A	Pacific Gas & Electric	DINUBA TIMBER CO	DINUBA TIMBER CO	7	Atmospheric fluidized bed boiler, Steam turbine with steam sendout	Completed, In commercial operation	1985	11.5	Intermediate	12 to 48	100% of full
CHESTER COLLINS	Chester / Plumas	Pacific Gas & Electric Co.	COLLINS PINE CO	COLLINS PINE CO	7	Steam turbine with steam sendout	Completed, In commercial operation	1986	12.0	Intermediate	12 to 48	100% of full
QUINCY (CA)	QUINCY / N/A		SIERRA PACIFIC INDUSTRIES	SIERRA PACIFIC INDUSTRIES	7	Steam turbine	Completed, In commercial operation	1983	12.5	Intermediate	12 to 48	100% of full
LONG BEACH (CA) P&G	LONG BEACH / N/A	Southern California Edison Company	PROCTER & GAMBLE	PROCTER & GAMBLE	7	Stoker, Steam turbine	Completed, In commercial operation	1983	13.5	Intermediate	12 to 48	100% of full
ANTIOCH MILL	ANTIOCH / N/A	Pacific Gas & Electric Company	LOUISIANA PACIFIC CORP	LOUISIANA PACIFIC CORP	7	Spreader stoker, Steam turbine	Completed, In commercial operation	1982	14.5	Intermediate	12 to 48	100% of full
FORT BRAGG GP	FORT BRAGG / Mendocino	Pacific Gas & Electric Co.	GEORGIA PACIFIC CORP	GEORGIA PACIFIC CORP	7	Steam turbine with steam sendout	Completed, In commercial operation	1980	15.0	Intermediate	12 to 48	100% of full
FAIRHAVEN POWER	FAIRHAVEN / Humboldt	Pacific Gas & Electric Co.	FAIRHAVEN POWER INC	FAIRHAVEN POWER INC	7	Fixed grate boiler, Steam turbine with steam sendout	Completed, In commercial operation	1986	17.3	Intermediate	12 to 48	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
MARTELL	Martell / N/A		WHEELABRATOR ENV SYSTEMS	WHEELABRATOR ENV SYSTEMS	7	Fixed grate boiler, Steam turbine	Completed, In commercial operation	1986	18.0	Intermediate	12 to 48	100% of full
TRACY BIOMASS	Tracy / San Joaquin	Pacific Gas & Electric Co.	Thermal Energy Devel. Part.	Thermal Energy Devel. Part.	7	Stoker, Steam turbine	Completed, In commercial operation	1990	18.5	Base	12 to 48	100% of full
PACIFIC OROVILLE	Oroville / N/A	Pacific Gas & Electric Company	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	7	Fixed grate boiler, Steam turbine	Completed, In commercial operation	1985	18.7	Intermediate	12 to 48	100% of full
PACIFIC LUMBER COMPANY	N/A / Humbolt	Pacific Gas & Electric	PACIFIC LUMBER COMPANY	PACIFIC LUMBER COMPANY	7	Grate Boiler	Completed, In commercial operation	1986	20			
BURNEY SPI	Burney / BURNEY	PACIFIC GAS & ELECTRIC CO.	SIERRA PACIFIC INDUSTRIES	SIERRA PACIFIC INDUSTRIES	7	Spreader stoker, Steam turbine	Completed, In commercial operation	1984	20.0	Intermediate	12 to 48	100% of full
RIO BRAVO FRESNO	N/A / Fresno	Pacific Gas & Electric	CONSTELLATION OPERATING SERVICES	CONSTELLATION OPERATING SERVICES	7		Completed, In commercial operation	1988	24.3			
RIO BRAVO ROCKLIN	Roseville / Placer	Pacific Gas & Electric	CONSTELLATION OPERATING SERVICES	ULTRAPOWER ROCKLIN	7		Completed, In commercial operation	1989	24.4			
WOODLAND BIOMASS	Woodland / Yolo	Pacific Gas & Electric	THERMO ECOTEK CORP	WOODLAND BIOMASS POWER	7		Completed, In commercial operation	1989	25			
CHINESE STATION	Jamestown / N/A	Pacific Gas & Electric Company	CONSTELLATION OPER SVCS	CONSTELLATION OPER SVCS	7	Atmospheric fluidized bed boiler, Steam turbine	Completed, In commercial operation	1986	25.0	Intermediate	12 to 48	100% of full
ANTIOCH MILL	ANTIOCH / N/A	Pacific Gas & Electric Company	LOUISIANA PACIFIC CORP	LOUISIANA PACIFIC CORP	7	Steam turbine	Completed, In commercial operation	1985	26.0	Intermediate	12 to 48	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
FAIRHAVEN SIMPSON	FAIRHAVEN / N/A		SIMPSON PAPER CO	SIMPSON PAPER CO	7	Steam turbine	Completed, In commercial operation	1982	27.9	Intermediate	12 to 48	100% of full
BURNEY DELWEST	Burney / N/A		DELWEST OPERATING CO	DELWEST OPERATING CO	7	Steam turbine with steam sendout	Completed, In commercial operation	1989	31.0	Intermediate	12 to 48	100% of full
HONEY LAKE	Susanville / N/A		OPERATIONAL ENERGY CORP	OPERATIONAL ENERGY CORP	7	Traveling-grate stoker, Steam turbine with steam sendout	Completed, In commercial operation	1989	36.0	Intermediate	12 to 48	100% of full
COLMAC	Mecca / Riverside	SOUTHERN CALIFORNIA EDISON CO.	CONSTELLATION OPER SVCS	CONSTELLATION OPER SVCS	7	Atmospheric fluidized bed boiler, Steam turbine	Completed, In commercial operation	1992	49.9	Base	12 to 48	100% of full
SHASTA	Anderson / Shasta	Pacific Gas & Electric Co.	WHEELABRATOR ENV SYSTEMS	WHEELABRATOR ENV SYSTEMS	7	Traveling-grate stoker, Steam turbine with steam sendout	Completed, In commercial operation	1987	49.9	Base	12 to 48	100% of full
CHOWCHILLA	Chowchilla / N/A	Pacific Gas & Electric	NRG ENERGY INC	NRG ENERGY INC	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, Retired	1987	12.5	Non-dispatchable	n/a	n/a
CHOWCHILLA	Chowchilla / N/A	Pacific Gas & Electric	NRG ENERGY INC	NRG ENERGY INC	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, Shutdown or standby	1990	10.0	Intermediate	12 to 48	100% of full
EL NIDO	Chowchilla / N/A	Pacific Gas & Electric	NRG ENERGY INC	NRG ENERGY INC	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, Shutdown or standby	1988	12.5	Intermediate	12 to 48	100% of full
MADERA SJVEP	Chowchilla / N/A	Pacific Gas & Electric	NRG ENERGY INC	NRG ENERGY INC	2	Atmospheric fluidized bed boiler, Steam turbine	Completed, Shutdown or standby	1989	28.0	Intermediate	12 to 48	100% of full
GLENDALE (CA) 3	GLENDALE / N/A	Municipal Systems	CITY OF GLENDALE	CITY OF GLENDALE	1	Internal combustion (reciprocating engine or diesel engine)	Completed, Shutdown or standby	1983	0.6	Intermediate	1	100% of full

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
LOMPOC	Lompoc / N/A	Pacific Gas & Electric	OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, Shutdown or standby	1985	0.6	Intermediate	1	100% of full
BURBANK LANDFILL	BURBANK / N/A	Municipal Systems	JW OPERATING CO	JW OPERATING CO	1	Internal combustion (reciprocating engine or diesel engine)	Completed, Shutdown or standby	1988	0.8	Intermediate	1	100% of full
BONSALL	Bonsall / N/A		OGDEN ENERGY GROUP	OGDEN ENERGY GROUP	1	Internal combustion (reciprocating engine or diesel engine)	Completed, Shutdown or standby	1986	1.5	Intermediate	1	100% of full
MESQUITE LAKE	El Centro / N/A		NEW CHARLESTON POWER 1 LP	NEW CHARLESTON POWER 1 LP	8	Atmospheric fluidized bed boiler, Steam turbine	Completed, Shutdown or standby	1987	18.0	Intermediate	12 to 48	100% of full
LASSEN COMMUNITY COLLEGE	Susanville / N/A		SUSANVILLE RESOURCES INC	SUSANVILLE RESOURCES INC	6	Steam turbine with steam sendout	Completed, Shutdown or standby	1984	1.2	Intermediate	12 to 48	100% of full
OROVILLE KOPPERS	OROVILLE / N/A	Pacific Gas & Electric	KOPPERS CO	KOPPERS CO	7	Steam turbine	Completed, Shutdown or standby	1983	6.0	Intermediate	12 to 48	100% of full
FEATHER RIVER	Marysville / N/A	Pacific Gas & Electric	AES CORP	AES CORP	7	Atmospheric fluidized bed boiler, Steam turbine with steam sendout	Completed, Shutdown or standby	1988	17.0	Intermediate	12 to 48	100% of full
CALIFORNIA MILL	Antioch / N/A	Pacific Gas & Electric	GAYLORD CONTAINER CORP	GAYLORD CONTAINER CORP	7	Steam turbine with steam sendout	Completed, Shutdown or standby		40.0	Intermediate	12 to 48	100% of full
BUENA VISTA DISPOSAL SITE	Watsonville		EMCON/Perennial Energy	Santa Cruz County	1	Unknown	Planned and still in design	2001	0.3			
BLYTHE DISPOSAL SITE	Blythe			Riverside County MWD	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	0.4			

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
SAN TIMOTEO SOLID WASTE DISPOSAL SITE	Redlands		BAS Associates	San Bernardino County/ NORCAL	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	1.0			
COACHELLA VALLEY DISPOSAL SITE	Coachella			Riverside County	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	1.2			
MILLIKEN SLF	Ontario		BAS Associates	San Bernardino County/ NORCAL	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	1.9			
EDOM HILL DISPOSAL SITE	Cathedral City			Riverside County	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2002	2.0			
LAMB CANYON DISPOSAL SITE	Beaumont			Riverside County	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	2.1			
BADLANDS DISPOSAL SITE	Moreno Valley			Riverside County WMD	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2002	2.5			
CHATEAU FRESNO LF	Fresno		EDI	Allied Waste Industries	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	2.6			
KELLER CANYON LF	Pittsburgh		EDI	Allied Waste Industries	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	2.6			

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
VASCO ROAD SLF	Livermore		GRS	Allied Waste Industries	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	4.0			
NEWBY ISLAND SLF	Milpitas		GRS	International Disposal Corporation	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	4.2			
SUSHINE CANYON/NORTH VALLY LF	Sylmar		GRS	Allied Waste Industries	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	6.0			
OX MOUNTAIN SLF	Half Moon Bay		GRS	Allied Waste Industries	1	Internal combustion (reciprocating engine or diesel engine)	Planned and still in design	2001	10.0			
CHIQUIT CANYON SLF	Valencia		DTE Biomass	Republic Industries, Inc.	1	High Btu	Planned and still in design	2001				
COLTON REFUSE DISPOSAL SITE	Colton		BAS Associates	San Bernardino County/NORCAL	1	Unknown	Planned and still in design	2001				
FRANK R. BOWERMAN SLF	Irvine		Ecogas	Orange County IWMD	1	Vehicle Fuel	Planned and still in design	2001				
MID-VALLEY LF	Rialto		BAS Associates	San Bernardino County	1	Direct Thermal	Planned and still in design	2001				
SANTIAGO CANYON SLF	Irvine			Orange County IWMD	1	Unknown	Planned and still in design	2001				
TRI-CITIES LF	Fremont		Earth Tech	WMI	1	Leachate Evaporation	Planned and still in design	2001				
AZUSA LANDFILL	Azusa / N/A	Los Angeles Dept. of Water /Power	GES-KMS III	GES-KMS III	1	Gas/combustion turbine	Under construction		3.9	Non-dispatchable	n/a	n/a

Project Name	City / County	Utility	Developer	Operator Or Owner	Biomass Fuel Type	Technology Employed	Status	Year Complete	Current Capacity (MW)	Base, Inter., Peaking or Non- Dis-patchable	Cold Start Time (Hrs)	Delay before Restart (Hrs)
MEAD VALLY DISPOSAL SITE	Perris			Riverside County	1	Internal combustion (reciprocating engine or diesel engine)	Under construction	2001	1.1		n/a	n/a
BADLANDS DISPOSAL SITE	Moreno Valley			Riverside County WMD	1	Internal combustion (reciprocating engine or diesel engine)	Under construction	2001	1.3		n/a	n/a
UNION MINE DISPOSAL SITE	El Dorado		El Dorado County	El Dorado County	1	Internal combustion (reciprocating engine or diesel engine)	Under construction	2001	1.9		n/a	n/a
SIMI VALLEY LF	Simi Valley		WMI	WMI	1	Leachate Evaporation	Under construction	2001			n/a	n/a

Biomass Fuel Type:
1 = Landfill gas
2 = Agricultural waste
3 = Biogas from wood or other biomass gasification
4 = Unspecified biomass
5 = Digester gas (sewage sludge gas)
6 = Refuse (unprocessed municipal solid waste)
7 = Wood or wood-waste fuel
8 = Manure fuel

Ramp Rate: 100% of full for all projects
All operating projects are 100% operational.

Solar-thermal Project Data

Project Name	City/ County	Utility	Owner	Operator	Developer	Technology	Status	Year Comp-leted	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Percent Oper-ational	Typical Avail-ability	Base, Intermediate, Peaking or Non-Dispatchable
SEGS I	Daggett/ San Bernadino	Southern California Edison	Sunray Energy	Sunray Energy	Luz International Ltd.	Trough (LS1) with steam power plant	Operating	1984	13.8			Power block-100 Solar field-N/A	N/A	Intermediate
SEGS II	Daggett/ San Bernadino	Southern California Edison	Sunray Energy	Sunray Energy	Luz International Ltd.	Trough (LS2) with steam power plant	Operating	1985	30			Power block-100 Solar field-N/A	N/A	Intermediate; dispatchable in hybrid operation
SEGS III	Boron/ San Bernadino	Southern California Edison	Limited Partnership	KJC Operating Company	Luz International Ltd.	Trough (LS2) with steam power plant	Operating	1986	30	70650	27%	100	99	Intermediate; dispatchable in hybrid operation
SEGS IV	Boron/ San Bernadino	Southern California Edison	Limited Partnership	KJC Operating Company	Luz International Ltd.	Trough (LS2) with steam power plant	Operating	1986	30	71400	27%	100	99	Intermediate; dispatchable in hybrid operation
SEGS V	Boron/ San Bernadino	Southern California Edison	Limited Partnership	KJC Operating Company	Luz International Ltd.	Trough (LS2) with steam power plant	Operating	1987	30	75250	29%	100	99	Intermediate; dispatchable in hybrid operation
SEGS VI	Boron/ San Bernadino	Southern California Edison	Limited Partnership	KJC Operating Company	Luz International Ltd.	Trough (LS2) with steam power plant	Operating	1988	30	71000	27%	100	99	Intermediate; dispatchable in hybrid operation
SEGS VII	Boron/ San Bernadino	Southern California Edison	Limited Partnership	KJC Operating Company	Luz International Ltd.	Trough (LS-2,3) with steam power plant	Operating	1988	30	66954	25%	100	99	Intermediate; dispatchable in hybrid operation
SEGS VIII	Harper Lake/ San Bernadino	Southern California Edison	FPL Energy	FPL Energy	Luz International Ltd.	Trough (LS3) with steam power plant	Operating	1989	80	137150	20%	100	>95	Intermediate; dispatchable in hybrid operation
SEGS IX	Harper Lake/ San Bernadino	Southern California Edison	FPL Energy	FPL Energy	Luz International Ltd.	Trough (LS3) with steam power plant	Operating	1990	80	129700	19%	100	>95	Intermediate; dispatchable in hybrid operation
Dish Engine Critical Component Project	Huntington Beach/ Orange	Boeing Co. grid	Stirling Energy Systems	Boeing	Stirling Energy Systems	Parabolic dish with Stirling engine	Operating	Unit 1-1998 Unit 2-2000	0.05	70	18%	100	95–96	Intermediate
Solar Two Power Tower Demo Project	Daggett/ San Bernadino	Southern California Edison	Consort-CEC, Utility, EPRI, DOE	Southern California Edison	Consortium - Utilities, DOE, EPRI, CEC	Molten-salt Power Tower with steam power plant	Project Complete Apr 2000	Operation Feb 1998	10				N/A	Intermediate; dispatchable with storage

Photovoltaic Project Data

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Edwin Curtis			1981	2
San Bernardino Westside Com. Dev.	San Bernardino	San Bernardino	1981	35
Arco Solar	San Diego	San Diego	1982	18
POCO Power Corporation	San Luis Obispo	San Luis Obispo	1982	20
Anoosh Mizany	San Raphael	Marin	1983	2
Jose D Villarica	Roseville	Placer	1983	3
Ridgecrest Naval Weapons	Ridgecrest	Kern	1983	2
Unknown Individual	Palo Alto	Santa Clara	1983	4
Dr. Alvin Gullock	Dixon	Solano	1984	2
Harry Kuszewski	San Leandro	Santa Clara	1984	5
James Baker	Santa Monica	Los Angeles	1984	2.5
LA Dept of Water/Power	Los Angeles	Los Angeles	1984	2
Rancho Seco PVI, Arco System	Sacramento County	Sacramento	1984	1230
Community Environmental Council, Inc.	Santa Barbara	Santa Barbara	1985	2
McDonald's Restaurant	Huntington		1985	6
Riolo Construction			1985	0.7

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Ruby and Donald Trent			1985	2
Southern California Edison	Daggett		1985	2
Unknown Individual	Escondido	San Diego	1985	2
Howlett Residence	Laguna Del Mar		1986	1.1
McDonald's Restaurant	Alhambra	Los Angeles	1986	10
McDonald's Restaurant	Bakersfield	Kern	1986	5
McDonald's Restaurant	Bakersfield	Kern	1986	5
McDonald's Restaurant	Diamond Bar	Los Angeles	1986	6
McDonald's Restaurant	Industry		1986	6
McDonald's Restaurant	La Verne	Los Angeles	1986	6
McDonald's Restaurant	Lawndale	Los Angeles	1986	6
McDonald's Restaurant	West Covina	Los Angeles	1986	6
Payne Residence			1986	3
Pedersen Residence			1986	0.8
RS PV2, Arco/Solarex/Mobil	Sacramento County	Sacramento	1986	1230
San Diego Townhomes	Laguna Del Mar		1986	1.1
Southern California Edison	Bishop Deep Springs	Inyo	1986	2

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Southern California Edison	Covina	Los Angeles	1986	2
Unknown Individual	Escondido	San Diego	1986	2
Unknown Individual	Escondido	San Diego	1986	0.5
Ridgecrest Naval Weapons	Ridgecrest	Kern	1988	4
City of Oceanside	Oceanside	San Diego	1989	10
PVUSA Davis - a-Si	Yolo County	Yolo	1989	16
PVUSA Davis - a-Si	Yolo County	Yolo	1989	15
PVUSA Davis - crystal Si	Yolo County	Yolo	1989	18
PVUSA Davis - poly-Si	Yolo County	Yolo	1990	15
PVUSA Davis - concentrator Si	Yolo County	Yolo	1991	16
Wexler Residence	Laguna Del Mar		1991	1.1
PV Residential Demonstration System	Sacramento County	Sacramento	1992	10
PVEV Charging Station	Sacramento County	Sacramento	1992	11
PVUSA Davis - a-Si	Yolo County	Yolo	1992	479
Hedge PV1m UPG/Siemens	Sacramento County	Sacramento	1993	258.00
Pacific Gas & Electric			1993	12
PG & E/ PVUSA Kerman	Fresno County	Fresno	1993	498
PV Pioneers 93, Siemens	Sacramento County	Sacramento	1993	3.0–4.0
PVUSA Davis -	Yolo County	Yolo	1993	289

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
PVUSA Davis - ribbon Si	Yolo County	Yolo	1993	196
San Diego Gas & Electric	San Diego	San Diego	1993	2.5
San Diego Townhomes	Laguna Del Mar		1993	1.1
South Coast Air Quality Management District	Diamond Bar	Los Angeles	1993	24
Southern California Edison	Los Angeles	Los Angeles	1993	4
Southern California Edison	Los Angeles	Los Angeles	1993	4
Southern California Edison	Los Angeles	Los Angeles	1993	12
Hedge PV2, APS	Sacramento County	Sacramento	1994	108
PV Commercial Pioneers, Solec	Sacramento County	Sacramento	1994	10.0–30.0
PV Pioneers 94, Siemens	Sacramento County	Sacramento	1994	3.0–4.0
PV Pioneers 94, Solec	Sacramento County	Sacramento	1994	3.0–4.0
PVUSA Davis - crystal Si	Yolo County	Yolo	1994	174
PVUSA Davis - poly-Si	Yolo County	Yolo	1994	16
Robert Siebert	Orange County	Orange	1994	1
SMUD Warehouse, PV, SEA	Sacramento County	Sacramento	1994	37
WAPA BIPV Roof Demo, Powerlight	Sacramento County	Sacramento	1994	3

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
PV Commercial Pioneers 94	Sacramento, CA	Sacramento	1994	144
LA Dept of Water/Power	Los Angeles	Los Angeles	1995	18
PV Pioneers 95, Placer/Solarex	Sacramento County	Sacramento	1995	3.0–4.0
PV Pioneers 95, RMI/Solarex	Sacramento County	Sacramento	1995	3.0–4.0
PV Pioneers 95, Solec	Sacramento County	Sacramento	1995	3.0–4.0
PV Solarport, UPG/Siemens	Sacramento County	Sacramento	1995	158
PVEV Airport, SMUD/Arco	Sacramento County	Sacramento	1995	9
PVUSA Davis - CdTe	Yolo County	Yolo	1995	11
Southern California Edison			1995	115
Monterey Hills Elementary School	South Pasadena, CA	Los Angeles	1995	85
BIPV Demo Systems	Sacramento County	Sacramento	1996	10
Hedge PV3, RMI/Solarex	Sacramento County	Sacramento	1996	102
Presidio National Park	Presidio National Park	San Francisco	1996	1.25
PV Commercial Pioneers 96, Solec	Sacramento County	Sacramento	1996	80

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
PV Pioneers 96, Placer/Solarex	Sacramento County	Sacramento	1996	3.0–4.0
PV Pioneers 96, Solarex	Sacramento County	Sacramento	1996	3.0–4.0
SMUD	Sacramento County	Sacramento	1996	
Southern California Edison	Sacramento	Sacramento	1996	128
US Navy	San Clemente Island	Orange	1996	94
US Navy	Superior		1996	344
WAPA BIPV Roof, Powerlight	Sacramento County	Sacramento	1996	40
Alameda Bureau of Electricity	Alameda	Alameda	1997	4
Craig Hoellwarth			1997	1
Hedge PV4, UPG/Siemens	Sacramento County	Sacramento	1997	132
PV Pioneers 97, Placer/Solarex	Sacramento County	Sacramento	1997	3.0–4.0
PVUSA Davis - crystal Si	Yolo County	Yolo	1997	3.1
PVUSA Davis - crystal Si	Yolo County	Yolo	1997	3.8
PVUSA Davis - poly-Si	Yolo County	Yolo	1997	2.9
RS PV3, UPG/Siemens	Sacramento County	Sacramento	1997	263

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Southern California Edison			1997	100
University of California, Irvine	Irvine	Orange	1997	4.9
Electric Vehicle Recharging Station at Sacramento Airport	Sacramento, CA	Sacramento	1997	129
Boys Republic	Chino Hills	San Bernardino	1998	8.105
Bureau of Electricity	Alameda	Alameda	1998	
Cal Poly			1998	1.3
California State University at Pomona	Pomona	Los Angeles	1998	1.06
Community Solar	Sacramento County	Sacramento	1998	6
Elizabeth Court	Cudahy	Los Angeles	1998	7.2
Elizabeth Court Carport	Cudahy	Los Angeles	1998	2.4
Elizabeth Court School	Victorville	San Bernardino	1998	4.1
Glenmade Elementary School	Chino Hills	San Bernardino	1998	10.6
Huntington Library	San Marino	Los Angeles	1998	98.3
IBEW			1998	2
IBEW Training Center	Sacramento County	Sacramento	1998	4
Knotts Berry Farm	Buena Park	Orange	1998	29.7
Krotzer Patio			1998	1.8

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Kyocera	San Diego	San Diego	1998	50
Menlo Park Residence	Menlo Park	San Mateo	1998	1.9
Monterey Hills Elementary School	South Pasadena	Los Angeles	1998	112
Northern California Power Agency			1998	6
Pacific Park	Santa Monica	Los Angeles	1998	39.06
PM Warehouse			1998	4.1
PV Commercial Pioneers 98, Solec	Sacramento County	Sacramento	1998	70
PV Partnership	Sacramento County	Sacramento	1998	44
PV Pioneers 98, Solarex	Sacramento County	Sacramento	1998	3.0–4.0
PV Poineer 98, Solarex Kits	Sacramento County	Sacramento	1998	2
Residence in Inverness	Inverness	Marin	1998	3.8
Residence in Vacaville	Vacaville	Solano	1998	3.8
Roseville Aquatic Center	Roseville	Placer	1998	8.5
RS PV4, UPG/Siemens	Sacramento County	Sacramento	1998	160
San Diego Gas & Electric			1998	4.1

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
San Diego Gas & Electric			1998	4.1
Southern California Edison			1998	5
Truckee Donner School			1998	2
	Goleta		1998	2
PVUSA (Small Systems Test Site)	Davis, CA	Yolo	1998	3.2
PVUSA (Small Systems Test Site)	Davis, CA	Yolo	1998	2
PVUSA (Small Systems Test Site)	Davis, CA	Yolo	1998	3
Effie Yeaw Nature Center	Carmichael, CA	Sacramento	1998	4.4
Sacramento Zoo	Sacramento, CA	Sacramento	1998	4
WAPA Folsom Operations Center	Folsom, CA	Sacramento	1998	3
WAPA Elverta Office Building	Elverta, CA	Sacramento	1998	29
Bob and Susan Cooley-Gilliom	Auburn	Placer	1998	1.02
Charles Gillet	Grass Valley	Nevada	1998	2.47
Chris A. Wills	Santa Ana	Orange	1998	3.07
Chris Klassen	San Jose	Santa Clara	1998	1.97
Christine Pielenz/Bill Lavens	San Francisco	San Francisco	1998	1.90
Coachman Inn	San Luis Obispo	San Luis Obispo	1998	0.86
David Reyes	Hollister	San Benito	1998	1.80
Don Coleman	Berkeley	Alameda	1998	2.85
Edison Technology Solutions	Buena Park	Orange	1998	29.72
Edison Technology Solutions	Chino Hills	San Bernardino	1998	10.48
Edison Technology Solutions	Garden Grove	Orange	1998	10.97

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Edison Technology Solutions	Irvine	Orange	1998	5.24
Edison Technology Solutions	Santa Monica	Los Angeles	1998	42.46
FAA Pacific Desert Management Office	San Diego	San Diego	1998	0.82
FAA Pacific Desert Management Office	San Diego	San Diego	1998	0.82
Fred Beasom	Tehachapi	Kern	1998	2.10
Fred Beasom	Tehachapi	Kern	1998	0.26
Greg Johanson	Westlake Village	Los Angeles	1998	2.95
Joel Davidson	Culver City	Los Angeles	1998	1.95
John Faatz	Nevada City	Nevada	1998	1.54
John Mracek/Leslie Fowler	Cupertino	Santa Clara	1998	1.50
John Paul Mitchell Systems	Santa Clarita	Los Angeles	1998	4.33
Karen Johnson	Paradise	Butte	1998	1.23
Kenneth & Gay Lott	Mariposa		1998	0.81
Leonard Barton	Walnut Creek	Contra Costa	1998	1.98
Lucy Henderson	Orinda	Contra Costa	1998	0.78
Marianne Walpert	Belmont	San Mateo	1998	3.94
Marva Hickman	Oakland	Alameda	1998	1.91
Michael Murphy	Half Moon Bay	San Mateo	1998	3.94
Minucha Colburn	Mendocino	Mendocino	1998	0.78
Norman Martel	Grass Valley	Nevada	1998	3.93
Norman Pease	Orinda	Contra Costa	1998	10.33
Pam Coxson/David Farley	San Francisco	San Francisco	1998	0.26
R.J. Garland	Brentwood	Contra Costa	1998	0.39
Reiko Hayashi	Moss Beach	San Mateo	1998	1.94
Robert Tingleff/Darien Payne	Santa Cruz	Santa Cruz	1998	1.97
Ron Rambin	Saugus		1998	5.02
Sherry Boschert/Meg D. Newman	San Francisco	San Francisco	1998	1.80

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Simon R. Avakian	Menlo Park	San Mateo	1998	1.97
Stuart Chaitkin	Berkeley	Alameda	1998	1.80
Suzanne M. Johnson	Sunnyvale	Lassen	1998	1.97
Tish Van Camp/Alex Kochkin	Point Reyes		1998	3.94
Cal Poly Wind/PV Hybrid System	Pomona	Los Angeles	1999	2.3
CalExpo Solarport	Sacramento County	Sacramento	1999	413
Church of Christ			1999	13.2
Community Solar	Sacramento County	Sacramento	1999	6
East End State Garage Solarport, UPG/EPG	Sacramento County	Sacramento	1999	25
Garage Mount System	Chino Hills	San Bernardino	1999	2
Kangas Residence	Northern California		1999	2.1
Kit Carson School	Sacramento County	Sacramento	1999	28
Lutheran Church			1999	20
Missionary Baptist Church			1999	13.2
Montara Avenue School	South Gate	Los Angeles	1999	4.8
Neighborhood PV & Solarports	Sacramento County	Sacramento	1999	238

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
PV Partnership	Sacramento County	Sacramento	1999	160
PV Pioneers: UPG/Shawnee/Siemens/Solarex/EPV	Sacramento County	Sacramento	1999	387
Residence in Emerald Hills	Emerald Hills	San Mateo	1999	9.1
RS PV5 UPG/EPV	Sacramento County	Sacramento	1999	145
Albion School	Albion		1999	4.71
Allen Glazer	Grass Valley	Nevada	1999	2.00
Allen Holmquist	Monrovia	Los Angeles	1999	2.37
Anne Bredon	North Fork		1999	0.99
Anthony Luisi	Fremont	Alameda	1999	3.95
Bentley Mills, Inc.	City of Industry		1999	99.97
Bentley Mills, Inc.	City of Industry		1999	14.86
Betty Smay	Arroyo Grande	San Luis Obispo	1999	1.63
Bill Brooks	Vacaville	Solano	1999	4.11
Bill Callison	Concord	Contra Costa	1999	1.92
Bob Black	Winchester		1999	1.54
Bob Dozer	Santa Rosa	Sonoma	1999	1.59
Bob Markstein	Diablo		1999	6.16
Bonnie Chase	Claremont	Los Angeles	1999	1.04
Bonnie Chase	Claremont	Los Angeles	1999	1.04
BP Solar Inc.	Fairfield	Solano	1999	1.78
Brendan Eich	Los Gatos	Santa Clara	1999	4.14
Brooks Gill	Santa Ynez	Santa Barbara	1999	2.03
Bruce Jenkins	Ramona	San Diego	1999	1.86
C & L Associates LLC	Redwood City	San Mateo	1999	9.86

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Chacko Neroth, BBA Scionix	Sunnyvale	Lassen	1999	0.40
Charles L. Alldrin	Chico	Butte	1999	1.71
Charles Wood	Albion		1999	2.88
Chris & Betty Broadwell	Santa Cruz	Santa Cruz	1999	2.23
Chris Agruss	Winters	Yolo	1999	5.34
Chris Beekhuis	San Jose	Santa Clara	1999	2.43
Claudia Williams	Mountain View	Santa Clara	1999	1.37
Curtis Bok/Sharon Bailey-Bok	Nevada City	Nevada	1999	9.71
Cynthia Randall	San Jose	Santa Clara	1999	2.25
Daryl Keech	Browns Valley		1999	0.52
David Arkin	Albany	Alameda	1999	0.38
David Bienert	Visalia	Tulare	1999	1.64
David K. Yoakum	Vacaville	Solano	1999	2.85
David Parker	Aromas		1999	1.01
David Weinsoff	Fairfax	Marin	1999	2.43
Debi Baker	Bonny Doon		1999	2.23
Del Schwichtenberg	Vallejo	Solano	1999	2.85
Dency Nelson	Hermosa Beach	Los Angeles	1999	1.78
Dennis Garret	Hayward	Alameda	1999	2.00
Don Dittman	Coarsegold		1999	0.39
Don Enderud	Winchester		1999	2.36
Don Larson	San Jose	Santa Clara	1999	2.28
Donald Leckie	Apple Valley	San Bernardino	1999	2.36
Edison Technology Solutions	Buena Park	Orange	1999	1.54
Edison Technology Solutions	Chino Hills	San Bernardino	1999	8.11
Edison Technology Solutions	Chino Hills	San Bernardino	1999	2.01
Edison Technology Solutions	Cudahy	Los Angeles	1999	4.33

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Edison Technology Solutions	Cudahy	Los Angeles	1999	6.18
Edison Technology Solutions	Monrovia	Los Angeles	1999	1.94
Edison Technology Solutions	Oxnard	Ventura	1999	12.53
Edison Technology Solutions	Pomona	Los Angeles	1999	0.76
Edison Technology Solutions	Pomona	Los Angeles	1999	1.43
Edison Technology Solutions	Santa Ana	Orange	1999	11.08
Edison Technology Solutions	Santa Monica	Los Angeles	1999	28.17
Edison Technology Solutions	Southgate	Los Angeles	1999	4.33
Edward A. Warburton	Willits	Mendocino	1999	3.94
Edward C. Dawkins	Winters	Yolo	1999	3.82
Elias A. Elias	Arcata	Humboldt	1999	0.25
Federal Aviation Administration	Rancho Cordova	Sacramento	1999	0.82
Federal Aviation Administration	Rancho Cordova	Sacramento	1999	0.82
Federal Aviation Administration	Rancho Cordova	Sacramento	1999	0.82
Federal Aviation Administration	Rancho Cordova	Sacramento	1999	0.82
Federal Aviation Administration	Rancho Cordova	Sacramento	1999	0.82
Federal Aviation Administration, Attn: John Milne	San Diego	San Diego	1999	0.81
Federal Aviation Administration, Attn: John Milne	San Diego	San Diego	1999	0.81
Fetzer Vineyards	Hopland		1999	35.12
Francis Mummery	Fullerton	Orange	1999	1.03
Frank Hervey, Jr.	Laytonville		1999	1.54
Frank Muschalek	Mountain Ranch		1999	0.69
Gary Cook	Castro Valley	Alameda	1999	4.78
Gerald & Linda Maloney	Grass Valley	Nevada	1999	1.61
Greg & Nicolette Hansen	Nevada City	Nevada	1999	1.04
Greg Bowlby	Alta Loma		1999	1.38
Hank Pellisier	San Francisco	San Francisco	1999	1.09

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Henry Mayer	Woodside	San Mateo	1999	1.25
Homestead Enterprises	Elk		1999	5.69
Howard Shaw	San Rafael	Marin	1999	2.05
Ian & Terry Thiermann	Ben Lomond	Santa Cruz	1999	3.66
Irene B. Borschardt	Wildomar	Riverside	1999	1.28
Irene Borchardt	Wildomar	Riverside	1999	0.26
J.B. Compton	Los Gatos	Santa Clara	1999	9.86
Jack West/Ken Gossett	Oakland	Alameda	1999	1.00
James Eniti	Livermore	Alameda	1999	1.50
James G. Moldenhauer	Weldon		1999	1.61
James Kochheiser	Madera	Madera	1999	2.03
Jeffery Arnold	Orinda	Contra Costa	1999	0.44
Jerry Fairchild	Redland	San Bernardino	1999	2.36
Jill Caruthers	Nevada City	Nevada	1999	1.63
Jim Davis	Arroyo Grande	San Luis Obispo	1999	1.96
Jim Lingrosso	Saugus		1999	3.11
Jim Lingrosso	Saugus		1999	1.56
Jocelyne Nielsen	San Francisco	San Francisco	1999	1.94
Joe & Barbara Kresse	Redwood	San Mateo	1999	2.44
John Barile	Big Bear	San Bernardino	1999	1.28
John Gallo M.D.	Albion		1999	1.24
John Hensley	Ukiah	Mendocino	1999	4.14
John M. Wagner	Tollhouse		1999	1.22
John Robbins	Soquel	Santa Cruz	1999	6.73
Jonathan Herr	Santa Rosa	Sonoma	1999	1.64
Judy Gede	Grass Valley	Nevada	1999	1.31
Kathy and Ellis Darling	Redondo Beach	Los Angeles	1999	1.16

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Kay Rudin	Westport		1999	0.66
Keith Robertson	Grass Valley	Nevada	1999	1.01
Keith Robertson	Grass Valley	Nevada	1999	1.61
Keith York	Ventura		1999	2.25
Ken Ling	Clearlake	Lake	1999	0.97
Kent Dogey	Scotts Valley	Santa Cruz	1999	2.25
Kerry Hosley & Kelly Roberts	Soquel	Santa Cruz	1999	1.18
Kirk Davies	Ramona	San Diego	1999	0.77
Larry & Sharon Ince	Oakhurst	Madera	1999	1.61
Leonard Starr	Agoura Hills	Los Angeles	1999	3.08
Liz Ryan	Santa Cruz	Santa Cruz	1999	2.23
Lynda Raff	Riverside	Riverside	1999	1.23
Lynda Raff	Santa Monica	Los Angeles	1999	2.05
Manny Aschemeyer	Warner Springs		1999	1.54
Manny Aschemeyer	Warner Springs		1999	0.77
Mark Lau Branson	Oakland	Alameda	1999	2.43
Mark Rousseau	Santa Barbara	Santa Barbara	1999	2.25
Mark Stevens	San Diego	San Diego	1999	1.82
Mark Walker	Hesperia	San Bernardino	1999	0.69
Marsha & Robin Williams	Napa	Napa	1999	28.70
Mary Minow & James Robenolt	Cupertino	Santa Clara	1999	2.57
Merrill & Alana Feldman	Hillsborough	San Mateo	1999	4.93
Michael Benson	Grass Valley	Nevada	1999	0.51
Michael Cordell	Camarillo	Ventura	1999	1.80
Michael Dru Sutton	Boulder Creek	Santa Cruz	1999	2.03
Michael Orians	Cayucas	San Luis Obispo	1999	1.15
Mona Brookes	Ojai	Ventura	1999	1.55
Mosby Ranch	Brentwood	Contra Costa	1999	1.20
Nancy & Mike Kerson	Napa	Napa	1999	1.52

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Nancy Bacon	Nevada City	Nevada	1999	2.05
Nick Chiapero	Pittsburg	Contra Costa	1999	2.44
Norman Malmskog	Downey	Los Angeles	1999	1.77
Norman S. Winneguth	Tehachapi	Kern	1999	0.39
Olivia Eielson	Oakland	Alameda	1999	1.94
Oran & Frankie Kangas	Fort Bragg	Mendocino	1999	2.11
Pamela O'Malley Chang	Berkeley	Alameda	1999	2.11
Pat & Niels Sundermeyer	Santa Cruz	Santa Cruz	1999	3.66
Patrick Healy	San Francisco	San Francisco	1999	0.95
Paul Carreiro	San Jose	Santa Clara	1999	0.79
Paula Jain	Rough & Ready		1999	2.09
Rancho Las Virgenes Municipal Water Dist.	Calabasas		1999	213.57
Rancho Las Virgenes, Municipal Water Dist.	Calabasas		1999	186.43
Raymond L. Isitt	Camino		1999	0.81
Rene & Selene Vega	Ben Lomond	Santa Cruz	1999	5.58
Richard H. Warren	Auburn	Placer	1999	0.82
Richard Prater	Mariposa		1999	1.64
Rob Jensen	Newcastle		1999	3.89
Rob Roy McDonald	Bishop	Inyo	1999	1.01
Robert Murray	Clovis	Fresno	1999	3.25
Ron Pargett	Mt. Ranch		1999	0.79
Ron Raymond	San Jose	Santa Clara	1999	9.11
Ronald Carpenter	Castroville	Montery	1999	4.56
Sam Dawson	Dulzura		1999	3.51
Sam Wyly	Malibu		1999	2.37
Stanley K. Monteith	Soquel	Santa Cruz	1999	3.99
Stephen Heckeroth	Albion		1999	3.16
Stephen Smith	Grass Valley	Nevada	1999	1.28

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Steve Fisch/Jane Gottesman	Berkeley	Alameda	1999	1.50
Steve Gold	San Francisco	San Francisco	1999	2.92
Steve Sargent	Paso Robles		1999	0.34
Steven H. Sargent	Paso Robles		1999	1.69
Susan & Jonathan Wittwer	Santa Cruz	Santa Cruz	1999	1.97
Terry R. Galloway	Berkeley	Alameda	1999	1.46
Thomas Jepsen	Brentwood	Contra Costa	1999	3.38
Todd Cass	San Francisco	San Francisco	1999	3.45
Todd Detzel	Laytonville		1999	2.35
Tom Cohen	Mill Valley	Marin	1999	1.35
Tom Dolan	Nipomo	San Luis Obispo	1999	1.78
Tom Lawrie	San Francisco	San Francisco	1999	1.71
Toney Ledford	San Luis Obispo	San Luis Obispo	1999	2.30
Torkil Olsen	Los Altos Hills	Santa Clara	1999	1.91
Ulrich Schmidt	Oregon House		1999	0.68
Verne S. Rockhold	Carmel Valley	Montery	1999	1.14
Vivienne Verdan-Roe & Michael Porter	Bolinas		1999	2.44
Walter Harris	Paso Robles		1999	3.45
Wayne Walker	Lancaster		1999	1.57
Wes Kingsley	Los Gatos	Santa Clara	1999	2.05
William Broadbent	San Luis Obispo	San Luis Obispo	1999	2.07
William Hardy	Auburn	Placer	1999	2.79
Willow & Jason Trent	Little River		1999	3.37
Rancho Seco PV5	Sacramento, CA	Sacramento	1999	255.00
PVUSA (Small Systems Test Site)	Davis, CA	Yolo	1999	3.60

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Edison Development Corp./Pleasonton PowerPark	Pleasanton	Alameda	2000	
Blue Mountain Center of Meditation	Tomales		2000	0.97
Colonel Ernest John Berger	Mission Viejo	Orange	2000	2.20
David Rowe	San Jose	Santa Clara	2000	2.03
Draeger Construction, Inc.	San Jose	Santa Clara	2000	6.83
Ed & Sherry Wilds	Los Gatos	Santa Clara	2000	3.29
Eleanor Wasson	Santa Cruz	Santa Cruz	2000	1.63
Elton M. Short	Hemet	Riverside	2000	1.57
FAA - Pacific Desert System Management Office	San Diego	San Diego	2000	2.81
Federal Aviation Administration, Attn: John Milne	San Diego	San Diego	2000	0.81
Fred Brodie	Yucca Valley	San Bernardino	2000	1.15
Gerry Blau	Pacifica	San Mateo	2000	0.85
GPU Solar, Inc.	Hopland		2000	92.53
H. Nona Hungate	Oakland	Alameda	2000	3.07
Jeanette Engelhart	Santa Cruz	Santa Cruz	2000	5.31
Jim & Melinda Atkins	Tracy	San Joaquin	2000	2.98
Joanne Abey	Livermore	Alameda	2000	2.44
John & Sue Olson	Laguna Hills	Orange	2000	1.27
Joseph Gorton	Vacaville	Solano	2000	5.84
Karina Garbesi & Mark Fischer	Kensington	Contra Costa	2000	1.49
Katherine Fagin	Redwood City	San Mateo	2000	1.50
Kent Fickett	Orinda	Contra Costa	2000	0.84
Laura Murra	Berkeley	Alameda	2000	2.99
Lay Kay	Pasadena	Los Angeles	2000	1.97
Leanne & Richard Rhodes	Escalon	San Juaquin	2000	5.27
Maurice Miller	San Francisco	San Francisco	2000	4.11

Name of Project or Owner	Location	County	Year Installed	Installed Capacity (kW)
Michael Arroyo	Lafayette	Contra Costa	2000	0.77
Michael Brock	San Diego	San Diego	2000	2.75
Michael Macaluso	Rosamond	Kern	2000	0.81
Paula & Etienne Wenger	Nevada City	Nevada	2000	4.49
Randall C. Milligan	Banning	Riverside	2000	1.63
Roy Lewis	Danville	Contra Costa	2000	5.17
Russian Convent	Moss Beach	San Mateo	2000	9.04
Solar Webb Inc.	Arcadia	Los Angeles	2000	0.20
Temescal Co-Housing	Oakland	Alameda	2000	5.69
Thomas & Sandra Murray	Lake Isabella	Kern	2000	0.34
GPI	Edwards Air Force Base	Kern		25
Mendoza School				9.4
Green Mountain Energy	Berkeley			<100
Pleasanton Power Park	Pleasanton			340
Powerlight Corporation	Berkeley	Alameda		<100
San Diego County	San Diego	San Diego		3000
SCI	Davis	Yolo		10
SCI	Edwards Air Force Base	Kern		25
South Coast Air Quality Management District	Compton	Los Angeles		
US Dept of Interior	Channel Islands National Network	Ventura		13
US Navy	Santa Cruz	Santa Cruz		139

Hydro Project Data

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Vermillion Valley	Fresno	Southern California Edison Co (CA)	Mono Creek	Completed		0			0	0	
Eckert	Humboldt	David W. & Penelope Jennings Eckert	Bluff Cr	Completed		0.001	0.72	8%	8.76	1	Non-Dispatchable
Boulder Creek	Del Norte	Clarke N. Moore	Boulder Cr	Completed	1985	0.001			8.76	1	Non-Dispatchable
Wolf Creek	Nevada	Adrian And Janice Haemmig	N Fk Wolf Cr	Completed		0.002	5	29%	17.52	2	Intermediate
Cornwell	Siskiyou	Cornwell Howard W & Verna J	Merrill Creek	Completed		0.008			70.08	8	
Little Bear Creek	Placer	Robert W Irvine	Little Bear Cr	Completed	1984	0.01	50	57%	87.6	10	Non-Dispatchable
Fire Mountain Lodge	Tehama	Willis Ken	Fern Springs Creek	Completed		0.015			131.4	15	
Peter Ranch	Plumas	James B. Peter	Peters Cr	Completed	1982	0.015			131.4	15	
Wright Ranch (Marie Wright)	Sierra	Bertha Wright Bertillion Trust	Rock Cr	Completed		0.02			175.2	20	
Burgess	Trinity	Tom & Carol Benninghoven	Burgess Cr	Completed	1982	0.025			219	25	
Shadybrook Pump Sta	Tuolumne	Tuolumne County Wd 1	Sullivan Cr	Completed		0.027			236.52	27	
29 Mile Creek	El Dorado	Hensley Larry Transferring Ownership To Mark Souza	Unnamed Tributary Of	Under Construction	2003?	0.03			262.8	30	
Nikola 1	Tehama	Lassen Research Co	Lower Booledth Pl (Digger Cr)	Completed		0.03			262.8	30	
Stovall 2	Colusa	Glenn-Colusa Irrig Dist	Glenn-Colusa Cnl (Sacramento R)	Completed		0.17	433	29%	1489.2	170	Intermediate
Biber Spellenburg	Trinity	Frank M. Biber, Et Al	Bidden Cr	Completed		0.03			262.8	30	
Luckey Hydro	Siskiyou	Northern Wasco County Util. Dist.	Natural Springs	Completed	1986	0.05	350	80%	438	50	Base
Powr Recovery No.1(826+70)	Kern	Tehachapi-Cummings Co Wd	Tcc Wd Pl (Calif Aque)	Completed		0.046			402.96	46	
Bell(Lower)	Trinity	Bell Enterprises	Battle Cr	Completed		0.05	365	83%	438	50	Base

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Site 2100	San Bernardino	City Of San Bernardino	Muni Pl (Carjein Cr) Cajon Cr	Completed		0.4	503	14%	3504	400	Peaking
Charcoal Ravine	Sierra	Neocene Exploration Inc	Charcoal Ravine	Removed		0	0	0%	0	0	
Squires	San Diego	Carlsbad Muni Wd	Muni Ws Pl (San Diego Aque)	Removed		0			0	0	
Placentia Avenue	Orange	Mesa Consolidated Water Dist	Water Supply Conduit	Completed		0.06			525.6	60	
Upper Cold Springs	Siskiyou	Harold E. Foster,Robert Z. Walker	Natural Springs	Completed		0.066	462	80%	578.16	66	Base
Cpud Pipeline 3(608+90)	Calaveras	Calaveras Pud	Cpud Pl (N Fk Calaveras R)	Completed		0.28	1000		2452.8	280	
Deep Springs	Inyo	Deep Springs College	Irrig Pl (Wyman Cr)	Completed		0.09			788.4	90	
Upland	San Bernardino	Upland Wtr Dept	San Antonio Water Co Pl	Completed		0.088			770.88	88	
Graeagle Golf Course	Plumas	Graeagle Land & Water Co (CA)	Frazier Creek	Completed		0.09			788.4	90	
Cold Springs Lower	Siskiyou	Foster, Harold E. Et Al.	Cold Cr	Completed		0.09	666	84%	788.4	90	Base
Mile 41.1	Colusa	Glenn-Colusa Irrig Dist	Glenn-Colusa Cnl (Sacramento R)	Completed		0.093			814.68	93	
Ace Ranch	Alpine	Bertea, Richard Sold To Bently, Donald A.	West Fork Carson River	Completed		0.113			989.88	113	
Landis-Harde	El Dorado	Harde David O	Perry Creek	Completed		0.1			876	100	
Hat Creek Hereford Ranch	Shasta	Robert Thompson	Hat Cr	Completed		0.1			876	100	
Oakcliff	Riverside	Lake Hemet Muni Wtr Dist	Wd Pl (San Jacinto R)	Completed		0.1			876	100	
Poulton	Shasta	Webb Morrow Sold To Steve And Bonnie Tetrick	S Cow Cr	Completed		0.1			876	100	
Prather Creek	Siskiyou	Ralph Ranches Inc	Prather Cr	Completed		0.1			876	100	
Shasta River	Siskiyou	Dewey Smith	Shasta R	Completed		0.1			876	100	
Bell	Placer	Swiss-American Co	Lower Fiddler Green Cnl(Sacramento	Completed		0.1			876	100	
Yellowjacket	Sonoma	John Neerhout, Jr.	Yellowjacket Cr	Completed		0.1			876	100	

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
West Hill	Siskiyou	Walker, Robert T., Et Al	Cold Cr	Completed		0.1	280	32%	876	100	Intermediate
Paradise Irr Dist Proj C&D	Butte	Beckwith, Herbert H.	Paradise Supply(Butte Cr)	Completed		0.105			919.8	105	
Lopez Wtp	San Luis Obispo	San Luis Obispo Co Fc & Wcd	Wtr Sup Pl(Arroyo Grande Cr)	Completed		0.12			1051.2	120	
Stovall 1	Colusa	Glenn-Colusa Irrig Dist	Glenn-Colusa Cnl(Sacramento R)	Completed		0.12			1051.2	120	
Picay	Santa Barbara	John Howard & Montecito Water Dist.	Picay Pressure Break	Completed		0.13			1138.8	130	
Sutters Mill	Shasta	Fred N. Sutter, Jr.	Millseat Cr	Completed		0.15			1314	150	
Santa Monica	Los Angeles	City Of Santa Monica, Ca	Sepulveda Fdr (Colo Aque)	Completed		0.15			1314	150	
Woodcreek Road	Ventura	Camrosa County Wd	Ws Pl (Calleguas Cr)	Completed		0.15			1314	150	
Cinnamon Ranch	Mono	Moss Richard	Middle Creek	Completed		0.175			1533	175	
Joint Water Line	Los Angeles	Walnut Valley Water Dist	Water Supply Pl(Southern Cr)	Completed		0.182			1594.32	182	
Turtle Rock-Quail Hill	Orange	Irvine Ranch Water Dist	Mwd Feeder Pl (Colo R Aque)	Completed		0.187			1638.12	187	
Clover Leaf Ranch	Shasta	Highland Hydro Construction Inc	Clover Cr	Completed		0.2			1752	200	
Dominguez Gap Barrier	Los Angeles	Los Angeles County Fcd	Dom. Gap Pl(Colo R Aque)	Completed		0.2			1752	200	
Alamitos	Los Angeles	Los Angeles County Fcd	Alamitos Pl(Colo R Aque)	Completed		0.2			1752	200	
Fulton Road Station	Los Angeles	Three Valleys Mun Wtr Dist	Fulton Water Trtmt Plt	Completed		0.2			1752	200	
Dardanelles Creek	Placer	Brad Reeves	Dardanelles Cr	Completed		0.224			1962.24	224	
Goose Valley	Shasta	Denny Land & Cattle Co. L.L.C.	Goose Cr	Completed		0.224			1962.24	224	
Santa Rosa Valley	Ventura	Calleguas Mun Wtr Dist	Pressure Redu Sta(Calif Aque)	Completed		0.224			1962.24	224	
Station 3	San Bernardino	Water Fac Auth-A Jpa	Wfa Pl(Ca Aque)San Antonio Cr	Completed		0.225			1971	225	
Middle Fork	Calaveras	Calaveras Pud	M Fk Mokelumne R	Completed		0.23			2014.8	230	

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Gansner Water & Power Co	Plumas	Kathleen Austin	Gansner Cr	Completed		0.25			2190	250	
Baker-Kosk Creek	Shasta	Joseph And Eleanor Vermilyea	Kosk Cr	Completed		0.27			2365.2	270	
Fleming Hill	Solano	City Of Vallejo, Ca	Fleming Hill Ws Pl(Lake Chabot)	Completed		0.3			2628	300	
Cedar Flat	Trinity	B.C. Hydro, Inc.	Cedar Flat Cr	Completed		0.3			2628	300	
Mud Creek	Butte	Mud Creek Hydro Partners	Mud Cr	Completed		0.3			2628	300	
Combie North	Nevada	Nevada Irrig Dist	Combie N Aque(Bear R)	Completed		0.3			2628	300	
Hammeken's Pwr House Cnl	Mendocino	The Hammeken's	Tailrace Of Pn77	Completed		0.3			2628	300	
Las Poras Basin	Ventura	Calleguas Mun Wtr Dist	Las Posas Basin Aquifer Storage	Completed		0.304	2500	94%	2663.04	304	Base
Mcfadden Farm	Mendocino	Mcfadden, Eugene J. M.	E Fk Russian R	Completed		0.348			3048.48	348	
Columbia Water Supply	Tuolumne	Tuolumne Utilities District (CA)	Columbia Ditch	Completed		0.35	1010	33%	3066	350	Non-Dispatchable
T & G Hydro	Shasta	T & G Hydro	Canyon Cr	Completed		0.35			3066	350	
San Gorgonio Upper	Riverside	City Of Banning, California	Banning Ws Conduit	Completed		0.35			3066	350	
Williams Ave Station	Los Angeles	Three Valleys Mun Wtr Dist	Williams Avenue Conduit	Completed		0.35			3066	350	
Graeagle	Plumas	Henwood Associates Inc	Gray Eagle Cr	Completed		0.36			3153.6	360	
Piute Creek	Mono	Hi-Head Hydro, Inc.	Piute Cr	Completed		0.371			3249.96	371	
Arbuckle Mt	Shasta	Arbuckle Mountain Hydro Partns (Wa)	Middle Fork Cottonwood Creek	Completed		0.4			3504	400	
Power Canal	Mendocino	Bes Hydro Co (CA)	Tailrace Canal Of Project 77	Completed		0.4			3504	400	
Millner Creek 1	Mono	Henwood Associates Inc	Millner Cr	Completed		0.4			3504	400	
Verdugo	Los Angeles	City Of Glendale, California	Metro Wtr Dist Pl(La Aque)	Completed		0.4			3504	400	
Snow Creek	Riverside	Desert Water Agency	Snow Cr	Completed		0.4			3504	400	

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Mwd F-8	Orange	Fullerton Hydro Ptns	Mwd Pl F-8(Colo R Aque)	Completed		0.411			3600.36	411	
Vanjop 1	Placer	South Sutter Water Dist	Conveyance Cnl(Bear R)	Completed		0.415			3635.4	415	
Deer Creek	Tulare	Merrill And Mary Lou Bates, Et Al.	Deer Cr	Completed		0.416			3644.16	416	
San Francisco Peak	San Diego	City Of Oceanside, California	Tri-Agencies Pl(Mwdsc)	Completed		0.42			3679.2	420	
Madera Canal	Madera	Madera-Chowchilla Power Auth (CA)	Usbr Madera Irrigation Canal	Completed		0.44			3854.4	440	
Lytle Creek	San Bernardino	Southern California Edison Co (CA)	Lytle Creek	Completed		0.45	2651	67%	3942	450	Base
Roger Miller	San Diego	Olivenhain Mun Wd	Gaty Res Pl(San Diego Aque)	Completed		0.45			3942	450	
Lost Creek No 2	Shasta	Snow Mountain Hydro Llc	Lost Creek	Completed		0.455			3985.8	455	
Dewey B Smith	Siskiyou	Smith Dewey B	Shasta River	Completed		0.48			4204.8	480	
Jackson Creek	Amador	Jackson Valley Irrig Dist	Jackson Cr	Completed		0.5			4380	500	
Fishwater Release	Fresno	Orange Cove Irrigation Dist (CA)	Bor Friant Dam On San Joaquin River	Completed		0.51			4467.6	510	
High Line Canal	Glenn	Santa Clara City Of (CA)	High Line Canal	Completed		0.53	582	13%	4642.8	530	Peaking
Miramar Treatment	Los Angeles	Three Valleys Mun Wtr Dist	Municipal Water Supply Conduit	Completed		0.535			4686.6	535	
Salmon Creek	Sierra	Henwood Associates Inc	Salmon Cr	Completed		0.6			5256	600	
San Luis Bypass	Merced	Central Ca Irrig Dist	Ccid Outside Cnl	Completed		0.6			5256	600	
Stone Drop	Stanislaus	Modesto Irrig Dist	L Main Cnl(Tuolumne R)	Completed		0.6			5256	600	
Canyon Creek	El Dorado	Eagle Hydro Partners	Canyon Cr	Completed		0.6			5256	600	
Silver Springs	Shasta	Mega Renewables	Silver Springs	Completed		0.6			5256	600	
Bailey Creek	Shasta	Bailey Creek Ranch	Bailey Cr	Completed		0.63			5518.8	630	
North Fork	Riverside	Lake Hemet Muni Wtr Dist	Lake Hemet Mwd Pl	Completed		0.66			5781.6	660	

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
San Luis Obispo	San Luis Obispo	City Of San Luis Obispo, Ca	San Luis Obispo Pl(Santa Margarita	Completed		0.68			5956.8	680	
Mcmillan 1	Shasta	Mcmillan Hydro Inc	N Fk L Cow Cr	Completed		0.699			6123.24	699	
Rock Creek	Calaveras	Rock Creek Wd	Orvis Dth(Rock Cr)	Completed		0.7			6132	700	
San Gorgonio	Riverside	City Of Banning, California	Banning Ws Conduit	Completed		0.728			6377.28	728	
Conejo Pump Station	Ventura	Calleguas Mun Wtr Dist	Calleguas Conduit(Calif Aque)	Completed		0.75			6570	750	
Digger Creek	Tehama	Rugraw, Inc.	S Digger Cr	Completed		0.75			6570	750	
Weber Flat	Trinity	Pan Pacific Hydro Inc	W Fk Trinity Alps Cr	Completed		0.75			6570	750	
Miramar	San Diego	San Diego Co Water Auth	Second Aque Pl(Filtration Plt)	Completed		0.8			7008	800	
Anderson Dam	Santa Clara	Santa Clara Valley Wd	Coyote Cr	Completed		0.8			7008	800	
Gibraltar	Santa Barbara	Santa Barbara Public Works (CA)	Santa Ynez R	Completed		0.82			7183.2	820	
Cottonwood Canyon	Mono	Edw S Cruz & William L Beaver	Lone Tree Cr	Completed		0.84			7358.4	840	
Upper Gorge	Merced	Merced I D & Merced County	Merced M Cnl(Merced R)	Completed		0.9			7884	900	
Fairfield	Merced	Merced I D & Merced County	Fairfield Cnl(Bear Cr)	Completed		0.9			7884	900	
Monte Vista	San Bernardino	Monte Vista Wtr Dist	Muni Wtr Pl(Ca Aque)	Completed		0.91			7971.6	910	
Georgetown Divide Conduit	El Dorado	Georgetown Divide P U D	Georgetown Conduit(Pilot Cr)	Completed		0.925			8103	925	
West Coast Basin Barrier	Los Angeles	Basin Barries Hydro Ltd Pnsp	Pressure Reduction Station	Completed		0.93			8146.8	930	
Five Bears	Plumas	Five Bears Hydro Inc (CA)	Ward Creek	Completed		0.935			8190.6	935	
Tinnemaha & Red Mountain Creeks	Inyo	Sierra Hydro Inc (CA)	Tinemaha River	Completed		0.95			8322	950	
Camp Creek	Butte	Lassen Station Hydroelec L P (Wa)	Camp Creek	Completed		0.99			8672.4	990	

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Tungstar	Inyo	Keating, Joseph M.	Morgan Creek	Completed		0.99			8672.4	990	
Mill And Sulphur Creeks	Humboldt	Mill & Sulfur Creek Power Plt (Wa)	Mill Creek	Completed		0.995			8716.2	995	
Virginia Ranch Dam	Yuba	Browns Valley Irrig Dist	Dry Cr	Completed		1			8760	1000	
Wolfsen By-Pass	Merced	Central Ca Irrig Dist	Ccid Outside Cnl	Completed		1			8760	1000	
Mega Hydro 1	Shasta	Mega Hydro Inc	Clover Cr	Completed		1			8760	1000	
Scotts Flat	Nevada	Nevada Irrig Dist	Deer Cr	Completed		1			8760	1000	
Springville	Ventura	Calleguas Mun Wtr Dist	Oxnard-Santa Rosa Feeder(Calif Aque	Completed		1			8760	1000	
San Dimas Wash	Los Angeles	San Gabriel Valley Mwd	Devil Canyon/Azusa Pl(La Aque)	Completed		1.05			9198	1050	
Drop No 9	Stanislaus	Turlock Irrig Dist	Main Cnl(Tuolumne R)	Completed		1.07			9373.2	1070	
Lost Creek Hydroelectric No 1	Shasta	Snow Mountain Hydro Llc	Lost Creek	Completed		1.1	8164	85%	9636	1100	Base
Ponderosa/Bailey	Shasta	Snow Mountain Hydro Llc	Bailey Creek	Completed		1.1	3639	38%	9636	1100	Intermediate
Grasshopper Flat	Shasta	Nelson Creek Power Inc (CA)	Nelson Creek-East And West Forks	Completed		1.1			9636	1100	
Santa Ana 3	San Bernardino	Southern California Edison Co (CA)	Santa Ana River	Completed		1.2	2974	28%	10512	1200	Intermediate
Kanaka	Butte	Sts Hydropower Ltd (Il)	Sucker Run Cr	Completed		1.2			10512	1200	
East Portal	Los Angeles	Calleguas Mun Wtr Dist	Santa Susana Tunnel(La Aque)	Completed		1.25			10950	1250	
Wtp No2 Supply Line	Alameda	Alameda County Wtr Dist	South Bay Aqueduct	Completed		1.25			10950	1250	
Three Forks	Trinity	Burgess Norman & Mary	Bluford Creek	Completed		1.3			11388	1300	
Point Loma	San Diego	City Of San Diego	Wwt Outfall(San Diego Ws)	Completed		1.35			11826	1350	
Whitewater	Riverside	Desert Water Agency	Colorado R Aque	Completed		1.375			12045	1375	
Kings River Siphon	Fresno	Orange Cove Irrigation Dist (CA)	Friant-Kern Canal	Completed		1.388	2403	20%	12158.88	1388	Intermediate

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Angels	Calaveras	Calaveras County Water Dist (CA)	Angels Creek	Completed		1.4			12264	1400	
Success	Tulare	Lower Tule River Irr District (CA)	Tule River	Completed		1.4	2877	23%	12264	1400	Intermediate
Santa Felicia	Ventura	United Water Conservation Dist (CA)	Piru Creek	Completed		1.42			12439.2	1420	
Re Badger Filt Plt	San Diego	San Diequito Wtr Dist	Pl3+Pl4	Completed		1.485			13008.6	1485	
Baker Creek	Humboldt	Baker Station Associates L.P. (Wa)	Baker Creek	Completed		1.495			13096.2	1495	
Lake Combie	Nevada	Nevada Irrig Dist	Bear R	Completed		1.5			13140	1500	
Escondido	San Diego	Escondido City Of (CA)	San Luis Rey R	Completed		1.64			14366.4	1640	
Santa Ana Low	San Bernardino	San Bernardino Val Mwd	Foothill Pl(Santa Ana R)	Completed		1.7			14892	1700	
Phoenix	Tuolumne	Pacific Gas & Electric Co (CA)	South Fork Stanislaus River	Completed		1.8	9440	60%	15768	1800	Intermediate
Bidwell Ditch	Shasta	Mega Renewables	Irrigation Conduit(Lost Cr)	Completed		1.855			16249.8	1855	
Rio Hondo	Los Angeles	Metro Water Dist Of S Ca	Middle Feeder Pl(Gabriel R)	Completed		1.91			16731.6	1910	
Deadwood Creek	Yuba	Yuba County Water Agency (CA)	Deadwood Creek	Completed		1.963	6030	35%	17195.88	1963	
Roaring Creek	Shasta	Roaring Creek Ranch (CA)	Roaring Creek	Completed		2	7552	43%	17520	2000	Intermediate
R W Matthews	Trinity	Humboldt Bay M U D	Mad R	Completed		2			17520	2000	
Alvarado	San Diego	San Diego Co Water Auth	Second Aque Pl(Filtration Plt)	Completed		2			17520	2000	
San Gorgonio	San Bernardino	Southern California Edison Co (CA)	San Gorgonio River	Completed		2.25	0		19710	2250	
Clear Lake	Lake	Yolo County Fc & Wcd	Cache Cr	Completed		2.5			21900	2500	
Lower Tule	Tulare	Southern California Edison Co (CA)	Tule River	Completed		2.52	19486	88%	22075.2	2520	Base
Montgomery Creek	Shasta	El Dorado Hydro	Montgomery Cr	Completed		2.6			22776	2600	
Rock Springs	San Bernardino	Mojave Water Agency	E Br Ca Aque(Mojave R)	Completed		2.6	10000	44%	22776	2600	Intermediate

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
New Hogan	Calaveras	Calaveras County Water Dist (CA)	New Hogan Dam	Completed		2.65	13813	60%	23214	2650	Intermediate
Slate Creek	Shasta	Catalyst State Creek Hydro Ptnsp	Slate Cr	Completed		2.71			23739.6	2710	
Warm Springs	Sonoma	Sonoma County Water Agency (CA)	Dry Creek	Completed		2.79	12991	53%	24440.4	2790	
Richard B Parker	Merced	Merced I D & Merced County	Merced M Cnl(Merced R)	Completed		2.8			24528	2800	
Woodward	Stanislaus	S San Joaquin Irrig Dist	Simmons Cr	Completed		2.85			24966	2850	
Temescal	Riverside	Metro Water Dist Of S Ca	Nwd L Fdr Pl(Colo Aque)	Completed		2.85			24966	2850	
Corona	Riverside	Metro Water Dist Of S Ca	Mwd L Fdr Pl(Colo R Aque)	Completed		2.85			24966	2850	
Indian Valley	Lake	Yolo County Fc & Wcd	N Fk Cache Cr	Completed		2.9			25404	2900	
Moccasin	Tuolumne	City And County Of San Franciso	L Moccasin Cr	Completed		2.9			25404	2900	
Azusa	Los Angeles	Pasadena City Of (CA)	San Gabriel River	Completed		3	9205	35%	26280	3000	Intermediate
Lundy	Mono	Southern California Edison Co (CA)	Mill Creek	Completed		3	15241	58%	26280	3000	Intermediate
Nichols	Shasta	Tko Power Inc	S Fk Bear Cr	Completed		3			26280	3000	
Coyote Creek	Orange	Metro Water Dist Of S Ca	Lower Fdr Pl(Coyote Cr)	Completed		3.125			27375	3125	
Mill Creek Nos. 2 & 3	San Bernardino	Southern California Edison Co (CA)	Mill Creek	Completed		3.25	10830	38%	28470	3250	Intermediate
Drop No 1	Stanislaus	Turlock Irrig Dist	Main Cnl(Tuolumne R)	Completed		3.261			28566.36	3261	
Merced Falls	Merced	Pacific Gas & Electric Co (CA)	Merced River	Completed		3.44	15605	52%	30134.4	3440	Intermediate
Burney Creek	Shasta	Snow Mountain Hydro Llc	Burney Cr	Completed		3.447			30195.72	3447	
Lake Mendocino	Mendocino	Ukiah City Of (CA)	East Fork Russian River	Completed		3.5	7105	23%	30660	3500	Intermediate
Whiskeytown	Shasta	Redding City Of (CA)	Clear Creek	Completed		3.53	19039	62%	30922.8	3530	Base
Rock Creek	El Dorado	Rock Creek Ltd Partnership (CA)	Rock Creek	Completed		3.544	7428	24%	31045.44	3544	Intermediate

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Utica	Calaveras	Calaveras County Water Dist (CA)	North Fork Stanislaus River	Completed		3.6			31536	3600	
Madera Canal	Madera	Madera-Chowchilla Power Auth (CA)	Usbr Madera Canal	Completed		3.645	6799	21%	31930.2	3645	Intermediate
Santa Ana No 1 & 2	San Bernardino	Southern California Edison Co (CA)	Santa Ana River	Completed		4	19000	54%	35040	4000	Intermediate
Valley View	Orange	Metro Water Dist Of S Ca	Mwd Valley View Pl(Colo R)	Completed		4.1			35916	4100	
Nacimiento	San Luis Obispo	Monterey Co Fc & Wcd	Nacimiento R	Completed		4.351			38114.76	4351	
Olsen	Shasta	Olsen Power Partners (Md)	Old Cow Creek	Completed		4.4	13797	36%	38544	4400	Intermediate
Kilarc - Cow Creek	Shasta	Pacific Gas & Electric Co (CA)	Old Cow Creek	Completed		4.44	37700	97%	38894.4	4440	Base
Upper Dawson	Stanislaus	Turlock Irrig Dist	Main Cnl(Tuolumne R)	Completed		4.45			38982	4450	
Big Creek	Trinity	Big Creek Water Works Ltd	Big Cr	Completed		4.61			40383.6	4610	
Frankenheimer	Stanislaus	S San Joaquin Irrig Dist	Main Cnl(Stanislaus R)	Completed		4.7			41172	4700	
Stony Gorge	Glenn	Santa Clara City Of (CA)	Stony Creek	Completed		4.9	16077	37%	42924	4900	Intermediate
Lake Mathews(Colo Aque)	Riverside	Metro Water Dist Of S Ca	Lake Mathews Cnl	Completed		4.9			42924	4900	
Kekawaka Creek	Trinity	Sts Hydropower Ltd (II)	Kekawaka Creek	Completed		4.95			43362	4950	
San Gabriel	Los Angeles	San Gabriel Hydroelec Pnsp	San Gabriel R	Completed		4.975			43581	4975	
Lake Siskiyou	Siskiyou	Synergics Inc	Sacramento R	Completed		5	18364	42%	43800	5000	Intermediate
Lower Haypress Creek	Sierra	Southern Pacific Land Co	Haypress Cr	Completed		5			43800	5000	
Haypress Creek	Sierra	Southern Pacific Land Co	Haypress Cr	Completed		5			43800	5000	
Cove	Shasta	Snow Mountain Hydro Llc	Hatchet Cr	Completed		5			43800	5000	
Red Mountain	San Diego	Metro Water Dist Of S Ca	Sd 5pl(San Diego Aque)	Completed		5.9			51684	5900	
Tule River	Tulare	Pacific Gas & Electric Co (CA)	Tule River North & Middle Forks	Completed		6.75	19465	33%	59130	6750	Intermediate

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Camp Far West	Yuba	South Sutter Water District (CA)	Bear River	Completed		6.8	38593	65%	59568	6800	
Black Butte	Tehama	Santa Clara City Of (CA)	Black Butte Dam	Completed		6.8	0		59568	6800	
Kaweah	Tulare	Southern California Edison Co (CA)	Kaweah R.(East,Marble & Middle Fks.	Completed		6.85	44238	74%	60006	6850	Base
Hatchet Creek	Shasta	Mega Renewables (CA)	Hatchet Creek	Completed		6.89	29388	49%	60356.4	6890	Intermediate
Chili Bar	El Dorado	Pacific Gas & Electric Co (CA)	South Fork American River	Completed		7	38963	64%	61320	7000	Base
Perris	Riverside	Metro Water Dist Of S Ca	Perris Bypass Pl(San Jacinto R)	Completed		7.94			69554.4	7940	
Rush Creek	Mono	Southern California Edison Co (CA)	Rush Creek	Completed		8.4	67574	92%	73584	8400	Base
Sepulveda Canyon	Los Angeles	Metro Water Dist Of S Ca	Sepulveda Fdr(Colo Aque)	Completed		8.54			74810.4	8540	
Potter Valley	Lake	Pacific Gas & Electric Co (CA)	East Fork Russian R	Completed		9.959	43861	50%	87240.84	9959	Intermediate
Venice	Los Angeles	Metro Water Dist Of S Ca	Sepulveda Fdr(Colo Aque)	Completed		10.12	16524	19%	88651.2	10120	Intermediate
Portal	Fresno	Southern California Edison Co (CA)	Rancheria Creek	Completed		10.8	25232	27%	94608	10800	Intermediate
Lee Vining	Mono	Southern California Edison Co (CA)	Lee Vining Creek	Completed		11.25	33053	34%	98550	11250	Intermediate
Kern Canyon	Kern	Pacific Gas & Electric Co (CA)	Kern River	Completed		11.5	74690	74%	100740	11500	Base
Monticello	Solano	Solano Irrigation District (CA)	Putah Creek	Completed		11.5	64031	64%	100740	11500	Base
Forks Of Butte	Butte	Hypower, Inc.	Butte Creek	Completed		11.6	52289	51%	101616	11600	Intermediate
Isabella	Kern	Isabella Partners (CA)	Kern River	Completed		11.95	72470	69%	104682	11950	Base
Borel	Kern	Southern California Edison Co (CA)	Kern River	Completed		12	66052	63%	105120	12000	Base
Narrows	Nevada	Pacific Gas & Electric Co (CA)	Yuba River	Completed		12	24123	23%	105120	12000	Intermediate
Rio Bravo	Kern	Olcese Water District (CA)	Kern River	Completed		14	55574	45%	122640	14000	Intermediate

Project Name	City/ County	Owner	River	Status	Year Completed	Current Capacity (MW)	Average Annual Production (MWh)	Average Capacity Factor	Potential Annual MWh	Current Capacity (kW)	Base, Intermediate, Peaking Or Non-Dispatchable
Terminus	Tulare	Kaweah River Power Authority (CA)	Kaweah River	Completed		17	63195	42%	148920	17000	Intermediate
Tulloch	Tuolumne	Oakdale & San Joaquin Irr Dist (CA)	Stanislaus River	Completed		17.1	93000	62%	149796	17100	Base
El Dorado	El Dorado	Pacific Gas & Electric Co (CA)	South Fork American River	Completed		20	185	0%	175200	20000	
Hat Creek Nos. 1 & 2	Shasta	Pacific Gas & Electric Co (CA)	Hat Creek	Completed		20	100382	57%	175200	20000	Intermediate
Crane Valley	Madera	Pacific Gas & Electric Co (CA)	Willow Creek North Fork	Completed		20.98	119212	65%	183784.8	20980	Base
Etiwanda	San Bernardino	Metropolitan Water Dist	Etiwanda Pl(Ca Aque)	Completed		23.9	34010	16%	209364	23900	Intermediate
Kern River No 1	Kern	Southern California Edison Co (CA)	Kern River	Completed		26.3	209314	91%	230388	26300	Base
De Sabla	Butte	Pacific Gas & Electric Co (CA)	Butte Creek	Completed		26.65	162359	70%	233454	26650	Base
Friant	Fresno	Friant Power Authority (CA)	San Joaquin River	Completed		27.36	122679	51%	239673.6	27360	Intermediate
Bishop Creek	Inyo	Southern California Edison Co (CA)	Bishop Cr	Completed		28.565	196034	78%	250229.4	28565	Base
Muck Valley	Lassen	Malacha Hydro Ltd Partnership (Md)	Pit River	Completed		29.9			261924	29900	

B
RENEWABLE TECHNOLOGY KEY COMPANIES

Wind Key Companies

Company	Product/Service	Telephone/Fax	CA Based
Bergey Windpower Company, Inc. 2001 Priestley Avenue Norman, OK 73069	Small Turbine Manufacturer	(405) 364-4212 Fax: (405) 364-2078 www.bergey.com	
Enron Wind Corp. 13000 Jameson Road P.O. Box 1910 Tehachapi, CA 93581	Developers, Manufacturers	(661) 823-6700 Fax: (661) 822-7880 www.wind.enron.com	X
EnXco P.O. Box 1043 63-665 19th Avenue North Palm Springs, CA 92258-0177	Consultants, Developers	(760) 329-1437 Fax: (760) 329-1503 www.enXco.com	X
FPL Energy P.O. Box 14000 Juno Beach, FL 33408-0420	Developers	(561) 691-7171 Fax: (561) 691-3615 www.fplenergy.com	
Molded Fiber Glass Companies/West P.O. Box 370 Adelanto, CA 92301-0370	Manufacture (accessories)	(760) 246-4042 Fax: (760) 246-5500 www.moldedfiberglass.com	X
NEG Micon USA, Inc. 1600 Golf Road, Suite 1200 Rolling Meadows, IL 60009	Manufacturers	(847) 981-6800 Fax: (847) 981-6801 www.neg-micon.com	
Oak Creek Energy Systems, Inc. 14633 Willow Springs Road Mojave, CA 93501	Developers	(661) 822-6853 Fax: (661) 822-5991	X
San Gorgonio Farms, Inc. 21515 Hawthorne Boulevard, Suite 1059 Torrance, CA 90503-6557	Developers	(310) 316-7337 Fax: (310) 316-7013 sangorgon@aol.com	X
SeaWest Windpower, Inc. 1455 Frazee Rd. San Diego, CA 92108	Developer	(619) 293-3340 Fax: (619) 293-3347 www.seawestwindpower.com	X
Southwest Windpower P.O. Box 2190 2131 N. First Street Flagstaff, AZ 86003-2190	Manufacturers	(520) 779-9463 Fax: (520) 779-1485 www.windenergy.com	
Vestas-American Wind Tech. P.O. Box 278 19020 N. Indian Avenue, Suite 4C North Palm Springs, CA 92258-0278	Manufacture (accessories), Manufacturers & Dealers	(760) 329-5400 Fax: (760) 329-5558 www.vestas-awt.com	X

Geothermal Key Companies

Company	Product/Service	Phone	CA Based
Caithness/ Coso Operating Co. 900 N. Herritage Drive, Bldg. D Ridgecrest, CA 93555-5517	Developer/Operator	(760) 499-2335 Fax: (760) 499-2308 Robert McCutchen	X
CalEnergy Company, Inc. 2101 L Street NW Washington DC 20037	Developer/Operator	(202) 828-1378 Fax: (202) 828 1380 Jonathon Weisgall	
Calpine Corporation 50 West San Fernando Street San Jose, CA 95113	Developer/Operator	(707) 431-6049 Fax: 408 995-0505 Fred Manuel	X
Fuji Electric Company 268 Wusi Road Fuzhou, 350003 China	Turbine/Generator Sales/Service	(949) 251-9600 Fax: Brett Sato	
Geothermal Power Company, Inc. 1460 West Water Street Elmira, NY 14905	Equipment Supplier	(607) 733-1027 Fax: 607 734 2709 Gary Schulman	
Geothermex, Inc. 5221 Central Avenue, Suite 201 Richmond, CA 94804	Project Development	(510) 527-9876 Fax: (510) 527 8164 Subir Sanyal	X
Ormat International, Inc. 980 Greg Street Sparks, NV 89431	Developer/Operator/Equipment	(775) 356-9029 Fax: (775) 356-9039 Dan Schochet	
Oxbow Power Services, Inc. 9790 Gateway Drive, Suite 220 Reno, NV 89511	Developer/Operator	(775) 851-1199 Fax: 702 850 2211 Vince Zodiaco	
Siemens Energy & Automation, Inc. 4900 Old Ironsides Drive Santa Clara, CA 95052	Equipment Supplier	(513) 841-3296 Fax: 408-492-7572 Dan Palagreco	X

Biomass Key Companies

Company	Product/Service	Phone	CA Based
ABB C-E Services, Inc. 200 Great Pond Dr. Windsor, CT 06095 USA	Stokers, Stokers: Mechanical	(860) 285-5400 Fax: 860-285-9611	
ASEA Brown Boveri, Inc. 2375 Lincoln Ave. Hayward, CA 94545	Manufacturer of IC engines, turbines, and combustion equipment	(510 887-6236	X
Babcock & Wilcox Company 3333 Vaca Valley Rd. Vacaville, CA 95688	Manufacturer of boilers/reactors	(707) 451-1100	X
BG Technologies 10480 Little Patuxent Parkway, Suite 400 Columbia, MD 21044	Mobile and small-scale biomass gasification systems for heat and power	(410) 740-3025 Fax: 208-728-8983 http://www.bgtechnologies.net/	
Capstone Turbine Corporation 6430 Independence Avenue Woodland Hills, CA 91367	Manufacturer of microturbines for LFG projects	(818) 654-1353	X
Caterpillar, Inc. 5491 E. Francis St. Ontario, CA 91761	Manufacturer of IC turbines/engines	(909) 390-1920	X
Coen Company, Inc. 1510-12 Rollins Rd. Burlingame, CA 94010	Manufacturer of high capacity burners and engines for biomass	(650) 697-0440	X
Cooper Industries, Inc. 1351 Harbor Bay Pkwy. Alameda, CA 94502	Manufacturer of IC engines/turbines	(510) 748-7320	X
D B Riley, Inc. 5 Neponset St., P.O. Box 15040 Worcester, MA 01615 0040	IPP/Utility/Industrial Boilers Including Field-Erected, Circulating Fluidized Bed, Waste Fuel	(508) 852-7100 Fax: 508-852-7548; 508-852-7558	
Detroit Stoker Co., Subsidiary Of United Industrial Corporation 1510 East First St. Monroe, MI 48161	Complete Line Of Combustion Equipment For Firing Of Solid, Liquid Or Gaseous Fuels. Stokers, Burners, Fuel Feeders, Overfire Air Systems, Ash Conveying Equipment, Aftermarket Parts, Service, Engineering, Upgrades (Additions & Betterments), Rotary Seal Feeders	(800) 739-9133 Fax: 734-241-7126	
Energy Products Of Idaho (EPI) 4006 Industrial Ave. Coeur d'Alene, ID 83814	Boilers: Steam, Fluidized Bed, Fluid Bed, Boilers: Wood Waste Fired, Energy Recovery, Fluidized Bed Combustion Systems, Steel Fabrication.	(208) 765-1611 Fax: 208-765-0503	

Company	Product/Service	Phone	CA Based
ESI Inc. of Tennessee 1250 Roberts Blvd. Kennesaw, GA 30144	Engineering & Construction Firm That Specializes In Steam & Power Projects. Combusting Of A Wide Range Of Fuels Including Coal, Wood-Waste, Paper Mill Sludge, TDF, Landfill, Gas	(800) 990-0374 Fax: 770-425-3660	
Foster Wheeler Energy Corporation 611 Anton Blvd. Costa Mesa, CA 92626	Manufacturer of boilers/reactors	(714) 444-5500	X
GE Energy and Environmental Research Corp. 18 Mason Irvine, CA 92618	Advanced combustion and NOx reduction Technology including biomass reburn systems	(949) 959-8851	X
Hurst Boiler & Welding Co., Inc. Dept. 33, P.O. Box 529, Hwy. 319 N. Coolidge, GA 31738 0529	For Use With Bituminous & Anthracite Coal. Meets Any Heating, High Pressure Process Steam Or Special Application. Repair Services	(888) 805-3545 Fax: 912-346-3874, Dept. 33	
SCS Engineers 3711-T Long Beach Blvd., 9th Floor Long Beach, CA 90807	Manufacturer of engine/generators for biomass	(562) 426-9544	X
TRIGEN – BioPower, Inc. 205 Regency Executive Park Dr. Suite 305 Charlotte, NC 28217	Biomass to energy service company	(704) 525-5819 Fax: 704-523-4967	
Wellons Inc. P.O. Box 1030 Sherwood, OR 97140 1030	Storage Bins.	(503) 625-6131 Fax: 503-625-5366	

Solar-thermal Key Companies

Company	Product/Service	Phone	CA Based
Boeing Company (SES/Boeing Test Site) 5301 Bolsa Avenue Huntington Beach CA 92647	Dish Stirling solar thermal electric system	Tel 714-896-1164 Fax --- Ken Stone kenneth.w.stone@boeing.com	
SAIC 10260 Campus Point Dr. Stop C2j San Diego, CA 92121-1522	25 kW dish Stirling solar thermal electric system	(858) 546-6004 Fax: (858) 546-6335 Barry Butler barry.l.butler@saic.com	X
KJC Operating Co. 41100 Hwy 395 Boron CA 93516	Operators: 150 MWe parabolic-trough solar thermal electric system	(760) 762-5562 Fax: (760) 762-5546 Scott Frier sfrier@kjcsolar.com	X
Nexant, Inc. (A Bechtel Technology & Consulting Company) 45 Freemont Street, 7th Floor San Francisco, CA 94105	MW-scale power-tower solar thermal electric system: develop; engineer; procure; construct	415-768-2342 Fax: 415-768-3580 William Gould wrgould@nextant.com	X
Stirling Energy Systems, Inc. 6245 N 24th Parkway, Ste 209 Phoenix, AZ 85016	25 kW dish Stirling solar thermal electric system	602-957-1816 Fax: 602-957-1919 Robert Liden, President rliden@stirlingenergy.com	
Industrial Solar Technology 4420 McIntyre Street Golden, CO 80403-1836	Parabolic-trough solar thermal electric system	3032798108 Fax: 3032798107 Kenneth May, President mayek@aol.com	
MWE & Associates 11022 Winners Circle, Ste. 208 Los Alamedas, CA 90720	Engineering for solar thermal electric systems	(562) 594-7190 Fax: (562) 594-7195 C. E. Miller, President cemiller@ix.netcom.com	X
Duke Solar Energy, LLC P.O. Drawer 10 Sanford, NC 27330	kW-MW scale solar thermal electric systems as well as process heat and cooling systems	(919) 774-4000 Fax: (919) 774-1979 John Myles, CEO srisolar@aol.com	

Photovoltaic Key Companies

Company	Product/Service	Phone	CA Based
Astropower 5036 Commercial Circle Suite B Concord, CA 94520	Manufacturer of modules and solar cells - installing	(925) 288-0400 Fax: (925) 288-0404	X
BP Solarex (BP Amoco and Solarex) 989 Corporate Drive Linthicum, MD 21090	World leader of manufacturing and technology development of photovoltaic products and systems.	Fax: (301) 698-4201	
IDACORP Technologies 1221 West Idaho St. Boise, ID 83702	Energy management, including electricity and natural gas.	(888) 388-5705	
Pacific Solar 1725 E Bayshore Road #103, Redwood City, CA 95063	Design and installation of grid-connected PV systems	(650) 556-9450 Fax: (650) 556-9451 Marianne Walpert	X
Powerlight 2954 San Pablo Ave. Berkeley, CA 94710	Manufacturer of complete kits of PV products, and is a bondable turn-key contractor for systems installation. Project development, management, design, construction, facilities management, and analysis services in support of its clients.	(510) 540-0550 Fax: (510) 540-0552	X
Real Goods Trading Company 200 Clara Avenue Ukiah, CA 95482	Complete resource; photovoltaic, wind, hydro systems; efficient appliances, lighting and refrigeration	(707) 468-9292 Fax: (707) 468-9394 Jeff Oldham	X
Siemens Solar 4650 Adohr Lane Camarillo, CA 93012-6032	Leading manufacturer and developer of photovoltaic modules and systems	(805) 388-6289 Fax: (805) 388-6395 Arthur Rodin	X
Solar Depot 61 Paul Drive San Rafael, CA 94903	Designer, integrator, supplier and component wholesaler of solar electric systems	(415) 499-1333 Fax: (415) 499-0316 Kija Mizany	X
Solar Electrical Systems 13700 W 108th Street Lenexa, KS 66215	Solar backup power systems, Y2K products, beacons and area lights	(913) 338-1939 Fax: (913) 469-5522 Bill Roush	

Hydropower Key Companies

Company	Product/Service	Phone	CA Based
Alstom Power 7921 South Park Plaza Littleton, CO 80120	Major Integrated Supplier of Turbines, Generators, and Controls	(303) 730-4008	
American Hydro Corporation 135 Stonewood Road P.O. Box 3628 York, PA 17402	Major Hydraulic Turbine Suppliers	(717) 755-5300	
Atkinson Construction Corporation 200 Union Blvd, Suite 400 Lakewood, CO 80228	Project Construction (including lead turnkey contracting)	(303) 985-1660	
Barnard Construction Company 701 Gold Ave Bozeman, MT 59715-2453	Project Construction (including lead turnkey contracting)	(406) 586-1995	
California Department of Water Resources 4201 S Sabodan St. Bakersfield, CA 93313	Project Developer	(661) 858-5500	X
CHI Energy, Inc. 680 Washington Boulevard, 5th Floor Stamford, CT 06901	Project Developer	(203) 425-8850	
Dillingham Construction Corporation 5960 Inglewood Drive Pleasonton, CA 94558	Project Construction (including lead turnkey contracting)	(925) 463-3300	X
Dix Corporation 4024 S Grove Road Spokane, WA 99224-5320	Project Construction (including lead turnkey contracting)	(509) 838-4455	
ENRON 333 Clay Street, Suite 3700 Houston, TX 77002	Project Developer	(713) 646-7236	
GE Hydro Power, Inc. 140 Geary Street, Suite 800 San Francisco, CA 94108	Major Integrated Supplier of Turbines, Generators, and Controls	(415) 392-6462	X
Ida-West Energy Company 3380 Americana Terrace, Suite 300 Boise, ID 83706	Project Developer	(208) 395-8930	
Ideal Electric Company 330 E 1st St Mansfield, OH 44902	Major Generator Suppliers	(419) 522-3611	
IMPSA International Manor Oak II, Suite 536 1910 Cochran Road Pittsburgh, PA 15220	Major Hydraulic Turbine Suppliers	(412) 344-7003	

Company	Product/Service	Phone	CA Based
L&S Electric Inc. 5101 Mesker Street Schofield, WI 54476	Controls Systems Suppliers	(715) 359-3155	
MODCOMP 1650 West McNab Road Fort Lauderdale, FL 33309	Controls Systems Suppliers	(954) 974-1380	
National Electric Coil 800 King Ave Columbus, OH 43212	Major Generator Suppliers	(614) 488-1151	
Pacific Gas and Electric 77 Beale Street San Francisco, CA 94105	Project Developer	(415) 973-7000	X
Peter Kiewit Sons Inc. 10704 Shoemaker Ave Santa Fe Springs, CA 90607	Project Construction (including lead turnkey contracting)	(562) 946-1816	X
Southern California Edison 1201 K Street Sacramento, CA 95814	Project Developer	(916) 441-3966	X
TIC – The Industrial Company 2211 Elk River Road Steamboat Springs, CO 80487	Project Construction (including lead turnkey contracting)	(970) 879-2561	
Toshiba Corporation Power Systems & Services Company 1-1 Shibaura 1-chome Minato-ku Tokyo 105-8001 Japan	Major Hydraulic Turbine and Generator Supplier	81 3 3457 3612	
VA Tech Voest MCE Corporation 1255 Post Street, Suite 946 San Francisco, CA 94109	Major Integrated Supplier of Turbines, Generators, and Controls	(415) 441-7230	X
Voith Siemens Hydropower Generation P.O. Box 712 York, PA 17405	Major Integrated Supplier of Turbines, Generators, and Controls	(717) 792-7000	X

C
AIR-EMISSIONS REDUCTIONS AND ECONOMIC BENEFITS OF RENEWABLE ENERGY

Introduction

The benefits of electricity generation from renewable resources are assumed for this report to include the following:

- Atmospheric-emissions reductions
- Taxes paid to State and local governments
- Benefits associated with using biomass solid fuels

In principle, one could also include as economic benefits other payments into State and local economies in California, such as payroll wages for power-plant construction, maintenance, operation, and repair, as well as truck-driver and transportation-fuel payments. However, although these additional payments are used in the method described in this appendix to calculate the tax benefits, they are not included in the overall benefits described in the main report.

Atmospheric Emissions Reductions

The air emissions avoided through use of renewable resources rather than fossil fuels are tabulated in this report for all the conventional ("criteria") pollutants as well as for greenhouse gases. However, air-emission reductions are given a dollar value only for the criteria pollutants, as greenhouse-gas emissions do not yet have a generally accepted economic value.

Except for oxides of sulfur (SO_X), biomass power generation is not expected to reduce any of the criteria pollutants relative to the fossil sources that it would displace in California. The emission reductions achieved via biomass power are only in greenhouse gases, SO_X, and some special cases of emissions avoided from non-power sources, such as wildfires and open burning of agricultural residues in fields. These special cases for biomass are calculated in the section below on "other" benefits.

Details on Emissions Calculations

Emission offsets are derived from the Section VIII scenarios and factors that convert electricity generated from renewable sources into the corresponding emissions avoided because the electricity would otherwise have been generated using fossil fuels. Two sets of conversion factors are used, one for the existing fleet of renewable-energy generators, and a second for all

new renewable resources. The existing renewables are assumed to displace only the fossil-fueled component of the existing generation mix, while new renewable-energy plants are assumed to displace new natural-gas-fired generation. The criteria-pollutant conversion factors for the existing renewables are derived from California Air Resources Board estimates of current emissions from electricity generation and California Energy Commission estimates of current generation mix.[1] The conversion factors for CO_2 and new renewables are derived from CEC estimates of total generation and EPRI data on advanced natural-gas technologies.[2,3]

As mentioned, biomass is treated differently for emissions reduction from the other renewables, except for greenhouse gases. It is credited with no reduction in non-sulfur criteria pollutants because biomass combustion emits no less of these pollutants than do fossil-fuel sources. But it gets half as much credit as the other renewables for SO_X reduction because biomass fuels contain smaller amounts of sulfur than do coal and oil. (None of the renewables receives net credit versus natural gas for SO_X reduction, because the latter is virtually sulfur-free.)

Greenhouse-gas (carbon dioxide or CO_2) emission avoidance for biomass is the same as for the other renewables, because the emitted CO_2 contains only non-fossil carbon. The landfill gas (LFG) and digester-gas portions of biomass power generation also reduce organic (TOG and ROG) emissions from their fuel sources. This is potentially important because methane, a major component of TOG, has 21 times the warming potential of CO_2 per unit weight. (Note, however, that the avoided organic sources are not found in the power-generation sector for CARB's analysis, but instead in municipal solid-waste disposal, municipal wastewater treatment, and animal agriculture) However, the majority of these potential emissions in California is already avoided by flaring, if not by existing biomass generation. Therefore, no TOG or ROG emission reduction is assigned to biomass in this analysis. Table C-1 gives the assumed biomass and non-biomass sets of emission-conversion factors for both existing and new renewable-energy generation.

Table C-1
Conversion Factors and Market Values for Avoided Air Emissions

	Market Value ($/Tonne)	Tonne/GWh			
		Non-Biomass		Biomass	
		Existing	New	Existing	New
CO_2	$0	707	400	707	400
NO_X	$21,289	0.216	0.216	0	0
SO_X	$12,615	0.016	0	0.008	0
CO	$8,536	0.192	0.192	0	0
TOG	$0	0.158	0	0	0
ROG	$7,224	0.025	0	0	0
PM	$0	0.028	0	0	0
PM10	$18,763	0.025	0	0	0

[1] Found respectively at http://www.arb.ca.gov/emisinv/emsmain/emsmain.htm and http://www.energy.ca.gov/electricity/electricitygen.html.

[2] Market Clearing Prices Under Alternative Resource Scenarios – 2000-2010, California Energy Commission P300-00-001

[3] Tables 5-2 and 5-3 of TR-113785,*Greenhouse Gas Reduction with Renewables*, EPRI, December 2000.

Except for CO_2, which yet has no accepted monetary value, it is possible to assign approximate dollar values to these avoided emissions. The values shown in Table C-1 were based on averages of recent California market data collected by CARB.[4]

Taxes paid to State and local governments

The tax benefits considered in this appendix derive from taxes on property values, payroll wages for power-plant construction, maintenance, operation, and repair, and truck-driver and transportation-fuel payments. The remainder of this section describes the methods of estimating the cost elements of near-future renewable-energy plants to show their approximate all-in costs of electricity generation, as well as to calculate the bases for these local tax benefits from the assumed properties of the various renewable-energy power plants. It must be emphasized that the performance and cost assumptions shown in this section are intended only to illustrate likely characteristics for the next 5–10 years—*these data are not to be mistaken for "best case" or maximum achievable performance over the long term.* Continued research and development will almost certainly supersede these characteristics within the next decade or so.

Technology Properties

Table C-2 shows approximate cost breakdowns of the renewable power generation sources relevant to this report. The ten assumed values used in the calculation are in boldface type, while calculated results are plainface type. The assumptions include:

1. plant capacity (technology dependent)
2. capital-equipment cost (technology dependent)
3. capacity factor (technology dependent)
4. number of operating employees (technology dependent)
5. average employee salary (assumed to be $50,000)
6. salary fringe-benefit rate (assumed to be 40%)
7. maintenance cost (taken to be a fraction of the capital cost)
8. fuel cost (technology dependent)
9. fuel-use heat rate (technology dependent)
10. rate of owner's capital-recovery cost (20%, which includes taxes and interest payments).

[4] Prices Paid in Dollars Per Ton for Offsets (Table 1) in "Emission Reduction Offsets Transaction Cost Summary Report for 2000" <http://www.arb.ca.gov/erco/erco.htm>

The last row of Table C-2 then gives the all-in cost of electricity for each plant, including the effects of all these assumptions.

Table C-3 continues from the cost breakdowns of Table C-2 to develop the four "technical parameters" used in the benefits estimates of Section VIII and this appendix: (1) numbers of construction employees per megawatt of new capacity, (2) numbers of operations and maintenance employees per megawatt of existing plants, (3) taxes paid to State and local governments, and (4) other benefits of solid-fuel biomass use, as described in Section IV and later in this appendix. Except in the cases of geothermal and solid-fuel biomass energy, which have significant hauling costs, the first three of these parameters are entirely derived in Table C-3 using the results of Table C-2 plus four added assumptions, whose values are boldfaced in the table:

1. Local construction labor consumes 20% of plant capital cost.

2. Local maintenance labor consumes 50% of total maintenance cost.

3. The effective local tax rate on payrolls is 2.5%.

4. The effective local property tax rate is 1.0% of plant capital cost.

Driver and Fuel Costs for Solid-Fuel Biomass and Geothermal Truck Transportation

For solid-fuel biomass power generation, the cost of fuel transportation can be substantial and truck-driver wages can be an important part of the State and local spending that this analysis is intended to quantify. Geothermal energy is also included here because it requires hauling of chemicals for control of air pollution (for example, hydrogen sulfide emissions), scale deposits, or brine-caused corrosion. Hauling these chemicals or associated solid wastes can present an appreciable cost, although not relatively as large as biomass fuel hauling. Table C-4 gives details of assumptions used in calculating the payrolls, numbers of drivers, and tax consequences for truck driving and fuel.

Table C-2
Technology Properties for Benefits Calculations

Item, Units	**Wind**	**Geo-therm.**	**Bio-mass**	**LFG/-biogas**	**Solar Therm.**	**Solar PV**	**Small Hydro**
Plant size, MW	**50**	**50**	**50**	**2**	**100**	**0.01**	**0.1**
Capital cost, $/kW	**900**	**1400**	**1500**	**1300**	**2000**	**2500**	**2000**
Capacity factor	**35%**	**90%**	**80%**	**70%**	**30%**	**24%**	**55%**
Generation, MWh/year	153,300	394,200	350,400	12,264	262,800	21	482
Number of employees	**8**	**40**	**40**	**4**	**8**	**0.001**	**0.1**
Employee salary "payroll"	**$50,000**	**$50,000**	**$50,000**	**$50,000**	**$50,000**	**$50,000**	**$50,000**
Fringe benefit rate	**40%**	**40%**	**40%**	**40%**	**40%**	**40%**	**40%**
Cost/employee to employer	$70,000	$70,000	$70,000	$70,000	$70,000	$70,000	$70,000
(1) Operating cost, $/MWh	$3.65	$7.10	$7.99	$22.83	$2.13	$3.33	$14.53
Maintenance, % of cap cost	**2.0%**	**7.0%**	**3.0%**	**3.0%**	**1.0%**	**0.1%**	**1.0%**
(2) Maintenance cost, $/MWh	$5.87	$12.43	$6.42	$6.36	$7.61	$1.19	$4.15
Fuel cost, $/MBtu	**none**	**none**	**$1.50**	**$0.50**	**none**	**none**	**none**
Heat Rate, MBtu/MWh	**n.a.**	**30**	**14**	**11**	**n.a.**	**n.a.**	**n.a.**
(3) Fuel cost, $/MWh	zero	zero	$21.00	$5.50	zero	zero	zero
Cap. cost recovery, %	**20%**	**20%**	**20%**	**20%**	**20%**	**20%**	**20%**
(4) Capital cost (incl. tax), $/MWh	$58.71	$35.51	$42.81	$42.40	$152.21	$237.82	$83.02
Tot. (1-4) electricity cost, $/MWh	$68.23	$55.05	$78.22	$77.09	$161.95	$242.34	$101.70

Table C-3
Payroll, Taxes, and Other Values

Item, Units	Wind	Geo-therm.	Bio-mass	LFG/-biogas	Solar Therm.	Solar PV	Small Hydro
Frac. local labor of new constr.	**20%**	**20%**	**20%**	**20%**	**20%**	**20%**	**20%**
Frac. local labor of maint. cost	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**
Local tax rate on payrolls	**2.5%**	**2.5%**	**2.5%**	**2.5%**	**2.5%**	**2.5%**	**2.5%**
Prop. tax rate, % of capital cost	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**
Property tax, $/MW	$9,000	$14,000	$15,000	$13,000	$20,000	$25,000	$20,000
Operations payroll, $/MW	$8,000	$40,000	$40,000	$100,000	$4,000	$5,000	$50,000
Maint. local labor payroll, $/MW	$6,429	$35,000	$16,071	$13,929	$7,143	$893	$7,143
Truck driver payroll, $/MW	$0	$8,475	$20,318	$0	$0	$0	$0
Loc. tax on O-M-T pay, $/MW	$361	$2,087	$1,910	$2,848	$279	$147	$1,429
Local taxes on truck fuel, $/MW	$0	$670	$1,303	$0	$0	$0	$0
Result: Numbers used for "Technical Parameters" in RE Benefits Calculator							
Construction employees, #/MW	2.57	4.00	4.29	3.71	5.71	7.14	5.71
O-M-T employees, #/MW	0.29	1.67	1.53	2.28	0.22	0.12	1.14
Taxes, $/MW	$9,361	$16,757	$18,213	$15,848	$20,279	$25,147	$21,429
Other benefits, $/MWh	$0.00	$0.00	$15.51	$0.00	$0.00	$0.00	$0.00

Table C-4
Truck Transportation Costs, Payroll, and Taxes

	Geotherm.	Biomass
Truck driver payroll:		
Fuel heat content, MBtu/dt	not appl.	**16**
Fuel feedrate in dry tons (dt), dt/MWh	" "	1.0
Moisture content, wgt.% (wet)	" "	**30%**
Load on truck, tons (wet)	**20**	**20**
Load on truck, tons (dry)	not appl.	14
Truck loads per MWh	**0.01**	0.06
Round-trip distance, miles	**200**	**70**
Average speed, mph	**50**	**45**
Load/unload time per rt, hours	**0.30**	**0.30**
Driver payroll, $/MWh	$1.08	$2.90
Fuel for trucks:		
Miles per gallon, mpg	**4.0**	**4.0**
Fuel cost per gallon, $/gal	**$1.70**	**$1.70**
State/local fuel tax rate	**10%**	**10%**
Truck fuel cost, $/MWh	$0.85	$1.86
State/local tax, $/MWh	$0.09	$0.19

Other Benefits

Solid-fuel biomass use has benefits that are not accounted for in the above items. These added benefits were estimated in a 1996 study done for the U.S. DOE Western Regional Biomass Energy Program (WRBEP) managed by EPRI. That study, cited and summarized in the biomass section of this report (Section IV), gave about $178 million in benefits from a 800 MW biomass power industry in California in 1992, at the peak of biomass power generation from solid-fuel biomass (i.e., not including landfill and digester gas). Because $67 million of the WRBEP result was payroll benefits, which are estimated separately here, the net result is about $110 million in other benefits not included above. Table C-5 enumerates these benefits from the 1992 industry. It also shows results of a calculation of the equivalent benefits for the year-2000 industry, based on that year's total generation and an assumed improvement in average heat rate from 20 to 16 MBtu/MWh. The bottom-line value used in the scenario calculations for "other" biomass benefits is then $15.51/MWh. Note that only the biomass solid fuel power plants are included for this benefit—i.e., the LFG/biogas plants and the MSW-based plants are not included.

Table C-5
Other Benefits of Solid-Fuel Biomass Power Generation

Industry Basis Year	Generation MWh	Capacity MW	Heat Rate MBtu/MWh
1992	5,606,000	800	20
2000	4,461,000	771	16

1992 Benefit Source	Benefit Value	
(from 1996 WRBEP Study)	**$million**	**$/MWh**
Open burn emissions	$26.7	$4.76
Wildfire emissions	$29.7	$5.30
Greenhouse emissions	$1.0	$0.00
Extension of landfill life	$20.6	$3.67
Wildfire risk reduction	$1.0	$0.18
Forest health improvement	$0.4	$0.07
Disposal benefits (vs open burning)	$30.3	$5.40
1992 Total of "Other" Benefits	**$109.7**	**$19.39**
2000 Calculated "Other" Benefits	**$69.2**	**$15.51**

Detailed Benefits Calculation Results

The 24 tables on the following pages present the complete results of the three forecast scenarios described in Section VIII. The first 20 tables show a single evolution scenario for an individual technology; and the final 4, a sum of all seven renewable-energy technology components of a single scenario.

Table C-6
Wind Scenario A1

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,646	1,646	1,809	1,972	1,972	1,972	1,972	1,972	1,972	1,972	1,972
Capacity Factor	24%	24%	26%	27%	27%	27%	27%	27%	27%	27%	27%
Percent of Peak Load	3.4%	3.4%	3.6%	3.9%	3.8%	3.8%	3.8%	3.7%	3.6%	3.6%	3.5%
Generation (GWh)	3,500	3,500	4,054	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601
Percent of Generation	1.3%	1.2%	1.4%	1.6%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%
Employment (#)	475	475	941	988	569	569	569	569	569	569	569
Avoided Emissions											
CO2 (Tonne/day)	6,783	6,783	7,390	7,989	7,989	7,989	7,989	7,989	7,989	7,989	7,989
NOx (Tonne/day)	2.07	2.07	2.40	2.72	2.72	2.72	2.72	2.72	2.72	2.72	2.72
SOx (Tonne/day)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
CO (Tonne/day)	1.84	1.84	2.13	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41
TOG (Tonne/day)	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51
ROG (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
PM (Tonne/day)	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
PM10 (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Emis. Ben. ($Million)	24.80	24.80	28.25	31.66	31.66	31.66	31.66	31.66	31.66	31.66	31.66
Taxes ($Million)	15.41	15.41	16.93	18.46	18.46	18.46	18.46	18.46	18.46	18.46	18.46
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	40.21	40.21	45.19	50.12	50.12	50.12	50.12	50.12	50.12	50.12	50.12

Table C-7
Wind Scenario A2

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,646	1,646	1,971	2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296
Capacity Factor	24%	24%	27%	28%	28%	28%	28%	28%	28%	28%	28%
Percent of Peak Load	3.4%	3.4%	3.9%	4.5%	4.4%	4.5%	4.4%	4.3%	4.2%	4.2%	4.1%
Generation (GWh)	3,500	3,500	4,604	5,685	5,685	5,685	5,685	5,685	5,685	5,685	5,685
Percent of Generation	1.3%	1.2%	1.6%	2.0%	1.9%	1.9%	1.9%	1.9%	1.8%	1.8%	1.8%
Employment (#)	475	475	1,404	1,498	663	663	663	663	663	663	663
Avoided Emissions											
CO2 (Tonne/day)	6,783	6,783	7,993	9,177	9,177	9,177	9,177	9,177	9,177	9,177	9,177
NOx (Tonne/day)	2.07	2.07	2.72	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36
SOx (Tonne/day)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
CO (Tonne/day)	1.84	1.84	2.42	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98
TOG (Tonne/day)	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51
ROG (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
PM (Tonne/day)	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
PM10 (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Emis. Ben. ($Million)	24.80	24.80	31.68	38.41	38.41	38.41	38.41	38.41	38.41	38.41	38.41
Taxes ($Million)	15.41	15.41	18.45	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	40.21	40.21	50.13	59.90	59.90	59.90	59.90	59.90	59.90	59.90	59.90

Table C-8
Wind Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,646	1,646	1,890	2,134	2,415	2,737	3,108	3,535	4,026	4,590	5,239
Capacity Factor	24%	24%	26%	27%	28%	29%	30%	30%	31%	32%	32%
Percent of Peak Load	3.4%	3.4%	3.8%	4.2%	4.7%	5.3%	6.0%	6.7%	7.4%	8.3%	9.3%
Generation (GWh)	3,500	3,500	4,329	5,143	6,004	6,994	8,133	9,442	10,948	12,680	14,671
Percent of Generation	1.3%	1.2%	1.5%	1.8%	2.0%	2.4%	2.7%	3.1%	3.5%	4.0%	4.6%
Employment (#)	475	475	1,173	1,243	1,418	1,620	1,851	2,118	2,424	2,776	3,181
Avoided Emissions											
CO2 (Tonne/day)	6,783	6,783	7,691	8,584	9,527	10,612	11,860	13,295	14,945	16,842	19,025
NOx (Tonne/day)	2.07	2.07	2.56	3.04	3.55	4.13	4.81	5.58	6.47	7.49	8.67
SOx (Tonne/day)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
CO (Tonne/day)	1.84	1.84	2.27	2.70	3.15	3.67	4.27	4.96	5.75	6.65	7.70
TOG (Tonne/day)	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51
ROG (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
PM (Tonne/day)	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
PM10 (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Emis. Ben. ($Million)	24.80	24.80	29.96	35.04	40.40	46.56	53.65	61.81	71.18	81.97	94.37
Taxes ($Million)	15.41	15.41	17.69	19.98	22.60	25.62	29.10	33.09	37.69	42.97	49.04
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	40.21	40.21	47.66	55.01	63.00	72.19	82.75	94.90	108.87	124.94	143.41

Table C-9
Wind Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,646	1,646	1,890	2,134	2,439	2,820	3,297	3,893	4,637	5,568	6,731
Capacity Factor	24%	24%	26%	27%	28%	29%	30%	31%	32%	32%	33%
Percent of Peak Load	3.4%	3.4%	3.8%	4.2%	4.7%	5.5%	6.3%	7.3%	8.6%	10.1%	12.0%
Generation (GWh)	3,500	3,500	4,329	5,143	6,079	7,249	8,711	10,539	12,823	15,679	19,249
Percent of Generation	1.3%	1.2%	1.5%	1.8%	2.1%	2.5%	2.9%	3.5%	4.2%	5.0%	6.0%
Employment (#)	475	475	1,173	1,243	1,488	1,794	2,177	2,655	3,253	4,000	4,934
Avoided Emissions											
CO2 (Tonne/day)	6,783	6,783	7,691	8,584	9,609	10,891	12,493	14,496	17,000	20,130	24,042
NOx (Tonne/day)	2.07	2.07	2.56	3.04	3.59	4.28	5.15	6.23	7.58	9.27	11.38
SOx (Tonne/day)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
CO (Tonne/day)	1.84	1.84	2.27	2.70	3.19	3.80	4.57	5.53	6.73	8.23	10.10
TOG (Tonne/day)	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51
ROG (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
PM (Tonne/day)	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
PM10 (Tonne/day)	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Emis. Ben. ($Million)	24.80	24.80	29.96	35.04	40.87	48.15	57.25	68.64	82.86	100.65	122.88
Taxes ($Million)	15.41	15.41	17.69	19.98	22.83	26.40	30.86	36.44	43.41	52.12	63.01
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	40.21	40.21	47.66	55.01	63.70	74.55	88.12	105.07	126.27	152.77	185.89

Table C-10
Geothermal Scenario A

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,754	1,754	1,813	1,953	1,953	1,953	1,953	1,953	1,953	1,953	1,953
Capacity Factor	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
Percent of Peak Load	3.6%	3.6%	3.6%	3.8%	3.8%	3.8%	3.7%	3.7%	3.6%	3.5%	3.5%
Generation (GWh)	13,223	13,223	13,668	14,723	14,723	14,723	14,723	14,723	14,723	14,723	14,723
Percent of Generation	4.8%	4.7%	4.8%	5.1%	5.0%	5.0%	4.9%	4.9%	4.8%	4.7%	4.6%
Employment (#)	2,928	2,928	3,263	3,821	3,261	3,261	3,261	3,261	3,261	3,261	3,261
Avoided Emissions											
CO2 (Tonne/day)	25,625	25,625	26,112	27,269	27,269	27,269	27,269	27,269	27,269	27,269	27,269
NOx (Tonne/day)	7.81	7.81	8.08	8.70	8.70	8.70	8.70	8.70	8.70	8.70	8.70
SOx (Tonne/day)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
CO (Tonne/day)	6.94	6.94	7.17	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73
TOG (Tonne/day)	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71
ROG (Tonne/day)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
PM (Tonne/day)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
PM10 (Tonne/day)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Emis. Ben. ($Million)	93.71	93.71	96.48	103.05	103.05	103.05	103.05	103.05	103.05	103.05	103.05
Taxes ($Million)	29.39	29.39	30.38	32.73	32.73	32.73	32.73	32.73	32.73	32.73	32.73
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	123.10	123.10	126.86	135.78	135.78	135.78	135.78	135.78	135.78	135.78	135.78

Table C-11
Geothermal Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,754	1,754	1,813	1,953	1,983	2,015	2,051	2,090	2,133	2,181	2,233
Capacity Factor	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
Percent of Peak Load	3.6%	3.6%	3.6%	3.8%	3.8%	3.9%	3.9%	3.9%	3.9%	4.0%	4.0%
Generation (GWh)	13,223	13,223	13,668	14,723	14,946	15,190	15,459	15,755	16,081	16,439	16,833
Percent of Generation	4.8%	4.7%	4.8%	5.1%	5.1%	5.2%	5.2%	5.2%	5.2%	5.2%	5.3%
Employment (#)	2,928	2,928	3,263	3,821	3,428	3,494	3,566	3,646	3,734	3,831	3,937
Avoided Emissions											
CO2 (Tonne/day)	25,625	25,625	26,112	27,269	27,513	27,781	28,076	28,400	28,757	29,150	29,581
NOx (Tonne/day)	7.81	7.81	8.08	8.70	8.83	8.98	9.14	9.31	9.50	9.71	9.95
SOx (Tonne/day)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
CO (Tonne/day)	6.94	6.94	7.17	7.73	7.84	7.97	8.11	8.27	8.44	8.63	8.83
TOG (Tonne/day)	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71
ROG (Tonne/day)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
PM (Tonne/day)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
PM10 (Tonne/day)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Emis. Ben. ($Million)	93.71	93.71	96.48	103.05	104.44	105.96	107.64	109.48	111.51	113.74	116.19
Taxes ($Million)	29.39	29.39	30.38	32.73	33.22	33.76	34.36	35.02	35.74	36.54	37.42
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	123.10	123.10	126.86	135.78	137.66	139.73	142.00	144.50	147.25	150.28	153.61

Table C-12
Geothermal Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,754	1,754	1,813	1,953	1,983	2,015	2,140	2,290	2,470	2,686	2,945
Capacity Factor	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
Percent of Peak Load	3.6%	3.6%	3.6%	3.8%	3.8%	3.9%	4.1%	4.3%	4.6%	4.9%	5.2%
Generation (GWh)	13,223	13,223	13,668	14,723	14,946	15,190	16,133	17,263	18,620	20,249	22,203
Percent of Generation	4.8%	4.7%	4.8%	5.1%	5.1%	5.2%	5.4%	5.7%	6.0%	6.4%	6.9%
Employment (#)	2,928	2,928	3,263	3,821	3,428	3,494	4,073	4,423	4,844	5,348	5,954
Avoided Emissions											
CO2 (Tonne/day)	25,625	25,625	26,112	27,269	27,513	27,781	28,814	30,053	31,540	33,324	35,466
NOx (Tonne/day)	7.81	7.81	8.08	8.70	8.83	8.98	9.53	10.20	11.00	11.97	13.12
SOx (Tonne/day)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
CO (Tonne/day)	6.94	6.94	7.17	7.73	7.84	7.97	8.47	9.06	9.77	10.63	11.65
TOG (Tonne/day)	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71
ROG (Tonne/day)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
PM (Tonne/day)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
PM10 (Tonne/day)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Emis. Ben. ($Million)	93.71	93.71	96.48	103.05	104.44	105.96	111.83	118.87	127.32	137.46	149.63
Taxes ($Million)	29.39	29.39	30.38	32.73	33.22	33.76	35.86	38.37	41.39	45.01	49.35
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	123.10	123.10	126.86	135.78	137.66	139.73	147.69	157.25	168.71	182.47	198.98

Table C-13
Solid-Fuel Biomass Scenario A

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	771	771	907	907	907	907	907	907	907	907	907
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	1.6%	1.6%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%
Generation (GWh)	4,461	4,461	5,248	5,248	5,248	5,248	5,248	5,248	5,248	5,248	5,248
Percent of Generation	1.6%	1.6%	1.8%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%
Employment (#)	1,178	1,178	1,969	1,386	1,386	1,386	1,386	1,386	1,386	1,386	1,386
Avoided Emissions											
CO2 (Tonne/day)	8,644	8,644	9,507	9,507	9,507	9,507	9,507	9,507	9,507	9,507	9,507
NOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOx (Tonne/day)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
CO (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Taxes ($Million)	14.04	14.04	16.52	16.52	16.52	16.52	16.52	16.52	16.52	16.52	16.52
Other ($Million)	69.19	69.19	81.40	81.40	81.40	81.40	81.40	81.40	81.40	81.40	81.40
Total Benefits ($Million)	83.68	83.68	98.37	98.37	98.37	98.37	98.37	98.37	98.37	98.37	98.37

Table C-14
Solid-Fuel Biomass Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	771	771	771	781	793	807	822	840	861	884	912
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	1.6%	1.6%	1.5%	1.5%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Generation (GWh)	4,461	4,461	4,461	4,520	4,588	4,667	4,757	4,861	4,980	5,117	5,275
Percent of Generation	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Employment (#)	1,178	1,178	1,178	1,238	1,262	1,290	1,323	1,360	1,403	1,453	1,510
Avoided Emissions											
CO2 (Tonne/day)	8,644	8,644	8,644	8,709	8,784	8,870	8,969	9,083	9,213	9,364	9,536
NOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOx (Tonne/day)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
CO (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Taxes ($Million)	14.04	14.04	14.04	14.23	14.44	14.69	14.97	15.30	15.68	16.11	16.60
Other ($Million)	69.19	69.19	69.19	70.11	71.17	72.39	73.79	75.40	77.25	79.37	81.82
Total Benefits ($Million)	83.68	83.68	83.68	84.79	86.06	87.53	89.21	91.14	93.37	95.93	98.87

Table C-15
Solid-Fuel Biomass Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	771	771	771	838	917	1,013	1,128	1,266	1,431	1,630	1,868
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	1.6%	1.6%	1.5%	1.6%	1.8%	2.0%	2.2%	2.4%	2.6%	3.0%	3.3%
Generation (GWh)	4,461	4,461	4,461	4,845	5,307	5,861	6,526	7,324	8,281	9,430	10,809
Percent of Generation	1.6%	1.6%	1.6%	1.7%	1.8%	2.0%	2.2%	2.4%	2.7%	3.0%	3.4%
Employment (#)	1,178	1,178	1,178	1,565	1,743	1,958	2,216	2,525	2,896	3,341	3,875
Avoided Emissions											
CO2 (Tonne/day)	8,644	8,644	8,644	9,066	9,572	10,179	10,908	11,782	12,831	14,090	15,601
NOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOx (Tonne/day)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
CO (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Taxes ($Million)	14.04	14.04	14.04	15.25	16.71	18.45	20.54	23.05	26.07	29.69	34.02
Other ($Million)	69.19	69.19	69.19	75.16	82.32	90.92	101.23	113.61	128.46	146.28	167.66
Total Benefits ($Million)	83.68	83.68	83.68	90.86	99.48	109.82	122.22	137.11	154.97	176.41	202.13

Table C-16
Biogas Scenario A

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	290	290	290	290	290	290	290	290	290	290	290
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%
Generation (GWh)	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678
Percent of Generation	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%
Employment (#)	661	661	661	661	661	661	661	661	661	661	661
Avoided Emissions											
CO2 (Tonne/day)	3,251	3,251	3,251	3,251	3,251	3,251	3,251	3,251	3,251	3,251	3,251
NOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOx (Tonne/day)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Taxes ($Million)	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76

Table C-17
Biogas Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	290	290	290	306	324	346	370	398	430	467	510
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.7%	0.8%	0.8%	0.9%
Generation (GWh)	1,678	1,678	1,678	1,770	1,877	1,999	2,140	2,302	2,488	2,702	2,948
Percent of Generation	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.8%	0.9%	0.9%
Employment (#)	661	661	661	757	808	866	933	1,011	1,099	1,202	1,319
Avoided Emissions											
CO2 (Tonne/day)	3,251	3,251	3,251	3,353	3,470	3,604	3,758	3,935	4,139	4,374	4,644
NOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOx (Tonne/day)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Taxes ($Million)	4.60	4.60	4.60	4.85	5.14	5.48	5.86	6.31	6.82	7.40	8.08
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	4.76	4.76	4.76	5.02	5.31	5.65	6.03	6.47	6.98	7.57	8.25

Table C-18
Biogas Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	290	290	290	312	338	369	407	452	506	572	650
Capacity Factor	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Percent of Peak Load	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.9%	0.9%	1.0%	1.2%
Generation (GWh)	1,678	1,678	1,678	1,804	1,955	2,137	2,355	2,616	2,930	3,307	3,759
Percent of Generation	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.9%	0.9%	1.1%	1.2%
Employment (#)	661	661	661	791	867	958	1,067	1,198	1,356	1,544	1,770
Avoided Emissions											
CO2 (Tonne/day)	3,251	3,251	3,251	3,390	3,556	3,755	3,993	4,280	4,624	5,037	5,532
NOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOx (Tonne/day)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Taxes ($Million)	4.60	4.60	4.60	4.94	5.36	5.85	6.45	7.17	8.03	9.06	10.30
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	4.76	4.76	4.76	5.11	5.52	6.02	6.62	7.34	8.20	9.23	10.46

Table C-19
Solar Thermal Scenario A

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	360	360	360	360	360	360	360	360	360	360	360
Capacity Factor	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Percent of Peak Load	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%
Generation (GWh)	947	947	947	947	947	947	947	947	947	947	947
Percent of Generation	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Employment (#)	80	80	80	80	80	80	80	80	80	80	80
Avoided Emissions											
CO2 (Tonne/day)	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835
NOx (Tonne/day)	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
SOx (Tonne/day)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO (Tonne/day)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
TOG (Tonne/day)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
ROG (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PM (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PM10 (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Emis. Ben. ($Million)	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71
Taxes ($Million)	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01

Table C-20
Solar Thermal Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	360	360	360	360	360	360	360	360	360	360	360
Capacity Factor	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Percent of Peak Load	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%
Generation (GWh)	947	947	947	947	947	947	947	947	947	947	947
Percent of Generation	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Employment (#)	80	80	80	80	80	80	80	80	80	80	80
Avoided Emissions											
CO2 (Tonne/day)	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835
NOx (Tonne/day)	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
SOx (Tonne/day)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO (Tonne/day)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
TOG (Tonne/day)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
ROG (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PM (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PM10 (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Emis. Ben. ($Million)	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71
Taxes ($Million)	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01	14.01

Table C-21
Solar Thermal Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	360	360	360	360	360	360	400	440	480	520	560
Capacity Factor	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Percent of Peak Load	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.8%	0.8%	0.9%	0.9%	1.0%
Generation (GWh)	947	947	947	947	947	947	1,052	1,157	1,262	1,367	1,473
Percent of Generation	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.5%
Employment (#)	80	80	80	80	80	80	318	327	336	344	353
Avoided Emissions											
CO2 (Tonne/day)	1,835	1,835	1,835	1,835	1,835	1,835	1,950	2,065	2,181	2,296	2,411
NOx (Tonne/day)	0.56	0.56	0.56	0.56	0.56	0.56	0.62	0.68	0.75	0.81	0.87
SOx (Tonne/day)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO (Tonne/day)	0.50	0.50	0.50	0.50	0.50	0.50	0.55	0.61	0.66	0.72	0.77
TOG (Tonne/day)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
ROG (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PM (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PM10 (Tonne/day)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Emis. Ben. ($Million)	6.71	6.71	6.71	6.71	6.71	6.71	7.36	8.02	8.67	9.33	9.98
Taxes ($Million)	7.30	7.30	7.30	7.30	7.30	7.30	8.11	8.92	9.73	10.54	11.36
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	14.01	14.01	14.01	14.01	14.01	14.01	15.48	16.94	18.41	19.87	21.34

Table C-22
Photovoltaics Scenario A

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	14	17	20	23	26	29	32	35	38	41	44
Capacity Factor	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Percent of Peak Load	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Generation (GWh)	29	36	42	48	55	61	67	74	80	86	93
Percent of Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Employment (#)	2	23	24	24	24	25	25	26	26	26	27
Avoided Emissions											
CO2 (Tonne/day)	57	64	71	78	85	92	99	105	112	119	126
NOx (Tonne/day)	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05
SOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO (Tonne/day)	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05
TOG (Tonne/day)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.21	0.25	0.29	0.33	0.37	0.41	0.44	0.48	0.52	0.56	0.60
Taxes ($Million)	0.35	0.43	0.50	0.58	0.65	0.73	0.80	0.88	0.96	1.03	1.11
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	0.56	0.68	0.79	0.91	1.02	1.13	1.25	1.36	1.48	1.59	1.71

Table C-23
Photovoltaics Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	14	17	20	23	26	29	32	35	38	41	44
Capacity Factor	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Percent of Peak Load	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Generation (GWh)	29	36	42	48	55	61	67	74	80	86	93
Percent of Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Employment (#)	2	23	24	24	24	25	25	26	26	26	27
Avoided Emissions											
CO2 (Tonne/day)	57	64	71	78	85	92	99	105	112	119	126
NOx (Tonne/day)	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05
SOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO (Tonne/day)	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05
TOG (Tonne/day)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.21	0.25	0.29	0.33	0.37	0.41	0.44	0.48	0.52	0.56	0.60
Taxes ($Million)	0.35	0.43	0.50	0.58	0.65	0.73	0.80	0.88	0.96	1.03	1.11
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	0.56	0.68	0.79	0.91	1.02	1.13	1.25	1.36	1.48	1.59	1.71

Table C-24
Photovoltaics Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	14	18	24	31	41	54	72	97	130	175	235
Capacity Factor	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Percent of Peak Load	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.3%	0.4%
Generation (GWh)	29	38	49	65	86	114	152	204	274	368	495
Percent of Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%
Employment (#)	2	31	42	56	76	102	138	187	252	340	459
Avoided Emissions											
CO2 (Tonne/day)	57	66	79	96	119	150	192	248	325	428	567
NOx (Tonne/day)	0.02	0.02	0.03	0.04	0.05	0.07	0.09	0.12	0.16	0.22	0.29
SOx (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO (Tonne/day)	0.02	0.02	0.03	0.03	0.05	0.06	0.08	0.11	0.14	0.19	0.26
TOG (Tonne/day)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
ROG (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10 (Tonne/day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emis. Ben. ($Million)	0.21	0.26	0.33	0.43	0.56	0.74	0.97	1.30	1.73	2.32	3.11
Taxes ($Million)	0.35	0.45	0.59	0.78	1.03	1.37	1.82	2.44	3.27	4.40	5.91
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	0.56	0.72	0.92	1.21	1.59	2.10	2.80	3.74	5.00	6.71	9.02

Table C-25
Small Hydro Scenarios A, B, & C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Capacity Factor	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
Percent of Peak Load	2.1%	2.0%	2.0%	2.0%	1.9%	1.9%	1.9%	1.9%	1.8%	1.8%	1.8%
Generation (GWh)	4,821	4,821	4,821	4,821	4,821	4,821	4,821	4,821	4,821	4,821	4,821
Percent of Generation	1.7%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.5%	1.5%
Employment (#)	1,143	1,143	1,143	1,143	1,143	1,143	1,143	1,143	1,143	1,143	1,143
Avoided Emissions											
CO2 (Tonne/day)	9,343	9,343	9,343	9,343	9,343	9,343	9,343	9,343	9,343	9,343	9,343
NOx (Tonne/day)	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
SOx (Tonne/day)	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
CO (Tonne/day)	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53
TOG (Tonne/day)	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08
ROG (Tonne/day)	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
PM (Tonne/day)	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
PM10 (Tonne/day)	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Emis. Ben. ($Million)	34.17	34.17	34.17	34.17	34.17	34.17	34.17	34.17	34.17	34.17	34.17
Taxes ($Million)	21.43	21.43	21.43	21.43	21.43	21.43	21.43	21.43	21.43	21.43	21.43
Other ($Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits ($Million)	55.60	55.60	55.60	55.60	55.60	55.60	55.60	55.60	55.60	55.60	55.60

Table C-26
All Renewables Scenario A1

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	5,835	5,838	6,199	6,505	6,508	6,511	6,514	6,517	6,520	6,523	6,526
Capacity Factor	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
Percent of Peak Load	12.1%	11.9%	12.4%	12.8%	12.6%	12.6%	12.5%	12.3%	12.0%	11.8%	11.6%
Generation (GWh)	28,659	28,665	30,457	32,066	32,072	32,079	32,085	32,091	32,098	32,104	32,110
Percent of Generation	10.4%	10.2%	10.7%	11.1%	10.9%	10.9%	10.8%	10.6%	10.4%	10.2%	10.0%
Employment (#)	6,467	6,489	8,080	8,102	7,124	7,124	7,124	7,125	7,125	7,125	7,126
Avoided Emissions											
CO2 (Tonne/day)	55,539	55,545	57,509	59,272	59,279	59,286	59,293	59,300	59,307	59,314	59,321
NOx (Tonne/day)	13.31	13.31	13.91	14.86	14.86	14.86	14.87	14.87	14.88	14.88	14.88
SOx (Tonne/day)	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12
CO (Tonne/day)	11.82	11.82	12.35	13.19	13.20	13.20	13.20	13.21	13.21	13.21	13.22
TOG (Tonne/day)	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73
ROG (Tonne/day)	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
PM (Tonne/day)	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73
PM10 (Tonne/day)	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Emis. Ben. ($Million)	160	160	167	177	177	177	177	177	177	177	177
Taxes ($Million)	93	93	98	102	102	102	102	102	102	102	102
Other ($Million)	69	69	81	81	81	81	81	81	81	81	81
Total Benefits ($Million)	322	322	346	360	360	360	360	360	360	360	360

Table C-27
All Renewables Scenario A2

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	5,835	5,838	6,361	6,829	6,832	6,835	6,838	6,841	6,844	6,847	6,850
Capacity Factor	56%	56%	56%	55%	55%	55%	55%	55%	55%	55%	55%
Percent of Peak Load	12.1%	11.9%	12.7%	13.4%	13.2%	13.3%	13.1%	12.9%	12.6%	12.4%	12.2%
Generation (GWh)	28,659	28,665	31,008	33,150	33,156	33,163	33,169	33,175	33,182	33,188	33,194
Percent of Generation	10.4%	10.2%	10.9%	11.4%	11.2%	11.3%	11.1%	10.9%	10.7%	10.6%	10.4%
Employment (#)	6,467	6,489	8,544	8,613	7,217	7,218	7,218	7,218	7,219	7,219	7,219
Avoided Emissions											
CO2 (Tonne/day)	55,539	55,545	58,113	60,460	60,467	60,474	60,481	60,488	60,495	60,502	60,509
NOx (Tonne/day)	13.31	13.31	14.23	15.50	15.50	15.51	15.51	15.51	15.52	15.52	15.52
SOx (Tonne/day)	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12
CO (Tonne/day)	11.82	11.82	12.64	13.76	13.77	13.77	13.77	13.78	13.78	13.78	13.79
TOG (Tonne/day)	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73
ROG (Tonne/day)	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
PM (Tonne/day)	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73
PM10 (Tonne/day)	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Emis. Ben. ($Million)	160	160	170	183	183	183	183	183	183	184	184
Taxes ($Million)	93	93	99	105	105	105	105	105	105	105	105
Other ($Million)	69	69	81	81	81	81	81	81	81	81	81
Total Benefits ($Million)	322	322	351	369	369	370	370	370	370	370	370

Table C-28
All Renewables Scenario B

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	5,835	5,838	6,144	6,557	6,901	7,293	7,743	8,258	8,848	9,523	10,298
Capacity Factor	56%	56%	56%	56%	55%	54%	54%	53%	52%	51%	51%
Percent of Peak Load	12.1%	11.9%	12.3%	12.9%	13.4%	14.1%	14.8%	15.5%	16.3%	17.3%	18.4%
Generation (GWh)	28,659	28,665	29,945	31,973	33,238	34,679	36,324	38,202	40,345	42,792	45,588
Percent of Generation	10.4%	10.2%	10.5%	11.0%	11.3%	11.8%	12.2%	12.6%	13.1%	13.6%	14.2%
Employment (#)	6,467	6,489	7,521	8,305	8,163	8,518	8,922	9,383	9,910	10,510	11,196
Avoided Emissions											
CO2 (Tonne/day)	55,539	55,545	56,948	59,171	60,556	62,136	63,939	65,996	68,345	71,027	74,091
NOx (Tonne/day)	13.31	13.31	14.07	15.18	15.82	16.55	17.39	18.34	19.43	20.67	22.08
SOx (Tonne/day)	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12
CO (Tonne/day)	11.82	11.82	12.49	13.48	14.05	14.70	15.44	16.29	17.25	18.35	19.61
TOG (Tonne/day)	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73
ROG (Tonne/day)	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
PM (Tonne/day)	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73
PM10 (Tonne/day)	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Emis. Ben. ($Million)	160	160	168	180	187	194	203	213	225	238	253
Taxes ($Million)	93	93	96	101	105	109	114	119	126	133	141
Other ($Million)	69	69	69	70	71	72	74	75	77	79	82
Total Benefits ($Million)	322	322	333	351	363	376	391	408	428	450	475

Table C-29
All Renewables Scenario C

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity (MW)	5,835	5,839	6,148	6,627	7,078	7,632	8,444	9,438	10,655	12,150	13,990
Capacity Factor	56%	56%	56%	56%	55%	54%	54%	53%	53%	52%	51%
Percent of Peak Load	12.1%	11.9%	12.3%	13.0%	13.7%	14.8%	16.2%	17.8%	19.7%	22.0%	24.9%
Generation (GWh)	28,659	28,667	29,952	32,349	34,141	36,319	39,750	43,925	49,012	55,221	62,807
Percent of Generation	10.4%	10.2%	10.5%	11.1%	11.6%	12.3%	13.3%	14.5%	15.9%	17.6%	19.6%
Employment (#)	6,467	6,496	7,539	8,699	8,826	9,530	11,131	12,457	14,078	16,061	18,489
Avoided Emissions											
CO2 (Tonne/day)	55,539	55,548	56,956	59,582	61,546	63,934	67,693	72,268	77,844	84,648	92,961
NOx (Tonne/day)	13.31	13.31	14.07	15.19	15.88	16.74	18.24	20.08	22.34	25.11	28.51
SOx (Tonne/day)	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12
CO (Tonne/day)	11.82	11.82	12.50	13.49	14.11	14.86	16.20	17.84	19.84	22.30	25.32
TOG (Tonne/day)	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73
ROG (Tonne/day)	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
PM (Tonne/day)	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73
PM10 (Tonne/day)	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Emis. Ben. ($Million)	160	160	168	180	187	196	212	232	255	285	320
Taxes ($Million)	93	93	96	102	108	115	125	138	153	172	195
Other ($Million)	69	69	69	75	82	91	101	114	128	146	168
Total Benefits ($Million)	322	322	333	358	378	402	439	483	537	603	683

Target:

Renewable Technology Options & Green Power Marketing

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

EPRI. Electrify the World

About PIER

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable and reliable energy services and products to the marketplace.

The PIER Program annually awards up to $62 million to conduct the most promising public interest energy research by partnering with RD&D organizations including individuals, businesses, utilities and public or private research institutions.

PIER brings new energy services and products to the marketplace and creates state-wide environmental and economic benefits.

© 2002 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute and EPRI are registered service marks of the Electric Power Research Institute, Inc.
EPRI. ELECTRIFY THE WORLD is a service mark of the Electric Power Research Institute, Inc.

Printed on recycled paper in the United States of America

1001193

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com