Itron

Knowledge to Shape Your Future

Electric | Gas | Water

information collection, analysis and application

CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation

Revised Final Report

Submitted to:

PG&E
and
The Self-Generation Incentive Program Working Group

Prepared by:

Itron, Inc.
601 Officers Row
Vancouver, WA 98661

July 2009

Originally published June 2009

Errata

July 2009 Revised Final Report

Two minor errors were identified in the Self-Generation Incentive Program Eighth-Year Impact Evaluation Report submitted in June 2009.

- The peak CAISO hour was incorrectly reported as 2:00 P.M. to 3:00 P.M. (PDT) on June 20, 2008. The peak CAISO hour actually occurred an hour later, from 3:00 P.M. to 4:00 P.M. (PDT) on June 20, 2008. This error has been corrected on the plots showing the impact of SGIP systems during the peak day and in the corresponding text. All tables summarizing peak impacts were correct and did not need to be changed.
- The month of November was missing on the plots showing the monthly capacity factors for each technology during 2008.

A list of revised items is documented in the following tables.

Section 1 Executive Summary Revisions

Page No.	Item Revised
1-6	Figure 1-4: SGIP Impact on CAISO 2008 Peak Day
1-6	Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
1-7	Figure 1-5: Heat Recovery Rate during CAISO 2008 Peak Day

Section 5 Program Impacts Revisions

Page No.	Item Revised
5-5	Figure 5-1: Weighted Average Capacity Factor by Technology and Month
5-9	Line 21: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
5-9	Line 22: Changed “same hour” to “prior hour”
5-10	Figure 5-2: CAISO Peak Day Capacity Factors by Technology
5-11	Line 6: Changed “second” to “third”
5-11	Figure 5-3: SGIP Impact on CAISO 2008 Peak Day
5-16	Figure 5-4: Electric Utility Peak Day Capacity Factors by Technology—PG&E
5-16	Line 16: Changed “1:00 pm to 3:00 pm” to “2:00 pm to 4:00 pm”
5-17	Figure 5-5: Electric Utility Peak Day Capacity Factors by Technology—SCE
5-18	Figure 5-6: Electric Utility Peak Day Capacity Factors by Technology—SDG&E/CCSE
5-23	Figure 5-8: Heat Recovery Rate during CAISO Peak Day

Appendix A Revisions

Page No.	Item Revised
A-7	Line 3: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-8	Figure A-1: CAISO Peak Day Output by Technology
A-8	Line 12: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-12	Figure A-2: CAISO Peak Day Output by Technology, and Fuel—PG&E
A-13	Figure A-3: CAISO Peak Day Output by Technology, and Fuel—SCE
A-14	Figure A-4: CAISO Peak Day Output by Technology, and Fuel—SDG&E
A-20	Figure A-5: Monthly Capacity Factors by Technology
A-21	Figure A-6: CAISO Peak Day Capacity Factors by Technology
A-22	Figure A-7: Electric Utility Peak Day Capacity Factors by Technology—PG&E
A-23	Figure A-8: Electric Utility Peak Day Capacity Factors by Technology—SCE
A-24	Figure A-9: Electric Utility Peak Day Capacity Factors by Technology—SDG&E
A-26	Line 25: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-28	Figure A-10: Monthly Capacity Factors by PA
A-29	Figure A-11: CAISO Peak Day Capacity Factors by PA
A-30	Figure A-12: Electric Utility Peak Day Capacity Factors—PG&E
A-31	Figure A-13: Electric Utility Peak Day Capacity Factors—SCE
A-32	Figure A-14: Electric Utility Peak Day Capacity Factors—SDG&E
A-35	Line 18: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-38	Figure A-16: CAISO Peak Day Capacity Factors by PA
A-39	Figure A-17: Electric Utility Peak Day Capacity Factors—PG&E
A-40	Figure A-18: Electric Utility Peak Day Capacity Factors—SCE
A-42	Line 21: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-44	Figure A-19: Monthly Capacity Factors by PA—Renewable IC Engine
A-45	Figure A-20: Monthly Capacity Factors by PA—Renewable Microturbine
A-46	Figure A-21: CAISO Peak Day Capacity Factors by PA—Renewable IC Engine
A-47	Figure A-22: CAISO Peak Day Capacity Factors by PA—Renewable Microturbine
A-48	Figure A-23: Electric Utility Peak Day Capacity Factors by Technology—PG&E
A-49	Figure A-24: Electric Utility Peak Day Capacity Factors by Technology—SCE
A-50	Figure A-25: Electric Utility Peak Day Capacity Factors by Technology—SDG&E
A-52	Line 18: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-55	Figure A-27: CAISO Peak Day Capacity Factors by PA
A-56	Figure A-28: Electric Utility Peak Day Capacity Factors—PG&E
A-57	Figure A-29: Electric Utility Peak Day Capacity Factors—SCE
A-58	Figure A-30: Electric Utility Peak Day Capacity Factors—SDG&E
A-61	Line 24: Changed “2:00 pm to 3:00 pm” to “3:00 pm to 4:00 pm”
A-64	Figure A-32: Monthly Capacity Factors by Technology—Natural Gas IC Engine
A-65	Figure A-33: Monthly Capacity Factors by Technology—Natural Gas Microturbine
A-66	Figure A-34: CAISO Peak Day Capacity Factors by Technology
A-67	Figure A-35: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas Turbine
A-68	Figure A-36: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas IC Engine
A-69	Figure A-37: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas Microturbine
A-70	Figure A-38: Electric Utility Peak Day Capacity Factors by Technology—PG&E
A-71	Figure A-39: Electric Utility Peak Day Capacity Factors by Technology—SCE
A-72	Figure A-40: Electric Utility Peak Day Capacity Factors by Technology—SDG&E

CPUC Self-Generation Incentive Program (SGIP) Eighth-Year Impact Evaluation Highlights

This report summarizes an evaluation of impacts resulting from distributed generation (DG) technologies under the eighth Program Year (PY08) of the SGIP.

Program Overview:

- SGIP established in 2001 as response to peak demand problems facing California
- DG technologies eligible under the SGIP have included solar PV; wind energy; and fossil and renewable-fueled internal combustion engines (IC Engine), fuel cells (FC), microturbines (MT), and small gas turbines (GT). As of 01/01/08, only wind and fuel cell technologies remained eligible. Additionally, advanced energy storage (AES) technologies are eligible for incentives if they accompany an eligible SGIP project.
- SGIP as of 12/31/08:
  - Over 1,270 on-line SGIP projects (1,268 Complete & 7 "on-line" Active)
  - Over 337 MW of rebated generating capacity
  - $601 million incentives paid to Complete projects, $90 million reserved for Active projects
  - Matched by private and public funds at a ratio of over 1.8 to 1
  - Total eligible project funds more than $1.7 billion, corresponding to Complete projects
- Rebated Capacity:
  - PV technologies: nearly 133 MW (close to 40% of SGIP total capacity)
  - FCs, IC Engines, GTs, and MTs powered by non-renewable fuels: over 177 MW (approx. 54% of SGIP total capacity)
- Incentives Paid:
  - PV technologies: nearly $454 million (approx. 76% SGIP total incentives paid)
  - IC Engines (renewable- and non-renewable fueled): over $86 million (approx. 14% SGIP total incentives paid)

Program Impacts:

- Energy: By the end of 2008, SGIP facilities were delivering over 718,000 MWh of electricity to California's electricity system; enough electricity to power nearly 109,000 homes for one year
  - Cogeneration facilities supplied over 63% of that total
  - PV systems provided nearly 27%; up 5% from PY07

  - PG&E largest PA contributor, providing 40% of total delivered electricity

- Peak Demand: 1,242 SGIP projects on-line during CAISO 2008 peak, providing over 320 MW of generating capacity and representing an aggregated capacity factor of 0.44 MW of peak SGIP capacity per MW of rebated capacity
  - GTs: highest peak capacity factor at 0.84 kWh of peak capacity per kWh of rebated capacity.
  - PV: aggregate CAISO peak capacity factor of 0.59 kWh per kWh.
  - PV: 54% of peak capacity from SGIP facilities during CAISO 2008 peak

- Greenhouse Gas (GHG) Emissions: SGIP provided net GHG emission reductions of over 175,000 tons of CO_2 equivalent in 2008; making a total cumulative GHG reductions from SGIP since 2005 of over 498,000 tons of CO_2 equivalent. For PY08:
  - PV provided approx 65% of total reduction; slightly less than PY07
  - Biogas-fueled DG facilities reduced over 60,000 tons of CO_2 equivalent
  - PA % of total: PG&E: approx. 59%; SCE: approx. 21%; CCSE: approx. 10%; SCG: approx. 10%

- Efficiency and Waste Heat Utilization: Cogeneration facilities made up close to 55% of the SGIP PY08 capacity, providing electricity and recovering and using waste heat for on-site heating and cooling needs. These facilities are required to achieve efficiency and waste heat requirements set by Public Utility Code (PUC).
  - All SGIP cogeneration technologies achieved and exceeded PUC 216.6(a) efficiency and waste heat requirements
  - FCs and GTs able to meet and exceed PUC 216.6(b), but IC Engines and MTs fell short
  - Good match of electrical and thermal loads can play significant role in offsetting peak demand and reducing GHG emissions

Additional Observations:

- The SGIP provides significant value as a unique test bed for examining the actual performance of a mix of DG technologies operating in a commercial setting within California's utility and regulatory framework.
  - Multiple year trend analyses have provided important information on the impact of aging and deterioration on DG performance.
  - Performance evaluations have also shown short-comings of DG facilities that must be addressed as California begins to embark on a plan to expand growth of DG technologies.

- Information gleaned from the annual evaluations of the SGIP can provide value for other energy programs in California, such as the California Solar Initiative. The SGIP data may also help the California Energy Commission in development of guidelines to reduce GHG emissions from CHP facilities, as required under Assembly Bill 1613.

Table of Contents

List of Figures

List of Tables

1

Executive Summary

Abstract

This report provides an evaluation of the impacts of the Self-Generation Incentive Program (SGIP) in its eighth year of operation. By the end of 2008, the SGIP was one of the single largest and long-lived distributed generation (DG) incentive programs in the United States. More than $601 million in incentives had been provided to SGIP facilities, matched by approximately $1.1 billion in other public and private funds, bringing total project investment to over $1.7 billion. By the end of the 2008 Program Year (PY08), 1,275 SGIP facilities were operational, representing 337 MW of rebated electricity generating capacity. During PY08, SGIP facilities provided over 718,000 MWh of electricity to California's grid; enough electricity to meet the needs of 109,000 homes for one year. SGIP facilities also supplied nearly 141 MW of needed generating capacity to the grid during the height of California's summer 2008 peak demand. SGIP facilities also offset over 175,000 tons of CO_2 equivalent greenhouse gas (GHG) emissions during 2008. Additionally, SGIP cogeneration facilities recovered waste heat from SGIP generation systems and used it to meet customer heating and cooling needs. While all SGIP cogeneration technologies achieved PUC 216.6(a) requirements, IC engines and microturbines were not able to meet those of PUC 216.6(b). As noted in the 2007 Impact Evaluation Report, the depth and breadth of performance information provided by the SGIP contributes value beyond the SGIP. Performance degradation information on photovoltaic (PV) technologies can be used in the California Solar Initiative (CSI). Similarly, performance trends and GHG emission impact data collected on SGIP combined heat and power (CHP) systems can help the California Energy Commission (CEC) in setting high but achievable targets for future CHP technologies and their role in reducing GHG emissions.

Some Words on the Executive Summary Format

This is the second year in which Itron has used a special format for the Executive Summary. Based on a request from the PG&E Project Manager, this format balances brevity with depth of information by using hyperlinks. In an acknowledgment of the fact that not every reader will be equally interested in every topic, nor have the time to read through an entire report to find detail on those findings that are of interest, this Executive Summary is, in essence, a deck of one-page snapshots of key report topics. Each page includes one or two graphics followed by a limited number of key "Take-Away" bullet points. Hyperlinks, indicated by blue underlined text, are used for ease of finding related sections in the body of the report or to related websites for such items as legislation and regulatory proceedings. For those reading a print copy, a "hard-copy link" to the main related report section is included immediately after the page heading, indicating the relevant section and page number (e.g., *Refer To Section 3.2, page 3-1*). While it is our intent that the Executive Summary provide a solid overview of evaluation findings, we strongly encourage reading the detail behind the graphics and "Take-Aways" to ensure they are not taken or used out of context. For further ease of use, tables of Key Terms related to the Executive Summary are included on the following page and a table of Useful Links follows the Conclusions & Recommendation section.

Table 1-1: Executive Summary Topic Directory

Executive Summary Topics	
1.1 Introduction & Background	1.7 Trends: Coincident Peak Demand
1.2 Program-Wide Findings	1.8 Trends: Aging and Performance Degradation: PV
1.3 Impacts: Energy	1.9 Trends: Aging and Performance Degradation: CHP
1.4 Impacts: Peak Demand	1.10 Trends: SGIP Portfolio
1.5 Efficiency & Waste Heat Utilization	1.11 Conclusions & Recommendations
1.6 Greenhouse Gas Emission Reduction Impacts	1.12 Useful Links

Table 1-2: Key Terms

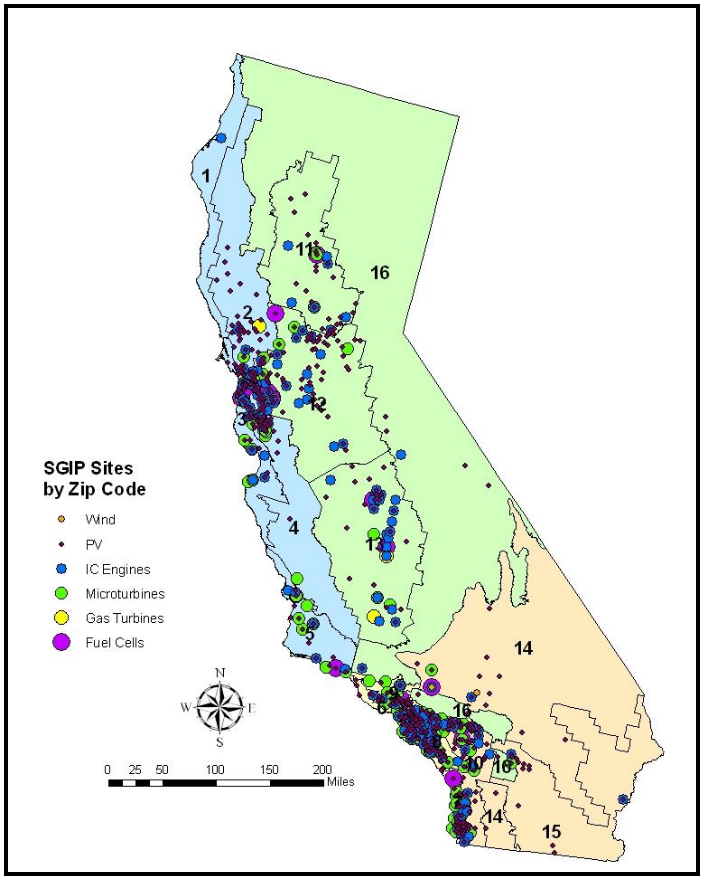
SGIP Project Categories	
Active	Have not been withdrawn, rejected, completed, or placed on a wait list. Active projects will eventually migrate either to the Complete or Inactive category.
Complete	Generation system has been installed, verified through on-site inspections, and an incentive check has been issued. All Complete projects are considered as "on-line" projects for impact evaluation purposes.
Inactive	No longer progressing in SGIP implementation process because they have been withdrawn by applicant or rejected by PA.
On-line	Have entered normal operations (i.e., projects are through the "shakedown" or testing phase and are expected to provide energy on a relatively consistent basis.)
Off-line	Projects that did not operate for the entire 2008 year due to any reasons whether operational or financial.
Rebated Capacity	The capacity rating associated with the rebate (incentive) provided to the applicant. The rebate capacity may be lower than the typical "nameplate" rating of a generator.
Technologies	
AES	Advanced Energy Storage
CHP	Combined Heat and Power (used interchangeably with "cogeneration")
DG	Distributed Generation
FC-N	Fuel Cells (Non-renewable)
FC-R	Fuel Cells (Renewable)
GT-N	Gas Turbines (Nonrenewable-fueled)
GT-R	Gas Turbines (Renewable-fueled)
IC Engine-N	Internal Combustion Engines (Non-renewable-fueled)
IC Engine-R	Internal Combustion Engines (Renewable-fueled)
MT-N	Microturbines (Non-renewable-fueled)
MT-R	Microturbines (Renewable-fueled)
PV	Photovoltaics
WD	Wind Turbines
Misc. Defined Terms	
CCSE	California Center for Sustainable Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
IOU	Investor-owned Utility
PA	Program Administrator
PG&E	Pacific Gas and Electric Company
PY	Program Year
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company
SCE	Southern California Edison
SGIP	Self-Generation Incentive Program

1.1 Introduction & Background (*Refer to Section 2, page 2-1)*

Table 1-3: SGIP Eligible Technologies

SGIP Generation Technologies	Applicable Program Years
Photovoltaics	PY01–PY06
Wind Turbines	PY01–PY11
Non-renewable fuel cells	PY01–PY11
Renewable fuel cells	PY01–PY11
Non-renewable-fueled internal combustion engines	PY01–PY07
Renewable-fueled internal combustion engines	PY01–PY07
Non-renewable-fueled microturbines	PY01–PY07
Renewable-fueled microturbines	PY01–PY07
Non-renewable-fueled gas turbines	PY01–PY07
Renewable-fueled gas turbines	PY01–PY07
Advanced Energy Storage Coupled with Eligible SGIP	PY08–PY11

Figure 1-1: Distribution of SGIP Facilities as of 12/31/08



Take-Aways:

- Per AB 970, CPUC D.01-03-073 (3/27/01) outlined provisions of a DG incentive program, which became the SGIP
- SGIP operates in service areas of PG&E, SCE, SCG, and SDG&E (some projects in municipal electric utility service areas)
- Administered by PG&E, SCE, and SCG, in respective territories, and by CCSE (formerly SDREO) in SDG&E's territory
- July 2001: 1st SGIP application accepted. December 31, 2008: SGIP one of the single largest and longest-lived DG incentive programs in the country
- Financial incentives for diverse family of technologies, including systems employing solar PV, wind energy, fuel cells, microturbines, small gas turbines, internal combustion engines and advanced energy storage
- SGIP M&E per D.01-03-073. This impact evaluation of the eighth program year covers all SGIP projects coming on-line prior to January 1, 2009.
- Examines impacts or requirements associated with energy delivery, peak demand, efficiency and waste heat utilization, and GHG emission reductions

1.2 Program-Wide Findings *(Refer to Section 3, page 3-1)*

Table 1-4: SGIP Projects and Rebated On-Line Capacity by PAs as of 12/31/08

PA	No. of Projects	Rebated Capacity (MW)	% of Total Capacity
PG&E	655	154.0	46%
SCE	283	64.2	19%
SCG	189	79.9	24%
CCSE	148	39.2	12%
Totals	**1,275**	**337.4**	**100%**

Figure 1-2: SGIP Capacity (MW) by Technology and Fuel Type as of 12/31/08 (Complete Projects)

Total Capacity = 330.2 MW

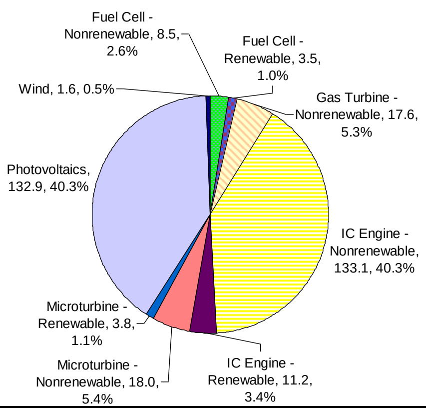
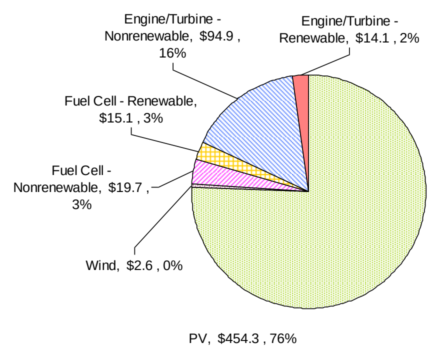


Figure 1-3: SGIP Incentive Payments by Technology and Fuel Type as of 12/31/08 (Complete Projects)

Total Payments = $601 million



Take-Aways:

- SGIP as of 12/31/08:
  - Over 1,270 on-line SGIP projects (1,268 Complete & 7 “On-Line” Active)
  - Over 337 MW of rebated generating capacity
  - $601 million incentives paid to Complete projects, $91 million reserved for Active projects
  - Matched by private and public funds at a ratio of 1.8 to 1
  - Total eligible project costs more than $1.7 billion, corresponding to Complete projects
  - PG&E: most SGIP projects and largest aggregated capacity, nearly 46% SGIP total capacity
- Rebated Capacity:
  - PV technologies: nearly 133 MW (40% of SGIP total capacity)
  - FCs, IC Engines, GTs, and MTs powered by non-renewable fuels: over 177 MW (approx. 54% of SGIP total capacity)
- Incentives Paid:
  - PV technologies: just over $454 million (approx. 76% of SGIP total incentives paid)
  - IC Engines (renewable and non-renewable fueled): nearly $86 million (approx. 14% of SGIP total incentives paid)

1.3 Impacts—Energy *(Refer to Section 5.1, page 5-2)*

Table 1-5: Statewide Energy Impact in 2008 by Quarter (MWh)

Technology	Fuel	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
FC	N	13,663	12,908	10,273	7,204	44,050 †
FC	R	1,769	2,742	3,014	5,048	12,572 †
GT	N	24,845	31,131	32,439	25,742	114,156 †
IC Engine	N	54,537	54,822	68,381	50,190	227,930 †
IC Engine	R	13,503	12,253	10,911	11,179	47,848 †
MT	N	18,201	16,221	16,482	17,059	67,963 †
MT	R	1,953	2,194	1,467	1,249	6,863 †
PV	X	37,062	66,034	60,815	33,268	197,178
WD	X	N/A	N/A	N/A	N/A	N/A
	TOTAL	**165,533**	**198,304**	**203,782**	**150,939**	**718,558**

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table 1-6: Annual Energy Impacts by PA (MWh)*

Technology		PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC		27,839 †	7,936 †	10,529 †	10,318	56,622 †
GT		21,799 [a]	N/A	31,229	61,128 †	114,156 †
IC Engine		90,570 †	62,044 †	104,105 †	19,058 †	275,777 †
MT		33,067 †	13,475 †	24,745 †	3,538 †	74,825
PV		118,935	37,625	18,904	21,713	197,178
WD		N/A	N/A	N/A	N/A	N/A
	Total	**292,210**	**121,081**	**189,512**	**115,755**	**718,558**

* Except for bottom row, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Take-Aways:

- During PY08, SGIP projects delivered over 718,000 MWh of electricity to California's grid—enough to meet electricity requirements of nearly 109,000 homes for a year and that did not have to be generated by central station power plants or delivered by T&D system
- Cogeneration systems (FC, engines, and turbines): over 63% (454,099 MWh) of electricity delivered by SGIP during 2008; 14% decline from 2007
- PV: approx. 27% (197,178 MWh) of electricity delivered by SGIP in 2008; 5% increase from 2007
- Natural gas-fueled IC Engines: 32% (227,930 MWh); largest share by single technology in 2008; 12% decline from PY07
- PG&E: largest PA contributor, approx. 41% (292,210 MWh) of total electricity delivered by SGIP during 2008; down 1% from PY07 at 42%
- SCG: approx. 26% (189,512 MWh); down 1% from PY07 at 27%
- SCE: approx. 17% (121,081 MWh); down 1% from PY07 at 18%
- CCSE: approx. 16% (115,755 MWh); up 3% from PY07 at 13%

1.4 Impacts—Peak Demand *(Refer to Section 5.2, page 5-8)*

Figure 1-4: SGIP Impact on CAISO 2008 Peak Day

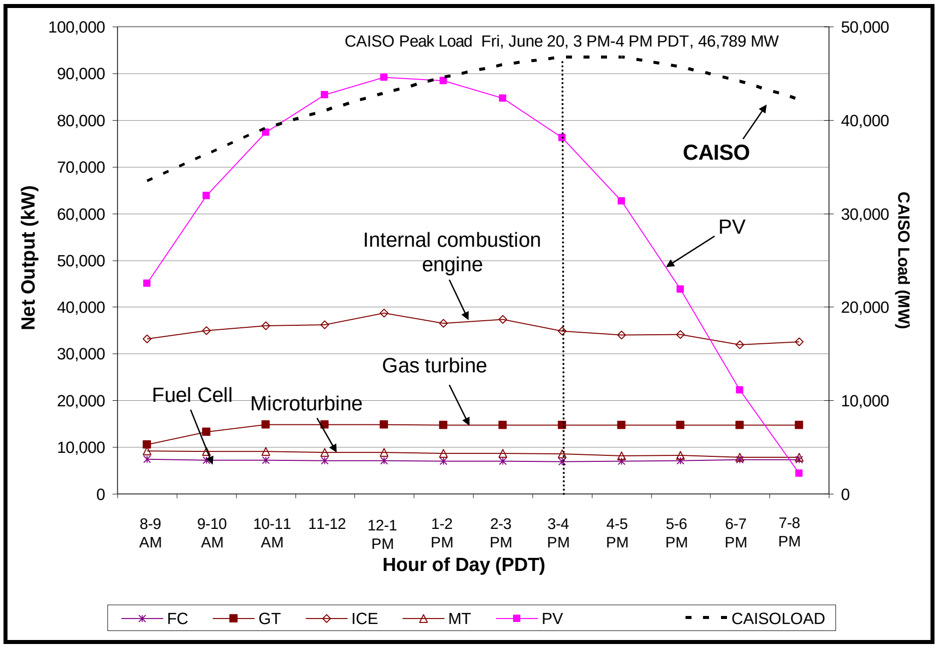


Table 1-7: Demand Impact Coincident with CAISO 2008 System Peak Load

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	19	10,700	6,889	0.644 †
GT	6	17,643	14,728	0.835 †
IC Engine	223	140,490	34,788	0.248 †
MT	129	20,692	8,509	0.411
PV	863	129,566	76,202	0.588
WD	2	1,649	N/A	N/A
TOTAL	**1,242**	**320,740**	**141,117**	

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Take-Aways:

- 1,242 SGIP projects on-line during CAISO 2008 summer peak (June 20, 3:00 P.M. to 4:00 P.M. (PDT), CAISO system reached max value of 46,789 MW)
- Total rebated capacity of these on-line projects exceeded 320 MW
- Total impact of SGIP projects coincident with CAISO peak load est. slightly above 141 MW
- Collective peak hour impact of SGIP projects on CAISO 2008 peak approx 0.44 kWh per kWh
- PV: approx. 54% of total SGIP peak impact in PY08
- IC Engines: approx. 25% of total SGIP peak impact in PY08
- Increased peak contribution by PV in 2008 as compared to 2007, wherein PV systems contributed approx 47% and IC Engines approx 37%. This was due to the higher capacity factor for PV (0.59) during the peak hour than for IC engines (0.25).
- Relatively high hourly capacity factor of 0.59 for PV result of early afternoon timing of CAISO system peak

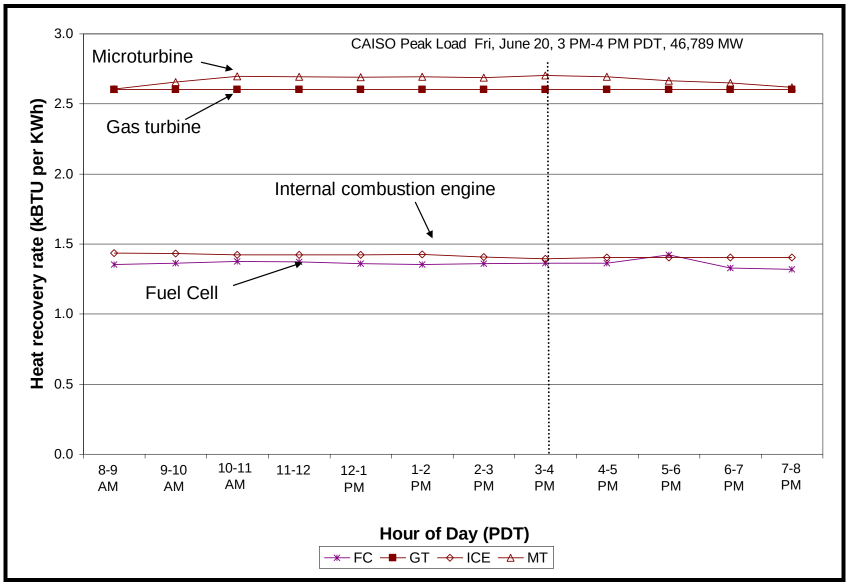
1.5 Efficiency and Waste Heat Utilization *(Refer to Section 5.3, page 5-20)*

Table 1-8: PUC 216.6 Cogeneration System Performance by Technology (PY08)

Technology	Number of projects (n)	216.6 (a) Proportion as Useful Heat (%)*	216.6 (b) Avg. Efficiency Level Achieved (%, LHV)*
FC	15	27.9% †	48.3%
GT	6	45.% †	42.3% †
IC Engine	208	29.8%	36.6%
MT	113	44.2%	33.1%

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates accuracy is at least 90/10.

Figure 1-5: Heat Recovery Rate during CAISO 2008 Peak Day



Take -Aways:

- PUC 216.6(a) requires recovered useful waste heat from cogeneration system to exceed 5% of combined recovered waste heat plus the electrical energy output of system.
  - All SGIP cogeneration technologies achieved and exceeded PUC 216.6(a) requirement
  - Recovered total output energy as useful heat: FC: 28%; IC engine: 30%; GT: 45%; MT: 44%
- PUC 216.6(b) requires sum of electric generation and half of heat recovery of the system to exceed 42.5% of energy entering system as fuel.
  - FC and GT able to meet and exceed PUC 216.6(b) requirement
  - IC engine and MT fell short of requirements, partly due to lower than anticipated electricity generation efficiencies and lack of a significant thermal load coincident with electricity generation
- Average thermal energy recovery by SGIP cogeneration facilities does not appear to have been influenced by peak hour electrical demands. This should be an important consideration for expansion of cogeneration facilities in California's electricity market.
- Good match of electrical and thermal loads can play significant role in contribution of DG cogeneration facilities to offset peak demand and reduce GHG emissions during peak
- Particularly true when recovered waste heat used to drive absorption chillers that offset air conditioning loads

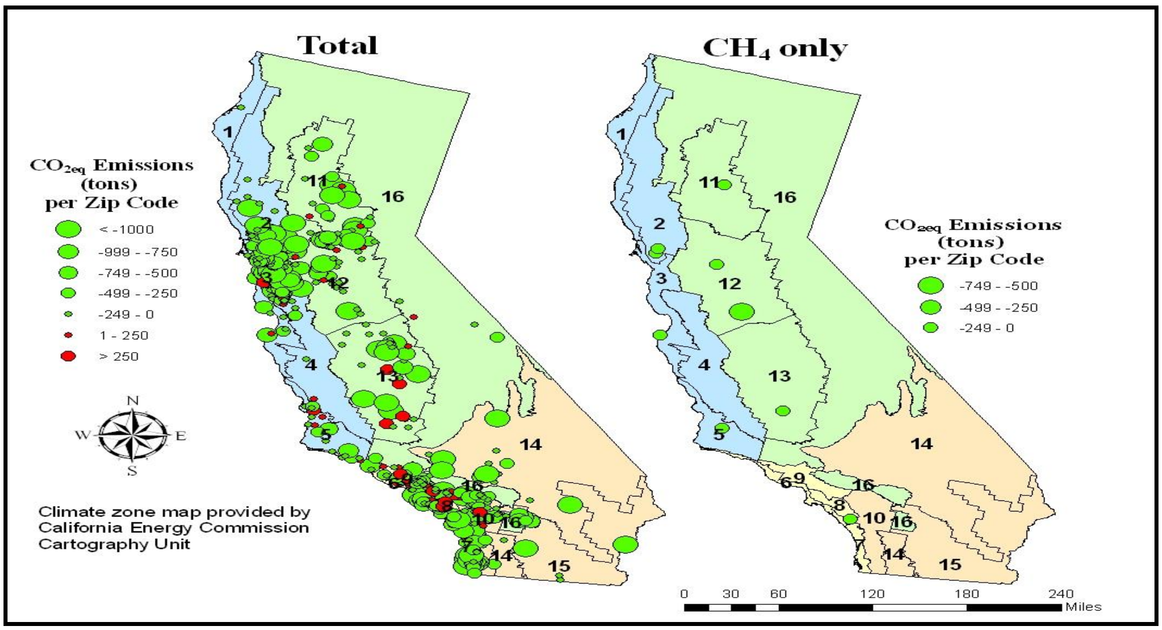
1.6 Greenhouse Gas Emission Reduction Impacts *(Refer to Section 5.4, page 5-26)*

Table 1-9: Net Reduction of GHG Emissions from SGIP Systems in PY08 by Fuel and Technology

Technology	Annual CO_2Eq Emissions Impact (Tons)	Annual CO_2Eq Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2Eq Impact Factor (Tons/MWh)
PV	-115,057	-100%	197,178	-0.58
WD*	N/A	N/A	N/A	N/A
FC-N	-5,968	-22%	44,050	-0.14
MT-N	8,815	19%	67,963	0.13
IC Engine-N	1,159	1%	227,930	0.01
Small GT-N / waste gas-fueled	-4,796	-6%	114,156	-0.04
FC-R	-6,895	-54%	12,572	-0.55
MT-R	-9,667	-20%	6,863	-1.41
IC Engine-R	-43,835	-33%	47,848	-0.92
Total	**-176,244**	**-35%**	**718,558**	**-0.25**

* Wind values were not available because valid metered data were not received.

Figure 1-6: PY08 Distribution of GHG Emission Reductions Among SGIP Facilities

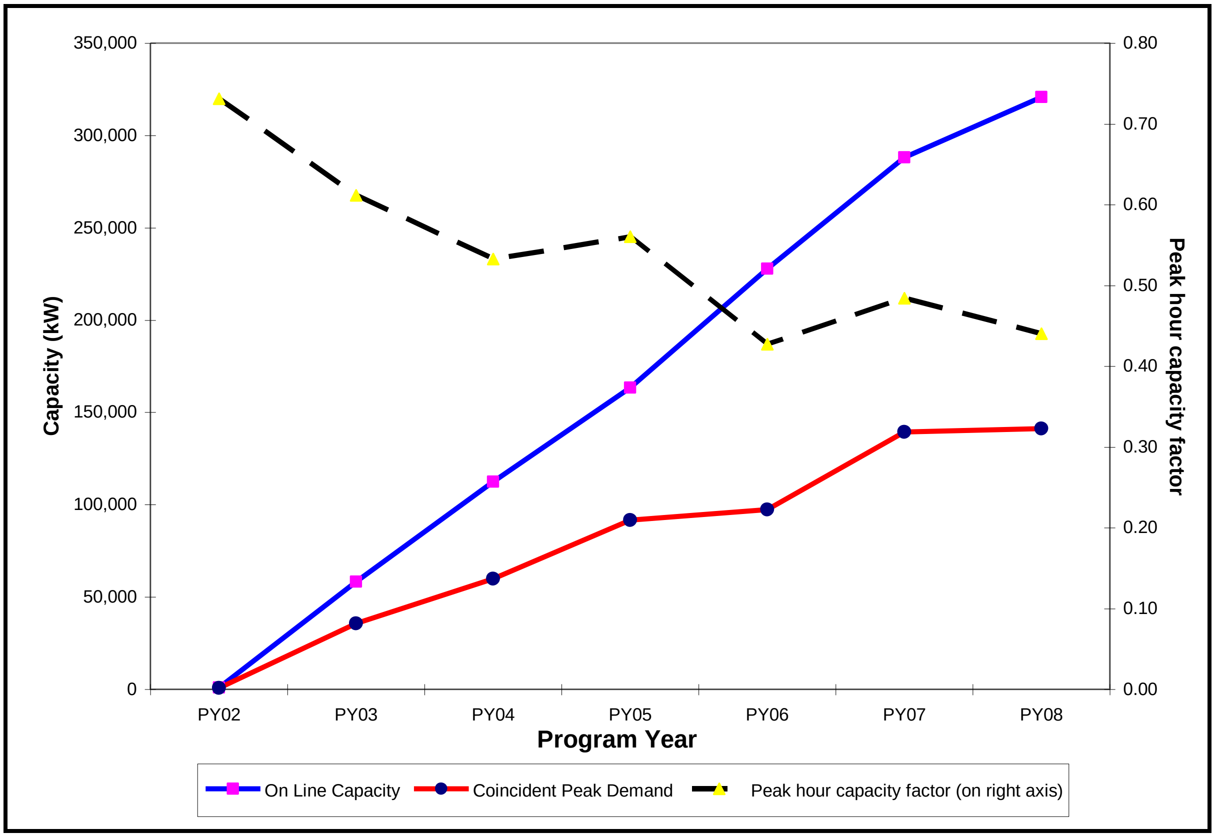


Take-Aways:

- Net GHG emissions from SGIP projects developed relative to baseline GHG emissions from "grid electricity"
- GHG emission reduction analysis focus remains primarily on CO_2 and CH_4 as main contributors of GHG from SGIP facilities
- PY08 SGIP Net GHG emission reductions:
  - PV systems: 65% of total; slightly less than PY07
  - Renewable-fueled SGIP facilities: nearly 34% of total, due to capture of methane in "biogas"
  - PA % of total: PG&E: approx 59%; SCE: approx 21%; CCSE: approx 10%; SCG: approx 10%

1.7 Trends: Coincident Peak Demand (*Refer to Section 3.5, page 3-28*)

Figure 1-7: Trend on Coincident Peak Demand from PY02 to PY08

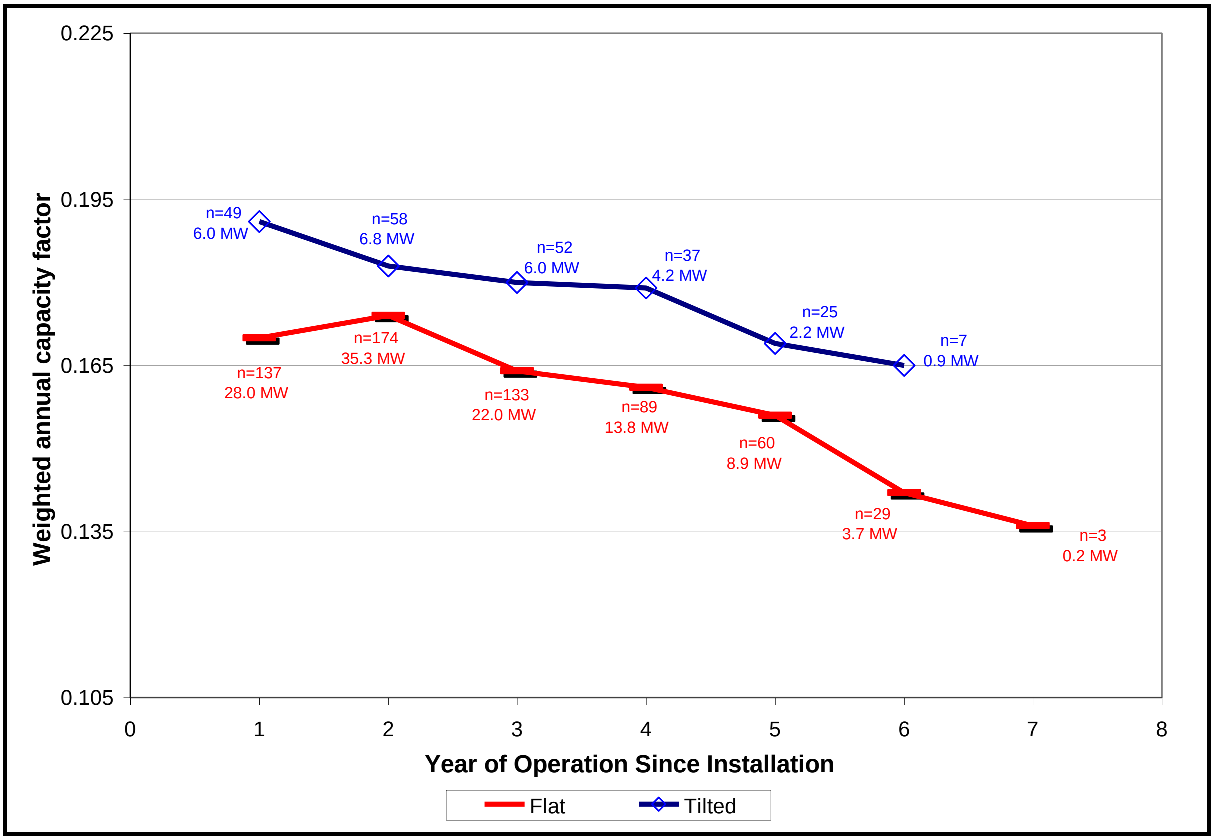


Take-Aways:

- Peak hour capacity factor (CF) reflects amount of capacity actually observed to be available during CAISO peak demand
- Relatively high peak hour CF observed in PY02 should not be considered indicative of DG technologies, as it may be due to the low number of systems monitored during that program year
- Peak hour CF from PY03 on has generally ranged between 0.45 and 0.6 and for PY08 averaged 0.56. Since this ratio resulted without pre-specified plans by the CPUC or the IOUs, it reflects the level of impact on coincident peak demand that could be expected from an unplanned expansion of DG technologies.
- In general, the downward trend in the overall peak hour CF is likely due primarily to a significantly decreasing trend in the IC engine and microturbine peak hour CFs from 2002 through 2008.
- Over the past three program years, PV's peak hour CF has been greater than 0.5. It is reasonable to assume that PV systems deployed in the future in California would achieve a peak hour CF of approximately 0.59. Consequently, successful installation of 3,000 MW of PV generating capacity could potentially provide approximately 1,800 MW of peak capacity that helps address the CAISO system peak.
- A lower contribution from DG technologies could possibly be achieved at lower costs by improved matching of coincident peak contributions of DG mix.

1.8 Trends: Aging & Performance Degradation–PV *(Refer to Section 3.5, page 3-31)*

Figure 1-8: PV Annual Capacity Factor versus Year of Operation

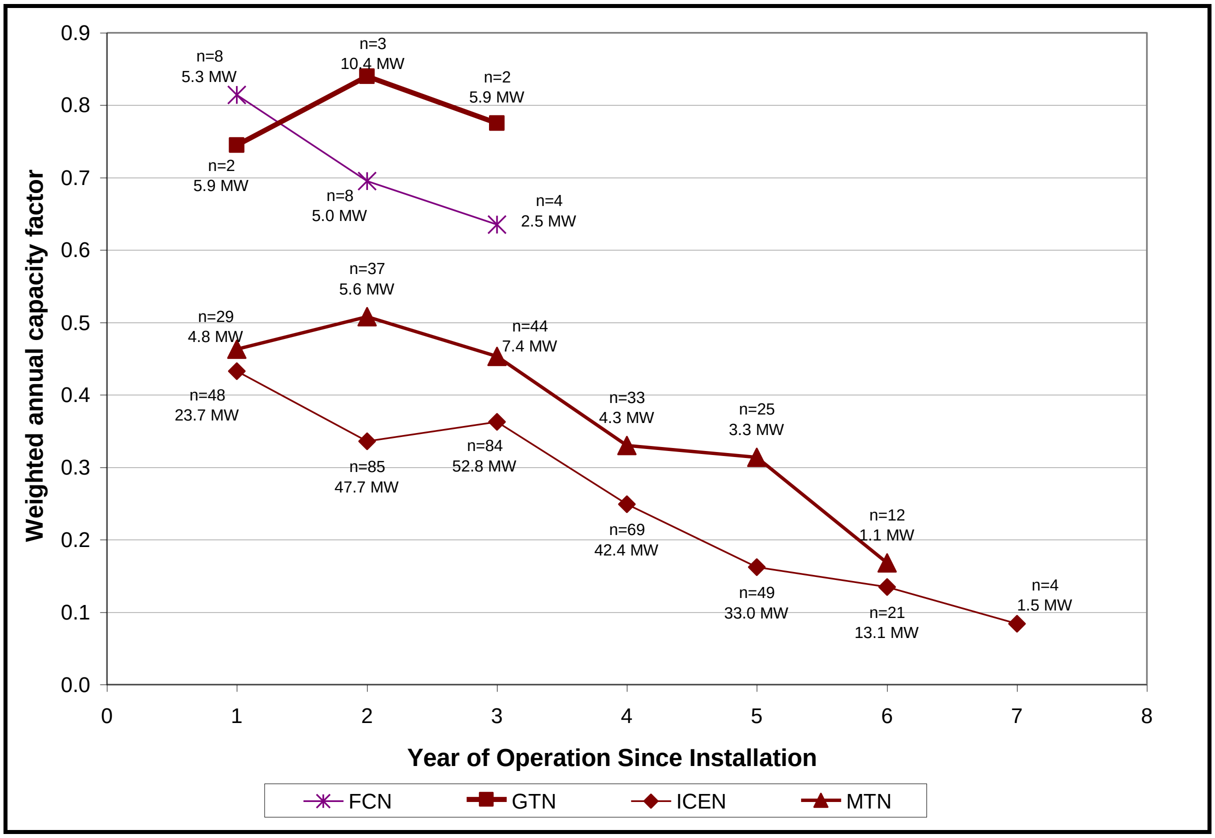


Take-Aways:

- Year-to-year variability in average annual CF of fixed and tilted PV systems is due to a range of factors including weather, maintenance/reliability issues, and location of projects
- Observed annual CFs for both tilted and flat PV systems have declined with age
- Decline in annual CF of PV systems over seven program years:
  - The observed average annual CF for flat PV systems has declined with age at an average rate of approximately 1.15% to 1.31% per year depending on the material type during Years 2 through 5 of operation.
  - The rate of degradation appears to increase as systems age and rapidly accelerates in Year 7. However, the sample size of systems operating seven years is relatively small and this data point may not be significant
  - Understanding reasons for the differences requires additional process evaluation information
- These data are important as they allow policy makers and CSI PAs to recognize the extent to which PV CFs may possibly be expected to decline over the life of the CSI

1.9 Trends: Aging & Performance Degradation–CHP *(Refer to Section 3.5, page 3-37)*

Figure 1-9: CHP Annual Capacity Factor versus Year of Operation

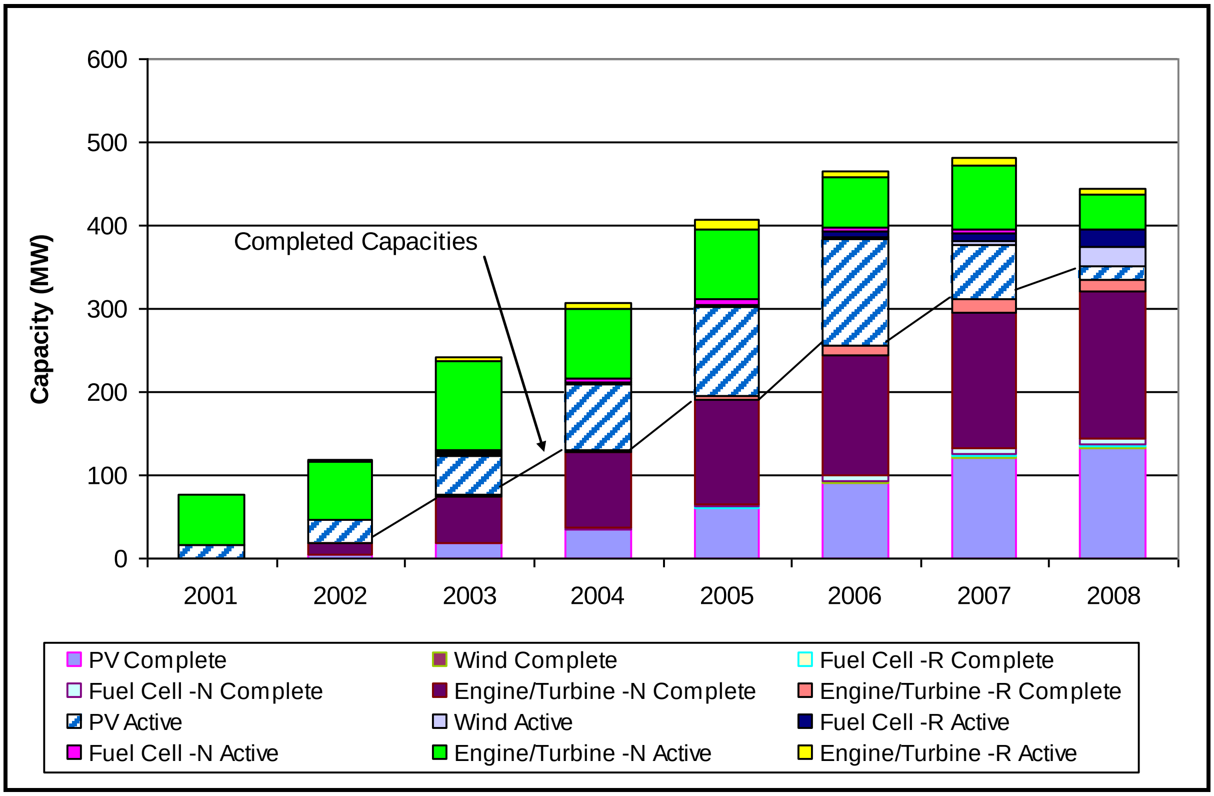


Take-Aways:

- Year-to-year variability in average annual CF of CHP systems is due to a range of factors including equipment maintenance/reliability issues, staff turnover, interruption in fuel or service provider contracts, fuel prices, and occupancy/operations schedules of metered CHP systems
- Annual CF trends for IC Engines and MTs exhibit noticeable downward trend over life of program:
  - IC Engines: decline of nearly 30 percentage points in annual CFs from Year 1 through Year 6, with very rapid decline between Years 3 and 6 accounting for nearly all the loss of annual CF. The small sample size for the seventh year of operation may not be representative of systems which have been operational for seven years. Annual average CFs for newer vintage IC engines were lower than IC engines installed prior to 2004.
  - MTs: decline of nearly 30 percentage points in annual CF over six program years. As with IC engines, a significant amount of decline occurred during middle years. Performance of newer vintage MTs was better than the performance of MTs installed prior to 2004.
- There is limited data on FCs and GTs due to the limited number of systems operating in the SGIP. No trends are apparent and increases or decreases in later years may be due to the limited data.
- Understanding reasons for changes requires additional process evaluation information

1.10 Trends: SGIP Portfolio (*Refer to Section 3.5, page 3-40*)

Figure 1-10: Capacity of Complete and Active SGIP Projects PY01 to PY08



Take-Aways:

- Changes in eligibility of SGIP technologies have changed the SGIP portfolio
- From PY01 through PY05, there was a steady increase in all Active projects but has changed by technology since PY05
- PV:
  - Steady growth in capacity of PV projects through end of PY06
  - With CSI, PV technologies no longer were eligible to receive incentives under SGIP. As of January 1, 2007, rapid decline in Active SGIP PV projects, with only legacy projects moving forward in PY07 and PY08. However, PV continues in PY08 to have dominant role in contributions to energy and GHG reductions.
- IC engines and turbine technologies: steady decline in applications since PY03
- Passage of AB 2778 (September 2006) limits eligibility of cogeneration projects within the SGIP to "ultra-clean and low emission distributed generation" technologies, defined as fuel cells and wind DG technologies that meet or exceed emissions standards required under the DG certification program adopted by the California Air Resources Board
- Fuel cells & wind technologies: PY08 showed some limited growth in active capacity of both
- Decreases in capacity additions from PV and cogeneration technologies will substantially affect SGIP portfolio of completed projects beyond PY08
- Changes in SGIP portfolio will influence impacts by technologies as well as observations on the impacts of those technologies within electricity system

1.11 Conclusions & Recommendations

In drawing conclusions and making recommendations about DG technologies, Itron has blended knowledge of DG system design and operation with performance data and observations obtained from the field. Based on this blend of knowledge and seven years of SGIP performance data, we provide the following conclusions and recommendations:

1. DG technologies can make valuable contributions to addressing peak electricity demand. On average, SGIP DG technologies have had more than half their rebated capacity on-line during the CAISO peak for the past seven years. Fuel cells and gas turbines deployed under the SGIP have demonstrated ratios of on-line peak capacity to rebated capacity of 0.84 and 0.64 kW (peak) per kW (rebated), respectively. Similarly, over the past seven years, PV systems deployed under the SGIP have shown an average ratio of 0.55 kW (peak) per kW (rebated) capacity.
2. Not surprisingly, performance trends show that both PV and CHP technologies (IC engines and microturbines) have experienced performance degradation over time.
    a) For PV systems deployed under the SGIP, performance deterioration rates were found to be slightly higher than those reported in the literature (i.e., on the order of one percent per year versus literature values of 0.5 percent per year). However, vintage tends to offset the overall PV degradation rates as newer vintage systems start with higher levels of performance. In addition, we found PV degradation rates to be affected by PV cell material.
    b) More pronounced performance degradation rates were observed for microturbines and IC engines, with performance deteriorating by over 20 percentage points over five years of operation.
3. SGIP technologies provide significant GHG emission reductions. PV technologies showed the greatest level of GHG emission reduction due to their direct replacement of electricity otherwise generated by combustion-based resources. However, waste heat recovery of CHP facilities provides a net reduction in GHG emissions by displacement of natural gas that would have otherwise been consumed onsite.
    a) The role of waste heat recovery is important to consider in establishing CHP programs that reduce GHG emissions. In general, the ability to obtain greater reductions in GHG emissions requires higher overall system efficiencies and a good match between electrical and thermal loads. While not quantified in this impact evaluation, it is possible to link GHG emissions to a minimum number of hours per year of matched thermal and electrical load for different CHP system efficiencies. Establishing this connection will help set CHP program designs to achieve targeted levels of GHG emission reductions.
4. Determining the causes of lower-than-expected contribution to coincident peak demand or for performance degradation is beyond the scope of an impact evaluation. However, determining the causes of these impacts is likely to be important when developing other energy programs involving CHP and PV technologies. As such, the CPUC and PAs should consider pursuing process evaluations to look into the causes of these performance issues.
5. Collecting performance data on PV and CHP facilities on a sustained basis (e.g., over seven years) and over a diverse population of systems has provided valuable insights into actual performance that can be expected in real world settings. To the extent possible, SGIP data on CHP systems should be linked to future CHP programs to help provide sustained performance information, similar to the way SGIP data are being used in combination with CSI performance data.

6. The state has set a goal of achieving 25 percent of its supply of peak electricity from CHP facilities by 2020. Achieving and maintaining this goal will require well designed, properly operated, and appropriately maintained CHP facilities. In addition, if designed and operated appropriately, these CHP facilities can also provide an important means of reducing GHG emissions. Based on Itron's past investigation into issues encountered with design and implementation of CHP facilities and on the performance results observed to date with SGIP CHP facilities, we recommend the following be considered in establishing a statewide CHP program:
    a) Establish tariffs that encourage CHP facilities to maximize electricity generation at times that will help provide relief to congested or highly loaded distribution feeders or help offset critical peak demand.
    b) Establish policies and tariffs that encourage CHP facilities to adopt the use of absorption chillers operated from waste heat recovered by the CHP facility and sized to offset onsite cooling needs.
    c) Establish design policies and approaches that require CHP system developers to identify and match thermal and electrical hourly load profiles for the host site for a minimum of the daily peak electricity demand hours of the host site.
    d) Establish policies and incentives that encourage CHP system owners and operators to maintain their systems such that no more than two percent (2%) performance degradation occurs annually. Such policies should consider the use of service agreements to help maintain CHP system operation; annual inspections of CHP systems and major components; and efficacy insurance.

1.12 Useful Links

Table 1-10: Useful Links

Legislation & Regulation	
Assembly Bill 578 (Blakeslee, September 30, 2008)	http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_0551-0600/ab_578_bill_20080930_chaptered.html
Assembly Bill 970 (Ducheny, September 7, 2000)	http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html
Assembly Bill 1470 (Huffman, October 12, 2007)	http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1451-1500/ab_1470_bill_20071012_chaptered.html
Assembly Bill 1613 (Blakeslee, October 14, 2007)	http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1601-1650/ab_1613_bill_20071014_chaptered.html
Assembly Bill 1685 (Leno, October 12, 2003)	http://www.leginfo.ca.gov/pub/03-04/bill/asm/ab_1651-1700/ab_1685_bill_20031012_chaptered.html
Assembly Bill 2267 (Fuentes, September 28, 2000)	http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_2251-2300/ab_2267_bill_20080928_chaptered.html
Assembly Bill 2768 (Levine, September 28, 2008)	http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_2751-2800/ab_2768_bill_20080928_chaptered.html
Assembly Bill 2778 (Lieber, September 29, 2006)	http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html
CPUC Proceeding R9807037	http://docs.cpuc.ca.gov/published/proceedings/R9807037.htm
CPUC Proceeding R0403017	http://docs.cpuc.ca.gov/published/proceedings/R0403017.htm
CPUC Proceeding R0803008	http://docs.cpuc.ca.gov/PUBLISHED/proceedings/R0803008.htm
CPUC Decision 01-03-073 (D.01-03-073, March 27, 2001)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/6083.htm
CPUC Decision 04-12-045 (D. 04-12-045, December 16, 2004)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/42455.htm
CPUC Decision 08-04-049 (D.08-04-049, April 24, 2008)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81915.htm
CPUC Decision 08-11-044 (D.08-11-044, November 21, 2008)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/94272.htm
CPUC Decision 09-01-013 (D.09-01-013, January 29, 2009)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/96779.htm
Public Utilities Code 216.6 (prev. Public Utilities Code 218.5)	http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=201-248
SGIP Study Reports	
SGIP Data & Reports	http://www.pge.com/sgipreports
PA SGIP Sites	
CCSE (in SDG&E territory)	http://energycenter.org/index.php/incentive-programs/self-generation-incentive-program
SCE	http://www.sce.com/sgip
SCG	http://www.socalgas.com/business/selfGen/
PG&E	http://www.pge.com/mybusiness/energysavingsrebates/selfgenerationincentive/

2

Introduction

2.1 Program Background

The Self-Generation Incentive Program (SGIP) was initiated in 2001 as part of a series of responses by the California legislature to address peak electricity demand problems confronting California. During the summer of 2000, California experienced a series of rolling blackouts that left thousands of electricity customers in Northern California without power and shut down hundreds of businesses. Enacted in response to these problems, Assembly Bill (AB) 970[1] directed the California Public Utilities Commission (CPUC), in consultation with the California Independent System Operator (CAISO), and the California Energy Commission (CEC) to "adopt energy conservation, demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods." The same legislation required the CPUC to consider establishing incentives for load control and distributed generation to enhance reliability with "differential incentives for renewable or super-clean distributed generation resources." The CPUC issued Decision (D.) 01-03-073[2] on March 27, 2001 outlining the provisions of a distributed generation (DG) incentive program, which became known as the Self-Generation Incentive Program.

The SGIP provided financial incentives to customers of Investor-Owned Utilities (IOUs) to install certain types of DG facilities that could meet all, or a portion of their energy needs. DG technologies eligible under the SGIP included solar photovoltaic (PV) systems, fossil- and renewable-fueled reciprocating engines, fuel cells, microturbines, small-scale gas turbines, and wind energy systems. The first SGIP application was accepted in July 2001.

In October 2003, AB 1685[3] extended the SGIP beyond 2004 through 2007 in largely the same form that existed on January 1, 2004. This legislation notwithstanding, a number of program modifications were made in 2004 and 2007. In particular, with the enactment of the

---

1 AB 970 (California Energy Security and Reliability Act of 2000) (Ducheny, September 6, 2000). http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

2 CPUC D.01-03-073, March 27, 2001. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/6083.htm

3 AB 1685 (Leno, October 12, 2003). http://www.leginfo.ca.gov/pub/03-04/bill/asm/ab_1651-1700/ab_1685_bill_20031012_chaptered.html

California Solar Initiative (CSI), incentive funding for PV moved outside of the SGIP. Effective January 1, 2007, PV projects could no longer apply to the SGIP for incentives. Approval of AB 2778[4] in September 2006 extended the SGIP through January 1, 2012 but limited project eligibility to "ultra-clean and low emission distributed generation" technologies. These technologies were defined as fuel cells and wind DG technologies that met or exceeded emissions standards required under the DG certification program adopted by the California Air Resources Board. AB 2778 also set minimum system efficiency eligibility for SGIP projects based on electrical and process heat efficiencies and taking into account oxides of nitrogen (NOx) emissions. Recent CPUC rulings have also modified incentive funding under the SGIP. D.08-11-044 expanded incentive payments to include advanced energy storage technologies if coupled to eligible SGIP technologies.[5] Similarly, D.08-04-049 removed the incentive payment ceiling that had been set at 1 MW and increased it to 3 MW.[6]

The SGIP has been operational since July 2001. As of the end of 2008, the SGIP represented one of the single largest and longest-running DG incentive programs in the country. As of December 31, 2008, over $743 million in incentives had been paid out or reserved through the SGIP, resulting in the installation of 1,331 "Complete" and 194 "Active" projects representing just under 458 megawatts (MW) of rebated capacity.

2.2 Impact Evaluation Requirements

Due to the magnitude of the SGIP, the CPUC felt evaluation was an essential element of the program. In D.01-03-073, the CPUC authorized the SGIP Program Administrators (PAs) "to outsource to independent consultants or contractors all program evaluation activities…." Impact evaluations were among the evaluation activities outsourced to independent consultants. D.01-03-073 also directed the assigned Administrative Law Judge (ALJ), in consultation with the CPUC Energy Division and the PAs, to establish a schedule for filing the required evaluation reports.

---

4 AB 2778 (Lieber, September 29, 2006). http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

5 D.08-11-044, November 21, 2008. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/94272.htm

6 D.08-04-049, April 24, 2008. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81915.htm

Table 2-1 lists the SGIP impact evaluation reports filed with the CPUC prior to 2008.

Table 2-1: SGIP Impact Evaluation Reports Prepared to Date

Program Year (PY) Covered	Date of Report
2001[7]	June 28, 2002
2002[8]	April 17, 2003
2003[9]	October 29, 2004
2004[10]	April 15, 2005
2005[11]	March 1, 2007
2006[12]	August 30, 2007
2007[13]	September 2008

7 Regional Economic Research (RER). *California Self-Generation Incentive Program: First Year Impact Evaluation Report*. Submitted to Southern California Edison. June 28, 2002. http://www.energycenter.org/uploads/Selfgen%20First%20Year%20Process%20Report.pdf

8 Itron, Inc. *California Self-Generation Incentive Program: Second Year Impact Evaluation Report*. Submitted to Southern California Edison. April 17, 2003. http://www.energycenter.org/uploads/SelfGen%20Second%20Year%20Impacts%20Report.pdf

9 Itron, Inc. *CPUC Self-Generation Incentive Program: Third Year Impact Assessment Report.* Submitted to The Self- Generation Incentive Program Working Group. October 29, 2004. http://www.energycenter.org/uploads/Selfgen%20Third%20Year%20Impacts%20Report.pdf

10 Itron, Inc. *California Self-Generation Incentive Program: Fourth Year Impact Evaluation Report.* Submitted to Southern California Edison. April 15, 2005. http://www.energycenter.org/uploads/SelfGen%202004%20Fourth%20Year%20Impacts.PDF

11 Itron, Inc. *California Self-Generation Incentive Program: Fifth Year Impact Evaluation Report.* Submitted to Pacific Gas & Electric. March 1, 2007. http://www.energycenter.org/uploads/SelfGen_Fifth_Year_Impact_Report.pdf

12 Itron, Inc. *California Self-Generation Incentive Program: Sixth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. August 30, 2007. http://www.energycenter.org/uploads/SGIP_M&E_Sixth_Year_Impact_Evaluation_Final_Report_August_30_2007.pdf

13 Itron, Inc. *California Self-Generation Incentive Program: Seventh Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. September 2008. http://www.energycenter.org/uploads/SGIP_7th_Year_Impact_Evaluation_FinalReport_20081001.pdf

In D.09-01-013, the CPUC approved a Measurement and Evaluation (M&E) plan for program years 2009 through 2011.[14] Table 2-2 identifies the schedule for filing of the 2009, 2010, and 2011 impact evaluation reports.

Table 2-2: Post-PY2008 SGIP Impact Evaluation Reports

Program Year (PY) Covered	Date of Report Filing to the CPUC
2009	June 25, 2010
2010	June 24, 2011
2011	June 22, 2012

This report provides the findings of an impact evaluation covering the 2008 program year (PY08) of the SGIP.

In addition to being one of the largest and longest-lived DG incentive programs in the country, the SGIP also represents a program with an extremely diverse family of technologies. DG technologies deployed under the SGIP receive incentives in accordance with their associated "incentive level." Because incentive levels and the groupings of technologies that fall within them have changed over time, impact results are summarized in this report by technology and fuel type instead of incentive level.[15]

---

[14] D. 09-01-013, January 29, 2009. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/96779.htm

[15] The use of technology and fuel type in lieu of incentive level was initiated with the Sixth Year Impact Report.

Table 2-3 summarizes the SGIP technology groups used in this report.

Table 2-3: SGIP Technologies and Applicable Program Years[16]

SGIP Generation Technology	Applicable Program Years
Photovoltaics (PV)	PY01–PY06
Wind turbines (WD)	PY01–PY11
Non-renewable fuel cells (FC-N)	PY01–PY11
Renewable fuel cells (FC-R)	PY01–PY11
Non-renewable-fueled internal combustion engines (IC engine-N)	PY01–PY07
Renewable-fueled internal combustion engines (IC engine-R)	PY01–PY07
Non-renewable-fueled microturbines (MT-N)	PY01–PY07
Renewable-fueled microturbines (MT-R)	PY01–PY07
Non-renewable-fueled gas turbines (GT-N)	PY01–PY07
Renewable-fueled gas turbines (GT-R)	PY01–PY07
Advanced energy storage (AES) coupled with eligible SGIP	PY08–PY11

2.3 Scope of the Report

The 2008 Impact Evaluation Report represents the eighth impact evaluation conducted under the SGIP. At the most fundamental level, the overall purpose of all annual SGIP impact evaluation analyses is identical: to produce information that helps SGIP stakeholders make informed decisions about the SGIP's design and implementation. However, impact evaluation information collected under the SGIP may have significant relevance to other energy programs. For example, PV performance degradation information gleaned from the SGIP can act as a benchmark for PV performance under the CSI and increase understanding of the types and magnitude of PV performance degradation expected in the future. Similarly, the SGIP provides information on the relationship between waste heat recovery and net greenhouse gas (GHG) emissions from combined heat and power (CHP) facilities. This information may help the CEC in development of guidelines to help reduce GHG emissions from CHP facilities as required under AB 1613.[17]

As the SGIP has evolved over time, the focus and depth of the impact evaluation reports have changed appropriately. Like prior impact evaluation reports, the 2008 report examines the

[16] This table lists technologies that have been eligible at some time during the SGIP to receive incentives. Effective January 1, 2007, new PV projects could no longer receive incentives under the SGIP. In addition, eligibility of other DG technologies was restricted to wind and fuel cells.

[17] AB 1613 (Waste Heat and Carbon Emissions Reduction Act) (Blakeslee, October 14, 2007). http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1601-1650/ab_1613_bill_20071014_chaptered.html

effects of SGIP technologies on electricity production and demand reduction; on system reliability and operation; on compliance with renewable fuel use and thermal energy efficiency requirements; and on GHG emission reductions associated with each SGIP technology category. Transmission and distribution (T&D) system operation and reliability impacts are not addressed in the 2008 Impact Evaluation Report, as they will be treated in a special report on T&D aspects of the SGIP.[18]

Impact Evaluation Objectives

2008 SGIP impact evaluation objectives include:

- Electricity energy production and demand reduction
  - Annual production and production at peak periods during summer (both at CAISO system and at individual IOU-specific summer peaks)
  - Peak demand impacts (both at CAISO system and at individual IOU-specific summer peaks)
  - Combined across technologies and by individual technology category
- Compliance of fuel cell, internal combustion (IC) engine, microturbine, and gas turbine technologies are assessed against PUC 216.6[19] requirements
  - PUC 216.6 (a): useful recovered waste heat requirements
  - PUC 216.6 (b): system efficiency requirements
- GHG emission reductions are estimated by SGIP technology
  - Net against CO_2 emissions generated otherwise from grid generation
  - Methane captured by renewable fuel use projects
- Trending of performance by SGIP technology from 2002 through 2008

---

[18] AB 578 (Blakeslee, September 30, 2008) requires the CPUC to assess the impacts of the SGIP on the T&D system as part of a larger T&D study report due to the Legislature on or before January 1, 2010. http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_0551-0600/ab_578_bill_20080930_chaptered.html

[19] Public Utilities Code 216.6 was previously Public Utilities Code 218.5. The requirements have not changed. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=201-248

2.4 Report Organization

This report is organized into five sections and six appendices, as described below.

- **Section 1** provides an executive summary of the key objectives and findings of this eighth-year impact evaluation of the SGIP through the end of 2008.
- **Section 2** is this introduction.
- **Section 3** presents a summary of the program status of the SGIP through the end of 2008.
- **Section 4** describes the sources of data used in this report for the different technologies.
- **Section 5** discusses the 2008 impacts associated with SGIP projects at the program level. The section provides a summary discussion as well as specific information on impacts associated with energy delivery; peak demand reduction; efficiency and waste heat utilization requirements; and GHG emission reductions.
- **Appendix A** gives more detailed information on costs, annual energy produced, peak demand, and capacity factors by technology and fuel type.
- **Appendix B** describes the methodology used for developing estimates of SGIP GHG impacts.
- **Appendix C** describes the data collection and processing methodology, including the uncertainty analysis of the program-level impacts. This appendix also contains the performance distributions used in the uncertainty analysis.
- **Appendix D** gives an overview of the metering systems employed under the SGIP for metering electric generation, fuel consumption, and heat recovery.
- **Appendix E** provides a listing of the various metering equipment installed by Itron for the purposes of this evaluation and the associated specification sheets (meters installed by other parties are not treated or discussed in this report).
- **Appendix F** provides copies of legislation and CPUC rulings relevant to the SGIP and referenced in this report.
- **Appendix G** lists cumulative system cost and incentive trends.

3

Program Status

3.1 Introduction

This section provides information on the status of the Self-Generation Incentive Program (SGIP) as of the end of December 31, 2008. The status is based on project data provided by the Program Administrators (PAs) relative to all applications extending from Program Year 2001 (PY01) through the end of Program Year 2008 (PY08). Information in this section includes the geographical distribution of SGIP projects, the status of projects in the SGIP, the associated amount of rebated capacity deployed under the SGIP, incentives paid or reserved, and project costs.

3.2 Overview

Table 3-1 provides a summary of the number and rebated capacity[1] of SGIP projects among the four PAs as of the end of PY08.

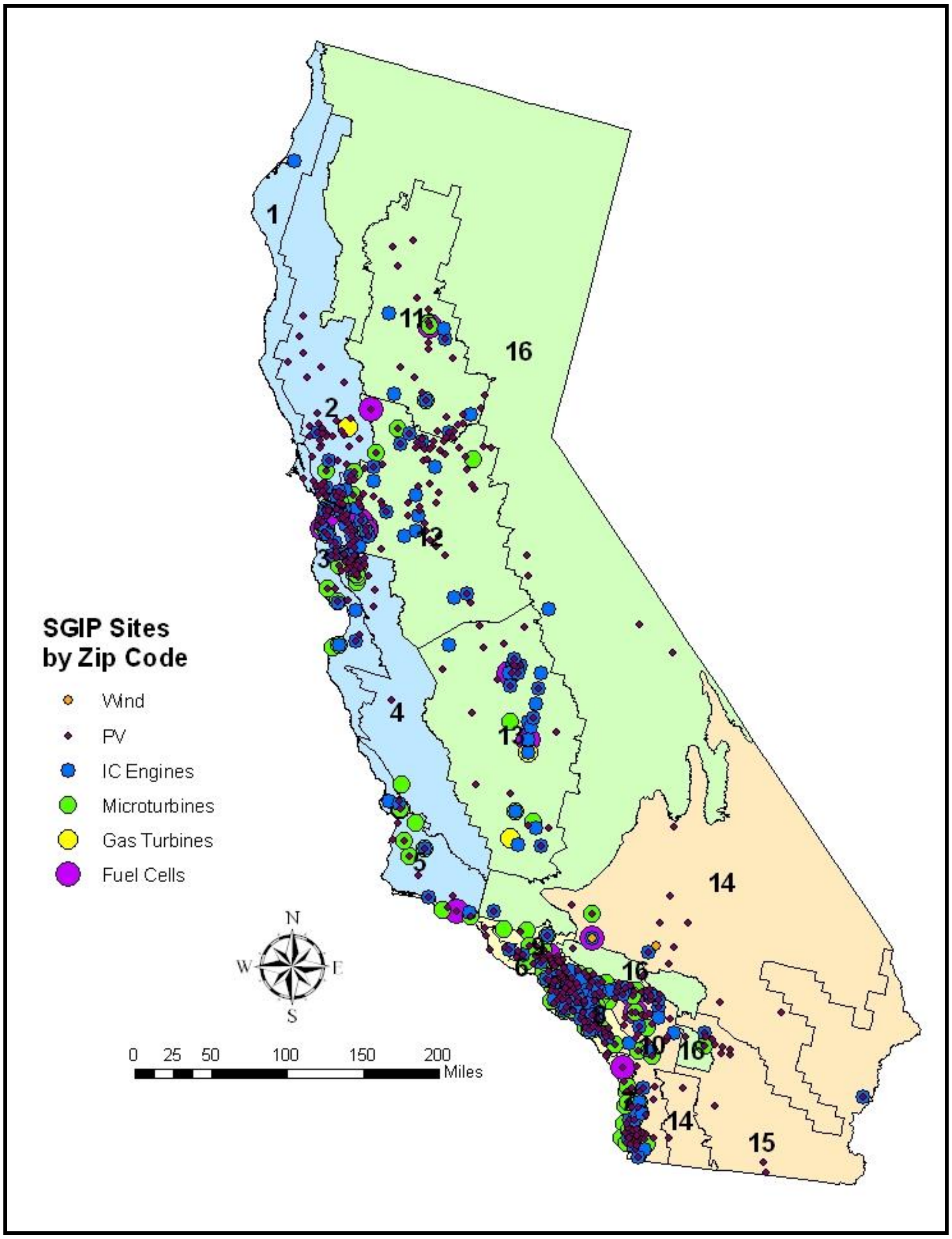
Table 3-1: SGIP Projects and Rebated On-Line Capacity by PAs as of 12/31/08

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	655	154.0	46%
SCE	283	64.2	19%
SCG	189	79.9	24%
CCSE	148	39.2	12%
Totals	**1275**	**337.4**	**100%**

[1] The rebated capacity is the rating associated with the rebate (incentive) provided to the applicant. The rebate capacity may be lower than the typical "nameplate" rating of a generator.

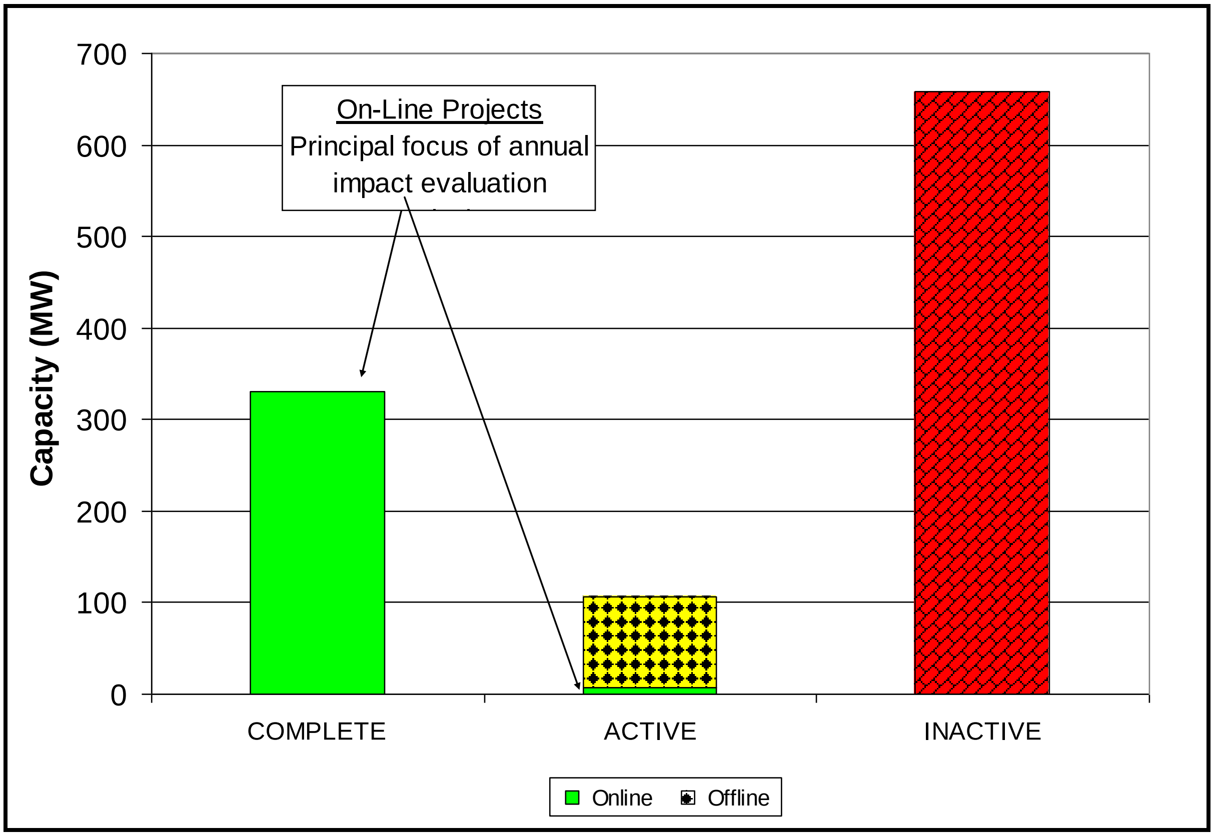
Geographically, projects deployed under the SGIP are located throughout the service territories of the three major investor-owned utilities (IOUs) in California as well as throughout a number of municipal electric utilities. Figure 3-1 shows the distribution of SGIP facilities across California by technology type. As may be expected, SGIP facilities tend to be concentrated in the urban centers of California. In addition, the map shows the predominance of PV facilities within the SGIP as of the end of PY08.

Figure 3-1: Distribution of SGIP Facilities as of 12/31/08



Once SGIP applications are received within the program, they proceed to eventually become either "Complete" or "Inactive" projects. Figure 3-2 summarizes the status of SGIP projects at a very high level. It shows the status of all SGIP projects by their stage of progress within the SGIP implementation process and their "on-line" status, as of the end of 2008. "On-line" projects are defined as those that have entered normal operations (i.e., projects are through the "shakedown" or testing phase and are expected to provide energy on a relatively consistent basis).[2]

Figure 3-2: Summary of PY01–PY08 SGIP Project Status as of 12/31/2008



Key stages in the SGIP implementation process include:

- ***Complete Projects:*** These represent SGIP projects for which the generation system has been installed, verified through onsite inspections, and an incentive check has been issued. We consider all Complete projects as "on-line" projects for impact evaluation purposes.

2 The reference to having entered 'normal operations' is not an indication that a system is actually running during any given hour of the year. For example, some systems that have entered normal operations do not run on weekends.

- ***Active Projects:*** These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a wait list.[3] Over time, the Active projects will migrate either to the Complete or to the Inactive category. Some of these projects entered normal operations as of the end of 2008. However, because an incentive check had not been issued, we do not consider these projects Complete projects. Note that we treat Active projects as "on-line" if they have entered normal operation, even if they have not received an incentive check.[4]
- ***Inactive Projects:*** These represent SGIP projects that are no longer progressing in the SGIP implementation process because they have been withdrawn by the applicants or rejected by the PA.

Complete and Active SGIP Projects

The status of Complete and Active projects within the SGIP is important because these projects represent technologies that can potentially affect the electricity system. Table 3-2 provides a breakdown by technology and fuel type of the Complete and Active projects depicted graphically in Figure 3-2. The "(n)" represents the number of Complete, Active, or total projects. The "(MW)" refers to the total rebated capacity in megawatts (MW) for those "n" projects.

Table 3-2: Quantity and Capacity of Complete and Active Projects

Technology & Fuel*	Complete		Active (All)		Total		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg. Size (kW)
PV	880	132.9	24	8.4	904	141.4	156
WD	2	1.6	11	23.1	13	24.8	1,904
FC–N	15	8.5	39	2.0	54	10.4	193
FC–R	5	3.5	19	22.7	24	26.2	1,090
Engine/Turbine–N	328	168.7	67	42.7	395	211.5	535
Engine/Turbine–R	38	15.0	15	6.9	53	21.9	414
All	**1268**	**330.2**	**175**	**105.9**	**1443**	**436.1**	**302**

* PV = Photovoltaic; WD = Wind; FC = Fuel Cell; N = Non-Renewable; R = Renewable

There were 1,443 Complete and Active projects, representing just over 430 MW of capacity in the SGIP by December 31, 2008. Seventy projects were completed in 2008, increasing the

---

3 When SGIP funding has been exhausted, eligible projects are placed on a wait list within the relevant incentive level has been exhausted for that Program Year. Previously, projects that remained on a wait list at the end of the Program Year were required to re-apply for funding for the subsequent funding cycle. This requirement was eliminated in December 2004 by D.04-12-045. (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/42455.htm). Over time, projects that are withdrawn or rejected are replaced by projects from the wait list.

4 "Off-line" projects are those projects that have active applications but are not yet operational.

capacity of Complete projects to over 330 MW.[5] However, the number of Active projects decreased between 2007 and 2008. The combined effect of the increase in Complete projects and decrease in Active projects resulted in a total Active project capacity of about 114 MW. With enactment of the California Solar Initiative (CSI), photovoltaic (PV) projects were no longer eligible to receive incentives under the SGIP effective January 1, 2007. In addition, many PV projects that applied to the SGIP in 2006 were transitioned to the CSI. These "SGIP transition" projects received their incentive payments from the CSI instead of SGIP. As PV projects were the largest contributors to new SGIP projects, the lack of growth in new PV projects was the primary reason for the decrease in Active projects.[6] Itron cross-referenced CSI and SGIP project databases in order to identify SGIP transition projects. Table 3-3 shows the number and capacity of PV projects that Itron was able to identify as SGIP transition projects, broken out by PA. Overall, 21.6 MW of PV capacity were identified as having been transferred from the SGIP to CSI. However, the CPUC reported that 23.6 MW have been transferred to the CSI.[7] This means that there are an additional 2.0 MW in PV capacity in the SGIP that have not yet been identified by Itron as SGIP transition projects.

Table 3-3: Number and Capacity of SGIP Transition Projects

PA	Complete		Active (All)		Total	
	(n)	(MW)	(n)	(MW)	(n)	(MW)
PG&E	39	7.18	11	6.02	50	13.19
SCE/SCG	24	6.30	7	2.07	31	8.37
CCSE	0	0.00	1	0.04	1	0.04
All	**63**	**13.48**	**19**	**8.12**	**82**	**21.60**

5 There were 1,205 Complete projects by the end of 2007 representing slightly less than 311 MW of rebated capacity.

6 At the end of 2007, there were over 253 Active PV projects, whereas at the end of 2008 there were only 24 projects awaiting completion.

7 California Public Utilities Commission. *California Solar Initiative Staff Progress Report.* January 2009. http://www.energy.ca.gov/2009publications/CPUC-1000-2009-002/CPUC-1000-2009-002.PDF

SGIP On-Line Projects

While Complete and Active projects represent SGIP projects with potential impacts, on-line projects are grid-connected and operational; and as such create actual impacts on the electricity system. Consequently, the principal focus of the 2008 impact evaluation is the subset of projects that were on-line by December 31, 2008. Table 3-4 provides information on the number and capacity of on-line projects. The information is broken down by technology and fuel type as well as identification of whether the project is Complete or Active on-line. By the end of 2008, on-line projects represented nearly 1,300 projects and 337 MW of rebated capacity; a growth of 66 on-line projects and an increase in approximately 36 MW of on-line capacity above 2007 levels.

Table 3-4: Quantity and Capacity of Projects On-Line as of 12/31/2008

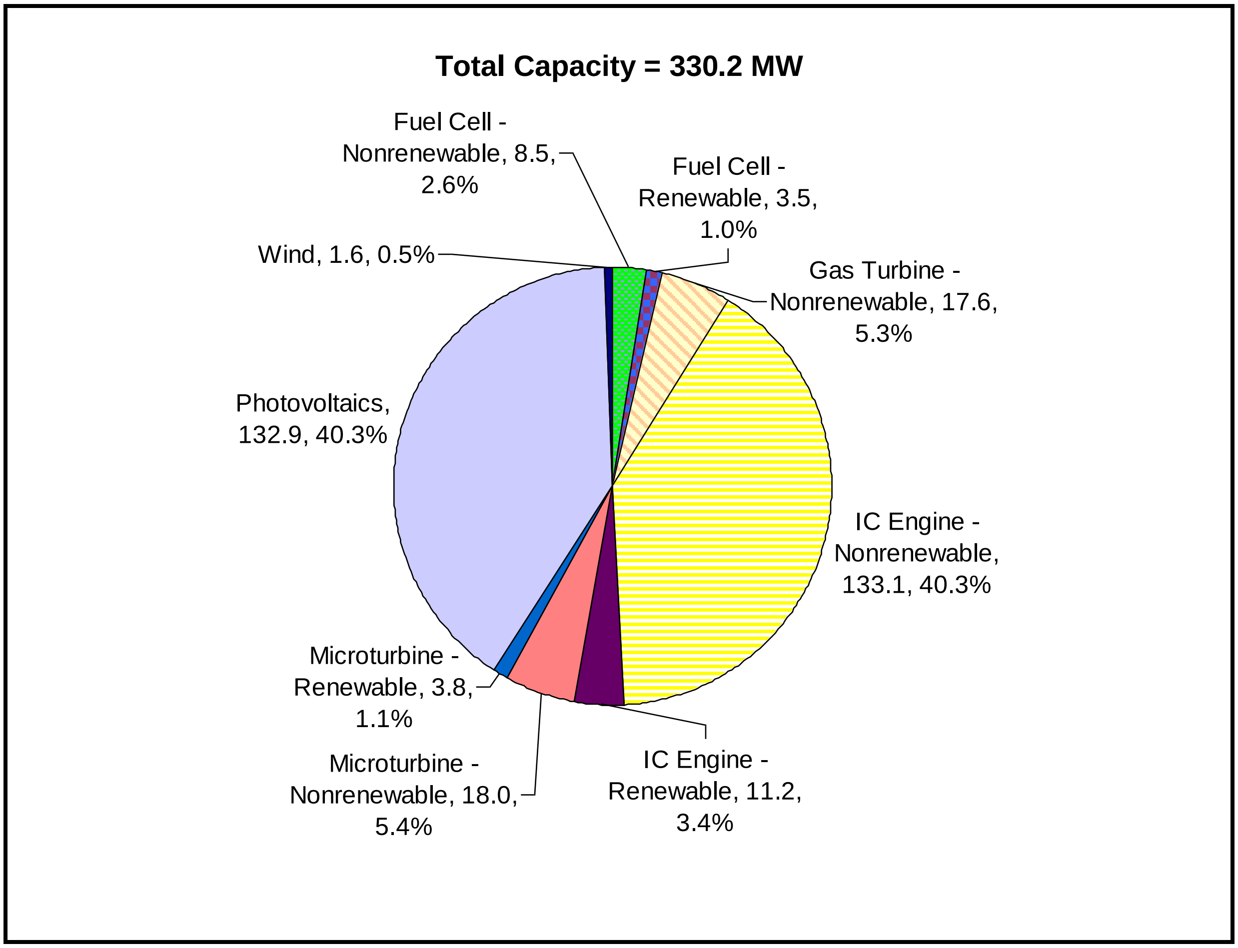
Technology & Fuel	Complete		Active (On-Line)		Total On-Line Projects		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg. Size (kW)
PV	880	132.9	2	0.3	882	133.3	151
WD	2	1.6	0	0.0	2	1.6	824
FC–N	15	8.5	1	0.4	16	8.9	553
FC–R	5	3.5	0	0.0	5	3.5	690
Engine/Turbine–N	328	168.7	4	6.4	332	175.2	528
Engine/Turbine–R	38	15.0	0	0.0	38	15.0	394
All	**1268**	**330.2**	**7**	**7.1**	**1275**	**337.4**	**265**

Complete SGIP Projects

Statistics on Complete projects serve as a benchmark in evaluating changes in the SGIP with respect to capacity, paid incentives and technology costs.

Figure 3-3 shows a breakout of the SGIP generating capacity for all Complete projects by technology and fuel type at the end of 2008.[8] IC engines, gas turbines, and microturbines powered by non-renewable fuels contributed over 168 MW of rebated capacity, or more than half the total capacity of the SGIP. PV technologies by themselves contributed nearly 133 MW of rebated capacity; just over 40 percent of the total SGIP capacity.

Figure 3-3: SGIP Complete Project Capacity (MW) by Technology and Fuel Type as of 12/31/08

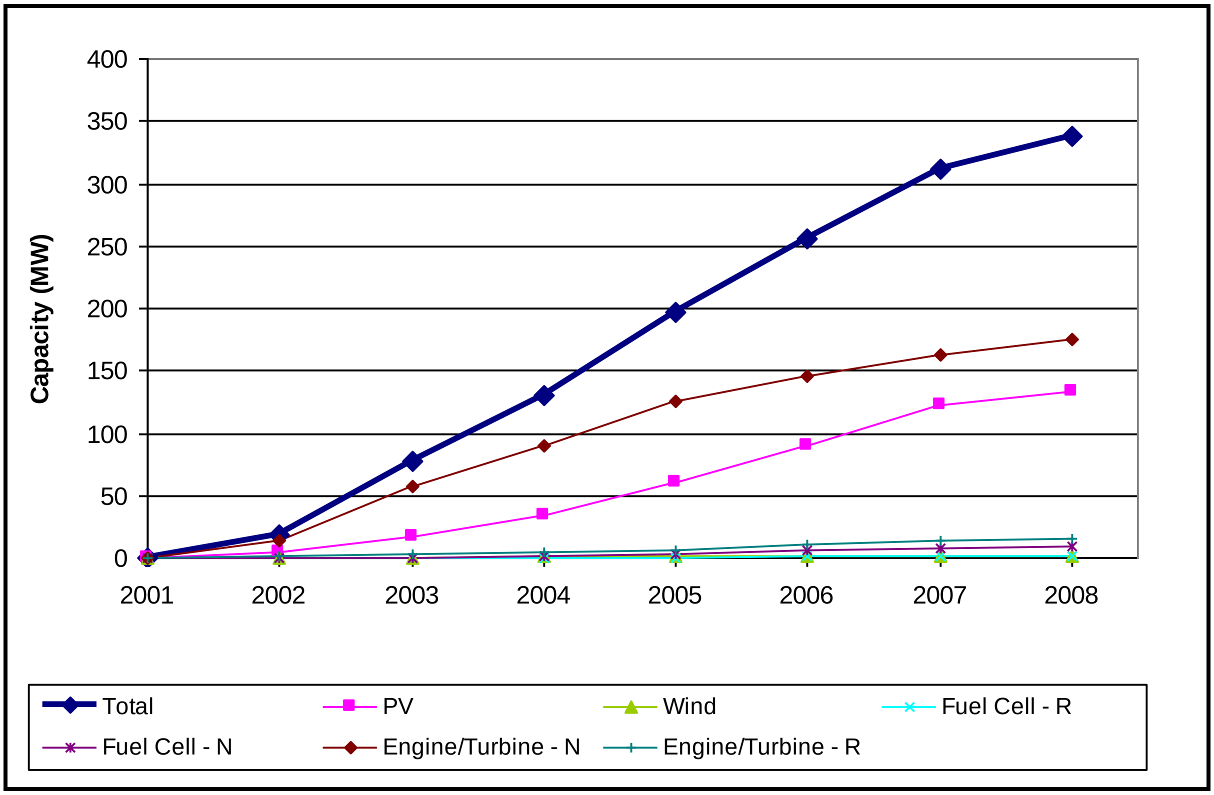


8 Here we refer only to Complete projects and do not include on-line Active projects. On-line Active projects had not received incentive checks and as such were not included in the formal count of projects until they receive their incentive check.

Trends of SGIP On-line Project Capacity

Figure 3-4 shows the increase in rebated capacity of on-line (Complete and Active) projects extending from 2001 through the end of 2008 by technology and fuel type. The capacity of Complete projects increased eight percent (26 MW) from 2007 to 2008. PV systems installed between 2007 and 2008 represent slightly less than 11 MW of capacity, contributing slightly less than half of the growth of the SGIP during this period. Slightly more than 12 MW of the remaining growth in capacity came from microturbines, IC engines, and gas turbines using non-renewable fuel. Fuel cells powered by non-renewable sources contributed one MW. Similarly, renewable-fueled microturbines and IC engines contributed less than one MW of increased capacity during 2008.[9]

Figure 3-4: Growth in On-Line Project Capacity from 2001-2008



While there is continued increased growth in on-line capacity of SGIP projects between 2007 and 2008, it is clearly less than that seen for previous years. There are three possible explanations for the reduction in growth of on-line project capacity in 2008 compared with previous years. The first reason is the lack of new PV project growth. As noted earlier, PV projects were no longer eligible to receive incentives through the SGIP effective January 1, 2007. Due to the lack of new applications, growth in PV capacity under the SGIP slowed.

9 There have been no new wind projects completed in the SGIP since 2005.

Additionally, many of the PV projects that applied in 2006 became transition projects to the CSI.

The second reason for reduced growth of on-line project capacity during 2008 is slower growth in non-renewable-fueled engine and turbine capacities. This slower growth in engine and turbine capacities was first reflected in 2005 and 2006. In 2005 and 2006, non-renewable-fueled engine/turbine projects were required to meet the 2005 California Air Resources Board (CARB) NOx emission standard of 0.14 pounds of NOx emitted per Megawatt-hour of generated electricity (lbs/MWh). In 2007, new non-renewable-fueled engine/turbine projects had to meet the CARB NOx emission standard of 0.07 lbs/MWh. The CARB standard could be met by using a fossil fuel combustion emission credit for waste heat utilization so long as the system achieved the 60 percent minimum efficiency standard. However, difficulties in meeting certification requirements, and extra permitting costs and NOx control costs may have discouraged technology adoption. Thirty-five (35) MW of new engine/turbine capacity came on-line between 2004 and 2005. In comparison, only 12 MW of new engine/turbine capacity came on-line between 2007 and 2008.

The third reason is restrictions on SGIP project eligibility, which also contributed to reduced growth in on-line capacity. Effective January 1, 2008, SGIP project eligibility was restricted to wind energy and fuel cell technologies. As there has been low growth in both wind and fuel cell technologies under the SGIP, the restricted eligibility has acted to reduce the number of projects completed under the program.

Overlap of SGIP Projects between IOU and Municipal Utilities

Customers of the California IOUs fund the SGIP through a cost recovery process administered by the CPUC. Every IOU customer is eligible to participate in the SGIP. In some cases, these same IOU customers are also customers of municipal utilities. Consequently, deployed SGIP projects can have impacts on both IOU and municipal utilities.[10]

Table 3-5 shows the breakout of SGIP projects by the electricity utility type (i.e., whether the customer has electric service with an IOU or municipal utility). In some instances customers fall into two overlapping service areas. Generally, the largest project capacity overlap between IOU and municipal utilities occurs with PV systems. At the end of 2008, approximately nine percent of the rebated PV capacity in the SGIP represented systems installed at sites of IOU customers who were also customers of municipal utilities. Approximately three percent of cogeneration (engine/turbine–non-renewable) capacity was attributable to municipal utility customers. Seventy-three of the 96 PV projects involving municipal utility customers correspond to SCG SGIP projects. Most of these projects received support from both the SGIP and a solar PV program offered by the municipal utility.

Table 3-5: Electric Utility Type for On-Line Projects as of 12/31/2008

Technology & Fuel	IOU		Municipal		Total On-Line	
	(n)	(MW)	(n)	(MW)	(n)	(MW)
PV	786	121.8	96	11.5	882	133.3
WD	2	1.6	0	0.0	2	1.6
FC–N	15	7.9	1	1.0	16	8.9
FC–R	4	2.3	1	1.2	5	3.5
Engine/Turbine–N	317	170.7	15	4.5	332	175.2
Engine/Turbine–R	38	15.0	0	0.0	38	15.0
All	**1162**	**319.2**	**113**	**18.2**	**1275**	**337.4**

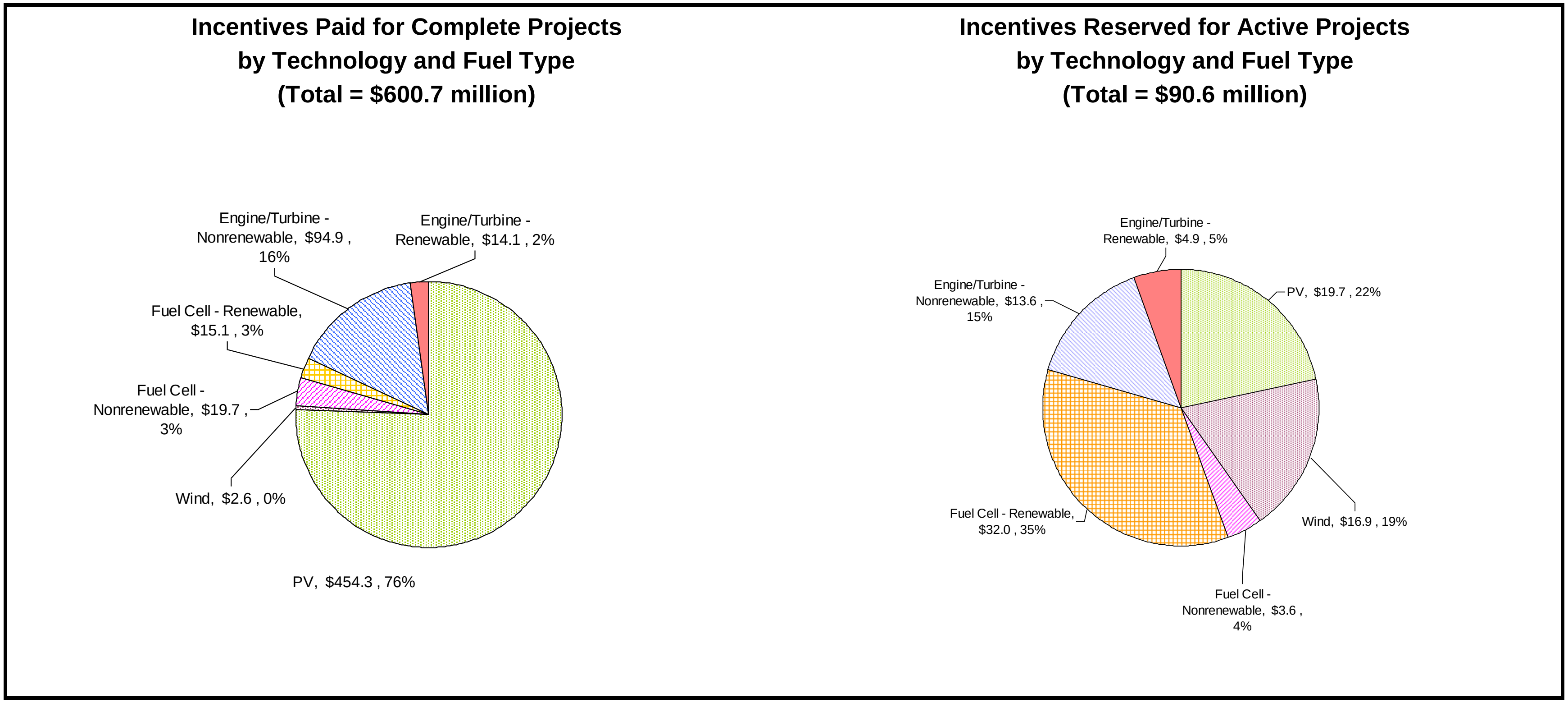
10 Situations where IOU customers can also be customers of municipal utilities occur when there is a geographical division of energy services. For example, due to their geographical location, a customer in Southern California may receive electricity service from a municipal utility such as Los Angeles Department of Water and Power and receive natural gas service from SCG. As SCG participates in the SGIP, that electricity customer was eligible to apply to the SGIP.

SGIP Project Progress and Incentive Payment Status

Another way to identify project status within the SGIP is by the stage of incentive payment. Incentives are only paid for Complete projects. In comparison, incentives are reserved for Active projects and are not paid until the project reaches the Complete stage. PAs can use incentive payment status to examine the funding backlog of SGIP projects by technology and fuel type. Figure 3-5 summarizes SGIP incentives paid or reserved as of December 31, 2008. By the end of PY08, over $600 million in incentive payments had been paid to Complete projects. The reserved backlog totaled slightly under $91 million. This is a significant reduction compared with the prior year, which had a backlog of over $283 million. The reduction in backlog is most likely due to the completion of PV projects that applied to the program prior to 2007 as well as the transition of some PV projects to the CSI Program.[11] Incentive reservations for renewable-fueled fuel cell projects stayed relatively constant from about $50 million at the end of 2007 to just under $51 million at the end of 2008.

[11] At the end of 2007, there was a total of $174 million reserved for PV projects, whereas at the end of 2008 there was roughly $20 million reserved for PV projects.

Figure 3-5: Incentives Paid or Reserved for Complete and Active Projects



3.3 Characteristics of Complete and Active Projects

Key characteristics of Complete and Active projects include system capacity and project costs.

System Size (Capacity)

Table 3-6 summarizes the system capacity characteristics of all Complete projects by technology and fuel type. Under the SGIP, only the first MW of capacity is rebated. This changed starting in PY08. Fuel cell and wind projects can now receive a rebate for the first three MW of capacity.[12] Because the SGIP has historically only provided an incentive for the first MW of capacity, most projects were sized within this cap and this is reflected when looking at the maximum system size by technology. Currently, only gas turbine and IC engine projects have a maximum project size substantially larger than the size rebated under the SGIP.

Table 3-6: Installed Capacities of PY01–PY08 Projects Completed by 12/31/2008

Technology & Fuel*	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
PV	880	151	28	78	1,050
WD	2	824	699	824	950
FC–N	15	563	200	500	1,000
FC–R	5	690	250	600	1,200
IC Engine–N	210	634	60	475	4,110
IC Engine–R	17	658	80	704	1,080
GT–N	6	2,941	1,210	2,962	4,600
MT–N	112	161	28	114	928
MT–R	21	180	30	210	420

* PV = Photovoltaic; WD = Wind; FC = Fuel Cell; IC Engine = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine; N = Non-Renewable; R = Renewable

Generally, gas turbines deployed under the SGIP tend to have the largest project capacities, followed by IC engines. Maximum capacities for IC engines and gas turbines using non-renewable fuel exceeded four MW, with average sizes of approximately 658 kW and 2.9 MW, respectively. While there are some large (i.e., greater than one MW) PV systems installed under the SGIP, most tend to be less than 150 kW in capacity. Similarly, non-

[12] Per D.08-04-049, carryover funds can be used during 2008 and 2009 to pay incentives for up to 3 MW of capacity for fuel cell and wind turbine projects. The incentive amount for the first MW installed is 100 percent of that allotted in the SGIP Handbook. The incentive amount for the second MW installed is 50 percent of that allotted and the incentive amount for the third MW installed is 25 percent of that allotted in the SGIP Handbook.

renewable-fueled microturbines deployed by the end of PY08 under the SGIP tended to be less than 160 kW in capacity, while renewable-fueled microturbines tended to be slightly larger with a mean size of 180 kW. Renewable-fueled fuel cell systems also tended to be larger than their non-renewable-fueled counterparts, with a mean size of 690 kW and 563 kW, respectively. The few wind systems deployed under the SGIP by the end of PY08 were medium-sized facilities with a mean capacity of 824 MW.

System capacities of Active projects may indicate incipient changes in SGIP project capacities. If a large number of Active projects have smaller capacities than their Complete project technology counterparts, migration of these Active projects into the Complete project category will act to decrease the average installed capacity. This is important because in some cases impacts from technologies can be more affected by project capacity rather than the number of projects. With the exception of wind and non-renewable fuel cells systems, SGIP technologies saw an increase in mean capacity during 2008. The mean system size of PV systems increased in 2008 from 136 to 151 kW, while the mean size of non-renewable IC engines grew slightly from 625 kW to 634 kW, and the mean size of renewable-fueled microturbines increased slightly from 177 kW to 180 kW.

Table 3-7 summarizes the system capacity characteristics of Active projects by technology and fuel type. With the exception of non-renewable fuel cells, the rebated capacities of Active projects tended to be greater than their Complete project technology counterparts. As a result, the average capacity of SGIP projects overall can be expected to continue to increase in 2008 as these larger, Active projects migrate to the Complete status. The same prediction was made for 2007 when Active project sizes were compared to Complete project sizes. However, some of the larger Active projects at the end of 2007 were still not completed in 2008. The result was only a small rise in average size of Complete projects from the end of 2007 to the end of 2008. If the larger Active projects are completed in 2009, this will continue to increase the average size per technology at the end of 2009 compared to the average size seen at the end of 2008. Beginning in 2008, non-renewable fuel cells no longer have a minimum size requirement[13] and the majority of the applications received in 2008 for non-renewable fuel cells projects are for systems five kW in size.

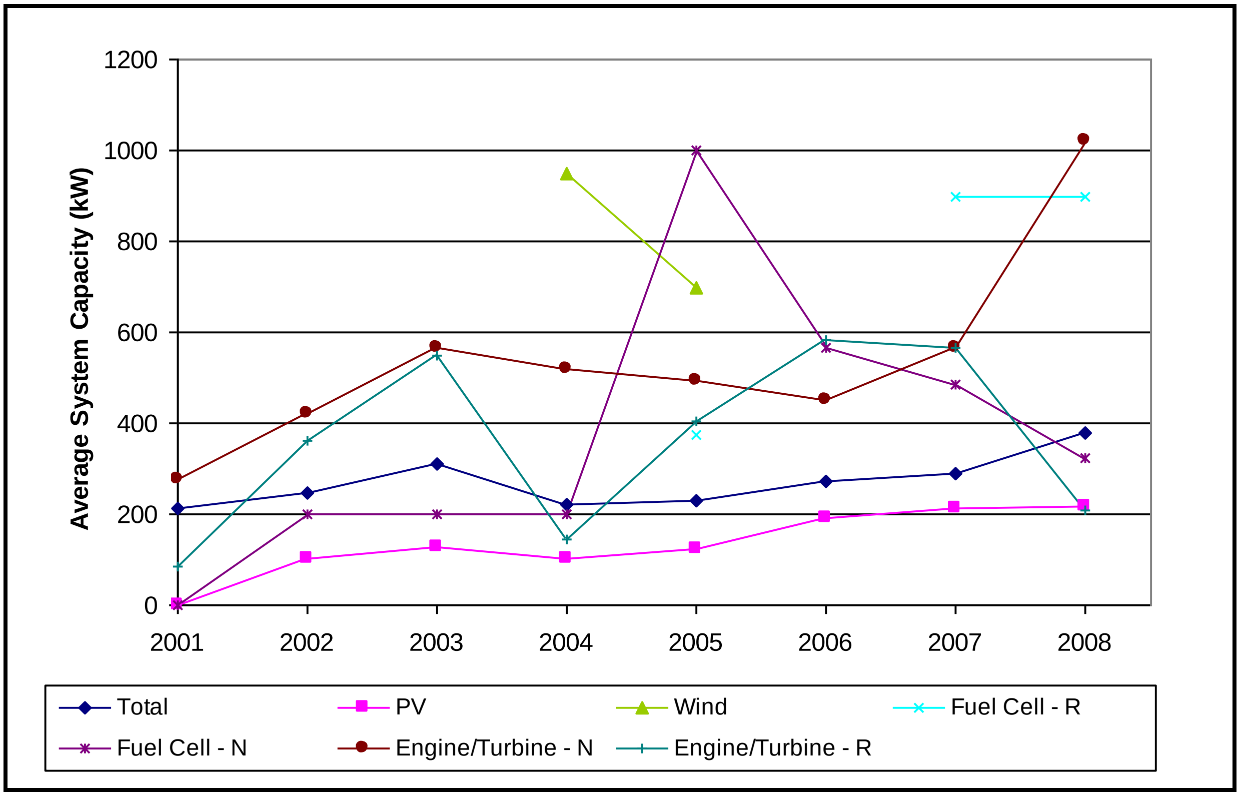
Table 3-7: Capacities of Projects Active as of 12/31/2008

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
PV	24	351	30	213	1,002
WD	11	2,100	225	1,500	5,000
FC–N	39	51	5	5	600
FC-R	19	1,195	200	1,000	5,000
IC Engine–N	50	524	50	314	2,375
IC Engine–R	10	571	56	385	1,696
GT-N	3	3,188	1,000	4,064	4,500
GT-R	2	425	100	425	750
MT-N	14	498	58	402	2,253
MT-R	3	127	52	130	200

[13] In PY01 through PY07, there was a minimum size requirement of 30 kW for all technology and fuel types.

Figure 3-6 shows the trend of average system capacity for projects completed each year from 2001 through 2008. Note that these are not cumulative averages and only represent projects completed in each calendar year. Natural gas turbines saw a marked increase in average capacity from 2007 to 2008 and PV saw a continued mild increase in average capacity as larger Active systems were completed. There were no new wind projects in 2008. Non-renewable-fueled engines/turbines show large variability in size because there are very few which completed each year. Average capacities of PV technologies ranged between 110 to 130 kW from 2002 through the end of 2005, but in 2006 increased to almost 200 kW and in 2007 increased to over 200 kW. The net result has been that the average overall capacity of SGIP projects increased slightly from 2002 to 2003, decreased in 2004 and 2005, and then increased from 2005 to 2008. The average capacity of all Complete projects through the end of 2008 was 325 kW.

Figure 3-6: Trend of Average Capacity of Complete Projects PY01–PY08



Total Eligible Project Costs

Total eligible project costs are regulated by SGIP guidelines and reflect the costs of the installed generating system and its ancillary equipment. Table 3-8 provides total and average project cost data for Complete and Active projects from PY01 through PY08. Average per-Watt eligible project costs represent capacity-weighted averages. Note that PV costs are not reflective of market conditions affecting the rest of the PV industry during 2008. PV costs under the SGIP reflect projects for which applications had been received prior to January 1, 2007. As such, the PV SGIP costs are reflective of the earlier time-period.

Table 3-8: Total Eligible Project Costs of PY01–PY08 Projects

Technology & Fuel	Complete			Active		
	Total (MW)	Wt.Avg ($/W)	Total ($ MM)	Total (MW)	Wt.Avg ($/W)	Total ($ MM)
PV	132.9	$8.98	$1,194	8.4	$8.64	$73
WD	1.6	$3.26	$5	23.1	$2.32	$54
FC-N	8.5	$7.55	$64	1.4	$6.83	$10
FC-R	3.5	$5.98	$21	12.3	$5.24	$64
IC Engine–N	133.1	$2.26	$301	25.3	$2.86	$72
IC Engine–R	11.2	$2.47	$28	5.7	$2.64	$15
GT-N	17.6	$2.11	$37	9.6	$1.57	$15
GT-R	N/A	N/A	N/A	0.8	$2.28	$2
MT-N	18.0	$3.12	$56	6.5	$3.10	$20
MT-R	3.8	$3.44	$13	0.4	$7.70	$3
Total	**330.2**	**$5.21**	**$1,719**	**93.5**	**$3.51**	**$328**

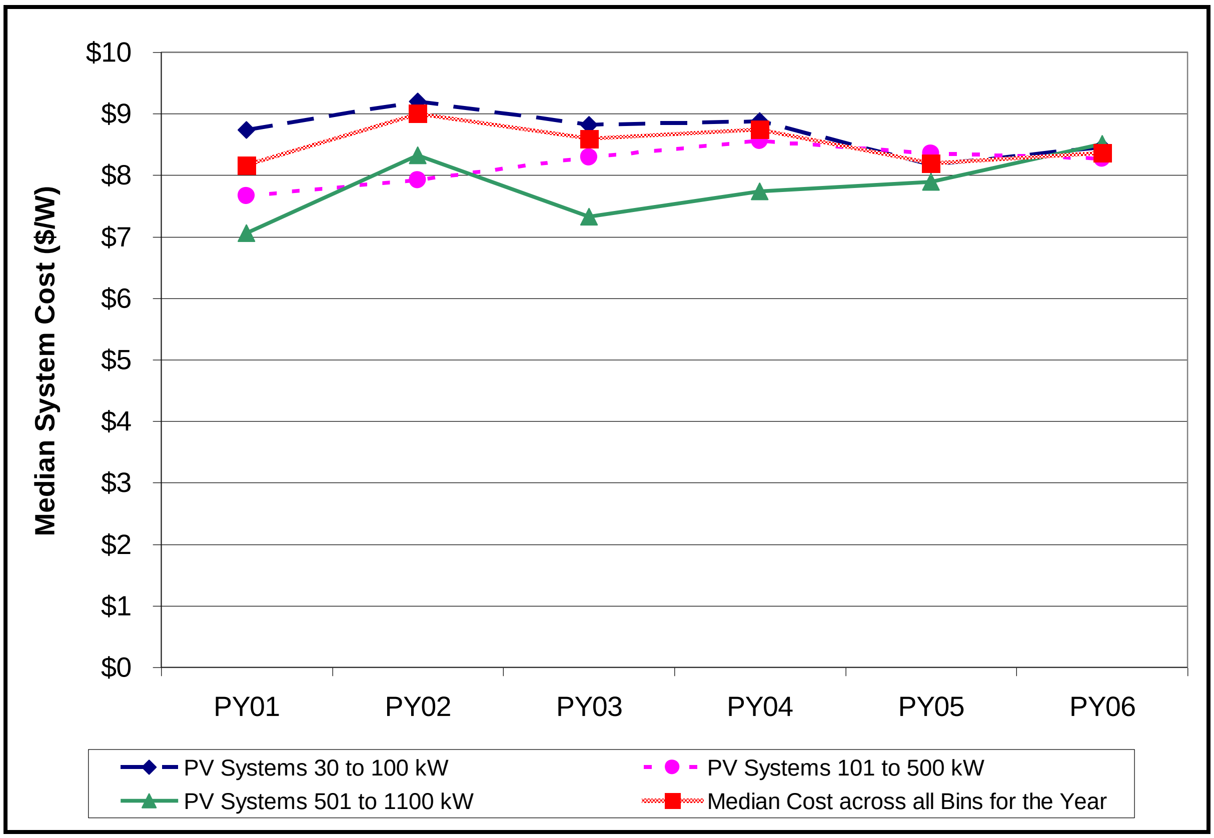
By the end of PY08, total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete projects were slightly over $1.7 billion. PV projects accounted for the vast majority (69 percent) of total eligible Complete project costs. Similarly, PV projects represent the single largest project cost category in either the Complete or Active project category. From a system capacity perspective, PV projects made up approximately 40 percent of the total Complete project capacity installed through PY08. The combined costs of renewable- and non-renewable-fueled engines and turbines accounted for the second highest total Complete project costs at $435 million (approximately 25 percent of the total eligible project costs), and corresponded to 59 percent of the total Complete project installed capacity.

On an average cost-per-installed-Watt ($/W)-basis, PV and fuel cell projects deployed under the SGIP have been more costly than engine and microturbine projects. However, any comparison of these project costs must take into consideration the fundamentally different characteristics of the technologies. In the case of cogeneration projects fueled with natural gas, ongoing fuel purchase and maintenance costs account for the majority of the lifecycle cost of ownership and operation. For PV systems, the capital cost is by far the most significant cost component while the fuel is free and operations and maintenance costs are generally not as significant as those of cogeneration systems. Similarly, fuel cells, although having high upfront capital costs, operate at very high efficiencies (which reduce fuel requirements) and with very low air emissions (which precludes the need for expensive pollution control equipment).[14] Renewable-fueled fuel cells did see a substantial decrease in cost from previous years ($9.70 in PY07 to $5.98 in PY08.)

PV Cost Trends

Cost trends for Complete PV projects between PY01 through PY06 are shown in Figure 3-7.

Figure 3-7: Cost Trend of Complete PV Projects



Starting on January 1, 2007, PV systems were no longer eligible under the SGIP. Consequently, there were no new applications for PV projects in 2007 or 2008 from which

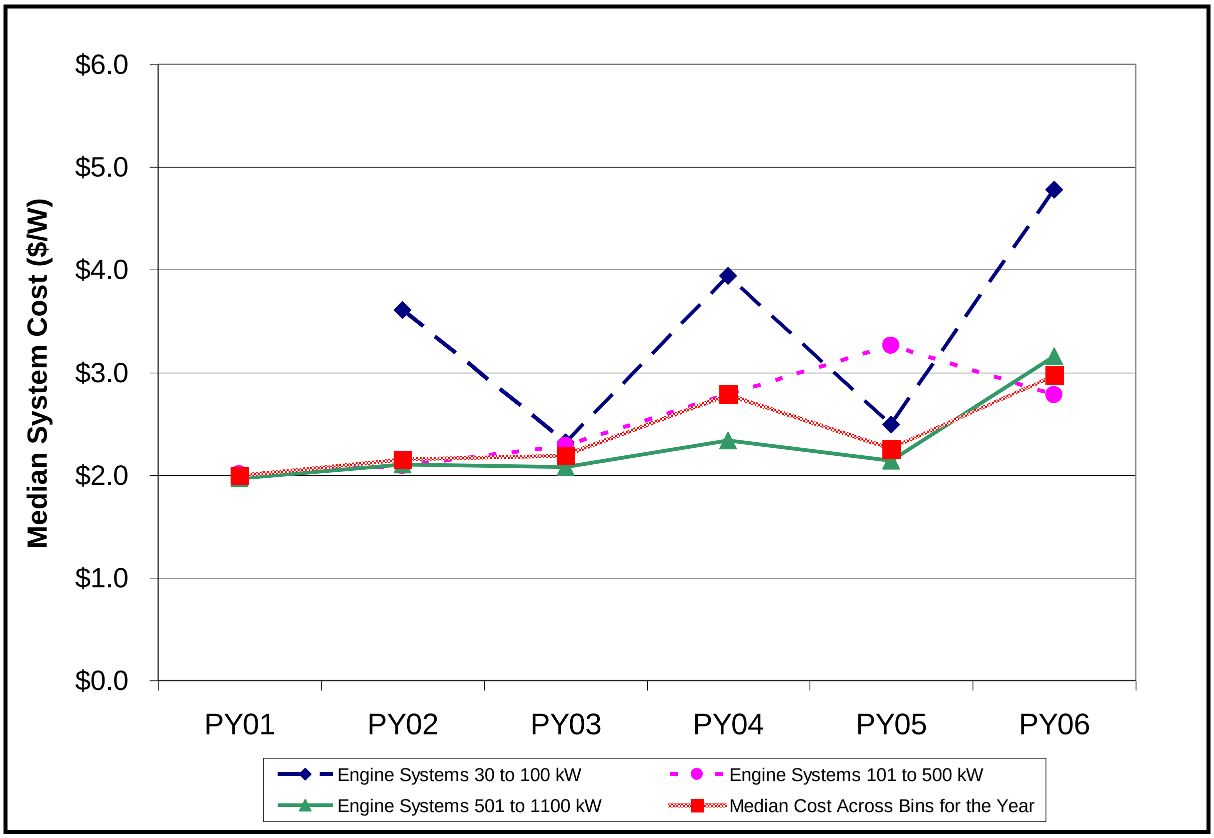
[14] Note that fuel cells powered by renewable resources, such as biogas, require preconditioning equipment to clean the fuel before it is charged to the fuel cell and, as such, have additional capital costs.

cost trends could be drawn. The shown cost trends are reported in terms of the median cost per Watt of rebated capacity. Several observations can be made from the PV cost trends. First, the overall median PV cost stayed between $7.93 and $9 per Watt from PY01 through PY06. While the smallest PV systems showed the highest median cost per Watt, the cost decreased in PY05, then increased slightly in PY06, but was still lower than the original median cost per Watt in PY01. The larger PV systems had lower installed costs but showed and an increase from the cost in PY01 ($7.06 per Watt for the largest systems). Of interest is the decrease in the difference of median cost per Watt between the smaller and larger size PV projects. In PY01, the difference in median cost per Watt between the smallest PV systems (i.e., those between 30 and 100kW) and the largest PV systems (i.e., those between 500 and 1100 kW) was $1.67 per Watt. This difference decreased to $0.33 per Watt in PY06, which reflects the decrease in median cost per Watt for small systems and an increase in median cost per Watt for large systems.

<u>Cogeneration Technology Cost Trends</u>

Cost trends for Complete natural gas-fired IC engines are shown in Figure 3-8.

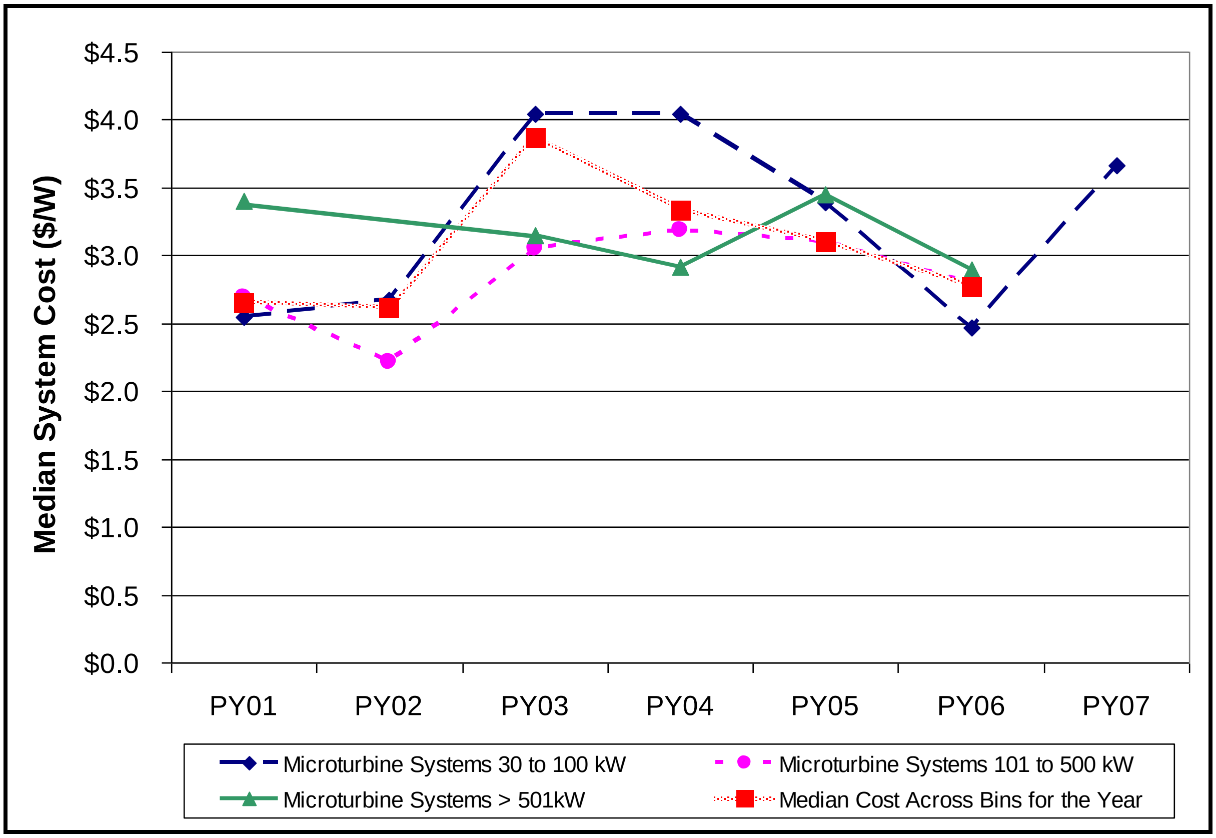
Figure 3-8: Cost Trend of Complete Natural Gas IC Engine Projects



Median project costs for small engines have varied widely from PY01 to PY06. The dip and rise in costs for the smaller IC engines can possibly be attributed to learning curves associated with the emergence of new systems in the marketplace. The first engines to emerge generally represented prototypes equipped with significant monitoring or other extra features that tended to drive up the capital costs. The prototypes were replaced by lower cost, more "commercial" systems. However, as the technologies were still new, costs increased as operational issues were discovered and addressed. Median project costs for medium- to larger-sized engines (i.e., those from 101 kW to over one MW) showed relatively slow increases from PY01 through PY06. So far, only one small non-renewable-fueled IC engine project that applied to the program in PY06 has moved to a Complete status. This project cost was $4.78 per Watt, which is much higher than the overall median cost per Watt across all systems that applied in PY06. This project may not be representative of other PY06 applications for engines less than 101 kW that have not yet moved to the Complete status. Costs for the small systems show the most variability because the sample size is small, with an average sample size of four systems per program year.

Figure 3-9 illustrates a cost trend for Complete natural gas-fired microturbines. Generally, small to medium-sized microturbines demonstrated moderate increases in median costs from PY02 through PY05, with the costs of the smaller systems (i.e., 30 to 100 kW) rising more substantially than those of the medium-sized ones (i.e., 101 kW to 500 kW).

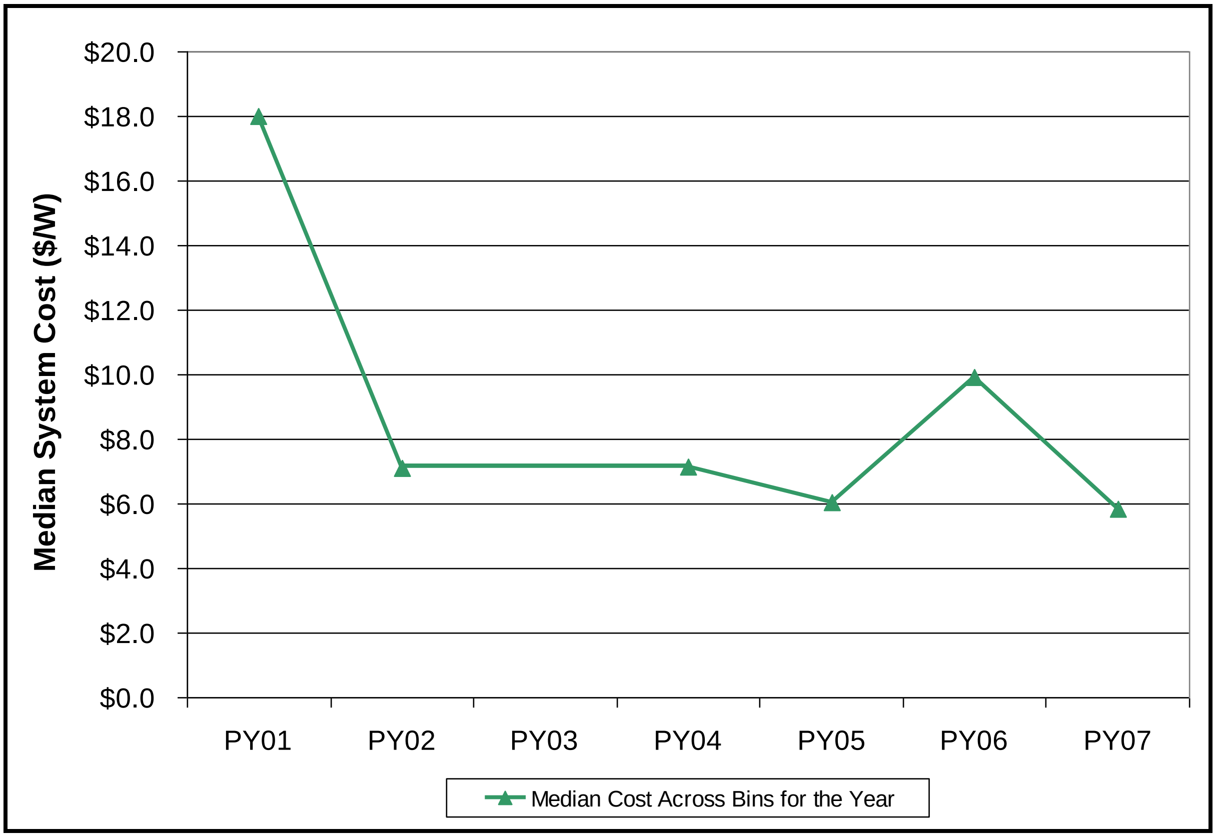
Figure 3-9: Cost Trend for Complete Natural Gas Microturbine Projects



The median cost per Watt of smaller microturbines (less than 101 kW) increased by nearly $2 per Watt to $4 per Watt from PY01 to PY05, but then dropped in PY06 back to the PY01 $2 per Watt cost. However, the PY06 median cost-per-Watt value for small microturbines was based on only three projects and the PY07 median cost-per-Watt is only based on two projects. Consequently, the median cost shown for PY06 and PY07 may not be representative of other projects that applied in those same years. Medium-sized projects saw a decreased cost-per-Watt value in PY05 back to the PY03 cost per Watt. The costs for large-sized projects show a slight downward trend from $3.40 in PY01 to $2.90 in PY06.

Figure 3-10 shows the cost trend for Complete natural gas fuel cell projects in the SGIP. Because there were only 15 Complete fuel cell projects, all sizes of fuel cells have been grouped together. Fuel cell costs reported for PY01 may not be representative of that year as there was only one fuel cell project completed in 2001. Costs remained level from PY02 through PY04, decreased by about $1 per Watt in PY05, increased by about $3 per Watt in PY06, and decreased by about $3 again in PY07. As with the PY01 fuel costs, the PY07 fuel cells costs may not be representative as there was only one Complete fuel cell project that applied in PY07.

Figure 3-10: Cost Trend for Complete Natural Gas Fuel Cell Projects



Incentives Paid and Reserved

Information on the amount of incentives paid and reserved is presented in Table 3-9.[15] Note that paid incentives are reported on a cumulative basis while reserved incentives are only reported on the basis of the program year. PV projects account for approximately 76 percent of the incentives paid for Complete projects but only 21 percent of the incentives reserved for Active projects. At the end of 2007 there was roughly $174 million reserved for PV projects, while at the end of 2008 there was $20 million reserved for PV projects. The decrease in reserved incentives for PV was due to PV projects no longer being eligible under the SGIP effective January 1, 2007 as well as the transition of some PV projects to the CSI. For this same reason, there were no new Active PV projects. The only Active PV projects remaining at the end of 2008 represent projects for which applications were received during or prior to PY06. The largest category of reserved incentives was tied to fuel cell projects. Reserved incentives for renewable- and non-renewable-powered fuel cells were approximately $55 million at the end of PY08. PV, IC engine, gas turbine, and microturbine projects with reserved incentives must be completed by January 1, 2009, or lose their incentive funding.

Table 3-9: Incentives Paid and Reserved

	Complete Incentives Paid			Active Incentives Reserved		
Technology & Fuel	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
PV	132.9	$3.42	$454	8.4	$2.34	$20
WD	1.6	$1.60	$3	23.1	$0.73	$17
FC-N	8.5	$2.33	$20	1.4	$2.50	$4
FC-R	3.5	$4.37	$15	12.3	$2.60	$32
IC Engine–N	133.1	$0.57	$76	25.3	$0.46	$12
IC Engine–R	11.2	$0.87	$10	5.7	$0.79	$4
GT-N	17.6	$0.25	$4	9.6	$0.21	$2
GT-R	0.0	N/A	N/A	0.8	$0.80	$1
MT-N	18.0	$0.82	$15	6.5	$0.59	$4
MT-R	3.8	$1.15	$4	0.4	$1.14	$0
Total	**330.2**	**$1.82**	**$601**	**93.5**	**$1.02**	**$95**

15 The maximum possible incentive payment for each system is the system size (up to one MW) multiplied by the applicable dollar-per-kW incentive rate.

Participants' Out-of-Pocket Costs after SGIP Incentive

Participants' out-of-pocket costs (total eligible project cost less the SGIP incentive) are summarized in Table 3-10.[16]. Insights regarding cost differences between the technologies are speculative, but take into account a combination of assumed project costs, information on additional monies obtained from other incentive programs (when available), and professional judgment.

On a cost-per-Watt basis[17], PV had the highest cost, followed by non-renewable-fueled fuel cells. The higher first cost of both PV and fuel cells was offset to some degree by their reduced fuel requirements and to a lesser degree by reduced cost for air pollution control equipment and purchased emission offsets. In certain instances, fuel cells also provide additional power reliability benefits that may have driven project economics. Renewable-fueled microturbines and non-renewable-fueled microturbines have the next highest capital cost followed by non-renewable-fueled gas turbines.

Table 3-10: SGIP Participants' Out-of-Pocket Costs after Incentive

	Complete			Active		
Technology & Fuel	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
PV	132.9	$5.26	$700	8.4	$5.82	$49
WD	1.6	$1.63	$3	23.1	$1.59	$37
FC-N	8.5	$4.87	$41	1.4	$4.33	$6
FC-R	3.5	$1.61	$6	12.3	$2.64	$32
IC Engine–N	133.1	$1.69	$225	25.3	$2.40	$61
IC Engine–R	11.2	$1.55	$17	5.7	$1.85	$11
GT-N	17.6	$1.86	$33	9.6	$1.36	$13
GT-R	N/A	N/A	$0	0.8	$1.48	$1
MT-N	18.0	$2.24	$40	6.5	$2.51	$16
MT-R	3.8	$2.24	$8	0.4	$6.56	$3
Total	**330.2**	**$3.25**	**$1,073**	**93.5**	**$2.45**	**$229**

Leveraging of SGIP Funding

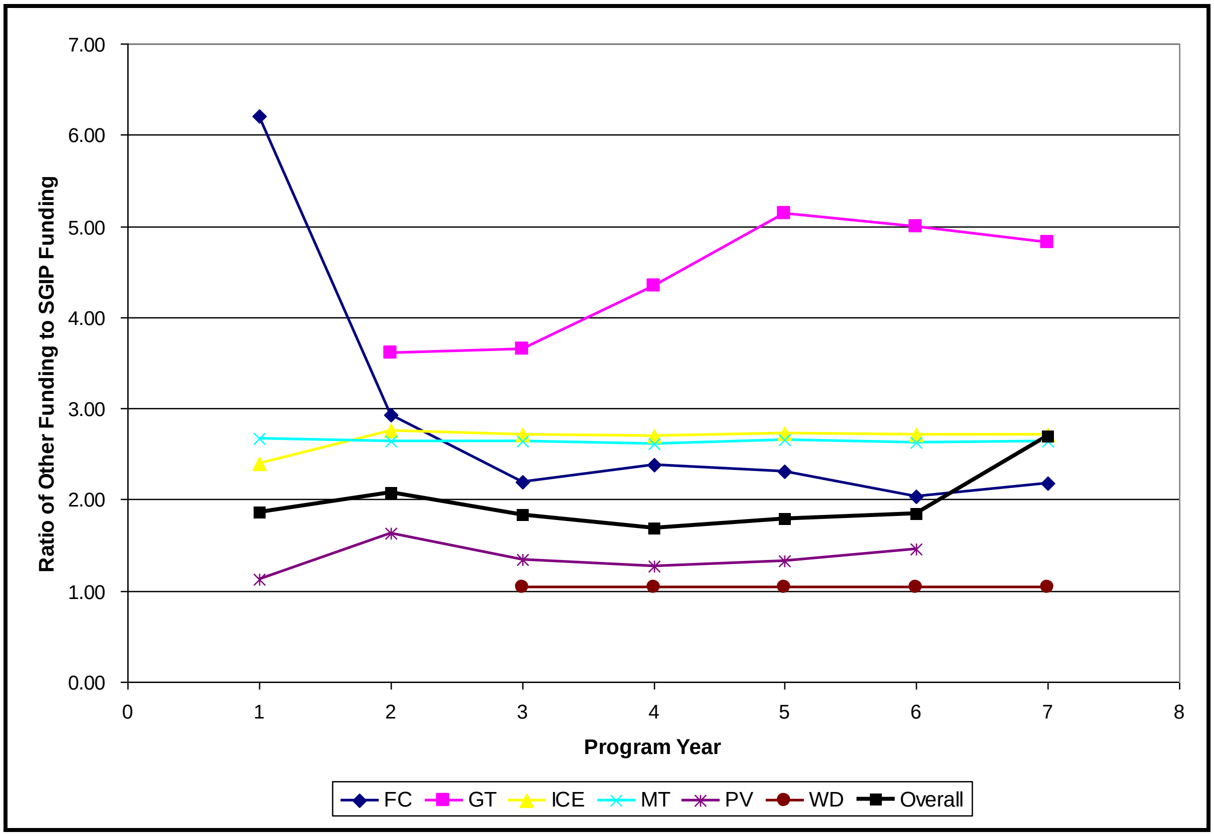
The SGIP is one of the largest DG incentive programs in the country. As identified earlier, over $600 million in incentive payments were made in 2008 alone. Leverage of SGIP incentives is also important as it represents the ability of the program to attract support for

[16] Out-of-pocket cost estimates provided in this table are adjusted for both SGIP incentives and incentives from other programs (where information was available as supplied by PAs) but do not adjust for federal investment tax credits.

[17] This is a rated capacity basis.

the deployed projects and the program overall. Figure 3-11 shows the ratio of other funding provided to SGIP technologies as well as the SGIP overall by program year. In general, leverage of the SGIP has been above a ratio of $2 of other funding invested per $1 of SGIP incentive but increased to approximately $2.7 to $1 by PY07.

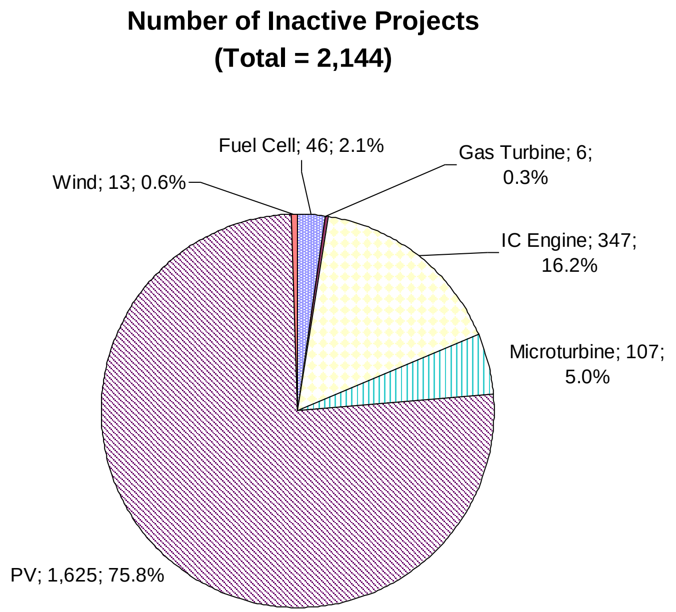
Figure 3-11: Ratio of Other Funding to SGIP Incentive Funding by Program Year

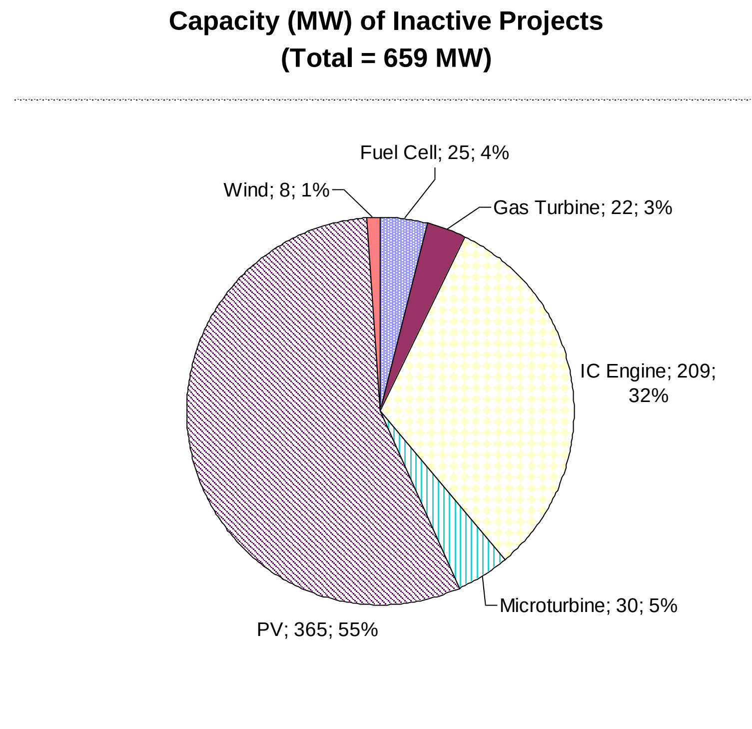


3.4 Characteristics of Inactive Projects

As of December 31, 2008, there were 2,144 Inactive projects (those projects that were either withdrawn or rejected), representing 659 MW of generating capacity. This represents a growth in both the number and capacity of Inactive projects from 2007 at 2,052 projects and 610 MW of capacity, respectively. Figure 3-12 presents the technology distribution of these Inactive projects as of the end of 2008.

Figure 3-12: Number and Capacity (MW) of Inactive Projects





It is interesting to note the following from Figure 3-12:

- PV projects continue to constitute the largest share of number of Inactive projects (1,625 projects or 75.8 percent) and the largest share of total Inactive capacity (365 MW or 55 percent).
- IC engines (fueled by either non-renewable or renewable fuel) accounted for the second largest share of number of Inactive projects (47 projects or 16 percent) and the second largest share of total Inactive capacity (209 MW or 32 percent).
- The 107 Inactive microturbine (fueled by either non-renewable or renewable fuel) projects accounted for 30 MW of total Inactive capacity (five percent).
- Six Inactive gas turbine projects accounted for 22 MW of total Inactive capacity (three percent).
- Thirteen Inactive wind projects accounted for eight MW of total Inactive capacity (one percent) and 46 Inactive fuel cell (fueled by either non-renewable or renewable fuel) projects represented 25 MW of total Inactive capacity (four percent).

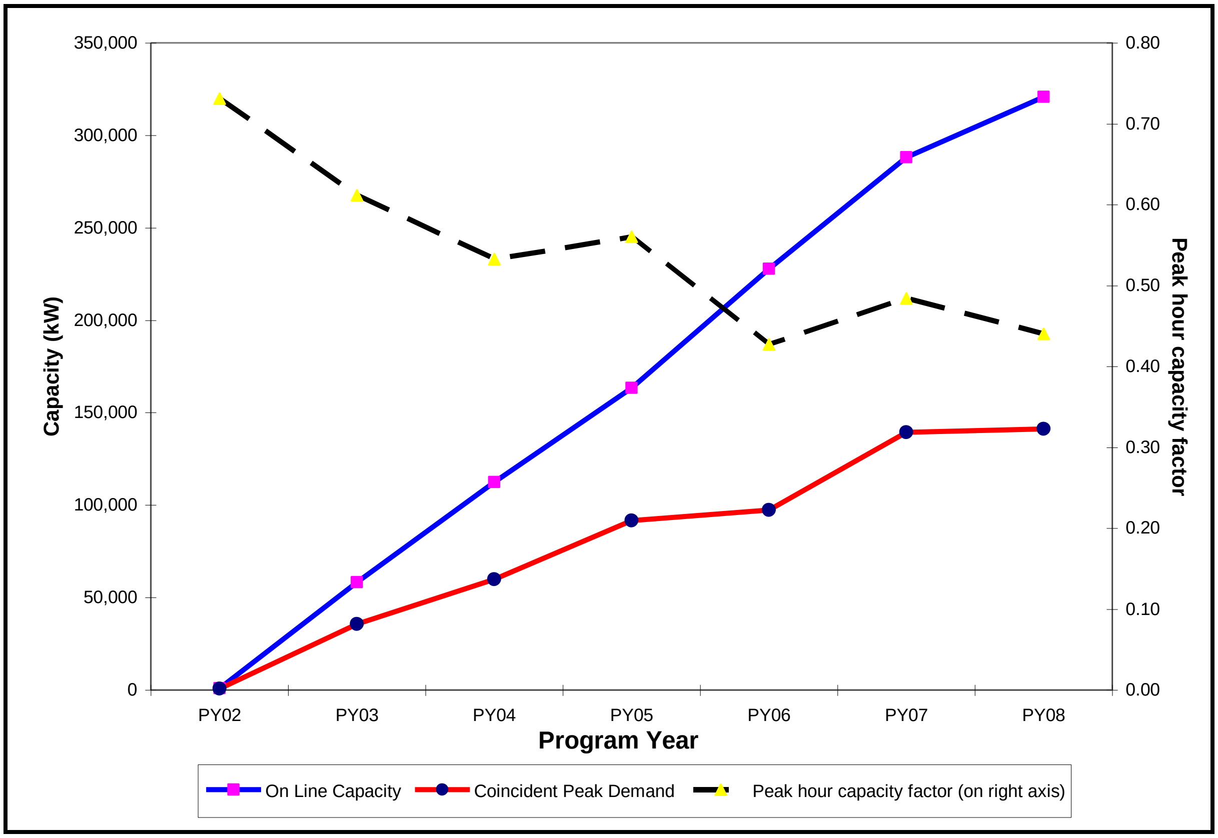
3.5 Trends on Program Impacts

Evaluation data collected for PY08 provides seven years' worth of operating experience on SGIP technologies, their performance and their impacts. Because the SGIP was established to help address peak demand problems, it is important to examine the trend of the SGIP's impact on CAISO system peak over time. As noted in the introduction to the report, impact evaluation information collected under the SGIP may have significant relevance to other energy programs, especially with respect to performance degradation. Consequently, trends on program impacts were examined in two areas: coincident peak demand, and technology performance degradation.

Coincident Peak Demand

Figure 3-13 shows the change in coincident peak demand (relative to the CAISO system peak) from PY02 through the end of PY08. In general, the SGIP coincident peak demand increased somewhat erratically from PY02 through PY07 and then flattened from PY07 to PY08. The flattening of the coincident peak demand is primarily due to the slowing growth in capacity overall for the SGIP. In particular, coincident peak demand in PY07 was approximately 140 MW out of a total rebated capacity of approximately 305 MW, while coincident peak demand in PY08 was approximately 145 MW out of a total rebated capacity of approximately 350 MW. In comparison, coincident peak demand in PY06 was approximately 103 MW out of 248 MW of rebated capacity.

Figure 3-13: Trend on Coincident Peak Demand from PY02 to PY08



A potentially more interesting trend is the peak hour capacity factor (CF), which reflects the amount of capacity actually available during the CAISO system peak relative to the rebated capacity.[18] In general, the peak hour CF for the mix of SGIP technologies from PY03 to the present ranged between 0.45 and 0.6. In the seventh-year impact evaluation, it was noted

---

18 The relatively high kWp/kW ratio observed in PY02 should not be considered indicative of DG technologies as it may be due to the low number of systems monitored during that program year.

that the peak hour CF could be used to estimate the amount of DG capacity needed to meet the CEC's goal of providing 25 percent of California's peak electricity from DG resources by 2020.[19] Further examination of the peak hour CF indicates an overall downward trend over time. Table 3-11 was developed to better understand the role different SGIP technologies play in the downward trend in the peak hour CF. Information on 2001 was not included as metered data was not available at the start of the program.

Table 3-11: Peak Hour Capacity Factor by Technology and PY

	CAISO Peak Hour Capacity Factor					
Year	**PV**	**IC Engine**	**MT**	**FC**	**GT**	**Overall**
2002	0.754	N/A	0.633	0.990	N/A	0.731
2003	0.496	0.647	0.600	1.023	N/A	0.611
2004	0.409	0.589	0.332	0.869	0.761	0.533
2005	0.458	0.620	0.467	0.670	0.733	0.560
2006	0.517	0.345	0.363	0.703	0.836	0.427
2007	0.600	0.343	0.500	0.748	0.853	0.484
2008	0.588	0.248	0.411	0.644	0.835	0.440
Mean	0.546	0.465	0.472	0.807	0.804	0.541

In general, the downward trend in the overall peak hour CF is likely due primarily to the decreasing trend in the IC engine and microturbine peak hour CF. Until recently, IC engines and microturbines provided the vast majority of the SGIP capacity. Consequently, reductions in their peak hour CF resulted in a decrease in the overall peak hour CF. Two other important observations can be made from the information presented in Table 3-11: one related to PV technologies and the other to CHP technologies.

Over the past three program years, PV's peak hour CF has been greater than 0.5. In addition, over the seven years of program operation, PV systems deployed under the SGIP have averaged a peak hour CF of approximately 0.55 kW of coincident peak per kW of rebated capacity. It is reasonable to assume that PV systems deployed in the future in California would achieve a peak hour CF of approximately 0.59. Consequently, successful installation of 3,000 MW of PV generating capacity could potentially provide approximately 1800 MW of peak capacity that helps address the CAISO system peak.

Due to their ability to quickly ramp their generating capacity and load follow, IC engines and microturbines would be expected to show high peak hour CFs. However, both CHP technologies show steady downward trends in their peak hour CFs from 2002 through 2008. Both IC engines and microturbines show average peak hour CFs of less than 0.55. This is a

---

19 Itron, Inc. *Seventh Year Impact Evaluation Final Report.* Page 3-22.

level significantly lower than that shown by fuel cells or gas turbines, their CHP counterparts.

It was outside the scope of this impact evaluation report to determine the causes for the downward trend in the IC engine and microturbine peak hour CFs. However, IC engines and microturbines are likely to constitute a significant portion of the DG mix of technologies in the future. As such, lower than expected peak hour CFs for these CHP technologies will require additional installed capacity throughout the state to achieve the proposed goal of offsetting 25 percent of the CAISO peak demand load by 2020 with CHP. This will require a higher capital investment and therefore have a greater financial impact on ratepayers.

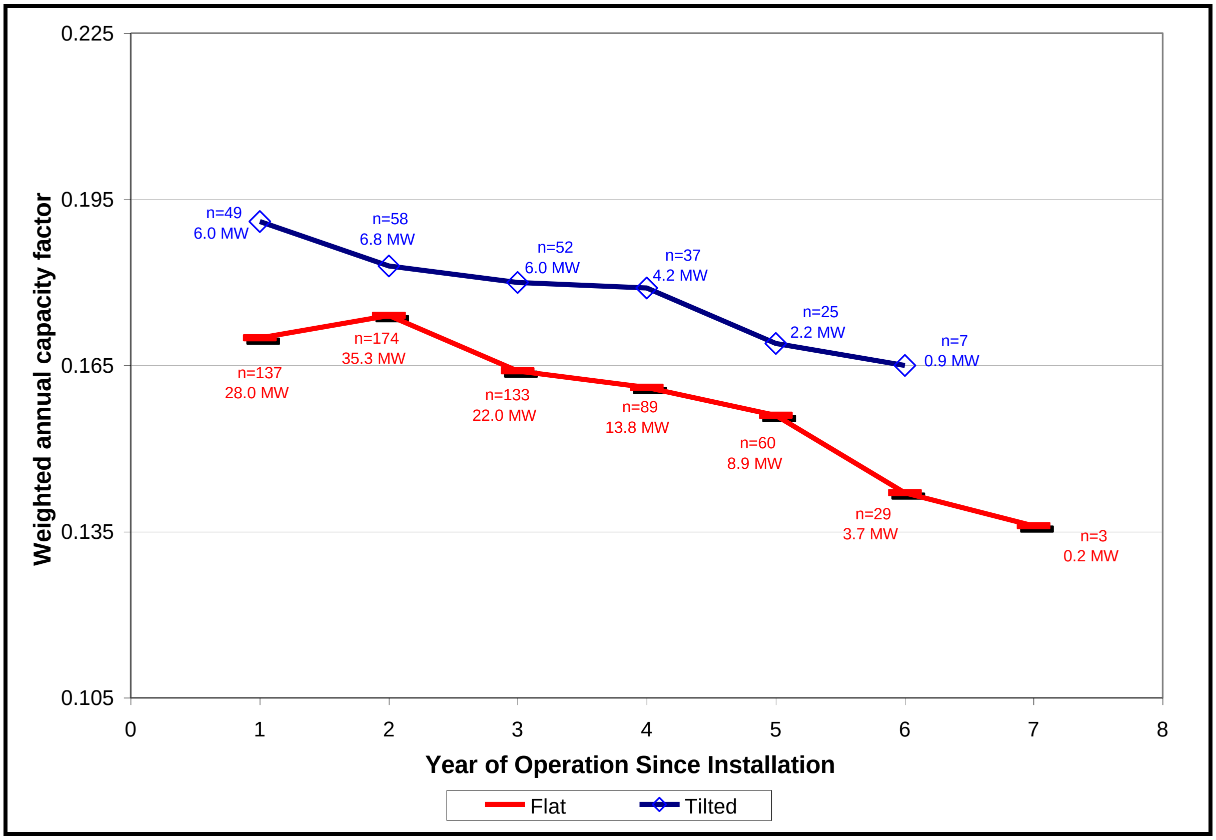
Aging and Performance Degradation of SGIP Technologies

Given the duration and variety of technologies deployed under the SGIP, the program also provides valuable information on the extent to which aging affects performance of DG technologies.

Performance Degradation of PV Technologies

Figure 3-14 summarizes the average annual CF of fixed flat (≤20º tilt) and tilted (>20º tilt) PV systems over the past seven years of the SGIP. Note that tracking PV systems are not displayed due to a relatively small sample size available. Year-to-year variability is due to a range of factors including weather, maintenance/reliability issues, location of projects, and vintage of the PV system. System vintage will be looked at more closely in Figure 3-15 and Figure 3-16. Even though vintage is embedded in the results shown in Figure 3-14, it is useful in showing the annual CF of all PV systems in the program during each year of the system's operation.

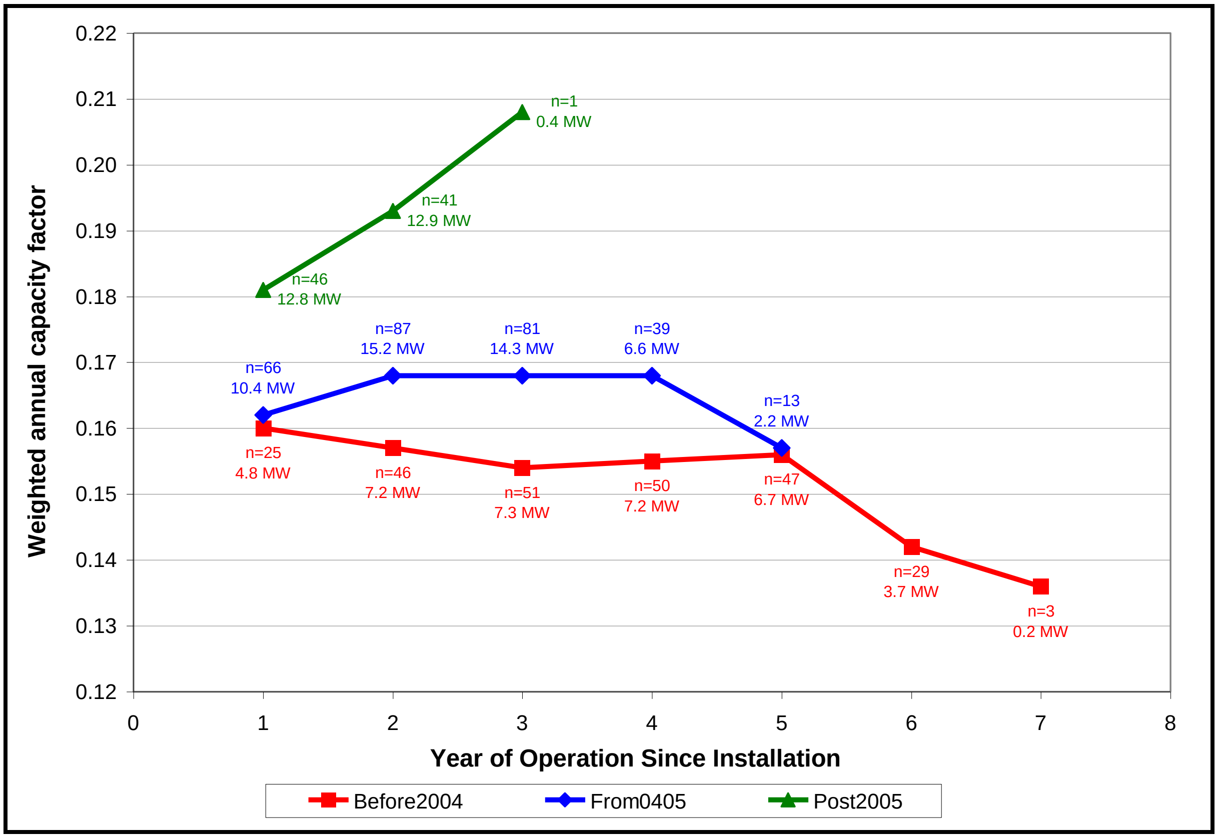
Figure 3-14: PV Annual Capacity Factor versus Year of Operation



Two interesting observations can be made from the PV CF trend lines. First, the observed average annual CFs for both tilted and flat PV systems appear to have declined with age at rates of approximately 0.5 percent per year absolute (2.5 percent relative) during the first six years of installed operation. However, Figure 3-15 and Figure 3-16 show that the annual CF of the systems installed after 2005 has raised the average annual CF in Years 1 and 2 of operation. The increased CF in these early years has the effect of exaggerating the trend downward for systems that have operated longer than two years, particularly for the flat systems. Therefore, a performance degradation of 2.5 percent per year is likely higher than what is actually occurring for flat systems of later vintage. The second observation is that the rate of degradation appears to increase as systems age and rapidly accelerates in Years 6 and 7. However, as the sample sizes of systems operating six or seven years is relatively small to date, these data points may not be significant.

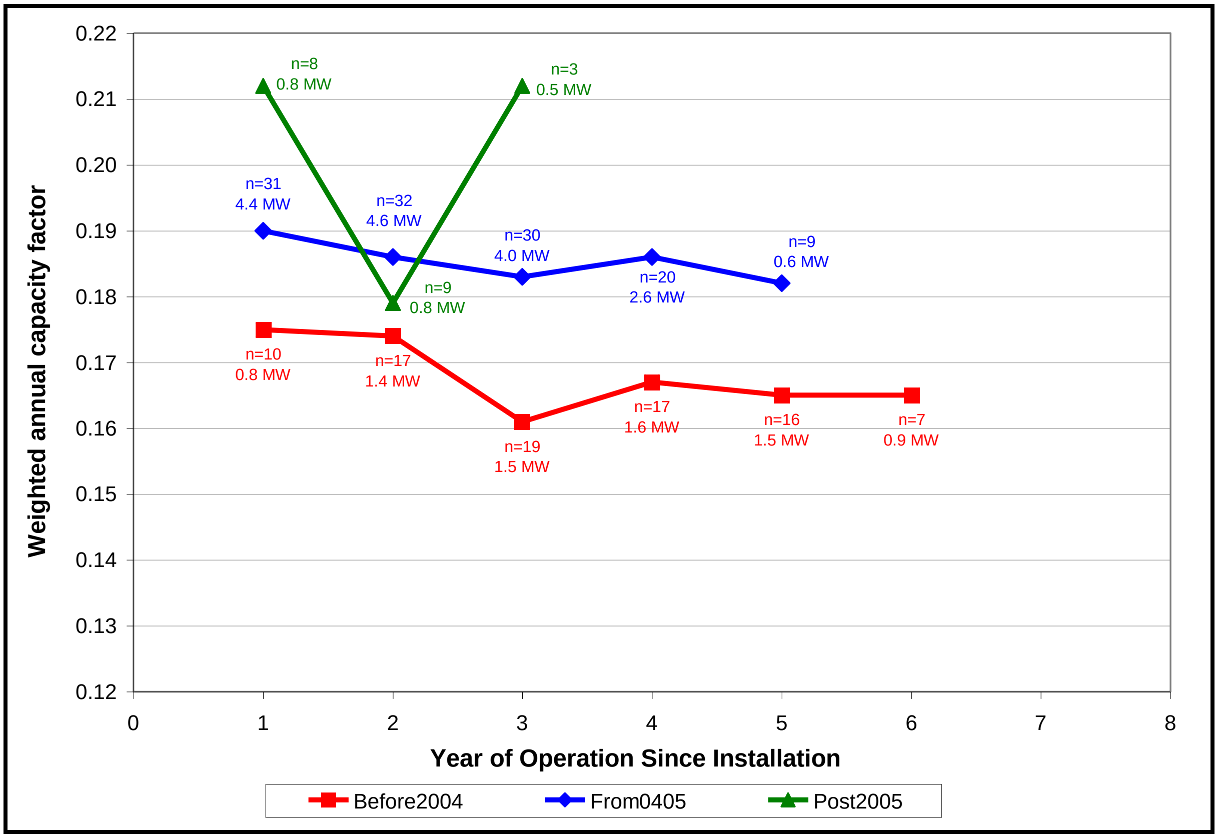
Performance of PV systems was also analyzed by the year that the system came on-line. PV systems were grouped into three vintages: those that came on-line in 2001 through 2003, those that came on-line in 2004 to 2005, and those that came on-line in 2006 through 2008. Figure 3-15 and Figure 3-16 show these results for near-flat and tilted PV systems, respectively. Figure 3-15 shows that PV systems installed after 2005 have a higher annual average CF by year-in-operation than those installed from 2004 to 2005 and those installed prior to 2004. Both groups of systems installed prior to 2005 have a somewhat consistent annual CF until Year 6 of operation for the systems installed before 2004. In Year 6, the performance declines nearly 0.03 points. However, this decline may not be significant as the sample size decreases by more than 50 percent from Year 5 to Year 6. Similarly, performance in Year 3 of operation for the systems installed after 2005 appears to have substantially increased. However, this point only represents one system and is likely not representative of the sample.

Figure 3-15: Annual Average Capacity Factors for Nearflat PV Systems by Year of Operation and Vintage



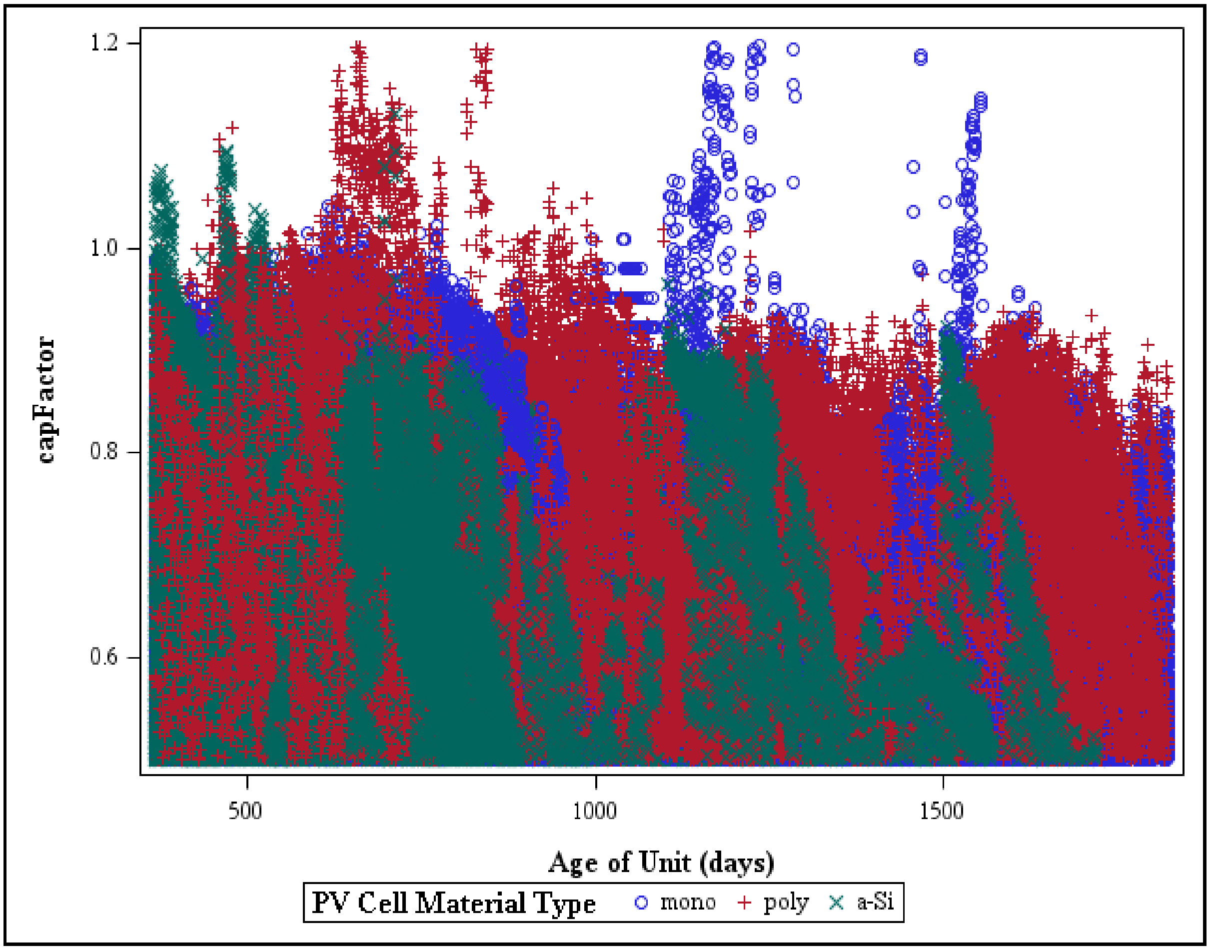
Performance degradation of tilted PV systems is shown in Figure 3-16. Tilted PV systems installed after 2005 have a higher annual average CF by year-in-operation than both those installed from 2004 to 2005 and those installed prior to 2004. In addition, both groups of systems installed prior to 2005 show a somewhat consistent annual CF. The group of systems installed after 2005 show greater variability, likely due to the smaller sample size. These results are similar to what was seen in Figure 3-15 for flat systems.

Figure 3-16: Annual Average Capacity Factors for Tilted PV Systems by Year of Operation and Vintage



Itron also examined PV performance data to see if there were discernable differences in performance degradation rates between PV cell material types. The sample for the near-flat PV systems was analyzed using an analysis of covariance to test for differences in system degradation rates between PV cell material types taking into account irradiance, ambient temperature, and days in operation. Figure 3-17 shows the distribution of PV CFs across the sample of PV systems over time.

Figure 3-17: Capacity Factors by Age of Unit for Systems with Modules Made of Monocrystalline, Polycrystalline, and a-Si



There are several important observations that can be made from Figure 3-17. First, the trend of system degradation is different and slightly faster than the rate found in studies of module degradation published in the past, which show a more linear degradation over time (approximately one percent relative[20]). The difference could reflect panel soiling and/or shading issues, wiring integrity, and other factors which would affect system performance

[20] Osterwald, C.R., et al. "Comparison of Degradation Rates of Individual Modules Held at Maximum Power." (Presented at 2006 IEEE 4th World Conference on Photovoltaic Energy Conversion, 7-12 May 2006.) http://www.photonenergysys.com/osterwald%20wcpec.pdf

and could not be accounted for in the analysis. Second, the effect of system vintage appears to be muted using this method. This muting occurs because the annual degradation rate is an average rate of change for all systems within the material type group and is independent of the starting point. Third, there appears to be significant differences in rates of performance degradation between types of PV cell materials. Table 3-12 is a summary of the average annual PV system degradation rates by PV cell material type. Systems containing monocrystalline PV cells showed the least amount of degradation from Year 2 to Year 5, with an average annual degradation rate of 1.15 percent. Systems containing polycrystalline and a-Si PV cells had average degradation rates of 1.31 percent and 1.26 percent, respectively; however, there was not a statistically significant difference between these two degradation rates. There was a statistically significant difference between a-Si and monocrystalline systems ($p<.05$) and between the polycrystalline and monocrystalline systems ($p<.0001$).[21]

Table 3-12: Average Annual System Degradation Rates by PV Cell Material Type

Material Type	Average Annual Degradation Rate For Years 2 Through 5 (Percent per Year)
a-Si	1.26%
Monocrystalline	1.15%
Polycrystalline	1.31%

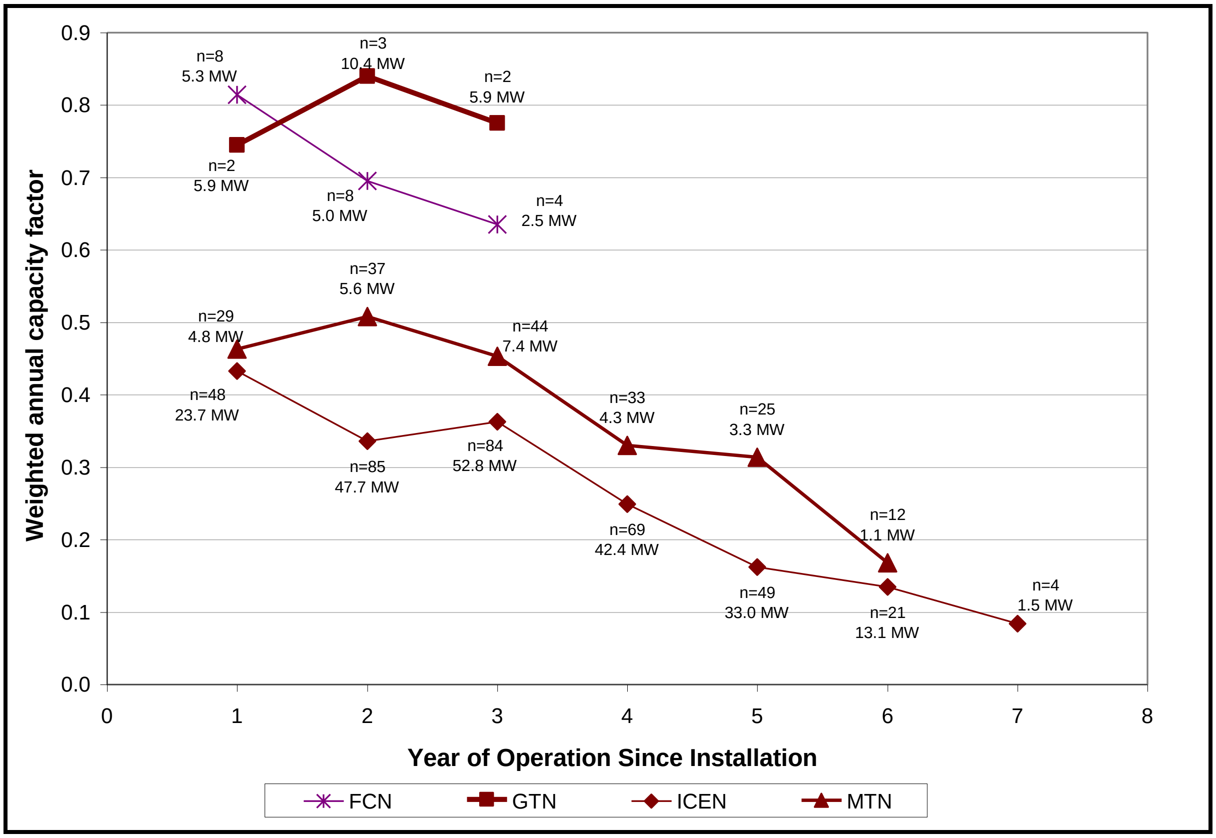
Without additional process evaluation information, we cannot conclusively state the reasons for the slightly higher performance degradation rates seen in the program when compared to those in the literature. Nonetheless, it is important for policy makers and the CSI program designers to recognize the possible extent to which PV CFs may decline over the life of the CSI.

[21] Ochsner, H., et al. "Observed Performance Degradation Over Five Years for a-Si and Crystalline PV Systems in California." (Presented at American Solar Energy Society Solar 2009 Conference. May 11-16, 2009.)

Performance Degradation of CHP Technologies

As with PV systems, it is important to examine performance of combined heat and power (CHP) systems over time. Year-to-year changes in the average annual CF for CHP systems deployed under the SGIP are presented in Figure 3-18. Results are presented separately for each of the four types of natural gas-fueled prime movers covered by the SGIP: fuel cells (FCN); gas turbines (GTN); microturbines (MTN) and IC engines (ICEN).

Figure 3-18: Annual Capacity Factor versus Year of Operation for Natural Gas-Fueled Systems



The annual CFs for microturbines and IC engines exhibit a noticeable downward trend over the life of the program. Annual CFs for IC engines show a decline of over 30 percentage points from the first year of operation to the sixth year of operation. Microturbines show a lesser overall decline, but still show an observed decline in annual CF of nearly 30 percentage points over five years of operation. Like PV, the reduction in CF during Year 7 is significant. However, similar to PV, the small sample sizes for systems which have been operating for seven years creates some question as to the significance of that data point. The more rapid decline in CF between Years 3 and 4 of operation for IC engines noted in the 2007 report is still apparent.

Itron also examined performance degradation of CHP technologies by vintage of the technology. Figure 3-19 and Figure 3-20 show the annual average CFs for natural gas-fueled IC engines and microturbines, respectively, by year of operation and vintage. Systems were grouped into three vintages: those that came on-line in 2001 through 2003, those that came on-line in 2004 to 2005, and those that came on-line in 2006 through 2008.

Figure 3-19 shows two interesting trends. First, systems installed prior to 2004 performed better during their first three years of operation than the systems installed during and after 2004. Systems installed after 2005 had the lowest CF of the three vintage groups during the first three years of operation. Second, similar to Figure 3-18, all vintage groups show a significant decline in performance as the systems age.

Figure 3-19: Annual Average Capacity Factors for Natural Gas IC Engines Systems by Year of Operation and Vintage

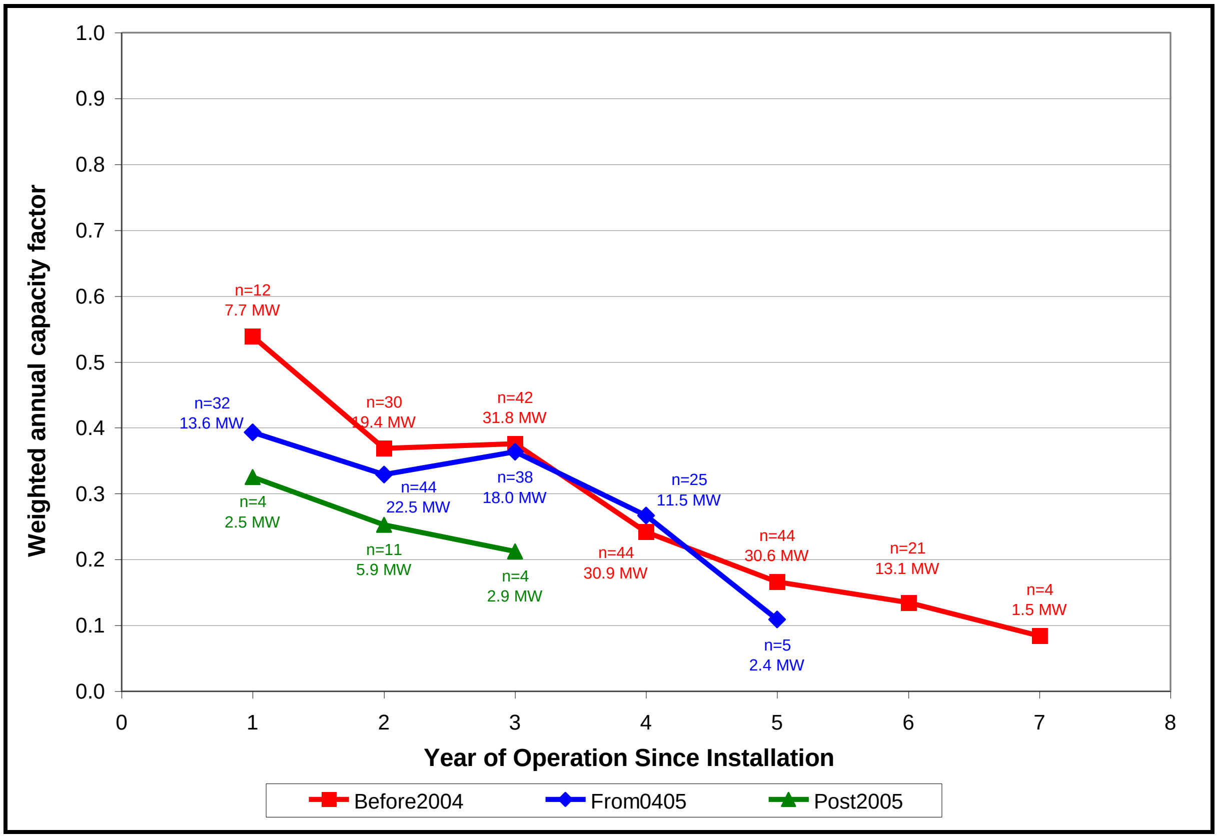
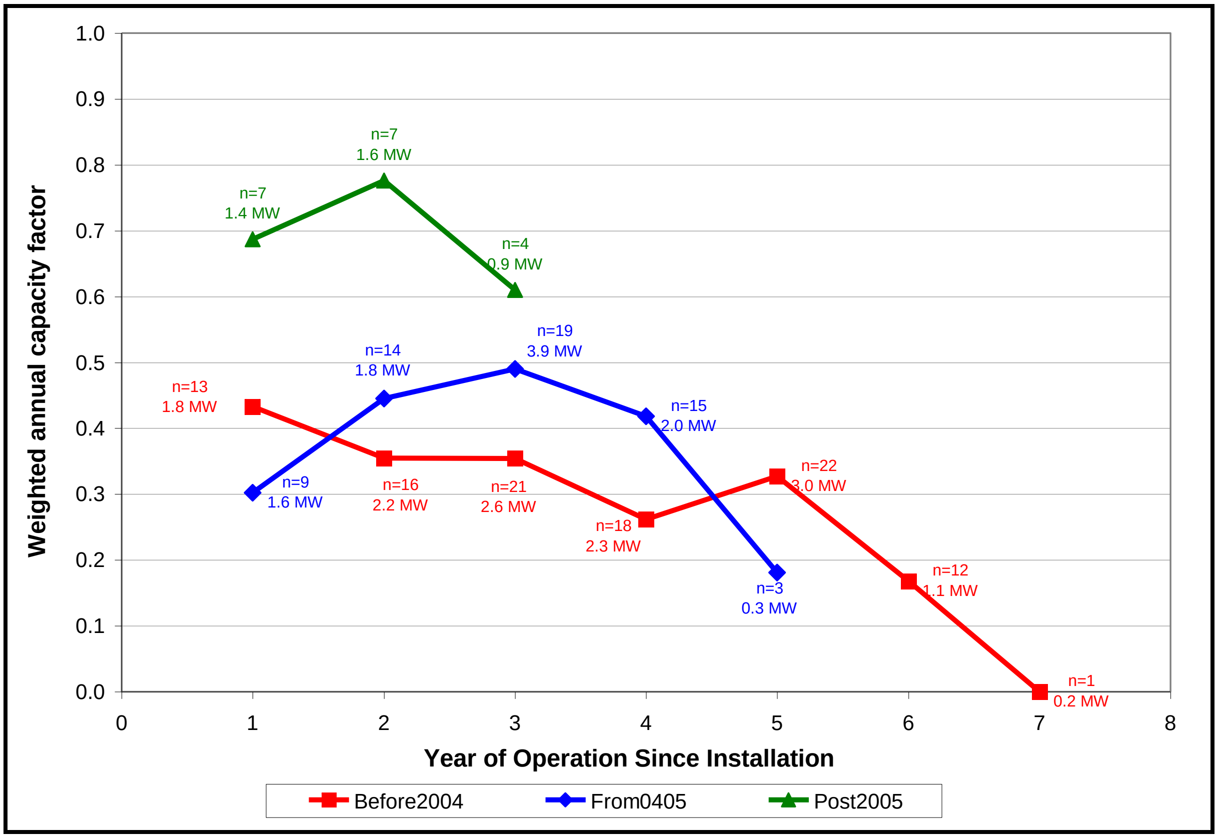


Figure 3-20 shows the annual CFs for natural gas-fueled microturbines by year of operation and vintage. Contrary to the IC engine results, microturbines installed after 2005 show the best performance out of the three vintage groups. Systems installed from 2004 to 2005 performed better than systems installed before 2004, except for Years 1 and 5 of operation. However, the sample size for systems installed in 2004 and 2005 was relatively small for both of those years. The better performance of the newer vintages likely indicates an improvement in reliability for a technology that was relatively new in 2001.

Figure 3-20: Annual Average Capacity Factors for Natural Gas Microturbines by Year of Operation and Vintage



Without additional information, it is difficult to identify the reasons for the decline in annual CFs observed for IC engines and microturbines. Year-to-year variability can be due to a variety of factors including equipment maintenance/reliability issues, staff turnover, interruption in fuel or service provider contracts, fuel prices, and occupancy/operations schedules of metered CHP systems. Nonetheless, the identification that CF has declined over time for CHP systems and the extent of that decline is valuable information as California begins considering programs to expand the use of DG technologies to help address peak electricity demand.

Changes in the SGIP Portfolio of DG Projects

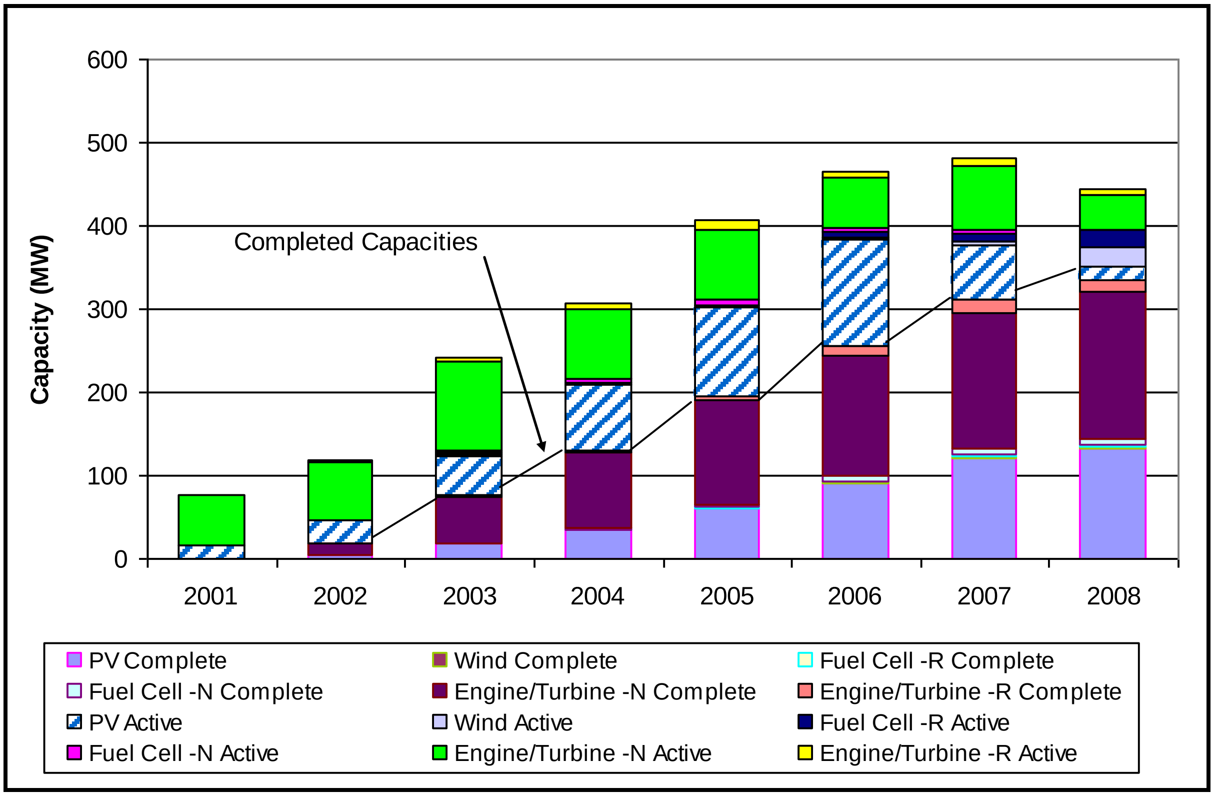
Beginning in 2007, the mix of technologies that comprise the SGIP portfolio underwent fundamental changes. As noted in the preceding discussion on program impact trends, changes in the SGIP technology portfolio have affected the manner and degree to which the SGIP affects California's energy landscape.

Figure 3-21 shows the capacity of both Complete and Active SGIP projects by technology from PY01 through PY08. From PY01 through PY05, there was a steady increase in all Active projects. The capacity of PV projects continued to grow steadily beyond PY05 to the end of PY06. With enactment of the CSI, PV technologies have no longer been eligible to receive incentives under the SGIP. Consequently, effective January 1, 2007, there was a rapid decline in Active PV projects, with only those legacy projects that had applied earlier than PY07 moving forward in PY07 and PY08.

Since PY03, there has also been a decline in the capacity of IC engines and turbine technologies Active under the SGIP. Passage of AB 2778 limited eligibility of cogeneration projects within the SGIP to "ultra-clean and low emission distributed generation" technologies. These technologies are defined as fuel cells and wind DG technologies that meet or exceed the emissions standards required under the DG certification program adopted by the CARB. Beginning in PY08, we have started to see some growth of Active fuel cell and wind technologies under the SGIP. However, the growth in new DG wind and gas turbine capacity has been small as these technologies are still emerging into the marketplace.

Wind energy systems and fuel cells will likely demonstrate different performance and cost characteristics than the PV, IC engines, and microturbines that have dominated the SGIP to date. Consequently, changes in the SGIP portfolio will influence impacts of the SGIP on California's electricity system. The extent of the changes will depend on the growth rate in wind versus fuel cell systems, and the degree to which energy storage systems are coupled with wind energy applications. However, fuel cells are normally operated as baseload units and wind resources are intermittent. Consequently, there is likely to be reduced ability of the SGIP to address peak electricity demands. Similarly, if market penetration of DG wind energy systems remains low, this will result in a net decrease in overall energy delivery by the SGIP relative to earlier program years.

Figure 3-21: Capacity of Complete and Active SGIP Projects PY01 to PY08



3.6 Conclusions and Recommendations

As noted in the 2007 SGIP Impact Evaluation report, California is poised to move forward with potentially rapid expansion of DG systems. However, successfulness of that expansion will require a thoughtful approach to the manner in which DG technologies can meet the sometimes-competing needs for increased electricity system performance, environmental improvements, and lower costs to ratepayers. Data gained from the SGIP can help inform policymakers about DG performance and important features of DG program design.

The SGIP provides over seven years of operational data across a wide variety of DG technologies. Operational data are valuable as they provide insights into the actual performance of DG technologies under real world conditions. Additional insights can be obtained by examining performance trends over time or comparing actual performance against theoretical performance. For example, differences in PV performance degradation by cell material type were identified by examining PV system performance over time. Similarly, comparing actual versus theoretical system efficiencies allows for conclusions regarding minimum waste heat recovery efficiencies. In drawing conclusions and making recommendations about DG technologies, Itron has blended knowledge of DG system design and operation with performance data and observations obtained from the field. Based on this blend of knowledge and seven years of SGIP performance data, we provide the following conclusions and recommendations:

1. DG technologies can make valuable contributions to addressing peak electricity demand. On average, SGIP DG technologies have had more than half their rebated capacity on-line during the CAISO peak for the past seven years. Fuel cells and gas turbines deployed under the SGIP have demonstrated ratios of on-line peak capacity to rebated capacity of 0.84 and 0.64 kW (peak) per kW (rebated), respectively. Similarly, over the past seven years, PV systems deployed under the SGIP have shown an average ratio of 0.55 kW (peak) per kW (rebated) capacity.
2. Not surprisingly, performance trends show that both PV and CHP technologies (IC engines and microturbines) have experienced performance degradation over time.
   a) For PV systems deployed under the SGIP, performance deterioration rates were found to be slightly higher than those reported in the literature (i.e., on the order of one percent per year versus literature values of 0.5 percent per year). However, vintage tends to offset the overall PV degradation rates as newer vintage systems start with higher levels of performance. In addition, we found PV degradation rates to be affected by PV cell material.
   b) More pronounced performance degradation rates were observed for microturbines and IC engines, with performance deteriorating by over 20 percentage points over five years of operation.

3. SGIP technologies provide significant GHG emission reductions. PV technologies showed the greatest level of GHG emission reduction due to their direct replacement of electricity otherwise generated by combustion-based resources. However, waste heat recovery of CHP facilities provides a net reduction in GHG emissions by displacement of natural gas that would have otherwise been consumed onsite.
   a) The role of waste heat recovery is important to consider in establishing CHP programs that reduce GHG emissions. In general, the ability to obtain greater reductions in GHG emissions requires higher overall system efficiencies and a good match between electrical and thermal loads. While not quantified in this impact evaluation, it is possible to link GHG emissions to a minimum number of hours per year of matched thermal and electrical load for different CHP system efficiencies. Establishing this connection will help set CHP program designs to achieve targeted levels of GHG emission reductions.
4. Determining the causes of lower-than-expected contribution to coincident peak demand or for performance degradation is beyond the scope of an impact evaluation. However, determining the causes of these impacts is likely to be important when developing other energy programs involving CHP and PV technologies. As such, the CPUC and PAs should consider pursuing process evaluations to look into the causes of these performance issues.
5. Collecting performance data on PV and CHP facilities on a sustained basis (e.g., over seven years) and over a diverse population of systems has provided valuable insights into actual performance that can be expected in real world settings. To the extent possible, SGIP data on CHP systems should be linked to future CHP programs to help provide sustained performance information, similar to the way SGIP data are being used in combination with CSI performance data.
6. The state has set a goal of achieving 25 percent of its supply of peak electricity from CHP facilities by 2020. Achieving and maintaining this goal will require well designed, properly operated, and appropriately maintained CHP facilities. In addition, if designed and operated appropriately, these CHP facilities can also provide an important means of reducing GHG emissions. Based on Itron's past investigation into issues encountered with design and implementation of CHP facilities and on the performance results observed to date with SGIP CHP facilities, we recommend the following be considered in establishing a statewide CHP program:
   a) Establish tariffs that encourage CHP facilities to maximize electricity generation at times that will help provide relief to congested or highly loaded distribution feeders or help offset critical peak demand.
   b) Establish policies and tariffs that encourage CHP facilities to adopt the use of absorption chillers operated from waste heat recovered by the CHP facility and sized to offset onsite cooling needs.
   c) Establish design policies and approaches that require CHP system developers to identify and match thermal and electrical hourly load profiles for the host site for a minimum of the daily peak electricity demand hours of the host site.

d) Establish policies and incentives that encourage CHP system owners and operators to maintain their systems such that no more than two percent (2%) performance degradation occurs annually. Such policies should consider the use of service agreements to help maintain CHP system operation; annual inspections of CHP systems and major components; and efficacy insurance.

4

Sources of Data for the Impact Evaluation

This section describes sources of data used in conducting the eighth-year impact evaluation. Several key types of data sources are presented first. This is followed by a description of metered data collection issues and current metered data collection status.

4.1 Overview of Key Data Types

There are three key data types:

1. Project lists maintained by the Program Administrators (PAs),
2. Reports from monitoring planning and installation verification site visits, and
3. Metered data received from project hosts, applicants, third party metering, or metering installed by Itron.

Project Files Maintained by Program Administrators

SGIP PAs maintain project tracking database files containing information essential for designing and conducting SGIP impact evaluation activities. The PAs provided Itron with regular updates of their program tracking database files; usually on a monthly basis. Information of particular importance includes basic project characteristics (e.g., technology type, rebated capacity of the project, and fuel type) and key participant characteristics (e.g., Host and Applicant names[1], addresses, and phone numbers). The project's technology type, program year, and project location (by PA area) were also used in developing a sample design to ensure collection of statistically significant data. Updated SGIP Handbooks were used for planning and reference purposes.[2]

1 The Host Customer is the customer of record at the site where the generating equipment is or will be located. An Applicant is a person or entity who applies to the PA for incentive funding. Third parties (e.g., a party other than the PA or the utility customer) such as engineering firms, installing contractors, equipment distributors or Energy Service Companies (ESCO) are also eligible to apply for incentives on behalf of the utility customer, provided consent is granted in writing by the customer.

2 SGIP Handbooks are available on PA websites.

Reports from Monitoring Planning and Installation Verification Site Visits

Information contained in the PA project database files is updated through visits to the SGIP project sites conducted by independent consultants hired by the PAs to perform verification of SGIP installations. Project-specific information is reported in Inspection Reports produced by these independent consultants. The PAs regularly provided copies of the Inspection Reports. In addition, site visits are conducted by Itron engineers in preparing monitoring plans for on-site data collection activities. Among the types of information collected during site inspections or in preparation of monitoring plans include meter nameplate rating and the date the system entered normal operation.

Metered Performance Data

In addition to information collected from the PA project database and from project site visits, metered data were also used when available. The metered data collected and used for evaluation purposes include electric net generator output (ENGO) data, useful thermal energy (HEAT) data, and fuel use (FUEL) data.

Electric Net Generator Output (ENGO) Data

ENGO data provide information on the amount of electricity generated by the metered SGIP project. This information is needed to assess annual and peak electricity contributions from SGIP projects. ENGO data were collected from a variety of sources, including meters Itron installed on SGIP projects under the direction of the PAs and meters installed by project Hosts, Applicants, electric utilities, and third parties. Some electric utilities may install different types of ENGO metering depending on project type. In some cases, this impeded Itron's ability to assess peak demand impacts. For example, some of the installed meters did not record electricity generation data in sub-hour intervals. These types of meters were encountered with some cogeneration systems installed in schools, as well as with some renewable-fueled engine/turbine projects eligible for net metering. As a result, peak demand impacts could not be determined for these projects. Itron has been working with the affected PAs and electric utility companies on a plan to have a sample of SGIP projects equipped with interval recording electric metering in order to present statistically significant peak demand impacts in future evaluation reports.

Useful Thermal Energy (HEAT) Data

Useful thermal energy (also referred to as HEAT) data are used to assess compliance of SGIP cogeneration facilities with required levels of efficiency and useful waste heat recovery. In addition, useful thermal energy data enable us to estimate electricity or natural gas displaced by SGIP facilities that would have otherwise been provided by the utility companies. This information is used to assess energy efficiency impacts as well as determine net GHG emission impacts. HEAT data are collected from metering systems installed by Itron as well as metering systems installed by applicants, Hosts, or third parties.

Over the course of the SGIP, the approach for collecting HEAT data has changed. Collecting HEAT data has historically involved installation of invasive monitoring equipment (i.e., insertion type flow meters and temperature sensors). Many third parties or Hosts had this type of HEAT metering equipment installed at the time the SGIP project was commissioned, either as part of their contractual agreement with a third-party vendor or as part of an internal process/energy monitoring plan. In numerous cases, Itron was able to obtain the relevant data being collected by these Hosts and third parties. Itron initially adopted an approach of obtaining HEAT data from others in an effort to minimize both the cost- and disruption-related aspects of installing HEAT monitoring equipment. The majority of useful thermal energy data for 2003 to 2004 were obtained in this manner.

Itron began installing HEAT meter systems in the summer of 2003 for SGIP projects that were included in the sample design but for which data from existing HEAT metering were not available. As the HEAT data collection effort grew, it became clear that Itron could no longer rely on data from third party or host customer metering. In numerous instances agreements and plans concerning these data did not translate into validated data records available for analysis. Uninterrupted collection and validation of reliable metered performance data was labor intensive and required examination of the collected data by more expert staff, thereby increasing costs. In addition, reliance on HEAT data collected by SGIP Host customers and third-parties created evaluation schedule impacts and other risks that more than outweighed the benefits of lower metering installation costs.

In mid-2006, Itron responded to the HEAT data issues by changing the approach to collection of HEAT data. Itron continued to collect HEAT data from others in those instances where the data could be obtained easily and reliably. In all other instances, an approach has been adopted of installing HEAT metering systems for those projects in the sample design. Itron adopted the installation of non-invasive metering equipment such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications to reduce the time and invasiveness of the installations and increase data communication reliability. The increase in equipment costs was offset by the decrease in installation time and a decrease in maintenance problems. This approach has been used to obtain HEAT data and using non-invasive systems throughout 2008. Appendix E provides detailed information on the non-invasive metering equipment that has been installed.

Fuel Usage (FUEL) Data

Fuel usage (also called FUEL) data are used in the impact evaluation to determine overall system efficiencies of SGIP cogeneration facilities, to determine compliance of renewable fuel use facilities with renewable fuel use requirements, and to estimate net GHG emission impacts. To date, fuel use data collection activities have focused exclusively on monitoring consumption of natural gas by SGIP generators. In the future it may also be necessary to monitor consumption of gaseous renewable fuel (i.e., biogas) to more accurately assess compliance of SGIP projects using blends of renewable and non-renewable fuels with renewable fuel use requirements.

FUEL data used in the eighth-year impact evaluation were obtained mostly from FUEL metering systems installed at SGIP projects by natural gas utilities, SGIP participants, or by third parties. Itron reviewed FUEL data obtained from others and their bases were documented prior to processing the FUEL data into a data warehouse. Reviews of data validity included combining fuel usage data with power output data to check for reasonableness of gross engine/turbine electrical conversion efficiency. In cases where validity checks failed, the data provider was contacted to further refine the basis of data. In some cases it was determined that data received were for a facility-level meter rather than from metering dedicated to the SGIP cogeneration system. These data were excluded from the impact analysis. It was also found that much of the FUEL data being obtained from others are collected and reported on time intervals much greater than one hour (e.g., daily or monthly). In the past, hourly FUEL consumption was estimated based on the associated ENGO readings. However, this approach did not work in a number of instances. For example, it failed in those instances where there were multiple generators, but the electricity production was metered for only a portion of the generators and FUEL data were collected for all generators. In those cases, estimates of FUEL consumption based on ENGO readings would provide inaccurate FUEL data. In addition, there were instances where it is important to know the FUEL data for a particular hour (e.g., to better understand what was happening to cogeneration system efficiency during peak electricity demand). In those situations, hourly FUEL data were required. In order to address these issues, Itron has recommended to the PAs installation of separate FUEL metering in special situations as well as the use of pulse recorders on existing gas meters to enable collection of hourly FUEL data.

4.2 Metered Performance Data Collection Status Summary

As of the end of 2008, over 1,500 SGIP projects were determined to be on-line. These projects corresponded to approximately 460 MW of rebated SGIP project capacity. It was necessary to collect metered data from a certain portion of on-line projects to support the impact evaluation analysis. This section presents summaries of actual data collection based on availability of metered data through the end of December 2008. Data collection status by PA is discussed in Appendix C.

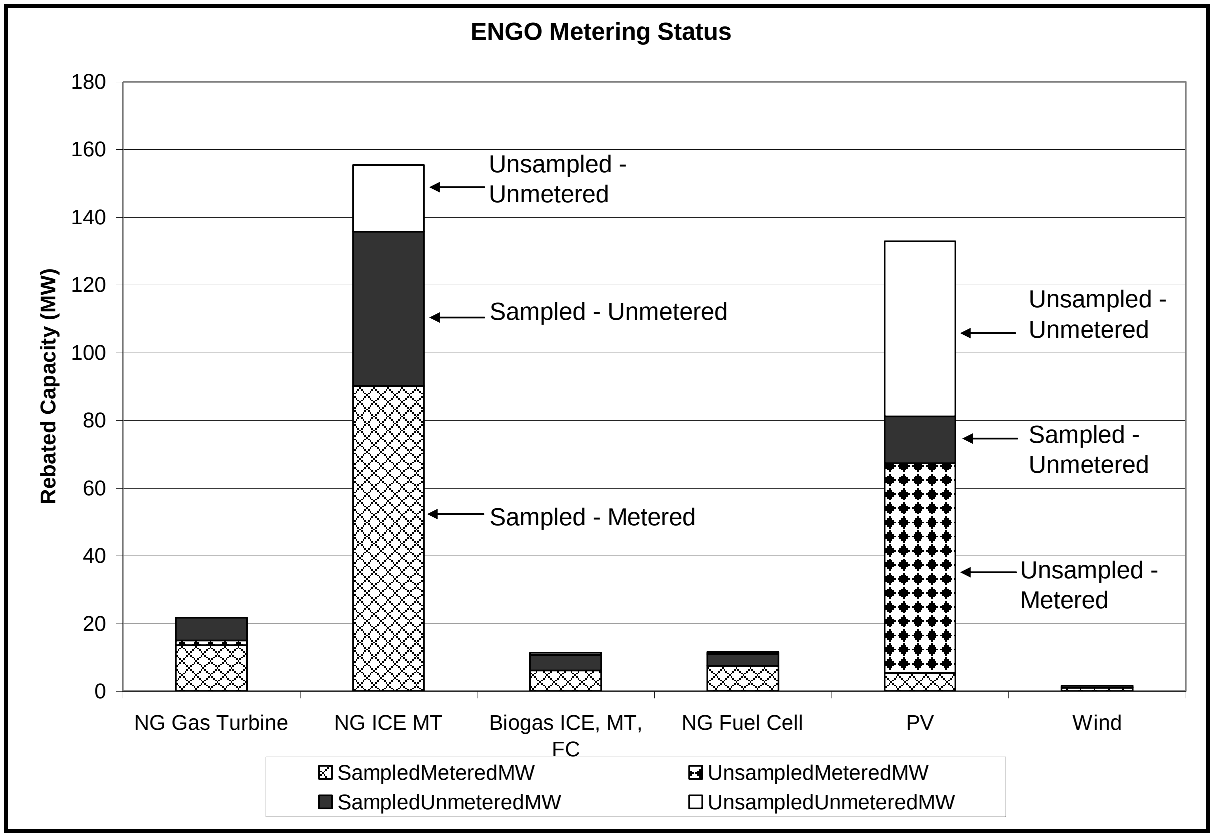
The status of ENGO data collection is summarized in Figure 4-1. Note that the population of projects for data collection includes Complete projects as well as all Active projects.[3] Data collection efforts have been classified into four general categories. "Sampled-Unmetered" projects refer to projects that fall within the sample design and should be metered but have not yet been metered. For example, this includes projects that have not yet received incentive checks. In those instances, metering is placed on hold until the incentive check has been issued and the project moves into the Complete category. "Unsampled-Unmetered" represent those projects that fall outside the sample design and, consequently, are not intended for metering. "Sampled-Metered" refers to projects that are contained in the sample design and are metered as of the date of the evaluation. "Unsampled-Metered" are projects that are outside the sample design but for which metering is already being conducted. An example would be a project for which there is currently sufficient data to meet the 90/10 confidence level target of the sample design, but ENGO data is being collected by someone else (e.g., Host, applicant or third party). While additional ENGO data collection activity would not be pursued in this situation, the data would still be used for impact evaluation purposes, if provided.

A substantial quantity of ENGO metering installation activity remains to be completed. In particular, because of the importance of having ENGO data for cogeneration facilities, Itron was directed by the PAs beginning in late 2006 to initiate a census approach to have ENGO metering on all cogeneration facilities. Similarly, prior to 2006, the PAs were to be responsible for providing ENGO data for all PV projects greater than 300 kW in rebated capacity. Itron was responsible for installing ENGO meters on PV projects smaller than 300 kW based on a statistical sample design approach. In late 2006, Itron was directed by the PAs to employ a statistical sample design approach to collecting PV ENGO data, regardless of rebated capacity. This activity is ongoing and is being carried out in consultation and collaboration with the PAs. Moving through PY2009, the highest priority is installation of additional ENGO metering for non-renewable-fueled engines/turbines and renewable-fueled engines/turbines.

---

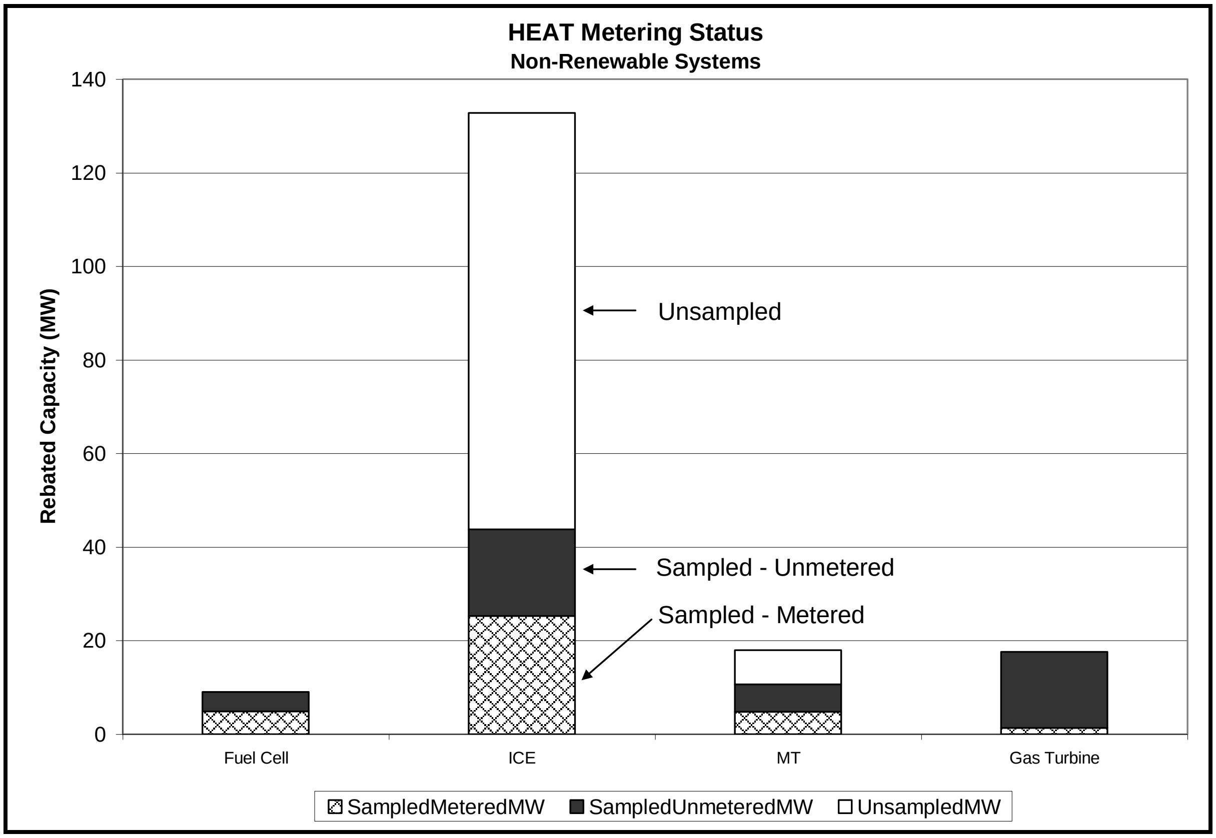
[3] All Active projects are included rather than just on-line Active projects because it is impossible to know which projects will move forward to become Complete projects. Consequently, the population is based inclusive to all projects to ensure the sample design has not been underestimated.

Figure 4-1: ENGO Data Collection as of 12/31/2008



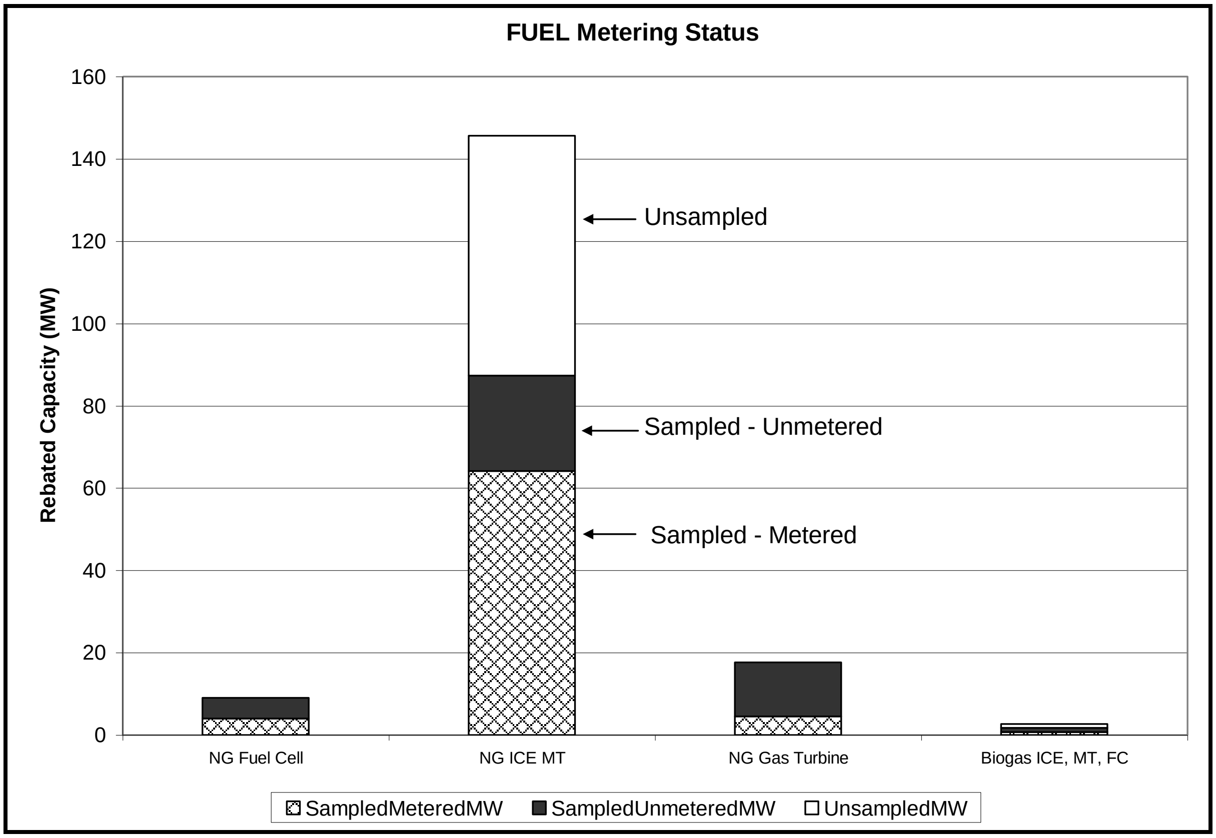
The status of HEAT data collection is summarized in Figure 4-2. Overall, significantly more HEAT metering is needed for all technologies. However, the most important area for improvement in 2009 is non-renewable-fueled gas turbines. These systems are relatively larger capacity and it is more likely that HEAT metering will be available from the Applicant. While the focus will be on obtaining HEAT data from others, HEAT metering will be installed in situations where data are unavailable or of insufficient quality for the purposes of the impact evaluations.

Figure 4-2: HEAT Data Collection as of 12/31/2008



The status of FUEL data collection is summarized in Figure 4-3. Most of the FUEL data have been obtained from IOUs. A principal use of these data is to support calculation of electrical conversion efficiencies and cogeneration system efficiencies. As indicated in the figure, there is a significant amount of FUEL metering needed for SGIP cogeneration facilities and particularly for renewable fuel use projects using blends of renewable and non-renewable fuels.

Figure 4-3: FUEL Data Collection as of 12/31/2008



5

Program Impacts

This section presents impacts from SGIP projects that were on-line through the end of PY08. Impacts examined include effects on energy delivery; peak demand; waste heat utilization and efficiency requirements; and greenhouse gas (GHG) emission impacts. Impacts of SGIP technologies are examined at a program-wide level and at PA-specific levels.

Impacts were estimated for all on-line projects regardless of their stage of advancement in the program, so long as they began normal generation operations prior to December 31, 2008. On-line projects included projects for which SGIP incentives had already been disbursed (Complete projects), as well as projects that had yet to complete the SGIP process (Active projects which were installed and operational, but for which incentives had not yet been disbursed). This same assumption was used in prior year impact evaluations.

Impacts were determined for all projects regardless of whether they had been equipped with metering equipment. Impacts were estimated for unmetered systems as well as for metered systems for which data had not been received by Itron. These estimates relied on metered data and a combination of statistical methods and engineering assumptions. Appendix C describes the methods used for estimating performance where metered data were unavailable. Data availability and corresponding analytic methodologies varied by program level and technology.

This section is composed of the following four subsections:

- 5.1: Energy and Non-coincident Demand Impacts
- 5.2: Peak Demand Impacts
- 5.3: Efficiency and Waste Heat Utilization
- 5.4: Greenhouse Gas Emission Impacts

5.1 Energy and Non-Coincident Demand Impacts

Section 5.1 presents the annual energy and non-coincident demand impacts for the overall program as well as by each PA.

Overall Program Impacts

Electrical energy and demand impacts were calculated for Complete and Active projects that began normal operations prior to December 31, 2008. The extra day in the 2008 leap year provided a 0.3 percent increase over non-leap years and so potentially increased annual energy totals slightly. Impacts were estimated using available metered data for 2008 and known system characteristics. System characteristic data came from program tracking systems maintained by the PAs and were augmented with information obtained over time by Itron.

By the end of 2008, 1275 SGIP facilities were on-line, representing over 337 MW of electrical generating capacity. Some of these facilities (e.g., PV and wind) provided their host sites with only electricity, while cogeneration[1] facilities provided both electric and thermal energy (i.e., heating or cooling). Table 5-1 provides information on the amount of electricity delivered by SGIP facilities throughout calendar year 2008. Energy delivery is described by technology and fuel.

Table 5-1: Statewide Energy Impact in 2008 by Quarter (MWh)

Technology*	Fuel	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total** (MWh)
FC	N	13,663	12,908	10,273	7,204	44,050 †
FC	R	1,769	2,742	3,014	5,048	12,572 †
GT	N	24,845	31,131	32,439	25,742	114,156 †
IC Engine	N	54,537	54,822	68,381	50,190	227,930 †
IC Engine	R	13,503	12,253	10,911	11,179	47,848 †
MT	N	18,201	16,221	16,482	17,059	67,963 †
MT	R	1,953	2,194	1,467	1,249	6,863 †
PV	X	37,062	66,034	60,815	33,268	197,178
WD	X	N/A	N/A	N/A	N/A	N/A
	TOTAL	**165,533**	**198,304**	**203,782**	**150,939**	**718,558**

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind

** [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

[1] Cogeneration facilities are also known as combined heat and power (CHP) facilities and these terms are used interchangeably in this report.

During PY08, SGIP projects generated over 718,000 MWh of electricity; enough electricity to meet the electricity requirements of nearly 109,000 homes for a year[2]. SGIP projects are located at customer sites of the IOUs[3] to help meet onsite demand. Consequently, the 718,558 MWh of electricity provided by SGIP facilities represented electricity that did not have to be generated by central station power plants or delivered by the transmission and distribution system.

Natural gas-fueled technologies provided 63 percent of the electricity generated by SGIP systems during 2008. This share declined from 71 percent in 2007 and from 78 percent in 2006. The continued growth in PV's contribution was one reason for this decline; PV contributed 27 percent in 2008, 23 percent in 2007, and 17 percent in 2006. Another reason was the decrease in generation from natural gas-fueled internal combustion (IC) engines particularly, a technology composing 40 percent of the total program generating capacity in 2008. Natural gas-fueled IC engines contributed the single largest share in 2008, 32 percent, but that was down from the 2007 share of 40 percent.

Annual weighted average capacity factors (CFs) were developed for all SGIP technologies by comparing annual generation to maximum possible generation, i.e., generation at full capacity for entire year. CF represents the fraction of rebated capacity effectively generating over a specific time period. Consequently, CF provides insight into the capability of a generating technology to provide power over a particular time period. For example, peak hour CFs indicate the fraction of capacity from a technology during that particular hour. Table 5-2 lists weighted average annual CFs by technology. Appendix A provides further discussion of annual CFs.

Table 5-2: Annual Capacity Factors by Technology

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	0.598 †
GT	0.737 †
IC Engine	0.223 †
MT	0.407
PV	0.175
WD	N/A

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

---

2 Assuming the typical home consumes approximately 6,670 kWh of electricity per year. From Brown, R.E. and Koomey, J.G. *Electricity Use in California: Past Trends and Present Usage Patterns.* Lawrence Berkeley National Laboratory. May 2002. http://enduse.lbl.gov/info/LBNL-47992.pdf. Value derived from Table 2 on page 8.

3 Although rebated through the SGIP, approximately 9 percent of SGIP facilities are located at customer sites of municipal electric utilities.

Some of the cogeneration or combined heat and power (CHP) technologies listed in Table 5-2 included systems that were fueled by natural gas and systems fueled by renewable fuels (e.g., biogas). For those technologies the CFs reflect both fuels types. Table 5-3 provides a fuel-specific weighted average annual CFs for those technologies that used either natural gas or renewable biogas.

Table 5-3: Annual Capacity Factors by CHP Technology and Fuel

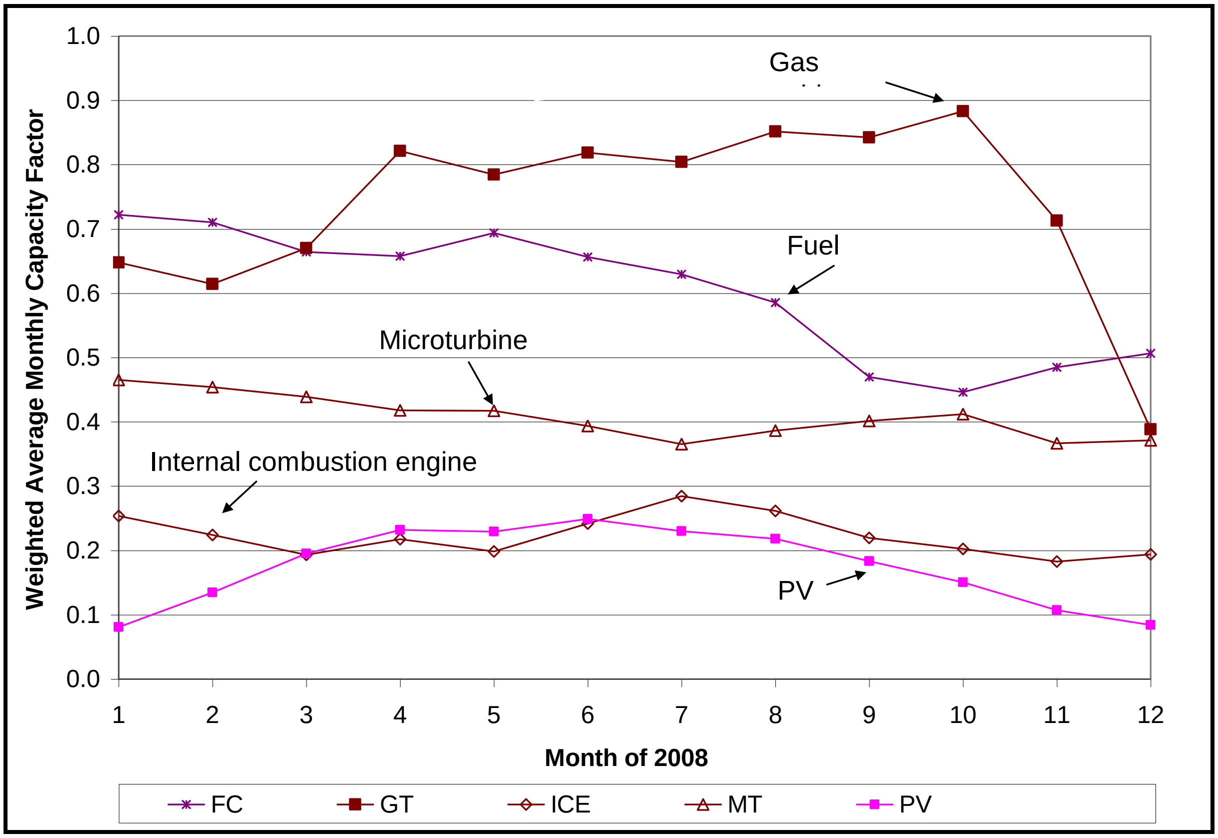
Technology	Annual Capacity Factor* (kWyear/kWyear)	
	Natural Gas	Renewable Fuel
FC	0.594 †	0.612 †
GT	0.737 †	N/A
IC Engine	0.200 †	0.487 †
MT	0.449 †	0.211 †

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Not unexpectedly, among natural gas-fueled technologies the gas turbines and fuel cells had the highest annual CFs; staying above 0.59. In 2007, both these technologies had annual CFs above 0.7. Both technologies are known to be more efficient and tend to be operated more continuously than IC engines or microturbines, thus contributing to higher CFs. Fuel cells powered by biogas also delivered a high annual CF in 2008, exceeding the previous two years for which the factor had not exceeded 0.4. Conversely, more intermittent technologies, such as PV listed in Table 5-2, had an annual CF less than 0.2.

The average annual CF provides an overview perspective of the generating capability of a technology. A higher resolution and potentially more useful view is provided by monthly CFs throughout the year. Figure 5-1 shows monthly weighted average CFs for SGIP technologies during 2008. As expected, gas turbines in the program maintained the highest monthly CFs throughout the year, falling below 0.6 only in December. Fuel cell monthly CFs fell below 0.6 in the last calendar quarter. Figure 5-1 also shows that microturbines had relatively low monthly CFs that tended to run consistently above 0.35 throughout the year, but well below 0.5. Similarly, IC engines had relatively low monthly CFs that did not exceed 0.3 but were fairly consistent from month to month.

Figure 5-1: Weighted Average Capacity Factor by Technology and Month



The monthly CFs shown in Figure 5-1 for fuel cells represent a mix of fuel cells; some powered by natural gas and some powered by biogas. Fuel cells are extremely sensitive to fuel quality. As a result of the lower fuel quality of biogas, biogas-powered fuel cells encountered additional operational issues that reduced their CFs. The annual CFs shown in Table 5-3 along with data provided in Appendix A reveal that CFs for natural gas-powered fuel cells were higher than the CFs for biogas-powered fuel cells. Appendix A provides similar CF charts that distinguish technologies by fuel type.

Off-Line Projects

Off-line projects are projects that did not operate at all during the 2008 year. Impacts of off-line projects were included in the evaluation as having zero generation. Some projects determined to have been off-line were not in the sample of metered projects. The zero impacts of an off-line project contributed to estimates for unmetered projects only if the off-line project had been part of the sample.

Table 5-4 presents the number and corresponding capacities of projects known to be off-line during the entire year of 2008. The rightmost column shows the off-line capacity as a percent of the total metered capacity. In 2008, there were 23 IC engines (20 percent of metered capacity) and 13 microturbines (21 percent of metered capacity) off-line. Reasons behind their being off-line included operational issues as well as relatively high natural gas prices. The off-line PV projects included one where the modules had been blown off the roof and could not be repaired, and another where the modules all had been stolen.

Table 5-4: Number and Capacity of Sites Known to Be Off-Line All of 2008

Technology	Number of Off-line sites (n)	Capacity Off-line (kW)	Percent of Total Metered Capacity* (kW/kW)
FC	0	0	0%
GT	0	0	0%
IC Engine	23	10,715	20.0%
MT	13	1,994	20.8%
PV	2	66	0.1%
WD	0	0	0%

* A site was considered metered if metered data was available for more than 75 percent of the hours in the year.

PA-Specific Program Impacts

Aggregating projects by PA, Table 5-5 provides annual energy impacts for SGIP technologies deployed within each PA service territory. Appendix A provides similar tables of annual energy impacts broken out by both technology and fuel type.

Table 5-5: Annual Energy Impacts by PA (MWh)

Technology		PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC		27,839 †	7,936 †	10,529 †	10,318	56,622 †
GT		21,799 [a]	N/A	31,229	61,128 †	114,156 †
IC Engine		90,570 †	62,044 †	104,105 †	19,058 †	275,777 †
MT		33,067 †	13,475 †	24,745 †	3,538 †	74,825
PV		118,935	37,625	18,904	21,713	197,178
WD		N/A	N/A	N/A	N/A	N/A
	Total	**292,210**	**121,081**	**189,512**	**115,755**	**718,558**

* Except for bottom row, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

As in 2007, roughly 40 percent of the total electricity delivered by the program in 2008 came from SGIP projects operating in PG&E's service territory. SGIP projects in SCG's service territory delivered 25 percent of the total electricity delivered by the program. SCE and CCSE each provided about 17 percent of the total electricity.

In PG&E territory in 2008, PV projects contributed 41 percent of the electricity, surpassing IC engines which in prior years had generated the greatest share. In 2008, the contribution from PG&E's IC engines was 31 percent, down from 45 percent in 2007. Of SCG's energy, 55 percent came from its IC engines, down from 60 percent in 2006. Within PG&E and SCE territory, PV contributed at least 30 percent of the annual electricity delivery.[4] Overall, PV system contributions to program total annual electricity delivery grew from 22 to 27 percent between 2007 and 2008.

[4] PV systems in SCG service territory contributed approximately 10 percent of the annual electricity delivery. PV systems in CCSE service territory contributed approximately 19 percent of the annual electricity delivery.

Table 5-6 presents annual weighted average CFs for each technology and PA for the year 2008. Where entries are "N/A" the PA had no on-line projects of that technology. A special case is for SCE Wind where no valid data were received for 2008 for either of its two Wind projects. Additional tables in Appendix A differentiate annual CFs by both technology and fuel type.

Table 5-6: Annual Capacity Factors by Technology and PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
FC	0.628 †	0.509 †	0.698 †	0.525
GT	0.618 [a]	N/A	0.790	0.762 †
IC Engine	0.187 †	0.251 †	0.256 †	0.190 †
MT	0.452 †	0.315 †	0.482 †	0.213 †
PV	0.177	0.163	0.181	0.177
WD	N/A	N/A	N/A	N/A

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

PA-specific CFs in Table 5-6 generally follow the program-wide CFs shown earlier with exception of microturbine CF for CCSE. In CCSE territory, the CF for microturbines was 0.213. Five of the 17 microturbines (40 percent of the total microturbine capacity) in CCSE territory were known to have been off-line for all of 2008, resulting in a substantially lower annual CF than for microturbines in other PA territories.

5.2 Peak Demand Impacts

Section 5.2 presents the peak demand impacts for the program as a whole. The examination of peak demand focused first upon the electricity produced by all SGIP projects during the CAISO system peak load day and hour. In addition, it focused on generation during IOU peak demand days considering electricity produced only by SGIP projects within each IOU territory.

Overall Peak Demand Impacts

The ability of SGIP projects to supply electricity at the customer site during times of CAISO peak demand represents a critical impact. By providing electricity directly at the customer site during peak hours, SGIP facilities reduce the need for utilities to power up peaking units to supply electricity to these customers. Likewise, SGIP provides some relief by decreasing transmission line congestion. In addition, by offsetting more expensive peak electricity, SGIP projects provide potential cost savings to the host site.

Table 5-7 summarizes by technology the overall SGIP program impact on electricity demand coincident with the 2008 CAISO system peak hour load. The table shows the number of projects on-line at the time of the peak hour, their combined capacities and demand impact, and their peak hour average CF.

Table 5-7: Demand Impact Coincident with 2008 CAISO System Peak Load

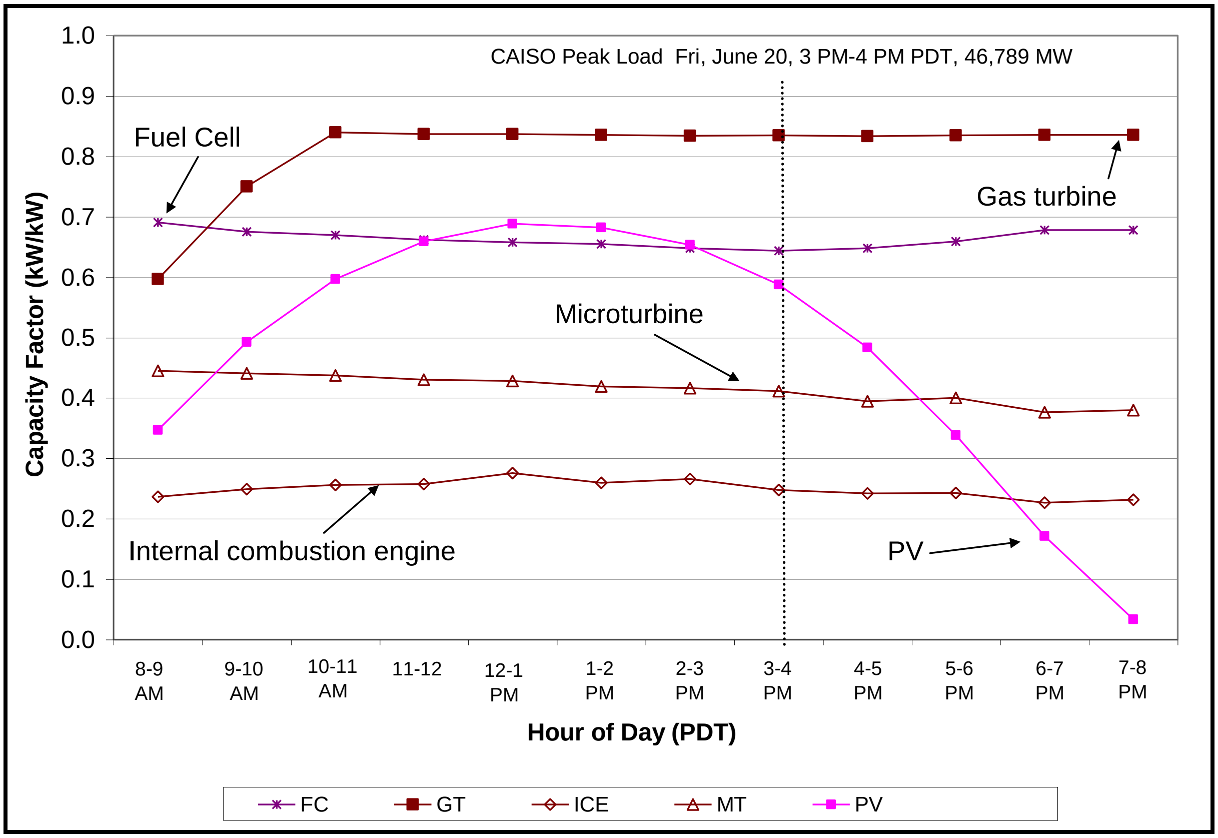
Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	19	10,700	6,889	0.644 †
GT	6	17,643	14,728	0.835 †
IC Engine	223	140,490	34,788	0.248 †
MT	129	20,692	8,509	0.411
PV	863	129,566	76,202	0.588
WD	2	1,649	N/A	N/A
TOTAL	**1,242**	**320,740**	**141,117**	

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

In 2008, the CAISO system peak reached a maximum value of 46,789 MW on June 20 during the hour from 3:00 to 4:00 P.M. (PDT). This was 2,046 MW less than the peak load of 48,835 MW that occurred during the prior hour on August 31 of 2007. There were 1,242 SGIP projects known to be on-line when the CAISO experienced the 2008 summer peak. Metered generation data were available for 464 of these on-line projects. Where metered data were unavailable, impacts were estimated based on these metered data. For the two Wind projects, however, no metered data were available and so no impacts were estimated.

While the total rebated capacity of these on-line projects exceeded 320 MW, the total impact of the SGIP projects coincident with the CAISO peak load was estimated at slightly above 141 MW. In essence, the collective peak hour CF of the SGIP projects on the CAISO 2008 peak was approximately 0.44 kW per kW of rebated capacity. For intermittent technologies such as wind and solar, the timing of peak demand is a crucial factor in contributing to peak capacity. Figure 5-2 profiles the hourly weighted average CF for each technology from morning to early evening during the 2008 peak day. The figure also indicates the hour and magnitude of the CAISO peak load. The influence of timing of peak demand is readily apparent with PV. If the CAISO peak hour had occurred two hours earlier, the peak hour average CF for PV would have been more than 15 percent greater.

Figure 5-2: CAISO Peak Day Capacity Factors by Technology

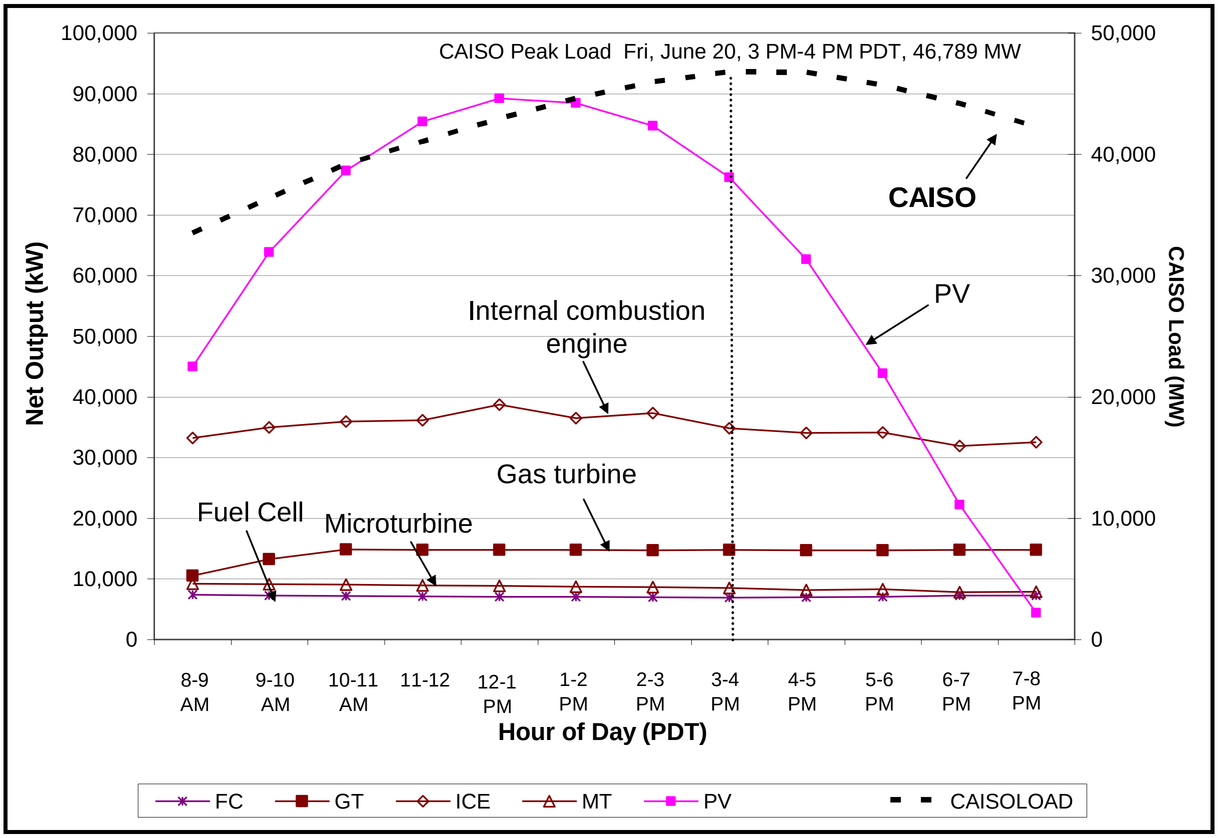


It is important to recognize that the individual and collective peak hour impacts of the SGIP projects can be used as a proxy for the peak hour impact that may be expected from a much larger penetration of DG technologies in California's electricity system under certain assumptions. Because the peak hour CFs for SGIP technologies were derived from metered data, use of these factors as proxies can be especially useful in estimating the influence of different mixes of DG technologies on peak demand. Tables in Appendix A further differentiate peak demand impacts by technology and fuel.

The peak hour CF indicates the capability of a technology to provide power when electricity demand is highest and additional generation is most needed in the electricity system. For the summer peak in 2008, gas turbines operating in the SGIP demonstrated the highest peak hour average CF; just below 0.84. Fuel cells followed with an average peak hour CF just under 0.65. Microturbines and IC engines had much lower average peak hour CFs of 0.41 and 0.25, respectively. Under the 2008 summer peak conditions, occurring in the third hour after the sun reached its apex, PV systems demonstrated a peak hour average CF of 0.59. The peak hour average CF for wind could not be estimated because metered data was not available.[5]

Figure 5-3 plots the hourly total net electrical contribution in kW for each SGIP technology from morning to early evening during the 2008 peak day. It also shows the hourly profile of the CAISO load plotted on a different scale and in MW on the right axis.

Figure 5-3: SGIP Impact on CAISO 2008 Peak Day



---

5 The California Energy Commission has collected and reported wind capacity factors for wind energy systems operating in the state over a number of years. Average annual wind capacity factors range from 14 to 26 percent. Peak hour capacity factors range from 30 to as high as 60 percent at 6:00 P.M. California Energy Commission. *Wind Power Generation Trends at Multiple California Sites*. CEC-500-2005-185. December 2005. http://www.energy.ca.gov/pier/project_reports/CEC-500-2005-185.html

This figure is useful in assessing the potential impact of increasing amounts of a particular SGIP technology on meeting peak hour demand. For example, SGIP's 880 PV systems provided approximately 76 MW to the grid during the peak hour. These PV systems represented approximately 129 MW of operational PV capacity. In comparison to the CAISO peak hourly demand of nearly 47,000 MW, SGIP's PV contribution represented only 0.16 percent of the total. However, in scaling up PV capacity to 3,000 MW as targeted in the CSI, PV potentially could have contributed nearly 1,800 MW of electricity during the peak hour; or over 3.8 percent of the 2008 peak hour demand. In addition, California's electricity mix relies on approximately 3,000 MW of older, more polluting, and costly peaking units to help meet peak summer demand.[6] Consequently, 3,000 MW of installed PV, with a commensurate peak capacity of nearly 1,800 MW would displace over half the capacity of the older, peaking units. Moreover, it should be noted that the performance results shown in Figure 5-3 represent PV systems with predominately a southern exposure. PV systems with a southwestern orientation would have a significantly higher contribution to peak.[7]

---

[6] California Energy Commission. "Database of California Power Plants." http://energyalmanac.ca.gov/powerplants/index.html

[7] A southwestern orientation could increase peak hour electricity delivery by as much as 30 percent, depending on location. Itron, Inc. *Solar PV Costs and Incentive Factors*. February 2007. http://energycenter.org/uploads/Selfgen_SolarPVCosts_FinalReport.pdf

PA-Specific Peak Demand Impacts

Table 5-8 through Table 5-10 present the total net electrical output during the respective peak hours of California's three large electric IOUs. The top portions of each table list the date, hour, and load of the utility's peak demand. The tables also show the number of SGIP type facilities on-line at the time of the peak, the operating capacity at peak, and the demand impact. Tables in Appendix A further differentiate utility peak demand impacts by technology and fuel.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table 5-8: Electric Utility Peak Hours Demand Impacts—PG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
PG&E	**21,827**	**8-Jul-08**	**5 PM**

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	9	5,100	2,965	0.581
GT	3	4,016	2,309	0.575
IC Engine	99	56,745	11,374	0.200
MT	53	8,304	3,286	0.396
PV	449	71,964	23,937	0.333
WD	N/A	N/A	N/A	N/A
Total	**613**	**146,129**	**43,872**	**0.300**

PG&E's 2008 peak demand occurred at 5:00 P.M. on July 8. Fuel cells had a peak hour average CF just below 0.6. Microturbines and IC engines both had peak hour CFs well under 0.5. PV systems, due to the limited amount of insolation available at 5:00 P.M., had a peak hour average CF of 0.33. The combined SGIP contribution to peak hour generation was an overall peak hour CF of 0.30. The output from the combined SGIP facilities operating in PG&E's service territory during the 2008 summer peak was 0.2 percent of the peak demand.

Table 5-9: Electric Utility Peak Hours Demand Impacts—SCE

Elec PA	Peak (MW)	Date	Hour (PDT)
SCE	**22,404**	**20-Jun-08**	**4 PM**

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	5	2,350	1,241	0.528
GT	1	4,500	4,132	0.918
IC Engine	97	67,580	21,199	0.314
MT	51	8,976	3,278	0.365
PV	210	29,919	12,217	0.408
WD	2	1,649	N/A	N/A
Total	**366**	**114,973**	**42,067**	**0.366**

SCE's 2008 peak demand occurred at 4:00 P.M. on June 20. The fuel cells operating in SCE's service territory had a peak hour CF somewhat less than those in PG&E's territory. The sole gas turbine in SCE's territory was running near capacity compared to just over half-capacity for the three projects in PG&E's territory. IC engines also operated in SCE's territory at a substantially higher CF than for PG&E. Microturbines for SCE, on the other hand, showed a slightly lower CF. PV facilities in SCE's territory had a slightly higher CF than for PG&E, explained in part by the SCE peak hour being one hour earlier than PG&E peak. The impact of the wind facilities in SCE territory during the peak hour could not be estimated because no valid data were received. The electricity contribution from the combined SGIP facilities operating in SCE's service territory during the 2008 summer peak was 0.51 percent of peak demand.

Table 5-10: Electric Utility Peak Hours Demand Impacts – SDG&E/CCSE

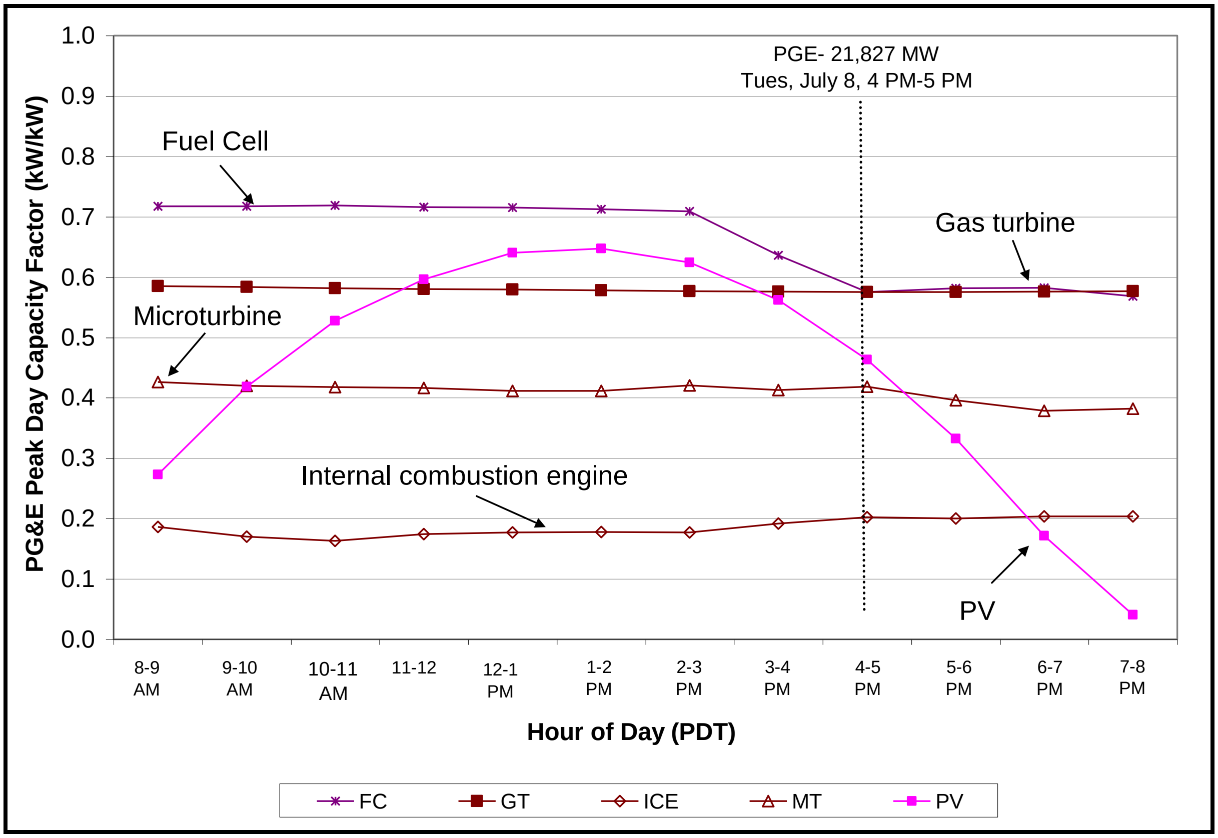
Elec PA	Peak (MW)	Date	Hour (PDT)
SDG&E	**4,348**	**1-Oct-08**	**3 PM**

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	4	2,250	678	0.302
GT	2	9,127	7,987	0.875
IC Engine	21	13,224	3,458	0.261
MT	17	1,902	279	0.147
PV	104	13,998	5,712	0.408
WD	N/A	N/A	N/A	N/A
Total	**148**	**40,502**	**18,114**	**0.447**

SDG&E's 2008 peak hour occurred at 3:00 P.M. on October 1. Fuel cells in SDG&E's territory during its peak had peak hour average CF of just 0.302, well below those greater than 0.5 observed for PG&E and SCE. Together, the two gas turbines were just below 90 percent of capacity. The IC engines had CFs about midway between their counterparts in PG&E and SCE service territories. SDG&E's PV peak hour average CF was just below 0.41, similar to that observed for SCE peak which occurred one hour later in the day. That it was not greater is due in part to the SDG&E peak occurring in October when insolation is less at that hour than in June when the SCE peak occurred. The electricity contribution from the combined SGIP facilities operating in SDG&E's service territory during the 2008 summer peak was 0.41 percent of demand.

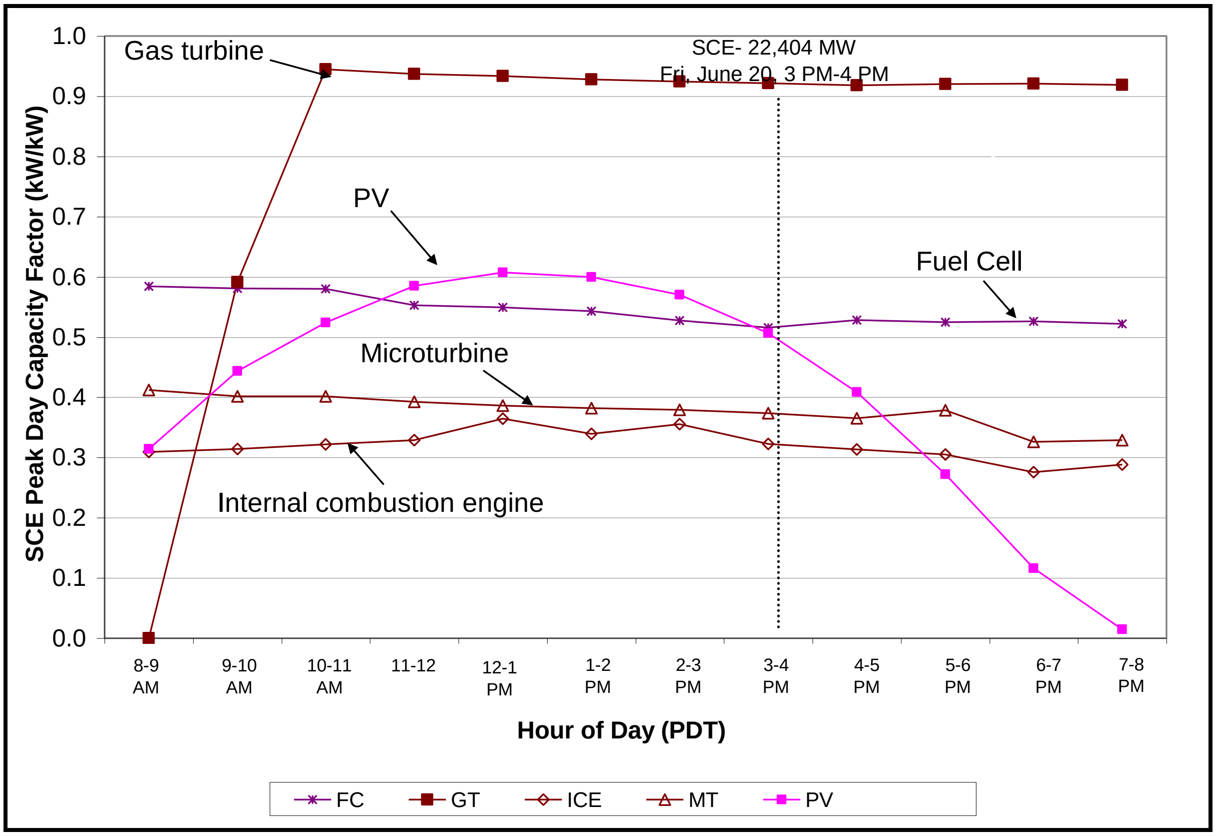
Figure 5-4 through Figure 5-6 plot profiles of hourly weighted average CFs by technology for the SGIP systems directly feeding the utilities on the dates of their respective peak demand. The plots also indicate the date, hour, and value of the peak load for the electric utility. Note that the plots include only those technologies that were operational for the electric utility, so not all technologies appear for all electric utilities. Again, results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. Appendix A plots separately those technologies that can use natural gas versus renewable fuel.

Figure 5-4: Electric Utility Peak Day Capacity Factors by Technology—PG&E



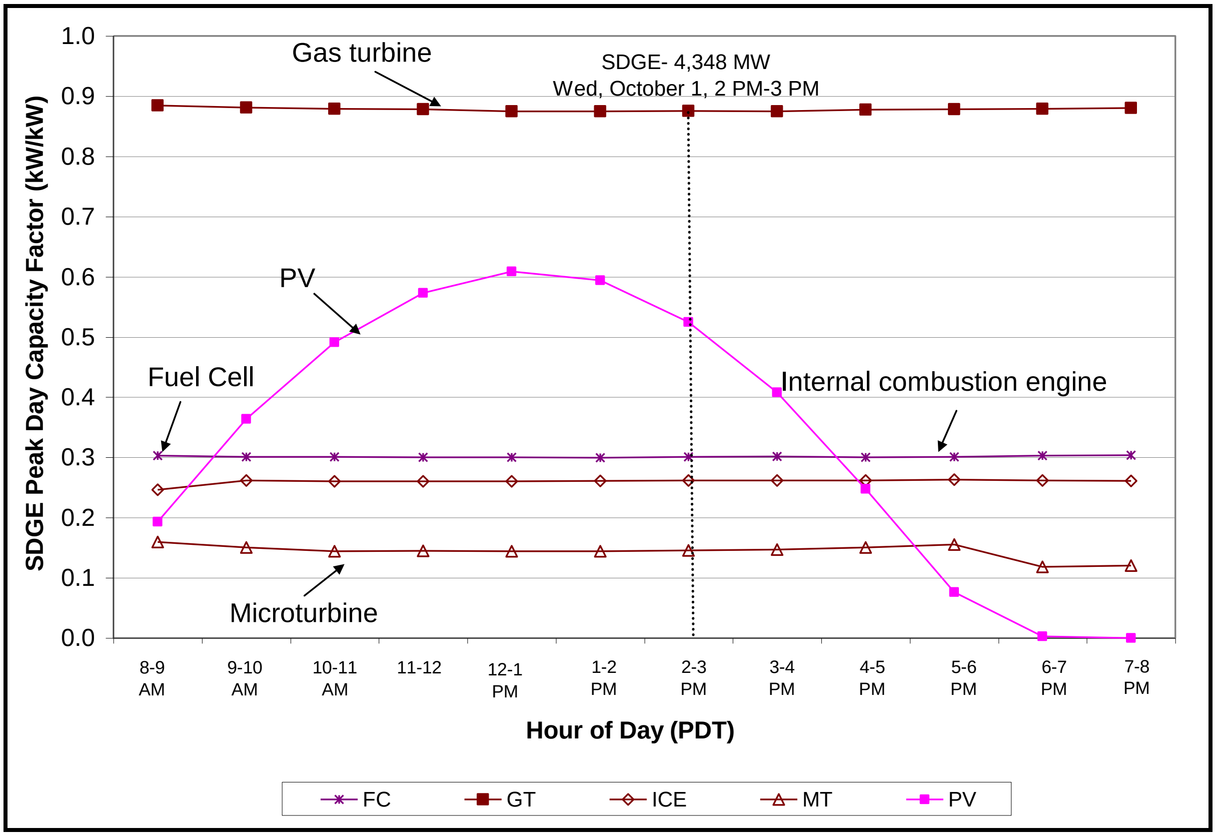
Except for a late afternoon dip for fuel cells, the hour-by-hour peak day CF plot for PG&E reflects the almost flat generation profiles exhibited on average from natural gas-fired cogeneration facilities operating under the SGIP. For PG&E fuel cells, the CF declined slightly from 2:00 P.M. to 4:00 P.M. when one of the five fuel cells for which metered data were available happened to decrease its power output. Likewise, gas turbines, microturbines, and IC engines had fairly constant CFs. Gas turbines consistently ran at a CF just less than 0.6. Microturbines reached 0.45 while IC engines never surpassed 0.25.

Figure 5-5: Electric Utility Peak Day Capacity Factors by Technology—SCE



For SCE, most of the natural gas-fired cogeneration facilities had steady peak day hourly CFs similar to those for PG&E. SCE fuel cells, microturbines, and IC engines all operated similarly with CFs between 0.3 and 0.6 for the majority of the day. Microturbines and fuel cells within PG&E territory operated at a higher CF than those in SCE territory; however, IC engines and gas turbines in SCE territory operated at a higher CF than those in PG&E territory.

Figure 5-6: Electric Utility Peak Day Capacity Factors by Technology—SDG&E/CCSE

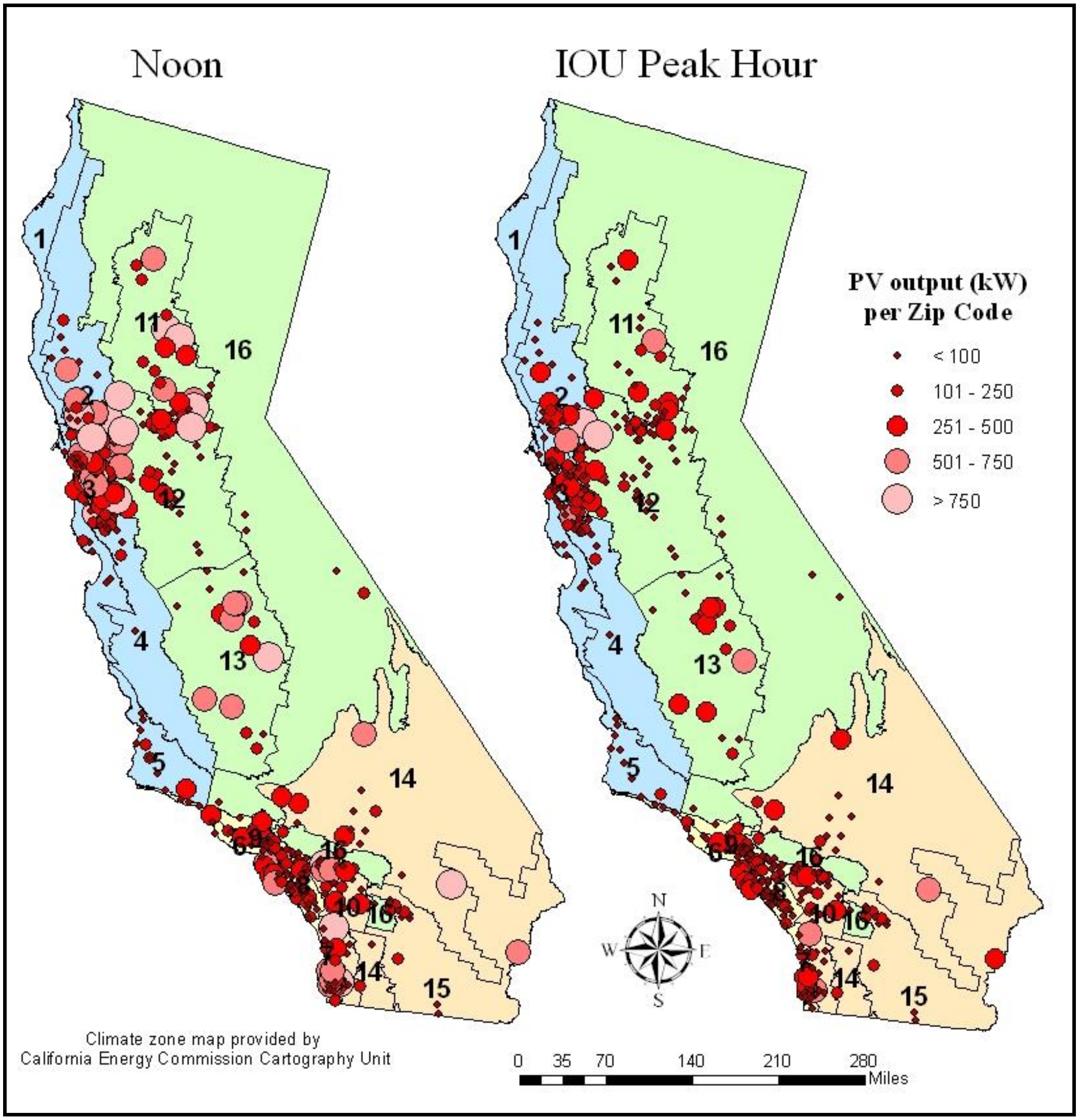


SDG&E shows peak day hourly CF profiles similar to PG&E and SCE. Fuel cells and IC engines both had CFs close to 0.3 for the entire day, similar to the IC engine CF seen in SCE territory. The gas turbine CF stayed close to 0.9 throughout the day. The microturbine CF during the peak day never exceeded 0.2, which is much less than the average CF for microturbines during the peak day in both SCE and PG&E territories.

The influence of timing of the CAISO peak hour on the ability of intermittent resources to contribute to peak electricity delivery was discussed earlier. Likewise, the timing of IOU peak hour, both by hour of day and month of year, largely determines the impact of PV project contribution. The CF for PV is strongly influenced by the amount of available solar resource: increasing over the course of the morning until it peaks near noon, and then decreasing as the sun sets. PV impacts on peak demand generally will be greater the nearer the peak hour is to noon and the nearer the month is to spring when temperatures are cooler at that time of day.

Figure 5-7 illustrates the impact of timing of peak demand on PV's ability to provide capacity. The figure on the left shows PV capacity at noon. Larger circles represent a higher capacity of PV. The figure on the right shows PV output at the time of peak demand during 2008 for each of the IOUs. As shown, PG&E's PV output at its 5:00 P.M. peak is significantly less than its PV output at noon. Conversely, there is little difference in PV output in SDG&E territory, which had its 2008 system peak at 3:00 P.M.

Figure 5-7: Impact of Peak Demand Time of Day on PV Capacity*



* Note: PG&E's peak was at 5.00 P.M. on July 8, 2008. SCE's peak was at 4.00 P.M. on June 20, 2008. SDG&E's peak occurred at 3.00 P.M. on October 1, 2008.

5.3 Efficiency and Waste Heat Utilization

Cogeneration systems represent nearly 60 percent of the on-line generating capacity of the SGIP. To ensure that these systems harness waste heat effectively and realize high overall system and electricity efficiencies, Public Utility Code (PUC) 216.6[8] requires that participating non-renewable-fueled fuel cells and engines/turbines meet minimum levels of thermal energy utilization and overall system efficiency.[9]

PUC 216.6(a) requires that recovered useful waste heat from a cogeneration system exceeds five percent of the combined recovered waste heat plus the electrical energy output of the system. PUC 216.6(b) requires that the sum of the electric generation and half of the heat recovery of the system exceeds 42.5 percent of the energy entering the system as fuel. Table 5-11 summarizes these requirements.

Table 5-11: Required Minimum PUC 216.6 Levels of Performance

Element	Definition	Minimum Requirement (%)
216.6 (a)	Proportion of facilities' total annual energy output in the form of useful heat	5.0
216.6 (b)	Overall system efficiency (50 percent credit for useful heat, LHV)	42.5

SGIP projects use a variety of means to recover heat and apply it to provide a variety of heating and cooling services. Table 5-12 summarizes the end uses served by recovered useful thermal energy and includes all projects subject to heat recovery requirements and on-line through December 2008.

Table 5-12: End-Uses Served by Recovered Useful Thermal Energy as of 12/31/2008

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	214	87,583
Heating & Cooling	72	55,006
Cooling Only	38	32,721
To Be Determined	23	8,566
Total	**347**	**183,876**

8 PUC 216.6 has replaced PUC 218.5; however the requirements remain the same.

9 Several renewable-fueled projects entering the program during its first years were also subject to heat recovery requirements and are included in the analysis covered in this section.

PY08 PUC 216.6 Compliance

Metered data collected from on-line cogeneration projects were used to estimate performance of similar unmetered projects. Resulting performance data for both metered and unmetered projects were used to calculate PUC 216.6 performance metrics by technology type. Results summarized in Table 5-13 represent capacity weighted averages for each technology type. These results may be thought of as representing the overall performance of a single, very large system if all of the systems were combined. This basis is intended to yield results that can be compared directly with other pertinent reference points (e.g., performance of large, centralized power plants).

Table 5-13: PUC 216.6 Cogeneration System Performance by Technology

Technology	Number of projects (n)	216.6 (a) Proportion as Useful Heat (%)*	216.6 (b) Avg. Efficiency Level Achieved (%, LHV)*
FC	15	27.9% †	48.3%
GT	6	45.% †	42.3% †
IC Engine	208	29.8%	36.6%
MT	113	44.2%	33.1%

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates accuracy is at least 90/10.

Within Table 5-13, the PUC 216.6(a) results are expressed as the proportion of the total output energy from the facility recovered as useful heat. For example, fuel cells in the SGIP recovered on average 28 percent of their total output energy as useful heat, whereas IC engines recovered on average 30 percent of their total output energy as useful heat. All of the cogeneration technologies in the SGIP achieved and exceeded the PUC 216.6(a) requirement of providing at least five percent of the output energy as useful heat.

The PUC 216.6(b) results in Table 5-13 are expressed as the average overall PUC 216.6(b) system efficiency achieved by the technology.[10] For example, fuel cells on average achieved an overall PUC 216.6(b) system efficiency of 48 percent, whereas IC engines on average achieved an overall system efficiency of 37 percent. The fuel cell 216.6(b) results exceeded the 42.5 percent threshold by a substantial margin while the gas turbine results just missed the requirement. Factors influencing this outcome include the high electric conversion efficiency of fuel cells and the high degree waste heat utilization for the group of gas turbines during 2008. The IC engine and microturbine 216.6(b) results from Table 5-13 both fall

[10] Please note that system efficiency typically includes the sum of all useful work (electricity plus thermal energy) divided by the amount of energy going into the system; whereas PUC 216.6(b) uses only one-half the recovered thermal energy

short of the 42.5 percent threshold. The shortfall is due in part to a difference in electrical conversion efficiency, which was higher for IC engines than for microturbines.

The cogeneration system performance results in Table 5-13 are based on metered electric output, metered fuel input, and metered heat recovery data. Availability of metered data varied from site to site and from month to month for some sites. The impact of data availability on accuracy of impacts estimates was examined in the uncertainty analysis described in Appendix C.

The shortfall of SGIP microturbine and IC engine technologies in meeting the PUC 216.6(b) requirements is due in part to lower than anticipated electricity generation efficiencies. Table 5-14 shows the electric conversion efficiencies of IC engines averaged 30 percent while microturbines averaged 24 percent; both well below the average electrical conversion efficiencies seen for fuel cells in the SGIP.

Table 5-14: Electric Conversion Efficiencies Among Metered Systems by Technology

Technology	Number of metered projects (n)	Electric Conversion Efficiency (%, LHV)
FC	8	40.6% ± 4.1%
GT	3	30.1% ± 8.2%
IC Engine	49	30.3% ± 14.4%
MT	22	23.5% ± 11.7%

Another reason IC engines and microturbines failed to meet PUC 216.6(b) requirements is the lack of a significant coincident thermal load. In other words, many facilities do not have a need for the waste heat provided by the generator, or the SGIP system design failed to appropriately match thermal load and electricity output. Because PUC 216.6(b) requires that half of the energy efficiency contribution comes from recovered waste heat, lack of thermal load reduces the overall efficiency. One reason gas turbines met the PUC 216.6(b) requirement was due to a significant coincident thermal load.

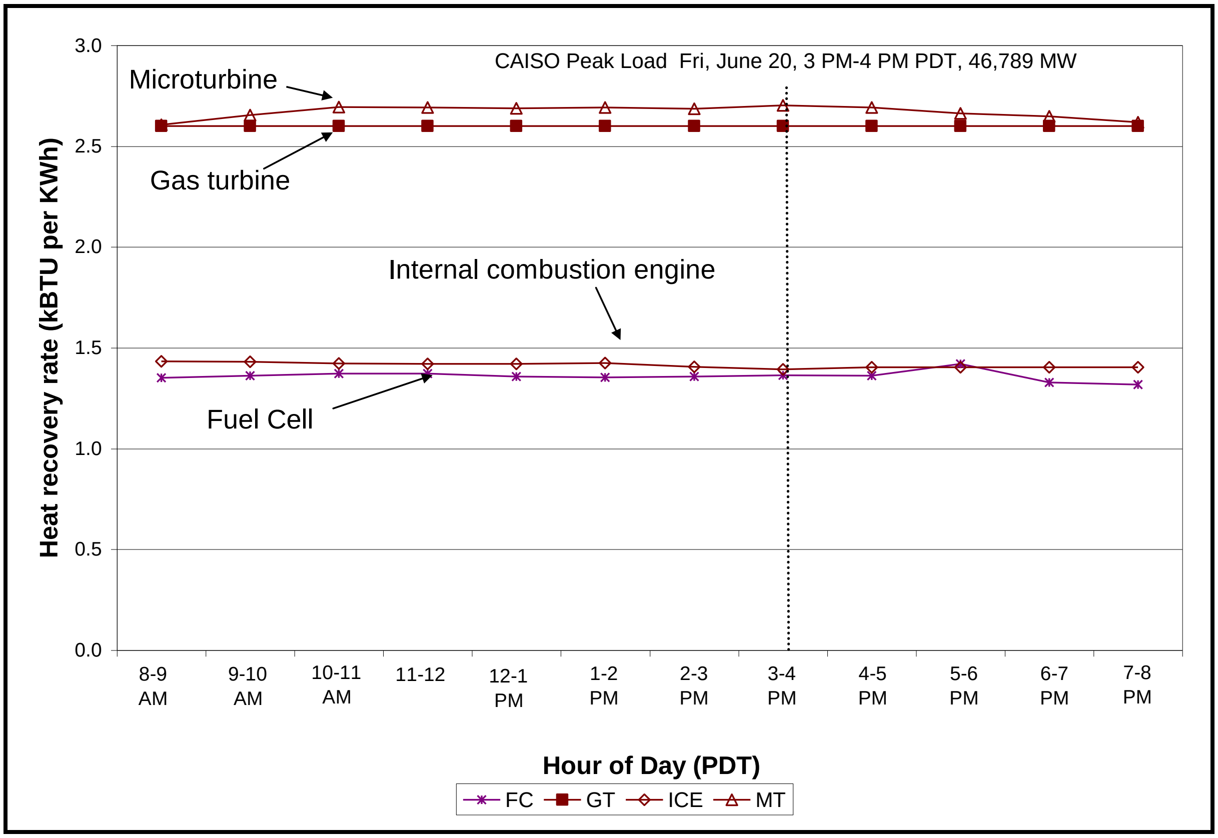
A good match between electrical and thermal loads also can play a significant role in the contribution of cogeneration systems toward reducing peak demand and GHG emissions during peak. This is particularly true for cogeneration systems that recover waste heat to drive absorption chillers that offset air conditioning loads that otherwise would be met by electric chillers. The lack of a good match between thermal and electrical loads for SGIP cogeneration projects was explored in a special report conducted by Itron for the CPUC in 2007.[11]

Peak Demand Impacts

Figure 5-8 shows hourly heat recovery rates during the 2008 CAISO system peak day. As shown, average thermal energy recovery by cogeneration facilities within the SGIP did not appear to have been influenced by peak hour electrical demands. Coordination during peak demand periods should be an important consideration for expansion of cogeneration facilities going forward in California's electricity market.

One of the fundamental objectives of the SGIP is to provide power at times of peak demand. Electrical generation impacts were provided earlier in this section. Figure 5-8 provides normalized heat recovery results by technology during the CAISO peak day. Results summarized in Figure 5-8 represent capacity weighted averages for each technology type.

Figure 5-8: Heat Recovery Rate during CAISO Peak Day



---

11 Itron, Inc. *In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems*. February 2007. http://www.energycenter.org/uploads/Selfgen_ThermalAnalysisReport.pdf

Observations of interest from the above figure include:

- All the CHP technologies exhibited consistently flat heat recovery rates (kBtu per kWh) throughout the CAISO peak day. Electrical production on the CAISO peak day, shown in Figure 5-3, was also steady throughout the day. This is somewhat surprising in that CHP systems might be expected to ramp up generation during peak hours to help offset higher priced peak electricity. In turn, as generation was ramped up, there should be a commensurate increase in heat recovery, if the facility had additional thermal load (e.g., for absorption chillers).
- Microturbines and gas turbines recovered more heat than fuel cells and IC engines. This is explained in part by the relatively lower electrical efficiency of microturbines and gas turbines. Lower electrical efficiency leaves more potential heat available for recovery.[12]

AB 1685 (60 Percent) Efficiency Status

Assembly Bill 1685 (Leno, October 12, 2003)[13] required that all SGIP combustion-based technologies operating in a combined heat and power application achieve a 60 percent system efficiency on a higher heating basis.[14] System efficiencies were calculated for each non-renewable-fueled cogeneration technology on-line in 2008. Table 5-15 provides technology-specific summary statistics for overall system efficiency.

Table 5-15: Cogeneration System Overall System Efficiency by Technology

Technology	Number of projects (n)	Overall System Efficiency (%, HHV)*
FC	15	50.6%
GT	6	49.3% †
IC Engine	208	38.8%
MT	113	38.4% †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

California Air Resources Board (CARB) NOx Compliance

Beginning in 2005, in addition to meeting the waste heat utilization requirement, non-renewable-fueled engine/turbine projects submitting applications to the SGIP were required to meet the 2005 CARB NOx emission standard of 0.14 pounds of NOx emitted per Megawatt-hour of generated electricity (lbs/MWh). This standard could be met by using a fossil fuel combustion emission credit for waste heat utilization so long as the system

---

12 Ibid.

13 AB 1685 (Leno, October 12, 2003). http://www.leginfo.ca.gov/pub/03-04/bill/asm/ab_1651-1700/ab_1685_bill_20031012_chaptered.html

14 It should be noted that this requirement is different from the PUC 216.6(b) efficiency requirement, which includes only one-half of the recovered thermal energy in estimating overall system efficiency.

achieved the 60 percent minimum efficiency standard. The following formula was used to determine system efficiency:

$$SystemEfficiency = \frac{(E + T)}{F}$$

Where E is the generating system's rated electric capacity converted into equivalent Btu per hour, T is the generating system's waste heat recovery rate (Btu per hour) at rated capacity, and F is the generating system's higher heating value (HHV) fuel consumption rate (Btu per hour) at rated capacity.

The waste heat utilization credit was calculated by the following equation:

$$MW_{WH} = \frac{UtilizedWasteHeat\left(\frac{1}{3.4}\right)}{EFLH}$$

Where *UtilizedWasteHeat* is the annual utilized waste heat in MMBtu per year, 3.4 is the conversion factor from MWh to MMBtu, and *EFLH* is the system's annual equivalent full load hours of operation.

The following equation was used to determine if the system meets the NOx requirement:

$$NO_x = \frac{NO_x emissionrate}{MW_r + MW_{WH}}$$

Where $NO_x emissionrate$ is the system's verified emissions in pounds per MWh without thermal credit, MW_r is the system's rated capacity in MW, and MW_{WH} is the waste heat utilization credit in MW. The result represents a NOx emission rate (lbs per MWh) which utilizes the thermal credit. If this rate was less than 0.14 lbs per MWh then the system qualified.

Effective January 1, 2007, cogeneration facilities receiving incentives under the SGIP were required to meet a CARB NOx emission limit of 0.07 lbs/MWh. There were two microturbine cogeneration facilities that applied in 2007 and were on-line by December 31, 2008. With the addition of the more stringent NOx requirement, no IC engine projects have yet been completed. Conversely, a few microturbine projects have been completed because microturbines have low NOx emissions without use of additional NOx controls. As of December 31, 2008, 57 non-renewable-fueled engines/turbines had come on-line under the less stringent 2005 CARB NOx requirement and only two had come on-line under the 2007 CARB NOx requirement. Of the 59 systems, 21 were microturbines, four were gas turbines, and 34 were IC engines. All 59 systems had gone through NOx emission tests and theoretically would meet the CARB NOx requirement. It cannot be determined, however, if these systems would actually meet the standard under normal operating conditions because NOx emission data and HEAT data were not available for all sites.

5.4 Greenhouse Gas Emission Impacts

Interest in climate change has continued to increase over the last several years with special emphasis being placed on GHG emission impacts. Obtaining accurate measures of GHG emission impacts will increase in importance, particularly in the event of a cap and trade program for carbon credits. This section measures the impact the installation of SGIP projects had on GHG emissions in 2008,[15] including carbon dioxide (CO_2) and methane (CH_4). The latter is ultimately measured in CO_2 equivalent units to facilitate comparisons.

GHG emission impacts are presented by technology and fuel group (e.g., renewable-fueled microturbines, non-renewable-fueled gas turbines, and renewable-fueled fuel cells). This allows the examination of possible relationships between net changes in CO_2- and CH_4-specific GHG emission impacts. Note that as in all prior SGIP Impact Evaluation Reports, the focus on GHG emission impacts is on two gases (CO_2 and CH_4) as these are the main GHG pertaining to SGIP facilities and baseline scenarios.

GHG Analysis Approach

To assess GHG emissions impacts the emissions of rebated SGIP DG systems were first calculated. Next the baseline emissions that would have occurred in PY08 in the program's absence were estimated. Baseline CO_2 emissions which include the baseline electric power plant GHG emissions per kWh which are displaced by SGIP projects, baseline CO_2 emissions corresponding to electric chiller operation, [16] baseline natural gas boiler CO_2 emissions, [17] and the baseline emissions from either venting biogas or capturing and flaring biogas. GHG emissions impacts attributed to the program were then calculated as the

---

[15] The year 2008 was a leap year, which resulted in an additional day of generation, for a total of 8,784 hours in the year rather than the standard 8,760. This is important when comparing GHG results of PY08 to other years.

[16] Baseline chiller electricity consumption was based on a typical efficiency (0.634 kW/ton) for a new, standard-efficiency chiller. The quantity of cooling provided was calculated based on CHP system heat recovered for cooling and the efficiency (0.60 COP) of a new, single-effect absorption chiller representative of those typically utilized by SGIP participants. This basis was prescribed for the impacts evaluation so that results would be consistent with assumptions underlying previous program cost-effectiveness evaluations.

[17] Baseline boiler natural gas consumption was calculated using an assumed efficiency for existing boilers (80 percent) in combination with CHP system heat recovered for heating. This basis was prescribed for the impacts evaluation so that results would be consistent with assumptions underlying previous program cost-effectiveness evaluations.

difference between the two scenarios. Detailed documentation of the GHG emissions impact evaluation methodology is included as Appendix B.

The E3 avoided cost calculation workbook[18] is used to estimate GHG impacts from the SGIP. The E3 avoided cost workbook provides hourly CO_2 emission factors for 1999 for northern California (PG&E only) and southern California (SCE, SCG, and SDG&E). For the PY08 analysis, there was a change in the methodology used to adjust the emission factors for a 1999 calendar to be appropriate for a 2008 calendar. In estimating GHG emission impacts from SGIP projects, the distinction between weekdays, weekend days, and the identification of holidays is important, particularly during the summer when peak demand occurs. Additionally, cogeneration projects are often load following and may not operate on weekends or holidays.

GHG Analysis Results

Due to their different GHG emission impacts pathways, results are broken down by wind and PV facilities; non-renewable cogeneration facilities; and renewable-fuel (i.e., biogas-fueled) SGIP facilities.

CO_2 Emission Impacts from PV and Wind Projects

PV and wind projects do not emit CO_2. The installation of PV and wind SGIP projects results in less electricity being purchased from the grid. This is a direct displacement of electricity that would have otherwise been generated from natural gas-fired central station power plants. As a result, the CO_2 emission impacts for PV and wind projects were based on the amount of CO_2 that would have been generated by the mix of utility electricity generation sources.

---

[18] Energy and Environmental Economics. *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs.* October 25, 2004. http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

The impact of PV projects on CO_2-specific GHG emissions is summarized in Table 5-16. During 2008 the operation of SGIP PV systems resulted in a reduction in CO_2 emissions equal to 115,057 metric tons. Because PV systems emit no CO_2 during operation this impact corresponds to a 100 percent reduction with respect to baseline CO_2 emissions that would have occurred in the program's absence. The amount of energy generated by PV increased from PY07 to PY08 (197,178 MWh compared to 161,770 MWh); however, PV has a slightly lower CO_2 factor in 2008 than in 2007 (-0.58 compared to -0.60 for PY07). Inter-year variability results from the influence of weather, which changes from year to year. The CO_2 emission impacts could not be calculated for the wind turbines in the SGIP because valid metered data were not received.

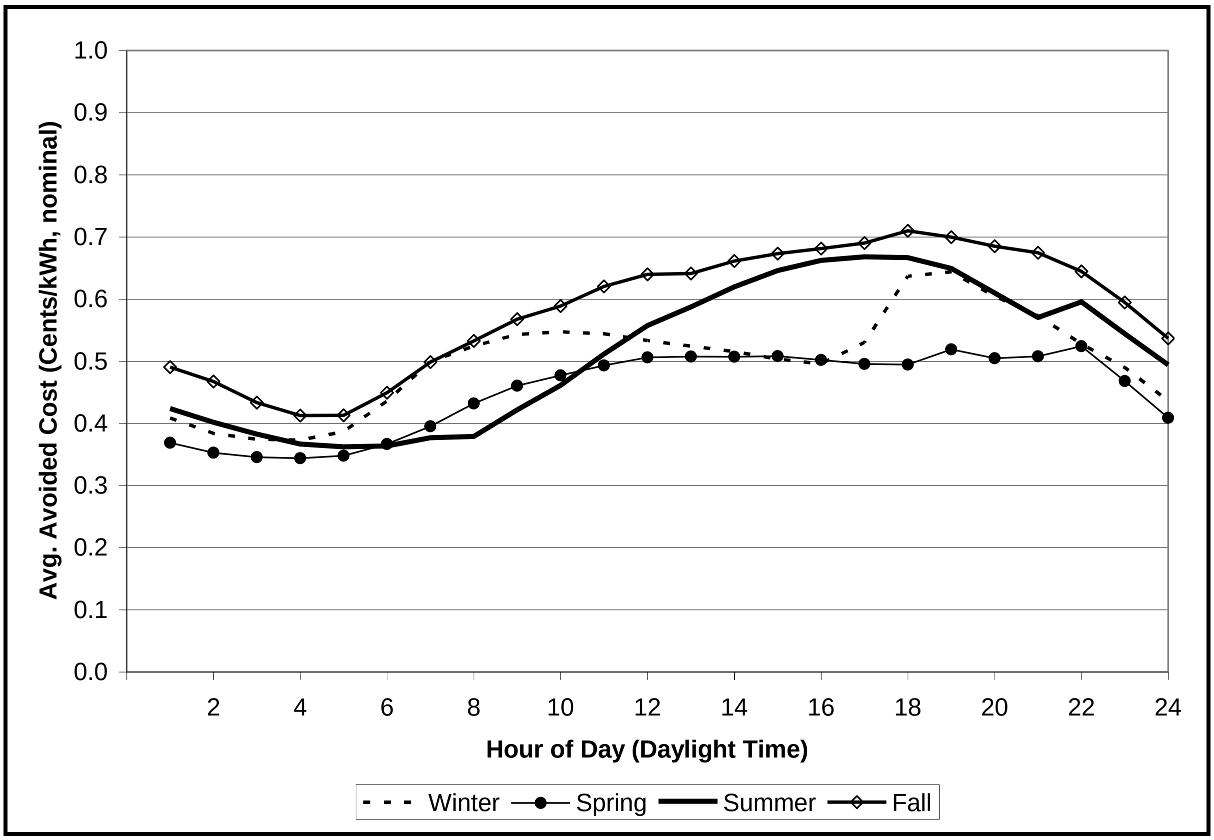
Table 5-16: CO_2 Emission Impacts from PV and Wind Projects in 2008 (Tons of CO_2)

Technology	Annual CO_2 Emissions Impact (Tons)	Annual CO_2 Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2 Impact Factor (Tons/MWh)
PV	-115,057	-100%	197,178	-0.58
WD*	N/A	N/A	N/A	N/A
Total	**-115,057**	**-100%**	**197,178**	**-0.58**

* Wind values were not available because valid metered data were not received.

CO_2 emissions rates from the grid exhibit variability across seasons, days, and hours of the day. To provide additional perspective for the results in Table 5-16 this variability is summarized graphically in Figure 5-9, which expresses this variability in terms of average avoided costs associated with CO_2 emissions. Because the E3 model includes a fixed CO_2 emissions value throughout the year (i.e., 8.32 \$/Ton, nominal 2006 dollars) the shapes of the curves in this chart mirror those that would be observed in a chart with Tons/MWh on the y-axis. Seasonal variability is a function not only of weather but also of power plant maintenance schedules. This explains why values for Fall can be higher than values for Summer. During Fall and Summer the shape of the CO_2 emissions curve is similar to the CAISO load shape. CO_2 emissions rates are higher during the day than at night, all else equal.

Figure 5-9: Average CO_2 Avoided Cost by Season and Hour of Day (Cents/kWh, 2006 Dollars)



***CO$_2$* Emission Impacts from Non-renewable Cogeneration Projects**

Unlike PV and wind projects, non-renewable cogeneration projects realize CO_2 emission impacts from more than just direct displacement of grid-based electricity. Non-renewable cogeneration facilities also realize CO_2 emission impacts due to displacement of natural gas burned in boilers to provide process heating. The natural gas is displaced through the use of waste heat recovery systems incorporated into the SGIP cogeneration facilities. In addition, some of the non-renewable cogeneration SGIP facilities use recovered waste heat in absorption chillers to provide facility cooling. If the absorption chillers replaced electric chillers, then CO_2 emission impacts accrue from the displaced electricity that would otherwise have driven the electric chiller. Table 5-17 provides a breakdown of CO_2 emissions from the various CO_2 sources possible for non-renewable SGIP cogeneration facilities and the overall impact on CO_2 emissions. Review of the impact on CO_2 emissions for each technology illustrates the importance of waste heat recovery and the importance of heat recovery boiler and chiller factors.

In the table below, the cogeneration program emissions represent emissions that are released by the SGIP project. The baseline columns include the electricity which is no longer purchased from the grid, as it has been displaced by the SGIP project. The columns also include the avoided CO_2 emissions from natural gas previously used to heat a boiler or electricity that previously powered a chiller. The CO_2 emission impact is calculated as the difference between the program emissions and the baseline, and is shown in the last column of Table 5-17 (CO_2 Emission Impact from SGIP Projects).

The net effect of all non-renewable cogeneration technology types was a decrease in CO_2 emissions, as shown by the total of 790 tons of CO_2 emissions avoided by the installations of SGIP projects. In 2007, the program impact from non-renewable SGIP projects was 15,394 tons of CO_2 emissions.

Table 5-17: CO_2 Emission Impacts from Non-Renewable Cogeneration Projects in 2008, Categorized by Direct/Indirect Displacement (Tons of CO_2)

	Program	Baseline				Impact
Technology	**SGIP CHP System CO_2 Emissions (A)**	**Electric Power Plant CO_2 Emissions (B)**	**CO_2 Emissions Associated with Heating Services (C)**	**CO_2 Emissions Associated with Cooling Services (D)**	**Total Baseline CO_2 Emissions (E) = (B)+ (C) + (D)**	**CO_2 Emission impacts from SGIP Projects (F) = (A) – (E)**
FC	20,576	23,112	3,365	68	26,545	-5,968
MT	54,247	36,928	7,497	1,007	45,432	8,815
IC Engines	142,650	126,551	12,902	2,038	141,491	1,159
GT	71,962	62,820	11,639	2,299	76,758	-4,796
Total	**289,435**	**249,411**	**35,403**	**5,412**	**290,226**	**-790**

It is beneficial to calculate a CO_2 factor when assessing the overall GHG emission impacts associated with SGIP DG facilities and making comparisons between DG technologies. Table 5-18 is a listing of CO_2 impact factors (in tons of CO_2 reduced per MWh of electricity generated) for non-renewable cogeneration technologies. Positive CO_2 impact factors represent an increase in CO_2 as a result of the installation of the SGIP projects. The CO_2 impact factors for non-renewable projects range from a high of 0.13 tons per MWh for microturbines to a low of -0.14 tons per MWh for fuel cells. As gas turbines resulted in a decrease in CO_2 emissions in PY08, this is reflected in the CO_2 impact factor of -0.04 shown in Table 5-18. Annual CO_2 emissions impacts expressed with respect to baseline CO2 emissions that would have occurred in the program's absence ranged from -22 percent for fuel cells to +19 percent for microturbines.

Table 5-18: CO_2 Emission Impacts from Non-Renewable Cogeneration Projects in 2008 (Tons of CO_2)

Technology	Annual CO_2 Emissions Impact (Tons)	Annual CO_2 Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2 Impact Factor (Tons/MWh)
FC	-5,968	-22%	44,050	-0.14
MT	8,815	19%	67,963	0.13
IC Engines	1,159	1%	227,930	0.01
GT	-4,796	-6%	114,156	-0.04
Total	**-790**	**0%**	**454,097**	**0.00**

There are four major factors which impact the net CO_2 emissions for a cogeneration facility. These include:

- Coincidence of onsite generation and waste heat utilization with grid peak demand hours
- Electrical conversion efficiency of the onsite generator
- The match between electric load and heating or cooling load at the site
- Utilizing the waste heat for process heating versus process cooling

Figure 5-10 through Figure 5-13 show the percent change in CO_2 emissions relative to obtaining the equivalent amount of energy from conventional means. The influence of the four factors above can be illustrated by comparing four groups of systems within the SGIP. These groups include: 1) IC engines utilizing waste heat for process heating, 2) IC engines utilizing waste heat for process cooling, 3) microturbines utilizing waste heat for process heating, and 4) microturbines utilizing waste heat for process cooling.

The baseline CO_2 emissions are made up of two components. The first component is the emissions from electric power plants that would have occurred if the SGIP site had obtained electricity from the grid instead of generating the electricity onsite. The second component is the emissions that would have occurred in the absence of waste heat utilization. For process heating, it is assumed that natural gas would have been used to fuel the boiler. For process cooling, it is assumed that an electric chiller would have been used.

Figure 5-10 shows the percent change in CO_2 emissions from operating IC engines which utilize waste heat for process heating in the SGIP. The green line (ICE ENGO only) represents the percent change in CO_2 emissions from the onsite electricity generation only. The red line (ICE ENGO + Waste Heat Utilization) represents the percent change in CO_2 emissions from utilizing waste heat to reduce boiler usage in addition to generating electricity onsite. If the line is above zero, the sites had a net increase in CO_2 emissions when compared to obtaining the equivalent amount of energy by conventional means. If the line is below zero the SGIP sites had a net decrease in CO_2 emissions. The figure highlights two of the key points: 1) a significant reduction in CO_2 emissions is observed when utilizing the waste heat as compared to the case when the waste heat is not utilized, and 2) a reduction in CO_2 emissions is most likely to occur during the summer months, when the electric grid is experiencing its peak demand and less efficient (greater CO_2 emitting) generation is on-line. Both of these patterns are observed for all four groups.

Figure 5-10: CO_2 Emission Impacts for IC Engines which Recover Waste Heat for Process Heating (2008)

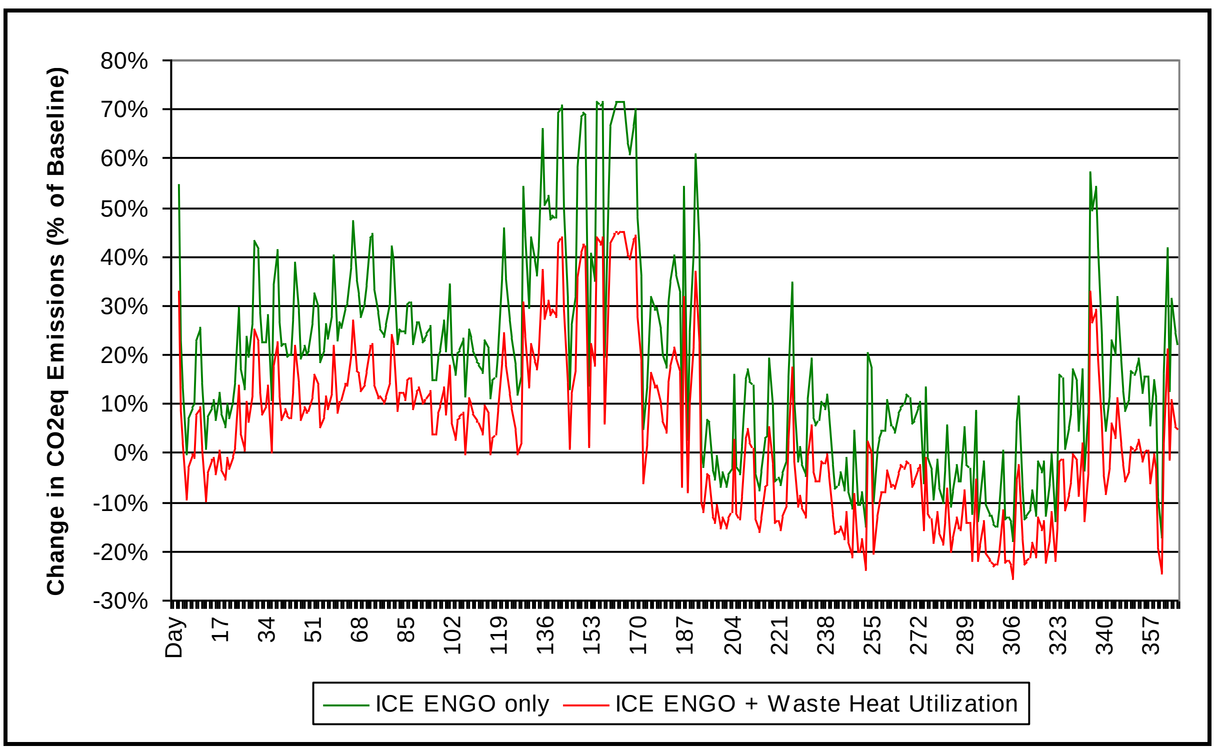


Figure 5-11 shows the percent change in CO_2 emissions for IC engines where waste heat is utilized for process cooling. The resulting trends are similar, except that the CO_2 emission impacts from utilizing the waste heat in absorption chiller applications are of a lesser magnitude than in process heating applications. This is because it is less efficient to utilize waste heat in an absorption chiller than to apply it directly for heating.

Figure 5-11: CO_2 Emission Impacts for IC Engines which Recover Heat for Process Cooling (2008)

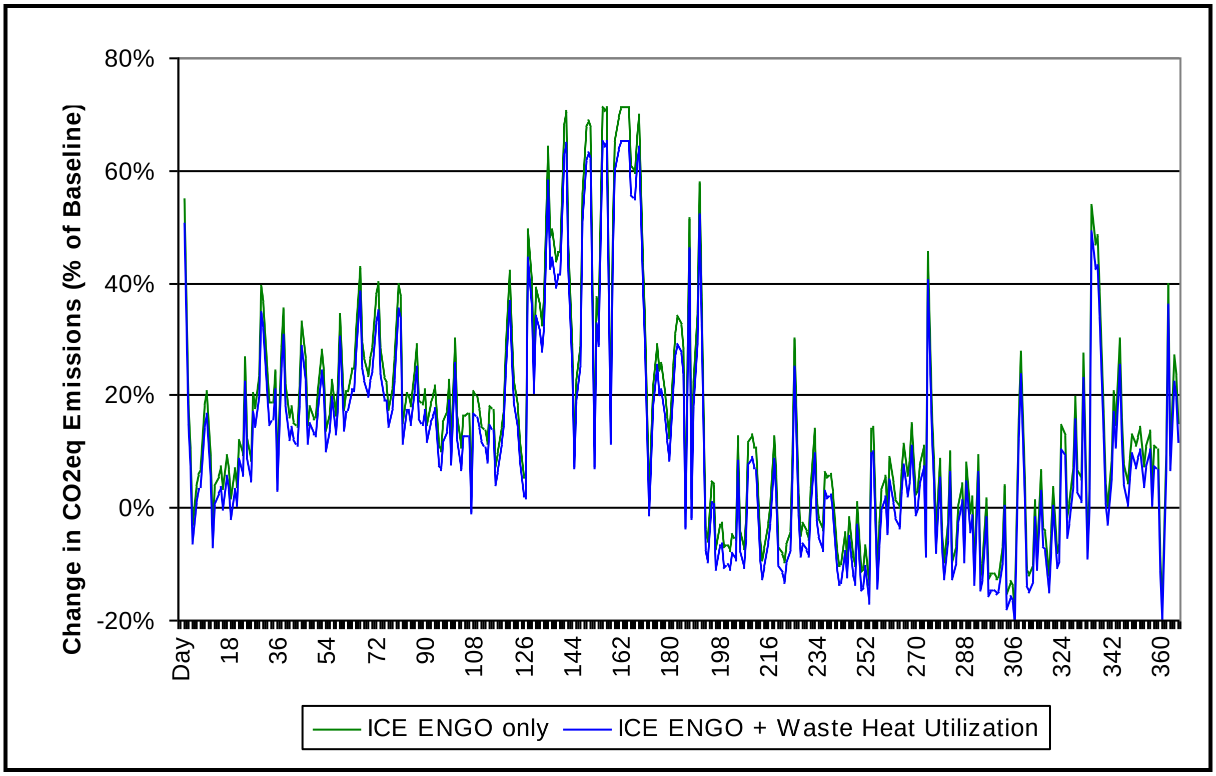


Figure 5-12 and Figure 5-13 are similar to Figure 5-10 and Figure 5-11, respectively, in that they show data for microturbines utilizing waste heat for process heating and process cooling. Comparing the IC engine figures to the microturbine figures reveals the importance of the electrical conversion efficiency. In 2008, IC engines on average had an electrical conversion efficiency of 31 percent, while microturbines had an average electrical conversion efficiency of 24 percent (see Table 5-14). This difference is reflected in the magnitude of the "ENGO only" value in the IC engine plots versus the microturbine plots. The magnitude of the "ENGO only" value for IC engines never exceeds a 100 percent increase in CO_2 emissions, while the magnitude of this value for microturbines does exceed a 100 percent increase. However, the importance of waste heat utilization is equally important in the CO_2 emission impacts. Because microturbines have lower electrical conversion efficiencies, there is more heat available to recover. Overall system efficiency (from Table 5-15) for microturbines is 38.6 percent, which is slightly less than the overall system efficiency of 39.5 percent for IC engines. The additional waste heat utilization for microturbines resulted in similar CO_2 impact factors for the two technologies. The CO_2 impact factor was only slightly higher for microturbines (0.8 tons CO_2 per kWh) than for IC engines (0.07 tons CO_2 per kWh). Both technologies result in an increase in CO_2 emissions if CO_2 equivalent emissions are not included.

Figure 5-12: CO_2 Emission Impacts for Microturbines which Recover Waste Heat for Process Heating (2008)

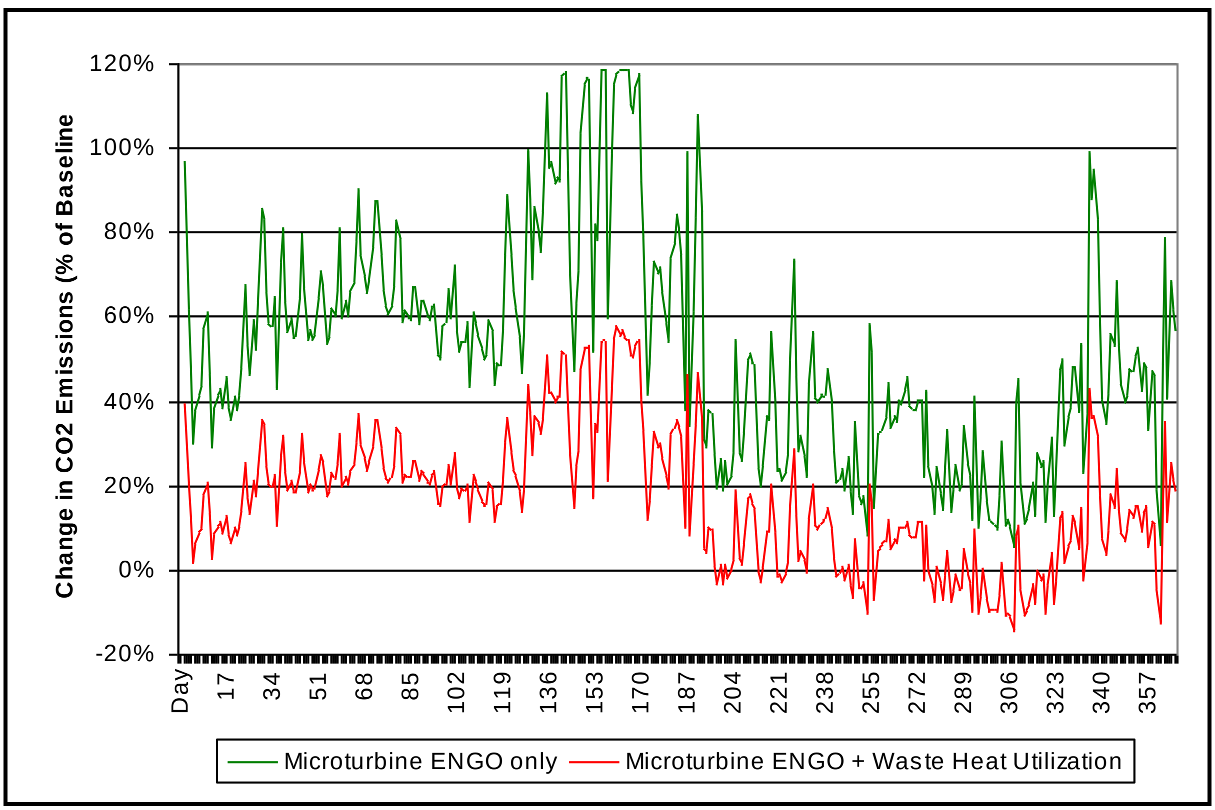
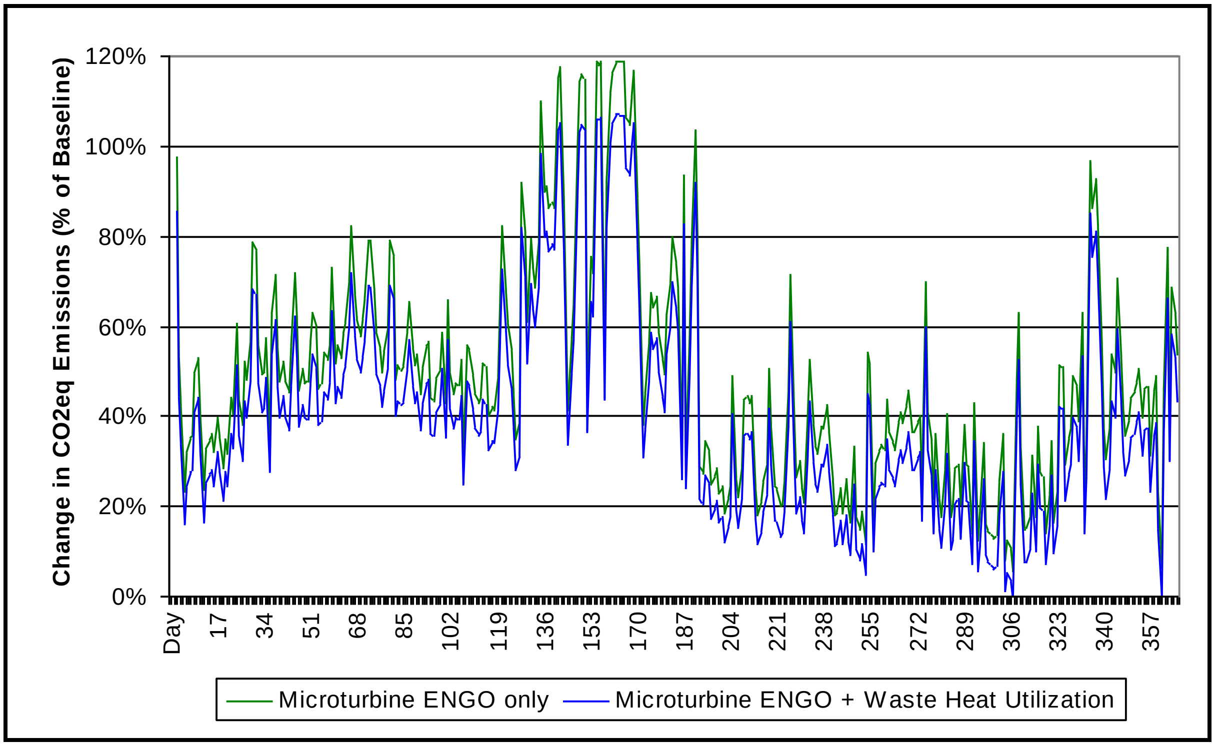


Figure 5-13: CO_2 Emission Impacts for Microturbines which Recover Heat for Process Cooling (2008)



GHG Emission Impacts (CO_2 and CH_4) from Renewable (Biogas) Projects

The last fuel and technology combinations considered in this GHG emission impacts analysis are fuel cells, microturbines, and IC engines fueled with renewable biogas. Some of the biogas-powered SGIP facilities generate only electricity. Others are cogeneration facilities that use waste heat recovery to produce process heating or cooling. Consequently, biogas-powered cogeneration facilities can directly impact CO_2 emissions in the same way as non-renewable cogeneration facilities, but they can also include GHG emission impacts due to captured CH_4 contained in the biogas.

Biogas-powered SGIP facilities capture and use CH_4 that otherwise may have been emitted to the atmosphere if vented. When reporting GHG emission impacts from different types of greenhouse gases, the convention is to report the GHG emissions in terms of tons of CO_2 equivalent (CO_2Eq.). CH_4 has a GHG equivalence 21 times that of CO_2. Consequently, the baseline estimation of CH_4 emission impacts from biogas powered SGIP facilities are converted to CO_2 equivalent through this conversion factor.

In the SGIP Sixth-Year Impact Evaluation Report[19], the assumption was made that small facilities of all types vented their CH_4. For this report, all landfill gas facilities were assumed

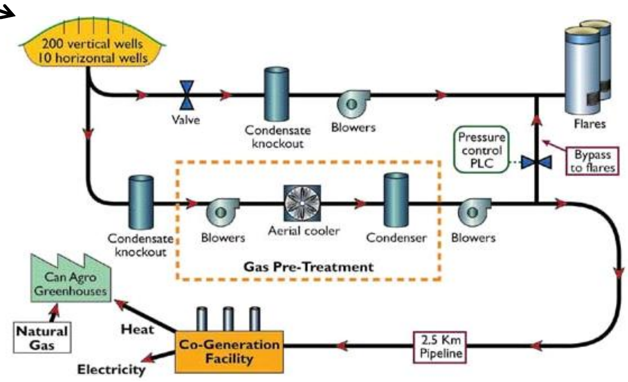
---

19 Itron, Inc. *Sixth Year Impact Evaluation Final Report.* Appendix C, pages C1-C3.

to have captured and flared the CH_4, all dairies were assumed to have vented the CH_4, and wastewater treatment plants and other digesters were assumed to have vented digester gas if under 150 kW of rebated capacity and flared otherwise. Figure 5-14 provides a pictorial depiction of the capturing and flaring of CH_4.

Figure 5-14 Landfill Gas with CH_4 Capture Diagram

Landfill gas (containing approximately 50% methane) is collected (captured) at the landfill using collection wells



When not being used to create power, the landfill gas is flared, which results in carbon dioxide emissions

Methane is naturally created at landfill gas facilities, wastewater treatment plants and dairies. If not captured, the methane escapes into the atmosphere contributing to greenhouse gas (GHG) emissions. Capturing the methane provides an opportunity to use it as fuel. When the methane is not used to create energy, it is burned in a flare. Because the resulting CO_2 has much less GHG potency than methane, the use of the flare reduces the CO_2 equivalent emissions. Distributed generation, such as SGIP projects, deliver additional economic and environmental benefits by reducing the need to generate electricity at central station power plants.

The total electricity generated from these sites was multiplied by technology-specific emission factors for CH_4 to calculate the total CH_4 emissions avoided by relying upon CH_4 to generate power from these SGIP facilities.[20] Of the biogas systems that were assumed to have vented CH_4 prior to participation in the SGIP, six were microturbines and four were IC engine facilities. There were no such fuel cell facilities during PY08. Fuel cell facilities will only show a CO_2 emission impacts as a result of avoided energy from the grid and the avoided CO_2 emissions from natural gas used to heat boilers under the baseline or electricity used to run the chiller under the baseline.

[20] See Appendix B for the derivation of renewable fuel technology-specific CH_4 emission factors. They are equal to 255 grams per kWh for IC engines, 275 grams per kWh for microturbines, and 168 grams per kWh for fuel cells.

Table 5-19 and Table 5-20 provide the CO_2 emission impacts occurring from biogas powered facilities. The tables are separated out into biogas powered facilities that flare the CH_4 based on the baseline assumptions and those that vented the CH_4 based on baseline assumptions.

Table 5-19: CO_2 Emission Impacts from Biogas Projects in 2008*—Flared CH_4 under Baseline (Tons of CO_2)

	Program	Baseline					Impact
Technology	SGIP CHP System Emissions (A)	Electric Power Plant GHG Emissions (B)	CO_2 Emissions Associated with Heating Services (C)	CO_2 Emissions Associated with Cooling Services (D)	CO_2 Emissions From Flaring CH_4 (E)	Total Baseline CO_2 Emissions (F) = (B)+ (C) + (D) + (E)	CO_2 Emission Impact from SGIP Projects (G) = (A) – (F)
FC	5,873	6,895	N/A	N/A	5,873	12,767	-6,895
MT	4,566	3,007	N/A	N/A	4,566	7,573	-3,007
IC Engines	27,310	23,598	391	N/A	27,310	50,908	-23,989
Total	**37,749**	**33,500**	**391**	**N/A**	**37,749**	**71,248**	**-33,891**

* The baseline values include the amount of CO_2 emissions associated with the capture and flaring of the CH_4 (column E).

Table 5-20 includes the CH_4 emission impacts and equivalent CO_2 emission impacts from the biogas facilities that previously vented the CH_4. The largest source of emission impacts stem from the capture and flaring of CH_4. In those cases, the CO_2 emission impacts from biogas facilities are negative (CO_2 emissions are lower as a result of the operation of this subset of SGIP facilities). If the benefits from capturing CH_4 are not included, then both microturbine and IC engines would be net emitters of GHG despite the use of renewable fuel.

Table 5-20: CO_2 Emission Impacts from Biogas Projects in 2008*—Vented CH_4 under Baseline

	Program	Baseline						Impacts
Technology	**SGIP CHP System Emissions (A)**	**Electric Power Plant GHG Emissions (B)**	**CO_2 Emissions Associated with Heating Services (C)**	**CO_2 Emissions Associated with Cooling Services (D)**	**Tons of CH_4 Emissions (E)**	**CO_2Eq Emissions (converted from CH4) (F)**	**Total Baseline CO_2 Emissions (G)**	**Net CO_2 Emissions (Includes CO_2Eq) (H) = D+F+G**
FC	N/A	N/A	N/A	N/A	N/A*	N/A*	N/A	N/A
MT	911	604	93	N/A	327	6,874	7,572	-6,660
IC Engines	2,635	2,199	N/A	N/A	966	20,282	22,481	-19,846
Total	**3,546**	**2,803**	**93**	N/A	**1,293**	**27,156**	**30,053**	**-26,506**

* Biogas projects powered by fuel cells operating in PY08 did not impact CH_4 emissions due to the assumptions regarding the baseline. The two SGIP fuel cell projects were both wastewater treatment plants with a rebated capacity greater than 150 kW.

Table 5-21 shows the impact of biogas projects that are assumed to have flared CH_4 as part of the baseline. Annual CO_2 emissions impacts expressed with respect to baseline CO2 emissions that would have occurred in the program's absence ranged from -40 percent for fuel cells to -54 percent for microturbines. The CO_2 emissions reduction percentages achieved by these renewable fuel projects are substantially larger than those achieved by their natural gas counterparts described in Table 5-18. While flares are an effective means of converting CH_4 into CO_2, they represent a lost opportunity where utilization of the CH_4's energy content is concerned. Utilization of that energy content in SGIP systems yields efficiencies that are reflected in the larger CO_2 emissions reduction percentages.

Table 5-21: CO_2 Emission Impacts from Biogas Projects in 2008—Flared CH_4 Under Baseline

Technology	Annual CO_2 Emissions Impact (Tons)	Annual CO_2 Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2 Impact Factor (Tons/MWh)
FC	-6,895	-54%	12,572	-0.55
MT	-3,007	-40%	5,721	-0.53
IC Engines	-23,989	-47%	43,637	-0.55
Total	**-33,891**	**-48%**	**61,930**	**-0.55**

Table 5-22 shows the impact of biogas projects that are assumed to have vented CH_4 as part of the baseline. The CO_2 impact factor of this group of biogas projects is much larger than the CO_2 impact factor for facilities that previously captured and flared the CH_4. For example, microturbines which previously captured and flared the CH_4 have a CO_2 factor of -0.53, compared to a CO_2 factor of -5.83 if the microturbine had vented the CH_4 under the baseline. Offering an incentive program which encourages facility owners who currently vent CH_4 to install a biogas project would have very large impacts on GHG emissions.

Table 5-22: CO_2 Emission Impacts from Biogas Projects in 2008 (Includes Tons of CO_2 and CO_2 Equivalent)—Vented CH_4 under Baseline

Technology	Annual CO_2Eq Emissions Impact (Tons)	Annual CO_2Eq Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2Eq Impact Factor (Tons/MWh)
FC	N/A	N/A	N/A	N/A
MT	-6,660	-88%	1,142	-5.83
IC Engines	-19,846	-88%	4,210	-4.71
Total	**-26,506**	**-88%**	**5,352**	**-4.95**

Table 5-23 presents the CH4 emission impacts and the equivalent CO_2 emission impacts by technology type.

Table 5-23: CH_4 Emission Impacts from Biogas Projects in 2008 (in Tons of CH_4 and Tons of CO_2 Equivalent)

Technology	CH_4 Emission Impacts (Tons)	CO_2 Eq Emission Impacts (Tons)
FC	N/A*	N/A*
IC Engines	-966	-20,282
MT	-327†	-6,874†
Total	**-1,293**	**-27,156**

* Biogas projects powered by fuel cells operating in PY08 did not impact CH_4 emissions due to the assumptions regarding the baseline. The two SGIP fuel cell projects were both wastewater treatment plants with a rebated capacity greater than 150 kW.

† The estimated emission impacts attributable to microturbines is changed due to the change in assumptions regarding the baseline. In particular, a number of microturbine projects used landfill gas and digester gas from wastewater treatment facilities. In this report, the CH_4 was assumed to be flared at all landfill gas facilities and at wastewater treatment facilities with a rebated nameplate capacity of 150 kW or greater. The result was a decrease in CH_4 emissions attributed to these facilities.

Total GHG Emission Impacts

Table 5-24 presents a summary of GHG emission impacts from the installation of SGIP projects measured in tons of CO_2 equivalent, broken down by the different SGIP fuel and technology combinations. [21] The total GHG emission impacts measured in CO_2 equivalent units is approximately 176,244 tons with the largest portions—almost two-thirds of this impact—coming from PV projects, followed by renewable-fueled IC engines. During the 2007 program year, the total GHG emission impacts calculated for the SGIP projects was 121,410 tons of CO_2 equivalent. Most of these emission impacts also came from PV projects. The fuel/technology cogeneration group contributing the largest energy impact is non-renewable-fueled IC engines.

The second to last column in Table 5-24 presents the tons of GHG emissions reduced per MWh generated by each fuel and technology category for the 2008 program year. Technologies utilizing renewable fuel result in the largest GHG emission reduction per unit of electricity generated, due to avoiding the release of CH_4, which is a more potent GHG than CO_2. Microturbines and IC engines utilizing non-renewable fuel resulted in a GHG emission increase. The CO_2 impact factors range from the lowest value of -1.41 for renewable fuel microturbines to a high of 0.13 for non-renewable-fueled microturbines. As shown in Table

[21] Note that the results in Table 5-25 can be developed by adding the equivalent CO_2 values in Table 5-22 to the direct CO_2 values in Table 5-17, Table 5-19, and Table 5-21 (note, due to rounding, this sum is approximately equal to the sum of total GHG emissions reduced presented in Table 5-23)..

5-19, when only CO_2 emissions are considered, renewable fuel IC engines and microturbines operating as part of the program emit more than would have been emitted under the baseline.

Table 5-24: GHG Emission Impacts from SGIP Systems Operating in Program Year 2008 (Tons of CO_2 Equivalent) by Fuel and Technology and Ratios of Tons of GHG Emission Impacts per MWh

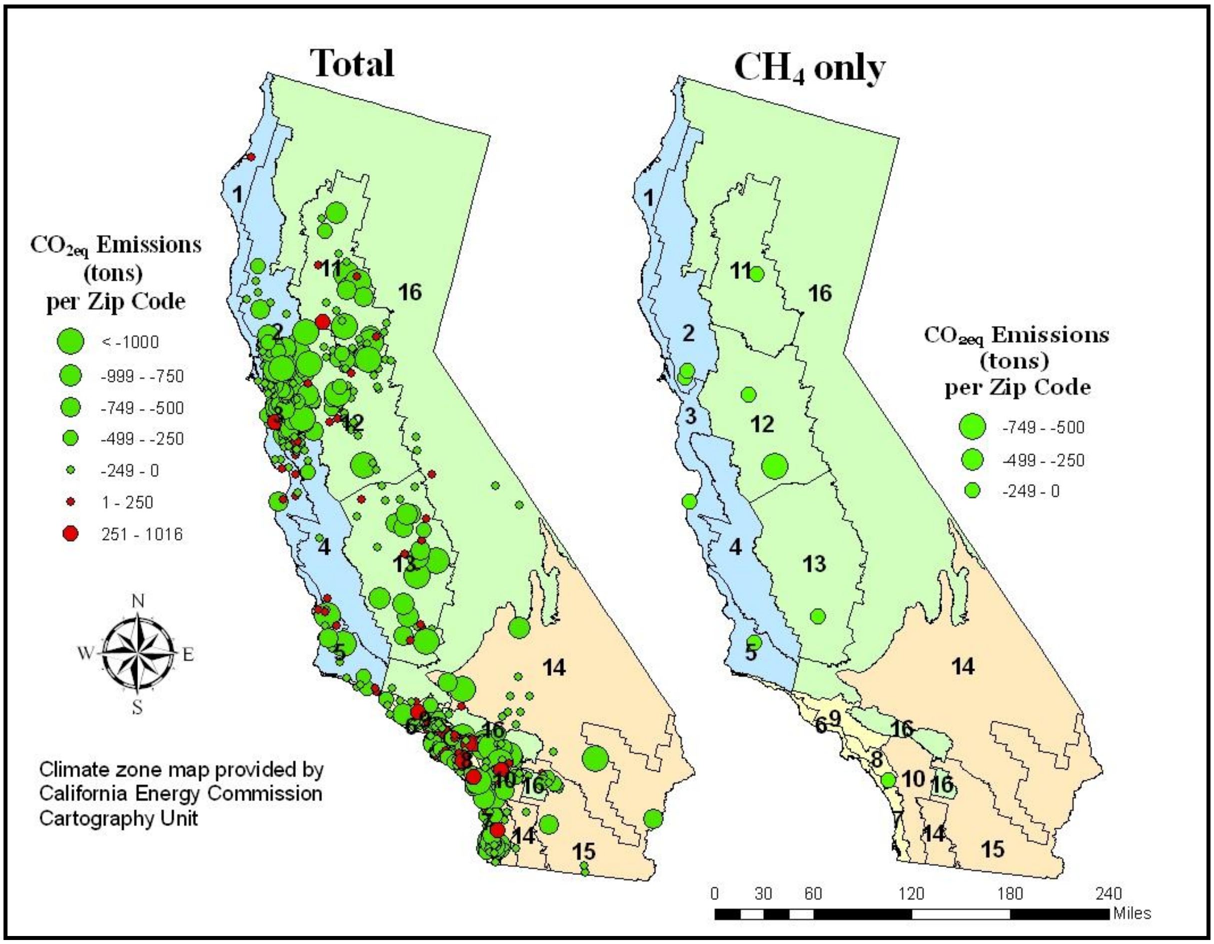
Technology*	Annual CO_2Eq Emissions Impact (Tons)	Annual CO_2Eq Emissions Impact (%)	Annual Energy Impact (MWh)	Annual CO_2Eq Impact Factor (Tons/MWh)
PV	-115,057	-100%	197,178	-0.58
WD†	N/A	N/A	N/A	N/A
FC-N	-5,968	-22%	44,050	-0.14
MT-N	8,815	19%	67,963	0.13
IC Engine-N	1,159	1%	227,930	0.01
Small GT-N and waste gas-fueled	-4,796	-6%	114,156	-0.04
FC-R	-6,895	-54%	12,572	-0.55
MT-R	-9,667	-20%	6,863	-1.41
IC Engine-R	-43,835	-33%	47,848	-0.92
Total	**-176,244**	**-35%**	**718,558**	**-0.25**

* N = Non-Renewable; R = Renewable

† Wind values were not available because valid metered data were not received.

Due to the increasing role of GHG emission impacts, it is also important to identify the distribution of GHG emission impacts within the SGIP. Figure 5-15 shows the distribution of GHG emission impacts from SGIP facilities located throughout California. The figure on the left depicts the total GHG emission impacts from all sources within the SGIP facilities. The figure on the right shows only the locations of those biogas-fueled SGIP facilities providing CH_4-based GHG emission impacts. It is interesting to note that while overall GHG emission impacts occur across a large number of SGIP facilities, the relatively large GHG emission impacts due to CH_4 capture occur from only a handful of projects, scattered throughout the state.

Figure 5-15: PY08 Distribution of GHG Emission Impacts Among SGIP Facilities



GHG Emission Impacts by Program Administrator

Table 5-25 through Table 5-28 present the CO_2 emission impacts in 2008 by PA and fuel/technology group. These tables also include the annual energy impact and the CO_2 impact factor for each group. A comparison of these tables show that the PA responsible for the largest impact of CO_2 emissions is PG&E (81,600 tons decrease in CO_2 emissions) followed by SCE (37,052 tons decrease in CO_2 emissions), SCG (17,433 tons decrease in CO_2 emissions, and CCSE (13,651 tons decrease in CO_2 emissions). PG&E's projects generate the most energy impacts overall (292,210 MWh), but are less than the energy impacts observed in 2007 (303,601 MWh). SCG projects generated 189,512 MWh in energy impacts, followed by SCE (121,081 MWh) and CCSE (115,755 MWh).

The tables also present GHG emission impacts of the program in terms of avoided CH_4 emissions for facilities which are assumed to vent the CH_4 under the baseline. Note that no CH_4-specific GHG emission impacts stemmed from projects administrated by SCE due to the change in the assumptions related to the baseline for calculating CH_4 emissions. PG&E projects resulted in the largest CO_2 equivalent emission impacts as a result of the CH_4 emission impact (23,777 tons decrease in CO_2 equivalent emissions from 1,132 tons decrease in CH_4 emissions). The renewable fuel projects under CCSE are responsible for a much smaller fraction of CH_4 emission impacts at 161 tons. This is due to the fact that CCSE oversees only two microturbine projects that were included in the baseline, while PG&E oversees five microturbine projects and four IC engine projects. SCE and SCG did not oversee any renewable fuel projects that met the new assumptions for the baseline.

The overall CO_2 factor is shown for each PA and is calculated by dividing the total CO_2 equivalent emissions reduced by the total annual energy impact. A comparison of these factors show that PG&E has the lowest ratio (-0.36), followed by SCE and CCSE (with ratios of -0.31 and -0.15, respectively). SCG had the highest ratio (-0.09), reflecting the smallest GHG emission impacts as a percent of total energy impacts. A more detailed examination of the CO_2 impact factors shows that the PA-specific ratios are lowest for PV projects, and for PAs that do not have renewable-fueled SGIP projects assumed to vent under the baseline. The lowest CO_2 impact factor for PG&E was for renewable-fueled IC engines as these are dairies that were assumed to have vented prior to the installation of the SGIP project. CO_2 impact factors tend to be highest for non-renewable-fueled microturbines and IC engines for all the PAs.

Table 5-25: Technology-Specific CO_2 Emission Impacts (Includes CO_2 Equivalent)—PG&E

Technology	CO_2 Emissions Impact (Tons)	CO_2Eq Emissions Impact from CH_4 (Tons)	Total CO_2Eq Emissions Impact (Tons)	Total CO_2Eq Emissions Impact (%)	Energy Impact (MWh)	CO_2Eq Impact Factor (Tons/MWh)
PV	-67,738	N/A	-67,738	-100%	118,935	-0.57
WD	N/A	N/A	N/A	N/A	N/A	N/A
FC-N	-3,242	N/A	-3,242	-23%	23,776	-0.14
MT-N	3,581	N/A	3,581	18%	29,550	0.12
IC Engine-N	307	N/A	307	1%	70,469	0.00
Small GT-N and waste gas-fueled	-2,479	N/A	-2,479	-15%	21,799	-0.11
FC-R	-2,169	N/A	-2,169	-53%	4,063	-0.53
MT-R	-1,501	-3,328	-4,829	-63%	3,517	-1.37
IC Engine-R	-8,359	-19,846	-28,205	-69%	20,101	-1.40
Total	**-81,600**	**-23,174**	**-104,774**	**-71%**	**292,210**	**-0.36**

Table 5-26: Technology-Specific CO_2 Emission Impacts—SCE

Technology	CO_2 Emissions Impact (Tons)	CO_2Eq Emissions Impact from CH_4 (Tons)	Total CO_2Eq Emissions Impact (Tons)	Total CO_2Eq Emissions Impact (%)	Energy Impact (MWh)	CO_2Eq Impact Factor (Tons/MWh)
PV	-22,832	N/A	-22,832	-100%	37,625	-0.61
WD*	N/A	N/A	N/A	N/A	N/A	N/A
FC-N	-186	N/A	-186	-26%	1,148	-0.16
MT-N	1,577	N/A	1,577	22%	11,061	0.14
IC Engine-N	108	N/A	108	0%	43,312	0.00
Small GT-N and waste gas-fueled	N/A	N/A	N/A	N/A	N/A	N/A
FC-R	-3,736	N/A	-3,736	-54%	6,788	-0.55
MT-R	-1,305	N/A	-1,305	-40%	2,414	-0.54
IC Engine-R	-10,678	N/A	-10,678	-49%	18,732	-0.57
Total	**-37,052**	**0**	**-37,052**	**-55%**	**121,081**	**-0.31**

Table 5-27: Technology-Specific CO_2 Emission Impacts—SCG

Technology	CO_2 Emissions Impact (Tons)	CO_2Eq Emissions Impact from CH_4 (Tons)	Total CO_2Eq Emissions Impact (Tons)	Total CO_2Eq Emissions Impact (%)	Energy Impact (MWh)	CO_2Eq Impact Factor (Tons/MWh)
PV	-11,341	N/A	-11,341	-100%	18,904	-0.60
WD	N/A	N/A	N/A	N/A	N/A	N/A
FC-N	-1,437	N/A	-1,437	-26%	8,807	-0.16
MT-N	3,427	N/A	3,427	21%	24,745	0.14
IC Engine-N	490	N/A	490	1%	95,091	0.01
Small GT-N and waste gas-fueled	-2,631	N/A	-2,631	-12%	31,229	-0.08
FC-R	-989	N/A	-989	-55%	1,721	-0.57
MT-R	N/A	N/A	N/A	N/A	N/A	N/A
IC Engine-R*	-4,952	N/A	-4,952	-47%	9,014	-0.55
Total	**-17,433**	N/A	**-17,433**	**-15%**	**189,512**	**-0.09**

* Based on assumptions the IC Engine in SCG is assumed to have flared rather than vented the CH_4 that was captured.

Table 5-28: Technology-Specific CO_2 Emission Impacts (Includes CO_2 Equivalent)—CCSE

Technology	CO_2 Emissions Impact (Tons)	CO_2Eq Emissions Impact from CH_4 (Tons)	Total CO_2Eq Emissions Impact (Tons)	Total CO_2Eq Emissions Impact (%)	Energy Impact (MWh)	CO_2Eq Impact Factor (Tons/MWh)
PV	-13,146	N/A	-13,146	-100%	21,713	-0.61
WD	N/A	N/A	N/A	N/A	N/A	N/A
FC-N	-1,103	N/A	-1,103	-19%	10,318	-0.11
MT-N	230	N/A	230	12%	2,606	0.09
IC Engine-N	254	N/A	254	2%	19,058	0.01
Small GT-N and waste gas-fueled	314	N/A	314	1%	61,128	0.01
FC-R	N/A	N/A	N/A	N/A	N/A	N/A
MT-R	-200	-3,332	-3,532	-83%	932	-3.79
IC Engine-R	N/A	N/A	N/A	N/A	N/A	N/A
Total	**-13,651**	**-3,332**	**-16,983**	**-27%**	**115,755**	**-0.15**

Table 5-29 and Table 5-30 show the amount of CH_4 emission impacts for PG&E and CCSE and the equivalent amount of CO_2 emission impacts for PG&E and CCSE. PG&E projects result in the largest amount of CH_4 reduced. As noted above, SCE and SCG did not oversee any renewable fuel projects which met the new assumptions for the baseline.

Table 5-29: Technology-Specific CH_4 Emission Impacts (in Tons of CH_4 and Tons of CO_2 Equivalent)—PG&E

Technology	CH_4 Emission Impacts (Tons)	CO_2 Eq. Emission Impacts (Tons)
FC	N/A	N/A
MT	-166	-3,495
IC Engine	-966	-20,282
Total	**-1,132**	**-23,777**

Table 5-30: Technology-Specific CH_4 Emission Impacts (in Tons of CH_4 and Tons of CO_2 Equivalent)—CCSE

Technology	CH_4 Emission Impacts (Tons)	CO_2 Eq. Emission Impacts (Tons)
FC	N/A	N/A
MT	-161	-3,380
IC Engine	N/A	N/A
Total	**-161**	**-3,380**

Appendix A

System Costs and Energy and Demand Impacts

A.1 Overview

This appendix summarizes system costs, energy and demand impacts, and relative performance (described in terms of capacity factors for specific time periods) of the eighth-year impact evaluation. It describes demand impacts and capacity factors for the CAISO peak day as well as for the individual electric utility peak days. This appendix is divided into three sections. The first section presents results for the program overall. The second and third sections present results for renewable and non-renewable technologies, respectively. The sequence of each section is as follows:

1. Costs
   Eligible Costs
   Incentives
   Other Incentives
   Total Incentives

2. Annual Energy
   Annual Electric Energy Totals by PA
   Quarterly Electric Energy Totals

3. Peak Demand
   CAISO Peak Hour Demand Impacts
   Electric Utility Peak Hours Demand Impacts

4. Capacity Factors
   Annual Capacity Factors
   Annual Capacity Factors by Technology
   Annual Capacity Factors by Technology and PA
   Monthly Capacity Factors by Technology
   CAISO Peak Day Capacity Factors by Technology
   Electric Utility Peak Day Capacity Factors by Technology

Reporting of overall program results and of annual energy by technologies includes a distinction between metered and estimated values. Metered values have very little uncertainty, with most meters having accuracies within one percent. The uncertainty of estimated values is greater and is the primary determinant of the margin of error of results.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of the systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

This appendix summarizes relative performance of groups of systems in terms of their weighted average capacity factors for specific time periods. These measures describe electric net generation output relative to a unit of system-rebated capacity. For example, an hourly capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system-rebated capacity.

A.2 Program Totals

Costs

Table A-1 on the following pages lists total eligible costs, SGIP incentives, and other incentives by system type and fuel.

Table A-1: Complete and Active System Costs by Technology and Fuel

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
FC	**N**	Eligible Cost	$63.80	$9.73
		Incentive	$19.68	$3.56
		Other Incentive	$2.95	$0.00
		Total Incentive	$22.63	$3.56
FC	**R**	Eligible Cost	$20.65	$64.45
		Incentive	$15.08	$31.95
		Other Incentive	$0.00	$0.00
		Total Incentive	$15.08	$31.95
GT	**N**	Eligible Cost	$37.26	$15.03
		Incentive	$4.46	$2.00
		Other Incentive	$0.00	$0.00
		Total Incentive	$4.46	$2.00
GT	**R**	Eligible Cost	N/A	$1.71
		Incentive	N/A	$0.60
		Other Incentive	$0.00	$0.00
		Total Incentive	$0.00	$0.60
IC Engine	**N**	Eligible Cost	$301.39	$72.22
		Incentive	$75.77	$11.58
		Other Incentive	$0.86	$0.05
		Total Incentive	$76.63	$11.63
IC Engine	**R**	Eligible Cost	$27.59	$15.06
		Incentive	$9.72	$4.50
		Other Incentive	$0.48	$0.00
		Total Incentive	$10.20	$4.50
MT	**N**	Eligible Cost	$56.14	$20.25
		Incentive	$14.71	$3.86
		Other Incentive	$1.06	$0.00
		Total Incentive	$15.77	$3.86
MT	**R**	Eligible Cost	$13.03	$2.94
		Incentive	$4.36	$0.44
		Other Incentive	$0.19	$0.00
		Total Incentive	$4.55	$0.44

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind

† N = Non-Renewable; R = Renewable

Table A–1: Complete and Active System Costs by Technology and Fuel (continued)

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
PV		Eligible Cost	$1,193.99	$72.86
		Incentive	$454.34	$19.73
		Other Incentive	$40.10	$4.07
		Total Incentive	$494.43	$23.80
WD		Eligible Cost	$5.38	$53.66
		Incentive	$2.63	$16.87
		Other Incentive	$0.06	$0.00
		Total Incentive	$2.69	$16.87
		Total Eligible Cost	$1,719.23	$327.92
		Total Incentive	$600.75	$95.08
		Total Other Incentive	$45.71	$4.12
		Total All Incentives	**$646.45**	**$99.20**

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind

† N = Non-Renewable; R = Renewable

Annual Energy

Table A-2 presents annual total net electrical output in MWh for the program and for each PA. It also shows subtotals for each PA and technology. Later tables in this appendix differentiate by natural gas versus renewable methane fuel. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-2: Annual Electric Energy Totals by Technology and PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	**Total***	**27,839 †**	**7,936 †**	**10,529 †**	**10,318**	**56,622 †**
	M*	19,355	1,608	7,386	10,317	38,666
	E*	8,484 †	6,328 [a]	3,142 [a]	1	17,956 †
GT	**Total***	**21,799 [a]**	**N/A**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		**114,156 †**
	M*	0	**N/A**			61,548
	E*	21,799 [a]	**N/A**			52,607 [a]
IC Engine	**Total***	**90,570 †**	**62,044 †**	**104,105 †**	**19,058 †**	**275,777 †**
	M*	23,452	24,834	44,946	15,346	108,579
	E*	67,118 †	37,210 †	59,159 †	3,711 [a]	167,198 †
MT	**Total***	**33,067 †**	**13,475 †**	**24,745 †**	**3,538 †**	**74,825**
	M*	11,615	9,473	11,559	2,718	35,364
	E*	21,452 †	4,002 †	13,187 †	820 [a]	39,461 †
PV	**Total***	**118,935**	**37,625**	**18,904**	**21,713**	**197,178**
	M*	57,420	4,234	8,220	20,361	90,235
	E*	61,515	33,391	10,685	1,352 †	106,943
WD	**Total***	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	M*	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	E*	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	Total	**292,210**	**121,081**	**189,512**	**115,755**	**718,558**

* For all but last row, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-3 presents quarterly total net electrical output in MWh for the program. It also shows subtotals for each technology and fuel, natural gas versus renewable methane. Additionally, it shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-3: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
FC	**N**	**Total**	**13,663**	**12,908**	**10,273**	**7,204**	**44,050 †**
		M	10,689	10,342	8,131	5,009	34,171
		E	2,974	2,566	2,142	2,196	9,879 †
	R	**Total**	**1,769**	**2,742**	**3,014**	**5,048**	**12,572 †**
		M	800	1,076	1,202	1,418	4,495
		E	969	1,666	1,812	3,630	8,077 [a]
GT	**N**	**Total**	**24,845**	**31,131**	**32,439**	**25,742**	**114,156 †**
		M	12,746	17,383	17,340	14,080	61,548
		E	12,099	13,747	15,099	11,662	52,607 [a]
IC Engine	**N**	**Total**	**54,537**	**54,822**	**68,381**	**50,190**	**227,930 †**
		M	25,228	22,310	27,222	18,783	93,543
		E	29,308	32,512	41,159	31,408	134,387 †
	R	**Total**	**13,503**	**12,253**	**10,911**	**11,179**	**47,848 †**
		M	4,132	3,731	3,339	3,834	15,036
		E	9,371	8,523	7,572	7,345	32,811 †
MT	**N**	**Total**	**18,201**	**16,221**	**16,482**	**17,059**	**67,963 †**
		M	9,224	8,033	7,479	7,626	32,362
		E	8,977	8,187	9,003	9,433	35,600 †
	R	**Total**	**1,953**	**2,194**	**1,467**	**1,249**	**6,863 †**
		M	941	985	599	477	3,002
		E	1,012	1,209	868	771	3,861 †
PV		**Total**	**37,062**	**66,034**	**60,815**	**33,268**	**197,178**
		M	16,586	30,665	28,494	14,489	90,235
		E	20,476	35,368	32,320	18,779	106,943
WD		**Total**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
		M	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
		E	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
		TOTAL	**165,533**	**198,304**	**203,782**	**150,939**	**718,558**

* In rightmost column only and except for last row, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-4 presents total net electrical output in kW for the program during the peak hour of 3:00 to 4:00 P.M. (PDT) on June 20, 2008. The table also shows for each technology and basis the subtotals of output, counts of systems, and total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate peak demand impacts by natural gas versus renewable methane fuel.

Table A-4: CAISO Peak Hour Demand Impacts

CAISO Peak (MW)	Date	Hour (PDT hour beginning)
46,789	**20-Jun-08**	**15**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	**Total**	**19**	**10,700**	**6,889**	**0.644 †**
	M	14	8,000	5,174	0.647
	E	5	2,700	1,716	0.635 †
GT	**Total**	**6**	**17,643**	**14,728**	**0.835 †**
	M	2	9,027	8,156	0.904
	E	4	8,616	6,572	0.763 [a]
IC Engine	**Total**	**223**	**140,490**	**34,788**	**0.248 †**
	M	97	55,515	13,553	0.244
	E	126	84,975	21,236	0.250 †
MT	**Total**	**129**	**20,692**	**8,509**	**0.411**
	M	62	10,770	4,243	0.394
	E	67	9,922	4,266	0.430 †
PV	**Total**	**863**	**129,566**	**76,202**	**0.588**
	M	289	58,933	36,675	0.622
	E	574	70,633	39,526	0.560
WD	**Total**	**2**	**1,649**	N/A	N/A
	M	N/A	N/A	N/A	N/A
	E	N/A	N/A	N/A	N/A
	TOTAL	**1,242**	**320,740**	**141,117**	N/A

* In column with hourly capacity factor only, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-1 plots profiles of hourly total net electrical output in kW for each technology from morning to early evening during the day of the annual peak hour, June 20, 2008. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. The preceding table shows the values of net output for each technology during the peak hour. Again, later tables and charts in this appendix differentiate by natural gas versus renewable methane fuel.

Figure A-1: CAISO Peak Day Output by Technology

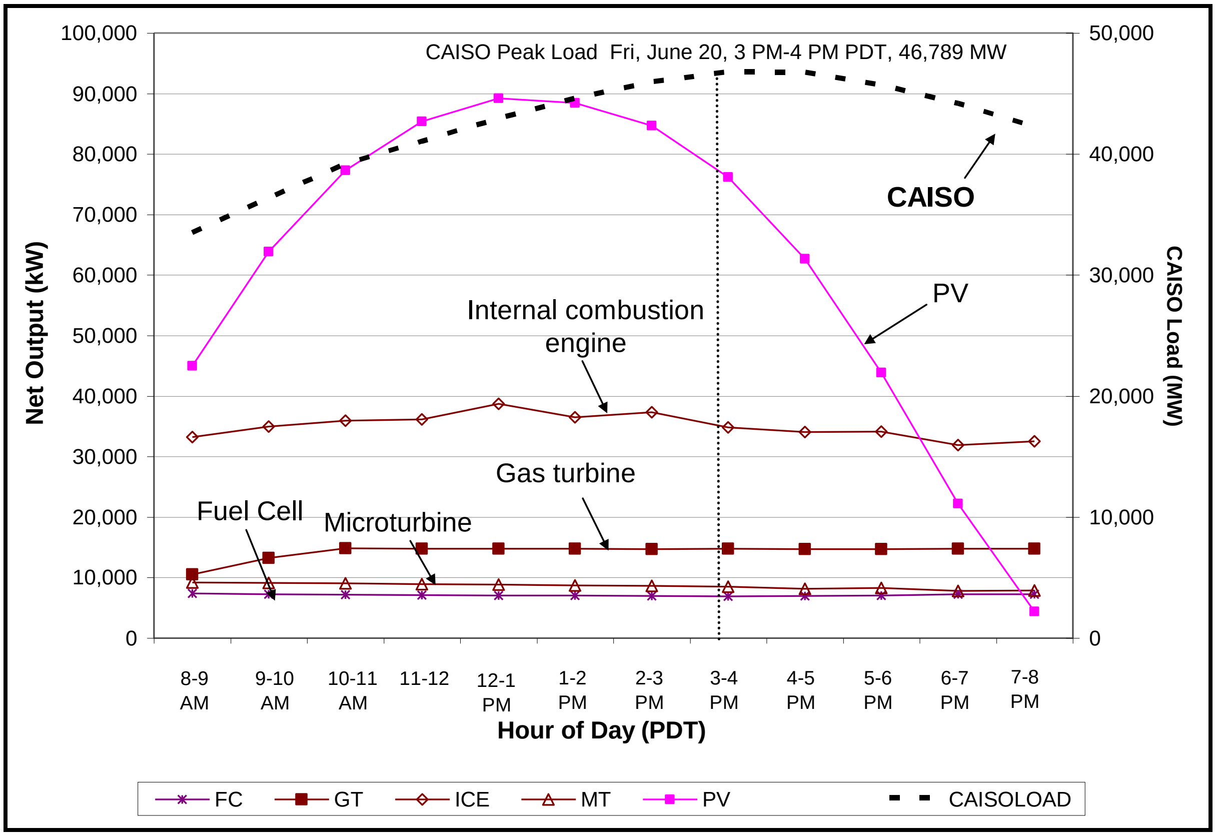


Table A-5, Table A-6, and Table A-7 list for each electric utility the hourly total net electrical output in kW during the annual peak hour from 3:00 to 4:00 P.M. (PDT) on June 20, 2008. The tables also list the number of systems online, their combined capacities, and their hourly capacity factors. The last three rows of each table summarize the results across all technologies and fuels. Results presented for the three individual electric utilities for the CAISO peak hour do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table A-5: CAISO Peak Hour Output by Technology, Fuel, and Basis—PG&E

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**8**	**4,500**	**3,008**	**0.668 †**
		M	5	2,950	1,972	0.668
		E	3	1,550	1,036	0.668 †
FC	**R**	**Total**	**1**	**600**	**221**	**0.368**
		M	1	600	221	0.368
		E	0	0	0	0.000
GT	**N**	**Total**	**3**	**4,016**	**2,405**	**0.599** [a]
		M	0	0	0	0.000
		E	3	4,016	2,405	0.599 [a]
IC Engine	**N**	**Total**	**89**	**51,062**	**6,017**	**0.118 †**
		M	35	16,368	1,584	0.097
		E	54	34,694	4,433	0.128 †
IC Engine	**R**	**Total**	**10**	**5,683**	**2,939**	**0.517** [a]
		M	2	700	308	0.439
		E	8	4,983	2,631	0.528 [a]
MT	**N**	**Total**	**40**	**6,334**	**3,644**	**0.575 †**
		M	11	2,430	1,413	0.581
		E	29	3,904	2,231	0.572 †
MT	**R**	**Total**	**13**	**1,970**	**485**	**0.246 †**
		M	2	520	145	0.279
		E	11	1,450	339	0.234 †
PV		**Total**	**447**	**71,583**	**44,349**	**0.620**
		M	142	36,984	23,508	0.636
		E	305	34,599	20,841	0.602
WD		**Total**	**N/A**	**N/A**	**N/A**	**N/A**
		M	**N/A**	**N/A**	**N/A**	**N/A**
		E	**N/A**	**N/A**	**N/A**	**N/A**
		TOTAL	**611**	**145,748**	**63,068**	**0.433**
		M	198	60,552	29,150	0.481
		E	413	85,196	33,918	0.398

* In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-6: CAISO Peak Hour Output by Technology, Fuel, and Basis—SCE

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**2**	**700**	**542**	**0.775**
		M	2	700	542	0.775
		E	0	0	0	0.000
FC	**R**	**Total**	**3**	**1,650**	**669**	**0.405** [a]
		M	1	500	-11	-0.021
		E	2	1,150	679	0.591 [a]
GT	**N**	**Total**	**1**	**4,500**	**4,148**	**0.922**
		M	1	4,500	4,148	0.922
		E	0	0	0	0.000
IC Engine	**N**	**Total**	**90**	**62,071**	**18,818**	**0.303 †**
		M	37	24,698	7,466	0.302
		E	53	37,373	11,353	0.304 †
IC Engine	**R**	**Total**	**7**	**5,509**	**2,971**	**0.539 †**
		M	3	2,725	1,501	0.551
		E	4	2,784	1,470	0.528 [a]
MT	**N**	**Total**	**47**	**7,936**	**3,069**	**0.387 †**
		M	32	5,664	2,153	0.380
		E	15	2,272	916	0.403 [a]
MT	**R**	**Total**	**4**	**1,040**	**287**	**0.276** [a]
		M	2	550	182	0.332
		E	2	490	104	0.213 [a]
PV		**Total**	**210**	**29,919**	**15,162**	**0.507**
		M	38	5,276	3,206	0.608
		E	172	24,643	11,956	0.485
WD		**Total**	**2**	**1,649**	N/A	N/A
		M	N/A	N/A	N/A	N/A
		E	N/A	N/A	N/A	N/A
		TOTAL	**366**	**114,973**	**45,667**	**0.397**
		M	117	45,563	19,189	0.421
		E	249	69,411	26,478	0.381

* In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-7: CAISO Peak Hour Output by Technology, Fuel, and Basis—SDG&E

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**4**	**2,250**	**1,558**	**0.692**
		M	4	2,250	1,558	0.692
		E	0	0	0	0.000
FC	**R**	**Total**	**0**	**0**	**0**	**0.000**
		M	0	0	0	0.000
		E	0	0	0	0.000
GT	**N**	**Total**	**2**	**9,127**	**8,175**	**0.896** [a]
		M	1	4,527	4,008	0.885
		E	1	4,600	4,167	0.906 [a]
IC Engine	**N**	**Total**	**21**	**13,224**	**2,979**	**0.225** [a]
		M	20	11,024	2,695	0.244
		E	1	2,200	285	0.129 [a]
IC Engine	**R**	**Total**	**0**	**0**	**0**	**0.000**
		M	0	0	0	0.000
		E	0	0	0	0.000
MT	**N**	**Total**	**13**	**1,128**	**347**	**0.308 †**
		M	11	958	295	0.308
		E	2	170	52	0.308 [a]
MT	**R**	**Total**	**4**	**774**	**100**	**0.129** [a]
		M	3	564	55	0.097
		E	1	210	45	0.213 [a]
PV		**Total**	**104**	**13,998**	**8,410**	**0.601**
		M	95	13,108	7,892	0.602
		E	9	891	518	0.582 †
WD		**Total**	**N/A**	**N/A**	**N/A**	**N/A**
		M	**N/A**	**N/A**	**N/A**	**N/A**
		E	**N/A**	**N/A**	**N/A**	**N/A**
		TOTAL	**148**	**40,502**	**21,569**	**0.533**
		M	134	32,431	16,502	0.509
		E	14	8,071	5,067	0.628

* In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-2, Figure A-3, and Figure A-4 plot for each electric utility profiles of hourly total net electrical output in kW for each technology from morning to early evening during the day of the annual peak hour, June 20, 2008. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. The preceding tables list the values associated with these charts for the peak hour. Results presented for the three individual electric utilities on the CAISO peak day do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Figure A-2: CAISO Peak Day Output by Technology, and Fuel—PG&E

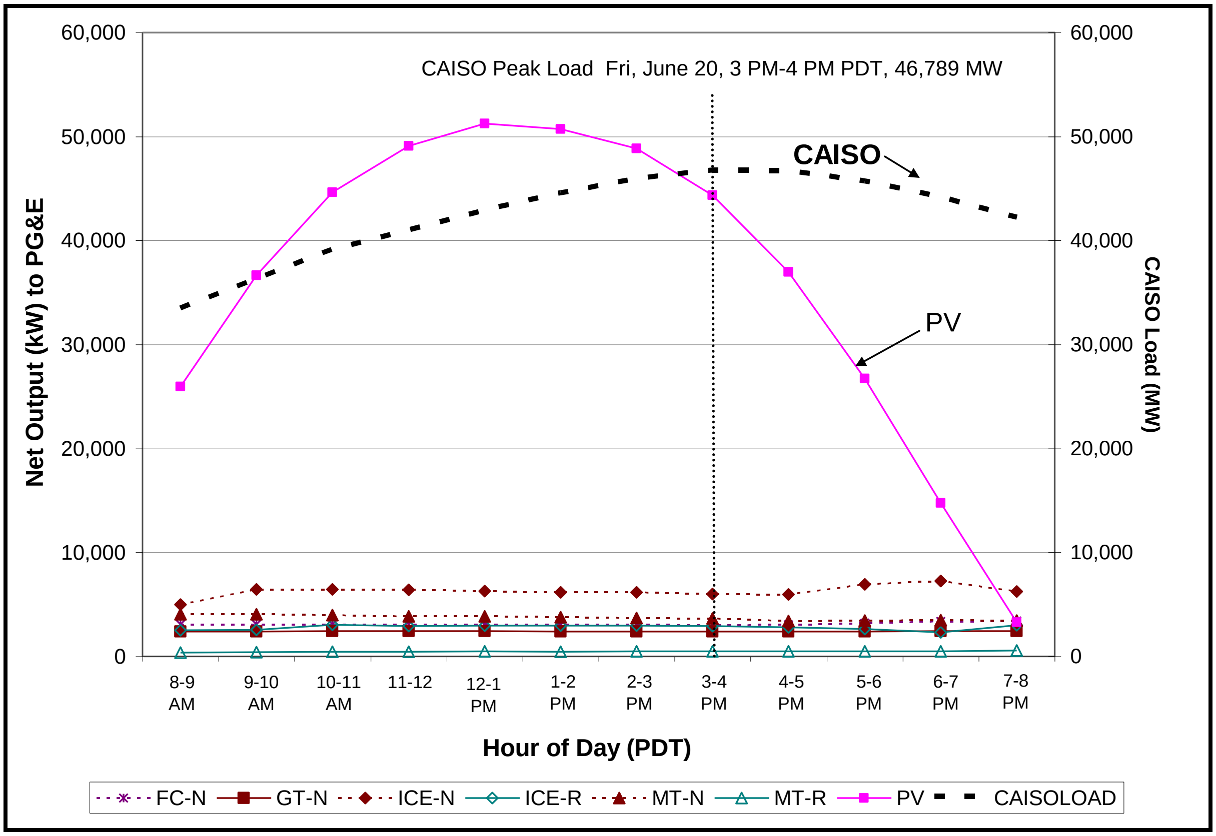


Figure A-3: CAISO Peak Day Output by Technology, and Fuel—SCE

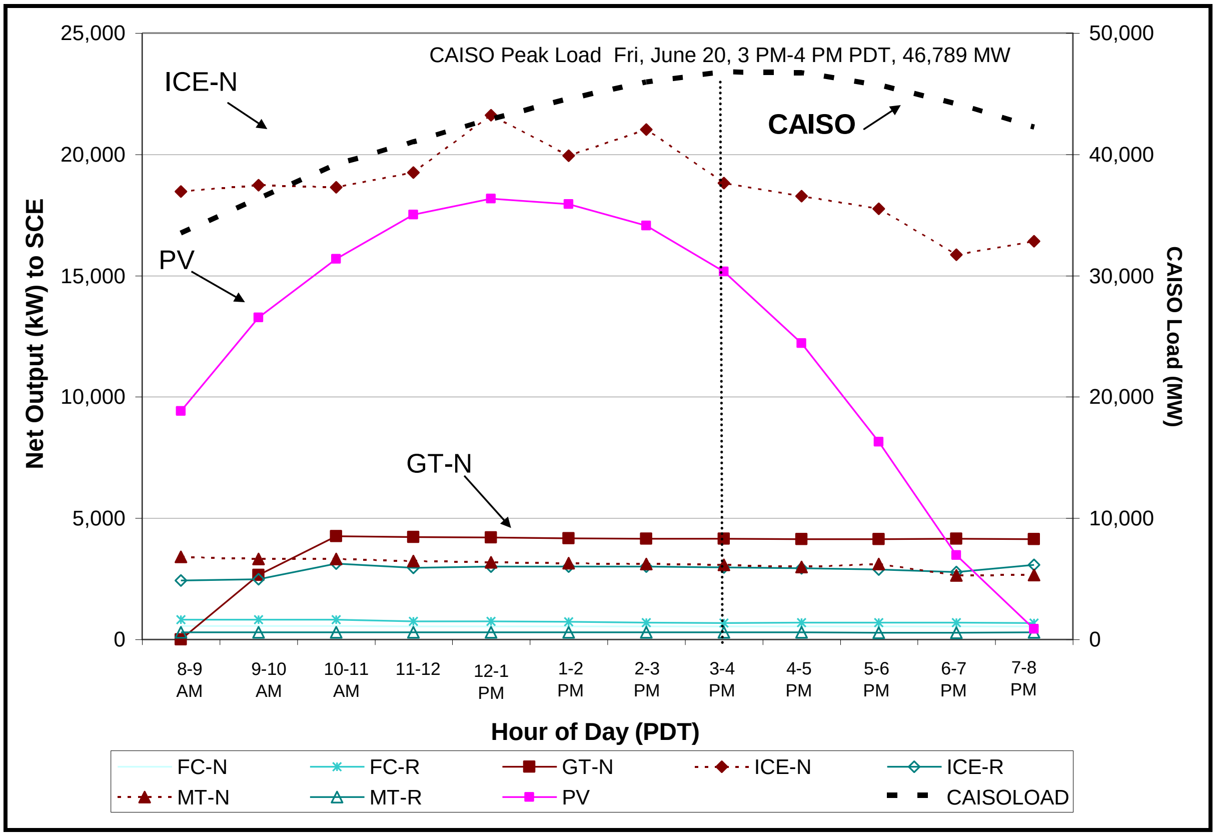


Figure A-4: CAISO Peak Day Output by Technology, and Fuel—SDG&E

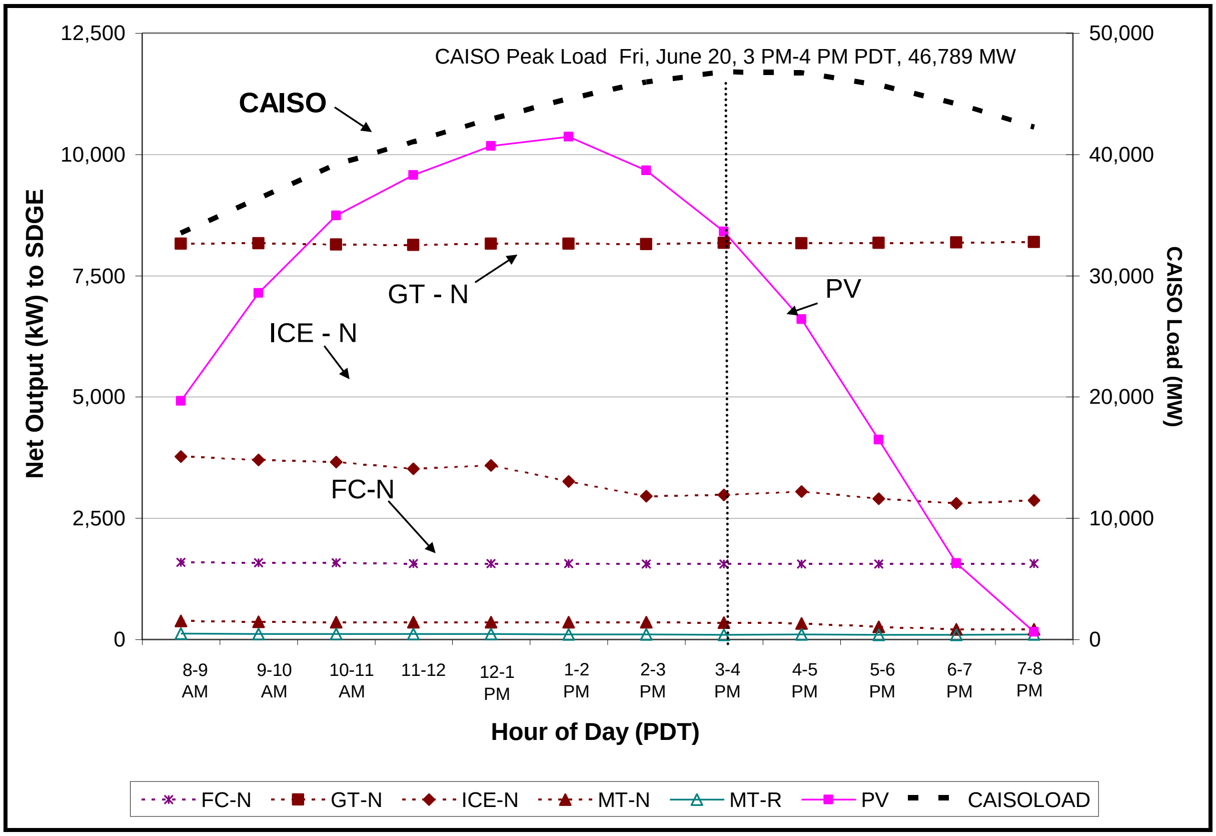


Table A-8, Table A-9, and Table A-10 present the total net electrical output in kW during the respective peak hours of the three large, investor-owned electric utilities. Preceding each of these are small tables listing the date, hour, and load of the utility's peak hour day. The tables also show for each technology and basis the subtotals of output, counts of systems, and total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate electric utility peak demand impacts by natural gas versus renewable methane fuel.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of the systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table A-8: Electric Utility Peak Hours Demand Impacts—PG&E

Elec PA	Peak (MW)	Date	Hour (PDT hour beginning)
PG&E	**21,827**	**8-Jul-08**	**17**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**9**	**5,100**	**2,965**	**0.581**
	M	5	3,350	1,818	0.543
	E	4	1,750	1,147	0.655
GT	**Total**	**3**	**4,016**	**2,309**	**0.575**
	M	0	0	0	0.000
	E	3	4,016	2,309	0.575
IC Engine	**Total**	**99**	**56,745**	**11,374**	**0.200**
	M	38	18,131	2,641	0.146
	E	61	38,614	8,734	0.226
MT	**Total**	**53**	**8,304**	**3,286**	**0.396**
	M	14	3,230	1,297	0.402
	E	39	5,074	1,989	0.392
PV	**Total**	**449**	**71,964**	**23,937**	**0.333**
	M	143	37,403	13,055	0.349
	E	306	34,561	10,882	0.315
WD	**Total**	**N/A**	**N/A**	**N/A**	**N/A**
	M	**N/A**	**N/A**	**N/A**	**N/A**
	E	**N/A**	**N/A**	**N/A**	**N/A**
Total		**613**	**146,129**	**43,872**	**0.300**

Table A-9: Electric Utility Peak Hours Demand Impacts—SCE

Elec PA	Peak (MW)	Date	Hour (PDT hour beginning)
SCE	**22,404**	**20-Jun-08**	**16**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**5**	**2,350**	**1,241**	**0.528**
	M	3	1,200	534	0.445
	E	2	1,150	707	0.615
GT	**Total**	**1**	**4,500**	**4,132**	**0.918**
	M	1	4,500	4,132	0.918
	E	0	0	0	0.000
IC Engine	**Total**	**97**	**67,580**	**21,199**	**0.314**
	M	40	27,423	8,779	0.320
	E	57	40,157	12,420	0.309
MT	**Total**	**51**	**8,976**	**3,278**	**0.365**
	M	34	6,214	2,277	0.366
	E	17	2,762	1,002	0.363
PV	**Total**	**210**	**29,919**	**12,217**	**0.408**
	M	38	5,276	2,766	0.524
	E	172	24,643	9,450	0.383
WD	**Total**	**2**	**1,649**	**N/A**	**N/A**
	M	**N/A**	**N/A**	**N/A**	**N/A**
	E	**N/A**	**N/A**	**N/A**	**N/A**
Total		**366**	**114,973**	**42,067**	**0.366**

Table A-10: Electric Utility Peak Hours Demand Impacts—SDG&E

Elec PA	Peak (MW)	Date	Hour (PDT hour beginning)
SDG&E	**4,348**	**1-Oct-08**	**15**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**4**	**2,250**	**678**	**0.302**
	M	4	2,250	678	0.302
	E	0	0	0	0.000
GT	**Total**	**2**	**9,127**	**7,987**	**0.875**
	M	1	4,527	3,824	0.845
	E	1	4,600	4,163	0.905
IC Engine	**Total**	**21**	**13,224**	**3,458**	**0.261**
	M	20	11,024	3,080	0.279
	E	1	2,200	378	0.172
MT	**Total**	**17**	**1,902**	**279**	**0.147**
	M	14	1,522	207	0.136
	E	3	380	73	0.191
PV	**Total**	**104**	**13,998**	**5,712**	**0.408**
	M	95	13,108	5,388	0.411
	E	9	891	324	0.364
WD	**Total**	**N/A**	**N/A**	**N/A**	**N/A**
	M	**N/A**	**N/A**	**N/A**	**N/A**
	E	**N/A**	**N/A**	**N/A**	**N/A**
Total		**148**	**40,502**	**18,114**	**0.447**

Capacity Factors

This section describes weighted average capacity factors that indicate system performance relative to system-rebated kW for specific time periods. For example, an hourly weighted average capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system-rebated capacity.

Table A-11 presents annual weighted average capacity factors for each technology for the year 2008. The table shows the annual weighted average capacity factors for each technology using all metered and estimated values, and by bases of metered and of estimated. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. The distinction by basis indicates simply that different sets of observations were used in the calculations, not that estimated capacity factors were systematically lower or higher than metered capacity factors. Again, later tables in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Table A-11: Annual Capacity Factors

Technology	Basis	Annual Capacity Factor* (kWyear/kWyear)
FC	**Total**	**0.598** †
	M	0.586
	E	0.626 †
GT	**Total**	**0.737** †
	M	0.776
	E	0.695 [a]
IC Engine	**Total**	**0.223** †
	M	0.215
	E	0.228 †
MT	**Total**	**0.407**
	M	0.387
	E	0.426 †
PV	**Total**	**0.175**
	M	0.182
	E	0.169
WD	**Total**	**N/A**
	M	**N/A**
	E	**N/A**

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-12 presents annual weighted average capacity factors for each technology and PA for the year 2008. These values arise from the combination of all metered and estimated values. Where entries are blank the PA had no operational systems of the technology type. Later tables in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Table A-12: Annual Capacity Factors by Technology and PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
FC	0.628 †	0.509 †	0.698 †	0.525
GT	0.618 [a]	0.000	0.790	0.762 †
IC Engine	0.187 †	0.251 †	0.256 †	0.190 †
MT	0.452 †	0.315 †	0.482 †	0.213 †
PV	0.177	0.163	0.181	0.177
WD	**N/A**	**N/A**	**N/A**	**N/A**

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-13 presents annual weighted average capacity factors for the technologies that can be fueled with either natural gas or renewable methane gas. Where entries are blank the PA had no operational systems of the technology type. This table allows easy comparison of these technologies by fuel type.

Table A-13: Annual Capacity Factors by Technology and Fuel

Technology	Annual Capacity Factor* (kWyear/kWyear)	
	Natural Gas	Renewable Fuel
FC	0.594 †	0.612 †
GT	0.737 †	**N/A**
IC Engine	0.200 †	0.487 †
MT	0.449 †	0.211 †

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Figure A-5 plots profiles of monthly weighted average capacity factors for each technology. Again, later charts in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Figure A-5: Monthly Capacity Factors by Technology

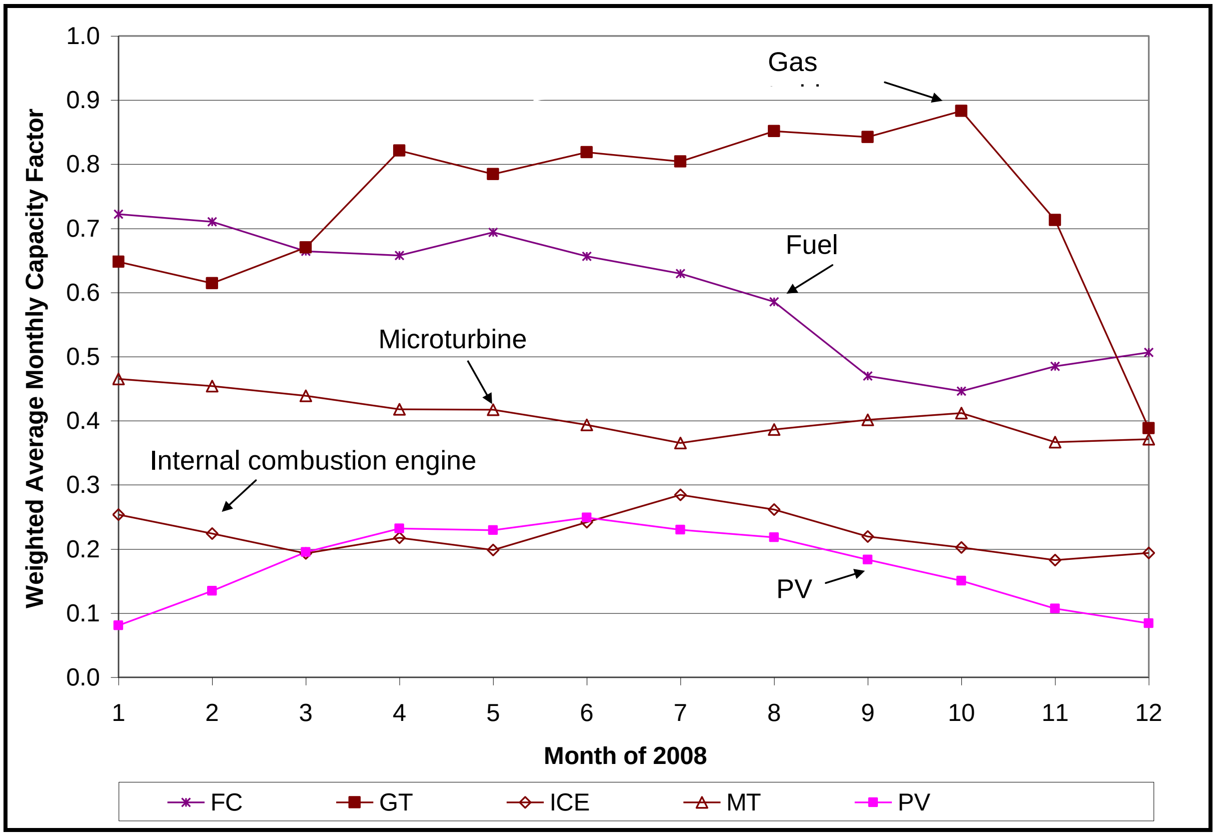


Figure A-6 plots profiles of hourly weighted average capacity factor for each technology from morning to early evening during the day of the annual peak hour, June 20, 2008. The plot also indicates the hour and value of the CAISO peak load. Again, later charts in this appendix differentiate by natural gas versus renewable methane fuel.

Figure A-6: CAISO Peak Day Capacity Factors by Technology

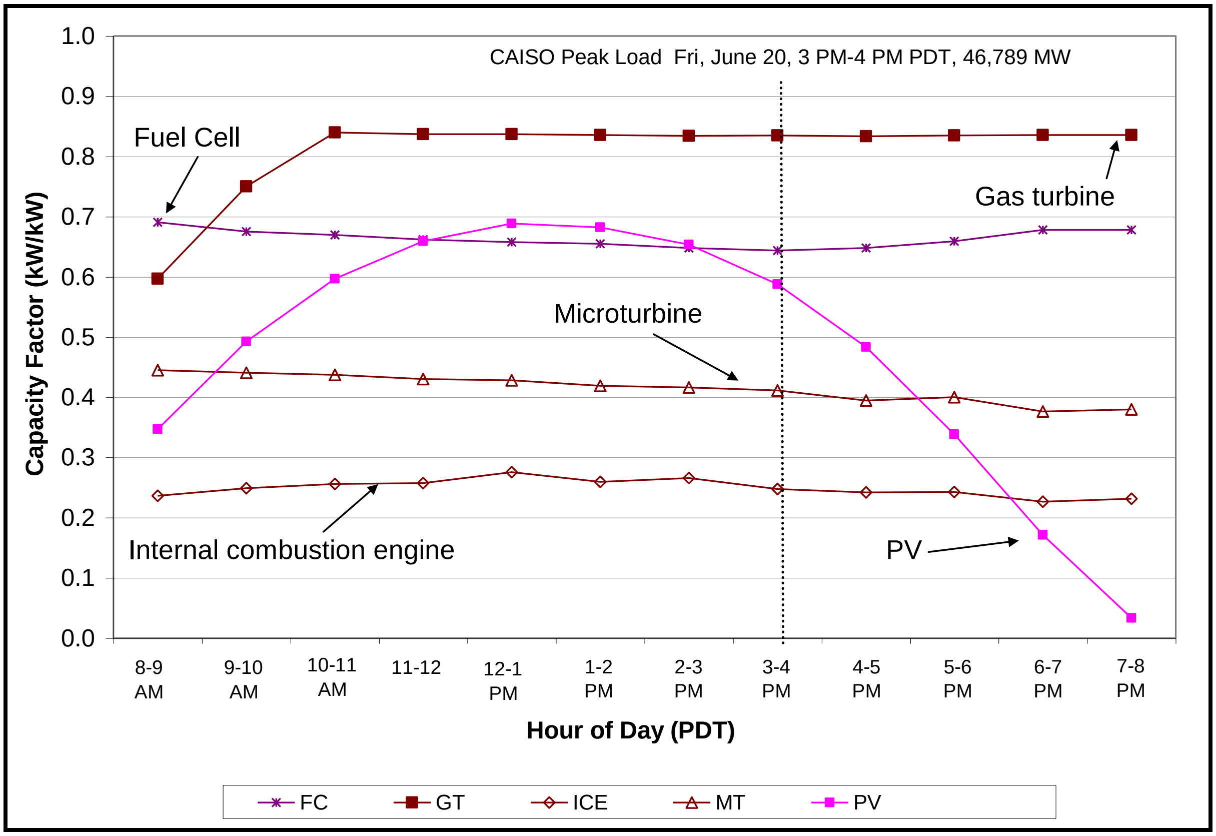


Figure A-7, Figure A-8, and Figure A-9 plot profiles of hourly weighted average capacity factors by technology for the systems directly feeding the utilities on the dates of their respective annual peak hours. The plots also indicate the date, hour, and value of the peak load for the electric utility. The plots include only those technologies that were operational for the electric utility, so not all technologies appear for all electric utilities. In later sections, this appendix describes separately those technologies that can use natural gas versus renewable fuel.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of all systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Figure A-7: Electric Utility Peak Day Capacity Factors by Technology—PG&E

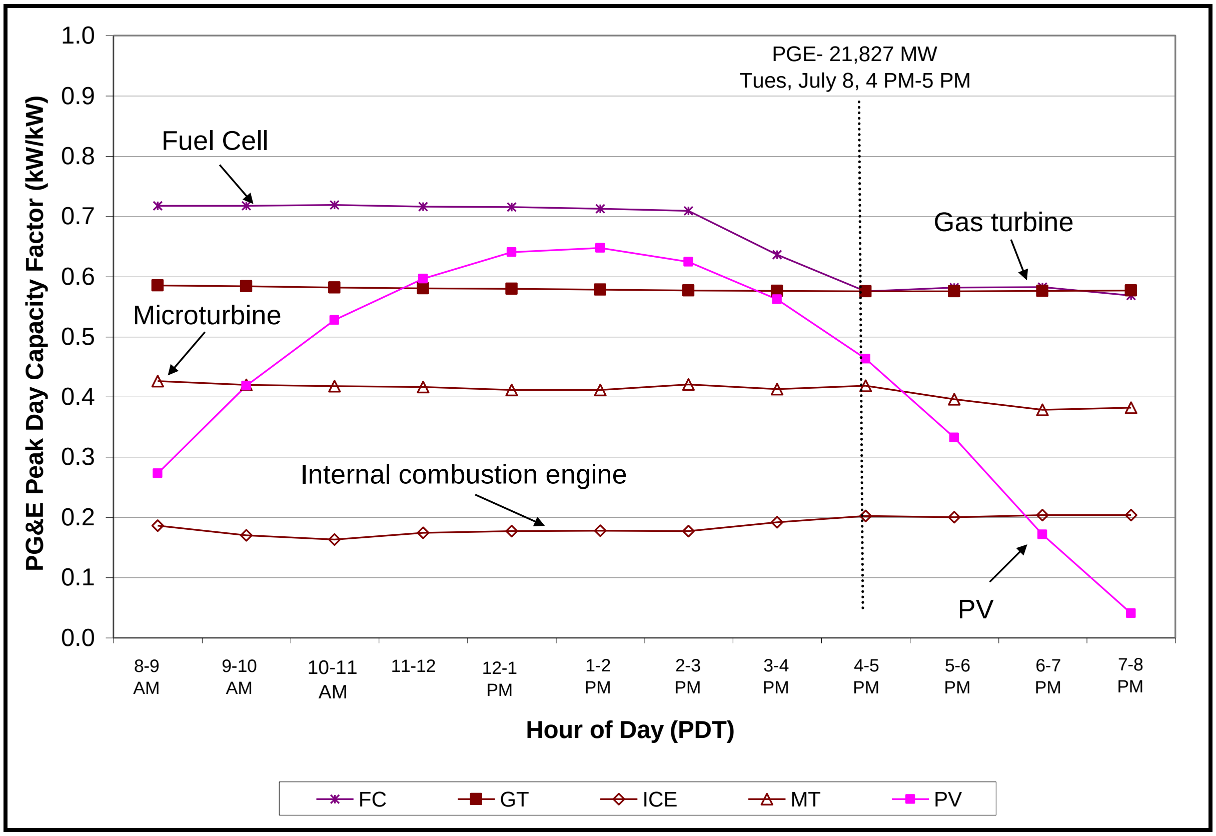


Figure A-8: Electric Utility Peak Day Capacity Factors by Technology—SCE

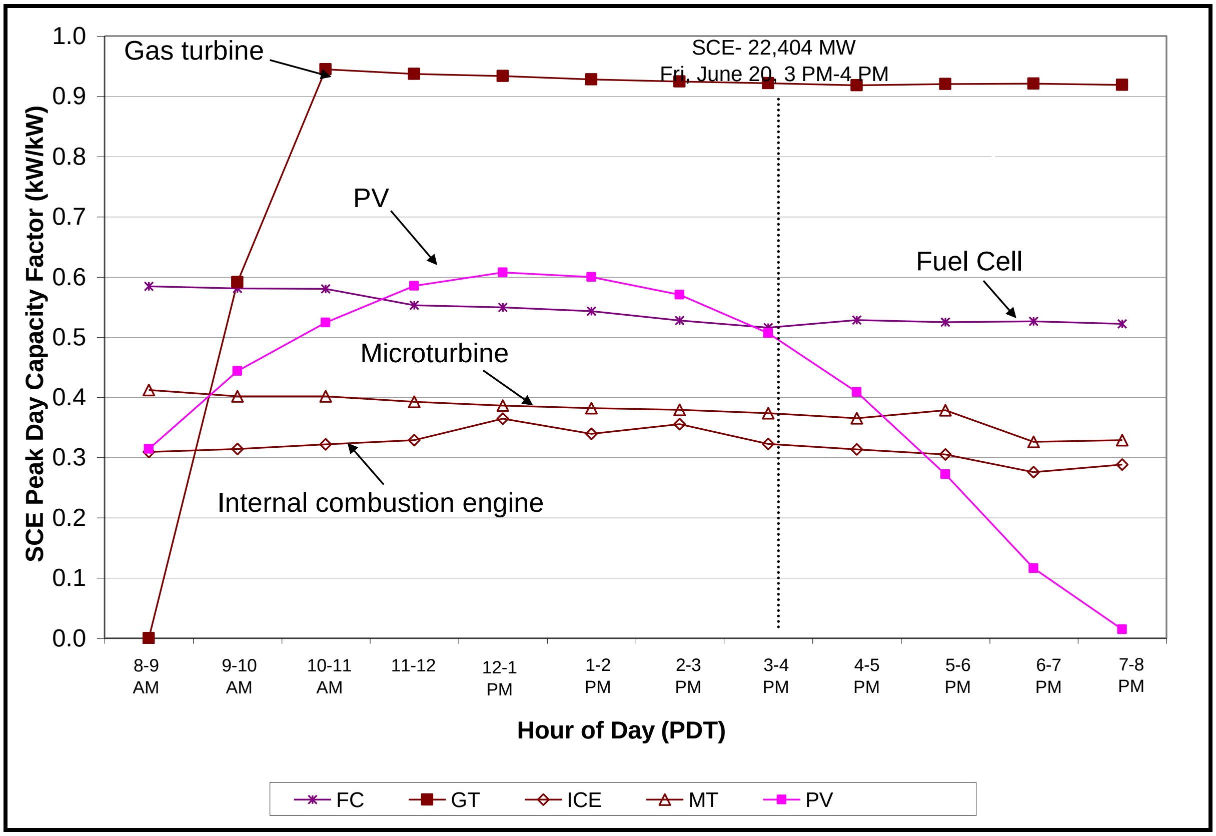
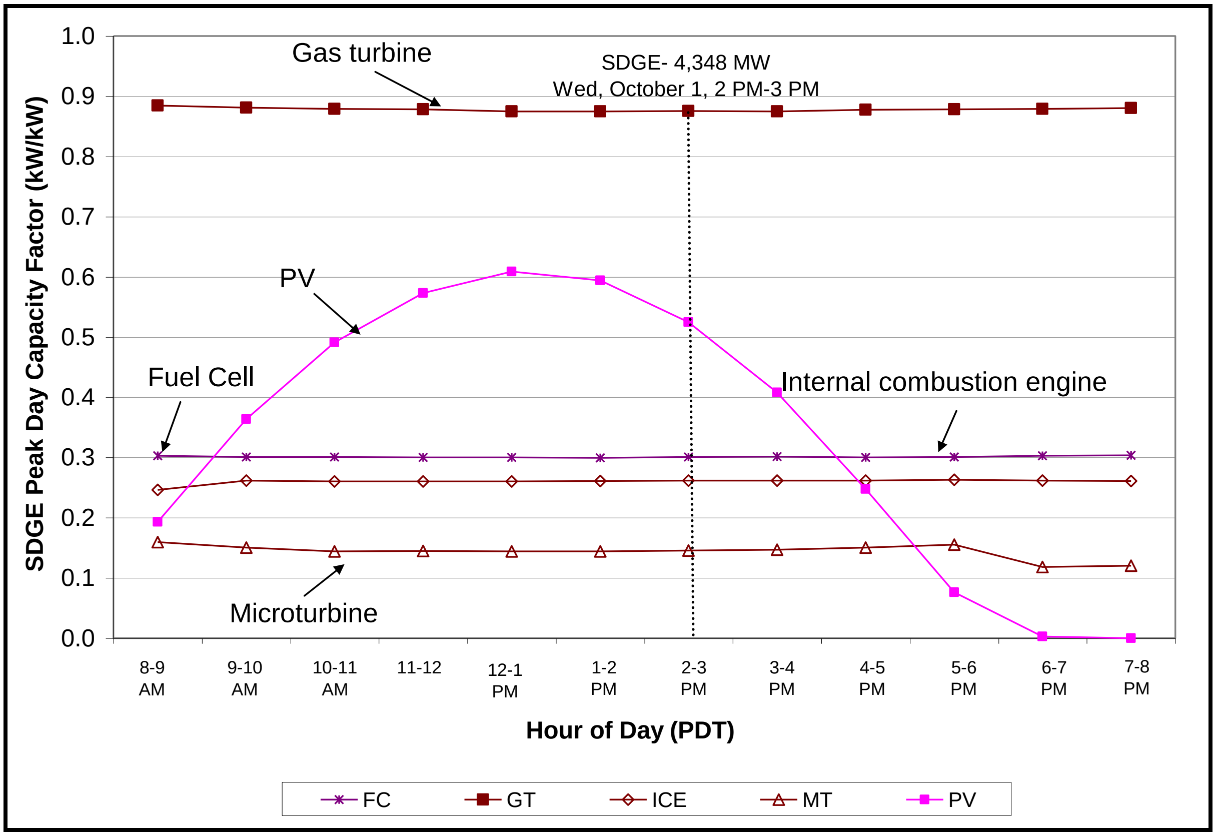


Figure A-9: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



A.3 Renewable Power Systems

This section describes impacts of renewable power systems. It begins with PV, followed by wind, renewable fuel cells, renewable IC engines, and renewable microturbines. There are no renewable gas turbines in the program. The next section describes non-renewable power systems.

Solar Photovoltaic

Costs

Table A-14 lists total eligible costs, SGIP incentives, and other incentives for PV systems.

Table A-14: Complete and Active System Costs

Technology	Cost Component	Completed Projects (M$)	Active Projects (M$)
PV	Eligible Cost	$1,299.70	$130.83
	Incentive	$486.73	$39.26
	Other Incentive	$40.52	$4.07
	Total Incentive	**$527.25**	**$43.33**

Annual Energy

Table A-15 presents annual total net electrical output in MWh from PV for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-15: Annual Electric Energy Totals* by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
PV	**Total***	**118,935**	**37,625**	**18,904**	**21,713**	**197,178**
	M*	57,420	4,234	8,220	20,361	90,235
	E*	61,515	33,391	10,685	1,352 †	106,943

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-16 presents quarterly total net electrical output in MWh for PV. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-16: Quarterly Electric Energy Totals

Technology	Basis	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
PV	**Total**	**37,062**	**66,034**	**60,815**	**33,268**	**197,178**
	M	16,586	30,665	28,494	14,489	90,235
	E	20,476	35,368	32,320	18,779	106,943

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-17 presents total net electrical output in kW for PV during the peak hour of 3:00 to 4:00 P.M. (PDT) on June 30, 2008. The table also shows counts of systems and total operational system capacity in kW.

Table A-17: CAISO Peak Hour Demand Impacts

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
PV	**Total**	**863**	**129,566**	**76,202**	**0.588**

* In column with hourly capacity factor only, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-18 presents the total net electrical output in kW for PV during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-18: Electric Utility Peak Hours Demand Impacts

PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	21,827	7/8/2008	17	**PV**	449	71,964	23,937
SCE	22,404	6/20/2008	16		210	29,919	12,217
SDG&E	4,348	10/1/2008	15		104	13,998	5,712

Capacity Factors

Weighted average capacity factors indicate PV performance relative to a system-rebated kW for specific time periods. Capacity factors for PV for time periods of a whole day or more are typically less than 0.3 as there generally is no net output between sunset and dawn. Table A-19 presents annual weighted average capacity factors for PV for the year 2008.

Table A-19: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
PV	0.175

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-20 presents annual weighted average capacity factors for PV for each PA for the year 2008.

Table A-20: Annual Capacity Factors by PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
PV	0.177	0.163	0.181	0.177

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Figure A-10 plots profiles of monthly weighted average capacity factors for PV for each PA. This particular plot uses a reduced height for the vertical axis, with a maximum of 0.30 to allow easier differentiation of capacity factor variations by month.

Figure A-10: Monthly Capacity Factors by PA

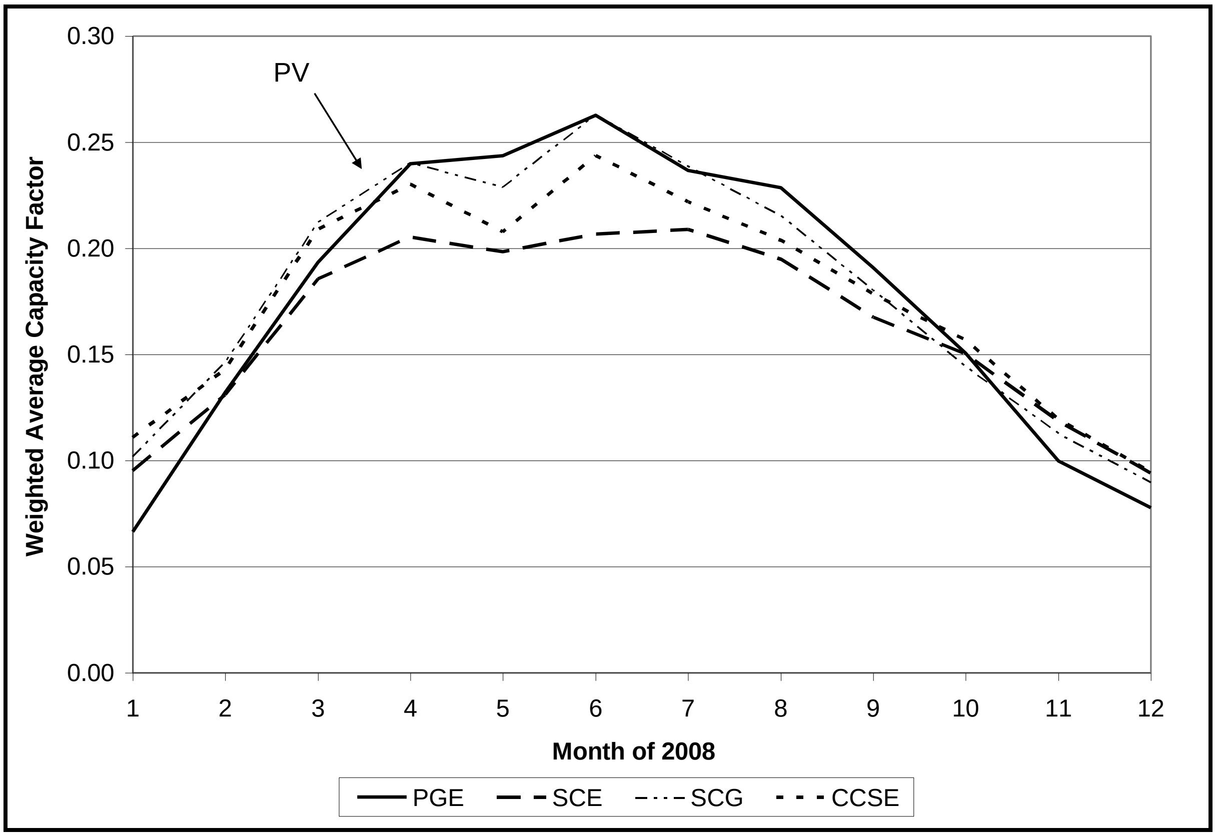


Figure A-11 plots the profiles of hourly weighted average capacity factor for PV for each PA from the morning to early evening during the day of the annual peak hour, June 20, 2008. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-11: CAISO Peak Day Capacity Factors by PA

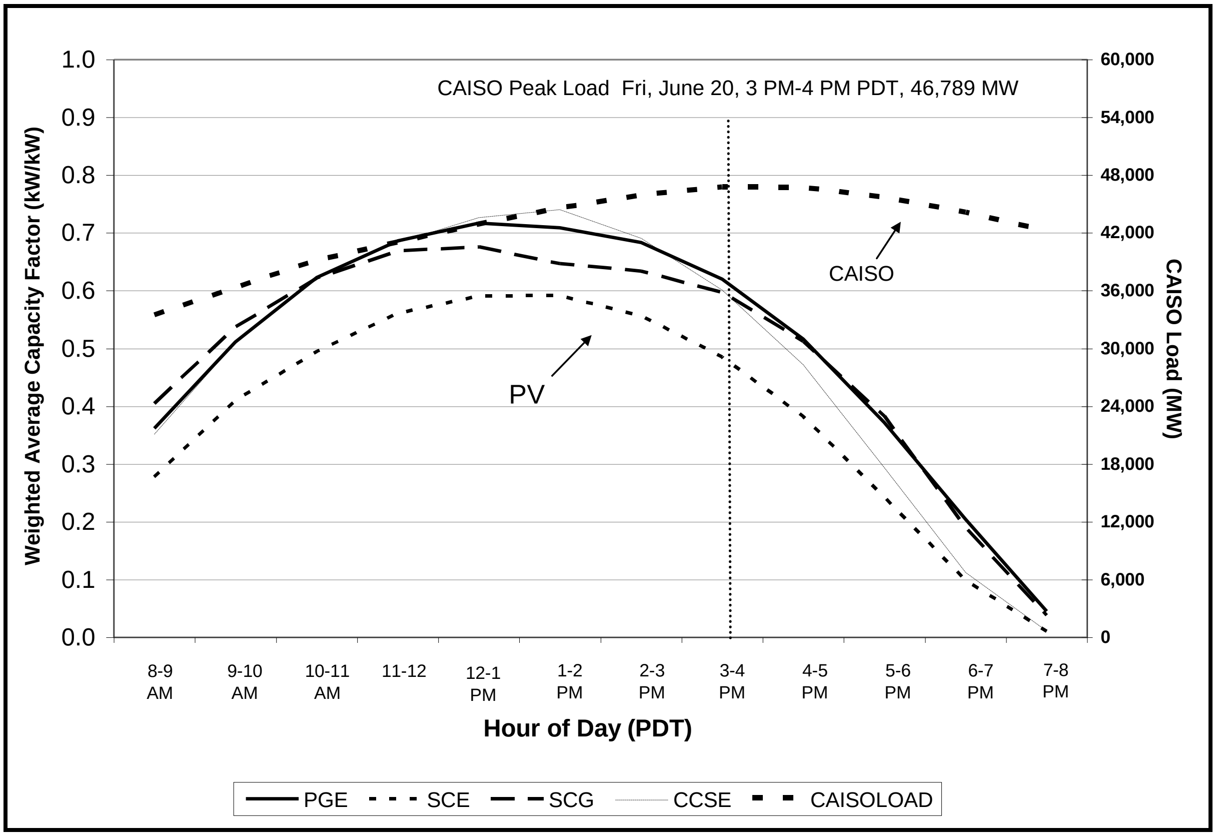


Figure A-12, Figure A-13, and Figure A-14 plot profiles of hourly weighted average capacity factors for PV systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-12: Electric Utility Peak Day Capacity Factors—PG&E

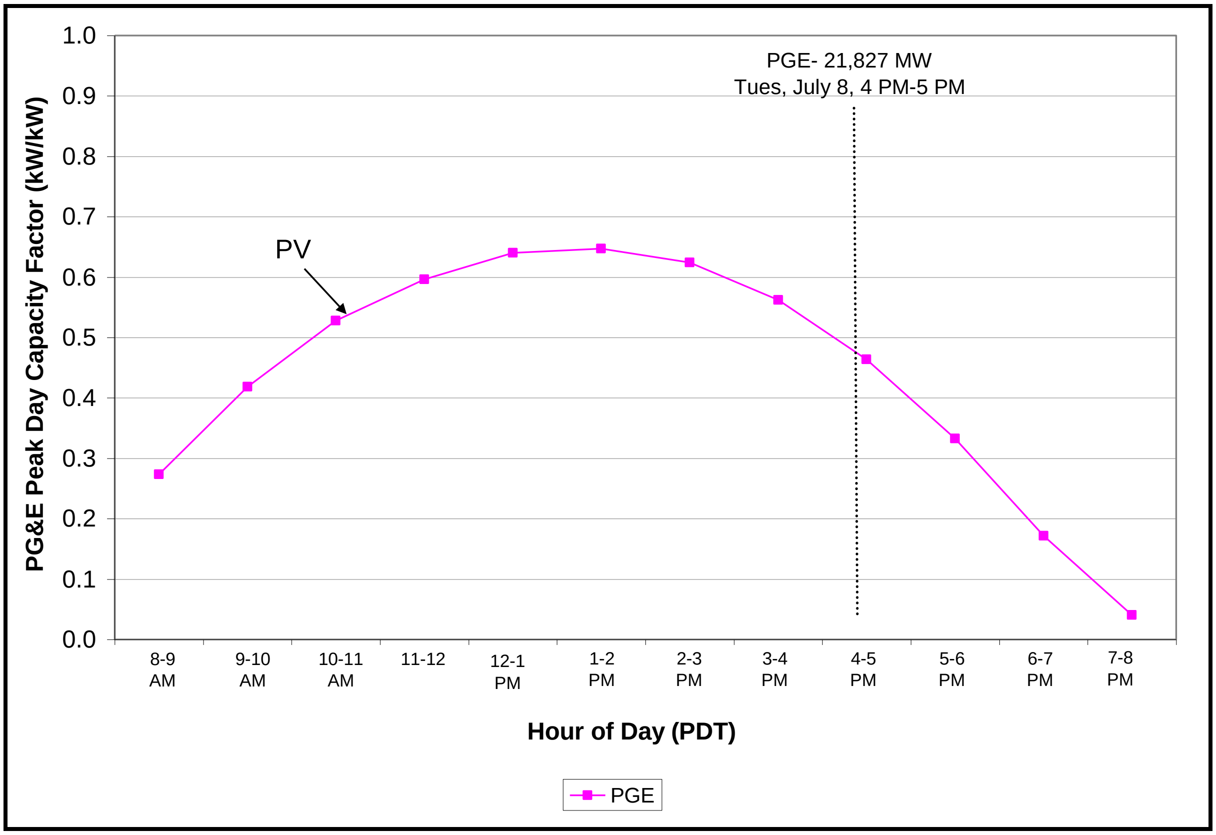


Figure A-13: Electric Utility Peak Day Capacity Factors—SCE

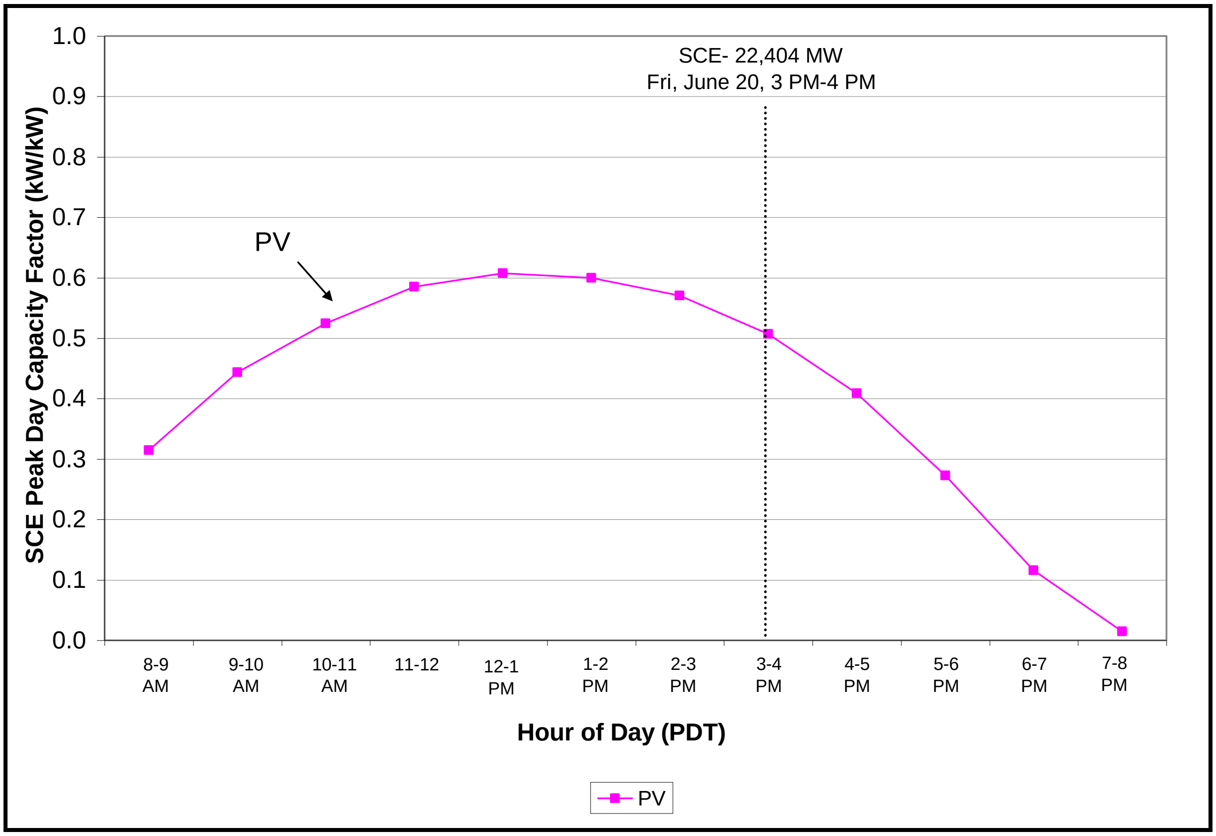
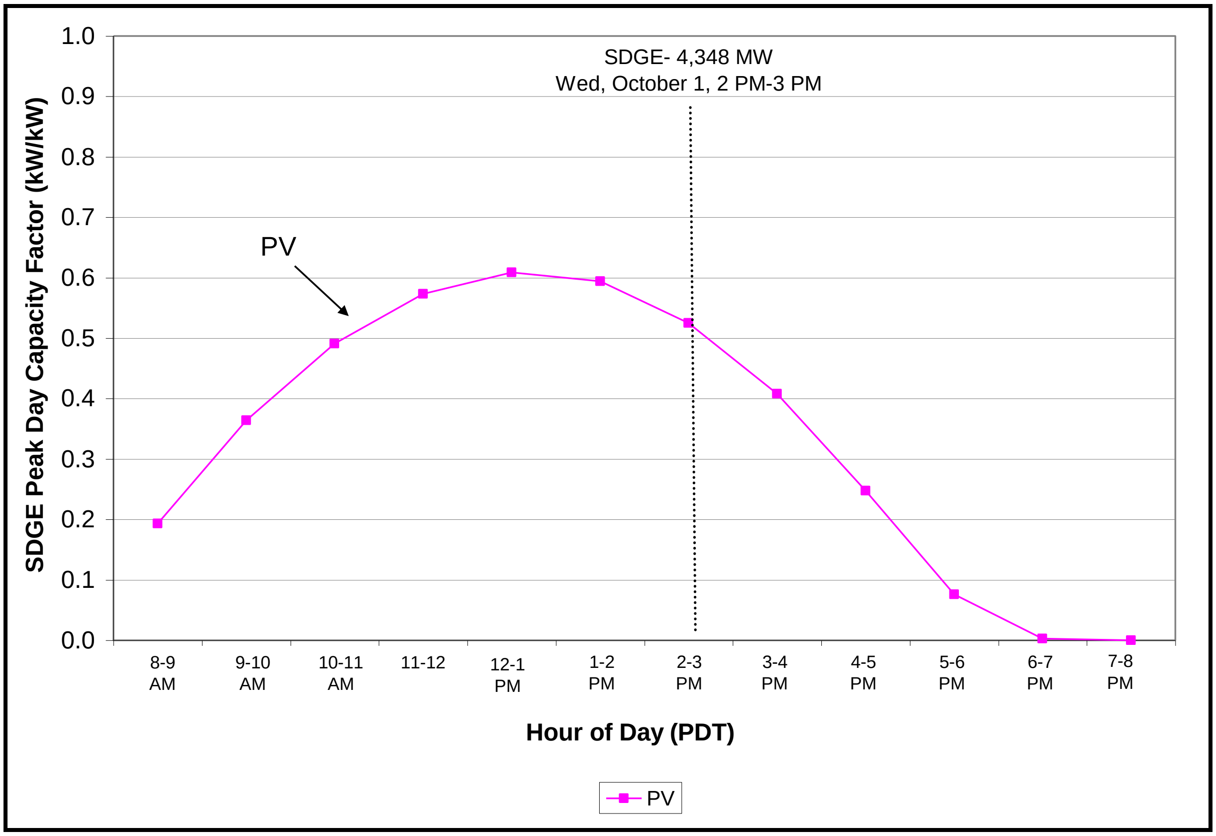


Figure A-14: Electric Utility Peak Day Capacity Factors—SDG&E



Wind

Costs

Table A-21 lists total eligible costs, SGIP incentives, and other incentives for wind systems.

Table A-21: Complete and Active System Costs

Technology	Cost Component	Completed Projects (M$)	Active Projects (M$)
WD	Eligible Cost	$5.38	$53.66
	Incentive	$2.63	$16.87
	Other Incentive	$0.06	$0.00
	Total Incentive	**$2.69**	**$16.87**

Performance data for wind sites was not available during 2008; therefore no annual or peak energy results are presented here.

Renewable Fuel Cells

Costs

Table A-22 lists total eligible costs, SGIP incentives, and other incentives for renewable fuel cell systems.

Table A-22: Complete and Active System Costs

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
FC	**R**	Eligible Cost	$20.65	$64.45
		Incentive	$15.08	$31.95
		Other Incentive	$0.00	$0.00
		Total Incentive	**$15.08**	**$31.95**

Annual Energy

Table A-23 presents annual total net electrical output in MWh from renewable fuel cells for the program and for each PA. This table also shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-23: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC-R	**Total***	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				**12,572 †**
	M					4,495
	E					8,077

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-24 presents quarterly total net electrical output in MWh for renewable fuel cells. This table also shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-24: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
FC	**R**	**Total**	**1,769**	**2,742**	**3,014**	**5,048**	**12572 †**
		M	800	1,076	1,202	1,418	4495
		E	969	1,666	1,812	3,630	8077 [a]

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-25 presents total net electrical output in kW for renewable fuel cells during the peak hour of 3:00 to 4:00 P.M. (PDT) on June 20, 2008. The table also shows counts of systems and total operational system capacity in kW.

Table A-25: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
FC-R	4	2,250	890 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-26 presents the total net electrical output in kW for renewable fuel cells during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-26: Electric Utility Peak Hours Demand Impacts

PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	21,827	7/8/2008	17	**FC**	1	600	-13
SCE	22,404	6/20/2008	16		3	1,650	697
SDG&E	4,348	10/1/2008	15		N/A	N/A	N/A

Capacity Factors

Weighted average capacity factors indicate renewable fuel cell performance relative to a system-rebated kW for specific time periods. Table A-27 presents annual weighted average capacity factors for renewable fuel cells for the year 2008.

Table A-27: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC-R	0.612 †

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-28 presents annual weighted average capacity factors for renewable fuel cells for each PA for the year 2008.

Table A-28: Annual Capacity Factors by PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
FC-R	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Figure A-15 plots profiles of monthly weighted average capacity factors for renewable fuel cells for each PA.

Figure A-15: Monthly Capacity Factors by PA

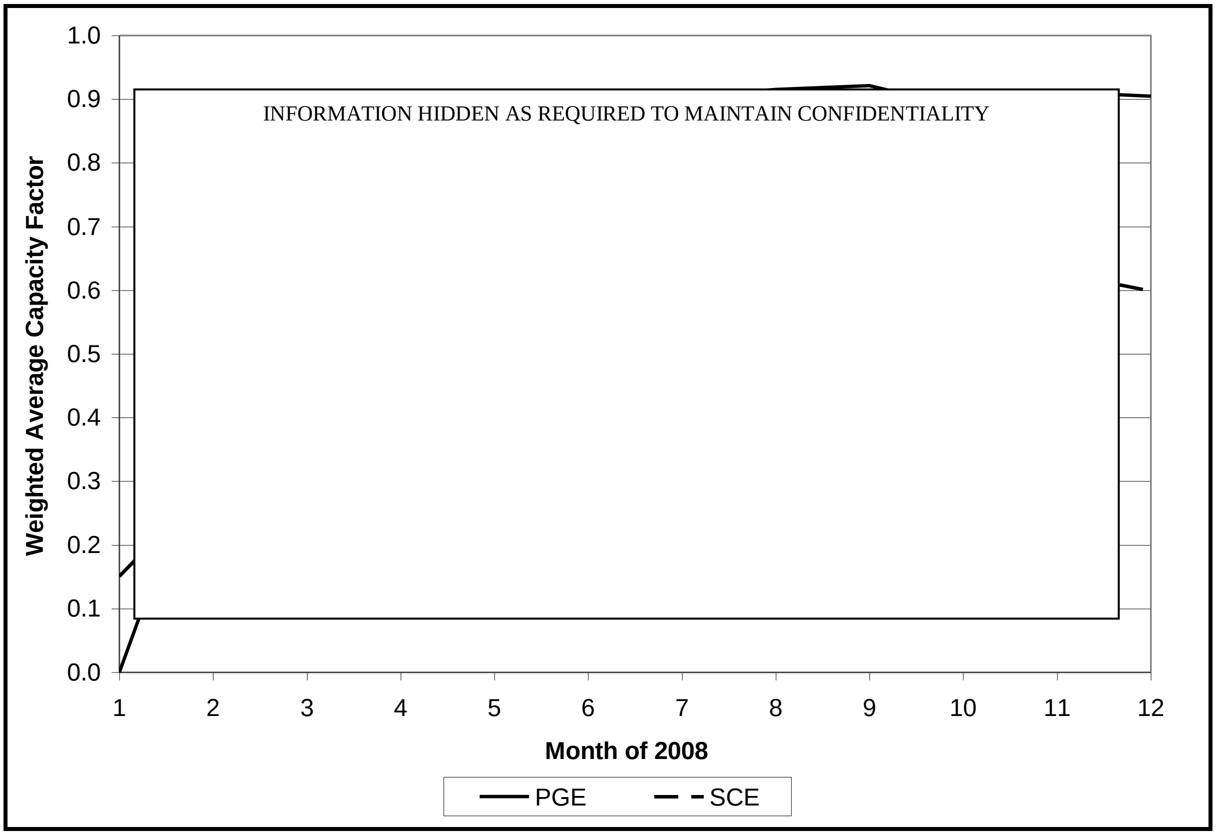


Figure A-16 plots the profiles of hourly weighted average capacity factor for renewable fuel cells for each PA from the morning to early evening during the day of the annual peak hour, June 20, 2008. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. SCE is the sole PA with renewable fuel cells, so no other PAs appear in the chart.

Figure A-16: CAISO Peak Day Capacity Factors by PA

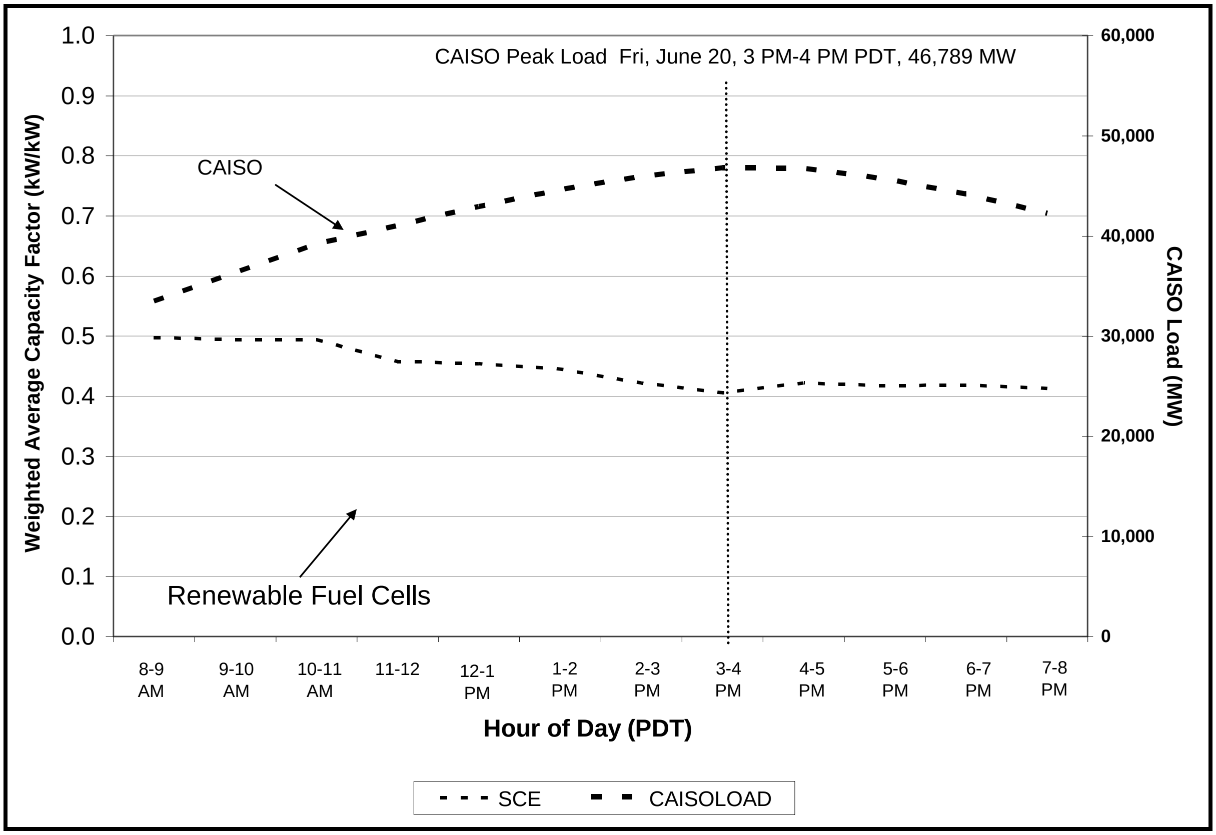


Figure A-17 and Figure A-18 plot profiles of hourly weighted average capacity factors for renewable fuel cells directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-17: Electric Utility Peak Day Capacity Factors—PG&E

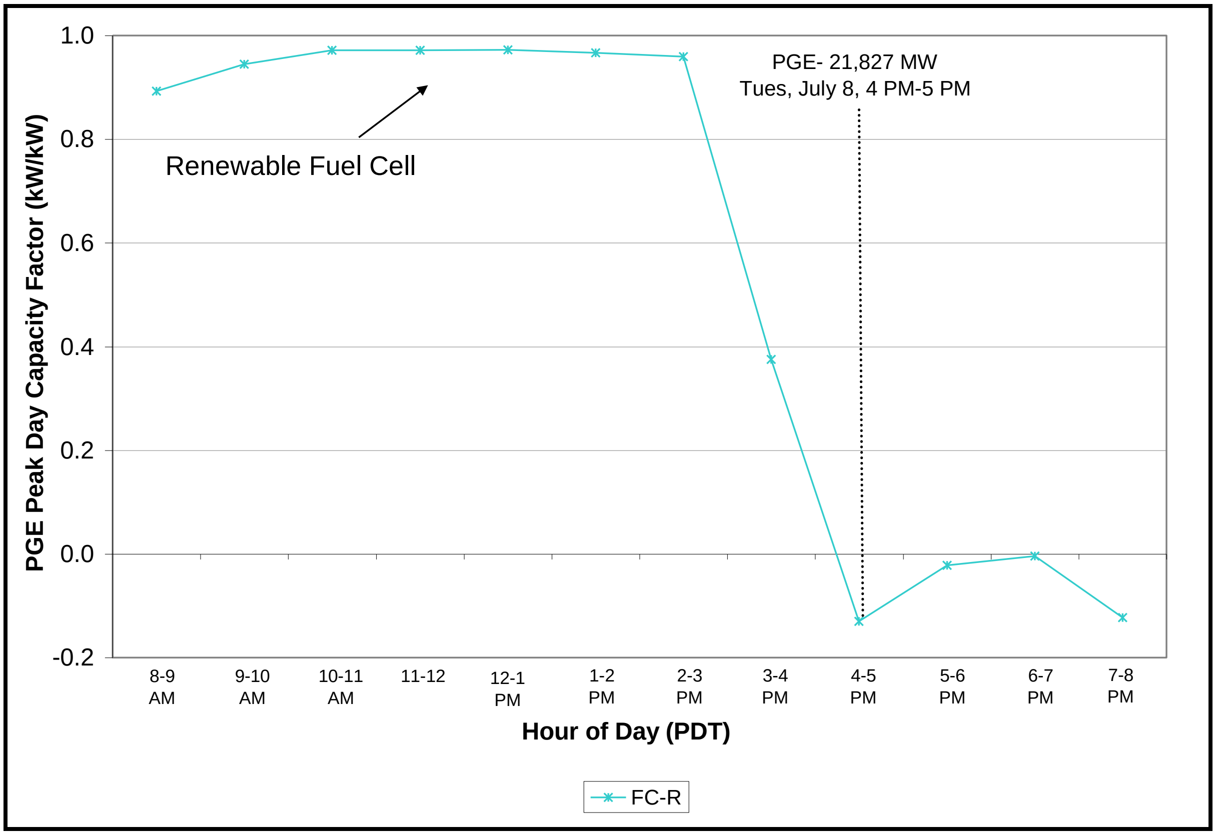
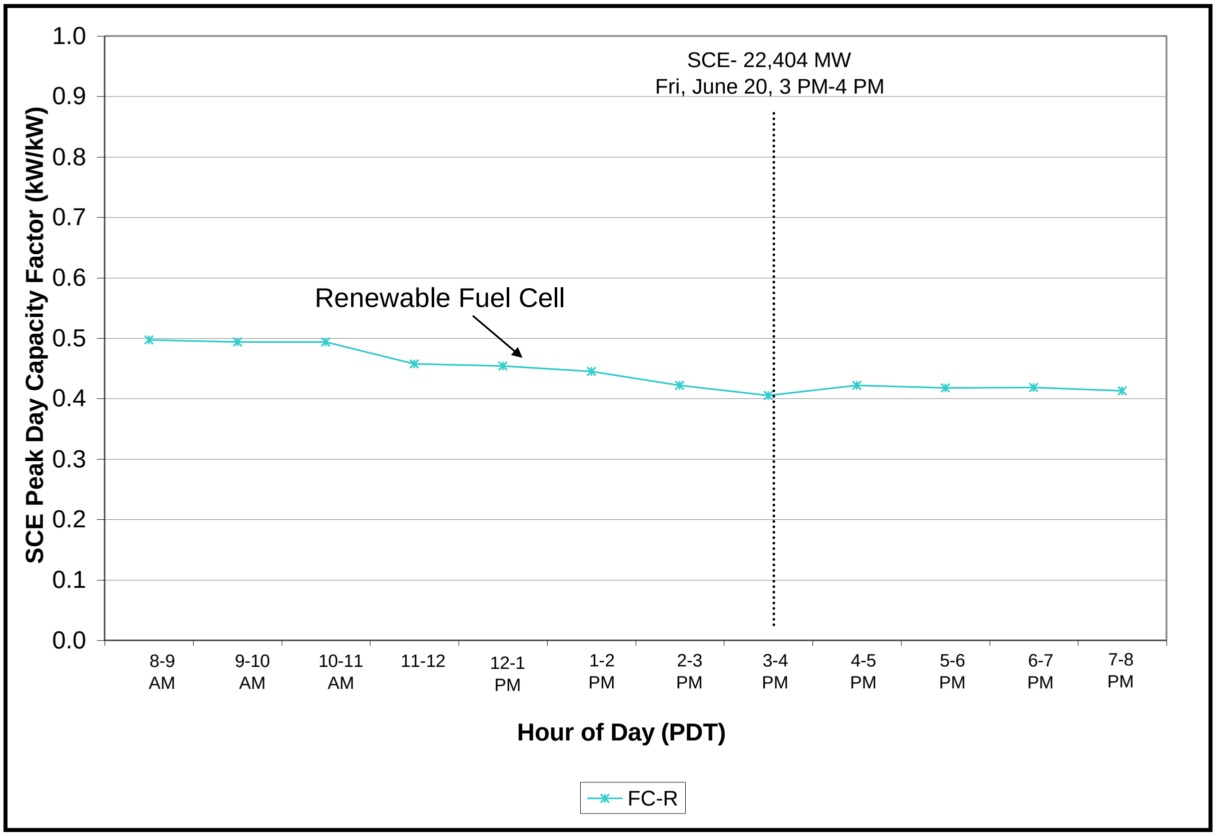


Figure A-18: Electric Utility Peak Day Capacity Factors—SCE



Renewable Internal Combustion Engines and Microturbines

Costs

Table A-29 lists total eligible costs, SGIP incentives, and other incentives for renewable IC engine and microturbine systems.

Table A-29: Complete and Active System Costs by Technology

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
IC Engine	**R**	Eligible Cost	$21.37	$23.81
		Incentive	$7.36	$7.83
		Other Incentive	$0.48	$0.00
		Total Incentive	**$7.84**	**$7.83**
MT	**R**	Eligible Cost	$11.76	$7.42
		Incentive	$3.81	$2.01
		Other Incentive	$0.19	$0.00
		Total Incentive	**$4.01**	**$2.01**

Annual Energy

Table A-30 presents annual total net electrical output in MWh from renewable IC engines and microturbines for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-30: Annual Electric Energy Totals by Technology and PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
IC Engine-R	**Total***	**20,101**	**18,732**	**9,014**	**N/A**	**47,848 †**
	M	3,172	11,864	0	**N/A**	15,036
	E	16,929	6,868	9,014	**N/A**	32,811

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
MT-R	**Total***	**3,517**	**2,414**	**N/A**	**932**	**6,863 †**
	M	1079	1,361	**N/A**	561	3,002
	E	2,438	1,053	**N/A**	370	3,861

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-31 presents quarterly total net electrical output in MWh for renewable IC engines and microturbines. These tables also show subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-31: Quarterly Electric Energy Totals by Technology

Technology	Fuel	Basis	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
IC Engine	**R**	**Total**	**13,503**	**12,253**	**10,911**	**11,179**	**47,848 †**
		M	4,132	3,731	3,339	3,834	15,036
		E	9,371	8,523	7,572	7,345	32,811 †
MT	**R**	**Total**	**1,953**	**2,194**	**1,467**	**1,249**	**6,863 †**
		M	941	985	599	477	3,002
		E	1,012	1,209	868	771	3,861 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-32 presents total net electrical output in kW for renewable IC engines and microturbines during the peak hour of 3:00 to 4:00 P.M. (PDT) on June 20, 2008. The table also shows counts of systems and total operational system capacity in kW.

Table A-32: CAISO Peak Hour Demand Impacts by Technology

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
IC Engine-R	17	11,192	5,910 †
MT-R	21	3,784	871 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-33 presents the total net electrical output in kW for renewable IC engines and microturbines during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-33: Electric Utility Peak Hours Demand Impacts by Technology

PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	21,827	7/8/2008	17	**IC Engine**	10	5,683	2,795
SCE	22,404	6/20/2008	16		7	5,509	2,931
SDG&E	4,348	10/1/2008	15		N/A	N/A	N/A

PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	21,827	7/8/2008	17	**MT**	13	1,970	376
SCE	22,404	6/20/2008	16		4	1,040	287
SDG&E	4,348	10/1/2008	15		4	774	112

<u>Capacity Factors</u>

Weighted average capacity factors indicate renewable IC engines and microturbines performances relative to a system-rebated kW for specific time periods. Table A-34 presents annual weighted average capacity factors for renewable IC engines and microturbines for the year 2008.

Table A-34: Annual Capacity Factors by Technology

Technology	Annual Capacity Factor* (kWyear/kWyear)
IC Engine-R	0.487 †
MT-R	0.211 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-35 presents annual weighted average capacity factors for renewable IC engines and microturbines for each PA for the year 2008.

Table A-35: Annual Capacity Factors by Technology and PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
IC Engine-R	0.481 †	0.492 †	0.486 [a]	N/A
MT-R	0.264 †	0.212 [a]	N/A	0.139

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-19 and Figure A-20 plot profiles of monthly weighted average capacity factors for renewable IC engines and microturbines for each PA.

Figure A-19: Monthly Capacity Factors by PA—Renewable IC Engine

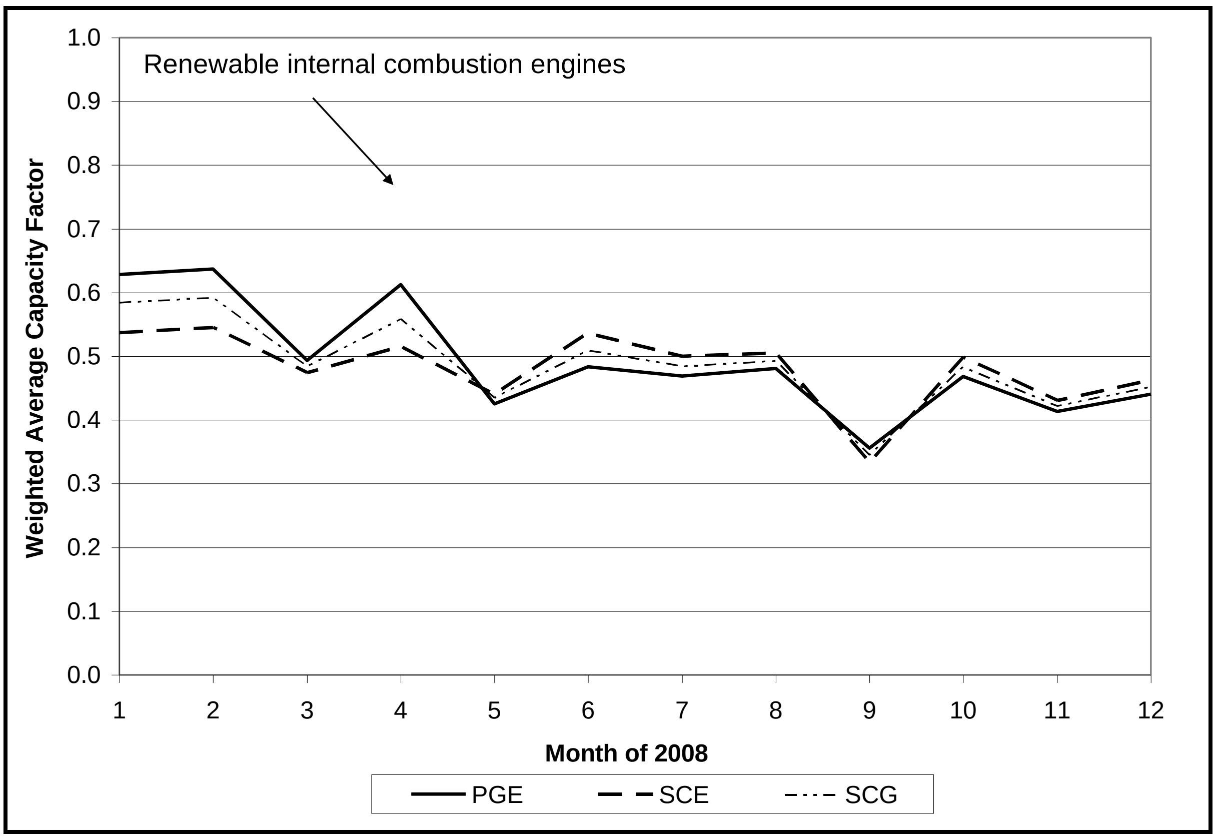


Figure A-20: Monthly Capacity Factors by PA—Renewable Microturbine

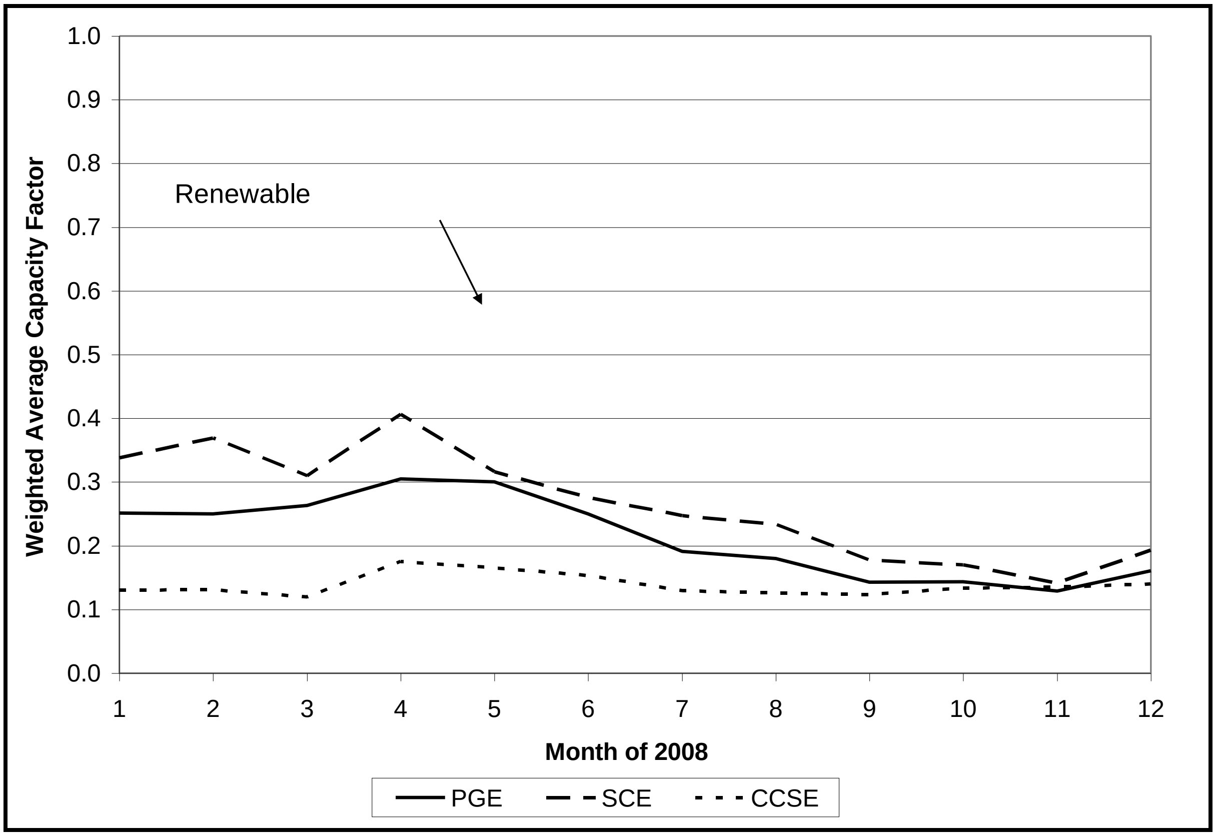


Figure A-21 and Figure A-22 plot the profiles of hourly weighted average capacity factor for renewable IC engines and microturbines for each PA from the morning to early evening during the day of the annual peak hour, June 20, 2008. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the charts.

Figure A-21: CAISO Peak Day Capacity Factors by PA—Renewable IC Engine

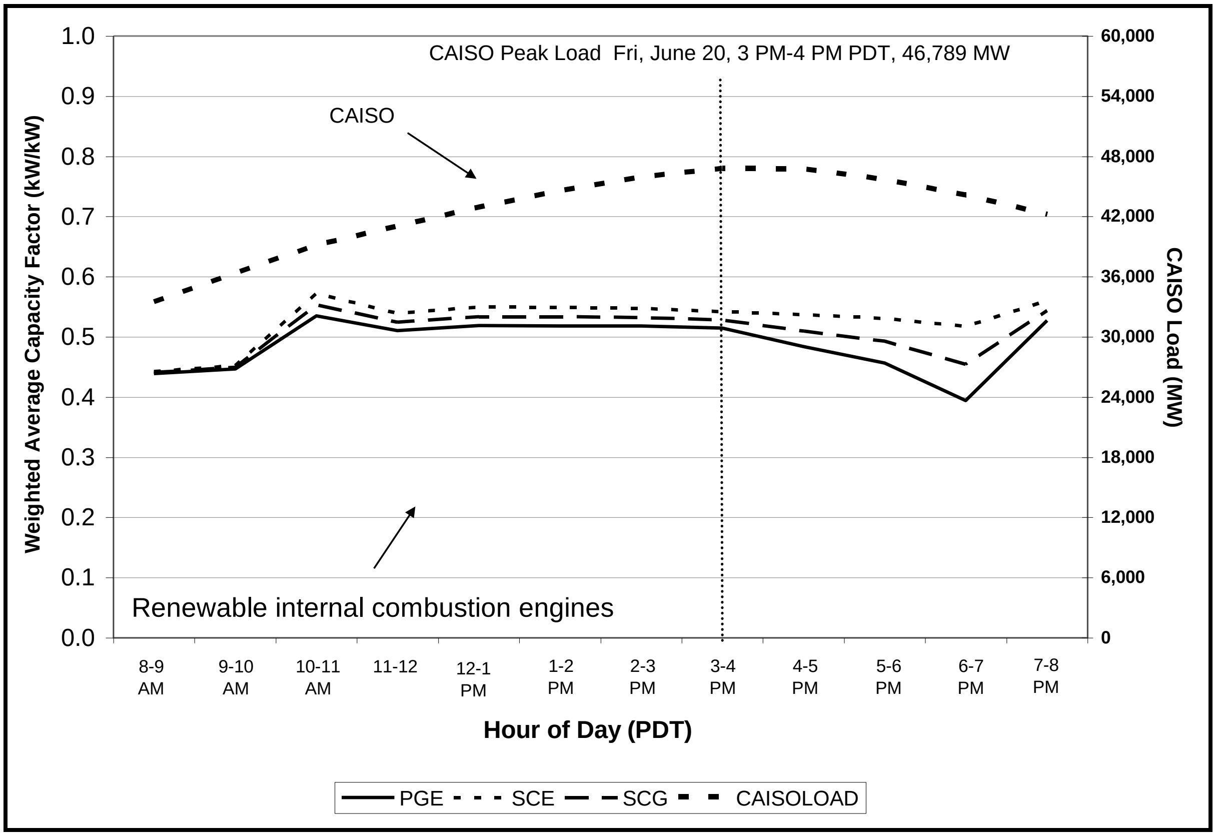


Figure A-22: CAISO Peak Day Capacity Factors by PA—Renewable Microturbine

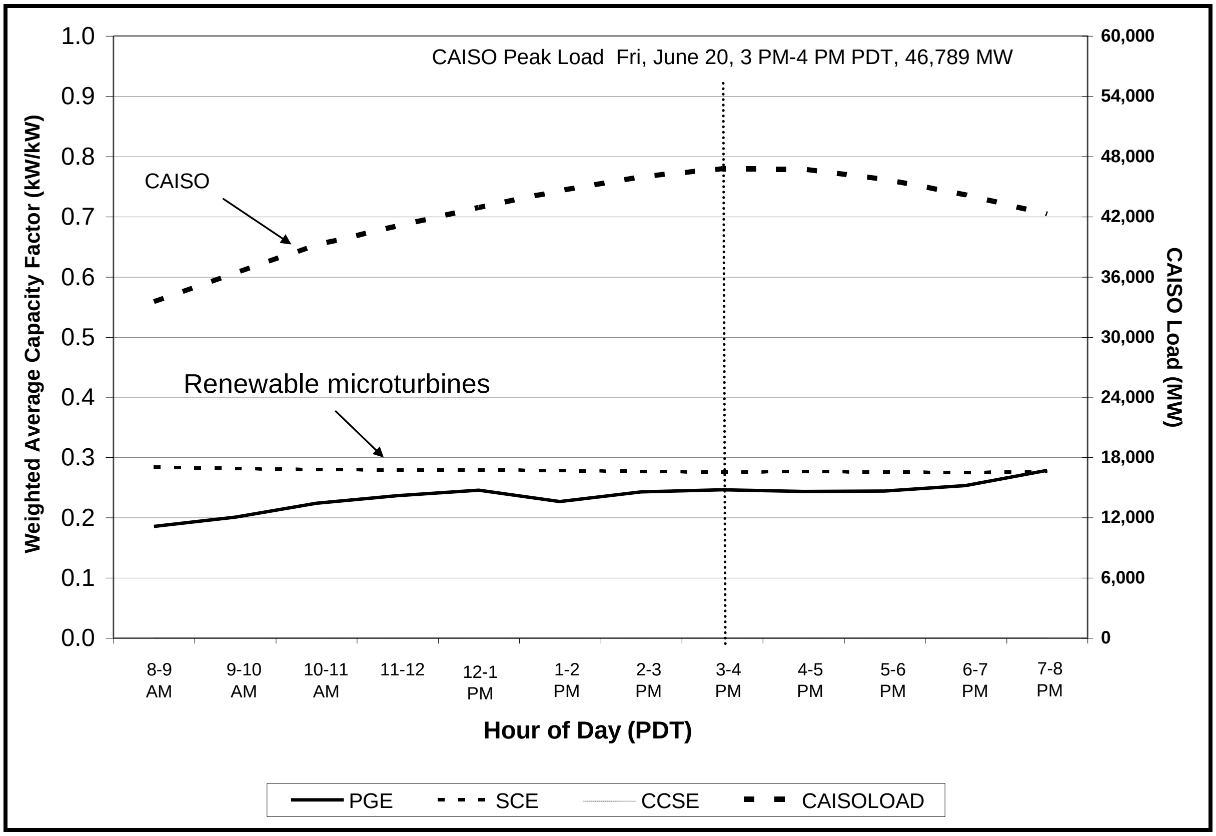


Figure A-23, Figure A-24, and Figure A-25 plot profiles of hourly weighted average capacity factors for renewable IC engines and microturbines directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SDG&E is the only electric utility without renewable IC engines, so no curve appears for that technology on its peak day.

Figure A-23: Electric Utility Peak Day Capacity Factors by Technology—PG&E

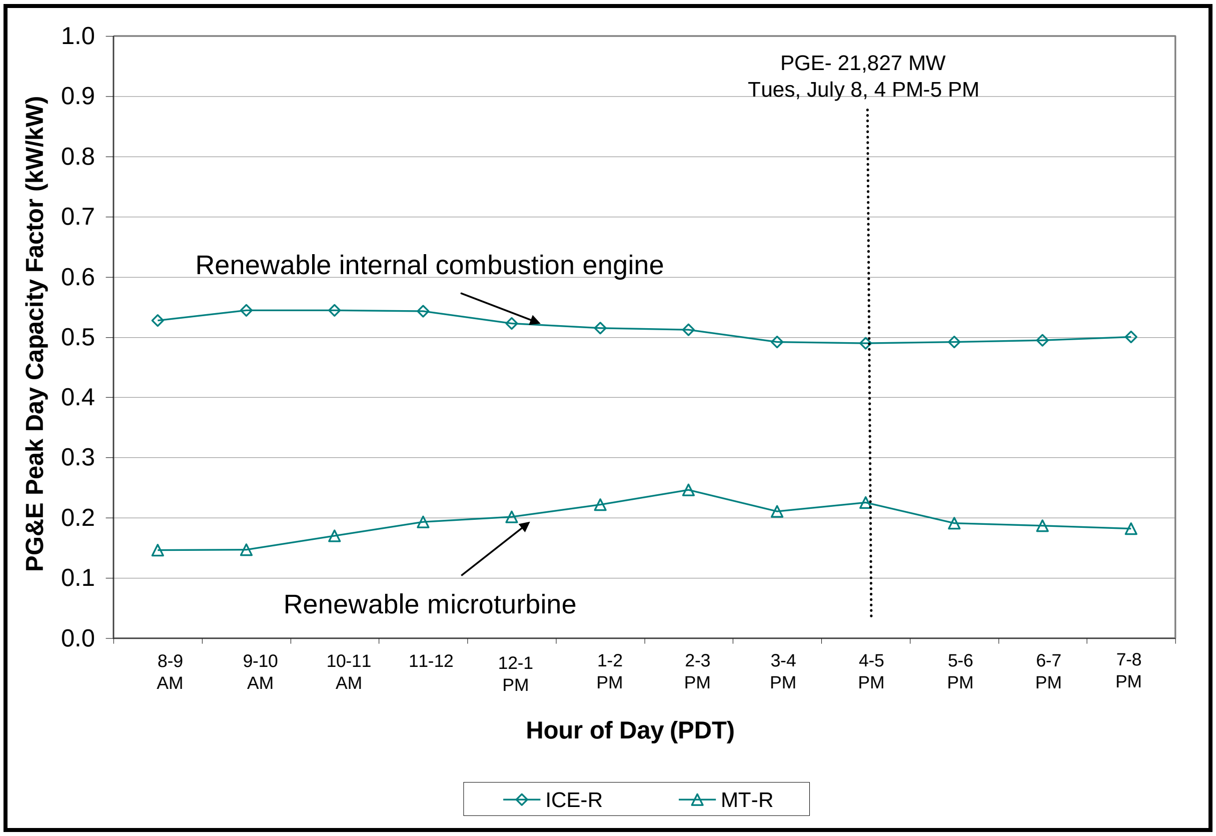


Figure A-24: Electric Utility Peak Day Capacity Factors by Technology—SCE

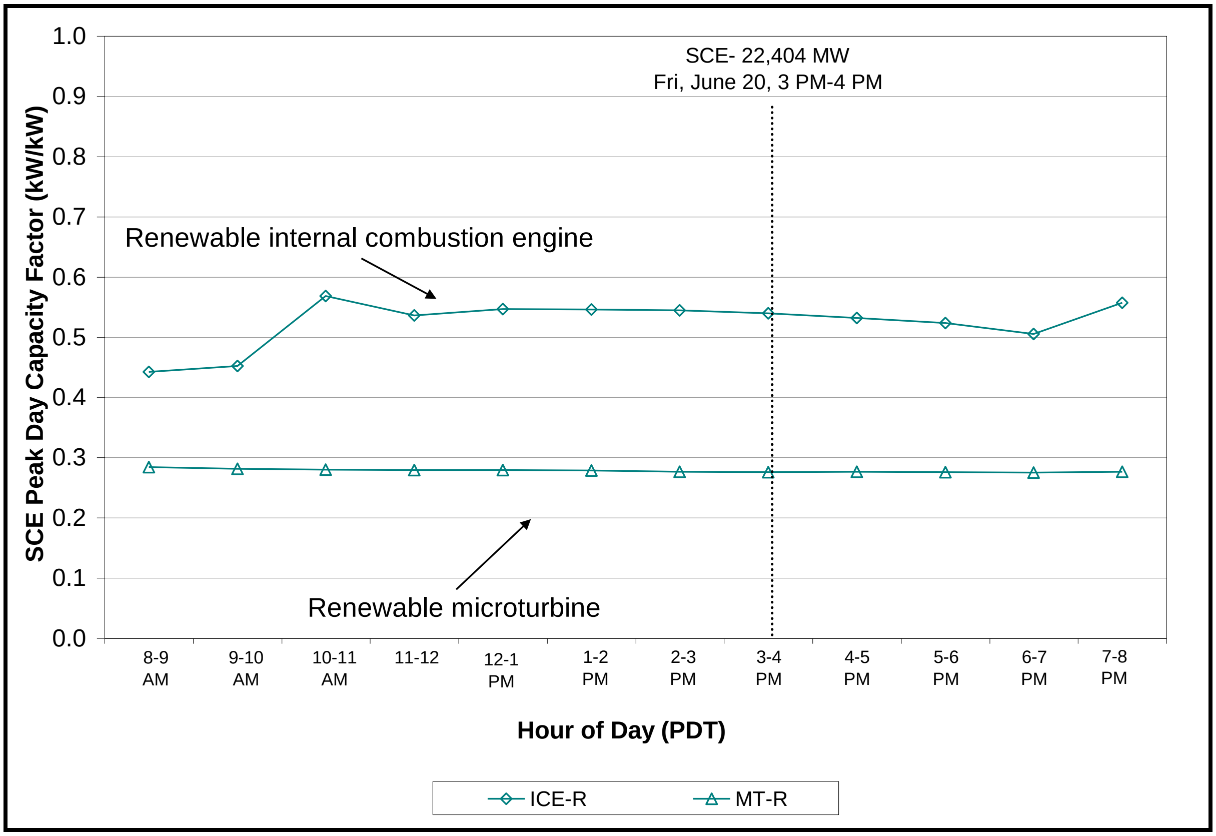
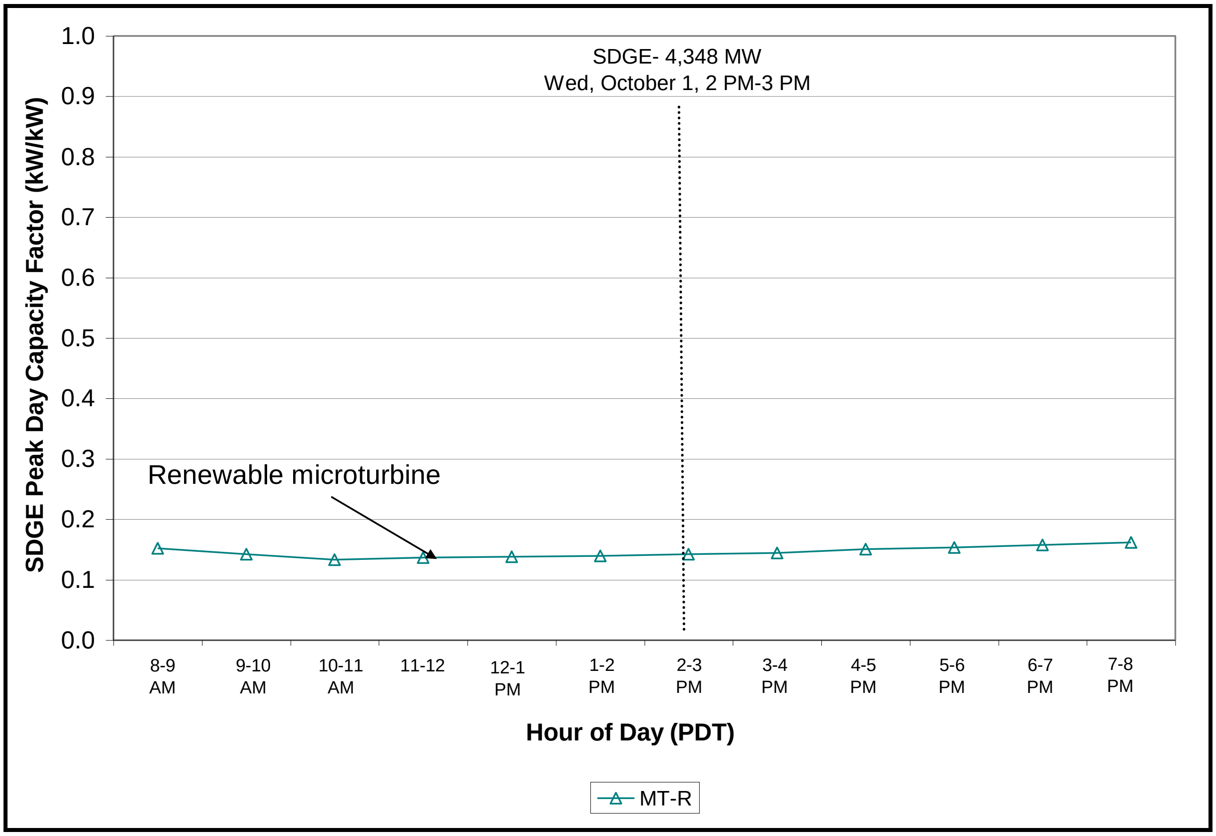


Figure A-25: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



A.4 Non-Renewable Power Systems

This section describes impacts of non-renewable power systems. It begins with fuel cells and proceeds to gas turbines, IC engines, and microturbines.

Natural Gas Fuel Cells

Costs

Table A-36 lists total eligible costs, SGIP incentives, and other incentives for natural gas fuel cells.

Table A-36: Complete and Active System Costs

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
FC	**N**	Eligible Cost	$63.80	$9.73
		Incentive	$19.68	$3.56
		Other Incentive	$2.95	$0.00
		Total Incentive	**$22.63**	**$3.56**

Annual Energy

Table A-37 presents annual total net electrical output in MWh from natural gas fuel cells for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-37: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC-N	**Total***	**23,776 †**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		**10,318**	**44,050 †**
	M	15,320			10,317	34,171
	E	8,456			1	9,879

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-38 presents quarterly total net electrical output in MWh for natural gas fuel cells. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-38: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
FC	**N**	**Total**	**13,663**	**12,908**	**10,273**	**7,204**	**44,050 †**
		M	10,689	10,342	8,131	5,009	34,171
		E	2,974	2,566	2,142	2,196	9,879 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-39 presents total net electrical output in kW for natural gas fuel cells during the peak hour of 3:00 to 4:00 P.M. (PDT) on June 20, 2008. The table also shows counts of systems and total operational system capacity in kW.

Table A-39: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
FC-N	15	8,450	5,999

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-40 presents the total net electrical output in kW for natural gas fuel cells during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-40: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	21,827	7/8/2008	17	**FC**	8	4,500	2,978
SCE	22,404	6/20/2008	16	**FC**	2	700	544
SDG&E	4,348	10/1/2008	15	**FC**	4	2,250	678

Capacity Factors

Weighted average capacity factors indicate natural gas fuel cell performance relative to a system-rebated kW for specific time periods. Table A-41 presents annual weighted average capacity factors for natural gas fuel cells for the year 2008.

Table A-41: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC-N	0.594 †

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-42 presents annual weighted average capacity factors for natural gas fuel cells for each PA for the year 2008.

Table A-42: Annual Capacity Factors by PA

Technology	PG&E	SCE	SCG	CCSE
		INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
FC-N	0.601 †			0.525

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Figure A-26 plots profiles of monthly weighted average capacity factors for natural gas fuel cells for each PA.

Figure A-26: Monthly Capacity Factors by Technology and PA

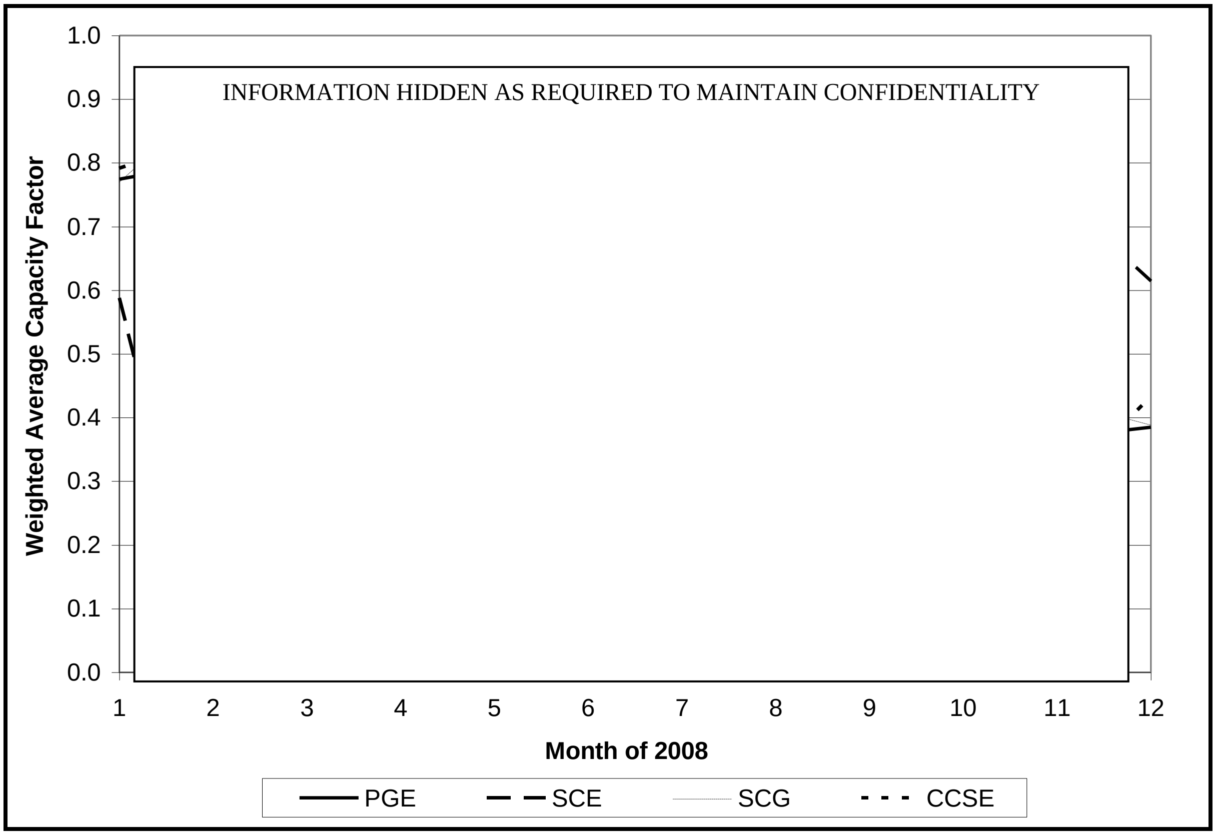


Figure A-27 plots the profiles of hourly weighted average capacity factor for natural gas fuel cells for each PA from the morning to early evening during the day of the annual peak hour, June 20, 2008. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-27: CAISO Peak Day Capacity Factors by PA

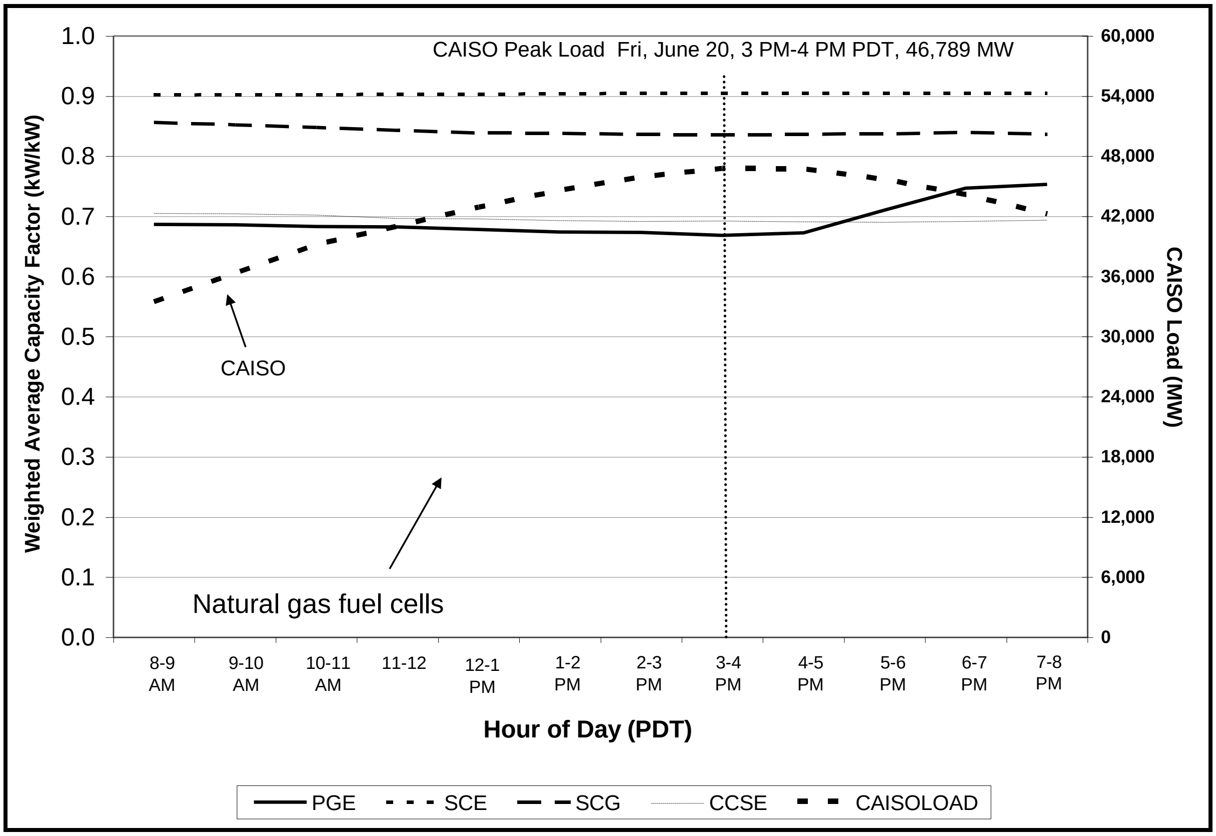


Figure A-28, Figure A-29, and Figure A-30 plot profiles of hourly weighted average capacity factors for natural gas fuel cells directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-28: Electric Utility Peak Day Capacity Factors—PG&E

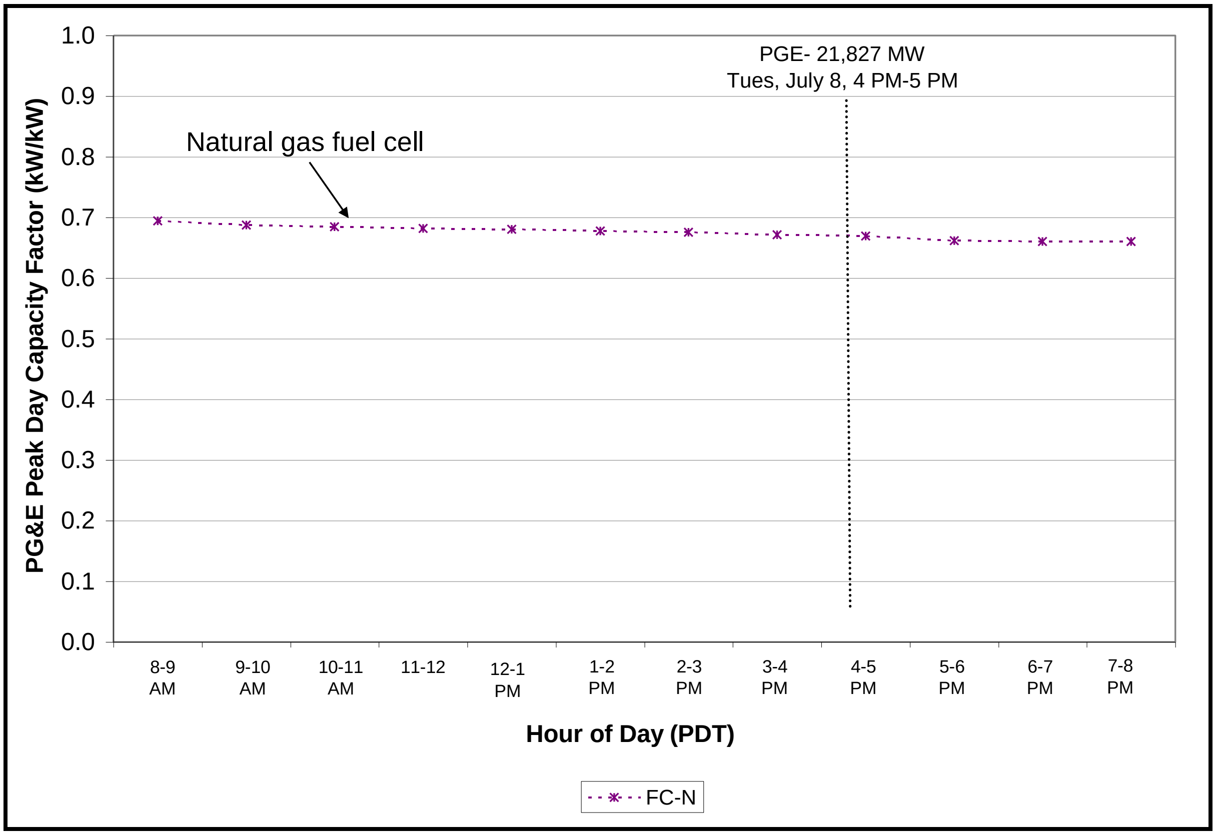


Figure A-29: Electric Utility Peak Day Capacity Factors—SCE

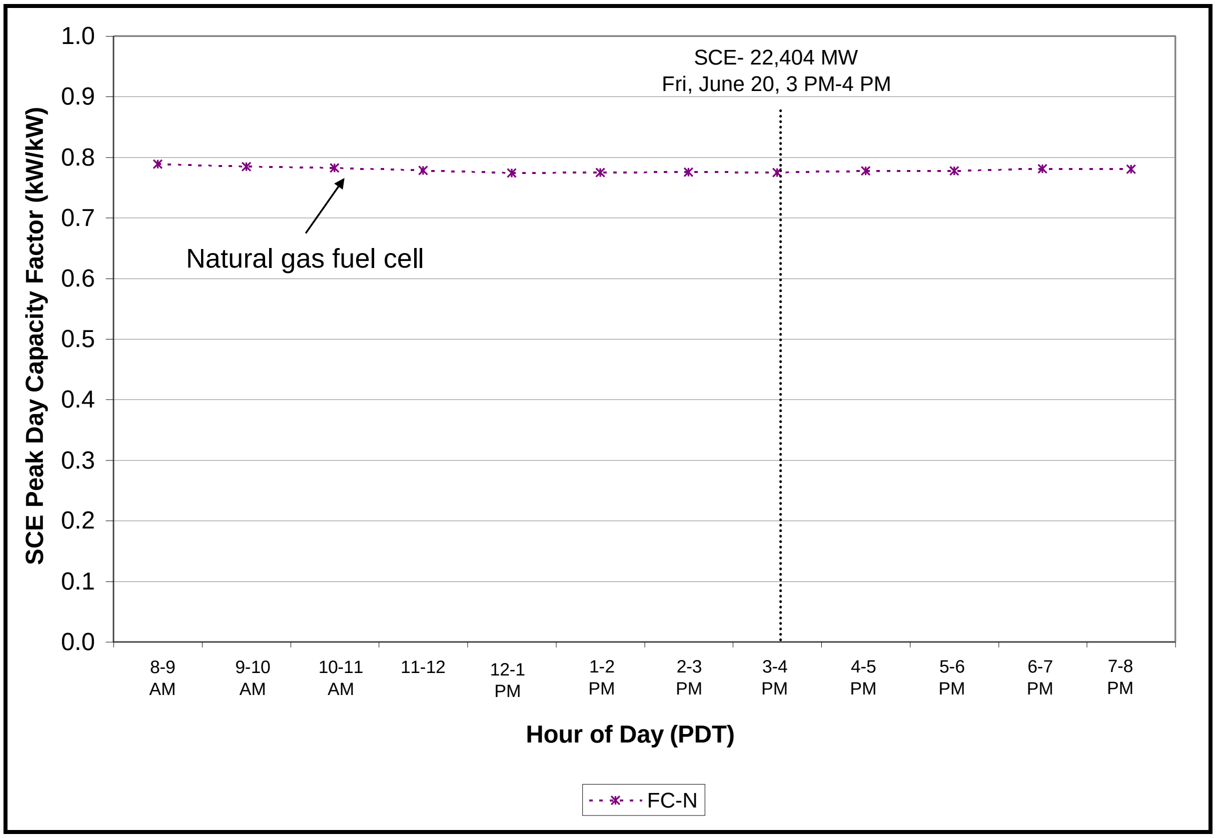
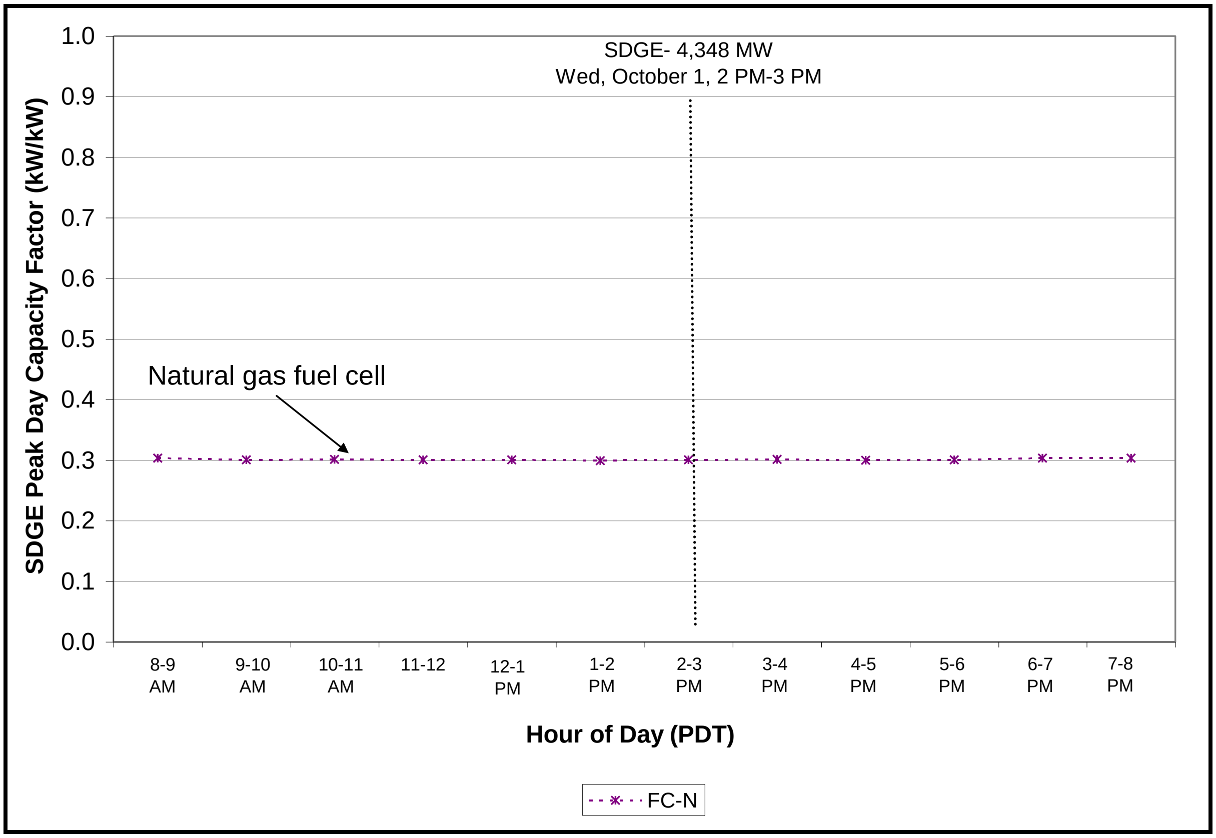


Figure A-30: Electric Utility Peak Day Capacity Factors—SDG&E



Natural Gas Turbines, Internal Combustion Engines, and Microturbines

Costs

Table A-43 lists total eligible costs, SGIP incentives, and other incentives for natural gas turbine, IC engine, and microturbine systems.

Table A-43: Complete and Active System Costs by Technology

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
GT	**N**	Eligible Cost	$37.26	$15.03
		Incentive	$4.46	$2.00
		Other Incentive	$0.00	$0.00
		Total Incentive	**$4.46**	**$2.00**
IC Engine	**N**	Eligible Cost	$301.39	$72.22
		Incentive	$75.77	$11.58
		Other Incentive	$0.86	$0.05
		Total Incentive	**$76.63**	**$11.63**
MT	**N**	Eligible Cost	$56.14	$20.25
		Incentive	$14.71	$3.86
		Other Incentive	$1.06	$0.00
		Total Incentive	**$15.77**	**$3.86**

Annual Energy

Table A-44 presents annual total net electrical output in MWh from natural gas turbine, IC engine, and microturbine systems for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-44: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
GT-N	**Total***	**21,799 [a]**	**N/A**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		**114,156 †**
	M	0	N/A			61,548
	E	21,799	N/A			52,607
IC Engine-N	**Total***	**70,469 †**	**43,312 †**	**95,091 †**	**19,058 †**	**227,930 †**
	M	20,280	12,971	44,946	15,346	93,543
	E	50,189	30,342	50,145	3,711	134,387
MT-N	**Total***	**29,550 †**	**11,061 †**	**24,745 †**	**2,606 †**	**67,963 †**
	M	10,536	8,111	11,559	2,157	32,362
	E	19,014	2,950	13,187	449	35,600
	Total	**121,817**	**54,373**	**151,066**	**82,792**	**410,048**

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-45 presents quarterly total net electrical output in MWh for natural gas turbine, IC engine, and microturbine systems. These tables also show subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-45: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2008 (MWh)	Q2-2008 (MWh)	Q3-2008 (MWh)	Q4-2008 (MWh)	Total* (MWh)
GT	**N**	**Total**	**24,845**	**31,131**	**32,439**	**25,742**	**114,156 †**
		M	12,746	17,383	17,340	14,080	61,548
		E	12,099	13,747	15,099	11,662	52,607 [a]
IC Engine	**N**	**Total**	**54,537**	**54,822**	**68,381**	**50,190**	**227,930 †**
		M	25,228	22,310	27,222	18,783	93,543
		E	29,308	32,512	41,159	31,408	134,387 †
MT	**N**	**Total**	**18,201**	**16,221**	**16,482**	**17,059**	**67,963 †**
		M	9,224	8,033	7,479	7,626	32,362
		E	8,977	8,187	9,003	9,433	35,600 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-46 presents total net electrical output in kW for natural gas turbine, IC engine, and microturbine systems during the peak hour of 3:00 to 4:00 P.M. (PDT) on June 20, 2008. The table also shows counts of systems and total operational system capacity in kW.

Table A-46: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
GT-N	6	17,643	14,728 †
IC Engine-N	206	129,298	28,878 †
MT-N	108	16,908	7,638 †
Total	**320**	**163,849**	**51,245**

* Except for the total, [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-47 presents the total net electrical output in kW for natural gas turbine, IC engine, and microturbine systems during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-47: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	21,827	7/8/2008	17	**GT-N**	3	4,016	2,309
				IC Engine-N	89	51,062	8,579
				MT-N	40	6,334	2,910
				Total	**132**	**61,412**	**13,798**
SCE	22,404	6/20/2008	16	**GT-N**	1	4,500	4,132
				IC Engine-N	90	62,071	18,268
				MT-N	47	7,936	2,991
				Total	**138**	**74,507**	**25,391**
SDG&E	4,348	10/1/2008	15	**GT-N**	2	9,127	7,987
				IC Engine-N	21	13,224	3,458
				MT-N	13	1,128	167
				Total	**36**	**23,479**	**11,612**

Capacity Factors

Weighted average capacity factors indicate natural gas turbine, IC engine, and microturbine systems performance relative to a system-rebated kW for specific time periods. Table A-48 presents annual weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems for the year 2008.

Table A-48: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
GT-N	0.737 †
IC Engine-N	0.200 †
MT-N	0.449 †

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-49 presents annual weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems for each PA for the year 2008.

Table A-49: Annual Capacity Factors by Technology and PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
GT-N	0.618 [a]	N/A	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY	
IC Engine-N	0.159 †	0.208 †		
MT-N	0.522 †	0.329 †		

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Figure A-31, Figure A-32, and Figure A-33 plot profiles of monthly weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems for each PA.

Figure A-31: Monthly Capacity Factors by Technology—Natural Gas Turbine

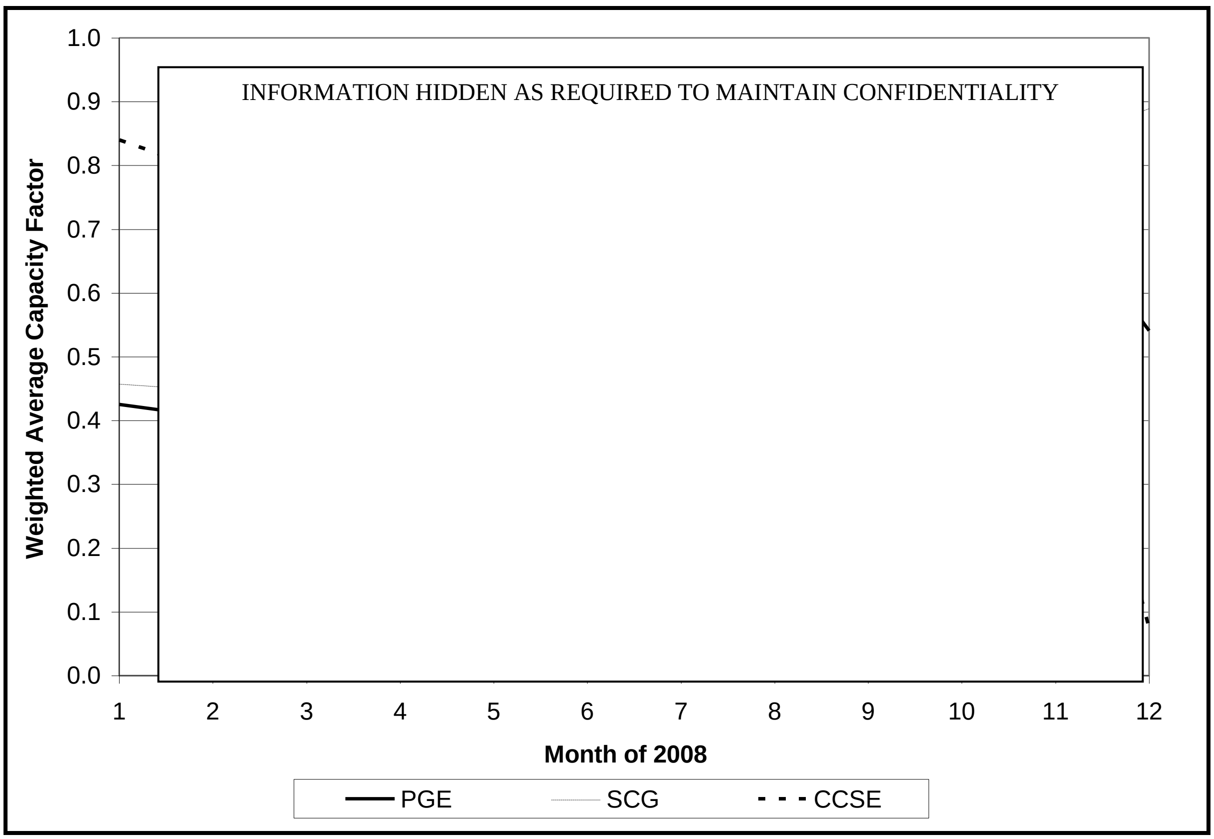


Figure A-32: Monthly Capacity Factors by Technology—Natural Gas IC Engine

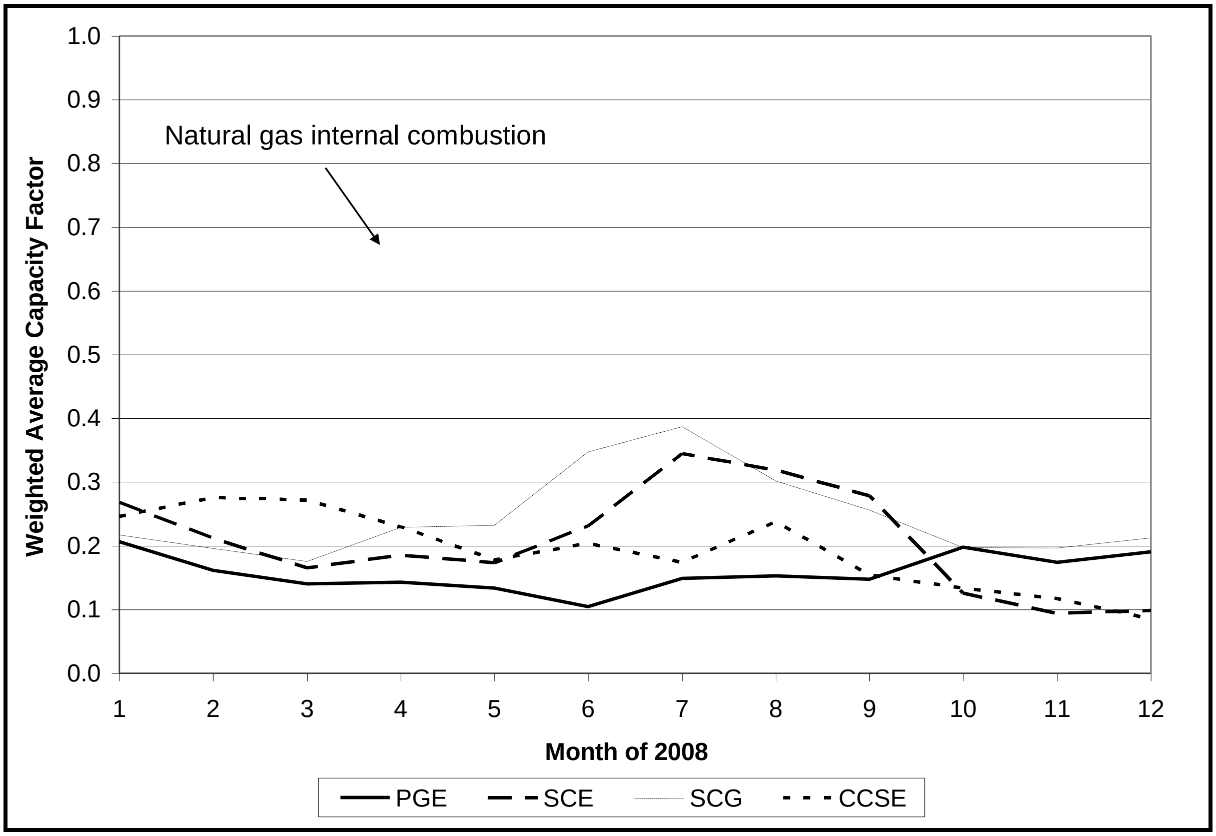


Figure A-33: Monthly Capacity Factors by Technology—Natural Gas Microturbine

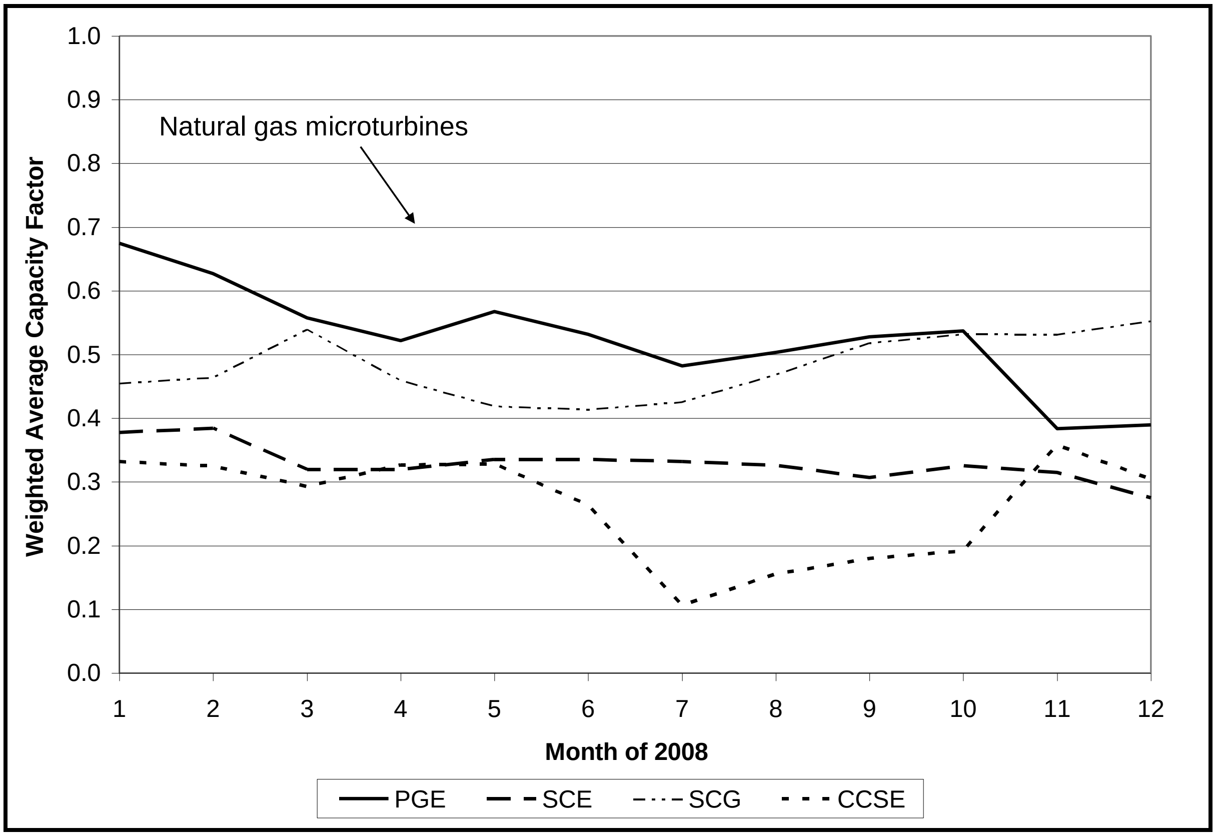


Figure A-34 plots the profiles of hourly weighted average capacity factor for natural gas turbine, IC engine, and microturbine systems from the morning to early evening during the day of the annual peak hour, June 20, 2008. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-34: CAISO Peak Day Capacity Factors by Technology

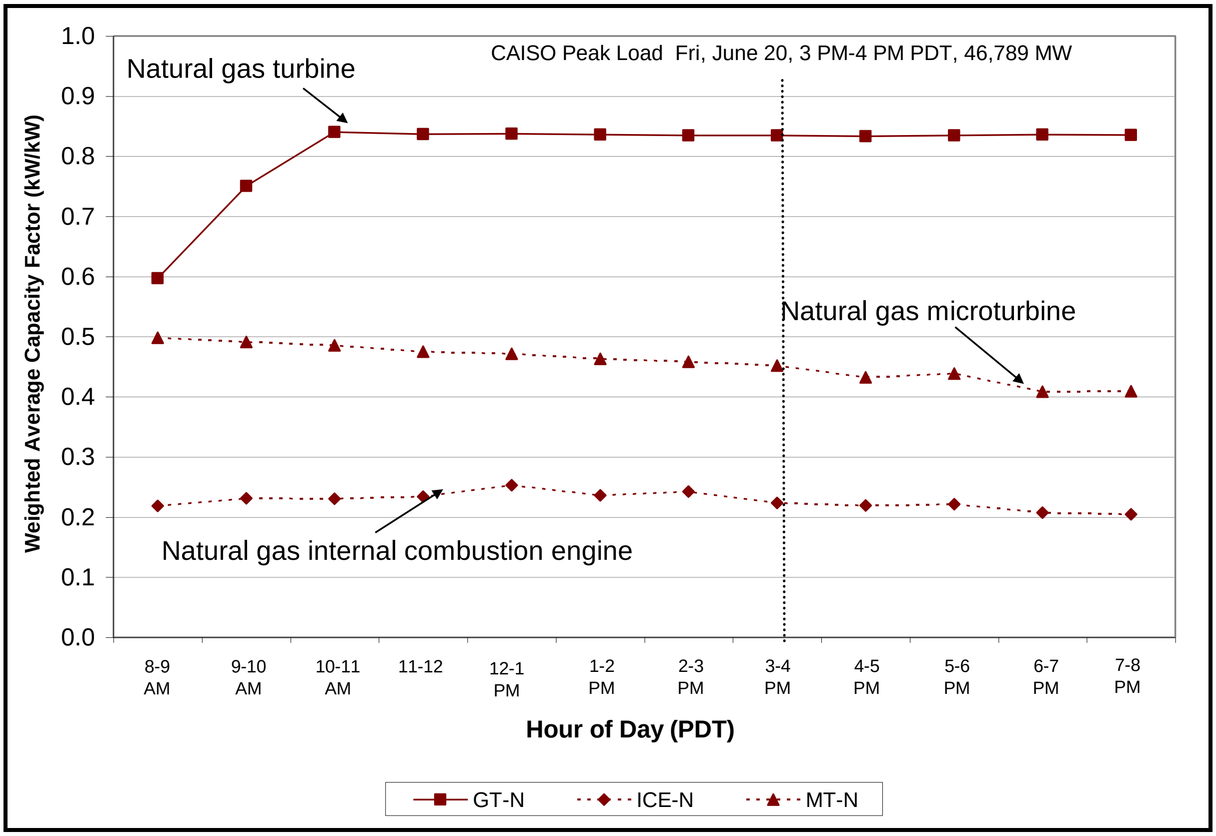


Figure A-35, Figure A-36, and Figure A-37 plot the profiles of hourly weighted average capacity factor for natural gas turbine, IC engine, and microturbine systems for each PA from the morning to early evening during the day of the annual peak hour, June 20, 2008. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-35: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas Turbine

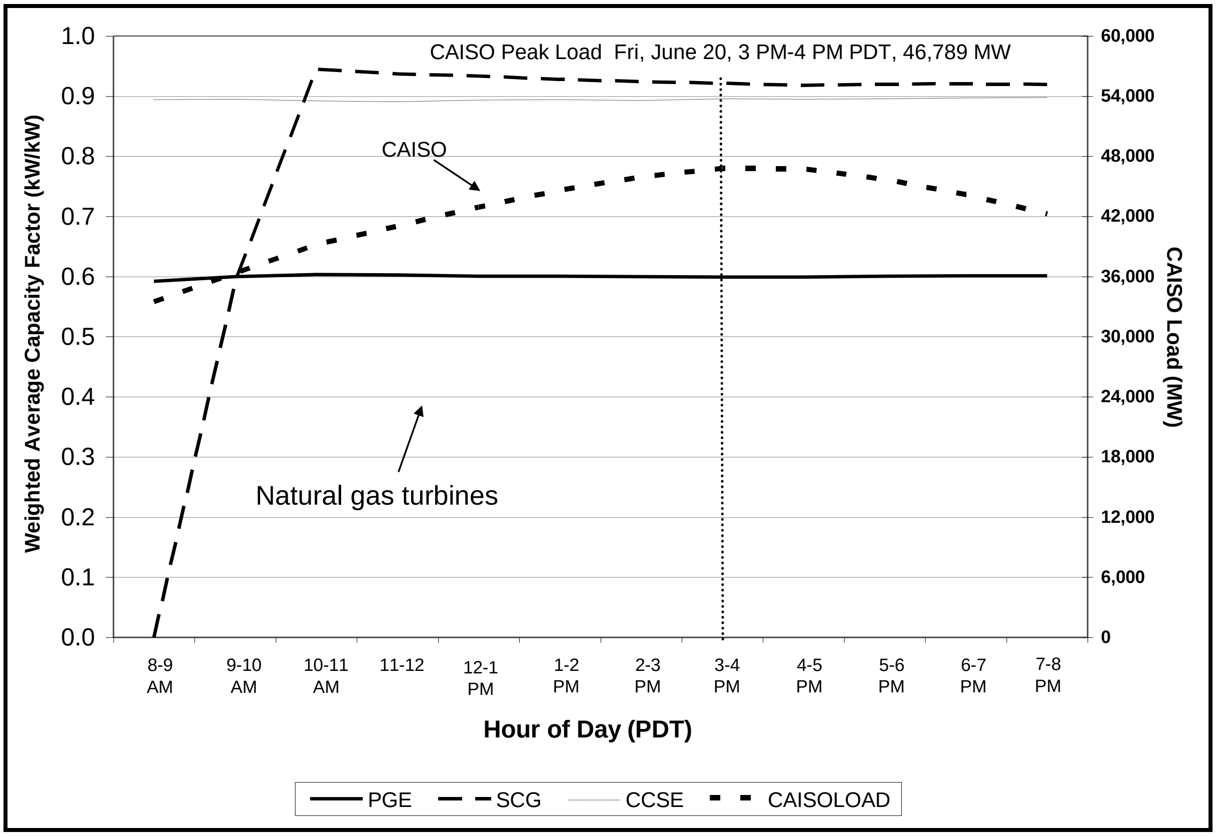


Figure A-36: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas IC Engine

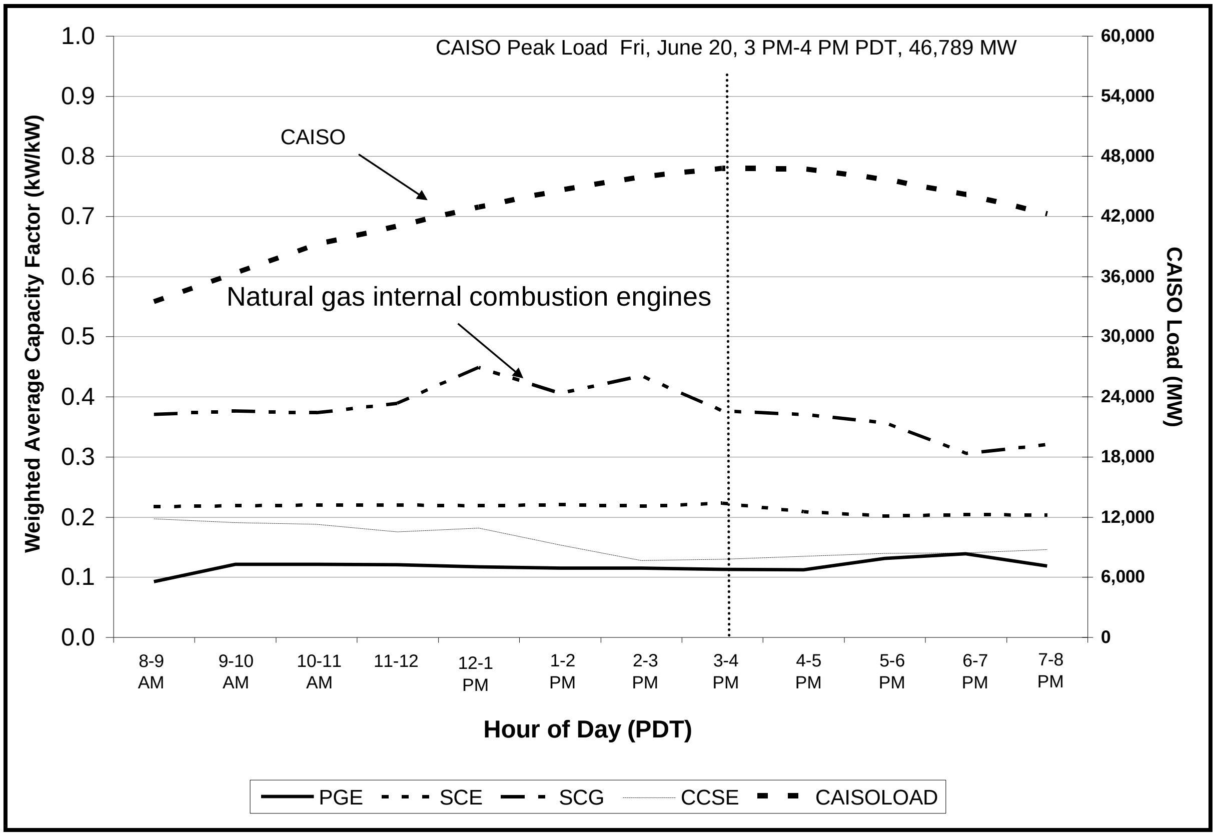


Figure A-37: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas Microturbine

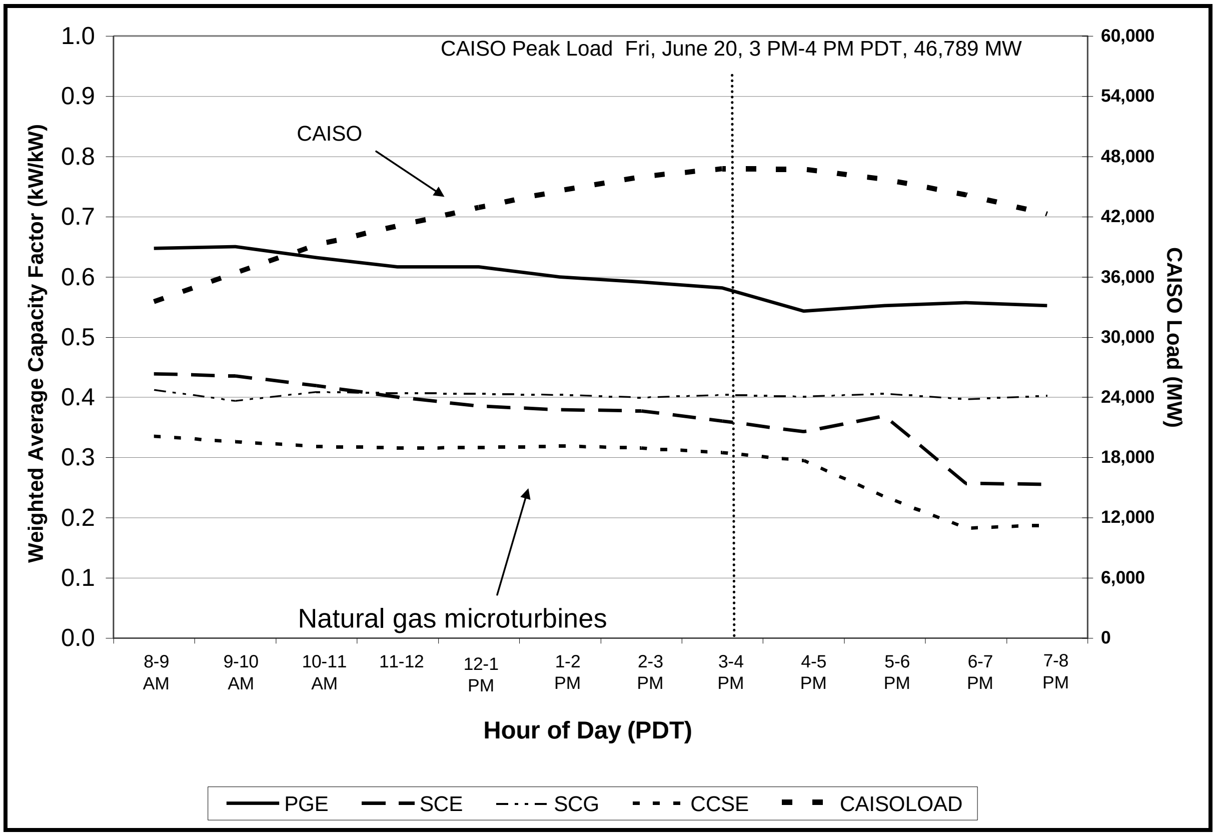


Figure A-38, Figure A-39, and Figure A-40 plot profiles of hourly weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-38: Electric Utility Peak Day Capacity Factors by Technology—PG&E

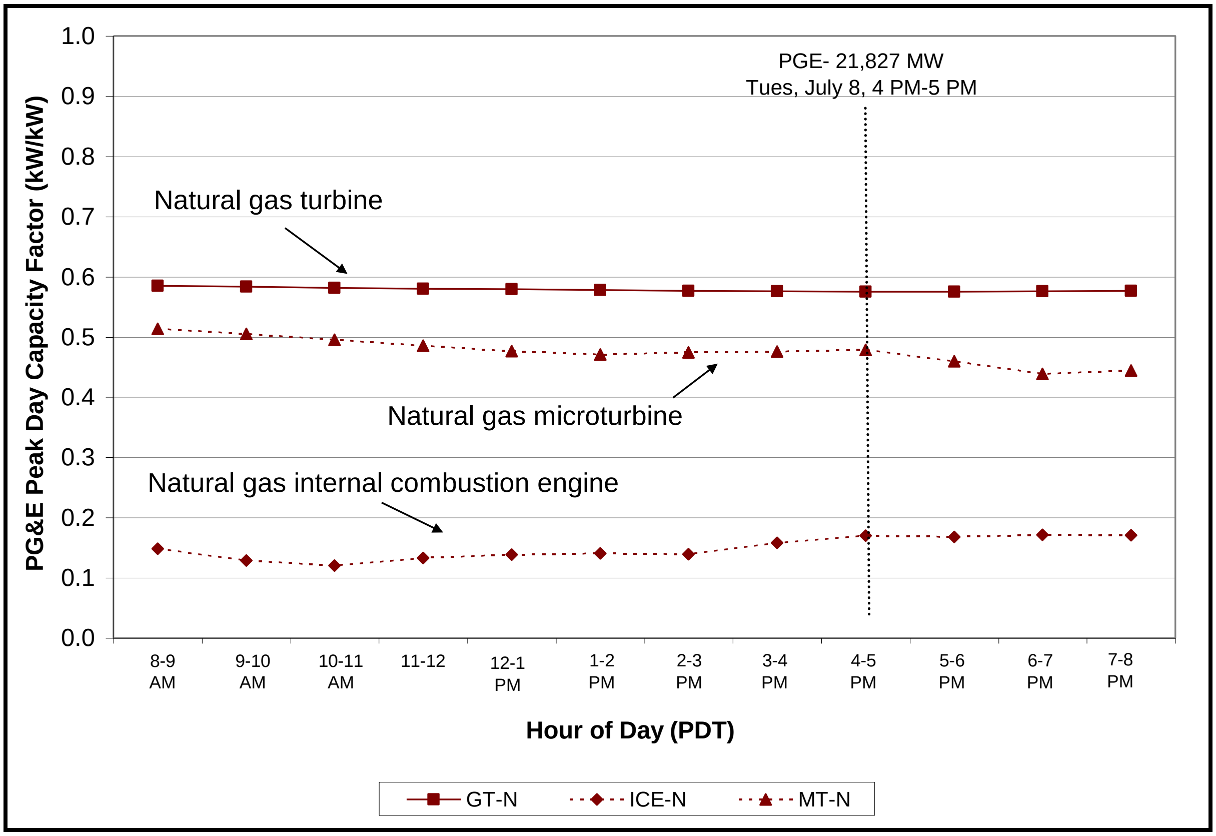


Figure A-39: Electric Utility Peak Day Capacity Factors by Technology—SCE

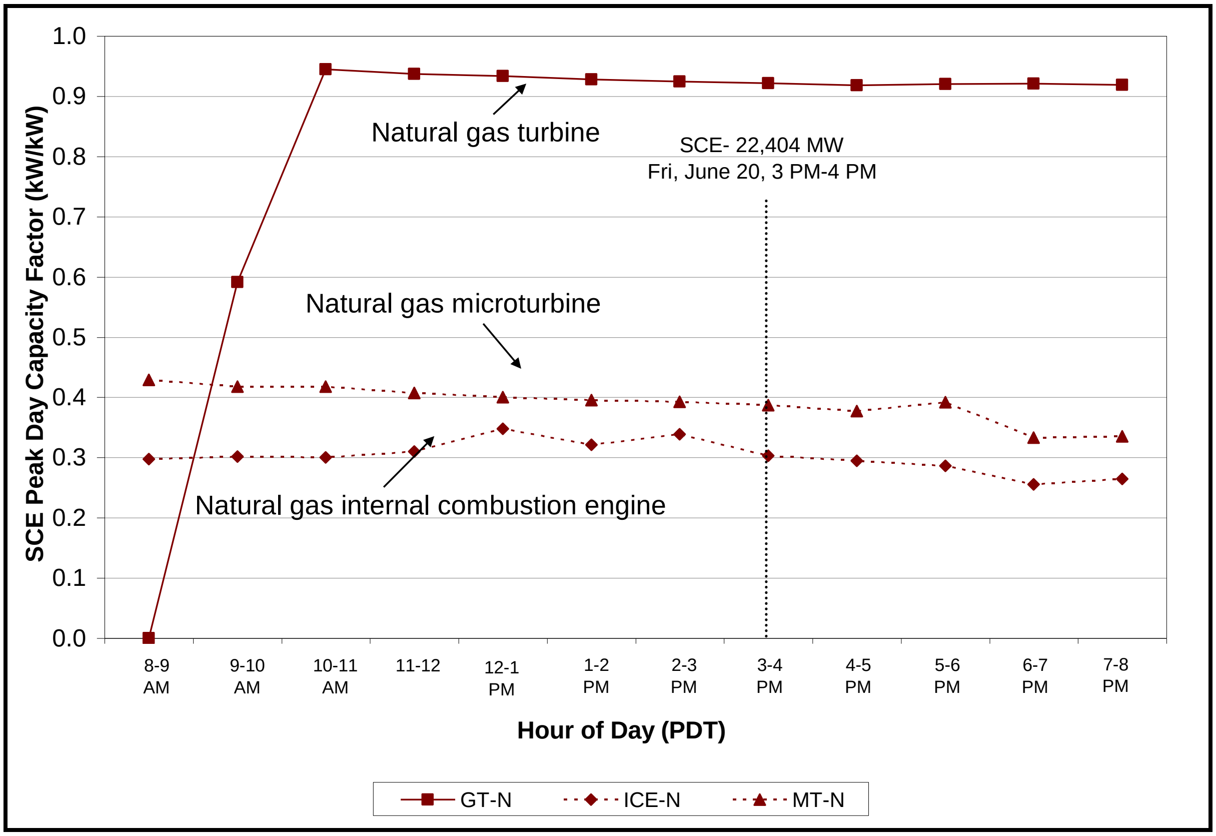
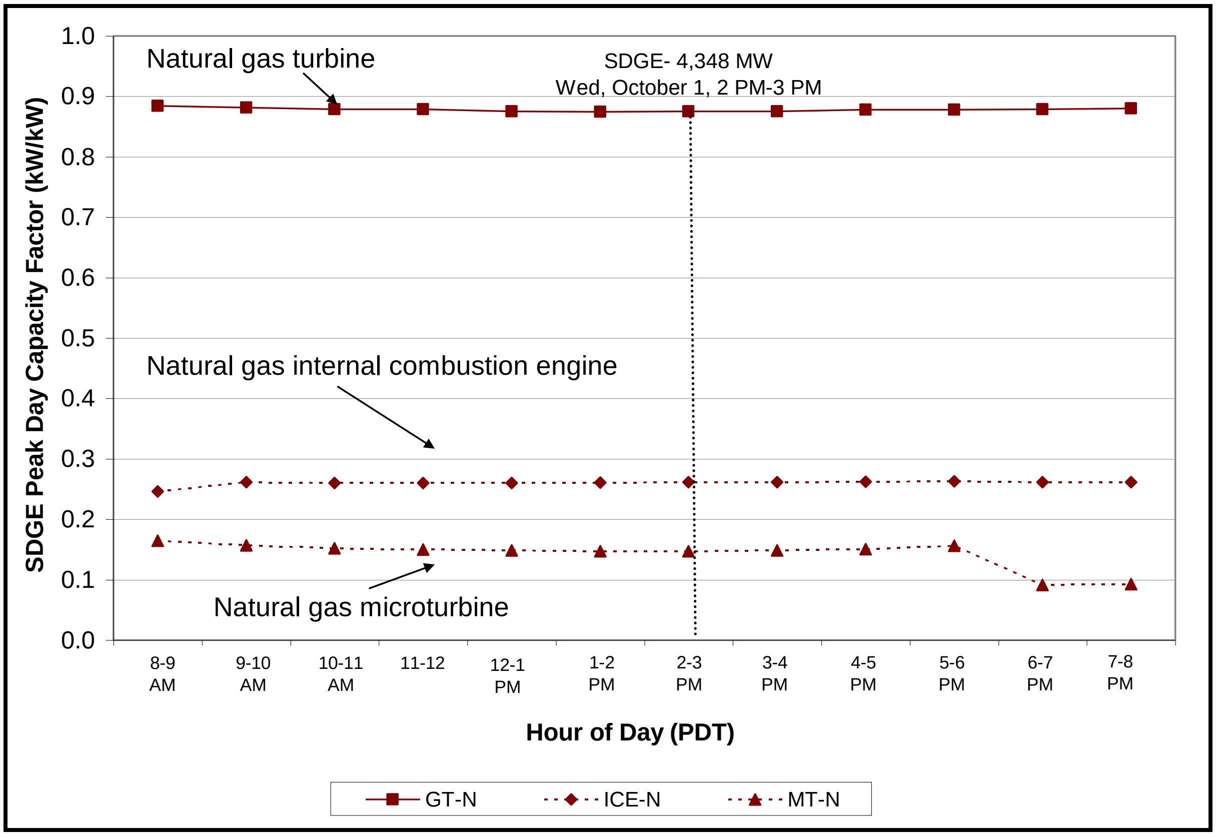


Figure A-40: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



Appendix B

Greenhouse Gas Emissions Impacts Methodology

This appendix describes the methodology used to estimate the impacts on specific greenhouse gas (GHG) emissions from the operation of SGIP systems on-line during 2008.[1] The GHG emissions considered in this analysis are carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants whose emissions are potentially affected by the operation of SGIP systems. Specifically, the operation of photovoltaic projects, wind turbines, and non-renewable microturbines, gas turbines, and internal combustion engines directly affect CO_2 emissions, while renewable microturbines, gas turbines, and internal combustion engines directly affect both CH_4 and CO_2 emissions.

B.1 Overview

To assess GHG emissions impacts the emissions of rebated SGIP DG systems were first calculated. Next, the baseline emissions that would have occurred in PY08 in the program's absence were estimated. GHG impacts attributed to the program were then calculated as the difference between the two scenarios. GHG emissions streams for SGIP DG systems and corresponding baseline scenarios vary depending on SGIP DG system type as described below.

- When in operation, power generated by SGIP systems of all types directly displaces grid electricity that would have been generated from central station power plants.[2] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The CO_2 emissions from these conventional power plants are estimated on an hour-by-hour basis over all 8,784 hours of 2008.[3] The CO_2 estimates are based on a methodology developed by Energy and Environmental

---

[1] Calendar year 2008 was a leap year consisting of 8,784 hours rather than the typical 8,760 hours.

[2] In this analysis, GHG emissions from SGIP facilities are compared only to GHG emissions from utility power generation that could be subject to economic dispatch (i.e., central station natural gas-fired combined cycle facilities and simple cycle gas turbine peaking plants). It is assumed that operation of SGIP facilities have no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP facilities to nuclear or hydroelectric facilities is not made as neither of these facilities is subject to dispatch.

[3] Consequently, during those hours when a SGIP facility is not in operation, displacement of CO_2 emissions from central station power plants is equal to zero.

Economics, Inc. (E3) and made publicly available on its website as part of its avoided cost calculator.[4]

- The operation of specific renewable and non-renewable-fueled cogeneration systems such as microturbines, fuel cells, gas turbines, and reciprocating internal combustion (IC) engines emit CO_2. While CO_2 emissions from central power plants are avoided when SGIP systems are in operation, the SGIP cogeneration plants emit CO_2 as well. Emissions of CO_2 from SGIP facilities are estimated based on the hour-by-hour electricity generated from SGIP facilities over all 8,784 hours of the 2008 year.
- Waste heat recovered from the operation of cogeneration systems displaces natural gas that would have been used to fuel boilers responsible for satisfying heating loads at the customer host site. This displaces accompanying CO_2 emissions from the boilers, which are taken into account by calculating the CO_2 emissions avoided from using natural gas to fuel boilers. Since virtually all carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in the estimated reduction in GHG emissions attributable to SGIP systems.
- SGIP systems delivering recovered heat to absorption chillers are assumed to reduce need to operate electric chillers operated using electricity purchased from the utility company. Estimates of avoided CO_2 emissions are based on the hour-by-hour electricity savings from reduced reliance on central station facilities.
- In the SGIP Sixth-Year Impact Evaluation Final Report,[5] the assumption was made that renewable fuel use facilities with a rebated capacity less than 400 kW, such as dairies, small landfill sites, and wastewater treatment plants, were assumed to capture CH_4 that typically would have been vented and instead used it for energy purposes. Beginning with the SGIP Seventh-Year Impact Evaluation Final Report[6] and continued in this Impact Report, the baseline differentiates between wastewater treatment plants, dairies, and landfill gas facilities. All dairies are assumed to have previously vented the CH_4. All landfill gas facilities are assumed to have previously captured and flared the CH_4. For wastewater treatment plants, the threshold of 150 kW was chosen as the cut-off point between venting and flaring CH_4. Smaller SGIP systems at wastewater treatment plants are assumed to operate using CH_4 that would otherwise have been vented. The avoided CH_4 emissions represent a direct reduction of greenhouse gas emissions. Flaring was assumed to have essentially the same degree of combustion completion as SGIP

---

4 Energy and Environmental Economics. *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs.* For the California Public Utilities Commission. October 25, 2004.

5 Itron, Inc. *CPUC Self-Generation Incentive Program Sixth Year Impact Evaluation: Final Report.* Submitted to Pacific Gas and Electric Company and the Self-Generation Incentive Program Working Group. August 30, 2007.

6 Itron, Inc. *CPUC Self-Generation Incentive Program Seventh Year Impact Evaluation: Final Report.* Submitted to Pacific Gas and Electric Company and the Self-Generation Incentive Program Working Group. September 2008.

renewable fuel use facilities. Consequently, SGIP systems equal to or larger than 150 kW at wastewater treatment plants, and all SGIP systems at landfill gas facilities, were assumed to yield no net CH_4 reduction benefit.

Section B.2 describes GHG emissions from SGIP DG systems, as well as provision of heating and cooling services by combined heat and power (CHP) systems. In Section B.3, the GHG emissions that would have occurred in the absence of the SGIP DG systems are estimated. Those emissions would have originated from three sources: power plants supplying the electric grid, natural gas boilers that would have provided heating services, and biomass whose decomposition would have resulted in emissions of CO_2 from flares or emissions of CH_4.

B.2 SGIP System GHG Emissions

The following description of SGIP DG system operations covers two areas. First, the GHG emissions from rebated SGIP systems when they operate. Second, the quantities of heating and cooling services provided by CHP SGIP systems. Heating and cooling services quantities estimated for CHP SGIP systems are used later in the analysis to estimate the baseline GHG emissions that would have resulted if conventional means (i.e., natural gas boiler, electric chiller) been used to provide those services.

Emissions from Rebated SGIP Systems

Some SGIP sites emit CO_2; this must be taken into account when calculating the GHG emission impacts for SGIP facilities. The following assumptions were made regarding the emissions generated per kWh of electricity generated for the various cogeneration technologies. Wind and photovoltaic SGIP sites do not emit CO_2. In this report, the electrical efficiency is shown separately for microturbines and gas turbines. In previous reports, gas turbines and microturbines were assumed to have the same value. Additionally, the values for the electrical efficiency for each technology type reflect the electrical efficiencies observed for each technology type for projects active in PY08.

Table B-1: CO_2 Emissions Per kWh by Technology Type (*T*)

Technology (*T*)	$(CO_2)_T$ (lbs. per kWh)
PV	0.00
Wind	0.00
Gas Turbine	1.39
Microturbine	1.76
IC Engine	1.38
Fuel Cell	1.03

CO_2 emission factors were calculated as:

$$(CO_2)_T \cong \left(\frac{3412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{ft^3\ of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO_2}\right)$$

where:

$(CO_2)_T$ is the CO_2 emission factor for technology T.

Units: $\dfrac{lbs\ of\ CO_2}{kWh}$

EFF_T is the electrical efficiency of technology T.

Value: Value dependent on technology type

Technology Type	EFF_T
Microturbine	0.24
Gas Turbine	0.30
IC Engine	0.30
Fuel Cell	0.40

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV). Metered data collected from SGIP CHP systems

Source: Table 5-14

The technology-specific emission factors were calculated to account for CO_2 emissions released from SGIP sites and, therefore, when multiplied by the electricity generated from cogeneration sites, represent hourly CO_2 emissions in pounds, which are converted into metric tons as CO_2 emissions are typically measured in metric tons.

$$SgipGHG_{ih} = \left((CO_2)_T \times engohr_{ih}\right) \times \left(\frac{metrictonCO_2}{2{,}205lbs}\right)$$

where:

$SgipGHG_{ih}$ is the CO_2 emitted for participant *i* during hour *h*.
Units: metric tons of CO_2

Heating and Cooling Services Provided by SGIP CHP Systems

The SGIP's CHP systems use heat recovered from prime movers to provide host facilities with heating and/or cooling services. The total quantity of heat recovered from each SGIP CHP system during each hour of the year is quantified via either direct measurement or estimation. The translation of these data into estimates of heating and/or cooling services provided is described below. This information is required later in the analysis to support the calculation of GHG emissions that would have occurred in the SGIP's absence if these services would have been provided by natural gas boilers and electric chillers.

The recovered heat data available for the SGIP's CHP systems includes the heat used for heating services and in the event that cooling services are used, the heat data represents the total for heating and cooling services. As only totals are available, the distribution between heating and cooling must be assumed if a CHP system uses both heating and cooling services.

Heating Services

A heat exchanger is typically used to transfer heat recovered from SGIP CHP systems to building HVAC systems or industrial process equipment delivering heating services.

$$HEATING_{iymdh} = BOILER_i \times heathr_{iymdh} \times EffHx$$

where:

$HEATING_{iymdh}$ is the heating services provided by SGIP CHP participant *i* for year *y*, month *m*, day *d*, and hour *h*.
Units: kBtu

$BOILER_i$ is an allocation factor whose value depends on SGIP CHP system design

Value: Value dependent on system design (e.g., Heating Only, Heating & Cooling, or Cooling Only)

System Design	$BOILER_i$
Heating Only	1.0
Heating & Cooling	0.5
Cooling Only	0.0

Units: Dimensionless

Basis: System design as represented in Installation Verification Inspection Report

heathr is the quantity of useful heat recovered from the SGIP unit and used for heating services for SGIP CHP participant *i* for year *y*, month *m*, day *d*, and hour *h*.

Units: *kBtu*

Basis: Metering or ratio analysis depending on HEAT metering status

EffHx is the efficiency of the SGIP CHP primary heat exchanger

Value: 0.9

Units: Dimensionless fractional efficiency

Basis: Assumed

Cooling Services

An absorption chiller is typically used to convert heat recovered from SGIP CHP systems into chilled water piped to building HVAC systems or industrial process equipment delivering cooling services.

$$COOLING_{iymdh} = CHILLER_i \times heathr_{iymdh} \times COP$$

where:

$COOLING_{iymdh}$ is the cooling services provided by SGIP CHP participant *i* for year *y*, month *m*, day *d*, and hour *h*.

Units: kBtu

$CHILLER_i$ is an allocation factor whose value depends on SGIP CHP system design

Value: Value dependent on system design (e.g., Heating Only, Heating & Cooling or Cooling Only)

System Design	$CHILLER_i$
Heating Only	0.0
Heating & Cooling	0.5
Cooling Only	1.0

Units: Dimensionless

Basis: System design as represented in Installation Verification Inspection Report

heathr is the quantity of useful heat recovered for SGIP CHP participant *i* for year *y*, month *m*, day *d*, and hour *h*.

Units: kBtu

Basis: Metered or estimated data depending on HEAT metering status (e.g., metered or non-metered)

COP is the efficiency of the absorption chiller using heat from the SGIP CHP system.

Value: 0.6

Units: $\frac{kBTU_{cold}}{kBTU_{hot}}$

Basis: Assumed

B.3 Baseline GHG Emissions

The following description of baseline operations covers three areas. First, the GHG emissions from electric power plants that would be required to operate more in the SGIP's absence. These emissions would correspond to electricity generated by SGIP DG systems, as well as to electricity that would otherwise be consumed by electric chillers to satisfy cooling load quantified in the previous section. Second, the GHG emissions from natural gas boilers that would otherwise be operated to satisfy heating load quantified in the previous section. Third, the GHG emissions corresponding to biogas that otherwise would have been flared (CO_2) or released directly into the atmosphere (CH_4).

Electric Power Plant GHG Emissions

This section describes the methodology used to calculate estimates of additional CO_2 emissions from electric power plants that would have occurred during PY08 in the absence of the program. The methodology involves combining emission factors (in pounds of CO_2 per kWh of electricity generated) that are technology, location, and hour-specific with information about the quantity of electricity either generated by SGIP DG systems or displaced by absorption chillers operating on heat recovered from CHP SGIP systems.

The different fuel/technology combinations that are accounted for include renewable and non-renewable; fuel cells, internal combustion engines, microturbines, and gas turbines. The location or service territory of a cogeneration site is also considered in the development of emission factors by accounting for whether the facility is located in PG&E's territory (northern California) or in SCE/SDG&E's territory (southern California). The geographic location naturally has an effect on the demand and use of electricity due to differences in climate and electricity market conditions. This in turn affects the emission factors used to estimate the avoided CO_2 released by conventional power plants. Lastly, the date and time that electricity is generated affects the emission factors because the mix of high and low efficiency plants used differs throughout the day. The larger the proportion of low efficiency plants that would have been used to generate electricity, the greater the avoided CO_2 emissions.

Electric Power Plant GHG Emissions per kWh

As described above, a number of elements can affect the emission factors used to estimate electric power plant CO_2 emissions and would have occurred in the SGIP's absence. The basic methodology used to formulate emission factors for this analysis relies upon certain assumptions made by E3 in their emission factor development and avoided cost calculation workbook.[7] These are as follows:

- The emissions of CO_2 released from a conventional power plant depends upon its heat rate, which in turn is dictated by the power plant's efficiency, and
- The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

Hourly CO_2 emission factors used in this study were based upon a methodology initially developed by E3. E3 provided CO_2 emission factors and the basis for those factors in a workbook available for download on their website. The premise for hourly CO_2 emission factors calculated in E3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the market demand conditions for electricity; as demand for electricity increases, all else being equal, the price of natural gas will rise. To meet the higher demand for natural gas, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission

[7] The filename of the workbook that contains the data used to generate hour-specific emission factors for CO_2 is "cpucAvoided26.xls" and can be downloaded from www.ethree.com/CPUC.

factor for CO_2. In other words, one can expect an emission factor representing the release of CO_2 from the central grid to be higher during peak hours than during off-peak hours. The avoided cost methodology initially developed by E3 is under review and may be modified in the future.

The E3 workbook mentioned previously includes the price of natural gas for each hour over the year 1999 presented as the percentage of the annual average price of natural gas for 1999. Two streams of hourly natural gas prices exist: one for northern California and another for southern California. These "price shape" data streams dictate the mix of high and low efficiency power plants used by the conventional power grid to meet demand. During the hours where the price of natural gas is high (e.g., weekday, on-peak versus weekend or holiday, off-peak), the demand for electricity is met using high efficiency as well as low efficiency peaking power plants ("peakers"). The price of natural gas is used to calculate an implied heat rate, which is dependent on the mix of low and high efficiency power plants. This implied heat rate is used to calculate the tons of CO_2 per kWh emission factors for each hour of the year. The greater the demand during these times (as indicated by a higher hourly price for natural gas), the higher the percentage of electricity generated by peakers and the greater the per-kWh impact of reducing consumption of electricity purchased from the electric utility company.

Two streams of 8,760 hourly emission factors for 1999 are included in the E3 workbook: one is for PG&E (hereafter these factors will be referred to as the northern California CO_2 emission factors), and the other is for SCE and SDG&E (hereafter referred to as the southern California CO_2 emission factors). Inputs to develop the hourly emission factors are geographically dependent due to different weather conditions, different central station plant heat rates, and different natural gas market conditions.

The hourly CO_2 emission factor (EF) equation (represented in metric tons per MWh) is described below:

$$CO2emissionfactor_{it} = HECO2EF + \left(impheatrate_{it} - HEheatrate\right) \times \left(\frac{LECO2EF - HECO2EF}{LEheatrate - HEheatrate}\right)$$

where:

$CO2emissionfactor_{it}$ is the hourly CO_2 emission factor for northern or southern California, *i*, for every hour, *t*.
Units: metric ton of CO_2 per MWh

ECO2EF is the high efficiency plant CO_2 emission factor.
Value: 0.3650
Units: metric tons of CO_2 per MWh
Basis: E3 avoided cost workbook

LECO2EF is the low efficiency plant CO_2 emission factor.
Value: 0.8190
Units: metric tons of CO_2 per MWh
Basis: E3 avoided cost workbook

HEheatrate is the heat rate associated with a high efficiency plant.
Value: 6,240
Units: Btu/kWh
Basis: E3 avoided cost workbook

LEheatrate is the heat rate associated with a low efficiency plant
Value: 14,000
Units: Btu/kWh
Basis: E3 avoided cost workbook

The high efficiency plant heat rate and low efficiency plant heat rates are used as bounds to provide an upper and lower limit for the heat rates used in calculating the CO_2 emission factors.

Impheatrate is the implied heat rate which is the heat rate based on the relative current price of natural gas multiplied by the average heat rate of the location (northern California or southern California). In equation form, this is written as follows:

$$impheatrate_{it} = \left(\frac{currentNGprice_{it}}{AvgNGprice_{it}} \right) \times avgheatrate_{it}$$

Location	$avgheatrate_{it}$
Northern California	9,160
Southern California	9,590

Units: Btu/kWh
Basis: E3 price parameters and "price shape" data or percentage mix representing low and high efficiency plants in operation.

This equation shows that for a given hour *t*, the emission factor is dependent upon how the implied heat rate of the average power plant differs from the average heat rate of a high efficiency power plant. The higher the heat rate (which indicates a heavier reliance on lower efficiency plants such as during times of high electricity demand), the greater the emission factor.

The hourly emission factor values ($CO2emissionfactor_{it,}$) as calculated above, are presented in metric tons per MWh. The base hourly emission factor values ($BaseCO2EF_{it}$) is obtained by converting *CO2emissionfactors* into metric tons per kWh.

$$BaseCO2EF = CO2emissionfactor\,\frac{metric\ ton}{MWh} \times \frac{1\ MWh}{1{,}000\ kWh}$$

Since CO_2 emissions avoided for every hour of the year 2008 were required, simply lining up the hourly emission factors from 1999 to the hourly totals of electricity that would have been generated from power plants in 2008 would not accurately capture the GHG emissions avoided by operating SGIP facilities. Cogeneration facilities may not be operated on the weekend or on holidays as the business itself may be closed on weekends and holidays. Upon examination, it was determined that January 1, 1999 occurred on a Friday while January 1, 2008 was a Tuesday. To properly align the days of the week, the dates January 1, 2008, January 2, 2008, and January 3, 2008 were created using January 1, 1999 as a holiday and replacing 2008 data with the nearest matching 1999 weekday. Holidays were identified in 2008 and the applicable price streams for the holidays in 1999 were applied to 2008 dates. In addition, since 2008 was a leap year and 1999 was not, an additional day had to be created from the 1999 data to represent February 29, 2008.

Baseline Electric Power Plant GHG Emissions Per Hour

Baseline Power Plant Operations Corresponding to Electric Chiller Operation

The fourth bullet presented in Section B.1 described one additional GHG reduction benefit derived from the presence of absorption chillers in cogeneration facilities. Since absorption chillers can replace the use of standard efficiency centrifugal electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions that deliver a reduction in GHG emissions.

Actual heat recovery rates and typical centrifugal chiller efficiencies were incorporated into an algorithm to estimate the avoided electricity that would have been serving a centrifugal chiller in the absence of the cogeneration system. This avoided electricity was calculated as:

$$ChlrElec_{iymdh} = COOLING_{iymdh}\ kBtu \times \left(EffElecChlr \frac{kWh}{ton - hr\ of\ cooling} \right) \left(\frac{ton - hr\ of\ cooling}{12\ kBtu} \right)$$

where:

$ChlrElec_{iymdh}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for participant *i* for year *y*, month *m*, day *d*, and hour *h*.
Units: kWh

EffElecChlr is the efficiency of the baseline new standard efficiency electric chiller
Value: 0.634
Units: $\frac{kWh}{Ton - hr\ of\ cooling}$
Basis: Assumed

<u>Baseline GHG Emissions from Power Plant Operations</u>

Location- and hour-specific emission factors, when multiplied by the quantity of electricity generated each hour, estimate the *hourly emissions avoided when SGIP sites operate* (expressed in metric tons of CO_2).

$$BasePpChiller_{ih} = \left(BaseCO2EF_{ih} \times ChlrElec_{ih} \right)$$
$$BasePpEngo_{ih} = \left(BaseCO2EF_{ih} \times engohr_{ih} \right)$$

Natural Gas Boiler GHG Emissions

The third bullet presented in Section B.1 described additional GHG reduction benefits derived from cogeneration. These benefits come in the form of waste heat recovered from SGIP facilities that is then used to provide heating services, thereby reducing reliance on natural gas boilers. The quantity of heating services provided by SGIP CHP systems was discussed in a previous section. Use of these data to estimate the baseline natural gas use corresponding to these heating services is described below.

Baseline natural gas boiler CO_2 emissions (measured in metric tons) were calculated based upon hourly heat recovery values for the SGIP CHP projects active in 2008 as follows:

$$BaseBlr_{iymdh} = \left(HEATING_{iymdh}\ kBtu_{out} \times \left(\frac{1}{EffBlr\ \frac{kBtu_{out}}{kBtu_{in}}} \right) \left(\frac{ft^3 of\ CH_4}{1\ kBtu_{in}} \right) \left(\frac{lbmole\ of\ CO_2}{360\ ft^3} \right) \left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO_2} \right) \right) \times \left(\frac{metrictonCO_2}{2{,}205 lbsCO_2} \right)$$

where:

BaseBlr$_{iymdh}$ is the CO_2 emissions of the baseline natural gas boiler for participant *i* for year *y*, month *m*, day *d*, and hour *h*.
Units: metric tons of CO_2

EffBlr is the efficiency of the baseline natural gas boiler
Value: 0.8
Units: $\frac{kBtu_{out}}{kBtu_{in}}$
Basis: Assumed

These CO_2 emission factors reflect the ability of waste heat to be recovered and used in lieu of natural gas and therefore help reduce CO_2 emissions (an environmental benefit).

Biomass GHG Emissions

Calculation of CH_4 emission reductions from cogeneration facilities was carried out for the subset of 39 renewable fuel use SGIP facilities. These facilities used exclusively or predominately biogas as the generation fuel source. These included the following facility types:

- Renewable-Powered Fuel Cells,
- Renewable-Fueled Microturbines, and
- Renewable-Fueled Internal Combustion Engines.

The baseline treatment of biogas is important for assessing the CH_4 emission impacts of renewable fuel facilities. Baseline treatment refers to the typical fate of the biogas in lieu of being used for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared). There are three common sources of biogas: landfills, wastewater treatment facilities, and dairies. For dairy digesters, the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2000 dairies in California, conventional manure management practice for flush dairies[8] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO_2 and water. These lagoons are typically uncovered, so all CH_4 generated in the lagoon escapes into the atmosphere. Currently, there are no requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for control of volatile organic compounds. Consequently, the baseline used in this report for dairy digesters is venting of the CH_4 to the atmosphere for all dairies.

For wastewater treatment facilities, the baseline is not as straightforward. There are approximately 250 wastewater treatment plants (WWTPs) in California and fewer than 30 of those conduct energy recovery. The larger facilities (i.e., those that could generate one MW or more of electricity) tend to install energy recovery systems. However, most of the remaining WWTPs do not recover energy and most flare the gas on an infrequent basis. Consequently, for smaller facilities (i.e., those with capacity less than 150 kW), venting of the biogas (CH_4) is used as the baseline.

Landfill gas recovery operations present the biggest challenge in defining the CH_4 treatment baseline. A study conducted by the California Energy Commission in 2002[9] showed that landfills with biogas capacities less than 500 kW would tend to vent rather than flare the

---

8 Most dairies manage their wastes via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in methane being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas systems).

9 California Energy Commission. *Landfill Gas to Energy Potential in California.* 500-02-041V1. September 2002.

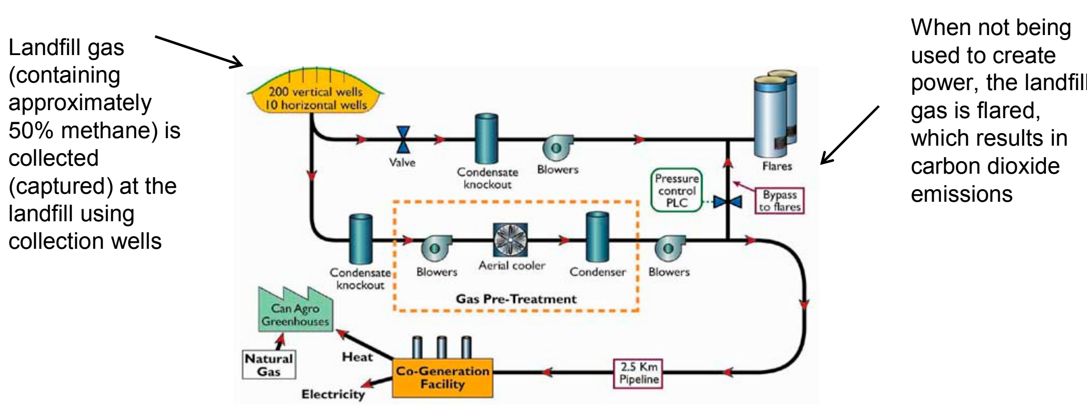
generated landfill gas by a margin of more than three to one. However, evidence also supports a lower threshold value, as landfills with over 2.5 million metric tons of waste are required to collect and either flare or use their gas. Additionally, inspection reports provided verification that those facilities participating in SGIP would have flared their CH_4. Consequently, for this impact evaluation, the threshold value was eliminated for landfill gas facilities. The baseline is to flare the CH_4.

The GHG emissions characteristics of biogas flaring and biogas venting are very different and therefore are discussed separately below.

GHG Emissions of Flared Biogas

Figure B-1 provides a depiction of a biogas facility that captures and flares CH_4. The CH_4 is assumed to be captured by the facility and then flared, destroying the CH_4 but still resulting in the release of CO_2. A facility that vents the CH_4 will have lower direct CO_2 emissions than a facility that flares the CH_4. However, the CO_2 equivalent value of CH_4 emissions is significantly greater when the CH_4 is vented rather than flared—one ton of emitted CH_4 is equivalent to 21 tons of emitted CO_2.

Figure B-1: Landfill Gas with Methane Capture Diagram



Methane is naturally created at landfill gas facilities, wastewater treatment plants and dairies. If not captured, the methane escapes into the atmosphere contributing to greenhouse gas (GHG) emissions. Capturing the methane provides an opportunity to use it as fuel. When the methane is not used to create energy, it is burned in a flare. Because the resulting CO_2 has much less GHG potency than methane, the use of the flare reduces the CO_2 equivalent emissions. Distributed generation, such as SGIP projects, deliver additional economic and environmental benefits by reducing the need to generate electricity at central station power plants.

In situations where flaring occurs, baseline GHG emissions comprise CO_2 only. The flaring baseline was assumed for the following types of biogas projects:

- Wastewater treatment plants and digesters with a nameplate capacity greater than 150 kW, and
- All landfill gas facilities.

The assumption is that the flaring of CH_4 results in the same amount of CO_2 emissions as would occur if CH_4 was captured and used by either a microturbine or internal combustion engine.

<u>GHG Emissions of Vented Biogas</u>

CH_4 captured and used at renewable fuel use facilities where the baseline is venting represents CH_4 emissions that are no longer emitted to the atmosphere. The venting baseline was assumed for the following types of biogas projects:

- Wastewater treatment plants and digesters with a nameplate capacity less than 150 kW, and
- All dairies.

Biogas consumption is not metered at SGIP facilities. In 2008, over 85 percent of the SGIP facilities that used a renewable fuel (other than wind or PV) used IC engines or microturbines as the prime mover. CH_4 emission factors were calculated for each renewable fuel technology type by assuming electrical efficiencies for each technology:

$$CH4EF_T \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\,ft^3 of CH_4}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$

where

$CH4EF_T$ is the CH_4 capture rate for SGIP DG systems of type T

Value: Value dependent on technology type

Technology Type	$CH4EF_T$
Microturbine	275
IC Engine	255
Fuel Cell	168

Units: $\frac{grams}{kWhr}$

EFF_T is the electrical efficiency of technology *T*.

Value: Value dependent on technology type

Technology Type	EFF_T
Microturbine	0.25
Gas Turbine	0.30
IC Engine	0.27
Fuel Cell	0.41

Units: Dimensionless multiplier

Basis: Metered data collected from SGIP CHP systems

The derived CH_4 emission factors (*CH_4EF*) are multiplied by the total electricity generated from the SGIP renewable fuel use sites (depending upon technology) to estimate the annual avoided CH_4 emissions. Since GHG emissions are often reported in terms of tons of CO_2 equivalent,[10] each facility's avoided CH_4 emissions were converted first from grams to pounds and then pounds to metric tons. Baseline CH_4 emissions in tons were calculated as follows:

$$BaseBioCH4 = \left(\left(\frac{CH_4EF_T grams}{kWh}\right)(engohr_{ih})\left(\frac{0.002204 lbs}{grams}\right)\right) \times \left(\frac{metricton CH_4}{2{,}205 lbs CH_4}\right)$$

The avoided metric tons of CH_4 emissions were then converted to metric tons of CO_2 equivalent by multiplying the avoided CH_4 emissions by 21, which represents the Global Warming Potential (GWP) of CH_4 (relative to CO_2) over a 100-year time horizon.

$$BaseBio = BaseBioCH4 * \left(\frac{21 metrictons\, CO_2}{metricton\ CH_4}\right)$$

[10] CO_2 equivalent is a metric measure used to compare the emissions of various greenhouse gases based upon their global warming potential (GWP). The CO_2 equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP.
OECD Glossary of Statistical Terms: http://stats.oecd.org/glossary/detail.asp?ID=285

B.4 GHG Emissions Impacts

Greenhouse gas emissions impacts were calculated as:

$$\begin{aligned} DeltaGHG_{ih} = & \left(BasePpEngo_{ih} + BasePpChiller_{ih} + BaseBlr_{ih} + BaseBio_{ih}\right) \\ & - SgipGHG_{ih} \end{aligned}$$

where:

$DeltaGHG_{ih}$ is the change in GHG emissions attributable to the SGIP for participant i for hour h.
Units: metric tons of CO_2 eq.

Appendix C

Data Analysis

The data sources for the evaluation impact report were described in Section 4. Program impact estimates and the uncertainty in those estimates were presented in Section 5. This appendix discusses data availability by Program Administrator (PA) and the data analysis methodology, including the bases of the impact estimates uncertainty characterizations.

C.1 Data Processing Methods

This section discusses the ENGO, HEAT, and FUEL data processing and validation methodology for photovoltaic (PV), fuel cells, and engines/turbines operating on non-renewable or renewable fuel.

ENGO Data Processing

PV data are processed differently from the fuel cell, engine, and turbine data. For PV, a code template has been developed which reads, processes and validates data, and outputs suspect data. When necessary, the code adjusts for daylight savings time, accounts for inverter losses, corrects a data stream which contains more than one site, as well as many other site-specific and data provider-specific issues. Validation of PV data utilizes irradiance, temperature, and rainfall data downloaded from the California Irrigation Management Information System (CIMIS). Each PV site is assigned a nearby CIMIS site. Data are flagged as suspect when there is low daily output, low hourly output, high daily output, or high hourly output compared to the available irradiation. The suspect data are reviewed internally and either validated or invalidated. An example of a suspect case that can be validated internally is a bad weather event which results in low daily output. An example of a suspect case that can be invalidated internally is consistently high daily output which greatly exceeds the system capacity. When the data validity cannot be determined internally the data provider is contacted. Data providers are most often contacted if a site has an outage for more than two days in order to determine if the outage was a PV system failure (indicates valid data) or a data acquisition system failure (indicates invalid data). Invalid data are excluded from the analysis.

For fuel cells, engines, and turbines, ENGO data refers to a measure of system output that excludes electric parasitic loads (e.g., onsite controls, pumps, fans, compressors, generators, and heat recovery systems). In some cases it is not possible to measure ENGO directly with a single meter. In those cases ENGO is calculated by subtracting the electrical parasitic loads from the gross generator output. Due to wide variety of formats in which raw data are received, conversion of raw data to a common format is essential in order to ensure that all data received are treated consistently. After converting the data to a common format, all data files are reviewed to identify suspicious data (low or high capacity factors). Data providers are contacted when data validity cannot be determined internally. In cases where anomalous behavior cannot be explained, the metered data are excluded from the analysis.

HEAT Data Processing

The main sources of thermal data are applicants and Itron-installed heat meters. If the data come from Itron data loggers, processing time is minimal because the raw data are already stored in 15-minute intervals. However, if the raw data come from applicants, then the data should be converted to the standard format of 15-minute interval kBtu data. When data are received from an applicant, Host, or some other party, certain validation steps must be passed before the data are incorporated into the analysis. These steps include comparing the HEAT data with the ENGO and FUEL data when available. HEAT data are validated when the heat recovery rate (kBtu/kWh) falls within an expected range based on system type and size.

FUEL Data Processing

The two main sources of fuel data for non-renewable projects are natural gas utilities and Itron metering. If the data comes from Itron data loggers, processing time is minimal because the raw data are already stored in 15-minute intervals. However, if the raw data come from a gas utility, data are typically reported in monthly or billing cycle intervals. Monthly electrical conversion efficiencies are calculated to validate the monthly fuel data. Validated monthly data are transformed into 15-minute data based on the monthly electrical efficiencies and 15-minute ENGO data. In this case, the fuel data are a ratio using other metered data (ENGO), so a flag in the permanent dataset is set to "R" in order to distinguish between sub-15-minute interval metered data, which has been transformed into 15-minute data, and actual 15-minute interval metered data, which is flagged as "M".

C.2 Estimating Impacts of Unmetered Systems

Data from metered systems were used to estimate impacts for unmetered systems of the same technology and fuel. In most cases, the metered data were for the exact same hour of the year and from systems of same technology, fuel, and PA. For PV systems, the metered data were further limited to systems with additional similarities to those of the unmetered systems.

By limiting the metered data used to those with the same PA, factors that can influence operational performance were better matched between the metered and unmetered systems. These PA-related factors include local economic climate, available tariffs, and, to some degree, the local meteorological climate. Likewise, in the case of PV, additional system similarities included technology details that can influence power output. These PV details included an output capacity class of large versus small (small defined as less than 300 kW), a locale category (coastal or inland), and a module configuration category (flat, tilted, tracking, or mixed).

All estimated hourly impacts were based on no fewer than five metered observations of the same technology and fuel type. For some unmetered systems there were hours with fewer than five metered observations with like technology, fuel, and PA. To estimate impacts for these, metered data from one or more of the other PAs were included until there were at least five metered observations for the same hour. For example, metered data from SCE could be used to estimate impacts for similar systems at the same hour for SCG unmetered systems when too few metered observations existed from SCG systems alone. If there still were fewer than five metered observations, then data from CCSE were allowed to be used. If inclusion of CCSE did not provide enough metered observations, then data from PG&E were allowed.

The inclusion of metered data from other PAs did not always satisfy the minimum requirement of five metered observations for the same hour of the year and same technology and fuel. In these cases the metered data were restricted again to the same PA but the time component of the metered data was allowed to include same hours of the day from like weekday types (weekday or weekend) from the same month. For example, an hourly estimate for 3:00 to 4:00 P.M. on Monday, July 24 for a renewable IC engine system administered by SCE might be based on metered observations from renewable IC engine systems administered by SCE from all July weekday hours of 3:00 to 4:00 P.M.

In fewer than three percent of the system hours needing to be estimated the relaxation of the metered data time component did not satisfy the minimum requirement of five metered observations. Estimates for these system hours thus were allowed to be based on metered observations during like weekday hours of the same month and from other PAs.

A ratio representing average power output per unit of rebated system capacity was calculated using at least five metered observations for each system hour needing an impact estimate. The product of this ratio and the system's rebated capacity was the system's estimated hourly average power output. Estimates of power output were calculated as:

$$EN\hat{G}O_{psdh} = \left(S_{ps}\right)_{Unmetered} \times \left(\frac{\sum ENGO_{psdh}}{\sum S_{ps}}\right)_{Metered}$$

Where:

$EN\hat{G}O_{psdh}$ = Predicted net generator output for project p in strata[1] s on date d during hour h

Units: kWh
Source: Calculated

S_{ps} = System size for project p in strata s

Units: kW
Source: SGIP Tracking Database

$ENGO_{psdh}$ = Metered net generator output for project p in strata s on date d during hour h

Units: kWh
Source: Net Generator Output Meters

C.3 Assessing Uncertainty of Impacts Estimates

Program impacts covered in Section 5 include those on electricity and fuel, as well as those on greenhouse gas (GHG) emissions. The principal factors contributing to uncertainty in those reported results are quite different for these two types of program impacts. The treatment of those factors is described below for each of the two types of impacts.

Electricity and Fuel Impacts

Electricity and fuel impact estimates reported in Section 5 are affected by at least two sources of error that introduce uncertainty into the estimates. The two sources of error are measurement error and sampling error. Measurement error refers to the differences between actual values (e.g., actual electricity production) and measured values (i.e., electricity production values recorded by metering and data collection systems).

Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average

1 Strata are always defined by like technology and fuel and like hour of like weekday in like month. As described in text, however, strata may be more specific by additional like technology details, like PA or like group of PAs, and by exact hour of the year.

performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

The actual performance of unmetered systems is not known, and will never be known. It is therefore not possible to directly assess the validity of the assumption regarding identical central tendencies. However, it is possible to examine this issue indirectly by incorporating information about the performance *variability* characteristics of the systems.

Theoretical and empirical approaches exist to assess uncertainty effects attributable to both measurement and sampling error. Propagation of error equations are a representative example of theoretical approaches. Empirical approaches to quantification of impact estimate uncertainty are not grounded on equations derived from theory. Instead, information about factors contributing to uncertainty is used to create large numbers of possible sets of actual values for unmetered systems. Characteristics of the sets of simulated actual values are analyzed. Inferences about the uncertainty in impact estimates are based on results of this analysis.

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact estimates uncertainty. The term MCS refers to "the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[2]

A principle advantage of this approach is that it readily accommodates complex analytic questions. This is an important advantage for this project because numerous factors contribute to variability in impact estimates, and the availability of metered data upon which to base impact estimates is variable. For example, metered electricity production and heat recovery data are both available for some cogeneration systems, whereas other systems may also include metered fuel usage, while still others might have other combinations of data available.

GHG Emission Impacts

Electricity and fuel impact estimates represent the starting point for the analysis of GHG emission impacts; thus, uncertainty in those electricity and fuel impact estimates, flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impacts analysis. GHG emissions impact estimates are, therefore, subject to greater levels of uncertainty than are electricity and fuel

2 Webster's dictionary

impact estimates. The two most important additional sources of uncertainty in GHG emissions impacts are summarized below.

Baseline Central Station Power Plant GHG Emissions. Estimation of net GHG emissions impacts of each SGIP system involves comparing emissions of the SGIP system with emissions that would have occurred in the absence of the program. The latter quantity depends on the central station power plant generation technology (e.g., natural gas combined cycle, natural gas turbine) that would have met the participant's electric load if the SGIP system had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and, hence, GHG emissions factors) were obtained from E3. Quantitative assessment of uncertainty in E3's avoided GHG emissions database is outside the scope of this SGIP impact evaluation.

Baseline Biogas Project GHG Emissions. Biomass material (e.g., trash in landfills, manure at dairies) would typically have existed and decomposed (releasing methane) even in the absence of the program. While the program does not influence the existence or decomposition of the biomass material, it may impact whether or not the methane is released directly into the atmosphere. This is critical because methane is a much more active GHG than are the products of its combustion (e.g., CO_2).

For this GHG impact evaluation Itron used the methane disposition baseline assumptions summarized in Table C-1. Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, Itron will continue collecting additional site-specific information about methane disposition and incorporating them into the analysis. Modification of installation verification inspection forms will be recommended, and information available from air permitting and other information sources will be compiled.

Table C-1: Methane Disposition Baseline Assumptions for Biogas Projects

Renewable Fuel Facility Type	SGIP System Size (Rebated kW)	Methane Disposition Baseline Assumption
Dairy Digester	Any size	Venting
Waste Water Treatment	≥150 kW	Flaring; otherwise Venting
Landfill Gas Recovery	Any size	Flaring

Data Sources

The usefulness of MCS results rests on the degree to which the factors underlying the simulations of actual performance of unmetered systems resemble factors known to influence those SGIP systems for which impact estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include PA, project status, project location, system type, and system size. This information is obtained from project lists that PAs update monthly for the CPUC. More detailed project information (e.g., PV system configuration) is obtained from Verification Inspection Reports developed by PAs just prior to issuance of incentive checks.

Metered Data for SGIP DG Systems

Collection and analysis of metered performance data collected from SGIP DG systems is a central focus of the overall program evaluation effort. In the MCS study the metered performance data are used for three principal purposes:

1. Metered data are used to estimate the actual performance of metered systems. The metered data are not used directly for this purpose. Rather, information about measurement error is applied to metered values to estimate actual values.
2. The central tendencies of groups of metered data are used to estimate the actual performance of unmetered systems.
3. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study to explore the likelihood that actual performance of unmetered systems deviates by certain amounts from estimates of their performance.

Manufacturer's Technical Specifications

Metering systems are subject to measurement error. The values recorded by metering systems represent very close approximations to actual performance; they are not necessarily identical to actual performance. Technical specifications available for metering systems provide information necessary to characterize the difference between measured values and actual performance.

Analytic Methodology

The analytic methodology used for this MCS study is described in this section. The discussion is broken down into the five steps listed below:

- Ask Question
- Design Study
- Generate Sample Data
- Calculate the Quantities of Interest for Each Sample
- Analyze Accumulated Quantities of Interest

Ask Question

The first step in the MCS study is to clearly describe the question(s) that the MCS study is being designed to answer. In this instance that question is: How confident can one be that *actual* program total impact deviates from *reported* program total impact by less than certain amounts? The scope of the MCS study includes the following program total impacts:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC216.6 (b) Cogeneration System Efficiency

Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility and accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the systems came on-line during 2008 and, therefore, contributed to energy impacts for only a portion of the year. Some of the systems for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2008. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came on-line during 2008 and, therefore, contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more labor- and processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the system is metered. However, for many of the SGIP systems metered data are available for a portion—but not all—of 2008. This complicates any analysis that requires classification of systems as either "metered" or "not metered".

It would be possible to design an MCS study that accommodated the project status and data availability details described above. However, such a study would require considerable resources and would not be likely to yield results that would differ substantially from those yielded by a simpler design. Therefore, two important simplifying assumptions are included in the MCS study design.

1. Each data archive (e.g., electricity, fuel, heat) for each project is classified as being either "metered" (at least 75 percent of reported impacts are based on metered data) or "unmetered" (less than 75 percent of reported impacts are based on metered data) for MCS purposes.
2. Only full years of data for unmetered systems are included in the MCS analysis. Projects on-line for fewer than six months are excluded from the analysis. Projects on-line for at least six months are treated as if they were on-line during the entire year.

Generate Sample Data

Actual values for each of the program impact estimates identified above ("Ask Question") are generated for each sample (i.e., "run", or simulation). If metered data are available for the system then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the system, the actual values are created using distributions that reflect performance variability assumptions. **A total of 10,000 simulation runs were used to generate sample data.**

Metered Data Available—Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table C-2. The ranges are based on typical accuracy specifications from manufacturers of metering equipment (e.g., specified accuracy of +/- 2%). A uniform distribution with mean equal to zero is assumed for all three measurement types. This distribution implies that any error value within the stated range has an identical probability of occurring in any measurement. This distribution is more conservative than some other commonly assumed distributions (e.g., normal “bell-shaped” curve) because the outlying values are just as likely to occur as the central values.

Table C-2: Summary of Random Measurement-Error Variables

Measurement	Range	Mean	Distribution
Electricity	-0.5% to 0.5%		
Natural gas	-2% to 2%	0%	Uniform
Heat recovered	-5% to 5%		

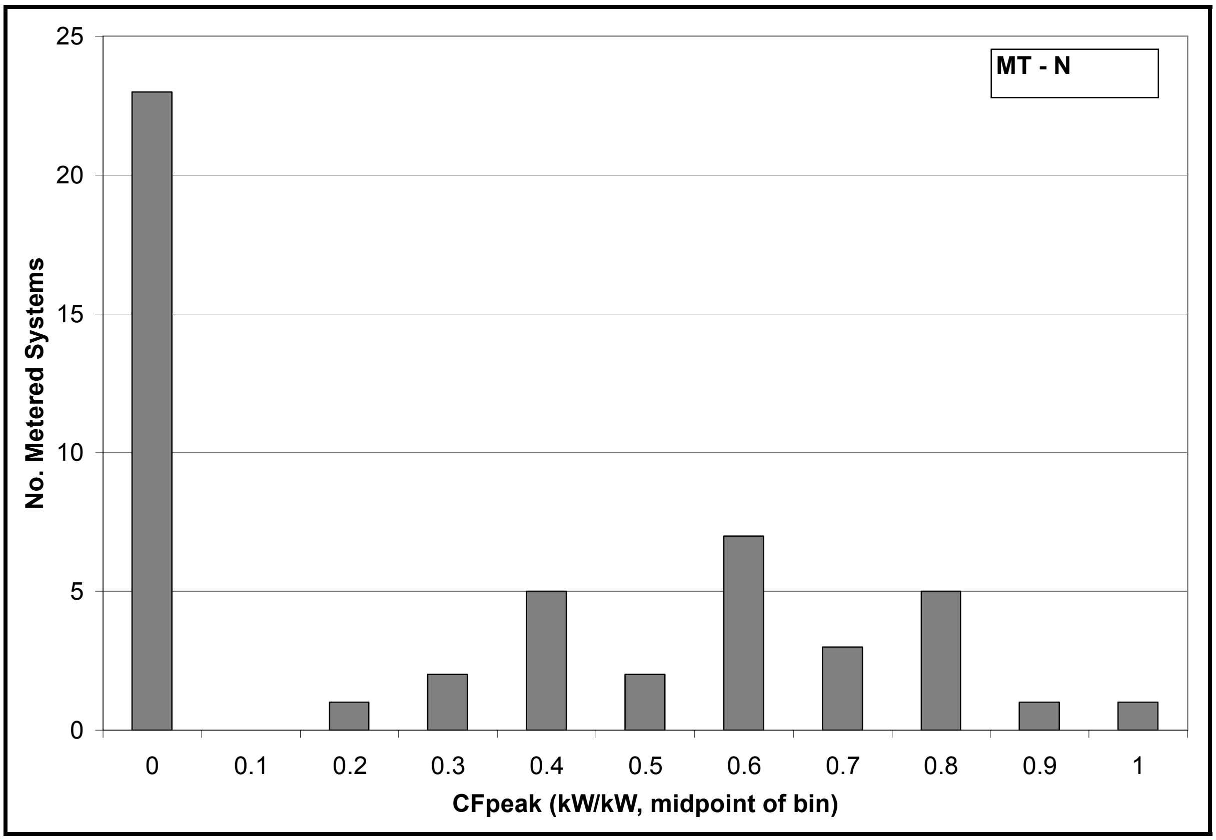
Metered Data Unavailable—Generating Sample Data from Performance Distributions

In the case of unmetered sites, the sample data are generated by random assignment from distributions of performance values assumed representative of entire groups of unmetered sites. Because measured performance data are not available for any of these sites, the natural place to look first for performance values is similar metered systems.

Specification of performance distributions for the MCS study involves a degree of judgment in at least two areas: first, in deciding whether or not metered data available for a stratum are sufficient to provide a realistic indication of the distribution of values likely for the unmetered systems; second, when metered data available for a stratum are not sufficient, in deciding when and how to incorporate the metered data available for other strata into a performance distribution for the data-insufficient stratum.

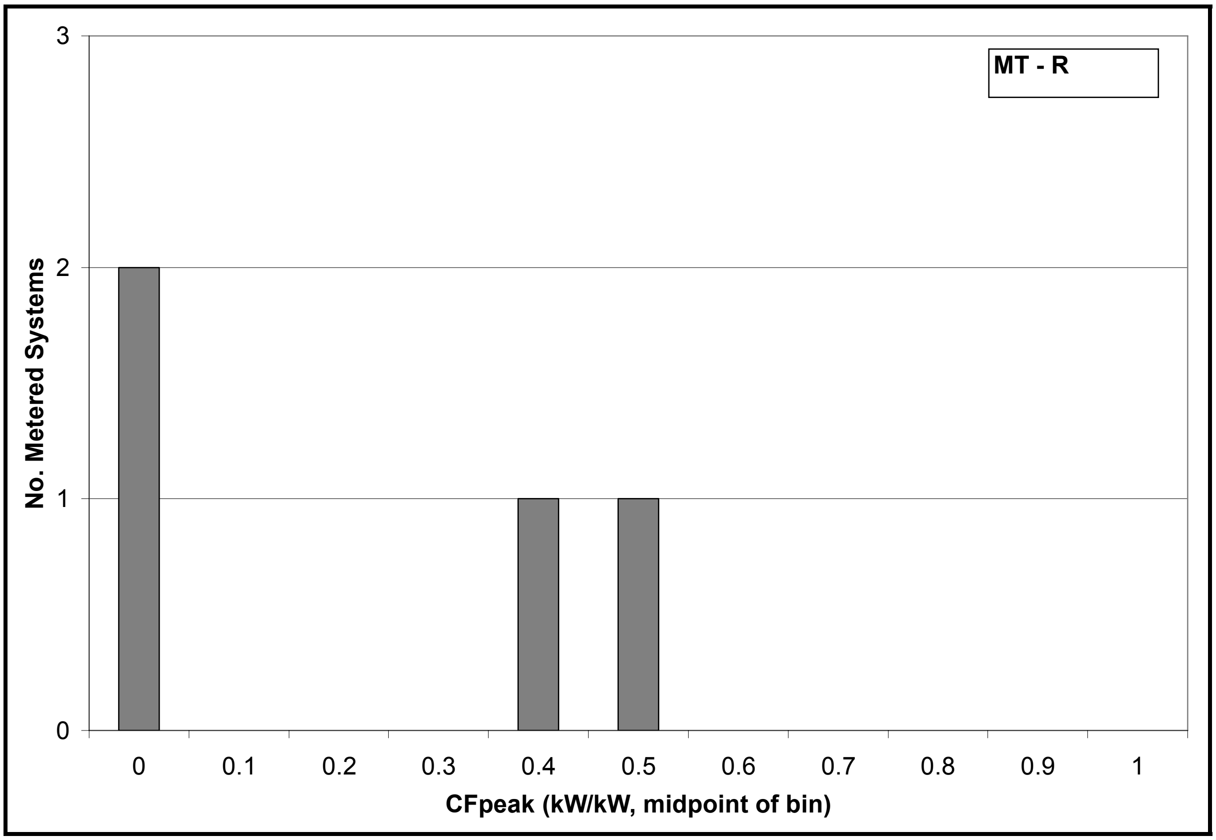
The assessment of the suitability of available metered data for use in MCS performance distributions is illustrated below with an example using 2008 data. The output of a group of non-renewable-fueled microturbines during the hour when CAISO system load reached its annual peak value is illustrated in Figure C-1. In this figure microturbine system output is expressed as metered power output per unit of system rebated capacity (CFpeak). Metered data were available for 50 systems. There were 62 systems for which metered data were not available for this hour. For each MCS run the actual performance of each of these systems must be assigned from an MCS performance distribution. The metered data available for this group of systems appear to provide a good general indication of the distribution of values likely for unmetered systems.

Figure C-1: Non-Renewable-Fueled Microturbine Measured Coincident Peak Output



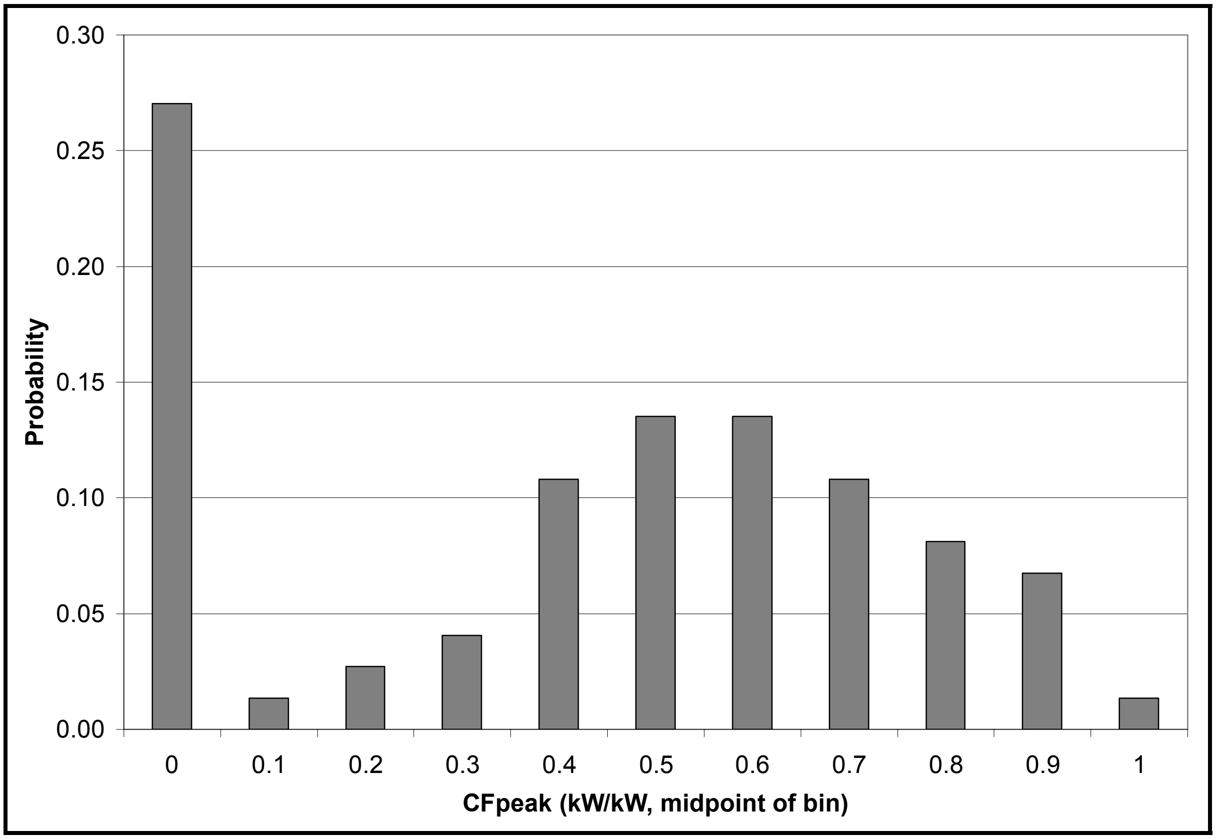
There are other sample design strata for which the quantity of metered data available is insufficient to provide a good indication of the distribution of values likely for unmetered projects. For example, there were only four metered renewable-fueled microturbines during the CAISO peak hour in 2008. The measured performance of these four systems is shown in Figure C-2.

Figure C-2: Renewable-Fueled Microturbine Measured Coincident Peak Output



If 10, 24, or 31 systems were metered it is unlikely that all of them would fall in this exact same distribution. Instead you would expect to see some systems have a CF of 0.1 and 0.2, and other systems could have been running at full capacity (CF = 1). The metered data available for this group of systems do not appear to provide a good general indication of the distribution of values likely for unmetered systems. Figure C-3 shows the distribution used in the MCS for renewable-fueled microturbines at the CAISO peak hour.

Figure C-3: CFpeak Distribution used in MCS for Renewable-Fueled Microturbines



Use of a distribution shown in Figure C-3 emphasizes the fact that the performance of the unmetered systems is not known, and that in the MCS the assumed distribution of CFpeak values is based on judgment. Lastly, the modification introduces a small measure of additional conservatism into MCS results.

Review of metered data availability for all technology and fuel sample design strata revealed numerous instances such as that described above. Consequently, in some instances simplifying assumptions were made. Fuel cell, engine, and turbine technologies were not separated by PA and renewable-fueled systems were assumed to follow a similar distribution to non-renewable-fueled systems within the same technology group. Engineering judgment was used for the wind turbine distribution to determine the maximum output possible for the wind speed at that day and hour. For PV, SCE and SCG systems were grouped together and PV groups were further broken down by configuration and location (coastal or inland). Lastly, the heat recovery distribution from 2005 for non-renewable engines/turbines was used for the 2008 analysis because there were more heat data available in 2005 than in 2008.

Table C-3 shows the groups used to estimate the uncertainty in the CAISO peak hour impact.

Table C-3: Technology and Fuel Groupings for the CAISO peak hour MCS Analysis

Technology	Fuel	PA[3]	PV Configuration	Coastal/Inland
PV	N/A	PG&E, CCSE, SCE & SCG	Near Flat, Other[4], Tracking[5]	Coastal, Inland
Wind	N/A	SCE[6]	N/A	N/A
IC Engine	Non-renewable, Renewable	All	N/A	N/A
Microturbine	Non-renewable, Renewable	All	N/A	N/A
Gas Turbine	Non-renewable[7]	All	N/A	N/A
Fuel Cell	Non-renewable, Renewable	All	N/A	N/A

3 PV projects are grouped by PA while engines are not because PV output is dependent on location.

4 Near Flat systems are those systems with a tilt of 20^o or less. Other systems are those systems with a tilt greater than 20^o.

5 Tracking systems are those systems with automatically adjusting tilts which allow the PV system to follow the sun. All tracking systems in SGIP are one-axis tracking systems. Tracking systems were not broken out by coastal/inland.

6 As of December 31, 2008 there are two Complete wind turbine projects in the SGIP and both are within SCE's service territory.

7 There are no renewable-fueled gas turbines in the program as of December 31, 2008.

Table C-4 shows the groups used to estimate the uncertainty in the yearly energy production. Yearly capacity factors for PV throughout California are less variable than for the CAISO peak hour; therefore, all fixed (near flat and other) PV systems are grouped together for the uncertainty analysis of the annual energy production. Tracking systems are kept separate because these systems are designed to have higher daily output than a fixed system. Internal combustion (IC) engines, gas turbines, and microturbines are grouped together for the uncertainty analysis of the annual energy production because of the small number of systems within each technology group for which data were available for 75 percent of the year and because a significant difference was not seen between the annual capacity factors of these systems.

Table C-4: Technology and Fuel Groupings for the 2008 Annual Energy Production MCS Analysis

Technology	Fuel	PV Configuration
PV	N/A	Fixed, Tracking
Wind	N/A	N/A
Engine/Turbine	Non-renewable, Renewable	N/A
Fuel Cell	All	N/A

Performance distributions were developed for each of the groups in the tables based on metered data and engineering judgment. In the MCS, a capacity factor is randomly assigned from the performance distribution and sample values are calculated as the product of CFpeak and system size. All of these performance distributions are shown in Figure C-4 through Figure C-59.

Performance Distributions for Coincident Peak Demand Impacts

Figure C-4: PG&E PV Measured Coincident Peak Output (Coastal, Near Flat)

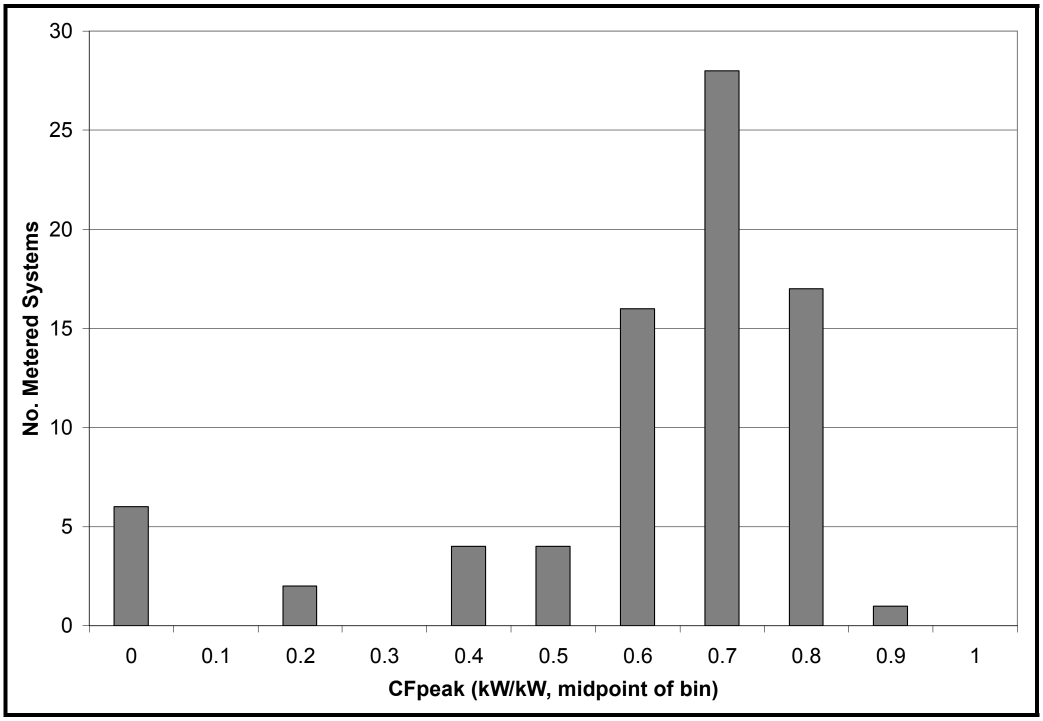


Figure C-5: MCS Distribution—PG&E PV Coincident Peak Output (Coastal, Near Flat)

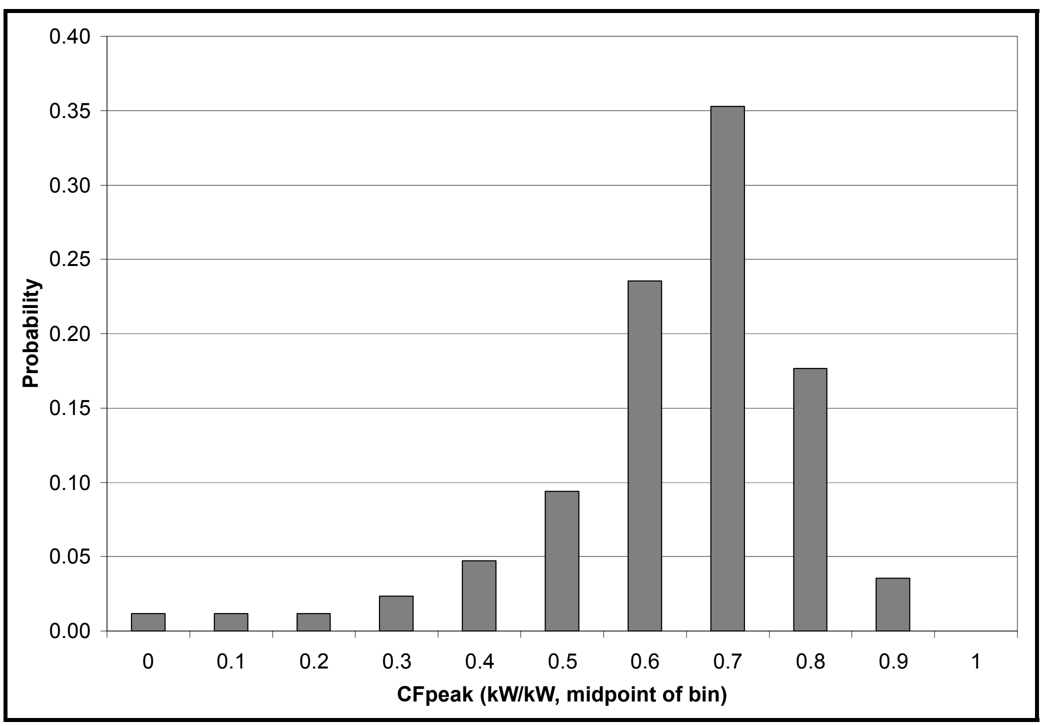


Figure C-6: PG&E PV Measured Coincident Peak Output (Coastal, Other)

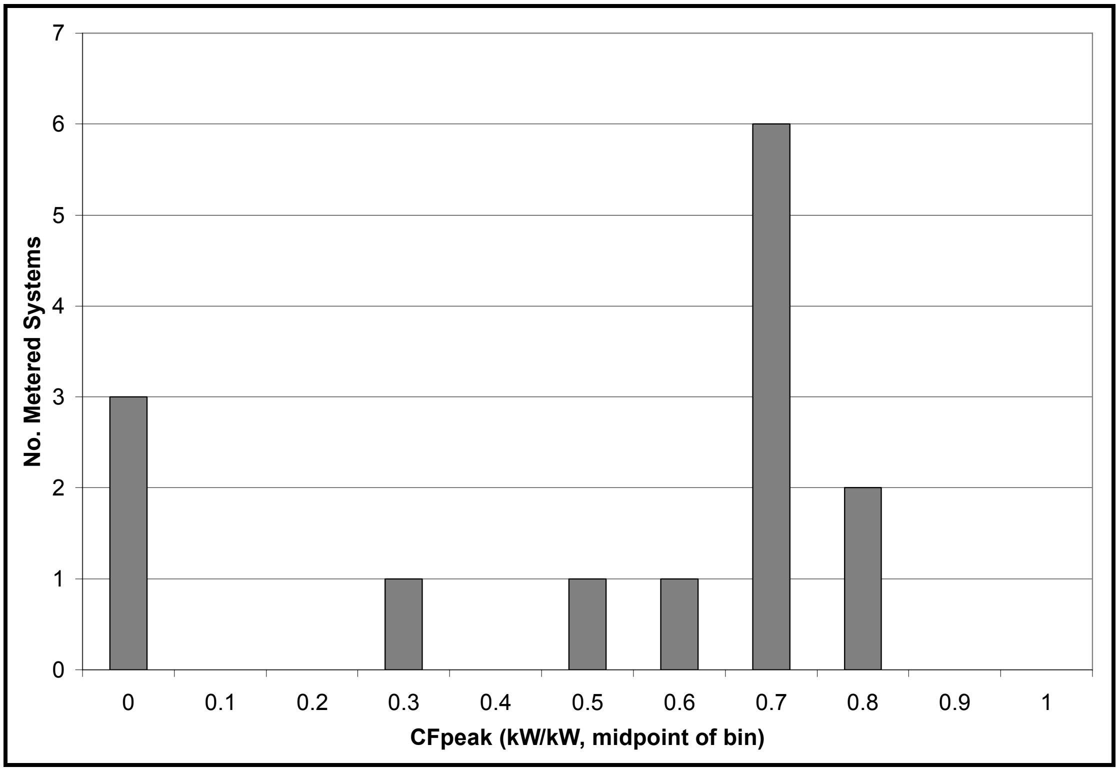


Figure C-7: MCS Distribution—PG&E PV Coincident Peak Output (Coastal, Other)

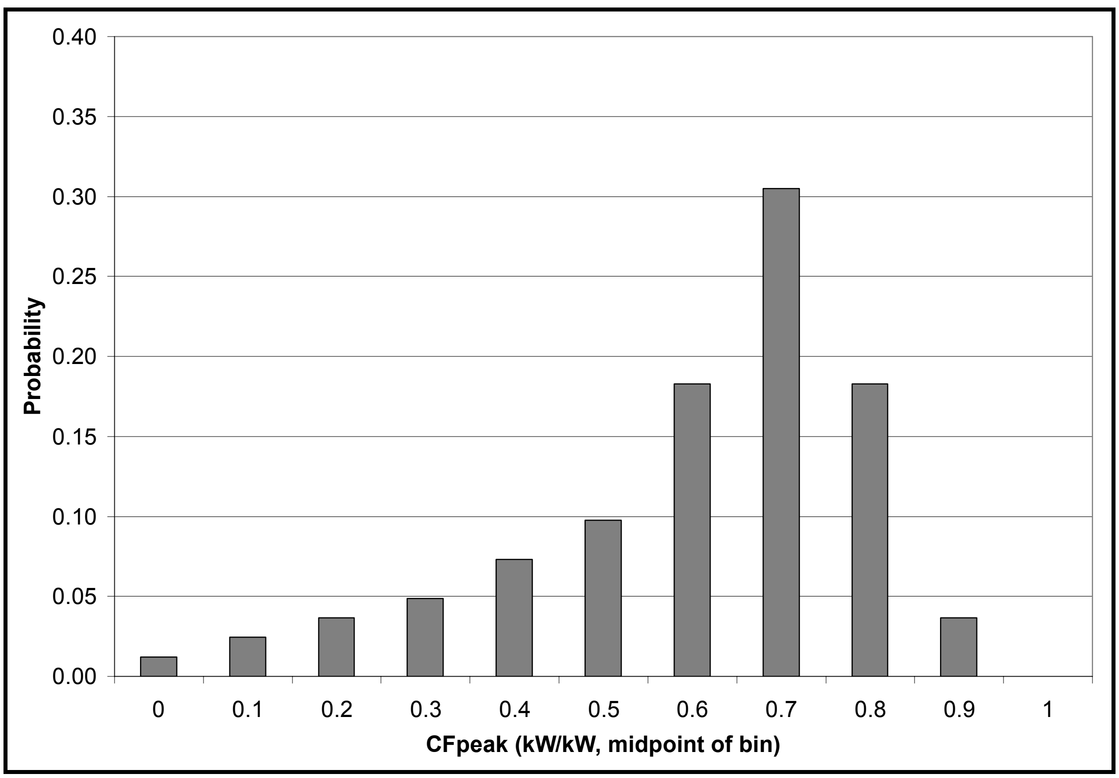


Figure C-8: PG&E PV Measured Coincident Peak Output (Inland, Near Flat)

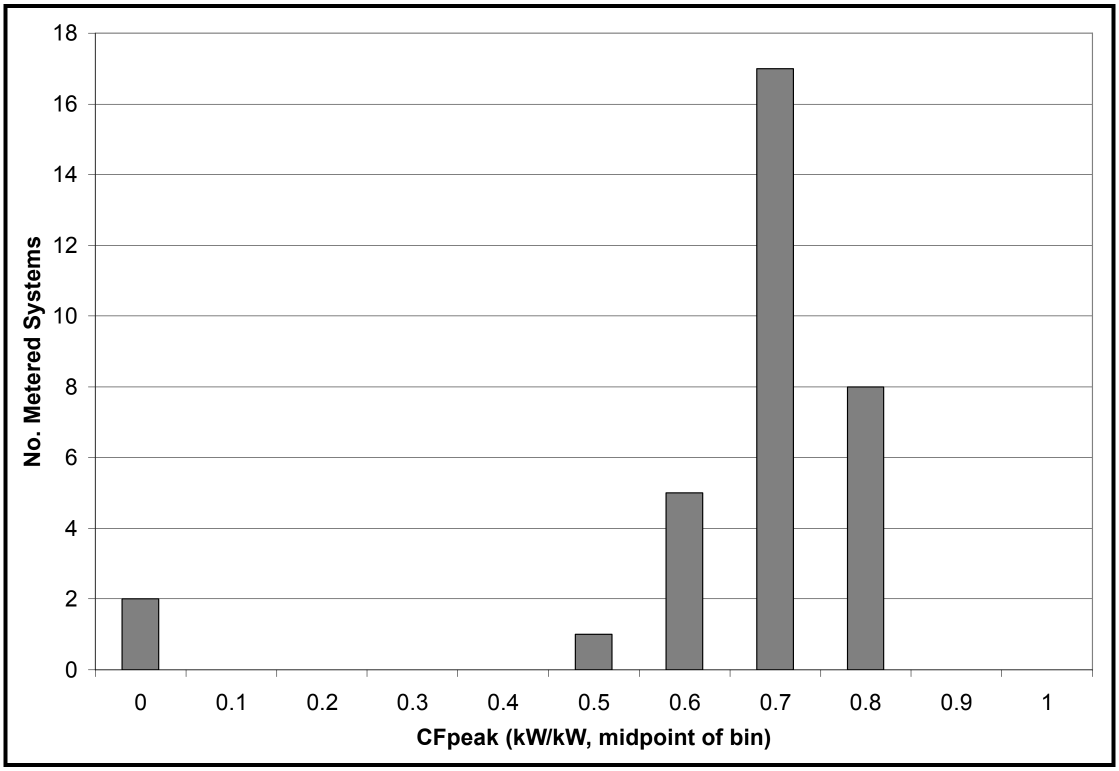


Figure C-9: MCS Distribution—PG&E PV Coincident Peak Output (Inland, Near Flat)

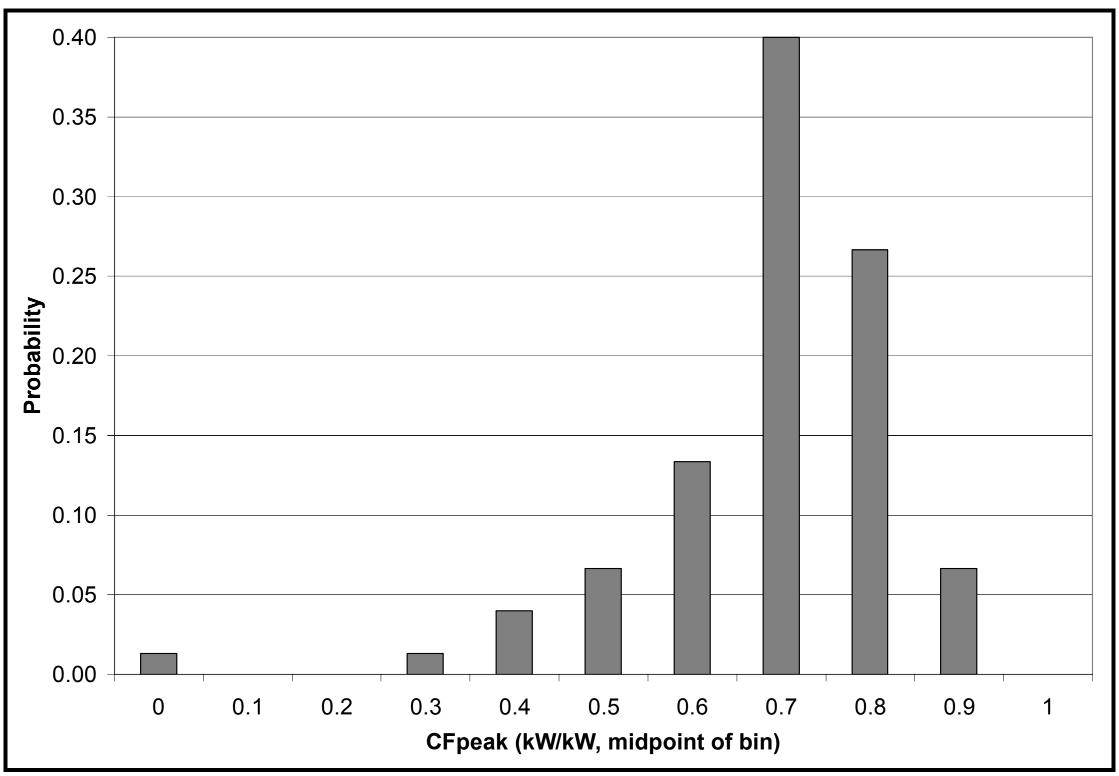


Figure C-10: PG&E PV Measured Coincident Peak Output (Inland, Other)

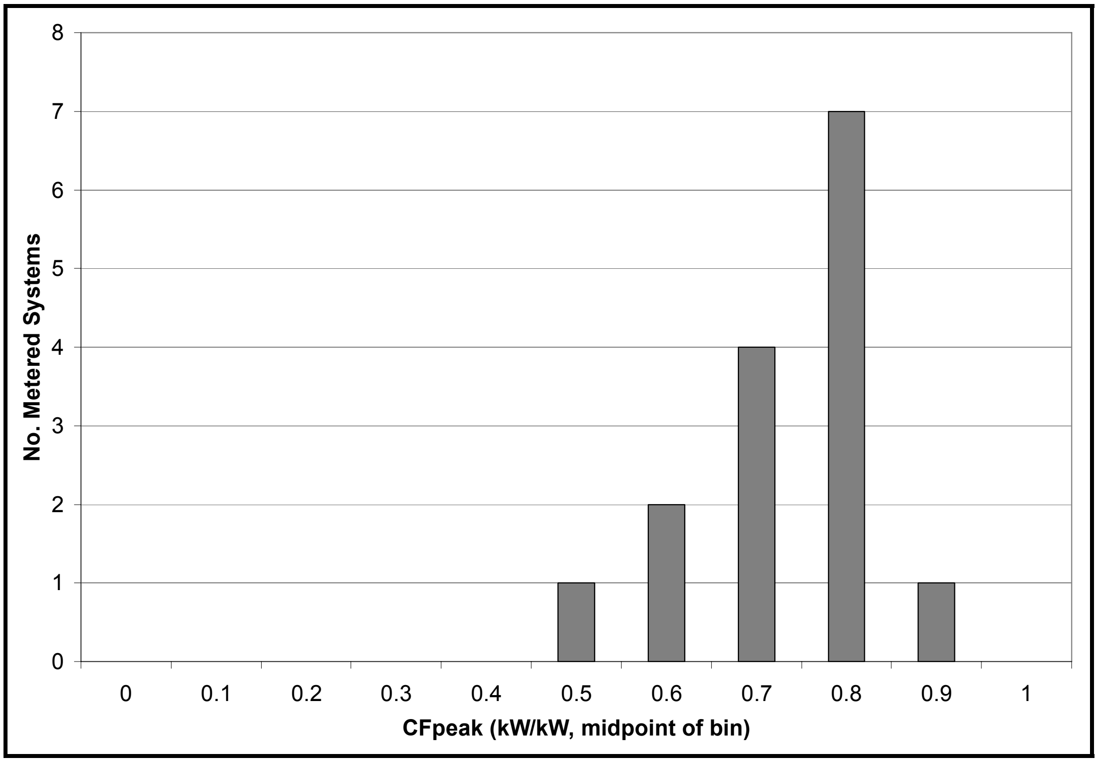


Figure C-11: MCS Distribution—PG&E PV Coincident Peak Output (Inland, Other)

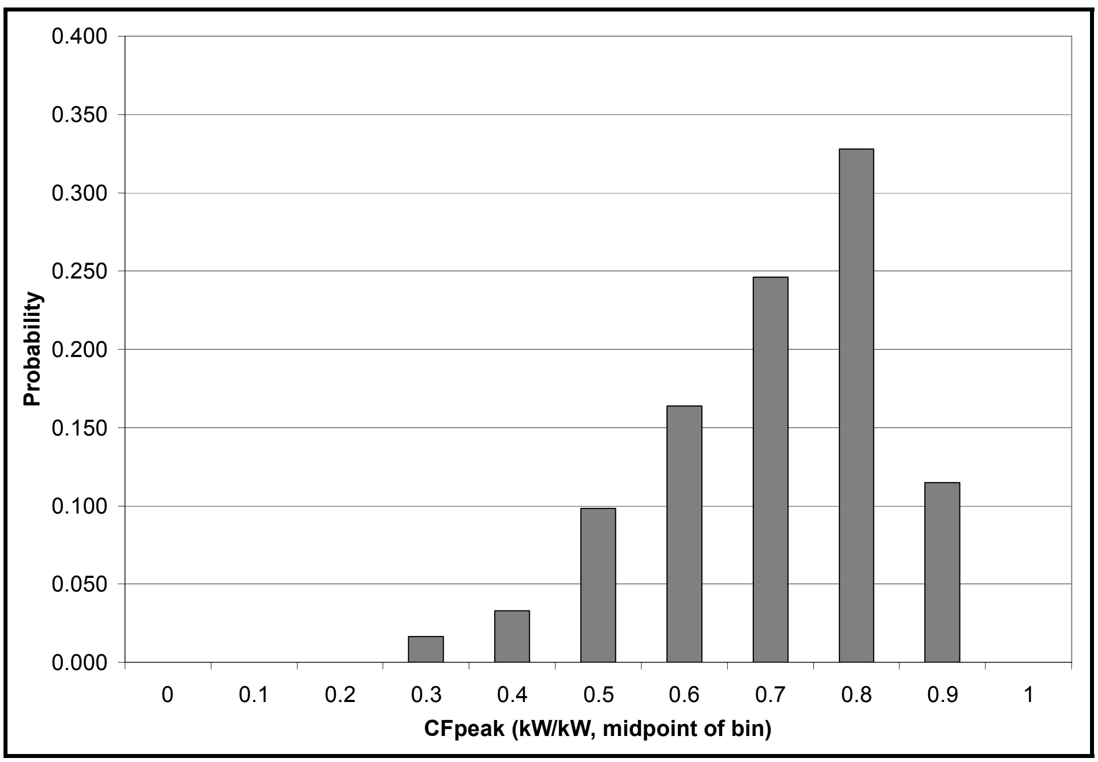


Figure C-12: PG&E PV Measured Coincident Peak Output (Tracking)

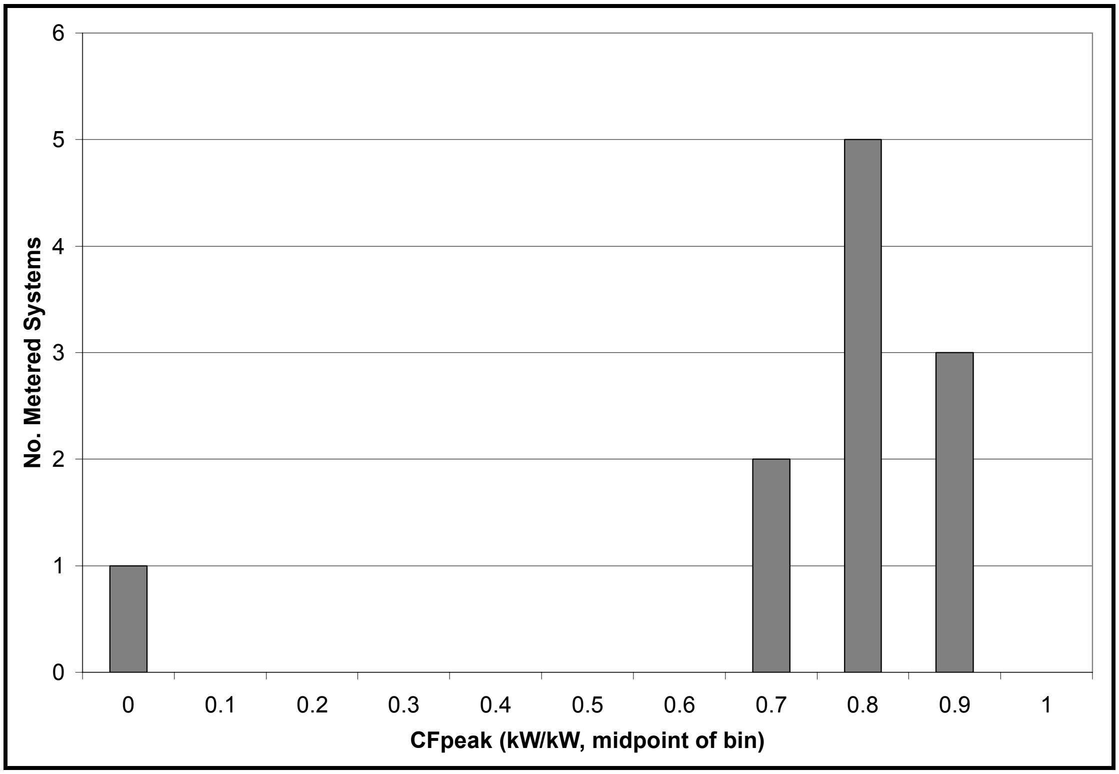


Figure C-13: MCS Distribution—PG&E PV Coincident Peak Output (Tracking)

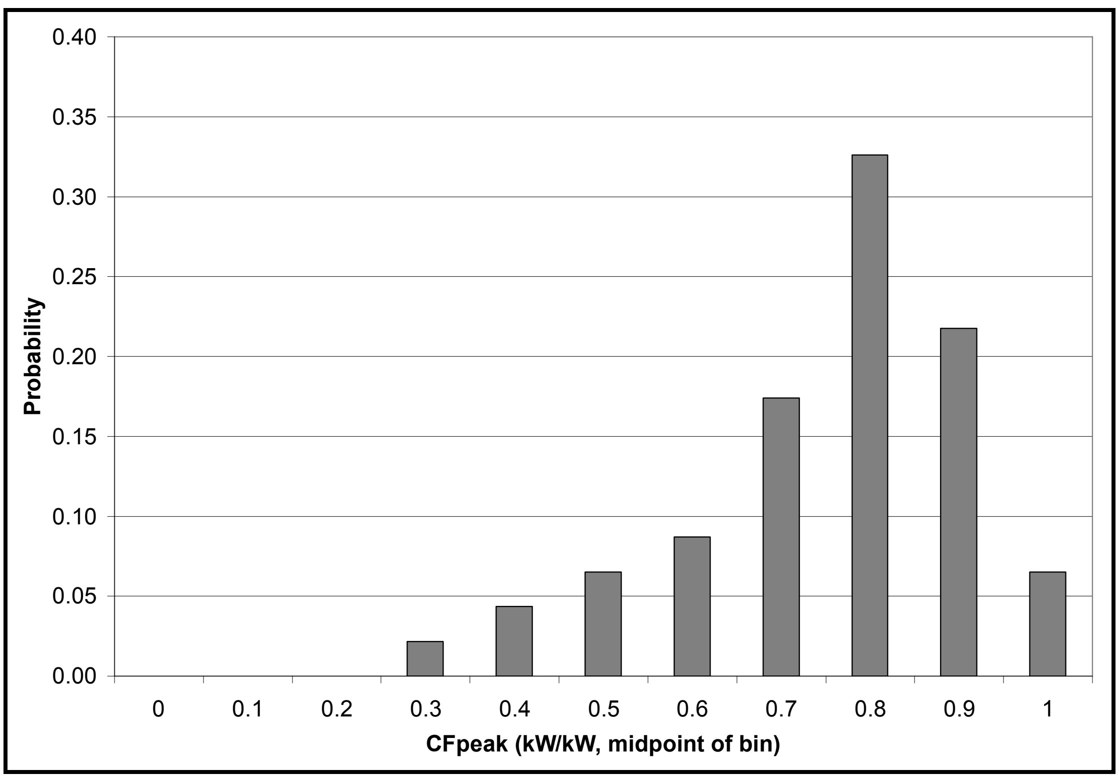


Figure C-14: LA (SCE & SCG) PV Measured Coincident Peak Output (Coastal, Near Flat)

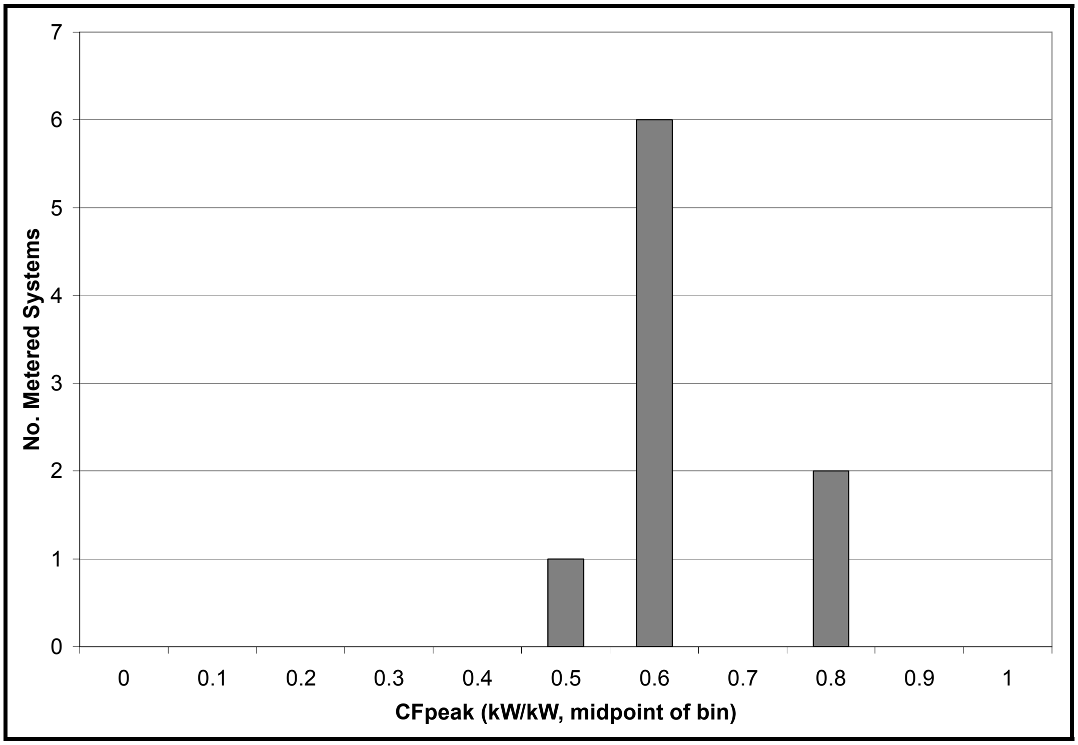


Figure C-15: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Coastal, Near Flat)

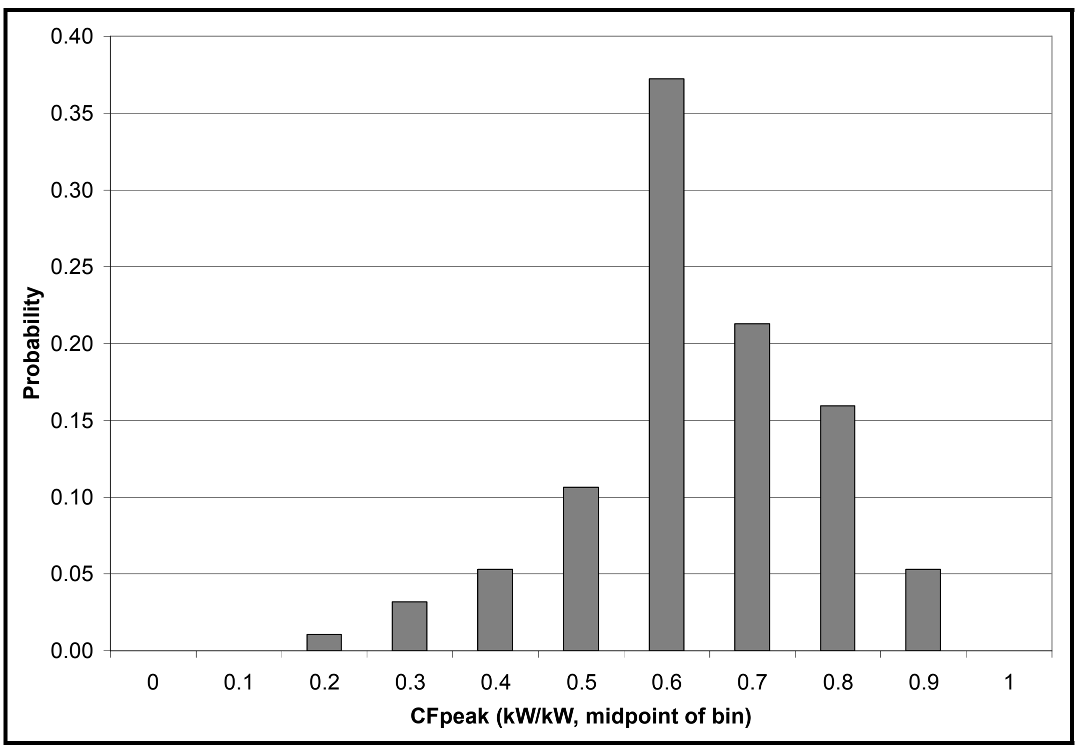


Figure C-16: LA (SCE & SCG) PV Measured Coincident Peak Output (Coastal, Other)

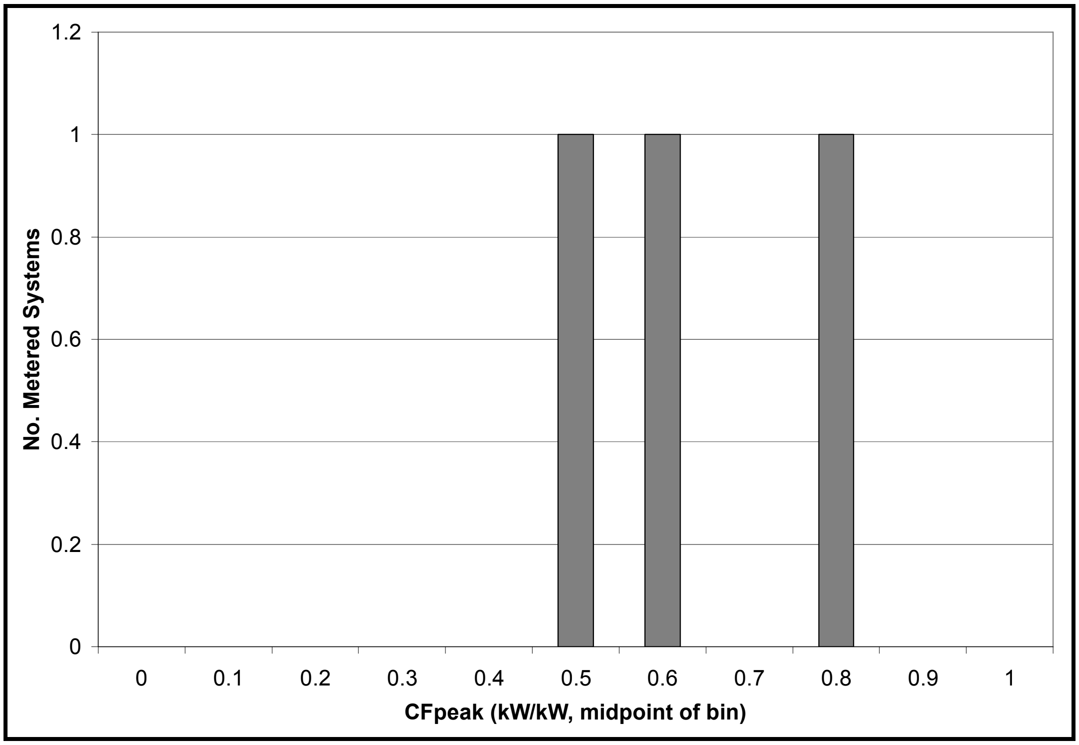


Figure C-17: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Coastal, Other)

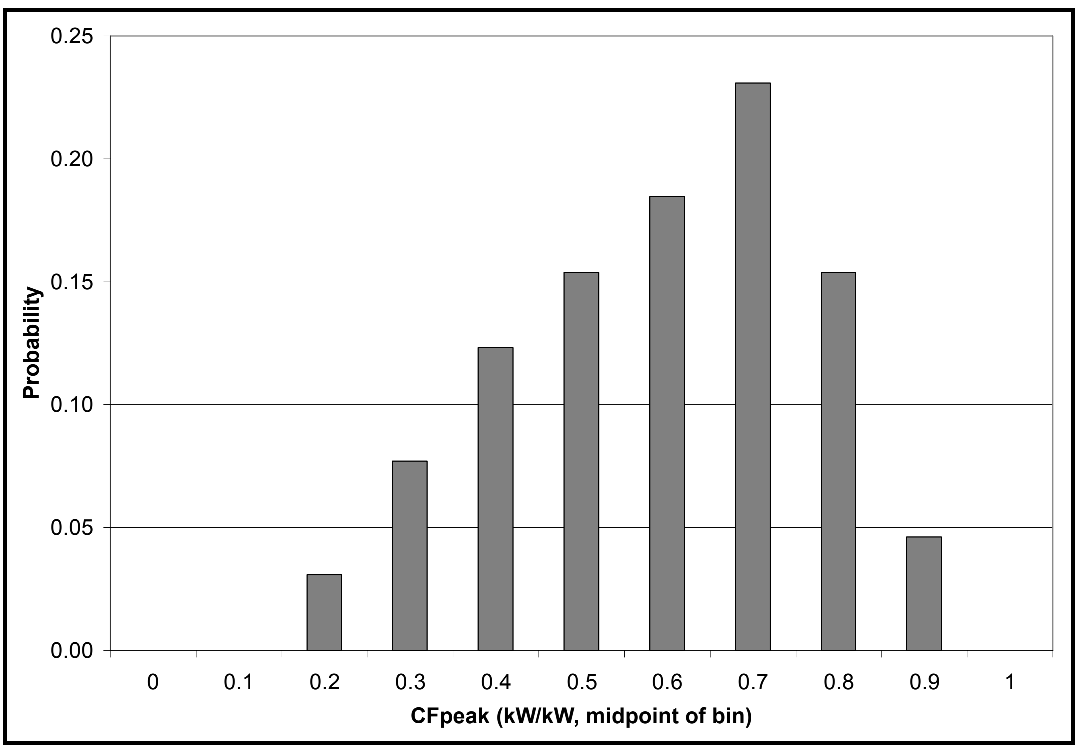


Figure C-18: LA (SCE & SCG) PV Measured Coincident Peak Output (Inland, Near Flat)

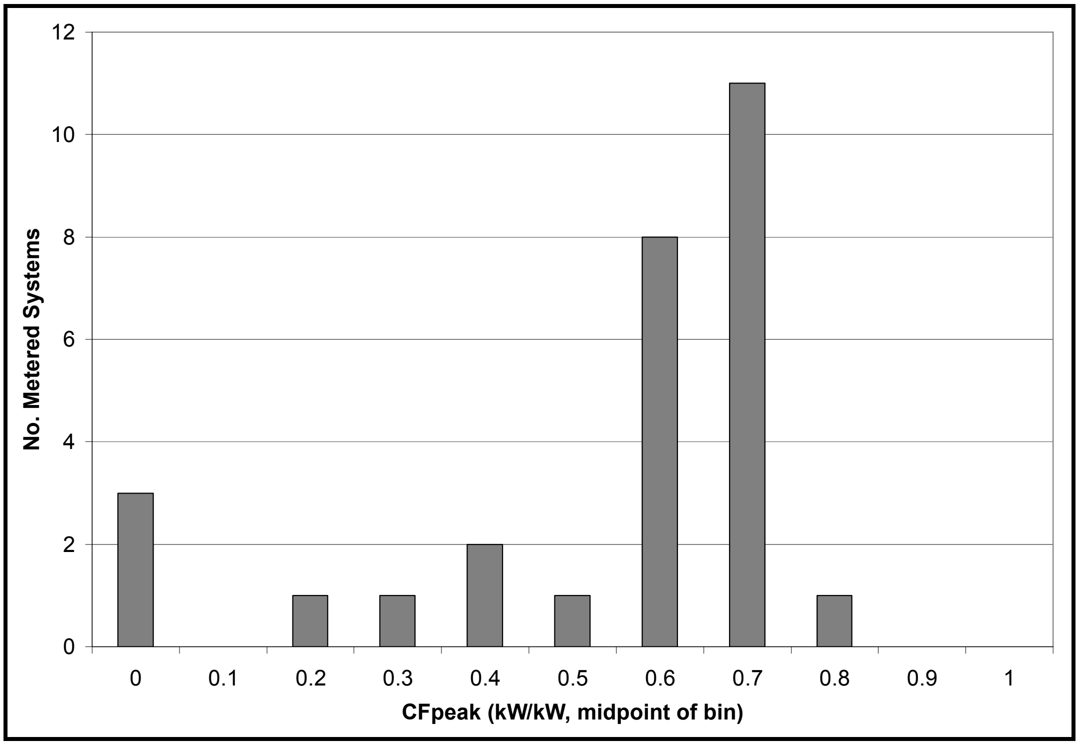


Figure C-19: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Inland, Near Flat)

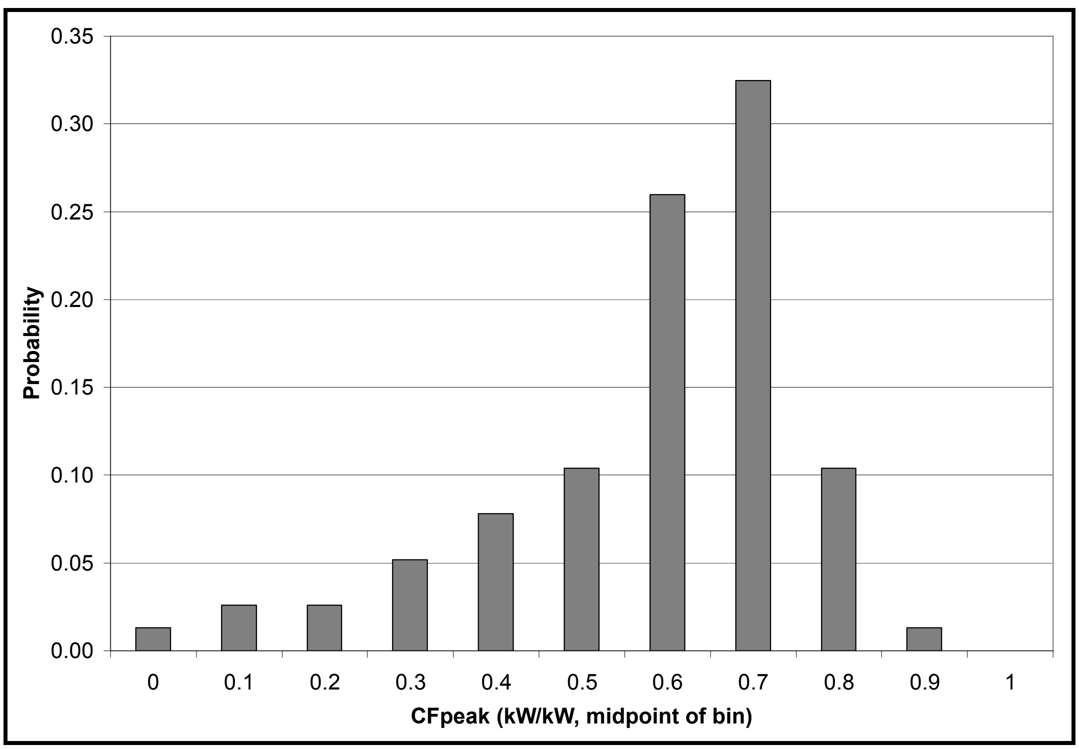


Figure C-20: LA (SCE & SCG) PV Measured Coincident Peak Output (Inland, Other)

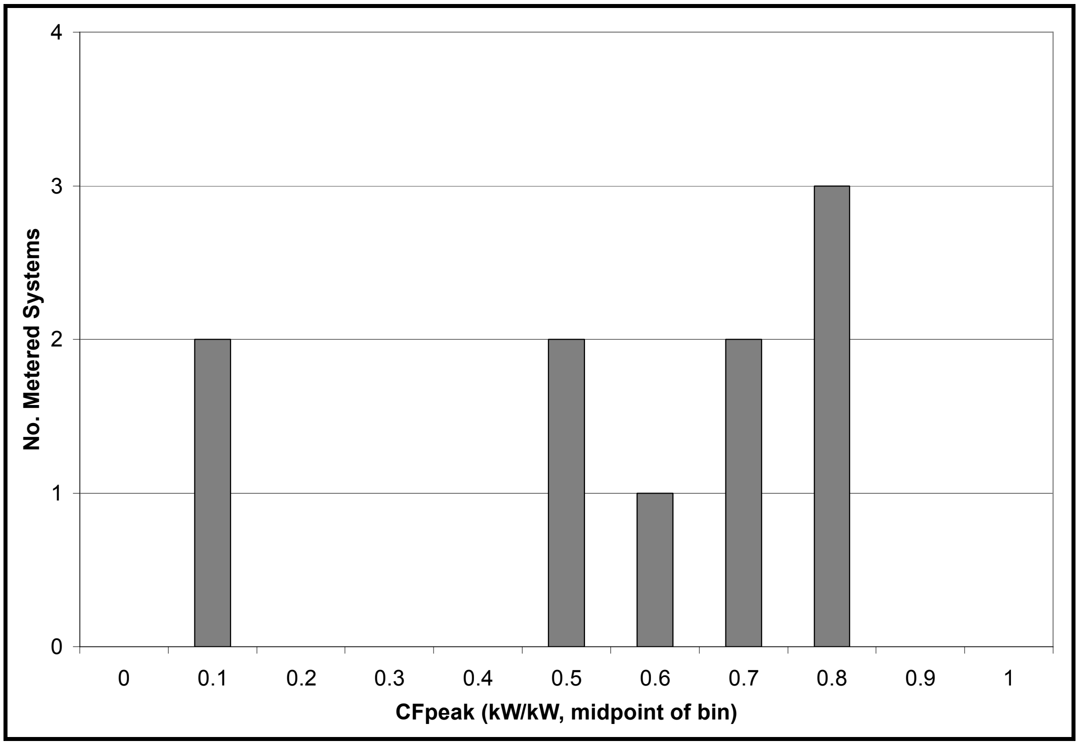


Figure C-21: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Inland, Other)

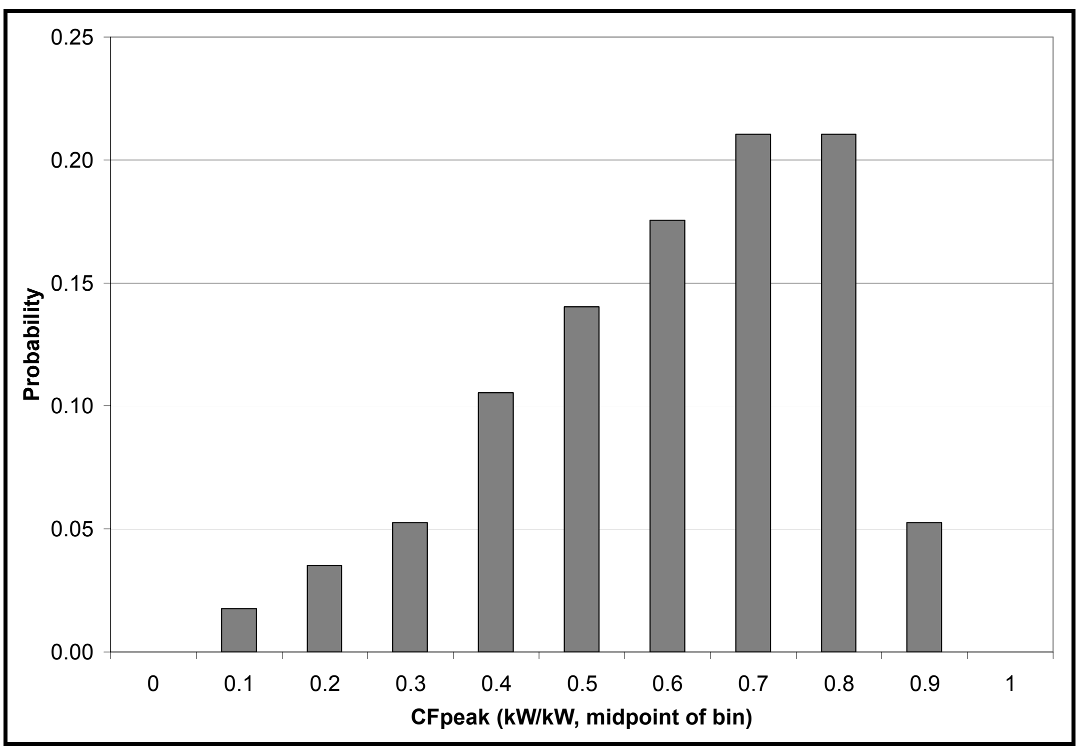


Figure C-22: LA (SCE & SCG) PV Measured Coincident Peak Output (Tracking)

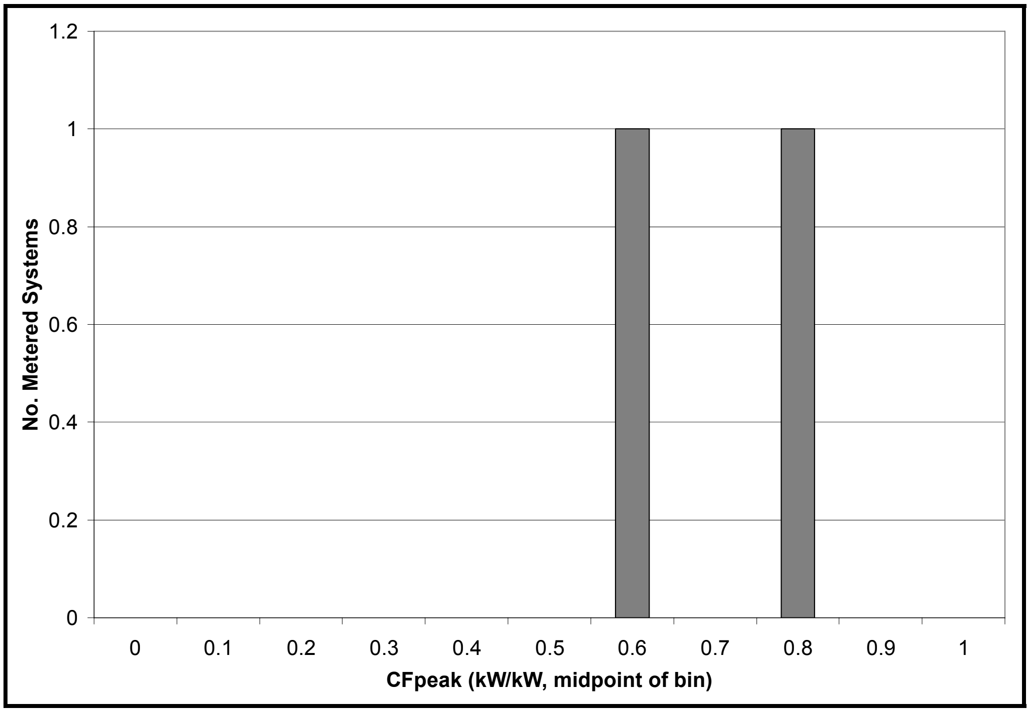


Figure C-23: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Tracking)

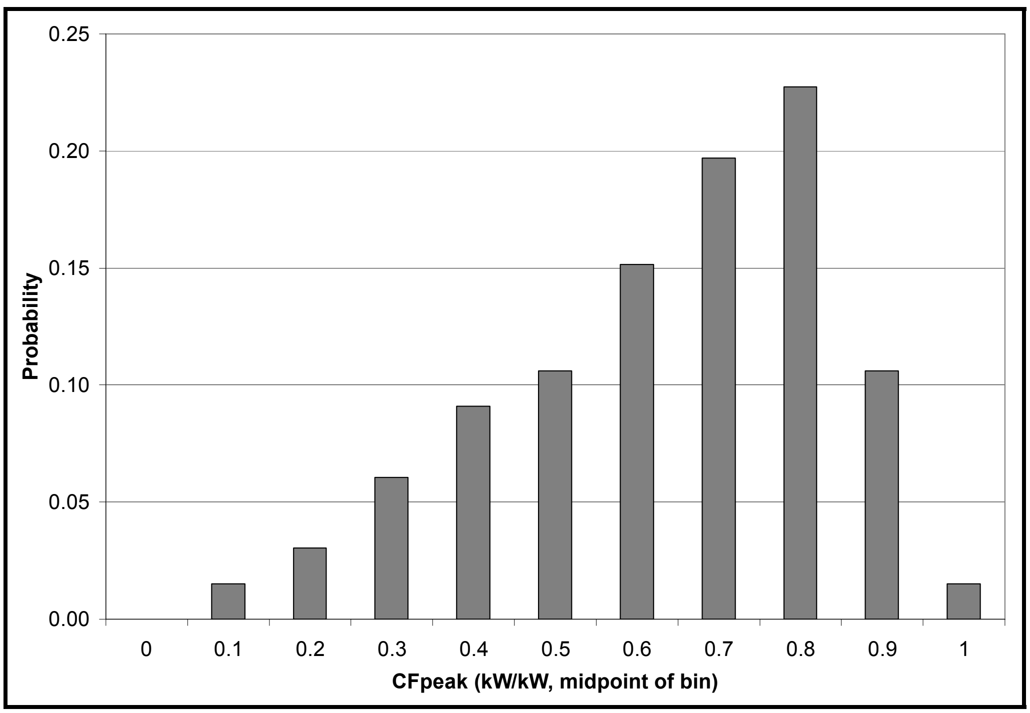


Figure C-24: CCSE PV Measured Coincident Peak Output (Coastal, Near Flat)

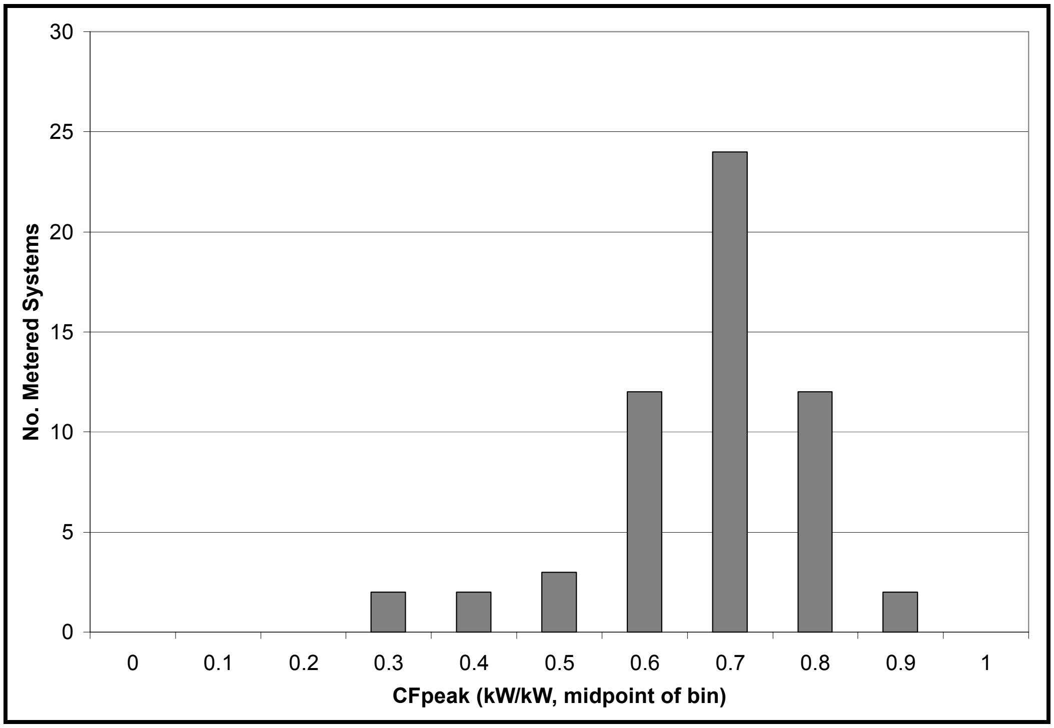


Figure C-25: MCS Distribution—CCSE PV Coincident Peak Output (Coastal, Near Flat)

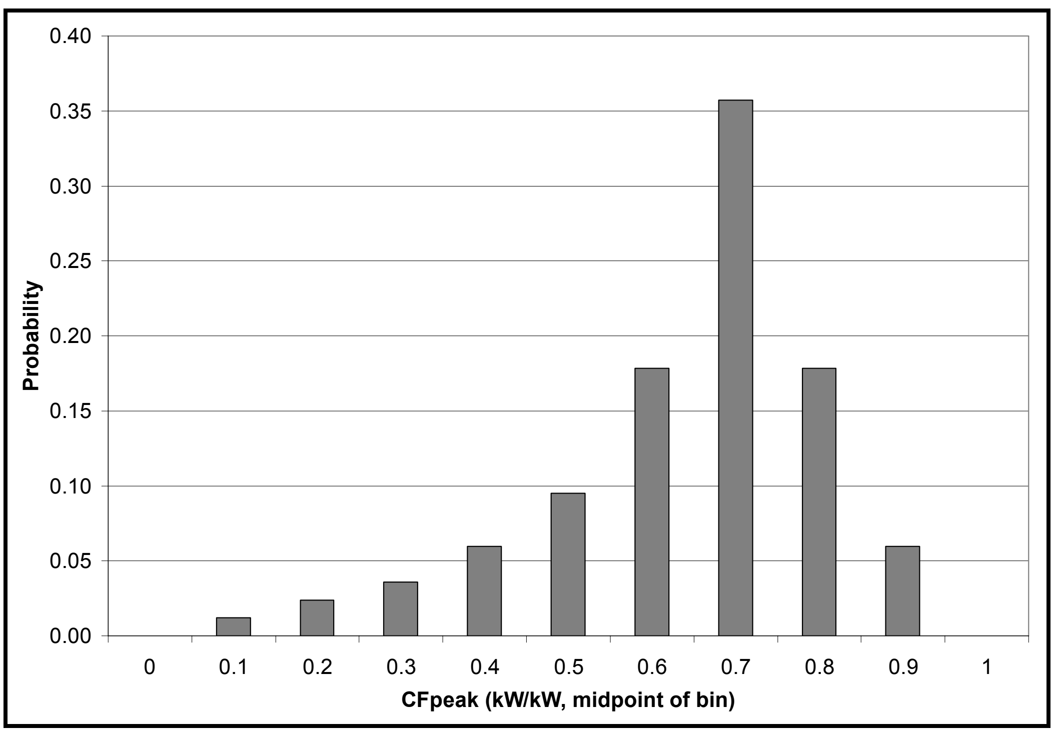


Figure C-26: CCSE PV Measured Coincident Peak Output (Coastal, Other)

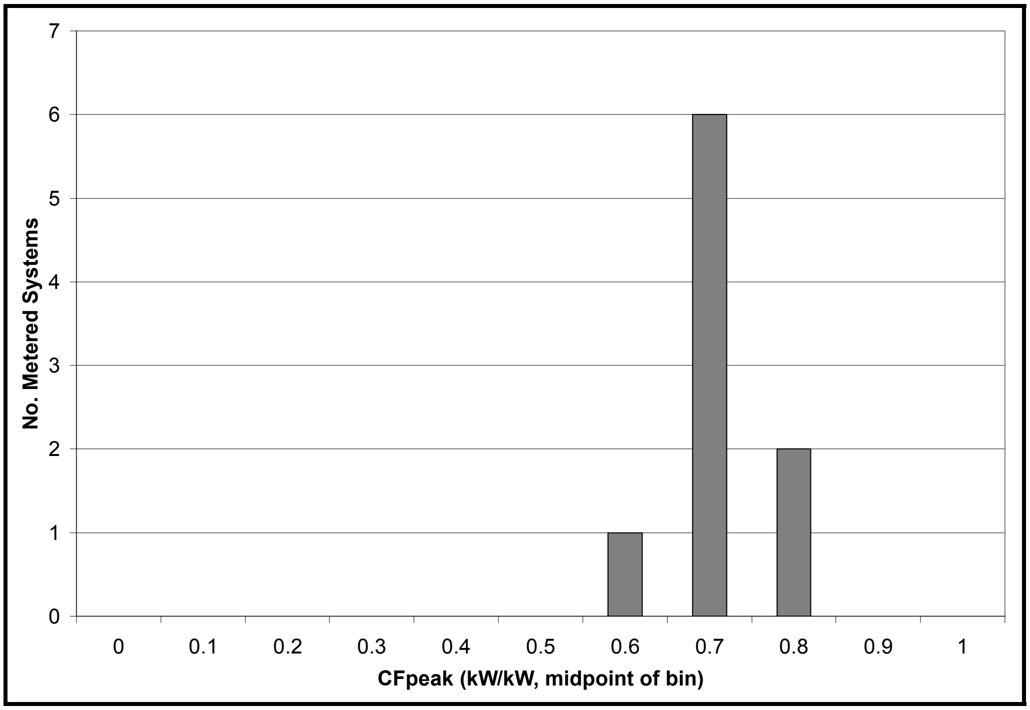


Figure C-27: MCS Distribution—CCSE PV Coincident Peak Output (Coastal, Other)

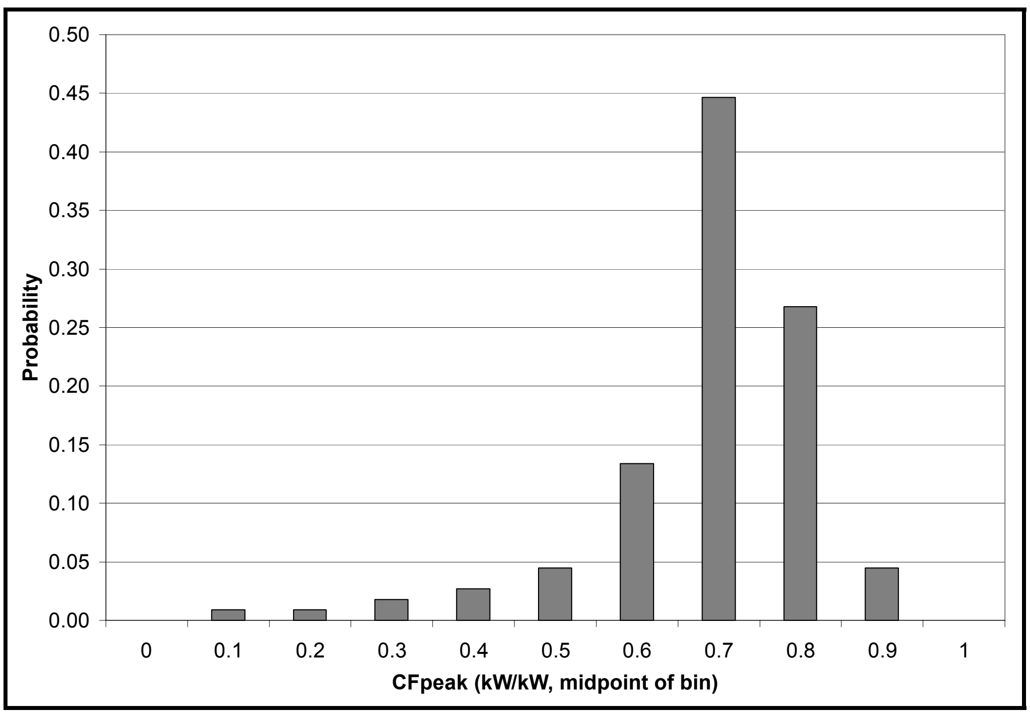


Figure C-28: CCSE PV Measured Coincident Peak Output (Inland, Near Flat)

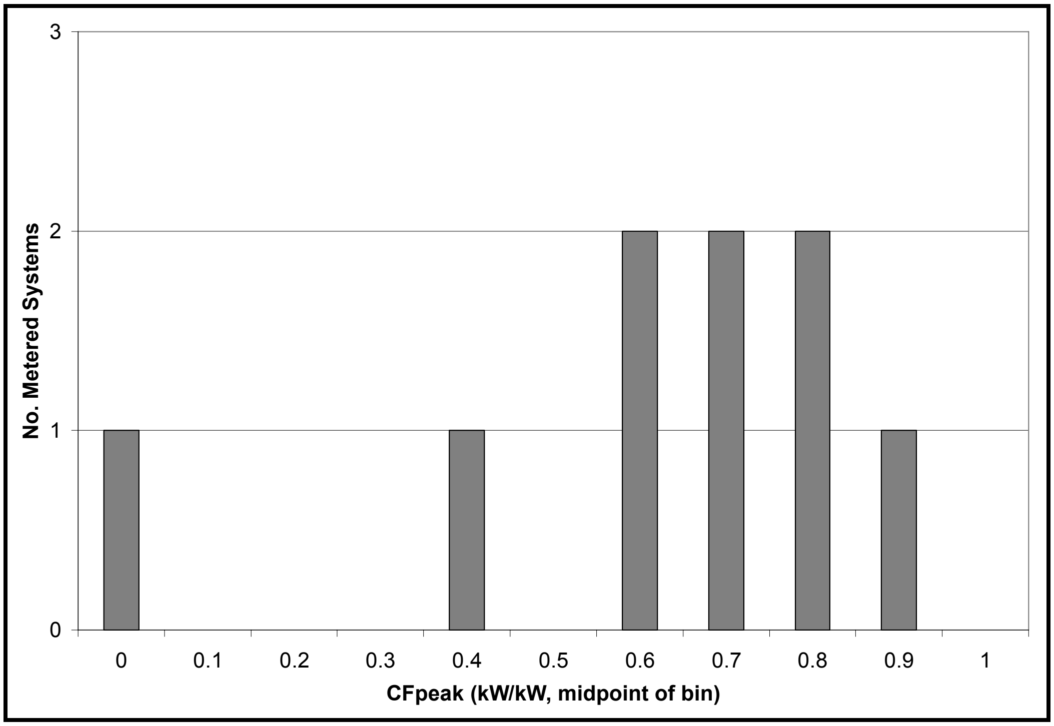


Figure C-29: MCS Distribution—CCSE PV Coincident Peak Output (Inland, Near Flat)

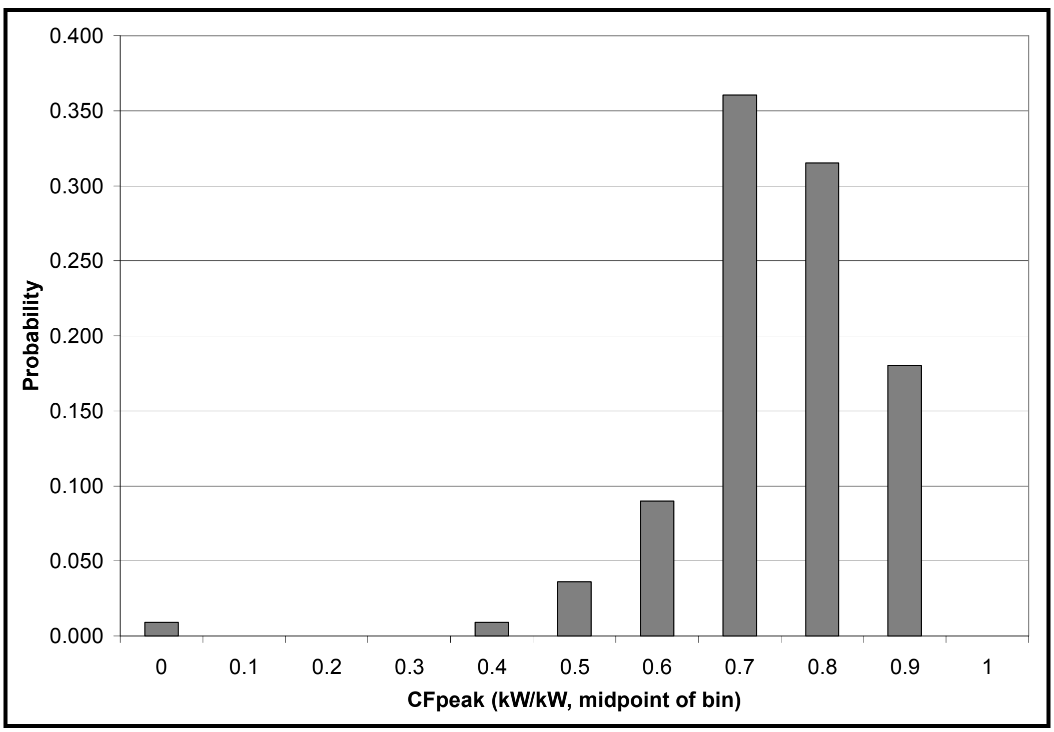


Figure C-30: CCSE PV Measured Coincident Peak Output (Inland, Other)

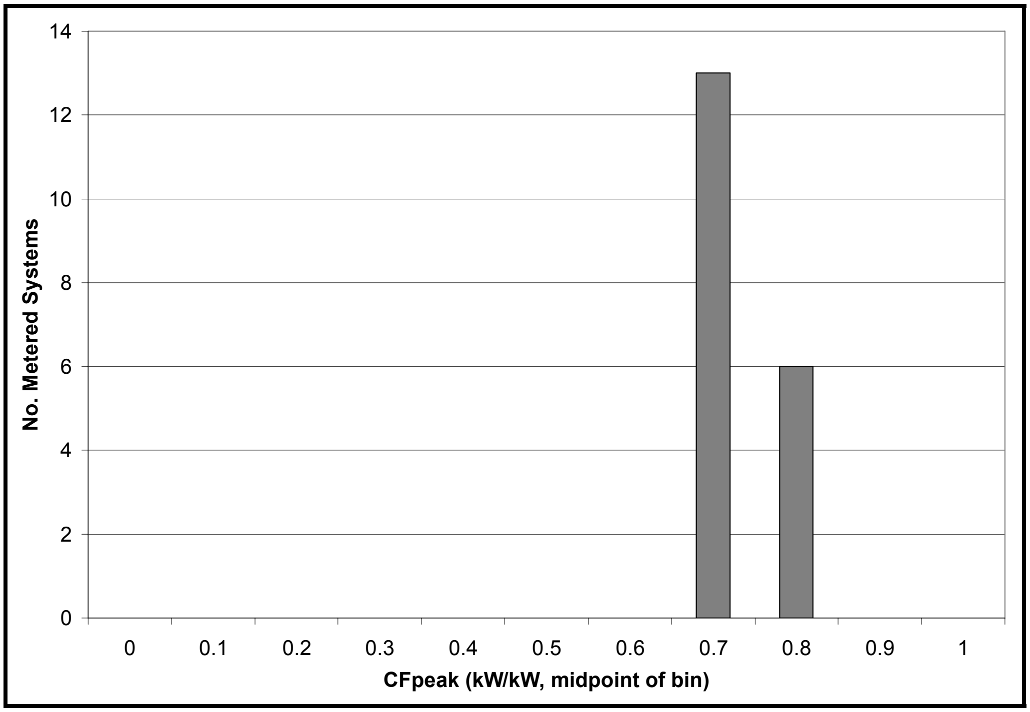


Figure C-31: MCS Distribution—CCSE PV Coincident Peak Output (Inland, Other)

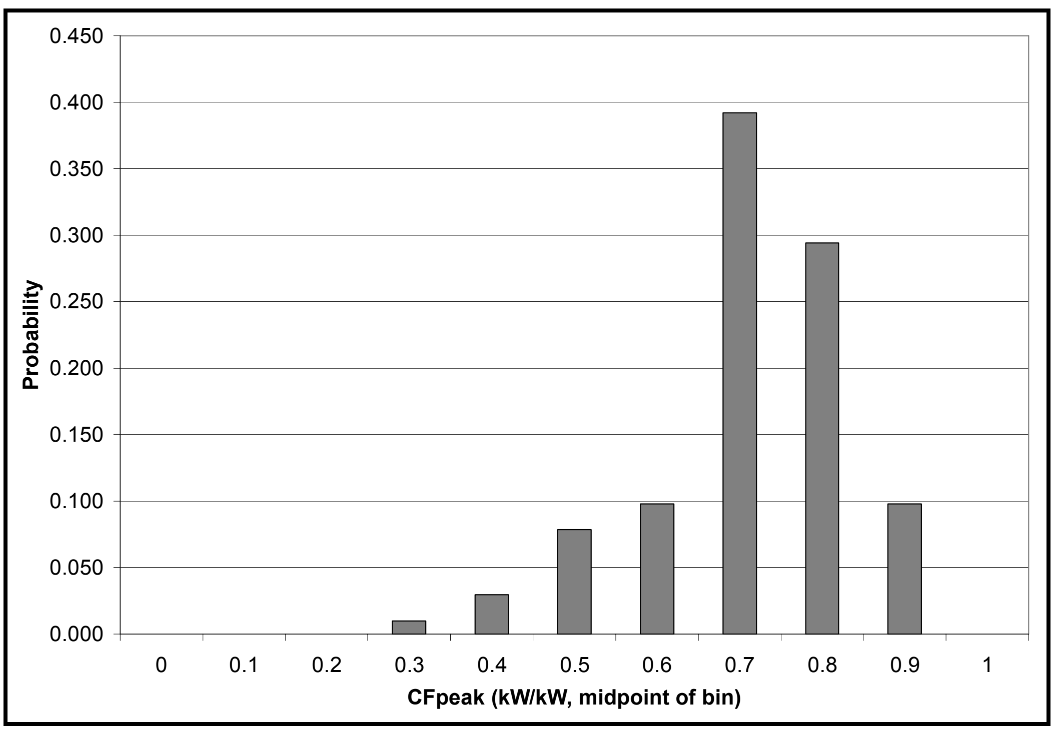


Figure C-32: Fuel Cell Measured Coincident Peak Output (Non-Renewable Fuel)

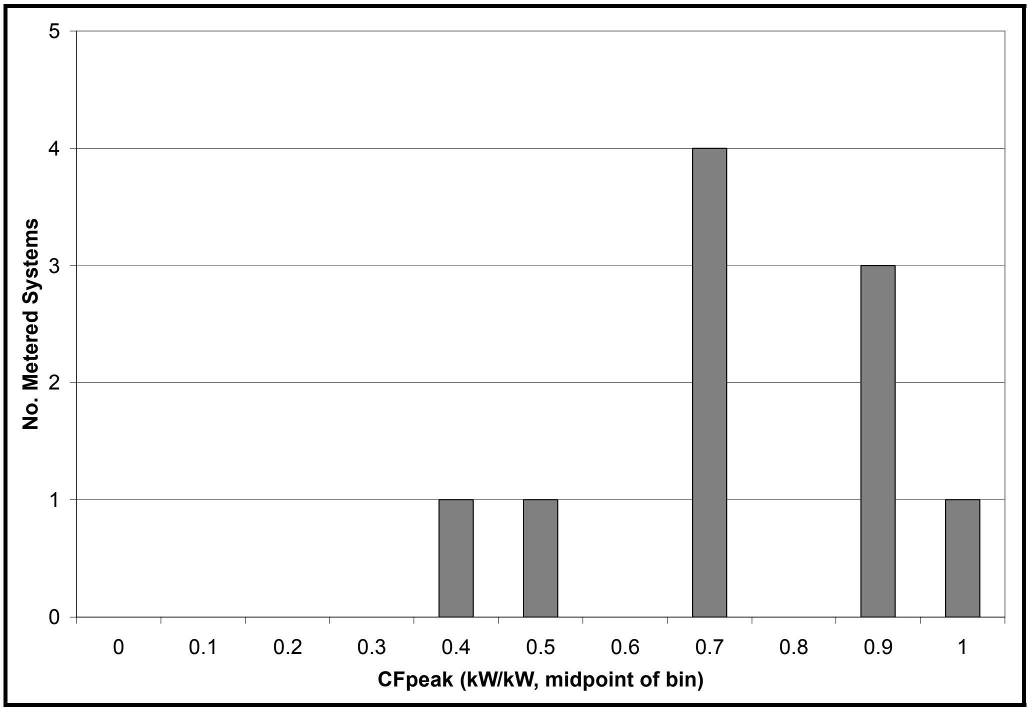


Figure C-33: MCS Distribution –Fuel Cell Coincident Peak Output (Non-Renewable Fuel)

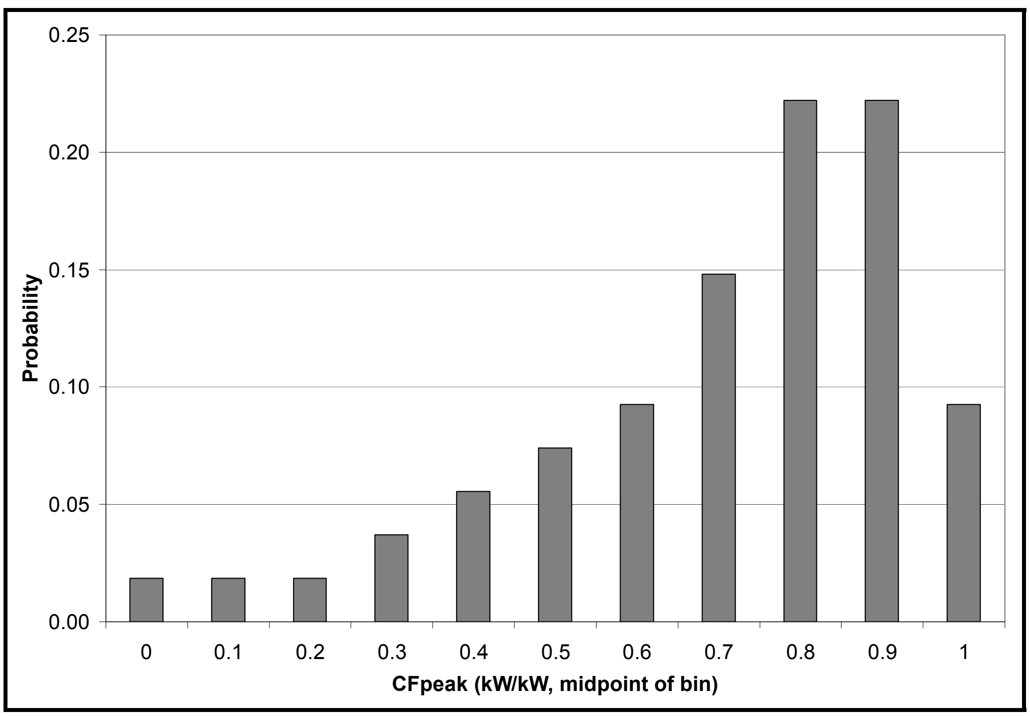


Figure C-34: Fuel Cell Measured Coincident Peak Output (Renewable Fuel)

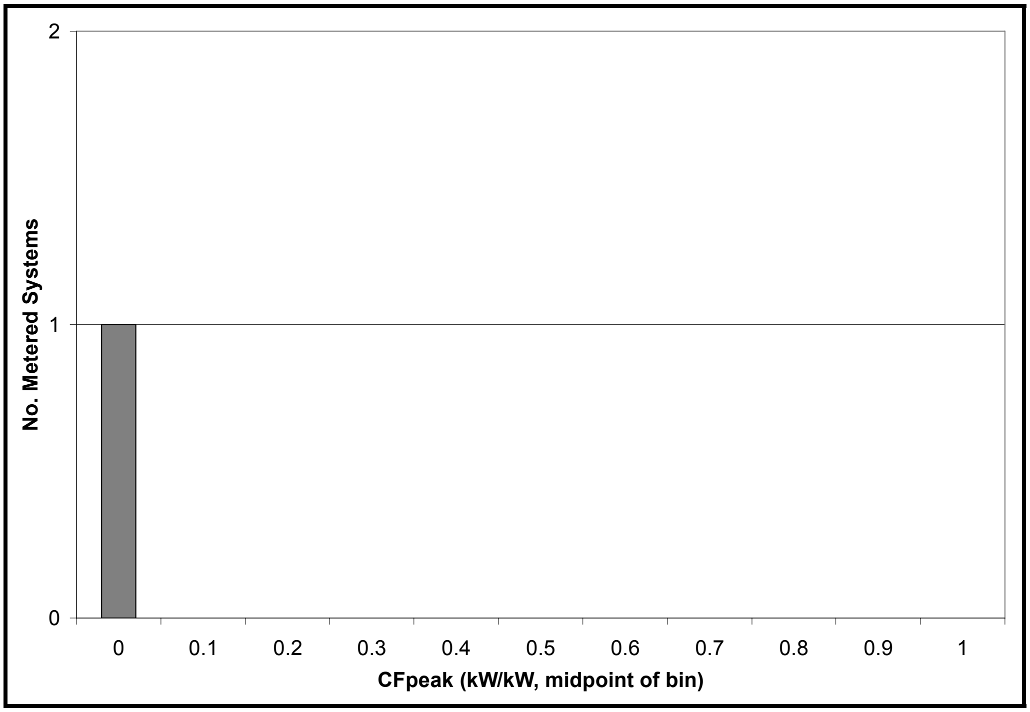


Figure C-35: MCS Distribution –Fuel Cell Coincident Peak Output (Renewable Fuel)

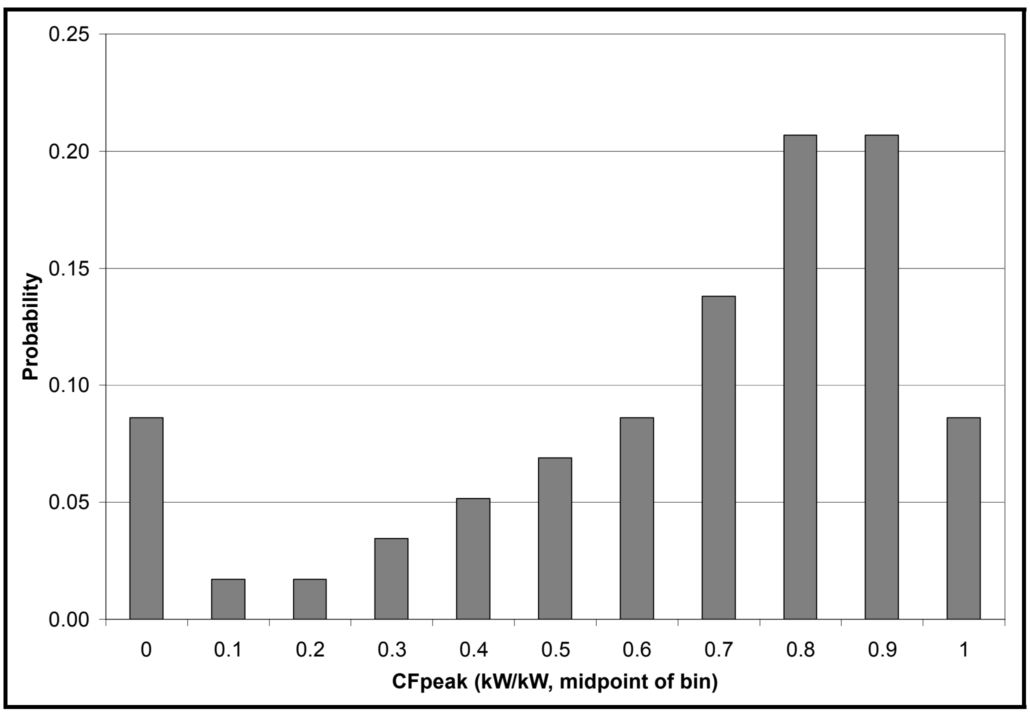


Figure C-36: IC Engine Measured Coincident Peak Output (Non-Renewable Fuel)

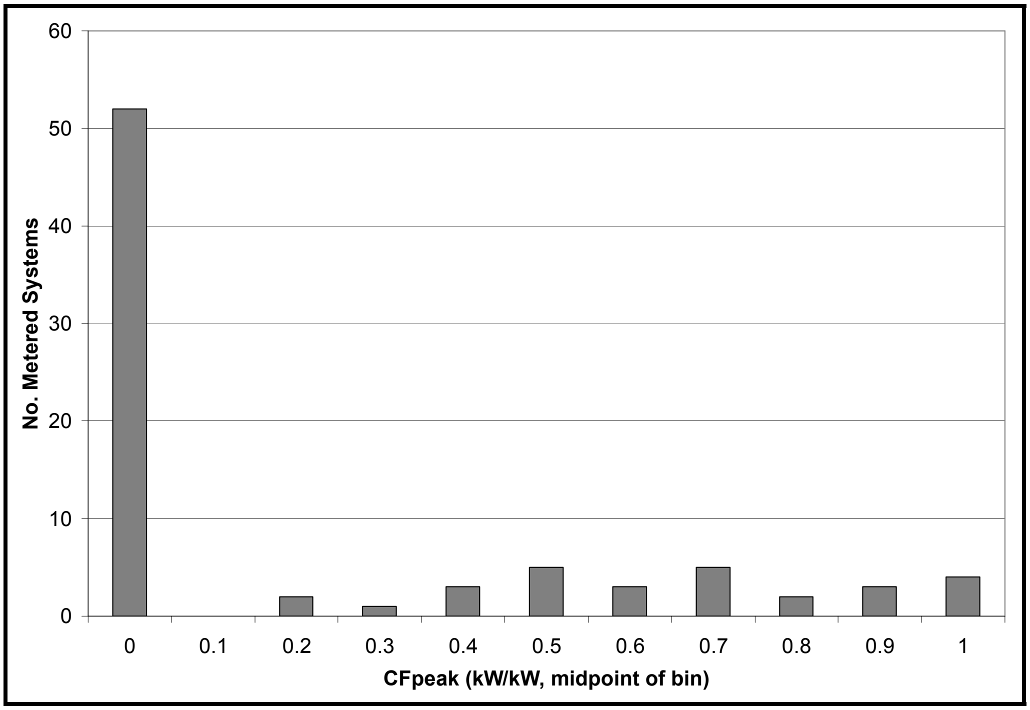


Figure C-37: MCS Distribution—IC Engine Coincident Peak Output (Non-Renewable Fuel)

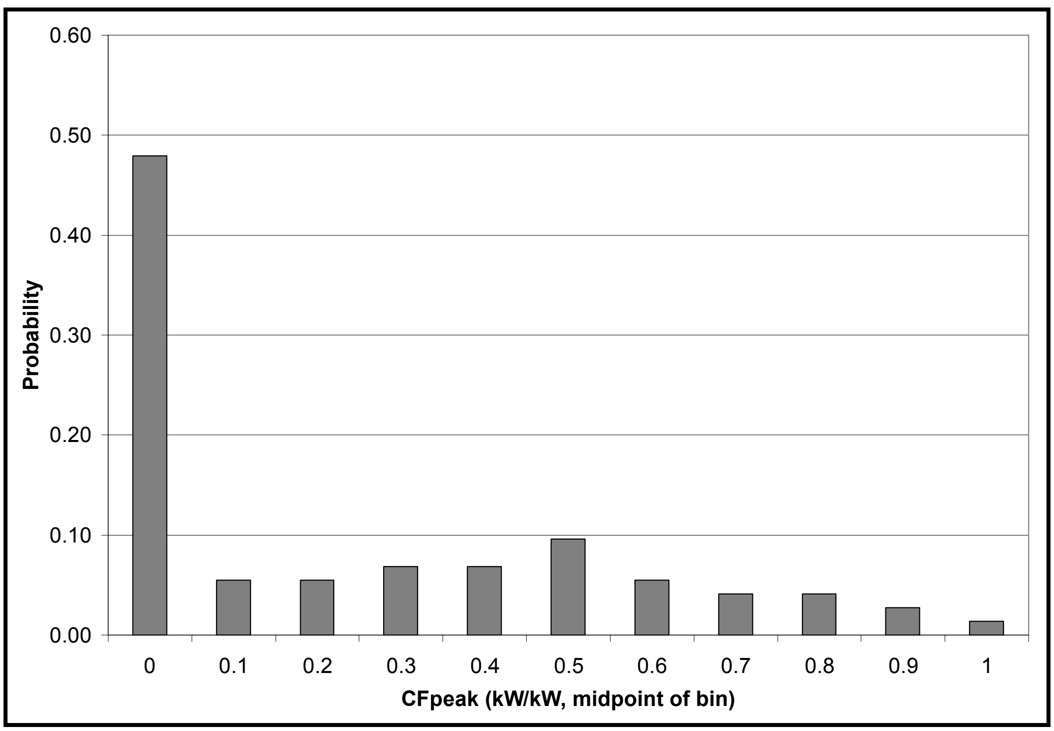


Figure C-38: IC Engine Measured Coincident Peak Output (Renewable Fuel)

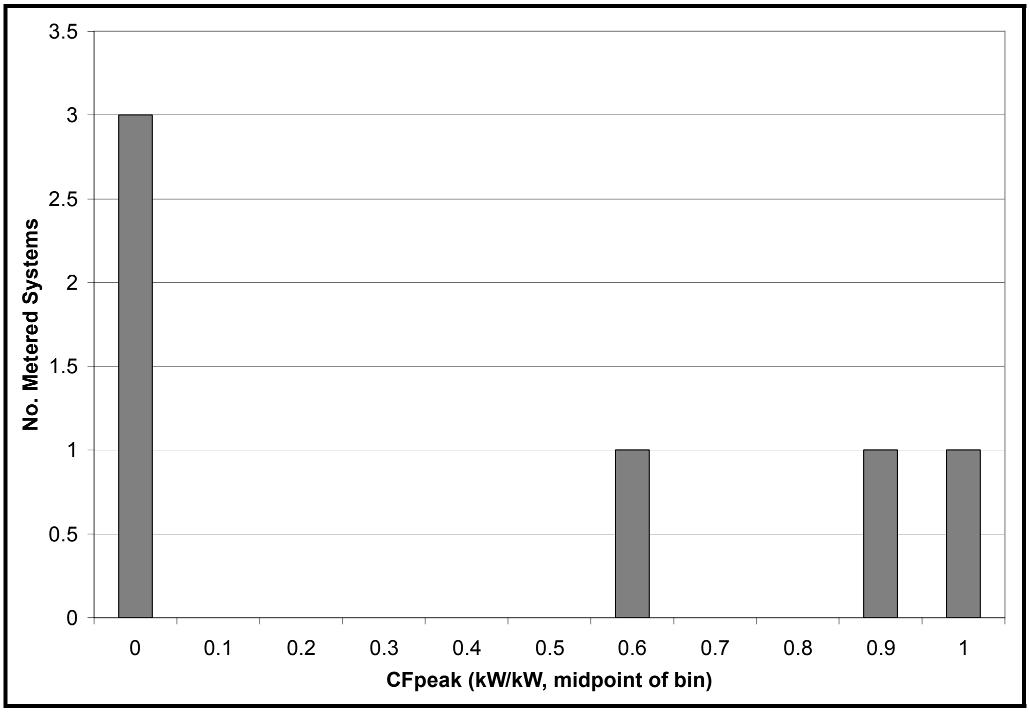


Figure C-39: MCS Distribution—IC Engine Coincident Peak Output (Renewable Fuel)

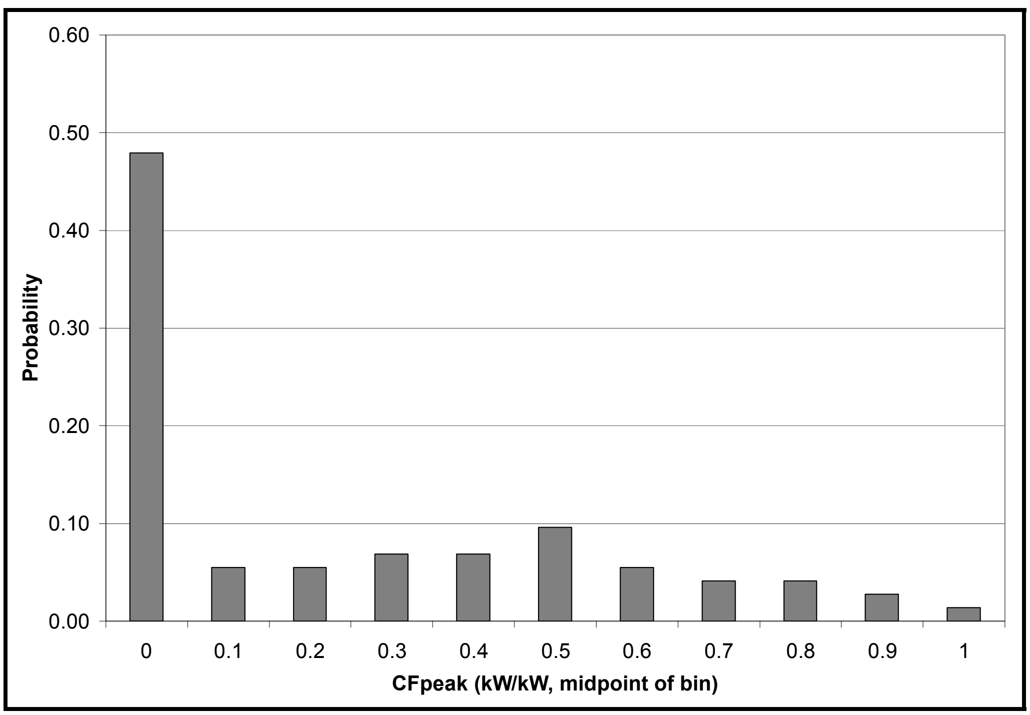


Figure C-40: Gas Turbine Measured Coincident Peak Output (Non-Renewable Fuel)

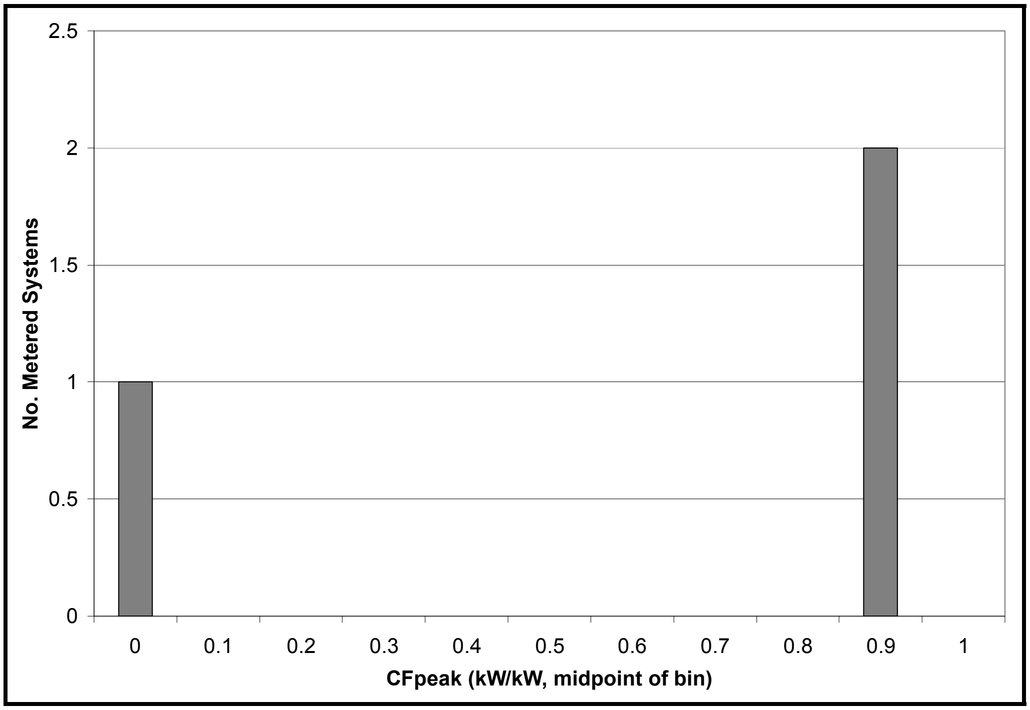


Figure C-41: MCS Distribution—Gas Turbine Coincident Peak Output (Non-Renewable Fuel)

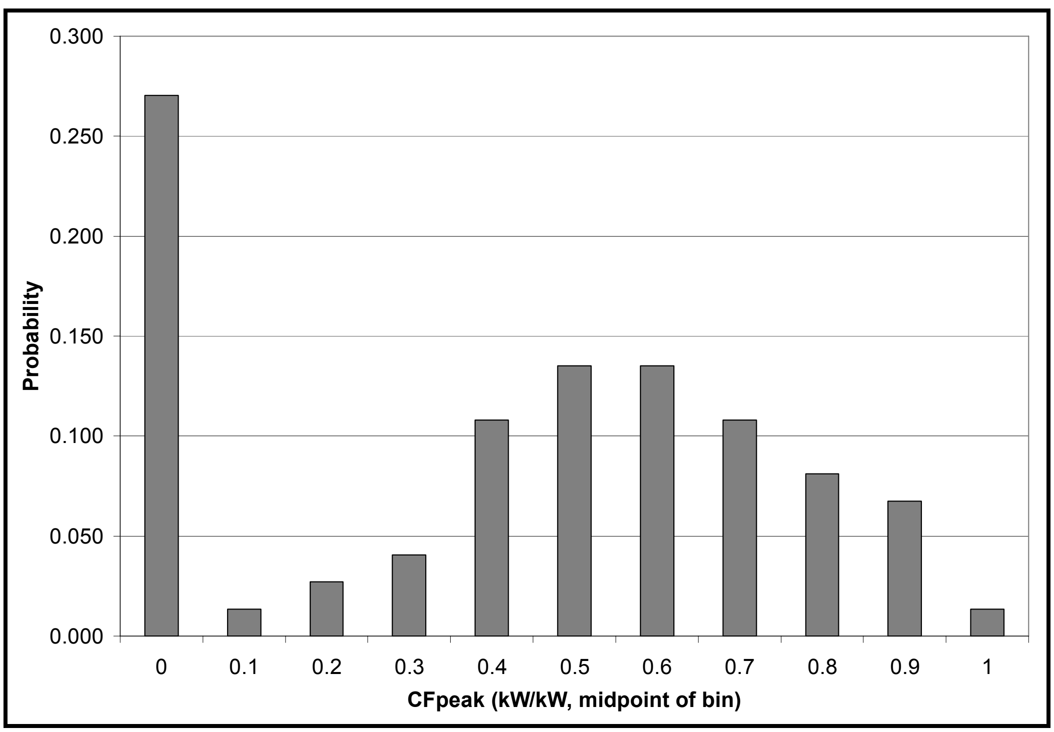


Figure C-42: Microturbine Measured Coincident Peak Output (Non-Renewable Fuel)

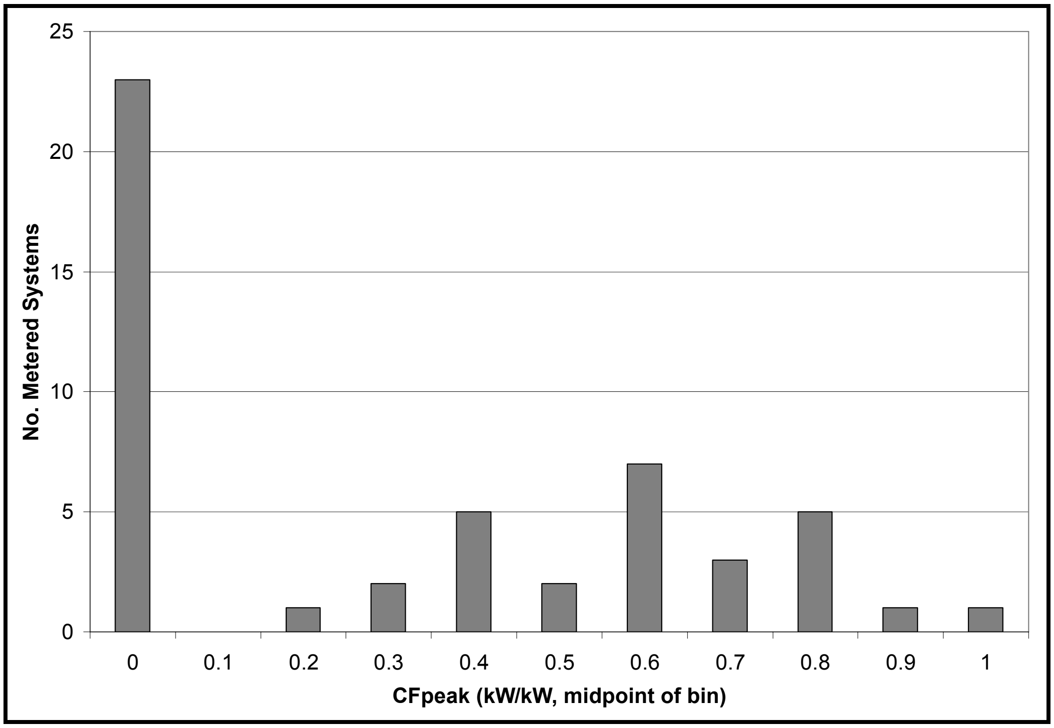


Figure C-43: MCS Distribution—Microturbine Coincident Peak Output (Non-Renewable Fuel)

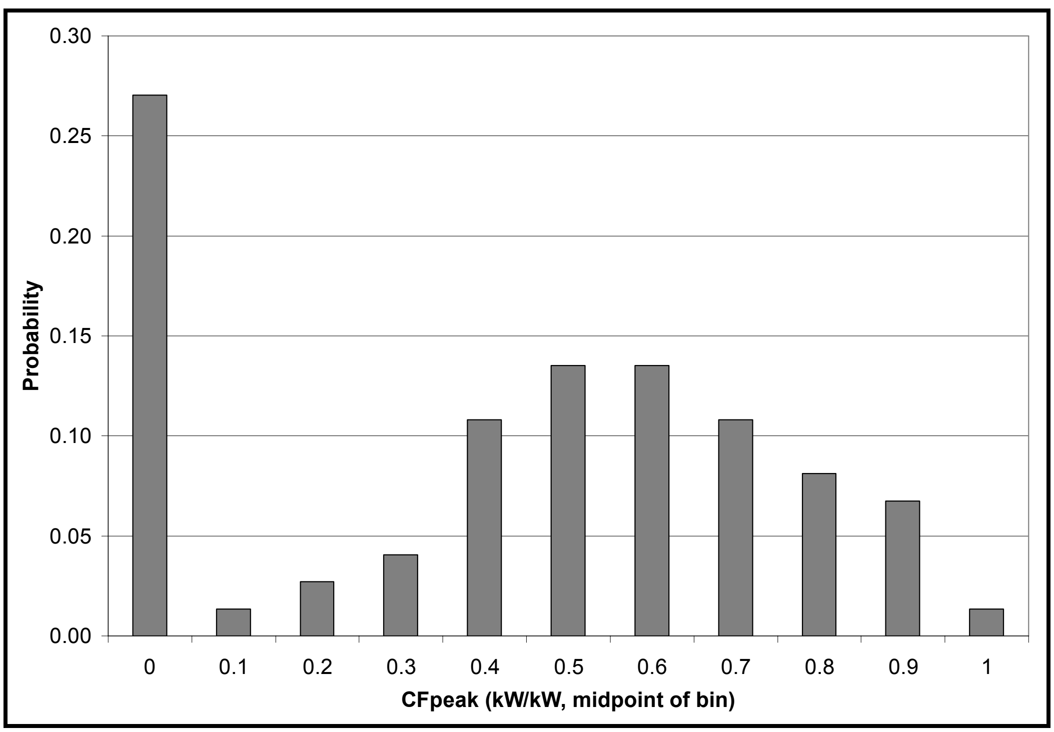


Figure C-44: Microturbine Measured Coincident Peak Output (Renewable Fuel)

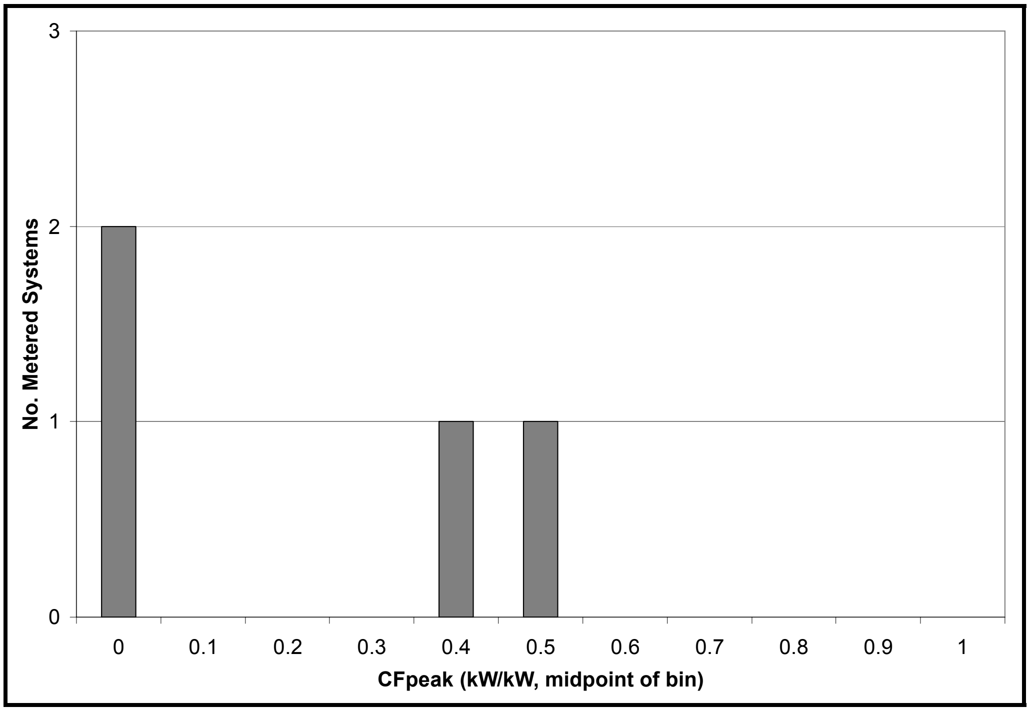
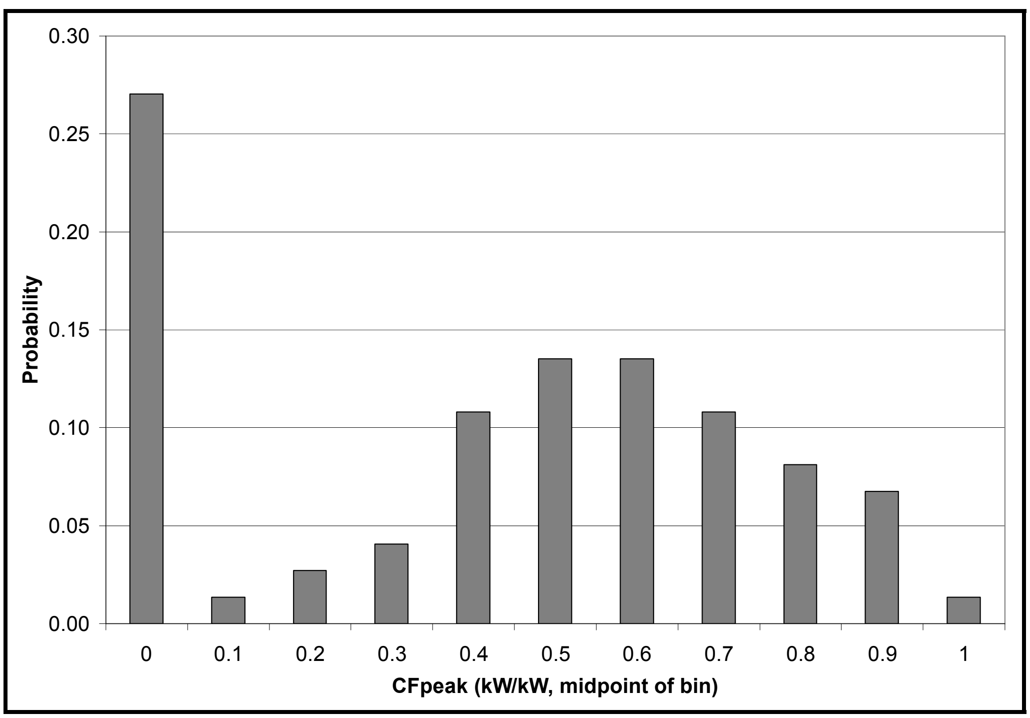


Figure C-45: MCS Distribution—Microturbine Coincident Peak Output (Renewable Fuel)



Performance Distributions for Energy Impacts

Figure C-46: PV (Non-tracking) Measured Energy Production (Capacity Factor)

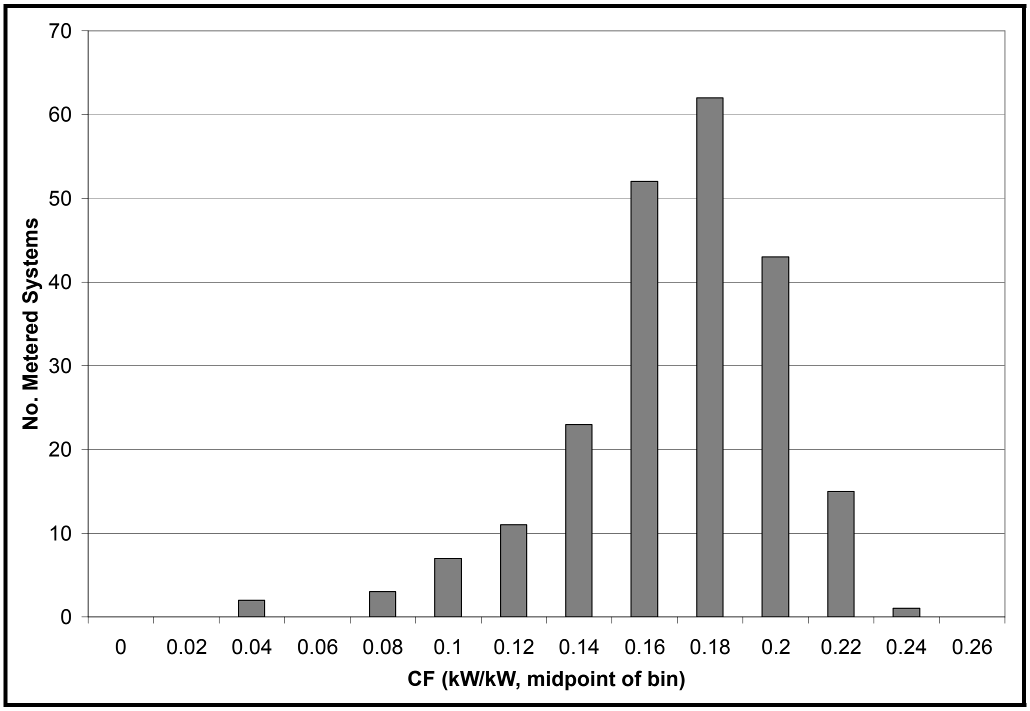


Figure C-47: MCS Distribution—PV (Non-tracking) Energy Production (Capacity Factor)

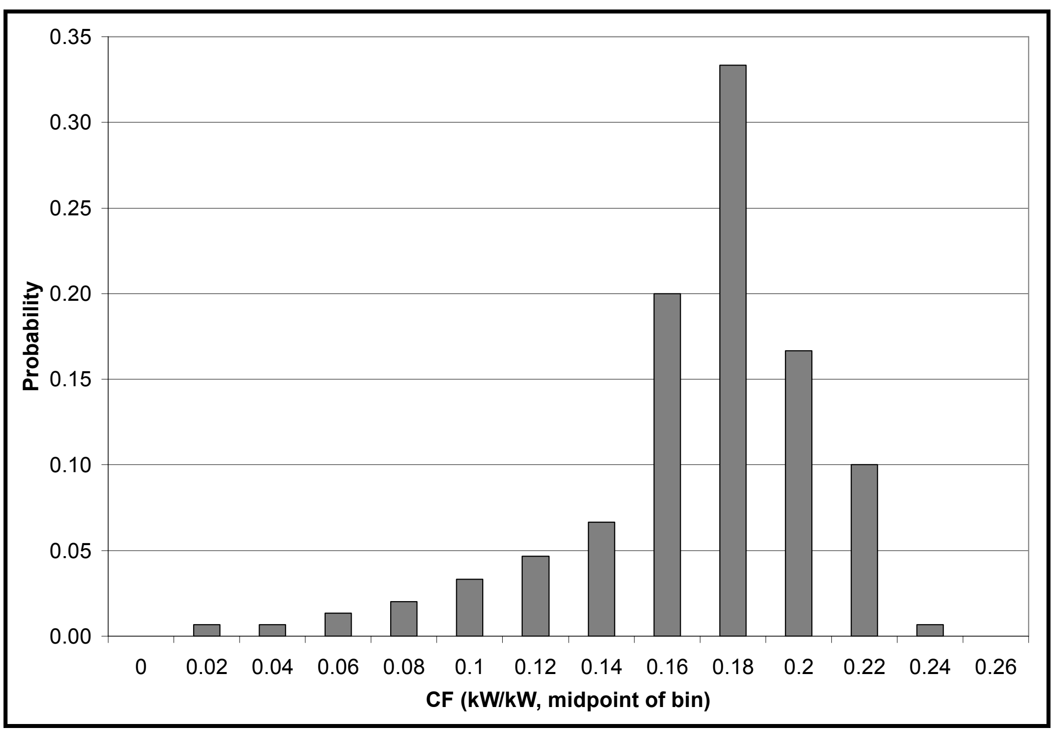


Figure C-48: PV (Tracking) Measured Energy Production (Capacity Factor)

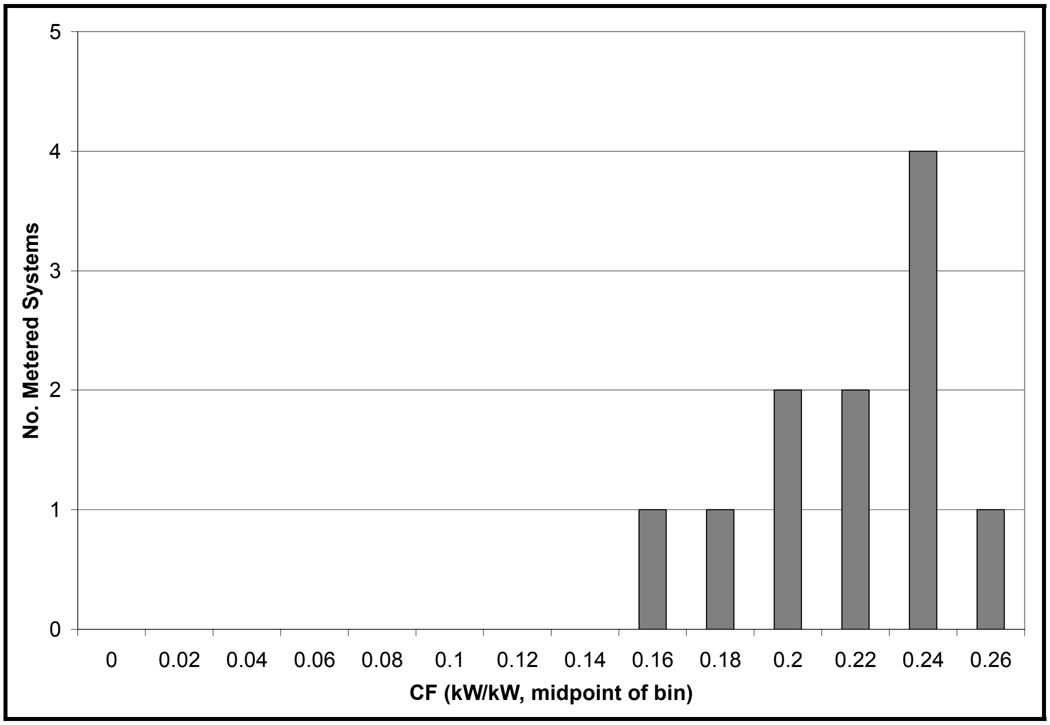


Figure C-49: MCS Distribution—PV (Tracking) Energy Production (Capacity Factor)

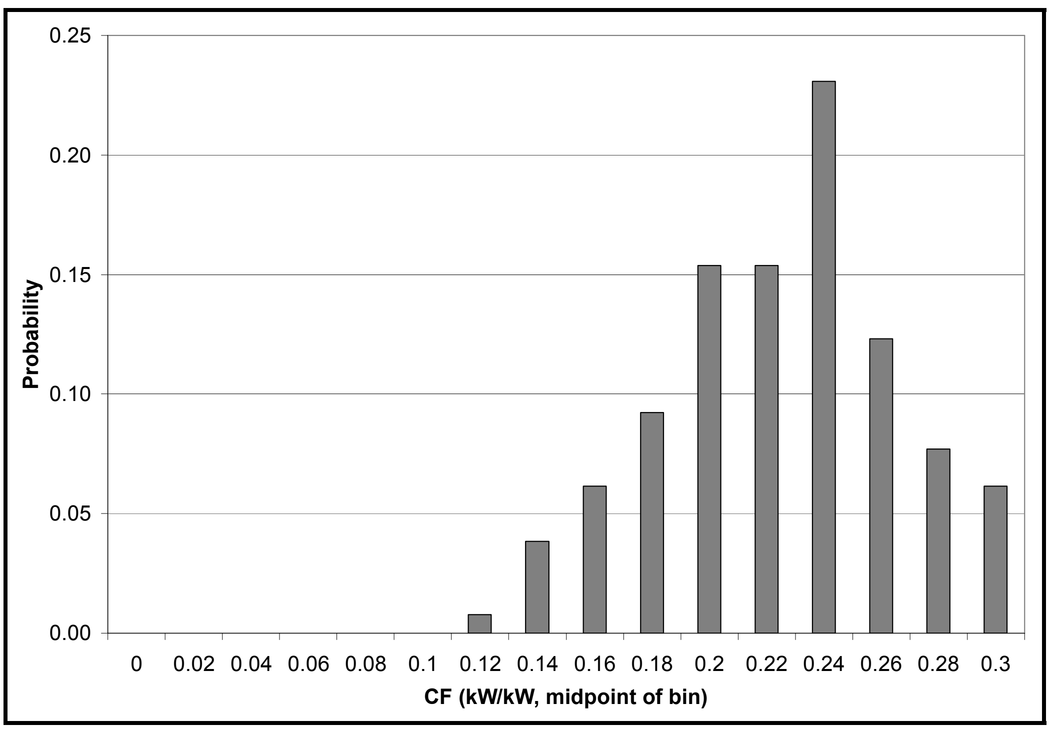


Figure C-50: Fuel Cell Measured Energy Production (Capacity Factor)

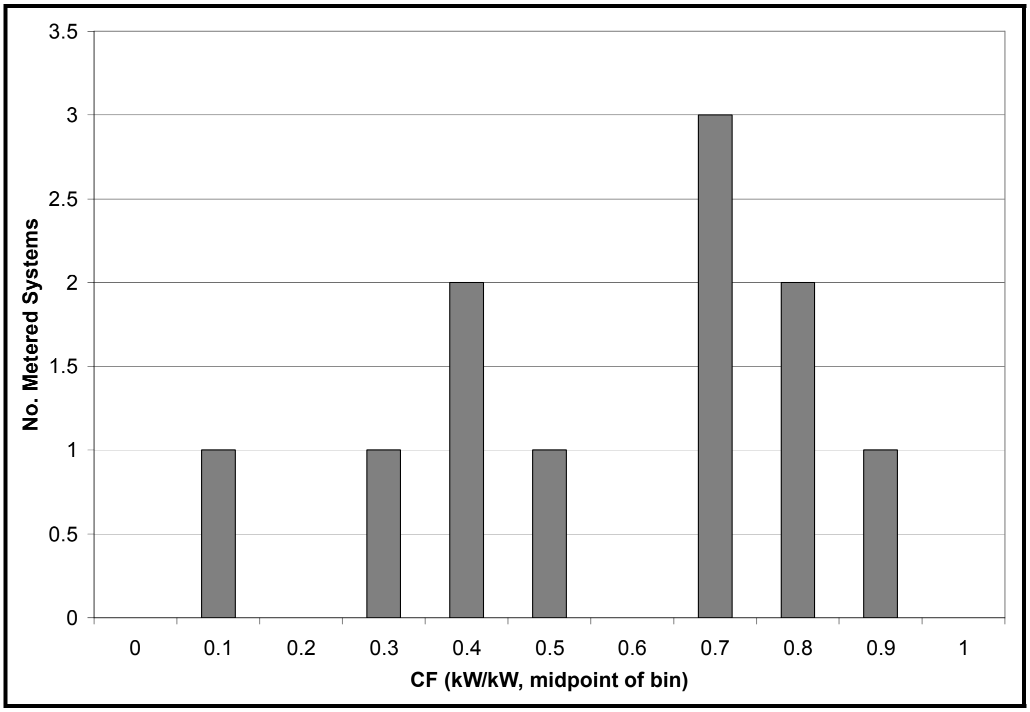


Figure C-51: MCS Distribution—Fuel Cell Energy Production (Capacity Factor)

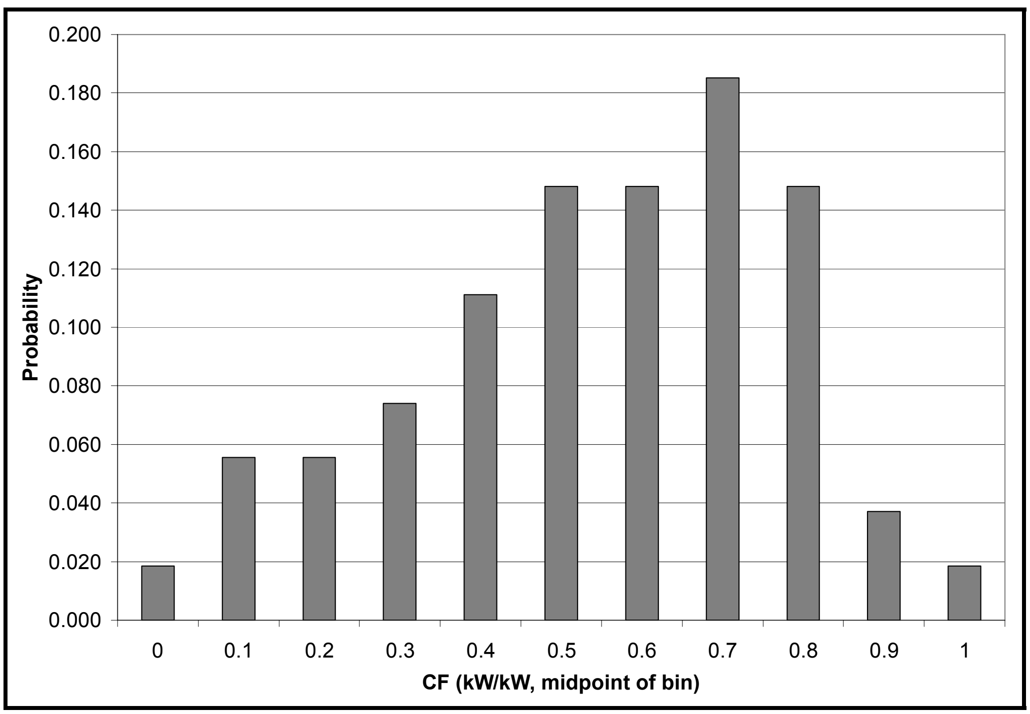


Figure C-52: Engine/Turbine (Non-Renewable) Measured Electricity Production (Capacity Factor)

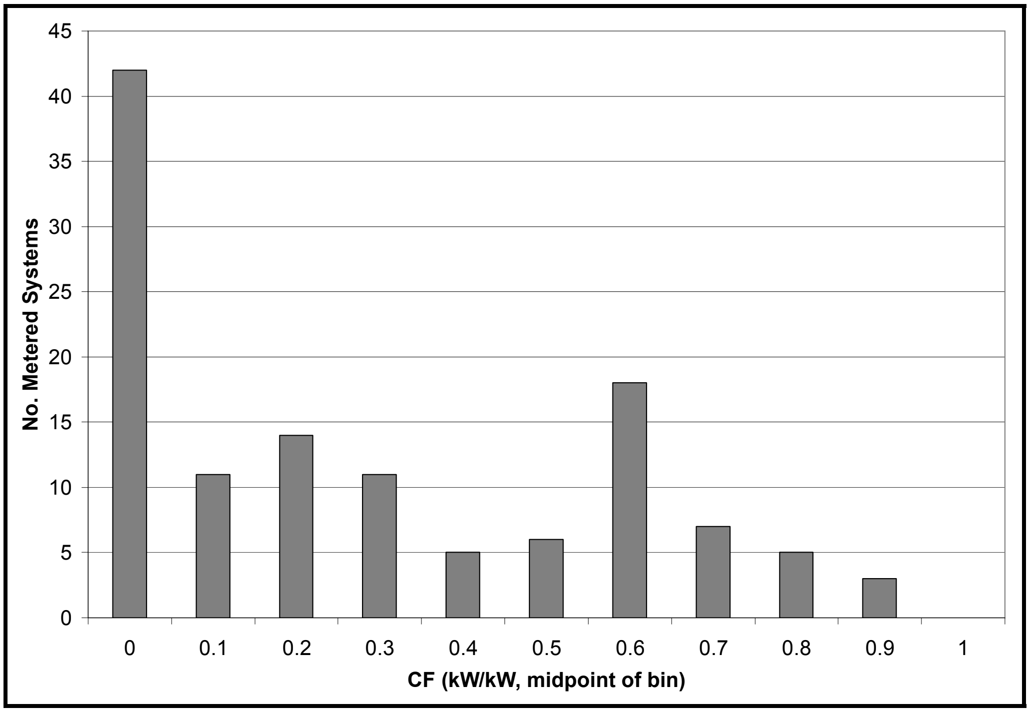


Figure C-53: MCS Distribution—Engine/Turbine (Non-Renewable) Electricity Production (Capacity Factor)

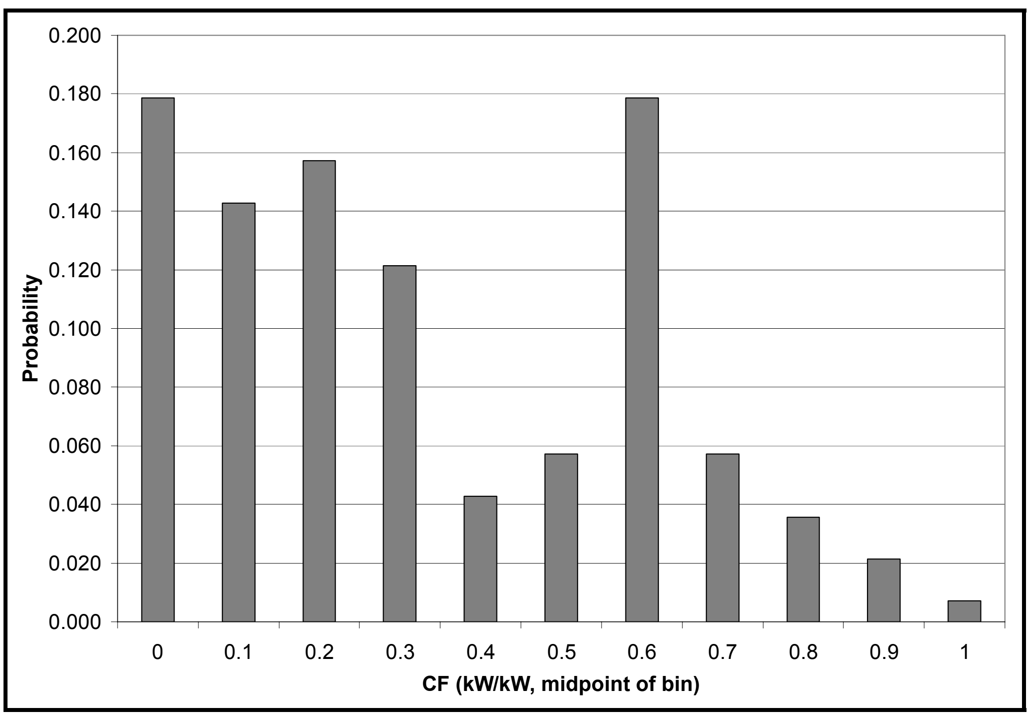


Figure C-54: Engine/Turbine (Renewable) Measured Electricity Production (Capacity Factor)

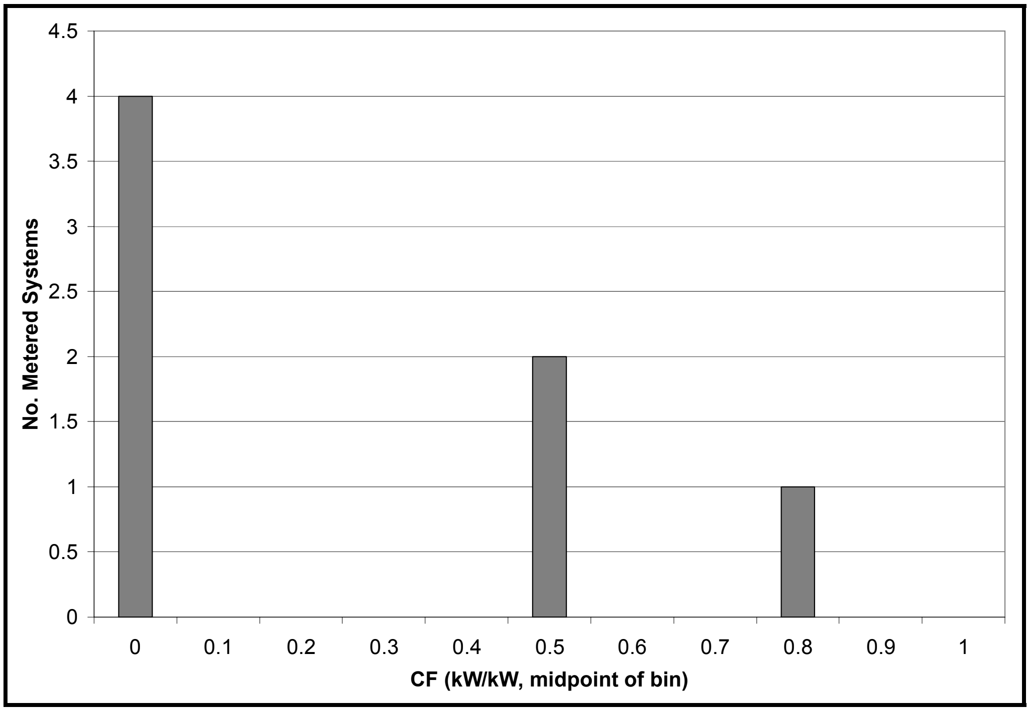


Figure C-55: MCS Distribution—Engine/Turbine (Renewable) Electricity Production (Capacity Factor)

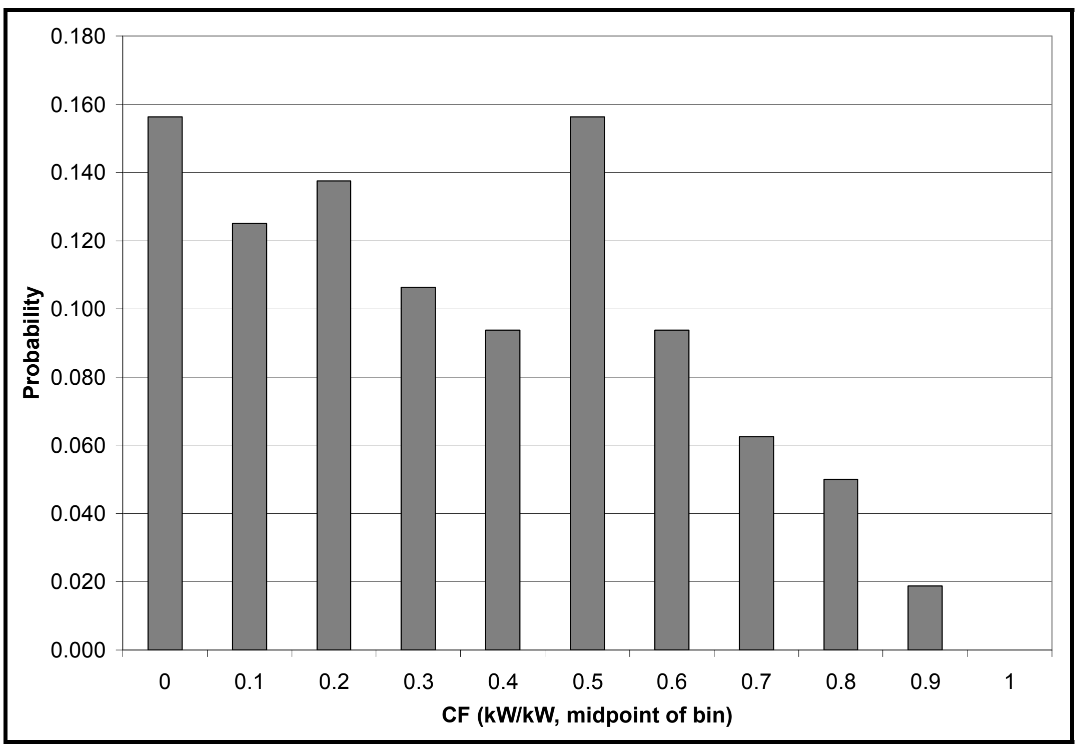


Figure C-56: Fuel Cell (Non-Renewable) Measured Heat Recovery Rate in 2006

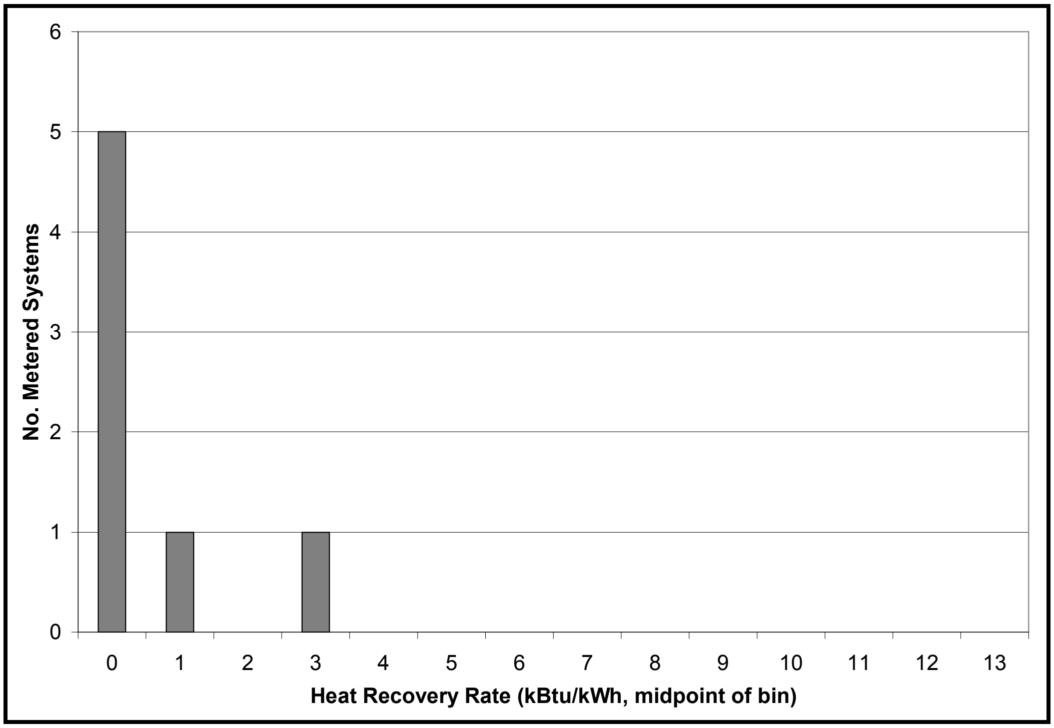


Figure C-57: MCS Distribution—Fuel Cell (Non-Renewable) Heat Recovery Rate

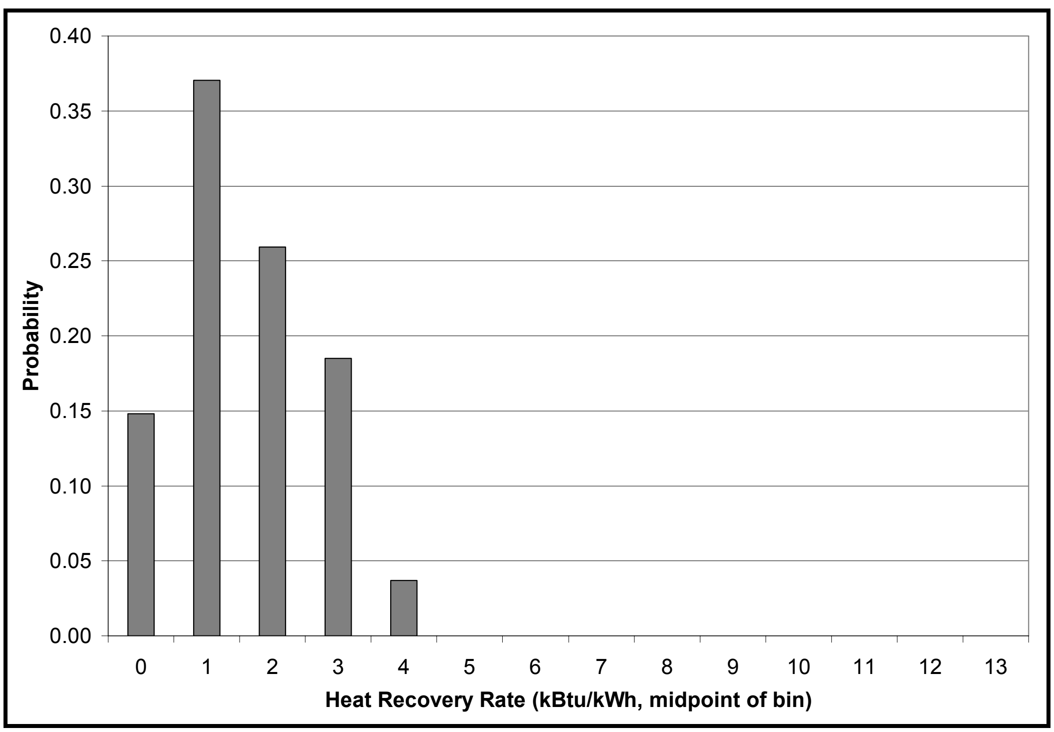


Figure C-58: Engine/Turbine Measured Heat Recovery Rate in 2006

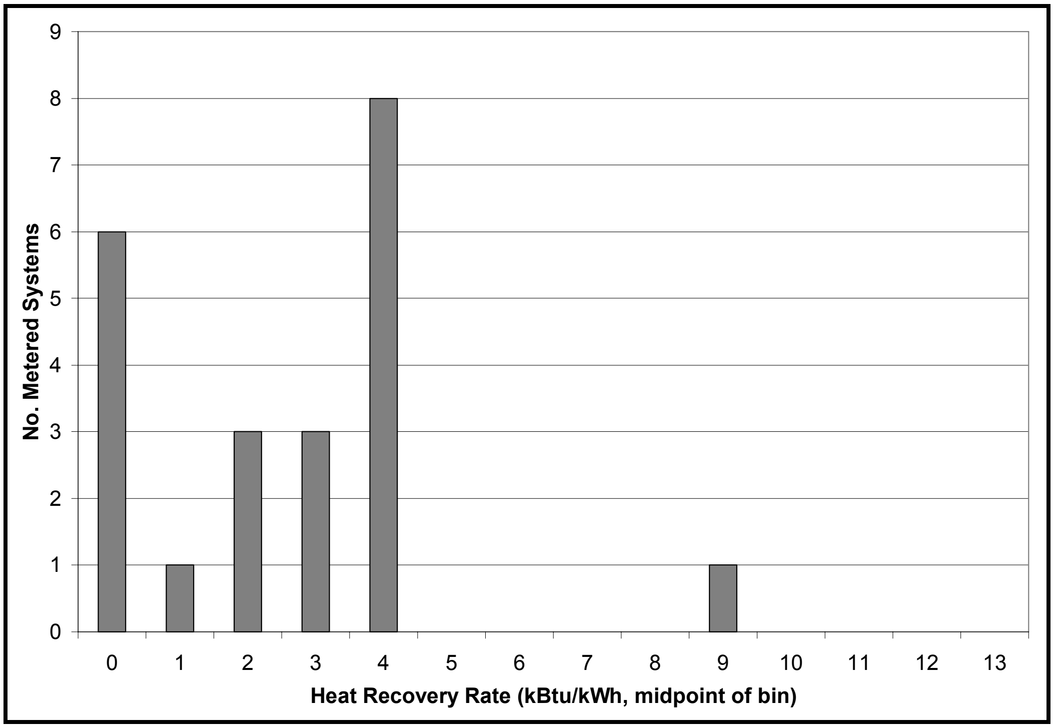
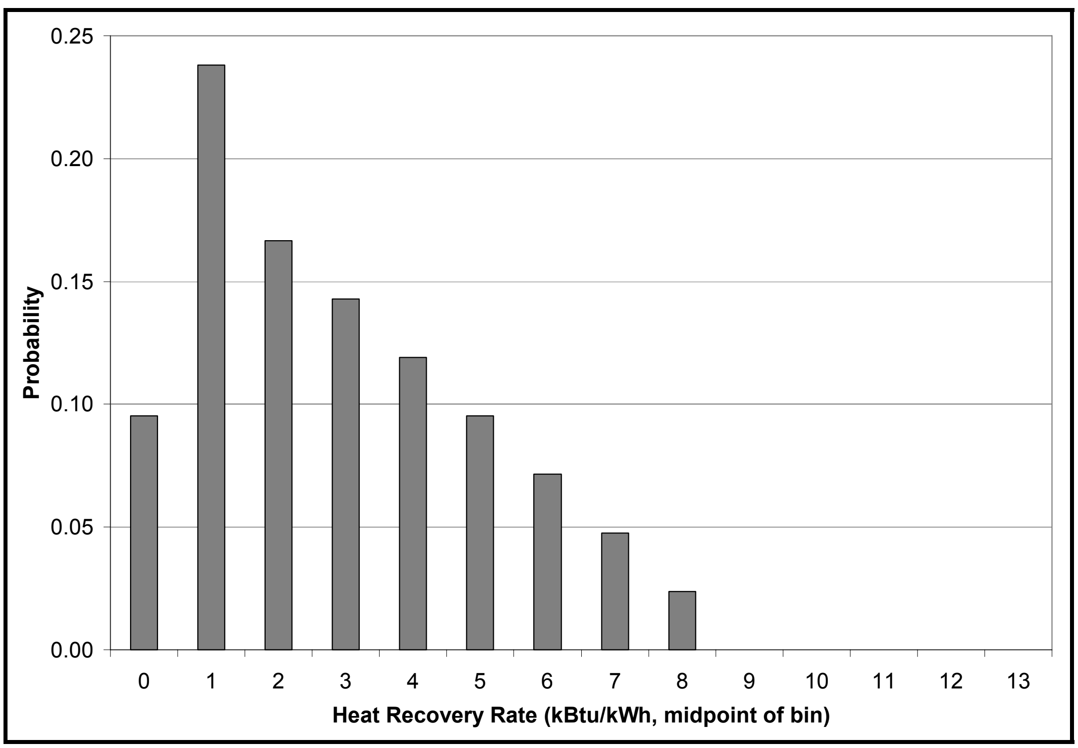


Figure C-59: MCS Distribution—Engine/Turbine Heat Recovery Rate



<u>Bias</u>

Performance data collected from metered sites were used to estimate program impacts attributable to unmetered sites. If the metered sites are not representative of the unmetered sites then those estimates will include systematic error called bias. Potential sources of bias of principle concern for this study include:

<u>Planned data collection disproportionally favors dissimilar groups</u>. For example, a limited number of new HEAT metering has been installed in the last 12 months, and metering is generally being installed on projects which are still under their three-year contract (or five-year contract for fuel cells) with SGIP. During this period 14 new projects have been completed and have entered commercial operations. If the actual heat recovery performance of the older systems differs systematically from the newer metered systems then estimates calculated for the older systems will be biased. A similar situation can occur when actual performance differs substantially from performance assumptions underlying data collection plans.

<u>Actual data collection allocations deviate from planned data collection allocations</u>. In program impact evaluation studies actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated for unmetered systems may be biased. For example, a limited number of ENGO meters for PV systems has been installed by Itron in the last 18 months. In some areas the result is a metered dataset containing a disproportionate quantity of data received from program participants who operate their own metering. This metered dataset is used to calculate impacts for unmetered sites. If the actual performance of the unmetered systems differs systematically from that of the systems metered by participants then estimates calculated for the unmetered systems will be biased. One example of this is if a participant metered system's output decreases unexpectedly the participant will know almost immediately and steps can be taken to get the system running normally again. However, a similar situation with an unmetered system could go unnoticed for months.

<u>Actual data collection quantities deviate from planned data collection quantities</u>. For example, plans called for collection of ENGO data from all RFU systems; however, data were actually collected only from a small proportion of completed RFU systems.

In the MCS analysis bias is accounted for during development of performance distributions assumed for unmetered systems. If the metered sample is thought to be biased then engineering judgment dictates specification of a relatively 'more spread out' performance distribution. Bias is accounted for, but the accounting does not involve adjustment of point estimates of program impacts. If engineering judgment dictates an accounting for bias then the performance distribution assumed for the MCS analysis has a higher standard deviation.

The result is a larger confidence interval about the reported point estimate. If there is good reason to believe that bias could be substantial, the confidence interval reported for the point estimate will be larger.

To this point the discussion of bias has been limited to sampling bias. More generally, bias can also be the result of instrumentation yielding measurements that are not representative of the actual parameters being monitored. Due to the wide variety of instrumentation types and data providers involved with this project it is not possible to say one way or the other whether or not instrumentation bias contributes to error in impacts reported for either metered or unmetered sites. Due to the relative magnitudes involved, instrumentation error—if it exists—accounts for an insignificant portion or total bias contained in point estimates.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered sites. The relative importance of this varies with metering rate. For example, where the metering rate is 90 percent, a 20 percent sampling bias will yield an error of only two percent in total (metered + unmetered) program impacts. All else equal, higher metering rates reduce the impact of sampling bias on estimates of total program impacts.

Calculate the Quantities of Interest for Each Sample

After each simulation run the resulting sample data for individual sites are summed to the program level and the result is saved. The quantities of interest were defined previously:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC216.6 (b) Cogeneration System Efficiency

Cogeneration system efficiency is a calculated value that is based on sample data for electricity production, fuel consumption, and heat recovery. The efficiency values for each simulation run were calculated as:

$$PUC218.5b_r = \frac{\left(\sum ELEC_{rs} \times \mathrm{KWH2KBTU}\right) + \left(\sum \mathrm{C1} \times HEAT_{rs}\right)}{\sum FUEL_{rs}} \times \frac{100\%}{1}$$

Where:

$PUC216.6b_r$	is program total PUC216.6 (b) cogeneration system efficiency for run r Units: %
$ELEC_{rs}$	is total electricity production for run r and system s Units: kWh
KWH2KBTU	is a conversion factor Value: 0.2931 (i.e., 1/3.412) Units: kWh/kBtu
C1	is a constant Value: 0.5 Units: none Basis: Cogeneration system efficiency definition of CPUC
$HEAT_{rs}$	is total useful waste heat recovery for run r and system s Units: kBtu
$FUEL_{rs}$	is total fuel consumption for run r and system s Units: kBtu Basis: Lower Heating Value of fuel

Analyze Accumulated Quantities of Interest

The pools of accumulated MCS analysis results are analyzed to yield summary information about their central tendency and variability. Mean values are calculated and the variability exhibited by the values for the many runs is examined to determine confidence levels (under the constraint of constant relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

Results

The confidence levels in the energy impacts, demand impacts, and PUC 216.6 compliance results have been presented along with those results. This section will present the precision and confidence intervals associated with those confidence levels in more detail. Three bins were used for Confidence Levels: 90/10 or better, 70/30 or better (but worse than 90/10), and worse than 70/30.

Table C-5: Uncertainty Analysis Results for Annual Energy Impact Results by Technology and Basis

Technology* / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**70%**	**7.6%**	**0.519 to 0.604**
Metered	90%	0.16%	0.573 to 0.575
Estimated	70%	18.3%	0.445 to 0.645
GT	**70%**	**15.4%**	**0.476 to 0.649**
Metered	90%	0.35%	0.774 to 0.779
Estimated	< 70%	52.4%	0.161 to 0.516
IC Engine	**70%**	**6.8%**	**0.267 to 0.306**
Metered	90%	0.10%	0.216 to 0.216
Estimated	70%	9.5%	0.299 to 0.362
MT	**90%**	**9.88%**	**0.329 to 0.401**
Metered	90%	0.11%	0.400 to 0.401
Estimated	70%	12.8%	0.291 to 0.376
PV	**90%**	**1.25%**	**0.196 to 0.201**
Metered	90%	0.05%	0.181 to 0.181
Estimated	90%	2.05%	0.207 to 0.216
WD	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-6: Uncertainty Analysis Results for Annual Energy Impact Results by Technology, Fuel, and Basis

Technology* & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**70%**	**7.1%**	**0.530 to 0.612**
Metered	90%	0.17%	0.582 to 0.584
Estimated	70%	23.0%	0.420 to 0.671
FC-R	**70%**	**20.7%**	**0.427 to 0.650**
Metered	90%	0.39%	0.526 to 0.531
Estimated	< 70%	30.2%	0.379 to 0.706
GT-N	**70%**	**15.4%**	**0.476 to 0.649**
Metered	90%	0.35%	0.774 to 0.779
Estimated	< 70%	52.4%	0.161 to 0.516
IC Engine-N	**70%**	**7.3%**	**0.257 to 0.298**
Metered	90%	0.11%	0.197 to 0.197
Estimated	70%	10.1%	0.296 to 0.362
IC Engine-R	**70%**	**15.5%**	**0.331 to 0.452**
Metered	90%	0.28%	0.497 to 0.500
Estimated	70%	25.5%	0.257 to 0.432
MT-N	**70%**	**6.7%**	**0.352 to 0.403**
Metered	90%	0.12%	0.424 to 0.425
Estimated	70%	15.3%	0.280 to 0.381
MT-R	**70%**	**18.7%**	**0.249 to 0.364**
Metered	90%	0.28%	0.216 to 0.217
Estimated	70%	23.5%	0.263 to 0.424

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind; N = Non-Renewable; R = Renewable

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-7: Uncertainty Analysis Results for PG&E Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**70%**	**7.8%**	**0.567 to 0.663**
Metered	90%	0.2%	0.650 to 0.653
Estimated	70%	25.7%	0.406 to 0.686
GT	**< 70%**	**50.1%**	**0.165 to 0.495**
Metered	N/A	N/A	N/A
Estimated	< 70%	50.1%	0.165 to 0.495
IC Engine	**70%**	**12.6%**	**0.243 to 0.313**
Metered	90%	0.1%	0.150 to 0.151
Estimated	70%	14.9%	0.281 to 0.380
MT	**70%**	**11.5%**	**0.340 to 0.429**
Metered	90%	0.2%	0.495 to 0.497
Estimated	70%	19.1%	0.272 to 0.400
PV	**90%**	**1.6%**	**0.195 to 0.201**
Metered	90%	0.1%	0.180 to 0.181
Estimated	90%	2.7%	0.206 to 0.218

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-8: Uncertainty Analysis Results for SCE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**70%**	**28.6%**	**0.315 to 0.567**
Metered	90%	0.3%	0.290 to 0.292
Estimated	< 70%	38.0%	0.330 to 0.735
IC Engine	**70%**	**13.1%**	**0.275 to 0.358**
Metered	90%	0.2%	0.284 to 0.286
Estimated	70%	18.3%	0.270 to 0.391
MT	**70%**	**11.8%**	**0.302 to 0.383**
Metered	90%	0.2%	0.347 to 0.348
Estimated	70%	29.7%	0.236 to 0.436
PV	**90%**	**3.6%**	**0.200 to 0.215**
Metered	90%	0.2%	0.171 to 0.172
Estimated	90%	4.0%	0.203 to 0.220
WD	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-9: Uncertainty Analysis Results for SCG Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**70%**	**24.4%**	**0.426 to 0.701**
Metered	90%	0.4%	0.660 to 0.666
Estimated	< 70%	31.1%	0.373 to 0.709
GT	**90%**	**0.5%**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY
Metered	90%	0.5%	
Estimated	N/A	N/A	
IC Engine	**70%**	**10.5%**	**0.265 to 0.328**
Metered	90%	0.2%	0.248 to 0.249
Estimated	70%	16.2%	0.277 to 0.384
MT	**70%**	**10.9%**	**0.352 to 0.438**
Metered	90%	0.2%	0.476 to 0.478
Estimated	70%	23.6%	0.251 to 0.407
PV	**90%**	**2.9%**	**0.201 to 0.213**
Metered	90%	0.2%	0.203 to 0.204
Estimated	90%	4.7%	0.200 to 0.220

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-10: Uncertainty Analysis Results for CCSE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**0.3%**	**0.526 to 0.528**
Metered	90%	0.3%	0.526 to 0.528
Estimated	N/A	N/A	N/A
GT	**70%**	**28.5%**	**0.379 to 0.682**
Metered	90%	0.5%	0.759 to 0.766
Estimated	< 70%	100.0%	0.000 to 0.600
IC Engine	**70%**	**26.4%**	**0.157 to 0.269**
Metered	90%	0.2%	0.192 to 0.193
Estimated	< 70%	100.0%	0.000 to 0.600
MT	**70%**	**15.1%**	**0.202 to 0.273**
Metered	90%	0.2%	0.212 to 0.213
Estimated	< 70%	53.1%	0.158 to 0.516
PV	**90%**	**0.9%**	**0.178 to 0.181**
Metered	70%	7.5%	0.196 to 0.228
Estimated	70%	7.5%	0.196 to 0.228

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-11: Uncertainty Analysis Results for Peak Demand Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**70%**	**6.6%**	**0.613 to 0.700**
Metered	90%	0.15%	0.647 to 0.649
Estimated	70%	19.8%	0.541 to 0.808
GT	**70%**	**15.4%**	**0.564 to 0.768**
Metered	90%	0.34%	0.900 to 0.907
Estimated	< 70%	50.2%	0.208 to 0.626
IC Engine	**70%**	**8.8%**	**0.223 to 0.266**
Metered	90%	0.12%	0.244 to 0.244
Estimated	70%	14.4%	0.210 to 0.281
MT	**90%**	**9.97%**	**0.368 to 0.450**
Metered	90%	0.11%	0.394 to 0.394
Estimated	70%	12.4%	0.373 to 0.479
PV	**90%**	**1.62%**	**0.617 to 0.637**
Metered	90%	0.05%	0.622 to 0.623
Estimated	90%	3.02%	0.612 to 0.651
WD	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-12: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for PG&E

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**70%**	**7.9%**	**0.625 to 0.732**
Metered	90%	0.2%	0.667 to 0.670
Estimated	70%	22.2%	0.542 to 0.852
FC-R	**90%**	**0.5%**	**0.367 to 0.370**
Metered	90%	0.5%	0.367 to 0.370
Estimated	N/A	N/A	N/A
GT-N	**< 70%**	**47.3%**	**0.224 to 0.625**
Metered	N/A	N/A	N/A
Estimated	< 70%	47.3%	0.224 to 0.625
IC Engine-N	**70%**	**20.5%**	**0.157 to 0.238**
Metered	90%	0.2%	0.097 to 0.097
Estimated	70%	24.3%	0.187 to 0.306
IC Engine-R	**< 70%**	**44.5%**	**0.153 to 0.399**
Metered	90%	0.4%	0.437 to 0.441
Estimated	< 70%	58.7%	0.102 to 0.392
MT-N	**70%**	**12.6%**	**0.424 to 0.546**
Metered	90%	0.2%	0.580 to 0.582
Estimated	70%	24.0%	0.321 to 0.523
MT-R	**70%**	**23.3%**	**0.296 to 0.476**
Metered	90%	0.4%	0.278 to 0.280
Estimated	70%	28.8%	0.302 to 0.546
PV	**90%**	**1.8%**	**0.639 to 0.662**
Metered	90%	0.1%	0.636 to 0.637
Estimated	90%	3.5%	0.641 to 0.688

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-13: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for SCE

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**90%**	**0.5%**	**0.900 to 0.908**
Metered	90%	0.5%	0.900 to 0.908
Estimated	N/A	N/A	N/A
FC-R	**< 70%**	**37.4%**	**0.279 to 0.612**
Metered	90%	0.0%	0.000 to 0.000
Estimated	< 70%	37.4%	0.400 to 0.878
GT-N	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A
IC Engine-N	**70%**	**22.0%**	**0.187 to 0.292**
Metered	90%	0.2%	0.222 to 0.223
Estimated	70%	28.9%	0.174 to 0.316
IC Engine-R	**70%**	**17.4%**	**0.355 to 0.505**
Metered	90%	0.3%	0.549 to 0.553
Estimated	< 70%	82.5%	0.041 to 0.431
MT-N	**70%**	**8.2%**	**0.336 to 0.395**
Metered	90%	0.2%	0.350 to 0.352
Estimated	< 70%	35.0%	0.275 to 0.571
MT-R	**< 70%**	**41.9%**	**0.209 to 0.511**
Metered	90%	0.3%	0.330 to 0.333
Estimated	< 70%	81.8%	0.071 to 0.714
PV	**90%**	**6.2%**	**0.540 to 0.611**
Metered	90%	0.1%	0.517 to 0.519
Estimated	90%	6.9%	0.543 to 0.623
WD	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-14: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for SCG

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**90%**	**0.4%**	**0.832 to 0.838**
Metered	90%	0.4%	0.832 to 0.838
Estimated	N/A	N/A	N/A
FC-R	**< 70%**	**38.5%**	**0.400 to 0.900**
Metered	N/A	N/A	N/A
Estimated	< 70%	38.5%	0.400 to 0.900
GT-N	**90%**	**0.4%**	**0.918 to 0.926**
Metered	90%	0.4%	0.918 to 0.926
Estimated	N/A	N/A	N/A
IC Engine-N	**70%**	**11.7%**	**0.267 to 0.338**
Metered	90%	0.2%	0.376 to 0.377
Estimated	70%	25.5%	0.183 to 0.309
IC Engine-R	**< 70%**	**100.0%**	**0.000 to 0.461**
Metered	N/A	N/A	N/A
Estimated	< 70%	100.0%	0.000 to 0.461
MT-N	**70%**	**12.1%**	**0.365 to 0.466**
Metered	90%	0.2%	0.400 to 0.402
Estimated	70%	21.4%	0.336 to 0.519
MT-R	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A
PV	**90%**	**4.5%**	**0.577 to 0.631**
Metered	90%	0.2%	0.624 to 0.626
Estimated	90%	7.7%	0.544 to 0.635

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-15: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for CCSE

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**90%**	**0.3%**	**0.690 to 0.694**
Metered	90%	0.3%	0.690 to 0.694
Estimated	N/A	N/A	N/A
FC-R	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A
GT-N	**< 70%**	**31.4%**	**0.439 to 0.841**
Metered	90%	0.4%	0.881 to 0.889
Estimated	< 70%	100.0%	0.000 to 0.800
IC Engine-N	**< 70%**	**34.9%**	**0.105 to 0.218**
Metered	90%	0.4%	0.129 to 0.130
Estimated	< 70%	100.0%	0.000 to 0.600
IC Engine-R	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A
MT-N	**70%**	**10.8%**	**0.292 to 0.363**
Metered	90%	0.2%	0.307 to 0.308
Estimated	< 70%	53.3%	0.206 to 0.676
MT-R	**70%**	**10.8%**	**0.292 to 0.363**
Metered	90%	0.5%	0.097 to 0.098
Estimated	< 70%	100.0%	0.000 to 0.800
PV	**90%**	**1.2%**	**0.594 to 0.609**
Metered	90%	0.1%	0.602 to 0.603
Estimated	70%	12.0%	0.530 to 0.675

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-16: Uncertainty Analysis Results for Annual PUC 216.6(b)

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**4.98%**	**0.520 to 0.574**
Metered	90%	1.35%	0.500 to 0.513
Estimated	90%	6.97%	0.526 to 0.605
GT	**70%**	**12.2%**	**0.378 to 0.484**
Metered	N/A	N/A	N/A
Estimated	70%	12.2%	0.378 to 0.484
IC Engine	**90%**	**4.60%**	**0.392 to 0.430**
Metered	90%	2.22%	0.393 to 0.411
Estimated	90%	4.62%	0.392 to 0.430
MT	**90%**	**8.07%**	**0.284 to 0.334**
Metered	90%	1.47%	0.352 to 0.362
Estimated	90%	8.77%	0.278 to 0.332

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Appendix D

Metering Systems

As a part of the Measurement & Evaluation (M&E) of the SGIP, Itron installs metering equipment at a sample of Host facilities. The exact metering required varies by incentive level but may include electric, fuel, and/or heat metering. Many considerations inform the metering decision process, including the presence of existing metering equipment, the quality or quantity of data from existing metering sources, and the relative difficulty, and, therefore, expense, of installing new metering equipment.

D.1 Electric Generation Metering Equipment

Metering equipment installed by Itron for the purpose of obtaining electric net generation output (ENGO) falls under two distinct categories: systems without an existing data logger and PV systems where data are already being logged onsite. In both cases ENGO data are not available via the electric utility. Each of these two systems seeks to achieve the same goal through slightly different approaches.

Systems without Existing Metering

Metering of these systems for ENGO involves the installation of current transducers (CTs), a meter, a socket, a panel, communications equipment, and associated wire and conduit. The exact equipment required varies based upon the equipment found onsite. For example, if an empty socket is available for use onsite than only the meter, CTs, and the communication equipment may be needed. For the purposes of this description the assumption is made that there is no existing empty panel socket that facilitates ENGO meter installation.

Itron's installation subcontractors install an electrical panel to house the wiring and meter. All wiring is run through conduit at least at the protective level as found onsite. Typical installation practices involve rigid conduit (EMT) but may involve flexible conduit if necessary or appropriate. A meter socket is installed on this panel that varies depending upon the electrical characteristics of the system such as 1-phase versus 3-phase and maximum amperage. CTs are installed on each phase of power and wired to the electrical meter. The meter used is a revenue-grade electrical meter equipped with a wireless modem for communications. If a wireless signal is not available, even with a higher frequency antenna, then a land-based telephone line is installed.

Systems with Existing Metering but No Communications

In some cases SGIP systems are found to be equipped with metering and recording equipment, but no remote communications. In these cases, to minimize overall data collection costs the existing equipment is retrofitted with a cellular-based modem using static IP. Data are downloaded daily and copied to a web-accessible server.

D.2 Fuel Consumption Metering Equipment

Fuel meters are installed in very few cases for M&E purposes. These include renewable-fueled systems that are piped to also use utility-supplied natural gas and in some fossil-fueled cogeneration systems lacking a dedicated fuel meter. Fuel meters are invasive; their installation requires a licensed contractor and typically requires the plant operator to shut down the cogeneration system. Gas meter technology varies based on the operating pressure of the system. Low pressure and low capacity systems use diaphragm meters while higher pressure or capacity systems will use rotary or turbine meters. Table D-1 below provides some guidelines that are used for meter selection.

Table D-1: Gas Meter Selection Criteria

Gas Meter Type	Maximum Pressure (psig)	Maximum Flow (SCFH)
Diaphragm	100	1,000
Rotary	175	141,000
Turbine	1,440	18,000,000

Electronic volume correctors may also be specified to correct for ambient conditions. Finally, gas meters are specified with a pulse output that is stored in a data logger. Data logger characteristics, including power and transmission of data to the Evaluation Contractor, use the method described on the following page for metering of heat recovery.

In a few cases, fuel data are needed for M&E purposes along with the heat data. A dedicated gas meter exists but these data are not being logged and transmitted. In these cases, a gas pulser is installed and the pulse is linked to the installed heat-monitoring data logger. Data are downloaded daily and copied to a web-accessible server.

D.3 Heat Recovery Metering Equipment

Heat recovery applies to non-renewable-fueled cogeneration systems. For the entire 2008 calendar year non-invasive equipment was installed. Conceptually, measurement of heat typically involves measurement of a fluid flow and the temperature of that fluid on both sides of a heat exchanger[1]. The fluid may be liquid (water, glycol mixture, oil, etc.) or gas (steam or exhaust air) and temperatures range from 32°F to 500°F. The heat exchanger may be a simple plate-and-frame heat exchanger or as complex as an absorption chiller.

Fluid flow is measured using an ultrasonic flow meter with clamp-on transducers. Itron researched all commercially available products and chose a product that is highly calibrated and has a much better low flow reading capability than other ultrasonic flow meters. Accuracy and precision are similar to that of insertion flow meters used in the past.

Temperature is measured using clamp-on thermocouples. These thermocouples are accurate and precise but suffer from a delay in temperature changes as it takes some time for the fluid temperature to migrate to the pipe surface. This delay is partially offset by utilizing a differential temperature, where the delay is seen on both measurements and is assumed to cancel out. As these temperature sensors are relatively inexpensive, redundant sensors are used (two on the hot side and two on the cold side). This allows for the average of each of the two sensors to be used in the differential temperature calculations, as long as they are within an acceptable range. Should one sensor fail and fall out of range, the calculation of heat may still be completed without requiring a service call.

Data are stored in a data logger capable of reading digital and analog inputs. Memory is sufficient to store data for at least one month should communications fail. Proprietary software is used to program the data logger and to communicate with the data logger in a server/client configuration for downloading data.

Communications are handled by a cellular-based modem using an IP connection. Data are downloaded daily and copied to a web-accessible server.

Power is supplied to the data logger, flow meter, and modem via an external battery. This battery is connected to facility power and, in the event of a power outage, is capable of operating the metering equipment for approximately two days.

All equipment is housed in a NEMA weatherproof enclosure, which is mounted to a wall near the thermal metering location. NEMA specification is typically 4X but varies based on conditions found at the facility.

---

1 There are some instances where exhaust air is used directly in a process without the use of a heat exchanger. As these systems do not represent a significant portion of the metering effort they will not be specifically discussed here. However, they are conceptually similar to heat exchanger-based systems.

Appendix E

Metering Equipment Specification Sheets

Appendix E contains the specification sheets for the major metering equipment installed so far under the Self-Generation Incentive Program. Below is a list of the specification sheets provided in this appendix for each type of metering system.

ENGO Equipment

- Metrum Electric Meter
- Sentinel Electric Meter
- Hawkeye Transducers
- Alpha Plus Meter (legacy ENGO meter installs). The Alpha Plus meter is representative of ENGO meters installed prior to 2006.
- Data Remote Modem

FUEL Equipment

Several gas pulsers have been installed on existing rotary dedicated cogeneration natural gas meters. Also, several rotary-type fuel meters were installed prior to 2006. To date, no rotary-type fuel meters have been installed post-2006. Consequently, the appendix contains specification sheets for representative legacy rotary fuel meters as well as the gas pulsers that were installed in 2008.

- Roots Solid State Pulser
- American Meters Rotary Flow Meter
- Campbell Scientific Data Logger
- Airlink Modem

HEAT Equipment

HEAT metering equipment installed under the SGIP consists of legacy equipment installed prior to 2006 and post-2006 systems.

Post-2006 HEAT metering systems consist of the following equipment:

- Flexim Flow Meter
- Flexim Clamp-on Transducers
- Newport Thermocouples
- Omega Thermocouple Extension Wire
- Campbell Scientific Data Logger
- Airlink Modem

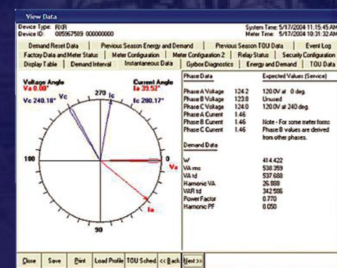
Legacy (pre-2006) HEAT metering systems consisted of the following equipment:

- Onicon Btu Meter
- DENT Data Logger DataPro
- Onicon Insertion Dual Flow Meter (with temperature sensors)

ENGO Equipment Specification Sheets

Wireless Under Glass

OV-2000 Digital Cellular for Landis+Gyr S4



Metrum OV-2000 Wireless Modem

Metrum Technologies' CDMA/1XRTT integrated solution for the Landis+Gyr S4 and S4e family of meters is the ideal wireless C&I meter communications product.

Completely contained "Under the Glass", this transparent modem makes remote communications and acquisition of meter data easy and dependable by utilizing the Verizon CDMA public network and the Utility's existing MV-90 meter reading systems and practices.

Available for all forms and voltages, the OV-2000 features rugged, auto-ranging power supply and supports bi-directional communications with speeds of up to 14.4K bps for circuit switched connections.

By going wireless with Metrum, many of the problems and costs associated with establishing and maintaining wire-line connections are eliminated.

Specifications:

Meter Compatibility
Landis+Gyr S4 and S4e

Voltage
120vac to 480vac

Operating Temperature
-30 to 60 degrees C

Meter Interface
TTLor RS232

Software
MV-90 and L+G Software

Communications
CDMA2000 1xRTT-IS-95A/B

DATA Transmission
up to 153Kbps

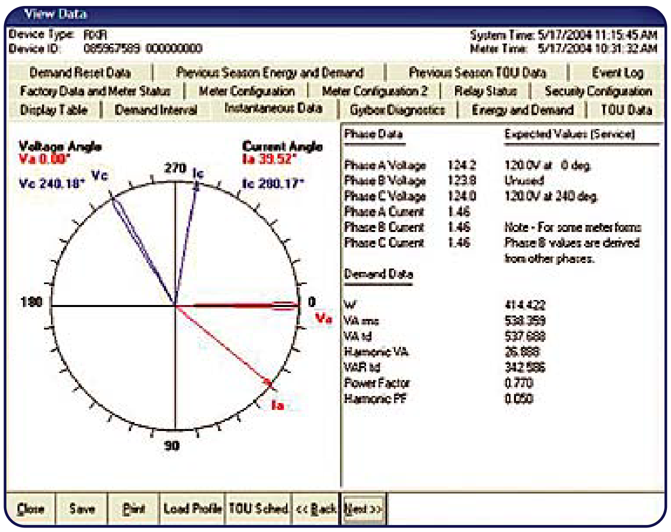
Sensitivity
-104dBm

Antenna
Internal Tri-Band

For More Information: Metrum Technologies / 507 Main Street Suite B / Lake Dallas, Texas 75065 U.S.A.
www.metrum.us / TEL: (940) 321-0267 / FAX: (940) 497-0178

Wireless Under Glass

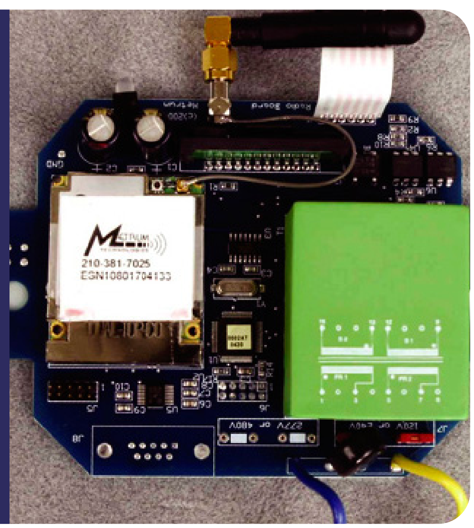
OV-2000 Digital Cellular for Landis+Gyr S4



Benefits:

- Under Glass Solution - No external devices to install, maintain, or replace
- Read with existing MV-90 system - no new software or monthly reading charges
- Extensive Wireless Network coverage and reliability
- Compatible with all forms and voltages
- Eliminates the delays, costs and maintenance of phone lines
- Available on Landis+Gyr S4 and S4e meters
- SMS Message Service
- Power restore notification
- Online modem diagnostics
- Save time and money

- **Rugged Power Supply**
- **RS232 or TTLVersions**
- **Install anywhere standard phone lines are not available**



verizon **CERTIFIED**

For More Information: Metrum Technologies / 507 Main Street Suite B / Lake Dallas, Texas 75065 U.S.A.
www.metrum.us / TEL: (940) 321-0267 / FAX: (940) 497-0178

Knowledge to Shape Your Future

CellReader® Meter SENTINEL®

introduction

Itron SENTINEL® Meter with Trilliant CellReader®

The Itron SENTINEL solid-state electricity meter now provides utilities the industry's leading wireless communication solutions for commercial and industrial applications. The SENTINEL Meter with Trilliant CellReader technology offers utilities RF communications capabilities, superior data acquisition and on-site monitoring. Complex meter information is available any time, from anywhere, via this under-the-cover solution. The SENTINEL CellReader meter is ideal for remote interval and time-of-use (TOU) data collection, including all necessary register, load profile and meter diagnostic data. Using today's digital cellular technology, SENTINEL meters can provide public network radio frequency (RF) communications with the best available wireless network coverage at the best available cost.

features

Key Features & Benefits

- Cost-effective meter communications for all load profile, register and diagnostic data
- Internal card for commercial and industrial solid-state Itron SENTINEL Meter
- Saves time and money – no telephone line connections, easy to install, near-zero operating costs
- Under-the-cover mounting
- Easy to retrofit and secure
- Tamper-resistant operation
- No external power supply
- No batteries
- Secure communications and data transfers
- Affordable on-demand, two-way communications for data retrieval or programming
- Configurable, programmable, and readable through public networks and even the Private iDEN™ network
- GSM, iDEN and CDMA public networks offer packet-switched mode
- GSM and CDMA Networks offer circuit-switched mode for dial-up access

features

Network Communications Options

A SENTINEL meter equipped with Trilliant CellReaders iDEN, CDMA, or GPRS communications is effectively always on and always connected.

> **iDEN Networks**
> SENTINEL meters equipped with Trilliant CellReaders operate on any iDEN wireless network in North America. The iDEN is a dedicated data-only network based on cellular technology that uses packet switching for maximum efficiency. This means the network is always and instantly accessible. The Private iDEN system enables backhaul communications at practically zero-variable cost.

> **CDMA Networks**
> Trilliant CellReaders enable SENTINEL meters to communicate meter data via any public CDMA network, such as Verizon Wireless, Bell Mobility, Telus Mobility and Spring Nextel. Packet data mode works on the latest generation of CDMA technology known as 1xRTT or CDMA2000.

> **GSM Networks**
> Utilizing Trilliant CellReader, SENTINEL meters operate on any public GSM network, such as those operated by Rogers Wireless, T-Mobile, and AT&T/Cingular Wireless. Packet data mode is available on GSM networks with recent upgrades to include GPRS data services.

specifications

Supply

- Uses meter's internal power supply

Local Port

- Supports meter ANSI Type 2 optical port
- Communications protocol: ANSI C12.18

Environmental

- Operating temperature: -30° C to 60° C (iDEN is -25° C)
- Humidity range: 0-95% (non-condensing)

Mechanical

- Enclosure: Fits inside meter
- Weight: 5 oz. (0.142 kg)

AMR Features

- Fully transparent gateway
- Total meter data accessibility
- Data traffic reduction and optimization
- ANSI C12.19

Systems Supported

- Itron MV-90 xi and data acquisition systems
- Itron PC-PRO+® Advanced
- Trilliant SerViewCom™ Communications Server Software
- Trilliant Table TestBench programming software

Antenna

- Internal 3db patch antenna
- V.S.W.R.: 1.5:1 or less
- Impedance: 50 ohms
- Cable: RG-174A/U
- Standard termination: SMA male

Optional Antenna

- External 4.9db omnidirectional whip antenna

communications

CDMA

> Power consumption:
  - 1.8 max.
  - (Average: <0.4W)
  - (Maximum: <2W)

> CDMA/1xRTT communications:
  - Circuit switched data mode: Up to 14.4 kbps
  - Packet switched data mode: Up to 153 kbps

> Reception sensitivity: -104 dBm

> Security: DES encryption

> Approvals:
  - FCC:09EQ2438
  - IC: 3651C-Q2438

iDEN

> Operating voltage: 5V DC

> Operating current: 75 ma

> Communications protocol:
  - TCP/IP over wireless packet data
  - Communications data rate: 19.2 kbps
  - Transmission power: 0.6 watts nominal
  - Reception sensitivity: <-111 dBm

> iDEN wireless packet data networks
  - Receiver Tx: 806-821 Mhz
  - Receiver Rx: 851-866 Mhz

> Approvals:
  - Contains a type-accepted transmitter approved under FCC ID#: AZ492FT5826
  - IC: 109U-92FT5826

GSM

> GSM/GPRS communications:
  - Circuit switched data mode: Up to 14.4 kbps
  - Packet switched data mode: Up to 115 kbps

> Reception sensitivity: -104 dBm

> Approvals:
  - Contains a type-accepted transmitter approved under FCC ID#: 09EQ2426-5K

profile

Itron Inc.

Itron is a leading technology provider and critical source of knowledge to the global energy and water industries. Nearly 3,000 utilities worldwide rely on Itron technology to deliver the knowledge they require to optimize the delivery and use of energy and water. Itron delivers value to its clients by providing industry-leading solutions for electricity metering; meter data collection; energy information management; demand response; load forecasting, analysis and consulting services; distribution system design and optimization; web-based workforce automation; and enterprise and residential energy management.

To know more, start here: www.itron.com

Itron

Corporate Headquarters
2111 North Molter Road
Liberty Lake, Washington 99019
U.S.A.
Tel.: 1.800.635.5461
Fax: 1.509.891.3355

Itron Inc.
Oconee Electricity Metering
313-B North Highway 11
West Union, SC 29696
U.S.A.
Tel.: 1.864.638.8300
Fax: 1.864.638.4950

Publication 100795SP-01
04/07

H6802, H6806, H6809 H6810, H6811, H6812

H68xx-V Series

1 VAC and 0.333 VAC Current Transducers

Installer's Specifications

Accuracy	1% from 10% to 100% of rated current
Leads	H6806, H6809: 22 AWG, 300 VAC, 6' standard length H6802, H6810, H6811, H6812: 18AWG, 600VAC, 6' standard length
Operating Temperature Range	-15° to 60°C (5° to 140°F)
Storage Temperature Range	-40° to 70°C (-40° to 158°)
Humidity Range	0-95% non-condensing
Max. Voltage L-N Sensed Conductor	H6802, H6806: 300VAC (basic insulation rating) H6809, H6810, H6811, H6812: 600VAC (basic insulation rating)
Frequency Range	50/60 Hz
Altitude of Operation	3km max.
Installation Category	Cat II or Cat III

⚠ DANGER ⚠

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Follow safe electrical work practices. See NFPA 70E in the USA, or applicable local codes.
- This equipment must only be installed and serviced by qualified electrical personnel.
- Read, understand and follow the instructions before installing this product.
- Turn off all power supplying equipment before working on or inside the equipment.
- Use a properly rated voltage sensing device to confirm power is off.
  DO NOT DEPEND ON THIS PRODUCT FOR VOLTAGE INDICATION
- Secondary terminals must be shorted, or connected to the burden at all times.

Failure to follow these instructions will result in death or serious injury.

NOTICE

- This product is not intended for life or safety applications.
- Do not install this product in hazardous or classified locations.
- The installer is responsible for conformance to all applicable codes.

Documentation must be consulted where this symbol is used on the product.

This symbol indicates an electrical shock hazard exist.

Always use this product in the manner specified or the protection provided by the product may be impaired.

This product must be installed in an appropriate Fire and Electrical enclosure per local regulations.

QUICK INSTALL

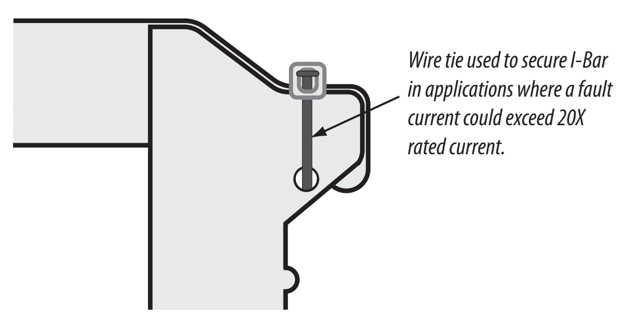
1. Installation must be performed by a qualified electrician. Disconnect and lock out power to the primary circuit before installing these current transducers (CTs).
2. Connect the transducer output leads to the meter inputs. The white wire is the X1 lead.
3. Depress the tabs on one end of the current transducer to open it and slip it over the primary leads. Note labeling on product indicating "source side."
4. Check the core ends on both sections of the CT to assure there is no rust or debris in the closure areas.
5. Close and latch the CT, and mount it securely.
6. Reconnect power to the panel.

Optional mounting kit available for the H6810, H6811, and H6812. See Veris AH06.

NOTES

Accuracy is specified with the primary conductor(s) centered in the CT window.

In any application where fault currents can exceed 20 times rated current of CT, wire ties or similar fasteners should be used to secure the I-Bar to the CT housing. Wire ties should be used on each side of each CT, see below. CTs should be secured using wire ties or brackets (models H6810, H6811, H6812 only).



Max. voltage without additional insulation: 300VAC (for the H6802 and H6806) or 600VAC (for the H6809, H6810, H6811, and H6812)

Do not apply current transducers to circuits having a phase-to-phase voltage greater than the stated maximum voltage unless adequate additional insulation is applied between the primary conductor and the current transducers. Veris assumes no responsibility for damage of equipment or personal injury caused by transducers operated on circuits above their published ratings.

DESCRIPTION

The H68xx-V series of 1 volt and 0.333 volt split-core current transducers provide secondary voltage AC proportional to the primary (sensed) current. For use with power meters, data loggers, chart recorders, and other instruments the H68xx-V series 1 volt and 0.333 volt CTs provide a cost-effective means to transform electrical service amperages to a voltage compatible with monitoring equipment.

RATINGS

Model	Sensing Current (A)	Frequency (Hz)	Output (V)	Weight (kg)
H6802	0 to 60	50/60	0 to 1	0.07
H6806	0 to 100	50/60	0 to 1	0.098
H6809	0 to 200	50/60	0 to 1	0.151
H6810	0 to 300	50/60	0 to 1	0.340
H6811	0 to 800	50/60	0 to 1	0.580
H6812	0 to 2400	50/60	0 to 1	0.870

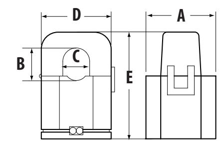
Models H6802 and H6806: These products provide basic insulation to 300VAC between the sensed conductor and the output leads. For reinforced applications, the sensed conductor must be provided with appropriate insulation. Reinforced insulation is provided for applications to 150VAC between the sensed conductor and the output leads.

Models H6809, H6810, H6811, and H6812: These products provide basic insulation to 600VAC between the sensed conductor and the output leads. For reinforced applications, the sensed conductor must be provided with appropriate insulation. Reinforced insulation is provided for applications to 300VAC between the sensed conductor and the output leads.

DIMENSIONS

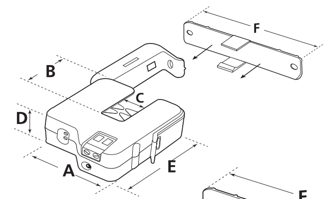
H6802
50 Amp

A = 1.0" (26 mm)
B = 0.5" (11 mm)
C = 0.4" (10 mm)
D = 0.9" (23 mm)
E = 1.6" (40 mm)



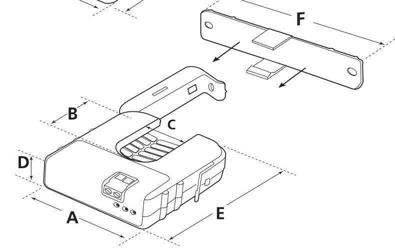
H6806
100 Amp

A = 2.2" (55 mm)
B = 1.3" (33 mm)
C = 0.5" (13 mm)
D = 0.9" (24 mm)
E = 2.3" (60 mm)
F = 3.5" (90 mm)



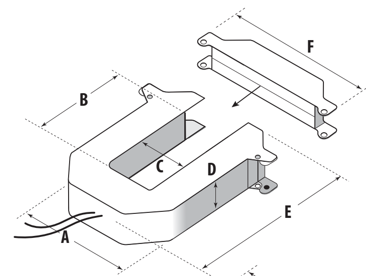
H6809
200 Amp

A = 2.6" (66 mm)
B = 1.1" (28 mm)
C = 0.8" (19 mm)
D = 1" (27 mm)
E = 2.9" (74 mm)
F = 3.5" (90 mm)



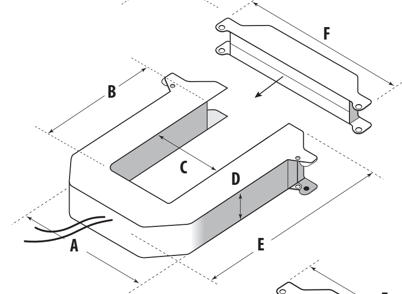
H6810
300 Amp

A = 3.8" (95 mm)
B = 1.5" (38 mm)
C = 1.3" (32 mm)
D = 1.1" (29 mm)
E = 3.9" (107 mm)
F = 4.8" (121 mm)



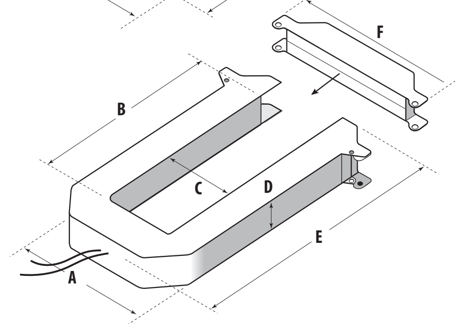
H6811
400/800 Amp

A = 4.9" (124 mm)
B = 2.9" (73 mm)
C = 2.5" (62 mm)
D = 1.1" (29 mm)
E = 5.3" (141 mm)
F = 5.9" (150 mm)



H6812
800/1600/2400 Amp

A = 4.9" (124 mm)
B = 5.5" (140 mm)
C = 2.5" (62 mm)
D = 1.1" (29 mm)
E = 8.1" (207 mm)
F = 5.9" (150 mm)



ALPHA Plus® Meter

ALPHA Plus Means Powerful Metering

Elster Electricity's ALPHA Plus meter is a powerful meter that builds on the patented ALPHA® metering technology. The ALPHA Plus meter can be a single phase, 240 volt, one–rate demand meter or a polyphase, wide voltage supply, multi–rate, real/reactive meter that validates meter service connections automatically, performs power quality monitoring, and provides load profile reading with remote communications.

Load Profile and Event Logs

The main circuit board has 28 KB of memory available to record load profile and data logs. The following table shows an example of the quantity of load profile data the meter can store with a 15–minute demand interval.

Number of channels	Maximum days stored
1 channel	141 days*
4 channels	36 days*

*Number of days may be fewer depending on the number of event log entries.

The integrity of load profile data does not depend on the meter battery because load profile memory is stored in nonvolatile EEPROM. When enabled with the load profile capability, the ALPHA Plus meter records date and time stamps for the following events:

- power failure
- test mode
- time change
- demand reset

With power quality monitoring enabled, the meter also includes date and time stamps of PQM events, including voltage sags.

Power Quality Monitoring

When this feature is enabled, the ALPHA Plus meter searches for exceptions to user-defined thresholds for items such as voltage, current, power factor, and total harmonic distortion. The meter performs various tests that measure and collect power quality data 24 hours a day.

System Service Tests

System service tests are performed to check the validity of the electrical service as wired to the meter. The ALPHA Plus meter verifies the service type, phase rotation, and validity of phase voltages. The ALPHA Plus meter also determines if phase currents are within a user–defined threshold.

Instrumentation

Instrumentation values provide near instantaneous analysis of the electrical service. All quantities can be programmed to display on the LCD in the normal or alternate display sequence:

- per phase voltage and per phase current
- per phase voltage and per phase current phase angles (as measured to phase A voltage)
- per phase current phase angle as measured to same–phase voltage
- per phase power factor and power factor angle
- per phase kW, kVAR, and kVA
- per phase total harmonic distortion for both voltage and current
- system frequency
- system kW, kVAR, kVA, power factor, and power factor angle

Revenue Metering

A1K+ and A1R+ meters measure, store, and display a full set of energy and demand values for both real/apparent and real/reactive quantities, respectively. These meters provide two complete blocks of time-of-use data. Each TOU rate is supported by separate fractional energy registers.

The A1R+ meter offers vectorial kVA values as a metered quantity choice. Average PF can be displayed when kW and kVA are selected as metered quantities.

Technology to Empower Utilities

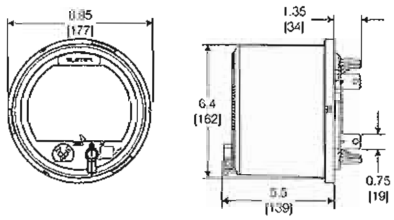
ELSTER

Communications

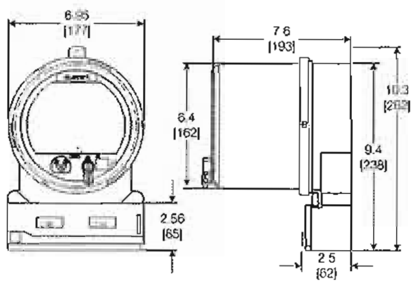
Data can always be retrieved using the standard optical port. By adding an option board, additional communications interfaces are available for the ALPHA Plus meter, including the following:

- 2400 bps internal telephone modem with outage callback
- RS-232 serial interface
- RS-485 serial interface
- 20 mA current loop
- external serial interface

S–base Dimensions



A–base Dimensions



Dimensions in inches [millimeters]. For reference only. Do not use in construction.

Specifications and Technical Data

Absolute Maximums		
Voltage	Continuous at maximum of operating range	
Surge voltage withstand	*ANSI C37.90.1 oscillatory*	2.5 kV, 2500 strikes
	ANSI C37.90.1 fast transient	5 kV, 2500 strikes
	ANSI C62.41	6 kV at 1.2/50 µs, 10 strikes
	IEC 61000-4-4	4 kV, 2.5 kHz repetitive burst for 1 minute
	ANSI C12.1 insulation	2.5 kV, 60 Hz for 1 minute
Current	Continuous at Class amperes Temporary (1 second) at 200 % of meter max. current	
Operating Ranges		
Voltage	*Nameplate nominal range*	*Operating range*
	120 V to 480 V	96 V to 528 V
	63 V to 240 V*	54 V to 264 V*
	Dedicated 240 V	192 V to 264 V
Current	0 to Class amperes	
Frequency	Nominal 50 Hz or 60 Hz ±5 %	
Temperature range	-40 °C to +85 °C inside meter cover	
Humidity range	0 % to 100 % noncondensing	
Operating Characteristics		
Power supply burden (Phase A)	Less than 3 W	
Per phase current burden	0.1 milliohms typical at 25 °C	
Per phase voltage burden	*120 V*	0.008 W
	240 V	0.03 W
	480 V	0.04 W
Accuracy	*Power supply* 120 V to 480 V 120 V to 240 V Dedicated 240 V	*ANSI C12.20 accuracy* Meets accuracy Class 0.2 %
	63 V to 240 V*	Meets accuracy Class 0.5 %
General Performance Characteristics		
Starting current	*Form 1S & Form 3S*	10 mA for Class 20 100 mA for Class 200 160 mA for Class 320
	All other forms	5 mA for Class 20 50 mA for Class 200 80 mA for Class 320
Startup delay	Less than 3 seconds from power application to pulse accumulation	
Creep 0.000A (no current)	No more than one pulse measured per quantity, conforming to ANSI C12.1 requirements	
Primary time base	Power line frequency (50 Hz or 60Hz), with selectable crystal oscillator	
Secondary time base	Meets the ANSI limit of 0.02 % using the 32.768 kHz crystal. Initial performance is expected to be equal to or better than ±55 seconds per month at room temperature	
Outage carryover capacity	6 hours at 25 °C. Supercapacitor rated at 0.1 Farads, 5.5 V	
Battery (optional)	$LiSOCl_2$ battery rated 1000 mAhr, 3.6 V and shelf life of 20+ years. 5 years continuous duty at 25 °C	
Communications rate	*Optical port*	9600 bps (nominal)
	Remote port	1200 to 19,200 bps
Shipping Weights *All values are approximate*		
S-base	*Single*	5.5 lbs [2.49 kg]
	4-pack	15.5 lbs [7.03 kg]
A-base	*Single*	7.5 lbs [3.4 kg]
	4-pack	26 lbs [11.8 kg]

*Not available on meters with the CPS power supply.

Elster Electricity, LLC
Raleigh, North Carolina, USA
+1 800 338 5251 (US Toll Free)
+1 905 634 4895 (Canada)
support@us.elster.com
www.elsterelectricity.com

CDS-9060

Remote Wireless Data Acquisition System

The CDS-9060 is a reliable, cost-effective, self-contained solution for remote meter reading and data communications applications. This rugged wireless data modem has long been the choice of companies and utilities looking to solve their wireless data needs. The CDS-9060 is incredibly versatile and supports CDMA dual mode – both circuit-switched and 1xRTT packet-switched services – as well as SMS and analog data transmissions. A GPS-enabled model is also available.

Easy to Use and Set Up

➤ *The CDS-9060 has been designed with the end user in mind. A simple-to-use configuration menu makes it easy to program the unit both locally and remotely – eliminating the need to travel hundreds of miles to a remote device. Seamless 1xRTT CDMA packet data sending and receiving is provided by the built-in TCP/IP stack. The unit is also smart enough to act like a PLC, providing 6 inputs and 6 outputs.*

Self-contained Solution for Remote Meter Reading and Data Communications

Distinctive Features

- Complete network approvals (approved by all major carriers)
- Acts like a PLC with 6 inputs/outputs controlled via DRiP
- Easy trouble-shooting via configuration menu
- 4 sleep windows for power-saving in solar applications
- Internal signal-strength meter
- Switches from CDMA to analog mode automatically (requires optional analog modem)
- FCC and Canada certified RF
- Easy set up includes customer support
- Customer support provided by wireless data experts

Typical Applications

Automatic Meter Reading (AMR), Remote Point of Sale (POS), Wireless Telemetry, SCADA, Video Monitoring, Traffic Sensor Monitoring, Alarm & Equipment Monitoring, Automatic Teller Machines (ATM), Short Message Service (SMS), Automatic Vehicle Location (AVL)

Standard Features

- Packet-switched data (1xRTT CDMA)
- Circuit-switched data (IS-95)
- SMS via AT-Commands over CDMA
- Dynamic IP management
- TCP/IP stack
- PPP/TCP/UDP/MIP/DMU/PAD
- Remote updates to PRL
- Simple modem configuration – remotely or locally
- 3 input triggers for cry-out alarms via SMS
- Optional analog modem (300bps to 33.6bps)
- Optional RS-485 for multi-drop applications

DATAREMOTE INCORPORATED
moving data over wireless

General Specifications

Standards:	Packet-switched data (CDMA 1xRTT), Short Message Service (SMS), circuit-switched data (IS-95), analog data
Power Requirements:	10-48VDC @ 1.2A (unregulated)
On-Board Backup:	3.6V 200MA (CR2032) Lithium Cell
Serial I/O:	RS-232 Async (optional terminal block for RS-232)
Control I/O:	12 pos. IDC header, 6 inputs/6 outputs (send cry-out alarms via SMS to your cell phone)
Command Protocol:	AT command set and DataRemote, Inc (DRiP) configuration menu
LED Indicators:	Power ON, Signal Status, TXD, RXD, DCD, DTR, AUX
CDMA Modem:	MSM-5105 (1xRTT; IS-95A/B - MDR verified)
Optional:	AMPS modem (Conexant chipset 300bps to 33.6bps)
Vocorder:	8 Kbps CELP, 13 Kbps QCELP, 8 Kbps EVRC

RF Specifications	800 MHz	1900 MHz (CDMA)
Interface Standards:	AMPS: ANSI/TIA/EAI-553 CDMA: TIA/EIA, IS-95A/B	J-STD-008
Operating Frequencies:	TX: 824-849 MHz RX: 869-894 MHz	TX: 1850-1910 MHz RX: 1930-1990 MHz
RF Power:	AMPS: 600mW (EIRP Nom.) CDMA: 600mW (EIRP Nom.)	400mW (EIRP Nom.)
Maximum TX Power:	AMPS: +26.7dBm Min. CDMA: +23dBm Min.	+23dBm Min.
Receiver Sensitivity:	AMPS: >116dBm @ 12dB Sinad CDMA: >-104dBm @ 0.5% FER	>104 dBm @ .05% FER
Frequency Stability:	< ± 2.5 PPM	< ± 2.5 PPM
Antenna Interface:	50 ohm, TNC	50 ohm, TNC
Current:	Normal current draw = 53ma in Idle Mode (can vary from network to network)	

connected M2M by kyocera

Physical Specifications	
Size:	6.3"L X 4"W X 1.2" H
Weight:	23.0 Oz.

Environmental Specifications	
Temperature:	Operating: -30 C to +60 C (-22° to 140°) Storage: -40 C to +70 C (-40° to 146°)
Humidity:	0-95% (non-condensing) 95° F (35° C)

Optional NEMA-4x Enclosure for Harsh Conditions

Features may change without notice.

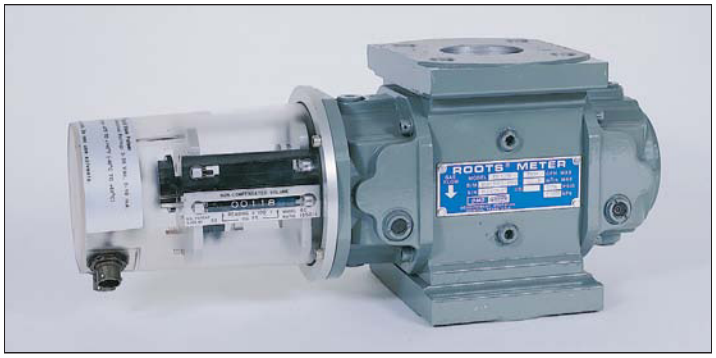
FUEL Equipment Specification Sheets

DRESSER

ROOTS Meters & Instruments

TECH SPECS

ROOTS® Solid State Pulser



Shown: ROOTS® Meter Series B3 with Pulser

Features

- Bounceless Switch
- Internal Mounting
- No Battery
- No Moving Parts
- Reliable Wiegand Technology
- Rugged, Weatherproof Housing
- Corrected & Uncorrected Outputs
- Universal Interface

The ROOTS® Solid State Pulser+ generates low frequency pulses which represent volumetric information necessary for remote data collection units. Solid state construction eliminates mechanical switches and ensures maximum reliability. No battery and no maintenance are required.

The dual connector option allows one connector to be used with your AMR system and a separate connector for your customer. These pulsers are available for our Series B3 (Life-Lubed™) meters and Series A1 (LM-MA) meters.

Specifications

Loop Voltage	3-30 VDC
Maximum Loop Current	10 mA
Contact Bounce	0 msec
Min. Pulse Width	50 msec or 50% of Duty Cycle (whichever is smaller)
Switch Closed	R < 10 OHMS
Switch Opened	R > 1 MEGA OHM
Temperature Range	-40°F to +140°F -40°C to +60°C
Humidity	95% non-condensing
Output*	Form C
Series 3 & 1 TC (Temp. Comp.) Version	Non-compensated and Compensated Pulse
Counter (CTR) Version	Non-compensated Pulse
Outputs	Single or Dual Connectors (MS Circular, Conduit, or Cable Gland)

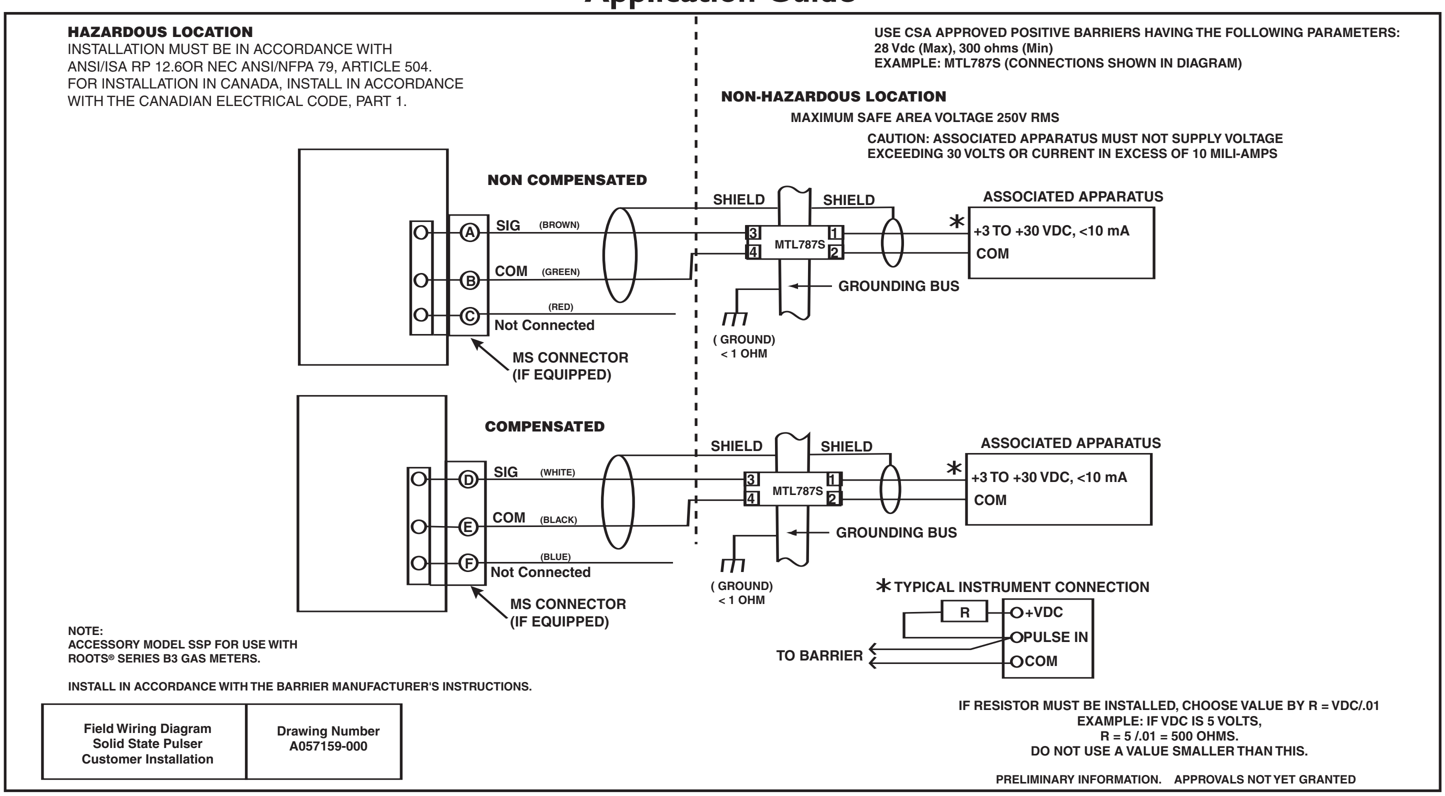
+ U.S. Patent Number; 5,530,298

* Form A wiring acceptable. A two-wire Form B will not function properly.
Note: Solid State Pulser can be purchased in a conversion kit or factory installed on a ROOTS® Meter.

Version	Type	# Connectors	P/N Amph. Conn. #399 Kit	P/N Conduit Conn. #399 Kit	Meter Size	Pulse Rate (English)	Pulse Rate (Metric)	Non-Comp. Pulse Wiring	Comp. Pulse Wiring
Series B3	Counter	Single	057128-060	057128-130	8C-3M	10 cf	0.1 m3	ABC	
(Life-Lubed)	Counter	Single	057128-060	057128-130	5M-11M	10 cf	1.0 m3	ABC	
	Counter	Single	057128-060	057128-130	16M-38M	100 cf	1.0 m3	ABC	
	Counter	Single	057128-060	057128-130	56M	100 cf	10.0 m3	ABC	
	Counter	Dual	057128-070	057128-130	8C-3M	10 cf	0.1 m3	ABC	
	Counter	Dual	057128-070	057128-130	5M-11M	10 cf	1.0 m3	ABC	
	Counter	Dual	057128-070	057128-130	16M-38M	100 cf	1.0 m3	ABC	
	Counter	Dual	057128-070	057128-130	56M	100 cf	10.0 m3	ABC	
	TC	Single	057128-310	057128-260	8C-3M	10 cf	.1 m3	ABC	DEF
	TC	Single	057128-310	057128-260	5M-11M	10 cf	1.0 m3	ABC	DEF
	TC	Single	057128-310	057128-260	16M	100 cf	1.0 m3	ABC	DEF
	TC	Dual	057128-320	057128-260	8C-3M	10 cf	.1 m3	ABC	DEF
	TC	Dual	057128-320	057128-260	5M-11M	10 cf	1.0 m3	ABC	DEF
	TC	Dual	057128-320	057128-260	16M	100 cf	1.0 m3	ABC	DEF
LM-MA	Counter	Single	052901-001	052901-101	1.5M-5M	10cf	0.1m3	ABC	
	Counter	Single	052901-003	052901-103	7M-11M	10cf	1.0m3	ABC	
	Counter	Single	052901-003	052901-103	16M	100cf	1.0m3	ABC	
	Counter	Dual	052901-002	052901-102	1.5M-5M	10cf	0.1m3	ABC	
	Counter	Dual	052901-004	052901-104	7M-11M	10cf	1.0m3	ABC	
	Counter	Dual	052901-004	052901-104	16M	100cf	1.0m3	ABC	
	TC	Single	052902-001	052902-101	1.5M-5M	10cf		ABC	DEF
	TC	Single	052902-003	052902-103	7M-11M	10cf		ABC	DEF
	TC	Single	052902-003	052902-103	16M	100cf		ABC	DEF
	TC	Dual	052902-002	052902-102	1.5M-5M	10cf		ABC	DEF
	TC	Dual	052902-004	052902-104	7M-11M	10cf		ABC	DEF
	TC	Dual	052902-004	052902-104	16M	100cf		ABC	DEF
FM	Counter	Single	052901-005	052901-105	23M-38M	100cf	1.0m3	ABC	
(Foot Mount)	Counter	Single	052901-005	052901-105	56M-102M	100cf	10.0m3	ABC	
	Counter	Dual	052901-006	052901-106	23M-102M	100cf	1.0m3	ABC	
	Counter	Dual	052901-006	052901-106	56M-102M	100cf	10.0m3	ABC	

Note: For Series 3 Pulser-Ready Accessory Units, a credit may be applied for deduction of magnets from SSP #399 Kits.

Application Guide



DRESSER
Roots Meters & Instruments

Dresser Roots Meters & Instruments **Dresser, Inc.**

P. O. Box 42176
Houston, TX USA 77242-2176
website: www.dresser.com

Inside US Ph: 800.521.1114 Fax: 800.335.5224
Outside US Ph: 832.590.2303 Fax: 832.590.2494
www.rootsmeters.com

SB 5500.4

RPM® SERIES Rotary Gas Meters

AMERICAN
METER COMPANY

RPM® SERIES

Rotary Gas Meters – *accurate, versatile, tough*

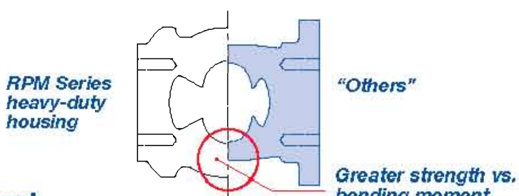
Accurate

American Meter Company offers a complete line of RPM® Series Rotary Gas Meters designed for commercial, industrial and pipeline applications. These meters are precision engineered to ANSI B109.3 National Standards to accurately measure natural gas flow at all standard line conditions.

Versatile

The meters are also suitable for propane and butane gases, as well as other inert gases. The meters are badge rated as standard to 175 (12 bar) MAOP and can be rated to ***285 (20 bar) MAOP at no extra charge*** for high-pressure applications.

All models can be modified to fit a variety of "meter read" formats including Mercury Mini-Max T Fixed Factor and Temperature Compensation, Mercury Full Pressure and Temperature Mini-Max or Mini AT Correction, Continuous Mechanical Temperature Compensation, Automated Meter Reading with ERTransponders and Low Frequency Pulser options; all to provide flexibility in meeting specific gas measurement needs.



Tough

These rotary meters provide outstanding performance in the most adverse of applications. The RPM Series meter housing provides greater strength and higher pressure ratings than other manufacturers of equal capacity. Their rugged construction and superior strength at the bending moment of the housing ensures this meter ***will not "lock up"*** even under the most unstable pipe stress conditions that can occur on new meter pipe sets.

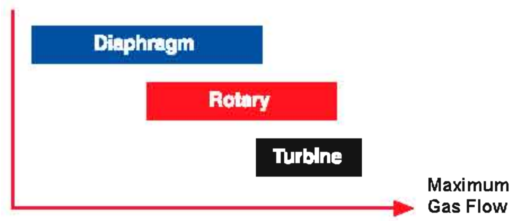
Meter Selection and Operating Principles

The Rotary Gas Meter complements American Meter's existing line of traditional diaphragm and turbine meters. A rotary gas meter, like a diaphragm meter, operates on the positive displacement theory of measurement by creating a fixed-volume measuring compartment. In the rotary's case, the positive displacement occurs between the meter's internal housing cavity and its rotating impellers.

Deciding whether a rotary, diaphragm, or turbine meter is the best choice for your particular application should depend on the following:

- pressure of the gas being measured
- maximum flow rate to be measured
- minimum flow rate to be measured
- desired rangeability

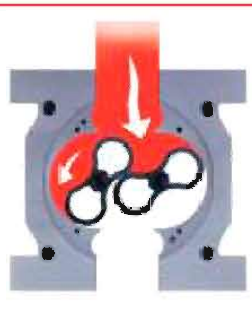
American Meter can offer you all three types.



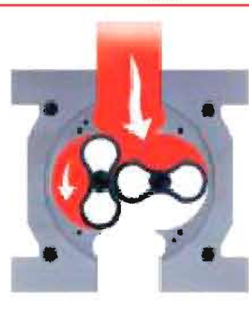
Rotary Operating Principles

As downstream demand initiates the flow of gas, a pressure drop develops between the meter's inlet and outlet. This creates an internal force on a pair of hour-glass shaped impellers that begin to rotate allowing the flow of gas to start. As the impellers rotate, gas alternately flows into two fixed-volume chambers created between the impellers and the internal cavity of the meter's housing. While cycling, these chambers measure a fixed-volume of gas and then discharge that gas downstream, filling the demand.

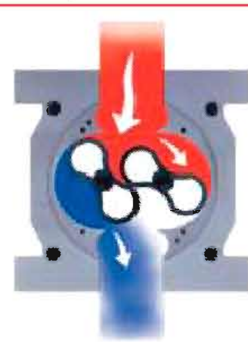
These impellers rotate by way of highly synchronized precision gears and will cycle four times during each revolution of the impeller shaft. During operation, there is no metal-to-metal contact between the meter's housing and impellers.



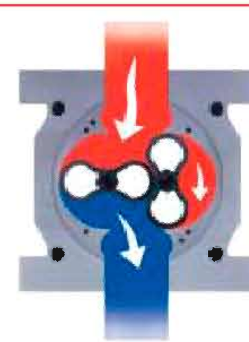
Demand initiates gas flow through the meter.



Impeller captures a fixed volume of gas.



Measuring cavity opens releasing gas downstream.



The meter cycles four times completing one revolution.

RPM Series Rotary Accessory Options

All RPM Series meters mount in either a horizontal or vertical position, depending on available space and convenience. Once installed, all standard and optional accessories can be easily positioned for convenient reading and quick service. All models have extremely good rangeability and are available in various pipe sizes to meet a variety of applications. For example, our 5.5M meter comes in 2" and 3" pipe inlet variations allowing you to increase capacity of a 3M meter 2" pipe installation without changing out the pipe set.

RPM Series meters are available in the following configurations:

RPM-STD

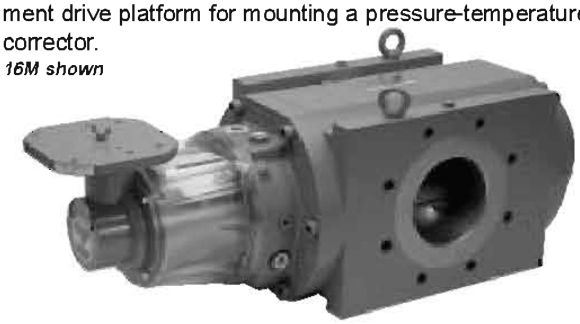
STANDARD meter with uncorrected mechanical register.

3.5M shown

RPM-ID

Meter with uncorrected mechanical register and instrument drive platform for mounting a pressure-temperature corrector.

16M shown



RPM-CMTC

Meter with Continuous Mechanical Temperature Compensator.

1.5M shown

RPM-CMTC-ID

Meter with Continuous Mechanical Temperature Compensator and instrument drive for mounting a pressure-compensating index or pressure corrector.

5.5M shown

RPM-CMTC with Direct-Mount TRACE® or ITRON® ERT

Meter with Continuous Mechanical Temperature Compensation. No more instrument drive accessory and sandwich pulsers are needed. The ERT can be programmed at our factory, in your meter shop, or in the field. Four optional kits are available.

7M shown with ITRON 40G ERT

RPM-CMTC or STANDARD Meter with Low-Frequency Pulser Options

Military and standard connections are available.

5.5M shown

American Meter

RPM® SERIES

Rotary Meter with Mercury Instrumentation

New Horizons in Measurement and Instrumentation

A new generation of Mercury Mini-Max® and Mini-AT® Correctors now mount three different ways: integrally on top, direct on the end, or on a standard instrument drive plate to American Meter's RPM® Series Rotary Meters.

The integral or direct-mount combination eliminates the need for the mechanical register and base plate of the corrector, as well as the instrument-mounting plate and mechanical-drive mechanism from the meter.

Cost savings are achieved on both integral and direct-mount units making for an attractive lower-price combination over standard Instrument Drive (ID) mountings.

These new Mercury correctors can be mounted to the AMCO rotary meter directly at American Meter's factory or installed in the field or meter shop.

Capabilities

- Unless the meter installation possesses an unusual obstruction, the corrector can rotate 360° and clear adjacent pipe, fittings, and bolts in 90°/180° intervals.
- The Mercury correctors work with both horizontal and vertical meter pipe set mountings.
- There is no need to open the corrector in order to mount or remove from the meter.
- The Instrument Drive (ID) assembly functions with other Mercury ID correctors or other brands. Available rotation of the larger correctors may be limited.

Contact your Mercury/AMCO sales representative for more information.

Mercury Instruments, Inc.
3940 Virginia Avenue, Cincinnati, Ohio 45227 USA
Phone: 513/272-1111 • Fax 513/272-0211
web: www.mercuryinstruments.com
e-mail: info@mercuryinstruments.com

Integral On Top
5.5M Shown

Direct Side Mount
1.5M Shown

Instrument Drive (ID)
16M Shown

Mercury Mini-Max® Specifications

Input Volume

- Dual dry-reed switches – one pulse per each meter revolution
- Uncorrected volume totalized on the mechanical index and displayed on LCD
- Uncorrected volume-pulse counting continues for 30 minutes with main battery removed

Input Pressure

Mini-Max Electronic Temperature Corrector (ETC) is Fixed-Factor only.

Mini-Max Pressure and Temperature (P&T) Corrector is as follows:

- Precision strain-gauge pressure transducer compensated to minimize ambient temperature effects
- Live LCD display of input pressure
- Standard transducer ranges (accuracy +/- .4% F.S.):

Pressure Ranges

(PSI)	*(BAR)*	*Transducer Type*
0-1	0.07	Gauge only
0-3	0.20	Gauge only
0-6	0.40	Gauge only
0-15	1.00	Gauge only
0-30	2.00	Gauge or Absolute
0-60	4.00	Gauge or Absolute
0-100	7.00	Gauge or Absolute
0-300	20.00	Gauge or Absolute
0-600	41.00	Gauge or Absolute
0-1000	70.00	Gauge or Absolute

Input Temperature

- Highly stable solid-state temperature sensor in a sealed 1/4-inch diameter, 6-inch long, stainless-steel probe with 6-foot shielded conductor and 1/2-inch NPT slip-along fitting to match thermowell
- Range: -40 to 150°F (-40 to 65.5°C)
- Live LCD display of input temperature

Corrected Volume

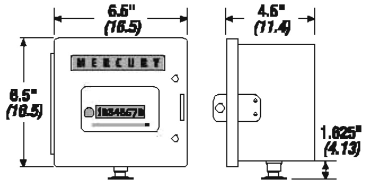
- Corrected to desired base pressure and base temperature within +/- .3% accuracy
- Corrected for supercompressibility (NX-19 or AGA-8)
- Selectable (metric and imperial) volume units
- Displayed continuously on 8-character x 1/2-inch LCD

Certifications

- Designed for Class I, Divisions 1 and 2, Group D (certifications pending)

Warranty

- Corrector 4 years



Mercury Mini-AT® Specifications

Input Volume

- Dual dry-reed switches – one pulse per each meter revolution
- Uncorrected volume totalized on the mechanical index and displayed on LCD

Input Pressure

- Precision strain-gauge pressure transducer compensated to minimize ambient temperature effects
- Live LCD display of input pressure
- Standard transducer ranges (accuracy +/- .25% F.S.):

Pressure Ranges

(PSI)	*(BAR)*	*Transducer Type*
0-1	0.07	Gauge only
0-3	0.20	Gauge only
0-6	0.40	Gauge only
0-15	1.00	Gauge only
0-30	2.00	Gauge or Absolute
0-60	4.00	Gauge or Absolute
0-100	7.00	Gauge or Absolute
0-300	20.00	Gauge or Absolute
0-600	41.00	Gauge or Absolute
0-1000	70.00	Gauge or Absolute
0-1500	100.00	Gauge or Absolute

Input Temperature

- Highly stable solid-state temperature sensor in a sealed 1/4-inch diameter, 9-inch long, stainless-steel probe with 6-foot armored conductor and 1/2-inch NPT slip-along fitting to match thermowell
- Range: -40 to 170°F (-40 to 76.6°C)
- Live LCD display of input temperature

Corrected Volume

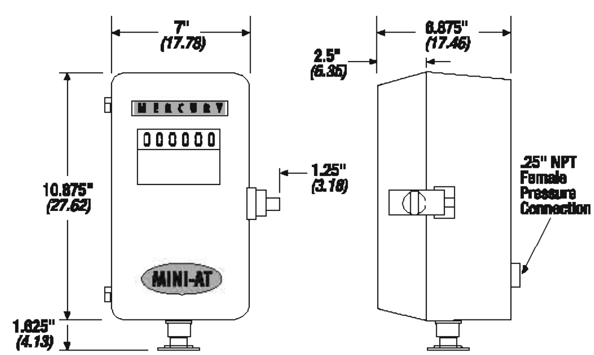
- Corrected to desired base pressure and base temperature within +/- .1% accuracy
- Corrected for supercompressibility (NX-19 or AGA-8)
- Selectable (metric and imperial) volume units
- Displayed continuously on 8-digit x 1/2-inch LCD

Certifications

- Designed for Class I, Divisions 1 and 2, Group D (certifications pending)

Warranty

- Corrector 4 years



Technical Data

Description	Units	Meter Size 8C –	9C G16	11C –	1.5M G25	2M G40	3.5M G65	5.5M G100	7M –	11M –	16M G250
Rated capacity @ 0.25 psig *(17 mBarg)*	scfh *(Sm³/h)*	800 *(22.4)*	900 *(25.2)*	1100 *(30.8)*	1500 *(42.0)*	2000 *(56.0)*	3500 *(98.0)*	5500 *(154.0)*	7000 *(196.0)*	11000 *(308.0)*	16000 *(448.0)*
Max. allowable pressure (MAOP) 285 optional	psig	175/285	175/285	175/285	175/285	175/285	175/285	175/285	175/285	175/285	175/285
Rangeability ±1%*		>30:1	>30:1	>40:1	>40:1	>75:1	>75:1	>120:1	>70:1	>120:1	>100:1
Rangeability ±2%*		>60:1	>60:1	>75:1	>75:1	>140:1	>140:1	>210:1	>115:1	>225:1	>150:1
Start rate	cfh	<3.0	<3.0	<3.0	<3.0	<4.0	<4.0	<4.4	<5.5	<5.5	<7.0
Drive register/I.D. CW/CCW	cf/rev	10	10	10	10	10	10	10/100	10/100	10/100	1000
Max. operating speed	rpm	2043	2043	2358	2358	2950	2950	2425	2098	2414	2976
Flange/flange dimension	in.	6.75	6.75	6.75	6.75	6.75	6.75	6.75	9.50	9.50	9.50
Nominal pipe size	in.	1.5/2	1.5/2	1.5/2	1.5/2	2	2	2/3	3	4	4

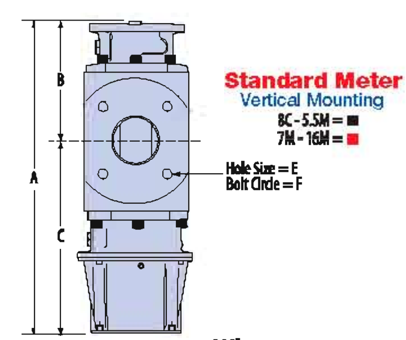
** Data represents averages taken from base model meters tested on Bell provers.*

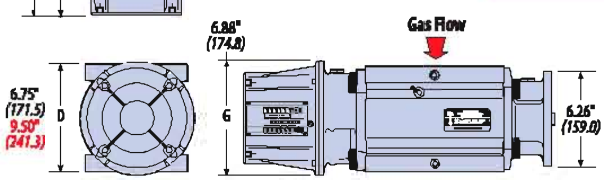
Dimensions inches *(metric)*

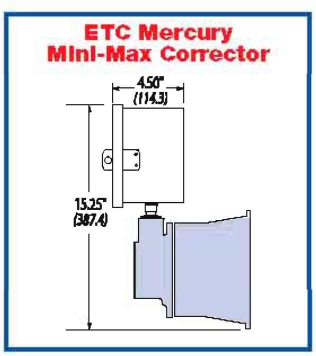
Standard meter with mechanical temperature compensator Horizontal and vertical mounting

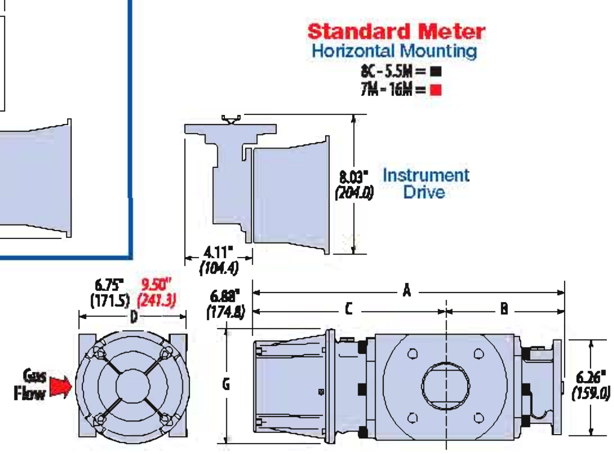
Meter Size	8C –	9C G16	11C –	1.5M G25	2M G40	3.5M G65	5.5M (2") G100	5.5M (3") G100	7M –	11M –	16M G250
A	16.080 *(408.43)*	16.080 *(408.43)*	17.580 *(446.53)*	17.580 *(446.53)*	15.580 *(395.73)*	15.580 *(395.73)*	19.520 *(495.81)*	19.520 *(495.81)*	18.650 *(473.71)*	20.410 *(518.41)*	22.822 *(579.68)*
B	5.810 *(147.60)*	5.810 *(147.60)*	6.390 *(162.30)*	6.390 *(162.30)*	5.390 *(136.90)*	5.390 *(136.90)*	7.360 *(186.90)*	7.360 *(186.90)*	6.970 *(177.40)*	7.980 *(202.70)*	9.056 *(230.02)*
C	10.280 *(261.11)*	10.280 *(261.11)*	11.200 *(284.48)*	11.200 *(284.48)*	10.190 *(258.83)*	10.190 *(258.83)*	12.160 *(308.86)*	12.160 *(308.86)*	11.420 *(290.07)*	12.370 *(314.20)*	13.506 *(343.05)*
D	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	9.50 *(241.3)*	9.50 *(241.3)*	9.50 *(241.3)*
E (ANSI) E *(metric)*	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2	5/8-11 M16X2
F (ANSI)	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	6.000 *(152.40)*	6.000 *(152.40)*	7.500 *(190.50)*	7.500 *(190.50)*
F *(metric)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	6.299 *(160.00)*	6.299 *(160.00)*	7.087 *(180.00)*	7.087 *(180.00)*
G	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*
Weight lbs. *(kg.)*	22.0 *(10.00)*	22.0 *(10.00)*	26.0 *(11.80)*	26.0 *(11.80)*	26.0 *(11.80)*	26.0 *(11.80)*	38.0 *(17.24)*	36.0 *(16.33)*	60.0 *(27.22)*	74.0 *(33.57)*	90.0 *(40.83)*

Warranty — Five-year limited warranty with conditions. See IM 5700 for details.









RPM® SERIES

Sizing and Ordering Specifications

RPM Series Rotary Meter Capacities * – scfh *(Sm³/h)*

Local Atm Pressure - (psia) 14 37
Sea Level Atm Pressure - (psia) 14 73

Line Pressure	Meter Size 8C	9C	11C	1.5M	2M	3.5M	5.5M	7M	11M	16M
0.25 psig *(17 mBarg)*	800 *(22.4)*	900 *(25.2)*	1,100 *(30.8)*	1,500 *(42.0)*	2,000 *(56.0)*	3,500 *(98.0)*	5,500 *(154.0)*	7,000 *(196.0)*	11,000 *(308.0)*	16,000 *(448.0)*
2 psig *(1.4 mBarg)*	891 *(24.9)*	1,002 *(28.1)*	1,225 *(34.3)*	1,670 *(46.8)*	2,227 *(62.3)*	3,897 *(109.1)*	6,124 *(171.5)*	7,794 *(218.2)*	12,247 *(342.9)*	17,814 *(498.8)*
5 psig *(345 mBarg)*	1,054 *(29.5)*	1,185 *(33.2)*	1,449 *(40.6)*	1,976 *(55.3)*	2,634 *(73.8)*	4,610 *(129.1)*	7,244 *(202.8)*	9,219 *(258.1)*	14,487 *(405.6)*	21,073 *(590.0)*
10 psig *(690 mBarg)*	1,325 *(37.1)*	1,491 *(41.7)*	1,822 *(51.0)*	2,485 *(69.6)*	3,313 *(92.8)*	5,798 *(162.3)*	9,111 *(255.1)*	11,595 *(324.7)*	18,221 *(510.2)*	26,504 *(742.1)*
25 psig *(1.7 Barg)*	2,140 *(59.9)*	2,407 *(67.4)*	2,942 *(82.4)*	4,012 *(112.3)*	5,350 *(149.8)*	9,362 *(262.1)*	14,711 *(411.9)*	18,724 *(524.3)*	29,423 *(823.8)*	42,797 *(1,198.3)*
50 psig *(3.4 Barg)*	3,498 *(97.9)*	3,935 *(110.2)*	4,809 *(134.7)*	6,558 *(183.6)*	8,744 *(244.8)*	15,302 *(428.5)*	24,046 *(673.3)*	30,604 *(856.9)*	48,092 *(1,346.6)*	69,952 *(1,958.7)*
75 psig *(5.2 Barg)*	4,855 *(136.0)*	5,462 *(152.9)*	6,676 *(186.9)*	9,104 *(254.9)*	12,138 *(339.9)*	21,242 *(594.8)*	33,381 *(934.7)*	42,485 *(1,189.6)*	66,762 *(1,869.3)*	97,108 *(2,719.0)*
100 psig *(6.9 Barg)*	6,213 *(174.0)*	6,990 *(195.7)*	8,543 *(239.2)*	11,650 *(326.2)*	15,533 *(434.9)*	27,183 *(761.1)*	42,716 *(1,196.0)*	54,365 *(1,522.2)*	85,431 *(2,392.1)*	124,263 *(3,479.4)*
150 psig *(10.3 Barg)*	8,929 *(250.0)*	10,045 *(281.3)*	12,277 *(343.8)*	16,741 *(468.8)*	22,322 *(625.0)*	39,063 *(1,093.8)*	61,385 *(1,718.8)*	78,126 *(2,187.5)*	122,770 *(3,437.6)*	178,574 *(5,000.1)*
175 psig *(12.1 Barg)*	10,286 *(288.0)*	11,572 *(324.0)*	14,144 *(396.0)*	19,287 *(540.0)*	25,716 *(720.1)*	45,003 *(1,260.1)*	70,720 *(1,980.1)*	90,007 *(2,520.2)*	141,439 *(3,960.3)*	205,730 *(5,760.4)*
200 psig *(13.8 Barg)*	11,644 *(326.0)*	14,585 *(408.4)*	17,826 *(499.1)*	24,308 *(680.6)*	32,411 *(907.5)*	56,719 *(1,588.1)*	89,130 *(2,495.7)*	113,439 *(3,176.3)*	178,261 *(4,991.3)*	259,288 *(7,260.1)*
250 psig *(17.2 Barg)*	14,360 *(402.1)*	16,155 *(452.3)*	19,745 *(552.9)*	26,925 *(753.9)*	35,900 *(1,005.2)*	62,824 *(1,759.1)*	98,724 *(2,764.3)*	125,648 *(3,518.2)*	197,447 *(5,528.5)*	287,196 *(8,041.5)*
285 psig** *(19.6 Barg)*	16,261 *(455.3)*	18,293 *(512.2)*	22,358 *(626.0)*	30,489 *(853.7)*	40,652 *(1,138.2)*	71,141 *(1,991.9)*	111,792 *(3,130.2)*	142,281 *(3,983.9)*	223,585 *(6,260.4)*	325,214 *(9,106.0)*

Using the chart above:

Select the appropriate size rotary meter based on maximum instantaneous flow rate and minimum pressure

- Size is determined by finding the maximum hourly flow rate in cubic feet per hour (scfh) and the corresponding pressure at that flow rate

  Note 1000 BTU's/hr of natural gas approximately equals 1 CFH
  (BTU input rating can be found on the equipment/burner name plate)

- Find a value larger than the required maximum instantaneous hourly flow rate in the row representative to the specific minimum operating pressure The proper rotary meter model heads the column For example, maximum load of 25,000 scfh at 100 PSIG requires a 3 5M meter

* Capacity data based upon natural gas with specific gravity of 0 60

*** 285 MAOP optional at no charge*

Ordering Information

Options	Meter Size 8C and 9C – G16	11C and 1.5M – G25	2M and 3.5M G40 G65	5.5M G100	7M –	11M –	16M G250
Type	← english or metric →						
Connections	NPT/flanged	NPT/flanged	flanged	flanged	flanged	flanged	flanged
Pipe size	1.5"/2"	1.5"/2"	2"	2" or 3"	3"	4"	4"
Mounting	← vertical or horizontal →						
Counter	← 4, 5 or 6 digit →						
Output drive	← STANDARD, ETC, CMTC or Instrument Drive →						
Multiplier	← 10, 100 →						1000
Carton size	← 16"H x 12"W x 21.5"L →				← 16"H x 13"W x 24"L →		
Shipping wgt. lbs. *(kg.)*	26 *(11.79)*	33 *(14.97)*	30 *(13.61)*	42 *(19.05)*	65 *(29.48)*	75 *(34.02)*	90 *(40.82)*

A Complete Family of Gas Measurement, Pressure Regulation, and Testing Systems

AL800/AL1000 Diaphragm Meter

American Meter is the industry's leading supplier of diaphragm meters with models for applications from domestic service to large industrial users. See bulletin SB 3500 for more information.

Rotary Meter with Prefabricated Sets

Prefabricated new or replacement meter sets to customer specifications are available.

Pre-Calibrated Replacement Cartridges

Tested at atmospheric or actual operating pressure, pre-calibrated measurement cartridges are available for field service changes. Cartridges returned to the factory for re-certification and/or service are tested at five flow rates and at specified pressure.

1800 PFM Series

1800 PFM industrial regulators are designed for applications requiring medium-to-high capacity, extremely precise outlet-pressure control, and fast response to changing loads. See bulletin SB 8551 for more information.

Turbine Gas Meters

High-performance meters provide accurate measurement of high-volume gas flow. Turbines are available from 3" to 12" line sizes and line pressures up to 1440 PSIG. See bulletin SB 4510 for more information.

ISO 9001: 2000

QMI REGISTERED

Certificate No. 006697

Contact your AMCO/CMCO sales representative for more information.

Filters

Filtration down to 10 microns. Protects meter and regulator stations from dirt and pipe scale damage. See bulletin SB 12521 for more information.

AMERICAN METER COMPANY
Measurement Engineers Since 1836
Yesterday...Today...Tomorrow
132 Welsh Road, Suite 140
Horsham, PA 19044-2217
Phone: 215/830-1800
Fax 215/830-1890
www.americanmeter.com

CANADIAN METER
275 Industrial Road
Cambridge, Ontario
Canada N3H 4R7
Phone: 519/650-1900
Fax 519/650-1917
www.canadianmeter.com

Represented by...

ELSTER AMCO

Printed in U.S.A. Core – 4M – 1/05

CR1000 *Measurement & Control System*

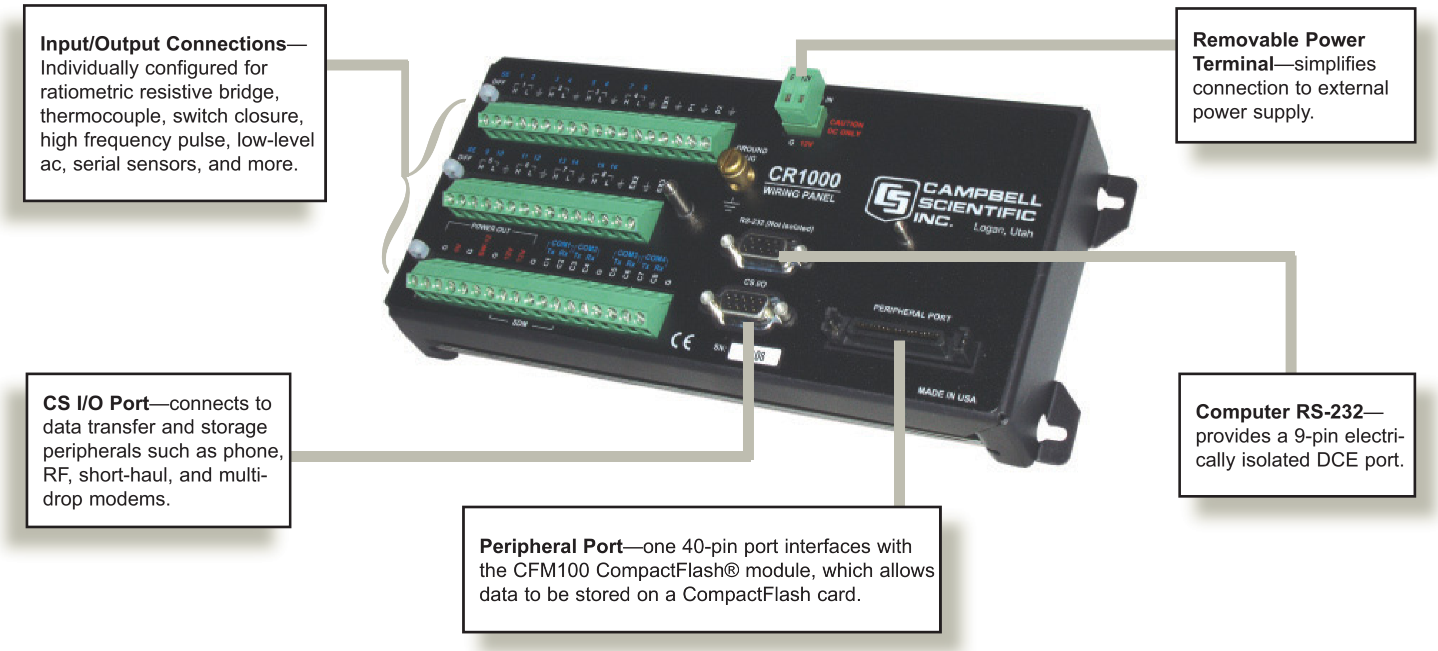
A Rugged Instrument with Research-Grade Performance

CAMPBELL SCIENTIFIC, INC.

815 W. 1800 N. • Logan, Utah 84321-1784 • (435) 753-2342 • FAX (435) 750-9540 • www.campbellsci.com

CR1000 Measurement and Control System

The CR1000 provides precision measurement capabilities in a rugged, battery-operated package. It consists of a measurement and control module and a wiring panel. Standard operating range is -25° to +50°C; an optional extended range of -55° to +85°C is available.



Features

- 2 Mbytes standard memory; 4 Mbytes optional memory
- Program execution rate of up to 100 Hz
- CS I/O and RS-232 serial ports
- 13-bit analog to digital conversions
- 16-bit H8S Hitachi Microcontroller with 32-bit internal CPU architecture
- Temperature compensated real-time clock
- Background system calibration for accurate measurements over time and temperature changes
- Single DAC used for excitation and measurements to give ratio metric measurements
- Gas Discharge Tube (GDT) protected inputs
- Data values stored in tables with a time stamp and record number
- Battery-backed SRAM memory and clock ensuring data, programs, and accurate time are maintained while the CR1000 is disconnected from its main power source
- Measures intelligent serial sensors without using an SDM-SIO4

Measurement and Control Module

The module measures sensors, drives direct communications and telecommunications, reduces data, controls external devices, and stores data and programs in on-board, non-volatile storage. The electronics are RF shielded and glitch protected by the sealed, stainless steel canister. A battery-backed clock assures accurate timekeeping. The module can simultaneously provide measurement and communication functions. The on-board, BASIC-like programming language supports data processing and analysis routines.

Wiring Panel

The CR1000WP is a black, anodized aluminum wiring panel that is compatible with all CR1000 and CR1000-4M modules. The wiring panel includes switchable 12 V, redistributed analog grounds (dispersed among analog channels rather than grouped), unpluggable terminal block for 12 V connections, gas-tube spark gaps, and 12 V supply on pin 8 to power our COM-series phone modems and other peripherals. The control module easily disconnects from the wiring panel allowing field replacement without rewiring the sensors. A description of the wiring panel's input/output channels follows.

Analog Inputs
Eight differential (16 single-ended) channels measure voltage levels. Resolution on the most sensitive range is 0.67 µV.

Pulse Counters
Two pulse channels can count pulses from high level (5 V square wave), switch closure, or low level ac signals.

Switched Voltage Excitations
Three outputs provide precision excitation voltages for resistive bridge measurements.

Digital I/O Ports
Eight ports are provided for frequency measurements, digital control, and triggering. Three of these ports can also be used to measure SDM devices.

RS-232 Port
A PC or laptop can be connected to this 9-pin port via an RS-232 cable.

CS I/O port
Data transfer peripherals that require power from the datalogger can be connected to this port via an SC12 cable. This port is also used for connecting the datalogger to a PC via an SC32B or SC-USB interface when optical isolation is required.

Peripheral Port
One 40-pin port interfaces with the CFM100 CompactFlash® Module or the NL115 Ethernet Interface and CompactFlash Module.

Switched 12 Volt
This terminal provides unregulated 12 V that can be switched on and off under program control.

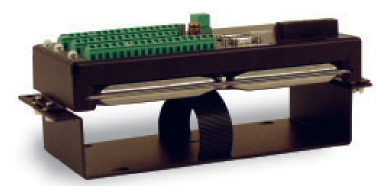
Storage Capacity
The CR1000 has 2 Mbyte of FLASH memory for the Operating System. The standard CR1000 provides 2 Mbytes battery-backed SRAM for CPU usage, program storage, and data storage; an optional version provides 4 Mbytes of SRAM. Data is stored in a table format. The storage capacity of the CR1000 can be increased by using a CompactFlash® card.

Communication Protocols
The CR1000 supports the PakBus® communication protocol. PakBus networks have the distributed routing intelligence to continually evaluate links. Continually evaluating links optimizes delivery times and, in the case of delivery failure, allows automatic switch over to a configured backup route.

The CR1000 also supports Modbus RTU protocol—both floating point and long formats. The datalogger can act as a slave, master, or both.

Enclosure/Stack Bracket
A CR1000 housed in a weather-resistant enclosure can collect data under extremely harsh conditions. The enclosure protects the CR1000 from dust, water, sunlight, or pollutants. An internal mounting plate is prepunched for easy system configuration and exchange of equipment in the field.

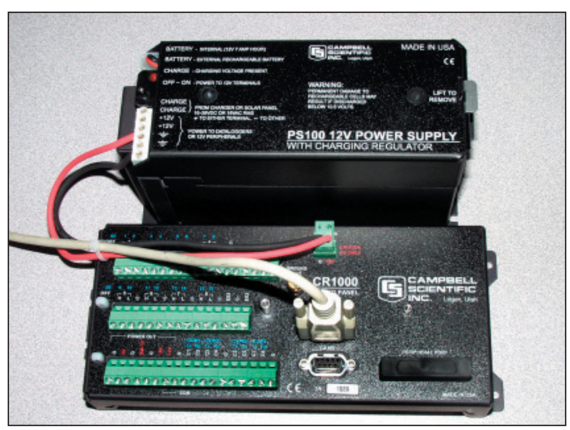
A stack bracket kit is available that allows you to attach the CR1000 to the backplate of an ENC10/12 enclosure in a "horizontal" orientation (i.e., the long axis of the CR1000 spanning the short axis of the ENC10/12 enclosure). This stack bracket also allows you to place a small peripheral under the mounting bracket and secure it with Velcro®, thus conserving space, and place the wiring panel terminals at about the same height as the terminals in one of our power supplies.



The stack bracket as viewed from the side with a CR1000 attached.

Power Supplies
Any 12 Vdc source can power the CR1000; a PS100 or BPALK is typically used. The PS100 includes one 7 Ahr rechargeable battery, charged with ac power (requires a wall charger) or a solar panel. The BPALK consists of eight non-rechargeable D-cell alkaline batteries with a 7.5 Ahr rating at 20°C. An external AA-cell battery pack supplies power while the D-cells are replaced.

Also available are the BP12 and BP24 battery packs, which provide nominal ratings of 12 and 24 Ahrs, respectively. These batteries should be connected to a charging regulator and a charging source. For information about analyzing your system's power requirements, see our Power Supply product literature or Application Note 5-F. Both can be obtained from: www. campbellsci.com



Its low-power design allows the CR1000 to operate for up to one year on the PS100 power supply, depending on scan rate, number of sensors, data retrieval method, and external temperature.

Data Storage and Retrieval Options

To determine the best option for your application, consider the accessibility of your site, availability of services (e.g., cellular phone or satellite coverage), quantity of data to collect, and desired time between data-collection sessions. Some communication options can be combined—increasing the flexibility, convenience, and reliability of your communications.

Radios

Radio frequency (RF) communications are supported via narrow-band UHF, narrow-band VHF, spread spectrum, or meteor burst radios. Line-of-sight is required for all of our RF options.

Meteorological conditions measured at Lake Louise, Alberta, Canada are telemetered via phone-to-RF link to a base station.

Telephone Networks

The CR1000 can communicate with a PC using landlines, cellular CDMA, or cellular GPRS transceivers. A voice synthesized modem enables anyone to call the CR1000 via phone and receive a verbal report of realtime site conditions.

Satellite Transmitters

Our NESDIS-certified GOES satellite transmitter provides one-way communications from a Data Collection Platform (DCP) to a receiving station. The transmitter complies with the High Data Rate (HDR) specifications. We also offer an Argos transmitter that is ideal for high-altitude and polar applications.

This station for the National Estuarine Research Reserve (NERR) in Virginia transmits data via our GOES satellite transmitter.

Multidrop Interface

The MD485 intelligent RS-485 interface permits a PC to address and communicate with one or more dataloggers over a single two-twisted-pair cable. Distances up to 4000 ft are supported.

Short Haul Modems

The SRM-5A RAD Short Haul Modem supports communications between the CR1000 and a computer via a four-wire unconditioned line (two twisted pairs).

Direct Links

A desktop or laptop PC connects directly to the CR1000's RS-232 port. If optical isolation is required, the PC is connected to the datalogger's CS I/O port via an SC32B or SC-USB interface.

PDAs

User-supplied PDAs can be used to set the CR1000's clock, monitor real-time data, retrieve data, graph data, and transfer CR1000 programs. PConnect software (purchased separately) is required for PDAs with a Palm™ OS, and PConnectCE software (purchased separately) is required for PDAs with a Windows® CE OS.

Keyboard Display

With the CR1000KD, you can program the CR1000, manually initiate data transfer, and display data. The CR1000KD displays 8 lines x 21 characters (64 x 128 pixels) and has a 16-character keyboard. Custom menus are supported allowing you to set up choices within the datalogger program that can be initiated by a simple "toggle" or "pick list".

One CR1000KD can be carried from station to station in a CR1000 network.

Ethernet

Use of an NL100 or NL115 interface enables the CR1000 to communicate over a local network or a dedicated internet connection via TCP/IP. The NL115 also supports data storage on CompactFlash cards.

CompactFlash®

The CR1000's data can be stored on a CompactFlash card using either a CFM100 or NL115 module. On the computer side, the CompactFlash cards are read by the computer's PCMCIA slot fitted with a CF1 CompactFlash adapter or by a USB port fitted with the ImageMate USB CompactFlash Reader/Writer.

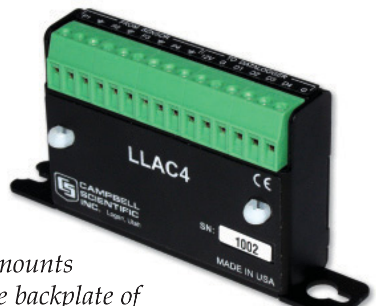
DSP4 Heads Up Display

Primarily intended for vehicle test applications, the DSP4 permits dashboard mounting in a variety of vehicles without obstructing the view of the driver.

Channel Expansion

4-Channel Low Level AC Module

The LLAC4 is a small peripheral device that allows you to increase the number of available low-level ac inputs by using control ports. This module is often used to measure up to four anemometers, and is especially useful for wind profiling applications.



The LLAC4 mounts directly to the backplate of our environmental enclosures.

Synchronous Devices for Measurement (SDMs)

SDMs are addressable peripherals that expand the CR1000's measurement and control capabilities. For example, SDMs are available to add control ports, analog outputs, pulse count channels, interval timers, or even a CANbus interface to your system. Multiple SDMs, in any combination, can be connected to one CR1000 datalogger.

Multiplexers

Multiplexers increase the number of sensors that can be measured by a CR1000 by sequentially connecting each sensor to the datalogger. Several multiplexers can be controlled by a single CR1000. The CR1000 is compatible with the AM16/32 and AM25T.

Software

Starter Software

Campbell Scientific offers easy-to-use starter software intended for first time users or applications that don't require sophisticated communications or datalogger program editing. These software products provide different functions and can be used in conjunction with each other. Starter software can be downloaded at no charge from www.campbellsci.com/resource.html. Our Resource CD also provides this software as well as PDF versions of our literature and manuals.

Our SCWin Short Cut for Windows® generates straightforward CR1000 programs in four easy steps. Short Cut supports programming for our multiplexers, ET106 stations, MetData1 stations, and virtually any sensor that our CR1000 can measure.

Our PC200W Starter Software allows you to transfer a program to, or retrieve data from, a CR1000 via a direct communications link.

Datalogger Support Software

Our general purpose datalogger support software packages provide more capabilities than our starter software. Each of these software packages contains program editing, communications, and display tools that can support an entire datalogger network.

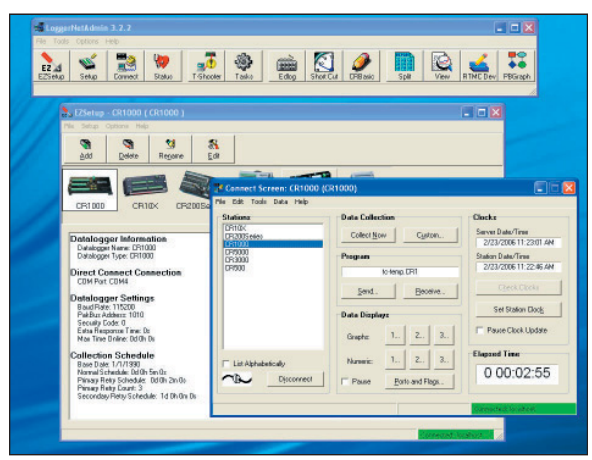
PC400, our mid-level software, supports a variety of telemetry options, manual data collection, and data display. For programming, it includes both Short Cut and the CRBasic program editor. PC400 does not support combined communication options (e.g., phone-to-RF), PakBus® routing, or scheduled data collection; LoggerNet software is recommended for those applications.

Campbell Scientific offers the following three LoggerNet Software Packages:

- **LoggerNet**, the standard package, is recommended for those who have datalogger networks that do not require the more advanced features offered in LoggerNet Admin. It consists of a server application and several client applications integrated into a single product. This software provides all of PC400's capabilities as well as support for combined communication options (e.g., phone-to-RF), PakBus® routing, and scheduled data collection

- **LoggerNet Admin** is intended for customers who have large networks. Besides providing better tools for managing large networks, LoggerNet Admin allows you to remotely manage a datalogger network over TCP/IP, and to remotely and automatically distribute data to other computers.

- **LoggerNetRemote** includes LoggerNet Admin clients to administer a running LoggerNet Admin server via TCP/IP from a remote PC. This software does not include the LoggerNet server.



LoggerNet provides a way to accomplish almost all the tasks you'll need to complete when using a datalogger.

Applications

The measurement precision, flexibility, long-term reliability, and economical price of the CR1000 make it ideal for scientific, commercial, and industrial applications.

Meteorology

The CR1000 is used in long-term climatological monitoring, meteorological research, and routine weather measurement applications.

Our rugged, reliable weather station measures meteorological conditions at St. Mary's Lake, Glacier National Park, MT.

Sensors the CR1000 can measure include:

- cup, propeller, and sonic anemometers
- tipping bucket rain gages
- wind vanes
- pyranometers
- ultrasonic distance sensors
- thermistors, RTDs, and thermocouples
- barometric pressure sensors
- RH sensors
- cooled mirror hygrometers

Data is output in your choice of units (e.g., wind speed in miles per hour, meters per second, or knots). Standard CR1000 outputs include wind vector averaging, sigma, theta, histograms, saturation vapor pressure, and vapor pressure from wet/dry bulb temperatures.

Agriculture and Agricultural Research

The versatility of the CR1000 allows measurement of agricultural processes and equipment in applications such as:

- plant water research
- canopy energy balance
- machinery performance
- plant pathology
- crop management decisions
- food processing/storage
- frost prediction
- irrigation scheduling
- integrated pest management

This vitaculture site in Australia integrates meteorological, soil, and crop measurements.

Wind Profiling

Our data acquisition systems can monitor conditions at wind assessment sites, at producing wind farms, and along transmission lines. The reliability of these systems ensures data collection, even under adverse conditions. Wide operating temperature ranges and weatherproof enclosures allow our systems to operate reliably in harsh environments.

The CR1000 makes and records measurements, controls electrical devices, and can function as PLCs or RTUs. Because the datalogger has its own power supply (batteries, solar panels), it can continue to measure and store data and perform control during power outages.

Typical sensors for wind assessment applications include, but are not limited to:

- sonic anemometers
- three-cup and propeller anemometers (up to 10 anemometers can be measured by using two LLAC4 peripherals)
- wind vanes
- temperature sensors (air, water, and equipment)
- barometric pressure
- wetness
- solar radiation

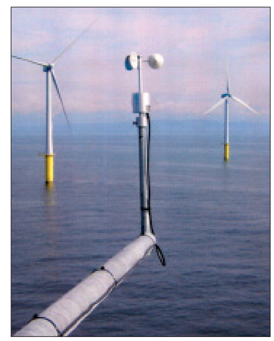


Photo courtesy npower renewables

A Campbell Scientific system monitors an offshore wind farm in North Wales.

For turbine performance applications, the CR1000 can monitor electrical current, voltage, wattage, stress, and torque.

Soil Moisture

The CR1000 is compatible with the following soil moisture measurement technologies:

- **Soil moisture blocks** are inexpensive sensors that estimate soil water potential.
- **Matric water potential sensors** also estimate soil water potential but are more durable than soil moisture blocks.
- **Time-Domain Reflectometry Systems (TDR)** use a reflectometer controlled by a CR1000 to accurately measure soil water content. Multiplexers allow sequential measurement of a large number of probes by one reflectometer, reducing cost per measurement.
- **Self-contained water content reflectometers** are sensors that emit and measure a TDR pulse.
- **Tensiometers** measure the soil pore pressure of irrigated soils and calculate soil moisture.

Air Quality

The CR1000 can monitor and control gas analyzers, particle samplers, and visibility sensors. It can also automatically control calibration sequences and compute conditional averages that exclude invalid data (e.g., data recorded during power failures or calibration intervals).

Road Weather/RWIS

Our fully NTCIP-compliant Environmental Sensor Stations (ESS) are robust, reliable weather stations used for road weather/RWIS applications. A typical ESS includes a tower, CR1000, two road sensors, remote communication hardware, and sensors that measure wind speed and direction, air temperature, humidity, barometric pressure, solar radiation, and precipitation. The CR1000 can also measure soil moisture and temperature sensors, monitor bridge vibrations, and control external devices.

Water Resources/Aquaculture

Our CR1000 is well-suited to remote, unattended monitoring of hydrologic conditions. Most hydrologic sensors, including SDI-12 probes, interface directly to the CR1000. Typical hydrologic measurements:

- **Water level** is monitored with incremental shaft encoders, double bubblers, ultrasonic level transducers, resistance tapes, or strain gage or vibrating wire pressure transducers. Some shaft encoders require a QD1 Interface. Vibrating wire transducers require an AVW1, AVW4, or AVW100 Interface.
- **Well draw-down tests** use a pressure transducer measured at logarithmic intervals or at a rate based on incremental changes in water level.
- **Ionic conductivity measurements** use one of the switched excitation ports from the CR1000.
- **Samplers** are controlled by the CR1000 as a function of time, water quality, or water level.
- **Alarm and pump actuation** are controlled through digital I/O ports that operate external relay drivers.

A turbidity sensor was installed in a tributary of the Cedar River watershed to monitor water quality conditions for the city of Seattle, Washington.

Vehical Testing

This versatile, rugged datalogger is ideally suited for testing cold and hot temperature, high altitude, off-highway, and cross-country performance. The CR1000 is compatible with our SDM-CAN interface, GPS16-HVS receiver, and DSP4 Heads Up Display.

Vehicle monitoring includes not only passenger cars, but locomotives, airplanes, helicopters, tractors, buses, heavy trucks, drilling rigs, race cars, and motorcycles.

The CR1000 can measure:

- **Suspension—**strut pressure, spring force, travel, mounting point stress, deflection, ride
- **Fuel system—**line and tank pressure, flow, temperature, injection timing
- **Comfort control—**ambient and supply air temperature, solar radiation, fan speed, ac on and off, refrigerant pressures, time-to-comfort, blower current
- **Brakes—**line pressure, pedal pressure and travel, ABS, line and pad temperature
- **Engine—**pressure, temperature, crank position, RPM, time-to-start, oil pump cavitation
- **General vehicle—**chassis monitoring, road noise, vehicle position and speed, steering, air bag, hot/cold soaks, wind tunnels, traction, CANbus, wiper speed and current, vehicle electrical loads

Other Applications

- Eddy covariance systems
- Wireless sensor/datalogger networks
- Mesonet systems
- Avalanche forecasting, snow science, polar, high altitude
- Fire weather
- Geotechnical
- Historic preservation

CR1000 Specifications

Electrical specifications are valid over a -25° to +50°C range unless otherwise specified; non-condensing environment required. To maintain electrical specifications, Campbell Scientific recommends recalibrating dataloggers every two years.

PROGRAM EXECUTION RATE

10 ms to 30 min. @ 10 ms increments

ANALOG INPUTS

8 differential (DF) or 16 single-ended (SE) individually configured. Channel expansion provided by AM16/32 and AM25T multiplexers.

RANGES, RESOLUTION AND TYPICAL INPUT NOISE: Basic resolution (Basic Res) is the A/D resolution of a single conversion. **Resolution of DF measurements with input reversal is half the Basic Res.** Noise values are for DF measurements with input reversal; noise is greater with SE measurements.

Input Range (mV)	*Basic Res (µV)*	*Input Referred Noise Voltage 250 µs Int. (µV RMS)*	*50/60 Hz Int. (µV RMS)*
±5000	1330	385	192
±2500	667	192	95.9
±250	66.7	19.2	19.2
±25	6.7	2.3	1.9
±7.5	2	0.62	0.58
±2.5	0.67	0.34	0.19

ACCURACY[1]:
±(0.06% of reading + offset), 0° to 40°C
±(0.12% of reading + offset), -25° to 50°C
±(0.18% of reading + offset), -55° to 85°C (-XT only)

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

MINIMUM TIME BETWEEN VOLTAGE MEASUREMENTS: Includes the measurement time and conversion to engineering units. For voltage measurements, the CR1000 integrates the input signal for 0.25 ms or a full 16.66 ms or 20 ms line cycle for 50/60 Hz noise rejection. DF measurements with input reversal incorporate two integrations with reversed input polarities to reduce thermal offset and common mode errors and therefore take twice as long.

250 µs Analog Integration:	~1 ms SE
1/60 Hz Analog Integration:	~20 ms SE
1/50 Hz Analog Integration:	~25 ms SE

COMMON MODE RANGE: ±5 V

DC COMMON MODE REJECTION: >100 dB

NORMAL MODE REJECTION: 70 dB @ 60 Hz when using 60 Hz rejection

SUSTAINED INPUT VOLTAGE W/O DAMAGE: ±16 Vdc max.

INPUT CURRENT: ±1 nA typical, ±6 nA max. @ 50°C; ±90 nA @ 85°C

INPUT RESISTANCE: 20 Gohms typical

ACCURACY OF BUILT-IN REFERENCE JUNCTION THERMISTOR (for thermocouple measurements):
±0.3°C, -25° to 50°C
±0.8°C, -55° to 85°C (-XT only)

ANALOG OUTPUTS

3 switched voltage, active only during measurement, one at a time.

RANGE AND RESOLUTION: Voltage outputs programmable between ±2.5 V with 0.67 mV resolution.

ACCURACY: ±(0.06% of setting + 0.8 mV), 0° to 40°C
±(0.12% of setting + 0.8 mV), -25° to 50°C
±(0.18% of setting + 0.8 mV), -55° to 85°C (-XT only)

CURRENT SOURCING/SINKING: ±25 mA

RESISTANCE MEASUREMENTS

MEASUREMENT TYPES: The CR1000 provides ratiometric measurements of 4- and 6-wire full bridges, and 2-, 3-, and 4-wire half bridges. Precise, dual polarity excitation using any of the 3 switched voltage excitations eliminates dc errors.

RATIO ACCURACY[1]: Assuming excitation voltage of at least 1000 mV, not including bridge resistor error.

$$\pm(0.04\% \text{ of reading + offset})/V_{ex}$$

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

Offset values are reduced by a factor of 2 when excitation reversal is used.

PERIOD AVERAGING MEASUREMENTS

The average period for a single cycle is determined by measuring the average duration of a specified number of cycles. The period resolution is 192 ns divided by the specified number of cycles to be measured; the period accuracy is ±(0.01% of reading + resolution). Any of the 16 SE analog inputs can be used for period averaging. Signal limiting are typically required for the SE analog channel.

INPUT FREQUENCY RANGE:

Input Range	*Signal (peak to peak)[2] Min*	*Max*	*Min. Pulse W.*	*Max[3] Freq.*
±2500 mV	500 mV	10 V	2.5 µs	200 kHz
±250 mV	10 mV	2 V	10 µs	50 kHz
±25 mV	5 mV	2 V	62 µs	8 kHz
±2.5 mV	2 mV	2 V	100 µs	5 kHz

[2]The signal is centered at the datalogger ground.
[3]The maximum frequency = 1/(Twice Minimum Pulse Width) for 50% of duty cycle signals.

PULSE COUNTERS

Two 24-bit inputs selectable for switch closure, high frequency pulse, or low-level ac.

MAXIMUM COUNTS PER SCAN: 16.7×10^6

SWITCH CLOSURE MODE:
Minimum Switch Closed Time: 5 ms
Minimum Switch Open Time: 6 ms
Max. Bounce Time: 1 ms open w/o being counted

HIGH FREQUENCY PULSE MODE:
Maximum Input Frequency: 250 kHz
Maximum Input Voltage: ±20 V
Voltage Thresholds: Count upon transition from below 0.9 V to above 2.2 V after input filter with 1.2 µs time constant.

LOW LEVEL AC MODE: Internal ac coupling removes dc offsets up to ±0.5 V.

Input Hysteresis: 16 mV @ 1 Hz
Maximum ac Input Voltage: ±20 V
Minimum ac Input Voltage:

Sine wave (mV RMS)	*Range (Hz)*
20	1.0 to 20
200	0.5 to 200
2000	0.3 to 10,000
5000	0.3 to 20,000

DIGITAL I/O PORTS

8 ports software selectable, as binary inputs or control outputs. C1-C8 also provide edge timing, subroutine interrupts/wake up, switch closure pulse counting, high frequency pulse counting, asynchronous communications (UART), SDI-12 communications, and SDM communications.

HIGH FREQUENCY MAX: 400 kHz

SWITCH CLOSURE FREQUENCY MAX: 150 Hz

OUTPUT VOLTAGES (no load): high 5.0 V ±0.1 V; low <0.1

OUTPUT RESISTANCE: 330 ohms

INPUT STATE: high 3.8 to 5.3 V; low -0.3 to 1.2 V

INPUT HYSTERISIS: 1.4 V

INPUT RESISTANCE: 100 kohms

SWITCHED 12 V

One independent 12 V unregulated sources switched on and off under program control. Thermal fuse hold current = 900 mA @ 20°C, 650 mA @ 50°C, 360 mA @ 85°C.

SDI-12 INTERFACE SUPPORT

Control ports 1, 3, 5, and 7 may be configured for SDI-12 asynchronous communications. Up to ten SDI-12 sensors are supported per port. It meets SDI-12 Standard version 1.3 for datalogger mode.

CE COMPLIANCE

STANDARD(S) TO WHICH CONFORMITY IS DECLARED: IEC61326:2002

CPU AND INTERFACE

PROCESSOR: Hitachi H8S 2322 (16-bit CPU with 32-bit internal core)

MEMORY: 2 Mbytes of Flash for operating system; 2 Mbytes of battery-backed SRAM for CPU usage, program storage and data storage; 4 Mbytes optional

SERIAL INTERFACES: CS I/O port is used to interface with Campbell Scientific peripherals; RS-232 port is for computer or non-CSI modem connection.

PARALLEL INTERFACE: 40-pin interface for attaching data storage or communication peripherals such as the CFM100 module

BAUD RATES: Selectable from 300 bps to 115.2 kbps. ASCII protocol is one start bit, one stop bit, eight data bits, and no parity.

CLOCK ACCURACY: ±3 min. per year

SYSTEM POWER REQUIREMENTS

VOLTAGE: 9.6 to 16 Vdc

TYPICAL CURRENT DRAIN:
Sleep Mode: ~0.6 mA
1 Hz Scan (8 diff. meas., 60 Hz rej., 2 pulse meas.)
w/RS-232 communication: 19 mA
w/o RS-232 communication: 4.2 mA
1 Hz Scan (8 diff. meas., 250 µs integ., 2 pulse meas.)
w/RS-232 communication: 16.7 mA
w/o RS-232 communication: 1 mA
100 Hz Scan (4 diff. meas., 250 µs integ.)
w/RS-232 communication: 27.6 mA
w/o RS-232 communication: 16.2 mA

EXTERNAL BATTERIES: 12 Vdc nominal; reverse polarity protected.

PHYSICAL SPECIFICATIONS

MEASUREMENT & CONTROL MODULE SIZE: 8.5" x 3.9" x 0.85" (21.6 x 9.9 x 2.2 cm)

CR1000WP WIRING PANEL SIZE: 9.4" x 4" x 2.4" (23.9 x 10.2 x 6.1 cm); additional clearance required for serial cable and sensor leads.

WEIGHT: 2.1 lbs (1 kg)

WARRANTY

Three years against defects in materials and workmanship.

CAMPBELL SCIENTIFIC, INC.
815 West 1800 North • Logan, Utah 84321-1784 • (435) 753-2342 • Fax (435) 750-9540
Offices also located in: Australia • Brazil • Canada • England • France • Germany • South Africa • Spain

AirLink COMMUNICATIONS

RAVEN

CDMA

> APPLICATIONS

UTILITIES
- Natural Gas Wellhead Monitoring
- C&I Meters
- Transmission Line Flow Meters
- Energy Management Systems

TRANSPORTATION
- Traffic Measurement
- Traffic Control
- Variable Message Signs

ATMOSPHERIC/ENVIRONMENTAL
- Weather Monitoring
- Irrigation Control
- Seismic Monitoring
- Water Level Monitoring

PRIMARY/REDUNDANT CONNECTIVITY
- Automated Teller Machines
- Routers
- Enterprise Servers

> APPLICATION INTERFACES

Standard interfaces include:
- AT command set
- Host TCP/IP stack communicates with Raven via PPP.
- Windows 95/98/2000/NT/XP Dial Up Networking communicates with Raven using PPP.

> SPECIAL FEATURES

- Class I Div 2 certified
- High speed data transfer rate
- Full duplex transceiver
- Low power consumption
- Proven technology
- Compact size
- Rugged aluminum case
- LEDs show status of network operation
- Optional mounting brackets

The AirLink Raven CDMA is a rugged, intelligent wireless data platform designed to enable real-time, two-way communications with remote assets.

THE ALEOS PLATFORM

The AirLink Embedded Operating System (ALEOS) is the power inside the Raven. ALEOS has its own embedded TCP/IP stack which enables transmission of date from non-IP devices. ALEOS enables several functions including remote configuration and diagnostics, packet assembly and dis-assembly for UDP and TCP, and dynamic IP management. The unique intelligence within ALEOS enables virtually any type of remote device to connect via the public wireless data network.

ALEOS
AirLink Embedded Operating System

FEATURES
- Integrated IP stack
- Standard AT commands
- Remote configuration, downloads, troubleshooting
- Telemetry protocols
- Encryption and security
- Dynamic DNS
- Network Address Translation
- Simple firewall to filter unauthorized IP adresses

BENEFITS
- Common ALEOS code used across all AirLink intelligent devices
- Provides a common experience to customers regardless of the network technology
- Allows customers to migrate to next generation networks with no change to their applications
- Over-the-air updates

HEAT Equipment Specification Sheets—Post-2006

The Multitalented

FLUXUS® ADM 7407 is an ultrasonic flowmeter for permanent installation. The instrument works according to the transit-time principle which makes use of the fact that the speed of propagation of an ultrasonic signal in a flowing medium depends on the flow velocity.

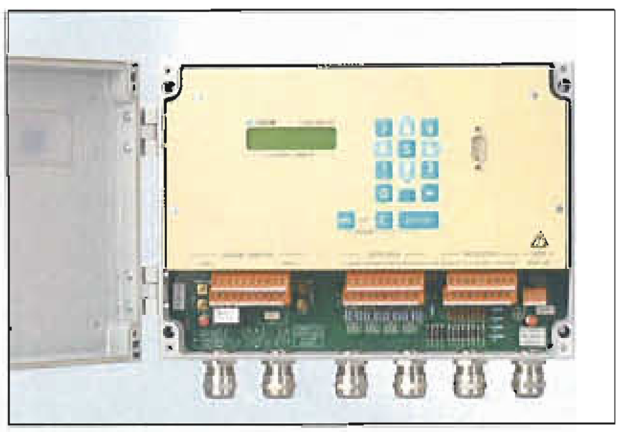
Since the transducers are mounted on the pipe, they are not subject to wear and tear and can be installed rapidly, without cutting into the pipe and without process interruption. The measurement causes no pressure loss. Chemically aggressive media are not a problem; there is no need for expensive materials.

Thanks to its exceptional dual-uP technology, high number of measuring cycles per second and adaptive signal processing, FLUXUS® ADM 7407 produces stable and reliable measuring results even under difficult conditions.

The operation of the flowmeter is especially easy thanks to the clearly structured user dialogue. A status display allows the user to assess application conditions while measuring flow. With the optional software FluxData, you can transfer your measuring data from the flowmeter to a PC, analyse and visualise the measuring results and manage the data files. All this can be done fast and easily thanks to the user-friendly graphical interface.

FLUXUS® ADM 7407 can be equipped with up to 4 process inputs. The input quantities (e.g. temperature or pressure) can be used by FLUXUS together with the measured flow for the calculation of further quantities: heat flow, mass flow, etc.

FLUXUS® ADM 7407



FLUXUS® ADM 7407, opened

Features

- non-invasive flow measurement for permanent installation
- 1 or 2 flow channels
- unique signal processing
- flexible configuration of inputs and outputs
- enhanced status information
- integrated energy calculator and flow calculator

Technical Data

Measurement

Measuring principle:	transit time difference correlation principle
Flow velocity:	(0.01 to 25) m/s
Resolution:	0.025 cm/s
Repeatability:	0.15% of reading ± 0.01 m/s
Accuracy	(for fully developed, rotationally symmetrical flow profile)
- Volume flow:	± 1% to 3% of read. ± 0.01 m/s depending on application ± 0.5% of reading ± 0.01 m/s with process calibration
- Path velocity:	± 0.5% of reading ± 0.01 m/s
Measurable fluids:	all acoustically conductive fluids with < 10% gaseous or solid content in volume

All FLEXIM transducers can be connected to the transmitter. Clamp-on flow transducers are available for a wide diameter range (DN 6 to DN 6500) and for temperatures ranging from -30°C to 400°C (also in explosive atmosphere). The transducers have a degree of protection of IP65 (consult factory for IP68). You will find more information about the transducers in the corresponding specification sheets.

Transmitter

Housing	
- Weight:	approx. 2.8 kg
- Deg. of protection:	IP65 acc. to. EN60529
- Material:	Aluminium, powder coated
- Dimensions:	(280 x 200 x 70) mm (WxHxD) without hinges
Flow channels:	1 or 2
Explosion protection in:	zone 2
Power supply:	(100 to 240) VAC (18 to 36) VDC
Display:	2 x 16 characters, dot matrix, backlit
Operating temperature:	-10 °C to 60 °C
Power consumption:	< 15W
Signal damping:	(0 to 100) s, adjustable
Measuring cycle:	(100 to 1000) Hz (1 channel)
Response time:	1 s (1 channel), 70 ms opt.

Measuring functions

Quantities of measurement:	Volume and mass flow rate, flow velocity, heat flow rate (only if temperature inputs are installed)
Totalizers:	Volume, mass, heat (opt.)
Calculation functions:	Average, difference, sum
Operating languages:	Czech, Danish, Dutch, English, French, German, Norwegian, Polish, Spanish

Data logger

Loggable values:	All measured quantities and totalized values
Capacity:	>100000 meas. values

Communication

Interface:	RS232, RS485 optional
Data:	actual meas. value, logged data, parameter records

Software FluxData (optional)

Function:	Downloading meas. data/parameter records, graphical presentation, conversion to other formats
Operating systems:	All Windows™ versions

Process outputs (optional)

- The outputs are galvanically isolated from the main device.
- The number of outputs that can be installed depends on the output type. Consult FLEXIM for more information.

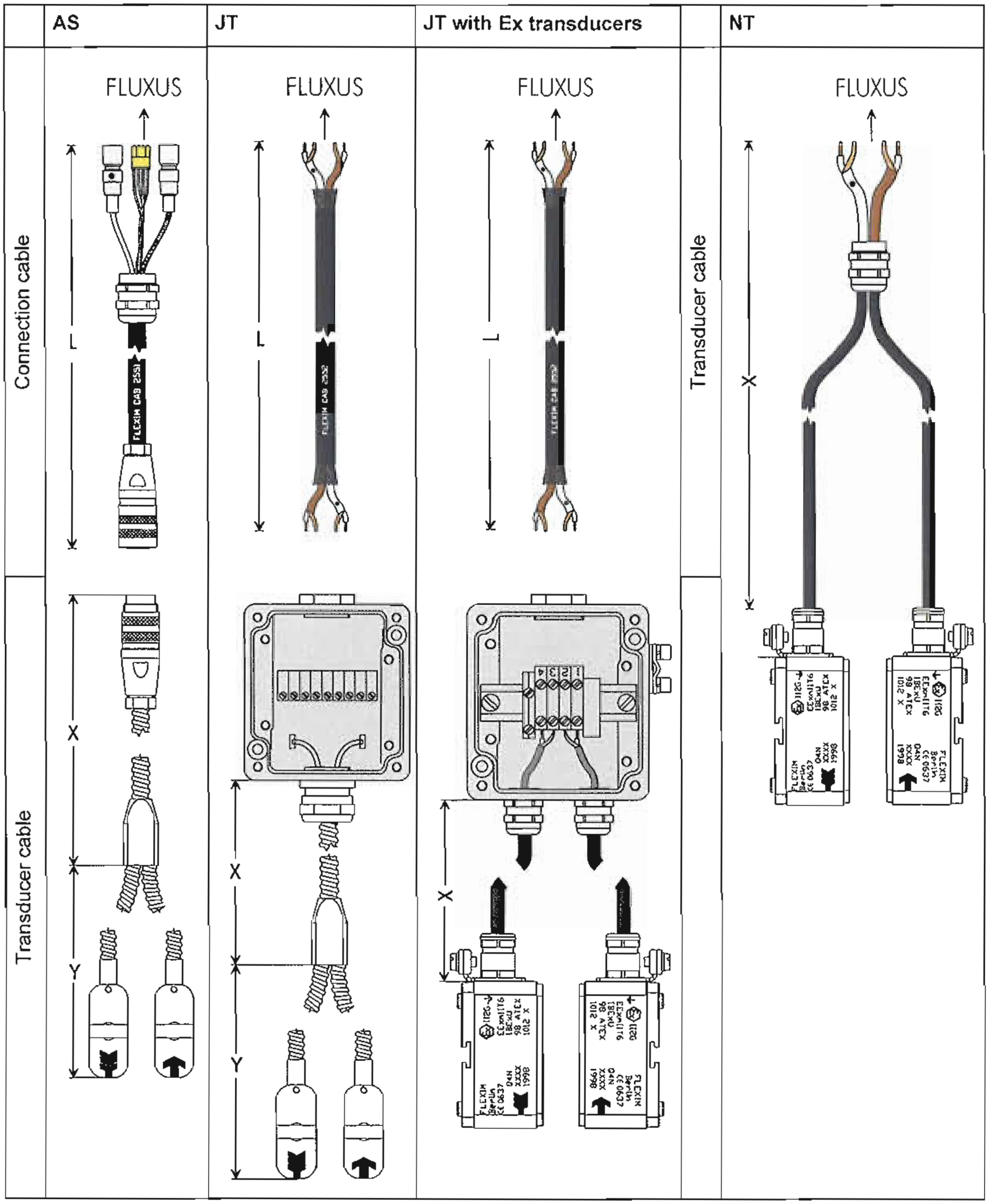
Current	
- Range:	(0/4 to 20) mA
- Accuracy:	0.1% of reading ± 15 µA
- Active output:	R_{ext} < 500 Ω
- Passive output:	U_{ext} < 24 V, R_{ext} < 1 kΩ
Voltage	
- Range:	(0 to 1) V or (0 to 10) V
- Accuracy:	0 to 1 V: 0.1% of reading ± 1 mV 0 to 10 V: 0.1% of reading ± 10 mV
- Intr. resistance:	R_i = 500 Ω
Frequency	
- Range:	0 to 1 kHz or 0 to 10 kHz
- Open collector:	24 V/4 mA
Binary	
- Open collector:	24 V/4 mA
- Reed relay:	48 V/0.1 A
- Function as state output:	limit, sign change or error
- Properties of the pulse output:	Value: (0.01 to 1000) units Width: (1 to 1000) ms

Process inputs (optional)

- The inputs are galvanically isolated from the main device.
- A maximum of 4 inputs can be installed.

Temperature	
- Type:	Pt100 four-wire circuit
- Range:	-50 °C to 400 °C
- Resolution:	0.1 K
- Accuracy:	± (0.02 K + 0.1% of reading)
Current	
- Range:	active: (0 to 20) mA passive input: (-20 to 20) mA
- Accuracy:	0.1% of reading ± 10 µA
- Active input:	R_i = 50 Ω
- Passive input:	U_{ext} < 24 V, R_{ext} < 1 kΩ
Voltage	
- Range:	(0 to 1) V or (0 to 10) V
- Accuracy:	0 to 1 V: 0.1% of reading ± 1 mV 0 to 10 V: 0.1% of reading ± 10 mV
- Intr. resistance:	R_i = 1 MΩ

Connection Types

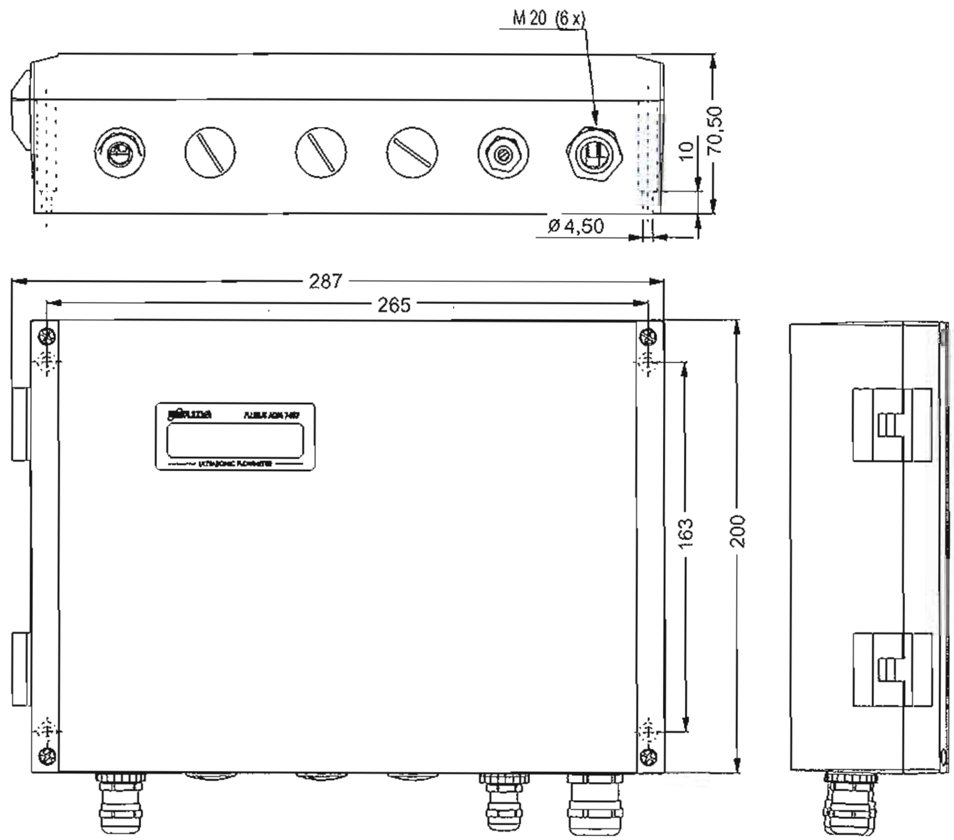


Cable Length

Lengths X and Y of the transducer cable and maximal length of the connection cable as indicated above. All lengths are given in meters.

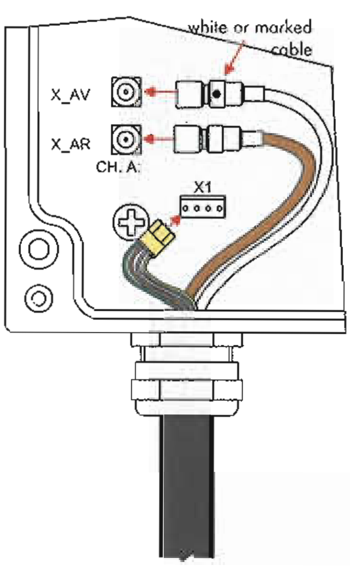
	Connection type AS	Connection type JT
K2	X=2m; Y=2.5m, L=100m (cable type 2551)	X=2 m; Y=2,5m, L=300m (cable type 2552)
K4	X=5 m; Y=7m, L=100m (cable type 2551)	X=5m; Y=7m, L=300m (cable type 2552)
M2	X=2m; Y=2.5m, L=100m (cable type 2551)	X=2m; Y=2.5m, L=300m (cable type 2552)
M3	X=5m; Y=7m, L=100m (cable type 2551)	X=5m; Y=7m, L=300m (cable type 2552)
M4	--	Y=5 m, L=300m (cable type 2552)
Q3	X=2m; Y=1m, L=50m (cable type 2551)	X=2m; Y=1m, L=90m (cable type 2552)
Q4	--	Y=5 m, L=90m (cable type 2552)
S2	X=1m; Y=1m, L=2 m (cable type 2551)	X=1 m; Y=1m, L=40m (cable type 2552)

Dimensions of the Housing (in mm)

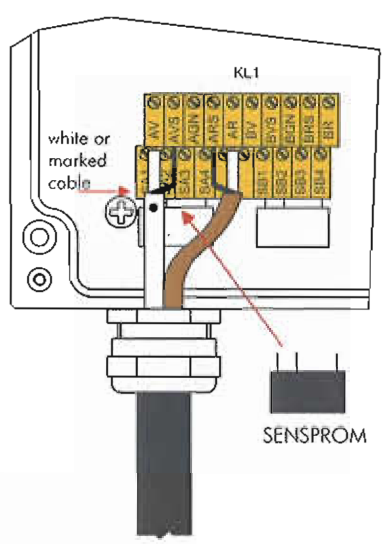


Connection of the Transducers

Connection type AS



Connection type JT



Internet: www.flexim.com
e-mail: flexim@flexim.com

FLEXIM GmbH
Wolfener Str. 36
12681 Berlin, Germany
Tel.:+49 (30) 93 66 76 60
Fax:+49 (30) 93 66 76 80

Non-invasive Ultrasonic Flow Measurement with FLUXUS® ADM

Flow transducers of the clamp-on type are mounted onto the pipe instead of inserted into it. They are not in contact with the medium and are therefore ideal for measurement on chemically aggressive, corrosive or ultra-pure media. With the clamp-on technology, retrofitting on existing installation is very easy and can be made without cutting into the pipe and without process interruption.

Q3N transducers, mounted with chains

Operating Conditions

Together, the various transducers cover a pipe diameter range from 6 mm to 6500 mm and a temperature range from -30°C to 400°C. The standard versions have a degree of protection IP65. Different types of explosion-proof transducers are also available.

All FLEXIM clamp-on transducers are watertight and suitable for use in harsh industrial environment. With the exception of the explosion-proof transducers, the transducer housings or caps and the transducer cable conduits are made of stainless steel. The robust integrated transducer cables guarantee good measurement results over long periods of extensive use.

Pair Calibrated Transducers

All transducer pairs delivered with the instrument have been wet-flow calibrated at the factory. The calibration, zero offset and other transducer parameters are stored in a transducer-resident non-volatile memory. These intelligent transducers automatically send their data to the instrument upon connection to optimize operation. Parameterisation errors are thus avoided and a zero adjustment is not necessary.

M2N transducers in the Variofix rail

S2N Transducers for Small Pipes

The S2N transducers have been specially designed for flow measurement on pipes of small diameter. They are typically used in hydraulic systems, enamelling lines as well as in ultra-clean water systems.

Features

- wet-flow calibrated transducers
- automatic transducer detection
- watertight stainless steel construction
- no contact with the medium, no risk of corrosion, hygienic measurement, suitable for ultra clean liquids
- low storekeeping costs since only 2 types of transducers are needed to cover the most common pipe sizes
- measurement is independent of fluid conductivity and pressure
- no pressure loss, no risk of leakage

Technical Data

Clamp-On Transducers Type M2N, M2E, M3N

Rated (possible) diameter range*:	M2N, M2E: (50) 100 to 2500mm M3N: (50) 100 to 6500mm
Dimensions:	(60 x 30 x 33.5)mm
Material:	Housing: stainless steel Contact surface: PEEK (M2N) or Polyimide (M2E)
Deg. of protection:	IP65 acc. to EN60529 M2N, M3N: consult factory for IP68
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking, M2N:	Ⓔx II3G T6... T4 T_a -30°C... 130°C
- Marking, M3N:	Ⓔx II3G T6... T4 T_a -30°C... 130°C
- Marking, M2E:	Ⓔx II3G T6... T3 T_a -30°C... 200°C

Clamp-On Transducers Type K2N

Rated (possible) diameter range*:	in liquids: (100) 200 to 6500mm
Dimensions:	(126.5 x 50 x 53.5)mm
Material:	PEEK with stainless steel cap
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking:	Ⓔx II3G T6... T4 T_a -30°C... 130°C

Clamp-On Transducers Type S2N

Rated (possible) diameter range*:	(6) 10 to 70mm
Dimensions:	(26 x 13 x 15)mm
Material:	Housing: stainless steel Contact surface: Polyetherimide
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking:	Ⓔx II3G T6... T4 T_a -30°C... 130°C

Clamp-On Transducers Type Q3N, Q3E

Rated (possible) diameter range*:	(10) 25 to 400mm
Dimensions:	(42.5 x 18 x 21.5)mm
Material:	Housing: stainless steel Contact surface: PEEK (Q3N) or Polyimide (Q3E)
Deg. of protection:	IP65 acc. to EN60529 Q3N: consult factory for IP68
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking Q3N:	Ⓔx II3G T6... T4 T_a -30°C... 130°C
- Marking Q3E:	Ⓔx II3G T6... T3 T_a -30°C... 200°C

Clamp-On Transducers Type M4N, Q4N

Rated (possible) diameter range*:	M4N: (50) 100 to 3000mm Q4N: (10) 25 to 400mm
Dimensions:	(60 x 30 x 33.5)mm
Material:	Housing: stainless steel Contact surface: PEEK
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 1 and 2
- Marking:	CE 0044; Ⓔx II2G EEx m II T6... T4 T_a -20°C... 120°C
- Certification:	IBExU 98 ATEX 1012 X
- Type of protection:	Encapsulation

Clamp-On Transducers Type K4N Ex-A, K4N Ex-Z**

Rated (possible) diameter range*:	in liquids: (100) 200 to 6500mm
Dimensions:	K4N Ex-A: (126.5 x 50 x 53.5)mm K4N Ex-Z: (126.5 x 47 x 53.5)mm
Material:	PEEK with stainless steel cap
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 1 and 2
- Marking:	CE 0044; Ⓔx II2G EEx q II T6... T3 T_a -30°C... 180°C
- Certification:	IBExU 04 ATEX 1011 X
- Type of protection:	Powder filling

*: The range specified in parenthesis is the range in which measurement might be possible under good conditions, but for which FLEXIM gives no specification.
**: The transducers K4N Ex-Z must always be used in the mounting fixture with which they were delivered in order to protect them against mechanical stress.

Operating Temperature and Explosion Protection Temperature of the Transducers

Operating temperature					
	M2N, M3N, Q3N, S2N	M2E, Q3E	K2N	Q4N, M4N, P4N	K4N
Process:	-30°C...130°C	-30°C...200°C, for short periods 300°C	-30°C...130°C	-30°C...130°C	-30°C...130°C
Ambient:	-30°C...130°C	-30°C...200°C, for short periods 300°C	-30°C...130°C	-30°C...130°C	-30°C...130°C

Explosion protection temperature					
	M2N, M3N, Q3N, S2N	M2E, Q3E	K2N	Q4N, M4N, P4N	K4N
Explosion protection in:	zone 2	zone 2	zone 2	zone 2 and 1	zone 2 and 1
Temperature class T3	--	-30°C...190°C	--	--	-30°C...180°C
Temperature class T4	-30°C...120°C	-30°C...125°C	-30°C...120°C	-20°C...120°C	-30°C...125°C
Temperature class T5	-30°C...90°C	-30°C...90°C	-30°C...90°C	-20°C...90°C	-30°C...90°C
Temperature class T6	-30°C...75°C	-30°C...75°C	-30°C...75°C	-20°C...75°C	-30°C...75°C

Note: With the WaveInjector®, the temperature range of nearly every transducer can be extended up to 400°C. You will find more information about the WaveInjector in the corresponding specification sheet.

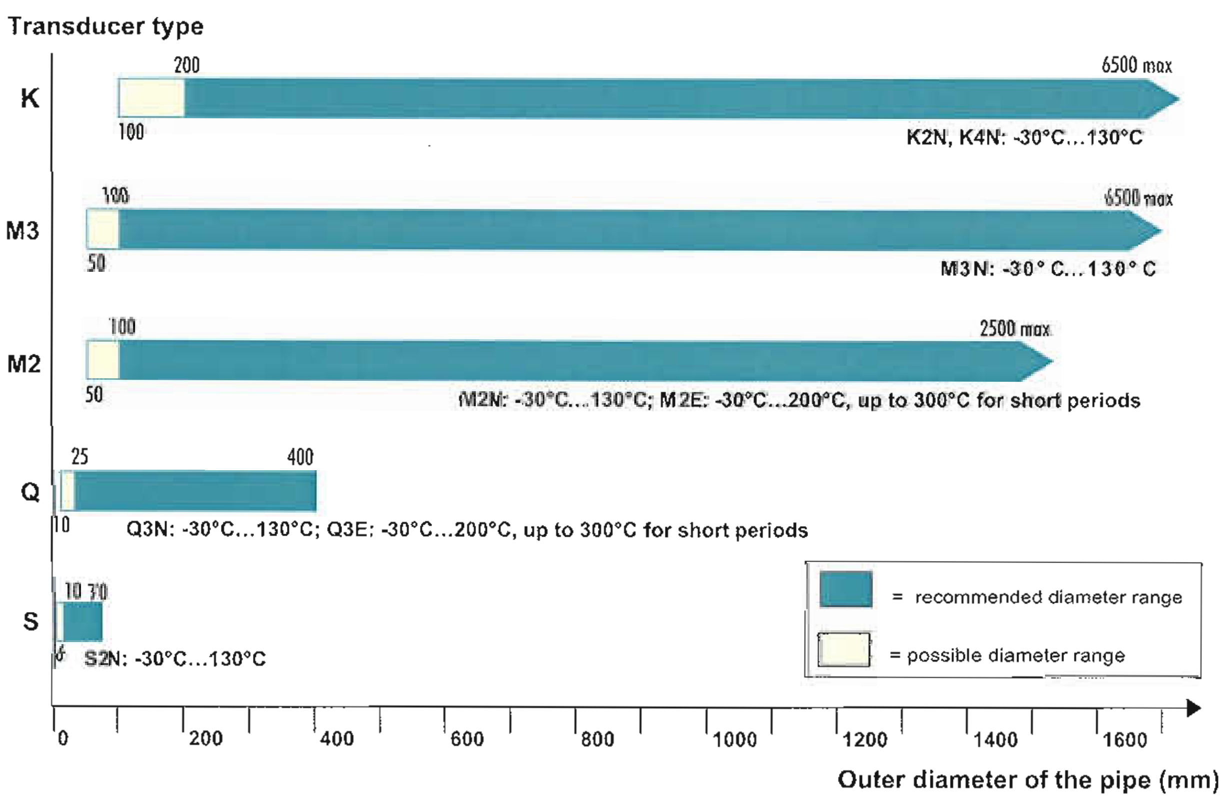
Diameter Range and Operating Temperature Range of the Transducers

The **recommended diameter range** is the diameter range covered by a transducer under normal measuring conditions (signal damping mainly through fluid, no gas or solid in the fluid).

The **possible diameter range** is the diameter range covered by a transducer under good measuring conditions.

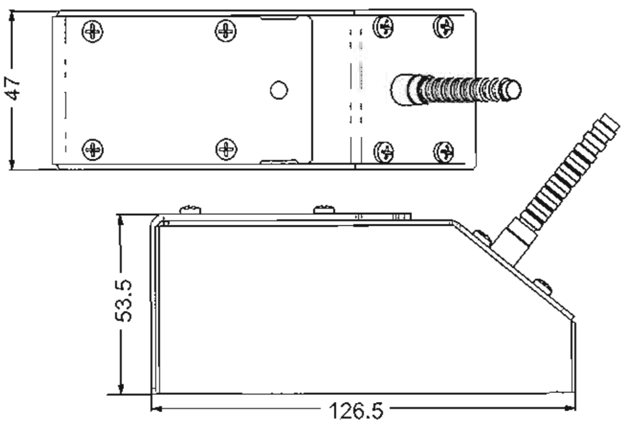
The specified temperature range is the **range of possible process temperatures** at which the transducers can be operated. The range of possible ambient temperatures is identical.

Note: With the WaveInjector®, the temperature range of nearly every transducer can be extended up to 400°C. You will find more information about the WaveInjector in the corresponding specification sheet.

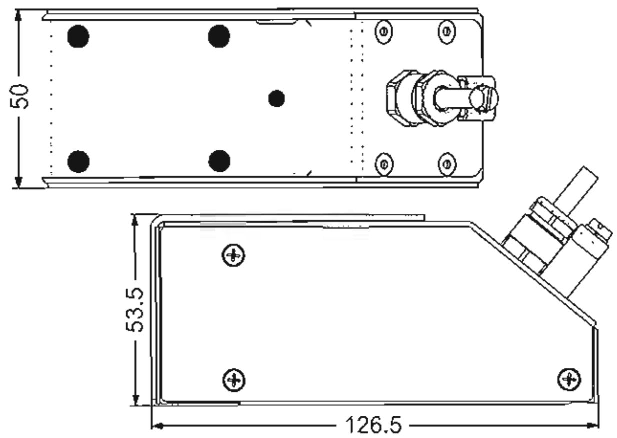


Dimensions (in mm)

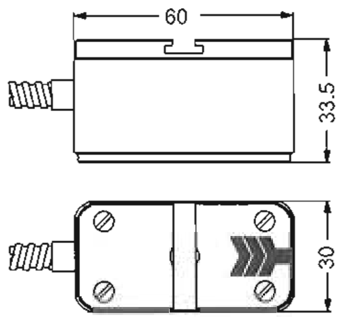
K2N



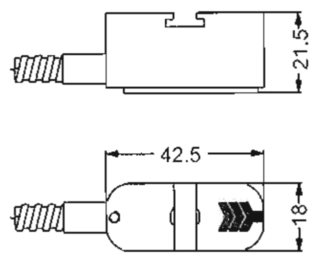
K4N Ex-A



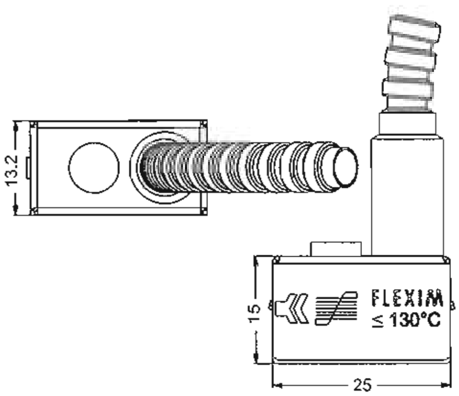
M2N, M2E, M3N



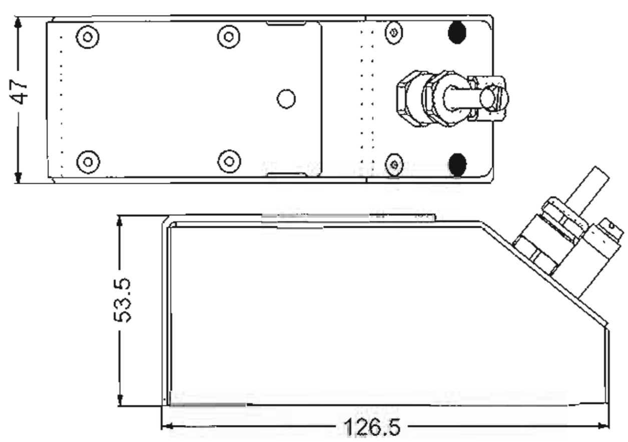
Q3N, Q3E



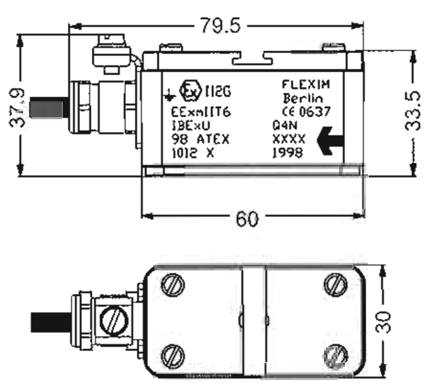
S2N



K4N Ex-Z



Q4N Ex, M4N Ex



Internet: www.flexim.com
e-mail: flexim@flexim.com

FLEXIM GmbH
Wolfener Str. 36
12681 Berlin, Germany
Tel.:+49 (30) 93 66 76 60
Fax:+49 (30) 93 66 76 80

HOME PRODUCTS ON-LINE STORE QUOTES PRICELIST MANUALS SITEMAP SEARCH E-MAIL NEWPORT
NEWPORT Navigation Guide* GO Product Selection Guide* GO

"Bolt-On" Washer Thermocouple Assemblies
WT

Features
- **New Rugged Design**
- **For #6, #8, #10 and 1⁄4" Screw Sizes**
- **Made from 20 AWG Glass-On-Glass or Teflon® Insulated Special Limits of Error Wire**
- **Stocked in 12, 24, 36 and 60" Lengths with Stripped End Leads**
- **Rated to 480°C (900°F)**

Washer Dimensions
#6 and #8 screw size: 0.875" L x 0.250" W
#10 and 1/4" screw size: 1" L x 0.360" W

To Order (Specify Model No.) *Prices Shown in U.S. Dollars*

Model No. 12" L $8.00 each	Model No. 24" L $9.00 each	Model No. 36" L $10.00 each	Model No. 60" L $12.00 each	Washer Hole Diameter	Nominal Screw Size	
					American	Metric
WT(*)-6-12	WT(*)-6-24	WT(*)-6-36	WT(*)-6-60	0.145"	#6	M3.5
WT(*)-8-12	WT(*)-8-24	WT(*)-8-36	WT(*)-8-60	0.170"	#8	M4
WT(*)-10-12	WT(*)-10-24	WT(*)-10-36	WT(*)-10-60	0.195"	#10	M4.5
WT(*)-14-12	WT(*)-14-24	WT(*)-14-36	WT(*)-14-60	0.260"	1/4"	M6

***Specify calibration:** J, K, T or E. Stripped leads are standard.
To order other terminations, add suffix "**L**" for #10 spade lugs ($4 add'l), "**M**" for OST male connector ($4 add'l), or "F" for OST female connector ($5 add'l). To order with lead lengths over 60", change "60" in model number to desired length in inches, and add $1 per add'l. foot to the 60" price.
To order with Teflon insulated lead wires, add suffix "**-TT**" to model no. No additional cost.
Example: WTK-14-12-TT, 1/4" washer probe, type K, 12" length, stripped leads, Teflon insulated wire, $8.
Ordering Example: WTK-6-12, washer thermocouple, type K, #6 screw, 12" length. glass braid insulated wire, **$8**

Heavy-Duty Armored Style - WT

Features
- **6 ft. 304 Stainless Steel Armor Cable**
- **Available with Stripped Leads or OSTW Connector**
- **0.275" Flexible Cable O.D. U 0.260" Washer I.D.**

Rugged thermocouple, for surface mount applications, has a washer mounting surface and an overall dimension of 0.680" O.D., with a 0.260" mounting hole of 304 SS material. Attached to the mounting surface: 6' of 304 SS flexible armor cable with stripped wire ends. Armor cable has 0.275" O.D., with 0.070" washer thickness. Standard male connectors are available for cold-end termination. Rated to

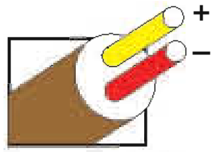
480°C (900°F).

Calibrations			
J =	K =	T =	E =
Iron-Constantan	CHROMEGA®-ALOMEGA®	Copper Constantan	CHROMEGA®-Constantan

Model No.	Termination	Price
WT(*)-HD-72-S	Stripped leads	$23
WT(*)-HD-72-OSTW-M	OSTW connector	$29

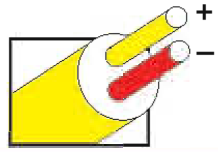
***Specify calibration:** J, K, T or E.
Ordering Example: **WTK-HD-72-S,** heavy duty washer thermocouple, type K, 72" cable, with stripped leads, **$23**

MAXIMUM TEMPERATURE RANGE
Thermocouple Grade
– 328 to 2282°F
– 200 to 1250°C
Extension Grade
32 to 392°F
0 to 200°C
LIMITS OF ERROR
(whichever is greater)
Standard: 2.2°C or 0.75% Above 0°C
2.2°C or 2.0% Below 0°C
Special: 1.1°C or 0.4%
COMMENTS, BARE WIRE ENVIRONMENT:
Clean Oxidizing and Inert; Limited Use in Vacuum or Reducing; Wide Temperature Range; Most Popular Calibration
TEMPERATURE IN DEGREES °F
REFERENCE JUNCTION AT 32°F



Thermocouple Grade

Nickel-Chromium vs. Nickel-Aluminum



Extension Grade

Revised Thermocouple Reference Tables

TYPE K

Reference Tables N.I.S.T. Monograph 175 Revised to ITS-90

Z

Thermoelectric Voltage in Millivolts

°F	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	°F
-450							-6.458	-6.457	-6.457	-6.456	-6.456	-450
-440	-6.456	-6.455	-6.454	-6.454	-6.453	-6.452	-6.451	-6.450	-6.449	-6.448	-6.446	-440
-430	-6.446	-6.445	-6.444	-6.443	-6.441	-6.440	-6.438	-6.436	-6.435	-6.433	-6.431	-430
-420	-6.431	-6.429	-6.427	-6.425	-6.423	-6.421	-6.419	-6.416	-6.414	-6.411	-6.409	-420
-410	-6.409	-6.406	-6.404	-6.401	-6.398	-6.395	-6.392	-6.389	-6.386	-6.383	-6.380	-410
-400	-6.380	-6.377	-6.373	-6.370	-6.366	-6.363	-6.359	-6.355	-6.352	-6.348	-6.344	-400
-390	-6.344	-6.340	-6.336	-6.332	-6.328	-6.323	-6.319	-6.315	-6.310	-6.306	-6.301	-390
-380	-6.301	-6.296	-6.292	-6.287	-6.282	-6.277	-6.272	-6.267	-6.262	-6.257	-6.251	-380
-370	-6.251	-6.246	-6.241	-6.235	-6.230	-6.224	-6.218	-6.213	-6.207	-6.201	-6.195	-370
-360	-6.195	-6.189	-6.183	-6.177	-6.171	-6.165	-6.158	-6.152	-6.146	-6.139	-6.133	-360
-350	-6.133	-6.126	-6.119	-6.113	-6.106	-6.099	-6.092	-6.085	-6.078	-6.071	-6.064	-350
-340	-6.064	-6.057	-6.049	-6.042	-6.035	-6.027	-6.020	-6.012	-6.004	-5.997	-5.989	-340
-330	-5.989	-5.981	-5.973	-5.965	-5.957	-5.949	-5.941	-5.933	-5.925	-5.917	-5.908	-330
-320	-5.908	-5.900	-5.891	-5.883	-5.874	-5.866	-5.857	-5.848	-5.840	-5.831	-5.822	-320
-310	-5.822	-5.813	-5.804	-5.795	-5.786	-5.776	-5.767	-5.758	-5.749	-5.739	-5.730	-310
-300	-5.730	-5.720	-5.711	-5.701	-5.691	-5.682	-5.672	-5.662	-5.652	-5.642	-5.632	-300
-290	-5.632	-5.622	-5.612	-5.602	-5.592	-5.581	-5.571	-5.561	-5.550	-5.540	-5.529	-290
-280	-5.529	-5.519	-5.508	-5.497	-5.487	-5.476	-5.465	-5.454	-5.443	-5.432	-5.421	-280
-270	-5.421	-5.410	-5.399	-5.388	-5.377	-5.365	-5.354	-5.343	-5.331	-5.320	-5.308	-270
-260	-5.308	-5.296	-5.285	-5.273	-5.261	-5.250	-5.238	-5.226	-5.214	-5.202	-5.190	-260
-250	-5.190	-5.178	-5.166	-5.153	-5.141	-5.129	-5.117	-5.104	-5.092	-5.079	-5.067	-250
-240	-5.067	-5.054	-5.042	-5.029	-5.016	-5.003	-4.991	-4.978	-4.965	-4.952	-4.939	-240
-230	-4.939	-4.926	-4.913	-4.900	-4.886	-4.873	-4.860	-4.847	-4.833	-4.820	-4.806	-230
-220	-4.806	-4.793	-4.779	-4.766	-4.752	-4.738	-4.724	-4.711	-4.697	-4.683	-4.669	-220
-210	-4.669	-4.655	-4.641	-4.627	-4.613	-4.599	-4.584	-4.570	-4.556	-4.542	-4.527	-210
-200	-4.527	-4.513	-4.498	-4.484	-4.469	-4.455	-4.440	-4.425	-4.411	-4.396	-4.381	-200
-190	-4.381	-4.366	-4.351	-4.336	-4.321	-4.306	-4.291	-4.276	-4.261	-4.246	-4.231	-190
-180	-4.231	-4.215	-4.200	-4.185	-4.169	-4.154	-4.138	-4.123	-4.107	-4.091	-4.076	-180
-170	-4.076	-4.060	-4.044	-4.029	-4.013	-3.997	-3.981	-3.965	-3.949	-3.933	-3.917	-170
-160	-3.917	-3.901	-3.885	-3.869	-3.852	-3.836	-3.820	-3.803	-3.787	-3.771	-3.754	-160
-150	-3.754	-3.738	-3.721	-3.705	-3.688	-3.671	-3.655	-3.638	-3.621	-3.604	-3.587	-150
-140	-3.587	-3.571	-3.554	-3.537	-3.520	-3.503	-3.486	-3.468	-3.451	-3.434	-3.417	-140
-130	-3.417	-3.400	-3.382	-3.365	-3.348	-3.330	-3.313	-3.295	-3.278	-3.260	-3.243	-130
-120	-3.243	-3.225	-3.207	-3.190	-3.172	-3.154	-3.136	-3.119	-3.101	-3.083	-3.065	-120
-110	-3.065	-3.047	-3.029	-3.011	-2.993	-2.975	-2.957	-2.938	-2.920	-2.902	-2.884	-110
-100	-2.884	-2.865	-2.847	-2.829	-2.810	-2.792	-2.773	-2.755	-2.736	-2.718	-2.699	-100
-90	-2.699	-2.680	-2.662	-2.643	-2.624	-2.605	-2.587	-2.568	-2.549	-2.530	-2.511	-90
-80	-2.511	-2.492	-2.473	-2.454	-2.435	-2.416	-2.397	-2.378	-2.359	-2.339	-2.320	-80
-70	-2.320	-2.301	-2.282	-2.262	-2.243	-2.223	-2.204	-2.185	-2.165	-2.146	-2.126	-70
-60	-2.126	-2.106	-2.087	-2.067	-2.048	-2.028	-2.008	-1.988	-1.969	-1.949	-1.929	-60
-50	-1.929	-1.909	-1.889	-1.869	-1.850	-1.830	-1.810	-1.790	-1.770	-1.749	-1.729	-50
-40	-1.729	-1.709	-1.689	-1.669	-1.649	-1.628	-1.608	-1.588	-1.568	-1.547	-1.527	-40
-30	-1.527	-1.507	-1.486	-1.466	-1.445	-1.425	-1.404	-1.384	-1.363	-1.343	-1.322	-30
-20	-1.322	-1.301	-1.281	-1.260	-1.239	-1.218	-1.198	-1.177	-1.156	-1.135	-1.114	-20
-10	-1.114	-1.094	-1.073	-1.052	-1.031	-1.010	-0.989	-0.968	-0.947	-0.926	-0.905	-10
0	-0.905	-0.883	-0.862	-0.841	-0.820	-0.799	-0.778	-0.756	-0.735	-0.714	-0.692	0

°F	0	1	2	3	4	5	6	7	8	9	10	°F
0	-0.692	-0.671	-0.650	-0.628	-0.607	-0.586	-0.564	-0.543	-0.521	-0.500	-0.478	0
10	-0.478	-0.457	-0.435	-0.413	-0.392	-0.370	-0.349	-0.327	-0.305	-0.284	-0.262	10
20	-0.262	-0.240	-0.218	-0.197	-0.175	-0.153	-0.131	-0.109	-0.088	-0.066	-0.044	20
30	-0.044	-0.022	0.000	0.022	0.044	0.066	0.088	0.110	0.132	0.154	0.176	30
40	0.176	0.198	0.220	0.242	0.264	0.286	0.308	0.330	0.353	0.375	0.397	40
50	0.397	0.419	0.441	0.463	0.486	0.508	0.530	0.552	0.575	0.597	0.619	50
60	0.619	0.642	0.664	0.686	0.709	0.731	0.753	0.776	0.798	0.821	0.843	60
70	0.843	0.865	0.888	0.910	0.933	0.955	0.978	1.000	1.023	1.045	1.068	70
80	1.068	1.090	1.113	1.136	1.158	1.181	1.203	1.226	1.249	1.271	1.294	80
90	1.294	1.316	1.339	1.362	1.384	1.407	1.430	1.453	1.475	1.498	1.521	90

°F	0	1	2	3	4	5	6	7	8	9	10	°F
100	1.521	1.543	1.566	1.589	1.612	1.635	1.657	1.680	1.703	1.726	1.749	100
110	1.749	1.771	1.794	1.817	1.840	1.863	1.886	1.909	1.931	1.954	1.977	110
120	1.977	2.000	2.023	2.046	2.069	2.092	2.115	2.138	2.161	2.184	2.207	120
130	2.207	2.230	2.253	2.276	2.298	2.321	2.344	2.367	2.390	2.413	2.436	130
140	2.436	2.459	2.483	2.506	2.529	2.552	2.575	2.598	2.621	2.644	2.667	140
150	2.667	2.690	2.713	2.736	2.759	2.782	2.805	2.828	2.851	2.874	2.897	150
160	2.897	2.920	2.944	2.967	2.990	3.013	3.036	3.059	3.082	3.105	3.128	160
170	3.128	3.151	3.174	3.197	3.220	3.244	3.267	3.290	3.313	3.336	3.359	170
180	3.359	3.382	3.405	3.428	3.451	3.474	3.497	3.520	3.544	3.567	3.590	180
190	3.590	3.613	3.636	3.659	3.682	3.705	3.728	3.751	3.774	3.797	3.820	190
200	3.820	3.843	3.866	3.889	3.912	3.935	3.958	3.981	4.004	4.027	4.050	200
210	4.050	4.073	4.096	4.119	4.142	4.165	4.188	4.211	4.234	4.257	4.280	210
220	4.280	4.303	4.326	4.349	4.372	4.395	4.417	4.440	4.463	4.486	4.509	220
230	4.509	4.532	4.555	4.578	4.601	4.623	4.646	4.669	4.692	4.715	4.738	230
240	4.738	4.760	4.783	4.806	4.829	4.852	4.874	4.897	4.920	4.943	4.965	240
250	4.965	4.988	5.011	5.034	5.056	5.079	5.102	5.124	5.147	5.170	5.192	250
260	5.192	5.215	5.238	5.260	5.283	5.306	5.328	5.351	5.374	5.396	5.419	260
270	5.419	5.441	5.464	5.487	5.509	5.532	5.554	5.577	5.599	5.622	5.644	270
280	5.644	5.667	5.690	5.712	5.735	5.757	5.779	5.802	5.824	5.847	5.869	280
290	5.869	5.892	5.914	5.937	5.959	5.982	6.004	6.026	6.049	6.071	6.094	290
300	6.094	6.116	6.138	6.161	6.183	6.205	6.228	6.250	6.272	6.295	6.317	300
310	6.317	6.339	6.362	6.384	6.406	6.429	6.451	6.473	6.496	6.518	6.540	310
320	6.540	6.562	6.585	6.607	6.629	6.652	6.674	6.696	6.718	6.741	6.763	320
330	6.763	6.785	6.807	6.829	6.852	6.874	6.896	6.918	6.941	6.963	6.985	330
340	6.985	7.007	7.029	7.052	7.074	7.096	7.118	7.140	7.163	7.185	7.207	340
350	7.207	7.229	7.251	7.273	7.296	7.318	7.340	7.362	7.384	7.407	7.429	350
360	7.429	7.451	7.473	7.495	7.517	7.540	7.562	7.584	7.606	7.628	7.650	360
370	7.650	7.673	7.695	7.717	7.739	7.761	7.783	7.806	7.828	7.850	7.872	370
380	7.872	7.894	7.917	7.939	7.961	7.983	8.005	8.027	8.050	8.072	8.094	380
390	8.094	8.116	8.138	8.161	8.183	8.205	8.227	8.250	8.272	8.294	8.316	390
400	8.316	8.338	8.361	8.383	8.405	8.427	8.450	8.472	8.494	8.516	8.539	400
410	8.539	8.561	8.583	8.605	8.628	8.650	8.672	8.694	8.717	8.739	8.761	410
420	8.761	8.784	8.806	8.828	8.851	8.873	8.895	8.918	8.940	8.962	8.985	420
430	8.985	9.007	9.029	9.052	9.074	9.096	9.119	9.141	9.163	9.186	9.208	430
440	9.208	9.231	9.253	9.275	9.298	9.320	9.343	9.365	9.388	9.410	9.432	440
450	9.432	9.455	9.477	9.500	9.522	9.545	9.567	9.590	9.612	9.635	9.657	450
460	9.657	9.680	9.702	9.725	9.747	9.770	9.792	9.815	9.837	9.860	9.882	460
470	9.882	9.905	9.927	9.950	9.973	9.995	10.018	10.040	10.063	10.086	10.108	470
480	10.108	10.131	10.153	10.176	10.199	10.221	10.244	10.267	10.289	10.312	10.334	480
490	10.334	10.357	10.380	10.402	10.425	10.448	10.471	10.493	10.516	10.539	10.561	490
500	10.561	10.584	10.607	10.629	10.652	10.675	10.698	10.720	10.743	10.766	10.789	500
510	10.789	10.811	10.834	10.857	10.880	10.903	10.925	10.948	10.971	10.994	11.017	510
520	11.017	11.039	11.062	11.085	11.108	11.131	11.154	11.176	11.199	11.222	11.245	520
530	11.245	11.268	11.291	11.313	11.336	11.359	11.382	11.405	11.428	11.451	11.474	530
540	11.474	11.497	11.519	11.542	11.565	11.588	11.611	11.634	11.657	11.680	11.703	540
550	11.703	11.726	11.749	11.772	11.795	11.818	11.841	11.864	11.887	11.910	11.933	550
560	11.933	11.956	11.978	12.001	12.024	12.047	12.070	12.093	12.116	12.140	12.163	560
570	12.163	12.186	12.209	12.232	12.255	12.278	12.301	12.324	12.347	12.370	12.393	570
580	12.393	12.416	12.439	12.462	12.485	12.508	12.531	12.554	12.577	12.600	12.624	580
590	12.624	12.647	12.670	12.693	12.716	12.739	12.762	12.785	12.808	12.831	12.855	590
600	12.855	12.878	12.901	12.924	12.947	12.970	12.993	13.016	13.040	13.063	13.086	600
610	13.086	13.109	13.132	13.155	13.179	13.202	13.225	13.248	13.271	13.294	13.318	610
620	13.318	13.341	13.364	13.387	13.410	13.433	13.457	13.480	13.503	13.526	13.549	620
630	13.549	13.573	13.596	13.619	13.642	13.665	13.689	13.712	13.735	13.758	13.782	630
640	13.782	13.805	13.828	13.851	13.874	13.898	13.921	13.944	13.967	13.991	14.014	640
650	14.014	14.037	14.060	14.084	14.107	14.130	14.154	14.177	14.200	14.223	14.247	650
660	14.247	14.270	14.293	14.316	14.340	14.363	14.386	14.410	14.433	14.456	14.479	660
670	14.479	14.503	14.526	14.549	14.573	14.596	14.619	14.643	14.666	14.689	14.713	670
680	14.713	14.736	14.759	14.783	14.806	14.829	14.853	14.876	14.899	14.923	14.946	680
690	14.946	14.969	14.993	15.016	15.039	15.063	15.086	15.109	15.133	15.156	15.179	690

Revised Thermocouple Reference Tables

TYPE K

Reference Tables N.I.S.T. Monograph 175 Revised to ITS-90

Thermocouple Grade

Extension Grade

Nickel-Chromium vs. Nickel-Aluminum

MAXIMUM TEMPERATURE RANGE

Thermocouple Grade
– 328 to 2282°F
– 200 to 1250°C

Extension Grade
32 to 392°F
0 to 200°C

LIMITS OF ERROR
(whichever is greater)
Standard: 2.2°C or 0.75% Above 0°C
2.2°C or 2.0% Below 0°C
Special: 1.1°C or 0.4%

COMMENTS, BARE WIRE ENVIRONMENT:
Clean Oxidizing and Inert; Limited Use in Vacuum or Reducing; Wide Temperature Range; Most Popular Calibration

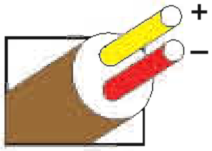
TEMPERATURE IN DEGREES °F
REFERENCE JUNCTION AT 32°F

Thermoelectric Voltage in Millivolts

°F	0	1	2	3	4	5	6	7	8	9	10	°F
700	15.179	15.203	15.226	15.250	15.273	15.296	15.320	15.343	15.366	15.390	15.413	700
710	15.413	15.437	15.460	15.483	15.507	15.530	15.554	15.577	15.600	15.624	15.647	710
720	15.647	15.671	15.694	15.717	15.741	15.764	15.788	15.811	15.834	15.858	15.881	720
730	15.881	15.905	15.928	15.952	15.976	15.998	16.022	16.045	16.069	16.092	16.116	730
740	16.116	16.139	16.163	16.186	16.209	16.233	16.256	16.280	16.303	16.327	16.350	740
750	16.350	16.374	16.397	16.421	16.444	16.468	16.491	16.514	16.538	16.561	16.585	750
760	16.585	16.608	16.632	16.655	16.679	16.702	16.726	16.749	16.773	16.796	16.820	760
770	16.820	16.843	16.867	16.890	16.914	16.937	16.961	16.984	17.008	17.031	17.055	770
780	17.055	17.078	17.102	17.125	17.149	17.173	17.196	17.220	17.243	17.267	17.290	780
790	17.290	17.314	17.337	17.361	17.384	17.408	17.431	17.455	17.478	17.502	17.526	790
800	17.526	17.549	17.573	17.596	17.620	17.643	17.667	17.690	17.714	17.738	17.761	800
810	17.761	17.785	17.808	17.832	17.855	17.879	17.902	17.926	17.950	17.973	17.997	810
820	17.997	18.020	18.044	18.068	18.091	18.115	18.138	18.162	18.186	18.209	18.233	820
830	18.233	18.256	18.280	18.303	18.327	18.351	18.374	18.398	18.421	18.445	18.469	830
840	18.469	18.492	18.516	18.539	18.563	18.587	18.610	18.634	18.657	18.681	18.705	840
850	18.705	18.728	18.752	18.776	18.799	18.823	18.846	18.870	18.894	18.917	18.941	850
860	18.941	18.965	18.988	19.012	19.035	19.059	19.083	19.106	19.130	19.154	19.177	860
870	19.177	19.201	19.224	19.248	19.272	19.295	19.319	19.343	19.366	19.390	19.414	870
880	19.414	19.437	19.461	19.485	19.508	19.532	19.556	19.579	19.603	19.626	19.650	880
890	19.650	19.674	19.697	19.721	19.745	19.768	19.792	19.816	19.839	19.863	19.887	890
900	19.887	19.910	19.934	19.958	19.981	20.005	20.029	20.052	20.076	20.100	20.123	900
910	20.123	20.147	20.171	20.194	20.218	20.242	20.265	20.289	20.313	20.336	20.360	910
920	20.360	20.384	20.407	20.431	20.455	20.479	20.502	20.526	20.550	20.573	20.597	920
930	20.597	20.621	20.644	20.668	20.692	20.715	20.739	20.763	20.786	20.810	20.834	930
940	20.834	20.857	20.881	20.905	20.929	20.952	20.976	21.000	21.023	21.047	21.071	940
950	21.071	21.094	21.118	21.142	21.165	21.189	21.213	21.236	21.260	21.284	21.308	950
960	21.308	21.331	21.355	21.379	21.402	21.426	21.450	21.473	21.497	21.521	21.544	960
970	21.544	21.568	21.592	21.616	21.639	21.663	21.687	21.710	21.734	21.758	21.781	970
980	21.781	21.805	21.829	21.852	21.876	21.900	21.924	21.947	21.971	21.995	22.018	980
990	22.018	22.042	22.066	22.089	22.113	22.137	22.160	22.184	22.208	22.232	22.255	990
1000	22.255	22.279	22.303	22.326	22.350	22.374	22.397	22.421	22.445	22.468	22.492	1000
1010	22.492	22.516	22.540	22.563	22.587	22.611	22.634	22.658	22.682	22.705	22.729	1010
1020	22.729	22.753	22.776	22.800	22.824	22.847	22.871	22.895	22.919	22.942	22.966	1020
1030	22.966	22.990	23.013	23.037	23.061	23.084	23.108	23.132	23.155	23.179	23.203	1030
1040	23.203	23.226	23.250	23.274	23.297	23.321	23.345	23.368	23.392	23.416	23.439	1040
1050	23.439	23.463	23.487	23.510	23.534	23.558	23.581	23.605	23.629	23.652	23.676	1050
1060	23.676	23.700	23.723	23.747	23.771	23.794	23.818	23.842	23.865	23.889	23.913	1060
1070	23.913	23.936	23.960	23.984	24.007	24.031	24.055	24.078	24.102	24.126	24.149	1070
1080	24.149	24.173	24.197	24.220	24.244	24.267	24.291	24.315	24.338	24.362	24.386	1080
1090	24.386	24.409	24.433	24.457	24.480	24.504	24.527	24.551	24.575	24.598	24.622	1090
1100	24.622	24.646	24.669	24.693	24.717	24.740	24.764	24.787	24.811	24.835	24.858	1100
1110	24.858	24.882	24.905	24.929	24.953	24.976	25.000	25.024	25.047	25.071	25.094	1110
1120	25.094	25.118	25.142	25.165	25.189	25.212	25.236	25.260	25.283	25.307	25.330	1120
1130	25.330	25.354	25.377	25.401	25.425	25.448	25.472	25.495	25.519	25.543	25.566	1130
1140	25.566	25.590	25.613	25.637	25.660	25.684	25.708	25.731	25.755	25.778	25.802	1140
1150	25.802	25.825	25.849	25.873	25.896	25.920	25.943	25.967	25.990	26.014	26.037	1150
1160	26.037	26.061	26.084	26.108	26.132	26.155	26.179	26.202	26.226	26.249	26.273	1160
1170	26.273	26.296	26.320	26.343	26.367	26.390	26.414	26.437	26.461	26.484	26.508	1170
1180	26.508	26.532	26.555	26.579	26.602	26.626	26.649	26.673	26.696	26.720	26.743	1180
1190	26.743	26.767	26.790	26.814	26.837	26.861	26.884	26.907	26.931	26.954	25.978	1190
1200	26.978	27.001	27.025	27.048	27.072	27.095	27.119	27.142	27.166	27.189	27.213	1200
1210	27.213	27.236	27.259	27.283	27.306	27.330	27.353	27.377	27.400	27.424	27.447	1210
1220	27.447	27.471	27.494	27.517	27.541	27.564	27.588	27.611	27.635	27.658	27.681	1220
1230	27.681	27.705	27.728	27.752	27.775	27.798	27.822	27.845	27.869	27.892	27.915	1230
1240	27.915	27.939	27.962	27.986	28.009	28.032	28.056	28.079	28.103	28.126	28.149	1240
1250	28.149	28.173	28.196	28.219	28.243	28.266	28.289	28.313	28.336	28.360	28.383	1250
1260	28.383	28.406	28.430	28.453	28.476	28.500	28.523	28.546	28.570	28.593	28.616	1260
1270	28.616	28.640	28.663	28.686	28.710	28.733	28.756	28.780	28.803	28.826	28.849	1270
1280	28.849	28.873	28.896	28.919	28.943	28.966	28.989	29.013	29.036	29.059	29.082	1280
1290	29.082	29.106	29.129	29.152	29.176	29.199	29.222	29.245	29.269	29.292	29.315	1290
°F	0	1	2	3	4	5	6	7	8	9	10	°F

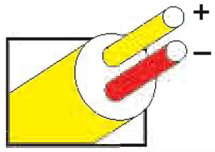
°F	0	1	2	3	4	5	6	7	8	9	10	°F
1300	29.315	29.338	29.362	29.385	29.408	29.431	29.455	29.478	29.501	29.524	29.548	1300
1310	29.548	29.571	29.594	29.617	29.640	29.664	29.687	29.710	29.733	29.757	29.780	1310
1320	29.780	29.803	29.826	29.849	29.873	29.896	29.919	29.942	29.965	29.989	30.012	1320
1330	30.012	30.035	30.058	30.081	30.104	30.128	30.151	30.174	30.197	30.220	30.243	1330
1340	30.243	30.267	30.290	30.313	30.336	30.359	30.382	30.405	30.429	30.452	30.475	1340
1350	30.475	30.498	30.521	30.544	30.567	30.590	30.613	30.637	30.660	30.683	30.706	1350
1360	30.706	30.729	30.752	30.775	30.798	30.821	30.844	30.868	30.891	30.914	30.937	1360
1370	30.937	30.960	30.983	31.006	31.029	31.052	31.075	31.098	31.121	31.144	31.167	1370
1380	31.167	31.190	31.213	31.236	31.260	31.283	31.306	31.329	31.352	31.375	31.398	1380
1390	31.398	31.421	31.444	31.467	31.490	31.513	31.536	31.559	31.582	31.605	31.628	1390
1400	31.628	31.651	31.674	31.697	31.720	31.743	31.766	31.789	31.812	31.834	31.857	1400
1410	31.857	31.880	31.903	31.926	31.949	31.972	31.995	32.018	32.041	32.064	32.087	1410
1420	32.087	32.110	32.133	32.156	32.179	32.202	32.224	32.247	32.270	32.293	32.316	1420
1430	32.316	32.339	32.362	32.385	32.408	32.431	32.453	32.476	32.499	32.522	32.545	1430
1440	32.545	32.568	32.591	32.614	32.636	32.659	32.682	32.705	32.728	32.751	32.774	1440
1450	32.774	32.796	32.819	32.842	32.865	32.888	32.911	32.933	32.956	32.979	33.002	1450
1460	33.002	33.025	33.047	33.070	33.093	33.116	33.139	33.161	33.184	33.207	33.230	1460
1470	33.230	33.253	33.275	33.298	33.321	33.344	33.366	33.389	33.412	33.435	33.458	1470
1480	33.458	33.480	33.503	33.526	33.548	33.571	33.594	33.617	33.639	33.662	33.685	1480
1490	33.685	33.708	33.730	33.753	33.776	33.798	33.821	33.844	33.867	33.889	33.912	1490
1500	33.912	33.935	33.957	33.980	34.003	34.025	34.048	34.071	34.093	34.116	34.139	1500
1510	34.139	34.161	34.184	34.207	34.229	34.252	34.275	34.297	34.320	34.343	34.365	1510
1520	34.365	34.388	34.410	34.433	34.456	34.478	34.501	34.524	34.546	34.569	34.591	1520
1530	34.591	34.614	34.637	34.659	34.682	34.704	34.727	34.750	34.772	34.795	34.817	1530
1540	34.817	34.840	34.862	34.885	34.908	34.930	34.953	34.975	34.998	35.020	35.043	1540
1550	35.043	35.065	35.088	35.110	35.133	35.156	35.178	35.201	35.223	35.246	35.268	1550
1560	35.268	35.291	35.313	35.336	35.358	35.381	35.403	35.426	35.448	35.471	35.493	1560
1570	35.493	35.516	35.538	35.560	35.583	35.605	35.628	35.650	35.673	35.695	35.718	1570
1580	35.718	35.740	35.763	35.785	35.807	35.830	35.852	35.875	35.897	35.920	35.942	1580
1590	35.942	35.964	35.987	36.009	36.032	36.054	36.076	36.099	36.121	36.144	36.166	1590
1600	36.166	36.188	36.211	36.233	36.256	36.278	36.300	36.323	36.345	36.367	36.390	1600
1610	36.390	36.412	36.434	36.457	36.479	36.501	36.524	36.546	36.568	36.591	36.613	1610
1620	36.613	36.635	36.658	36.680	36.702	36.725	36.747	36.769	36.792	36.814	36.836	1620
1630	36.836	36.859	36.881	36.903	36.925	36.948	36.970	36.992	37.014	37.037	37.059	1630
1640	37.059	37.081	37.104	37.126	37.148	37.170	37.193	37.215	37.237	37.259	37.281	1640
1650	37.281	37.304	37.326	37.348	37.370	37.393	37.415	37.437	37.459	37.481	37.504	1650
1660	37.504	37.526	37.548	37.570	37.592	37.615	37.637	37.659	37.681	37.703	37.725	1660
1670	37.725	37.748	37.770	37.792	37.814	37.836	37.858	37.881	37.903	37.925	37.947	1670
1680	37.947	37.969	37.991	38.013	38.036	38.058	38.080	38.102	38.124	38.146	38.168	1680
1690	38.168	38.190	38.212	38.235	38.257	38.279	38.301	38.323	38.345	38.367	38.389	1690
1700	38.389	38.411	38.433	38.455	38.477	38.499	38.522	38.544	38.566	38.588	38.610	1700
1710	38.610	38.632	38.654	38.676	38.698	38.720	38.742	38.764	38.786	38.808	38.830	1710
1720	38.830	38.852	38.874	38.896	38.918	38.940	38.962	38.984	39.006	39.028	39.050	1720
1730	39.050	39.072	39.094	39.116	39.138	39.160	39.182	39.204	39.226	39.248	39.270	1730
1740	39.270	39.292	39.314	39.335	39.357	39.379	39.401	39.423	39.445	39.467	39.489	1740
1750	39.489	39.511	39.533	39.555	39.577	39.599	39.620	39.642	39.664	39.686	39.708	1750
1760	39.708	39.730	39.752	39.774	39.796	39.817	39.839	39.861	39.883	39.905	39.927	1760
1770	39.927	39.949	39.970	39.992	40.014	40.036	40.058	40.080	40.101	40.123	40.145	1770
1780	40.145	40.167	40.189	40.211	40.232	40.254	40.276	40.298	40.320	40.341	40.363	1780
1790	40.363	40.385	40.407	40.429	40.450	40.472	40.494	40.516	40.537	40.559	40.581	1790
1800	40.581	40.603	40.624	40.646	40.668	40.690	40.711	40.733	40.755	40.777	40.798	1800
1810	40.798	40.820	40.842	40.864	40.885	40.907	40.929	40.950	40.972	40.994	41.015	1810
1820	41.015	41.037	41.059	41.081	41.102	41.124	41.146	41.167	41.189	41.211	41.232	1820
1830	41.232	41.254	41.276	41.297	41.319	41.341	41.362	41.384	41.405	41.427	41.449	1830
1840	41.449	41.470	41.492	41.514	41.535	41.557	41.578	41.600	41.622	41.643	41.665	1840
1850	41.665	41.686	41.708	41.730	41.751	41.773	41.794	41.816	41.838	41.859	41.881	1850
1860	41.881	41.902	41.924	41.945	41.967	41.988	42.010	42.032	42.053	42.075	42.096	1860
1870	42.096	42.118	42.139	42.161	42.182	42.204	42.225	42.247	42.268	42.290	42.311	1870
1880	42.311	42.333	42.354	42.376	42.397	42.419	42.440	42.462	42.483	42.505	42.526	1880
1890	42.526	42.548	42.569	42.591	42.612	42.633	42.655	42.676	42.698	42.719	42.741	1890
°F	0	1	2	3	4	5	6	7	8	9	10	°F

MAXIMUM TEMPERATURE RANGE
Thermocouple Grade
– 328 to 2282°F
– 200 to 1250°C
Extension Grade
32 to 392°F
0 to 200°C
LIMITS OF ERROR
(whichever is greater)
Standard: 2.2°C or 0.75% Above 0°C
2.2°C or 2.0% Below 0°C
Special: 1.1°C or 0.4%
COMMENTS, BARE WIRE ENVIRONMENT:
Clean Oxidizing and Inert; Limited Use in Vacuum or Reducing; Wide Temperature Range; Most Popular Calibration
TEMPERATURE IN DEGREES °F
REFERENCE JUNCTION AT 32°F



Thermocouple Grade

Nickel-Chromium vs. Nickel-Aluminum



Extension Grade

Revised Thermocouple Reference Tables

TYPE K

Reference Tables N.I.S.T. Monograph 175 Revised to ITS-90

Z

Thermoelectric Voltage in Millivolts

°F	0	1	2	3	4	5	6	7	8	9	10	°F
1900	42.741	42.762	42.783	42.805	42.826	42.848	42.869	42.891	42.912	42.933	42.955	1900
1910	42.955	42.976	42.998	43.019	43.040	43.062	43.083	43.104	43.126	43.147	43.169	1910
1920	43.169	43.190	43.211	43.233	43.254	43.275	43.297	43.318	43.339	43.361	43.382	1920
1930	43.382	43.403	43.425	43.446	43.467	43.489	43.510	43.531	43.552	43.574	43.595	1930
1940	43.595	43.616	43.638	43.659	43.680	43.701	43.723	43.744	43.765	43.787	43.808	1940
1950	43.808	43.829	43.850	43.872	43.893	43.914	43.935	43.957	43.978	43.999	44.020	1950
1960	44.020	44.041	44.063	44.084	44.105	44.126	44.147	44.169	44.190	44.211	44.232	1960
1970	44.232	44.253	44.275	44.296	44.317	44.338	44.359	44.380	44.402	44.423	44.444	1970
1980	44.444	44.465	44.486	44.507	44.528	44.550	44.571	44.592	44.613	44.634	44.655	1980
1990	44.655	44.676	44.697	44.719	44.740	44.761	44.782	44.803	44.824	44.845	44.866	1990
2000	44.866	44.887	44.908	44.929	44.950	44.971	44.992	45.014	45.035	45.056	45.077	2000
2010	45.077	45.098	45.119	45.140	45.161	45.182	45.203	45.224	45.245	45.266	45.287	2010
2020	45.287	45.308	45.329	45.350	45.371	45.392	45.413	45.434	45.455	45.476	45.497	2020
2030	45.497	45.518	45.539	45.560	45.580	45.601	45.622	45.643	45.664	45.685	45.706	2030
2040	45.706	45.727	45.748	45.769	45.790	45.811	45.832	45.852	45.873	45.894	45.915	2040
2050	45.915	45.936	45.957	45.978	45.999	46.019	46.040	46.061	46.082	46.103	46.124	2050
2060	46.124	46.145	46.165	46.186	46.207	46.228	46.249	46.269	46.290	46.311	46.332	2060
2070	46.332	46.353	46.373	46.394	46.415	46.436	46.457	46.477	46.498	46.519	46.540	2070
2080	46.540	46.560	46.581	46.602	46.623	46.643	46.664	46.685	46.706	46.726	46.747	2080
2090	46.747	46.768	46.789	46.809	46.830	46.851	46.871	46.892	46.913	46.933	46.954	2090
2100	46.954	46.975	46.995	47.016	47.037	47.057	47.078	47.099	47.119	47.140	47.161	2100
2110	47.161	47.181	47.202	47.223	47.243	47.264	47.284	47.305	47.326	47.346	47.367	2110
2120	47.367	47.387	47.408	47.429	47.449	47.470	47.490	47.511	47.531	47.552	47.573	2120
2130	47.573	47.593	47.614	47.634	47.655	47.675	47.696	47.716	47.737	47.757	47.778	2130
2140	47.778	47.798	47.819	47.839	47.860	47.880	47.901	47.921	47.942	47.962	47.983	2140
2150	47.983	48.003	48.024	48.044	48.065	48.085	48.105	48.126	48.146	48.167	48.187	2150
2160	48.187	48.208	48.228	48.248	48.269	48.289	48.310	48.330	48.350	48.371	48.391	2160
2170	48.391	48.411	48.432	48.452	48.473	48.493	48.513	48.534	48.554	48.574	48.595	2170
2180	48.595	48.615	48.635	48.656	48.676	48.696	48.717	48.737	48.757	48.777	48.798	2180
2190	48.798	48.818	48.838	48.859	48.879	48.899	48.919	48.940	48.960	48.980	49.000	2190
2200	49.000	49.021	49.041	49.061	49.081	49.101	49.122	49.142	49.162	49.182	49.202	2200
2210	49.202	49.223	49.243	49.263	49.283	49.303	49.323	49.344	49.364	49.384	49.404	2210
2220	49.404	49.424	49.444	49.465	49.485	49.505	49.525	49.545	49.565	49.585	49.605	2220
2230	49.605	49.625	49.645	49.666	49.686	49.706	49.726	49.746	49.766	49.786	49.806	2230
2240	49.806	49.826	49.846	49.866	49.886	49.906	49.926	49.946	49.966	49.986	50.006	2240
°F	0	1	2	3	4	5	6	7	8	9	10	°F

°F	0	1	2	3	4	5	6	7	8	9	10	°F
2250	50.006	50.026	50.046	50.066	50.086	50.106	50.126	50.146	50.166	50.186	50.206	2250
2260	50.206	50.226	50.246	50.266	50.286	50.306	50.326	50.346	50.366	50.385	50.405	2260
2270	50.405	50.425	50.445	50.465	50.485	50.505	50.525	50.545	50.564	50.584	50.604	2270
2280	50.604	50.624	50.644	50.664	50.684	50.703	50.723	50.743	50.763	50.783	50.802	2280
2290	50.802	50.822	50.842	50.862	50.882	50.901	50.921	50.941	50.961	50.981	51.000	2290
2300	51.000	51.020	51.040	51.060	51.079	51.099	51.119	51.139	51.158	51.178	51.198	2300
2310	51.198	51.217	51.237	51.257	51.276	51.296	51.316	51.336	51.355	51.375	51.395	2310
2320	51.395	51.414	51.434	51.453	51.473	51.493	51.512	51.532	51.552	51.571	51.591	2320
2330	51.591	51.611	51.630	51.650	51.669	51.689	51.708	51.728	51.748	51.767	51.787	2330
2340	51.787	51.806	51.826	51.845	51.865	51.885	51.904	51.924	51.943	51.963	51.982	2340
2350	51.982	52.002	52.021	52.041	52.060	52.080	52.099	52.119	52.138	52.158	52.177	2350
2360	52.177	52.197	52.216	52.235	52.255	52.274	52.294	52.313	52.333	52.352	52.371	2360
2370	52.371	52.391	52.410	52.430	52.449	52.468	52.488	52.507	52.527	52.546	52.565	2370
2380	52.565	52.585	52.604	52.623	52.643	52.662	52.681	52.701	52.720	52.739	52.759	2380
239052.759		52.778	52.797	52.817	52.836	52.855	52.875	52.894	52.913	52.932	52.952	2390
2400	52.952	52.971	52.990	53.010	53.029	53.048	53.067	53.087	53.106	53.125	53.144	2400
2410	53.144	53.163	53.183	53.202	53.221	53.240	53.260	53.279	53.298	53.317	53.336	2410
2420	53.336	53.355	53.375	53.394	53.413	53.432	53.451	53.470	53.490	53.509	53.528	2420
2430	53.528	53.547	53.566	53.585	53.604	53.623	53.643	53.662	53.681	53.700	53.719	2430
2440	53.719	53.738	53.757	53.776	53.795	53.814	53.833	53.852	53.871	53.890	53.910	2440
2450	53.910	53.929	53.948	53.967	53.986	54.005	54.024	54.043	54.062	54.081	54.100	2450
2460	54.100	54.119	54.138	54.157	54.176	54.195	54.214	54.233	54.252	54.271	54.289	2460
2470	54.289	54.308	54.327	54.346	54.365	54.384	54.403	54.422	54.441	54.460	54.479	2470
2480	54.479	54.498	54.517	54.536	54.554	54.573	54.592	54.611	54.630	54.649	54.668	2480
2490	54.668	54.687	54.705	54.724	54.743	54.762	54.781	54.800	54.819	54.837	54.856	2490
2500	54.856	54.875	54.894									2500
°F	0	1	2	3	4	5	6	7	8	9	10	°F

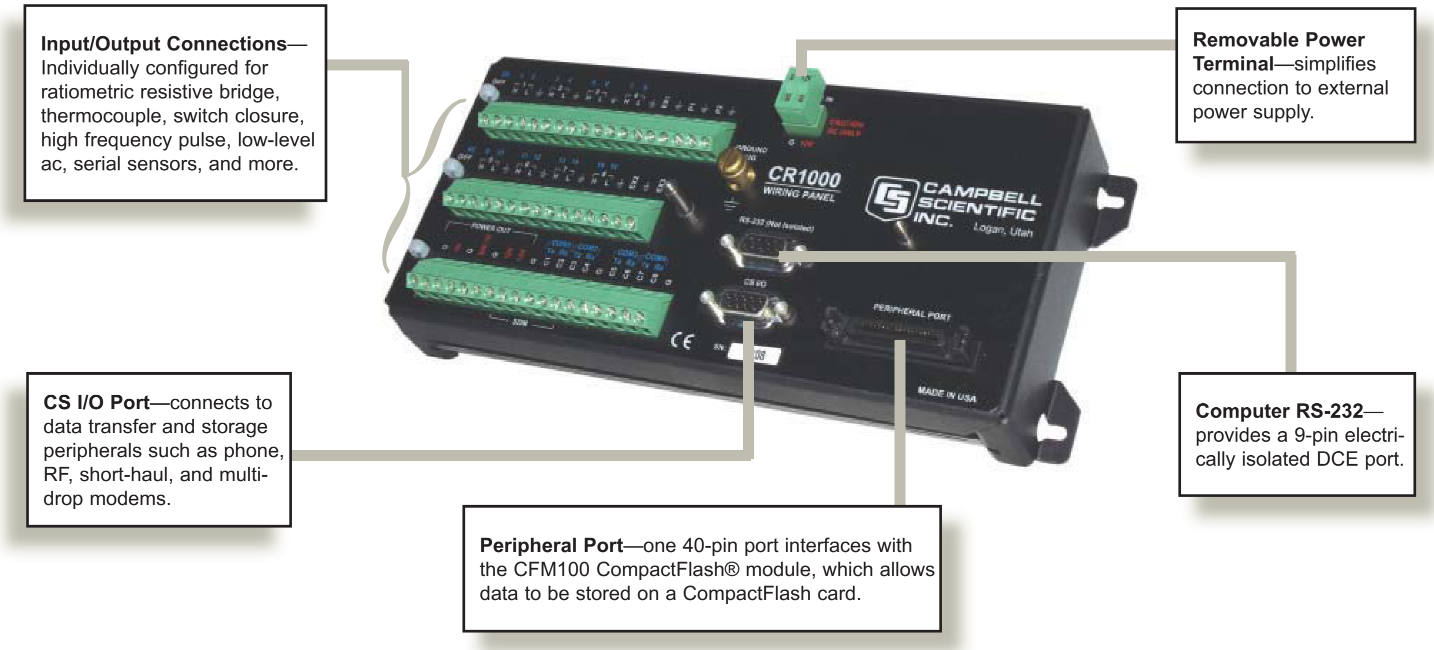
CR1000 Measurement & Control System

A Rugged Instrument with Research-Grade Performance

CAMPBELL SCIENTIFIC, INC.
815 W. 1800 N. • Logan, Utah 84321-1784 • (435) 753-2342 • FAX (435) 750-9540 • www.campbellsci.com

CR1000 Measurement and Control System

The CR1000 provides precision measurement capabilities in a rugged, battery-operated package. It consists of a measurement and control module and a wiring panel. Standard operating range is -25° to +50°C; an optional extended range of -55° to +85°C is available.



Features

- 2 Mbytes standard memory; 4 Mbytes optional memory
- Program execution rate of up to 100 Hz
- CS I/O and RS-232 serial ports
- 13-bit analog to digital conversions
- 16-bit H8S Hitachi Microcontroller with 32-bit internal CPU architecture
- Temperature compensated real-time clock
- Background system calibration for accurate measurements over time and temperature changes
- Single DAC used for excitation and measurements to give ratio metric measurements
- Gas Discharge Tube (GDT) protected inputs
- Data values stored in tables with a time stamp and record number
- Battery-backed SRAM memory and clock ensuring data, programs, and accurate time are maintained while the CR1000 is disconnected from its main power source
- Measures intelligent serial sensors without using an SDM-SIO4

Measurement and Control Module

The module measures sensors, drives direct communications and telecommunications, reduces data, controls external devices, and stores data and programs in on-board, non-volatile storage. The electronics are RF shielded and glitch protected by the sealed, stainless steel canister. A battery-backed clock assures accurate timekeeping. The module can simultaneously provide measurement and communication functions. The on-board, BASIC-like programming language supports data processing and analysis routines.

Wiring Panel

The CR1000WP is a black, anodized aluminum wiring panel that is compatible with all CR1000 and CR1000-4M modules. The wiring panel includes switchable 12 V, redistributed analog grounds (dispersed among analog channels rather than grouped), unpluggable terminal block for 12 V connections, gas-tube spark gaps, and 12 V supply on pin 8 to power our COM-series phone modems and other peripherals. The control module easily disconnects from the wiring panel allowing field replacement without rewiring the sensors. A description of the wiring panel's input/output channels follows.

Analog Inputs
Eight differential (16 single-ended) channels measure voltage levels. Resolution on the most sensitive range is 0.67 µV.

Pulse Counters
Two pulse channels can count pulses from high level (5 V square wave), switch closure, or low level ac signals.

Switched Voltage Excitations
Three outputs provide precision excitation voltages for resistive bridge measurements.

Digital I/O Ports
Eight ports are provided for frequency measurements, digital control, and triggering. Three of these ports can also be used to measure SDM devices.

RS-232 Port
A PC or laptop can be connected to this 9-pin port via an RS-232 cable.

CS I/O port
Data transfer peripherals that require power from the datalogger can be connected to this port via an SC12 cable. This port is also used for connecting the datalogger to a PC via an SC32B or SC-USB interface when optical isolation is required.

Peripheral Port
One 40-pin port interfaces with the CFM100 CompactFlash® Module or the NL115 Ethernet Interface and CompactFlash Module.

Switched 12 Volt
This terminal provides unregulated 12 V that can be switched on and off under program control.

Storage Capacity
The CR1000 has 2 Mbyte of FLASH memory for the Operating System. The standard CR1000 provides 2 Mbytes battery-backed SRAM for CPU usage, program storage, and data storage; an optional version provides 4 Mbytes of SRAM. Data is stored in a table format. The storage capacity of the CR1000 can be increased by using a CompactFlash® card.

Communication Protocols
The CR1000 supports the PakBus® communication protocol. PakBus networks have the distributed routing intelligence to continually evaluate links. Continually evaluating links optimizes delivery times and, in the case of delivery failure, allows automatic switch over to a configured backup route.

The CR1000 also supports Modbus RTU protocol—both floating point and long formats. The datalogger can act as a slave, master, or both.

Enclosure/Stack Bracket
A CR1000 housed in a weather-resistant enclosure can collect data under extremely harsh conditions. The enclosure protects the CR1000 from dust, water, sunlight, or pollutants. An internal mounting plate is prepunched for easy system configuration and exchange of equipment in the field.

A stack bracket kit is available that allows you to attach the CR1000 to the backplate of an ENC10/12 enclosure in a "horizontal" orientation (i.e., the long axis of the CR1000 spanning the short axis of the ENC10/12 enclosure). This stack bracket also allows you to place a small peripheral under the mounting bracket and secure it with Velcro®, thus conserving space, and place the wiring panel terminals at about the same height as the terminals in one of our power supplies.

The stack bracket as viewed from the side with a CR1000 attached.

Power Supplies
Any 12 Vdc source can power the CR1000; a PS100 or BPALK is typically used. The PS100 includes one 7 Ahr rechargeable battery, charged with ac power (requires a wall charger) or a solar panel. The BPALK consists of eight non-rechargeable D-cell alkaline batteries with a 7.5 Ahr rating at 20°C. An external AA-cell battery pack supplies power while the D-cells are replaced.

Also available are the BP12 and BP24 battery packs, which provide nominal ratings of 12 and 24 Ahrs, respectively. These batteries should be connected to a charging regulator and a charging source. For information about analyzing your system's power requirements, see our Power Supply product literature or Application Note 5-F. Both can be obtained from: www. campbellsci.com

Its low-power design allows the CR1000 to operate for up to one year on the PS100 power supply, depending on scan rate, number of sensors, data retrieval method, and external temperature.

Data Storage and Retrieval Options

To determine the best option for your application, consider the accessibility of your site, availability of services (e.g., cellular phone or satellite coverage), quantity of data to collect, and desired time between data-collection sessions. Some communication options can be combined—increasing the flexibility, convenience, and reliability of your communications.

Radios

Radio frequency (RF) communications are supported via narrow-band UHF, narrow-band VHF, spread spectrum, or meteor burst radios. Line-of-sight is required for all of our RF options.

Meteorological conditions measured at Lake Louise, Alberta, Canada are telemetered via phone-to-RF link to a base station.

Telephone Networks

The CR1000 can communicate with a PC using landlines, cellular CDMA, or cellular GPRS transceivers. A voice synthesized modem enables anyone to call the CR1000 via phone and receive a verbal report of realtime site conditions.

Satellite Transmitters

Our NESDIS-certified GOES satellite transmitter provides one-way communications from a Data Collection Platform (DCP) to a receiving station. The transmitter complies with the High Data Rate (HDR) specifications. We also offer an Argos transmitter that is ideal for high-altitude and polar applications.

This station for the National Estuarine Research Reserve (NERR) in Virginia transmits data via our GOES satellite transmitter.

Multidrop Interface

The MD485 intelligent RS-485 interface permits a PC to address and communicate with one or more dataloggers over a single two-twisted-pair cable. Distances up to 4000 ft are supported.

Short Haul Modems

The SRM-5A RAD Short Haul Modem supports communications between the CR1000 and a computer via a four-wire unconditioned line (two twisted pairs).

Direct Links

A desktop or laptop PC connects directly to the CR1000's RS-232 port. If optical isolation is required, the PC is connected to the datalogger's CS I/O port via an SC32B or SC-USB interface.

PDAs

User-supplied PDAs can be used to set the CR1000's clock, monitor real-time data, retrieve data, graph data, and transfer CR1000 programs. PConnect software (purchased separately) is required for PDAs with a Palm™ OS, and PConnectCE software (purchased separately) is required for PDAs with a Windows® CE OS.

Keyboard Display

With the CR1000KD, you can program the CR1000, manually initiate data transfer, and display data. The CR1000KD displays 8 lines x 21 characters (64 x 128 pixels) and has a 16-character keyboard. Custom menus are supported allowing you to set up choices within the datalogger program that can be initiated by a simple "toggle" or "pick list".

One CR1000KD can be carried from station to station in a CR1000 network.

Ethernet

Use of an NL100 or NL115 interface enables the CR1000 to communicate over a local network or a dedicated internet connection via TCP/IP. The NL115 also supports data storage on CompactFlash cards.

CompactFlash®

The CR1000's data can be stored on a CompactFlash card using either a CFM100 or NL115 module. On the computer side, the CompactFlash cards are read by the computer's PCMCIA slot fitted with a CF1 CompactFlash adapter or by a USB port fitted with the ImageMate USB CompactFlash Reader/Writer.

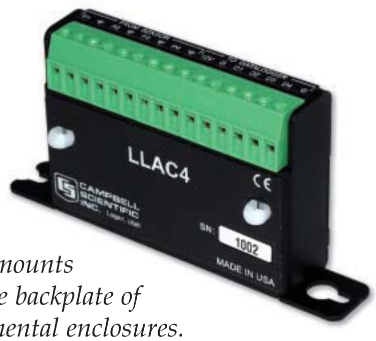
DSP4 Heads Up Display

Primarily intended for vehicle test applications, the DSP4 permits dashboard mounting in a variety of vehicles without obstructing the view of the driver.

Channel Expansion

4-Channel Low Level AC Module

The LLAC4 is a small peripheral device that allows you to increase the number of available low-level ac inputs by using control ports. This module is often used to measure up to four anemometers, and is especially useful for wind profiling applications.



The LLAC4 mounts directly to the backplate of our environmental enclosures.

Synchronous Devices for Measurement (SDMs)

SDMs are addressable peripherals that expand the CR1000's measurement and control capabilities. For example, SDMs are available to add control ports, analog outputs, pulse count channels, interval timers, or even a CANbus interface to your system. Multiple SDMs, in any combination, can be connected to one CR1000 datalogger.

Multiplexers

Multiplexers increase the number of sensors that can be measured by a CR1000 by sequentially connecting each sensor to the datalogger. Several multiplexers can be controlled by a single CR1000. The CR1000 is compatible with the AM16/32 and AM25T.

Software

Starter Software

Campbell Scientific offers easy-to-use starter software intended for first time users or applications that don't require sophisticated communications or datalogger program editing. These software products provide different functions and can be used in conjunction with each other. Starter software can be downloaded at no charge from www.campbellsci.com/resource.html. Our Resource CD also provides this software as well as PDF versions of our literature and manuals.

Our SCWin Short Cut for Windows® generates straightforward CR1000 programs in four easy steps. Short Cut supports programming for our multiplexers, ET106 stations, MetData1 stations, and virtually any sensor that our CR1000 can measure.

Our PC200W Starter Software allows you to transfer a program to, or retrieve data from, a CR1000 via a direct communications link.

Datalogger Support Software

Our general purpose datalogger support software packages provide more capabilities than our starter software. Each of these software packages contains program editing, communications, and display tools that can support an entire datalogger network.

PC400, our mid-level software, supports a variety of telemetry options, manual data collection, and data display. For programming, it includes both Short Cut and the CRBasic program editor. PC400 does not support combined communication options (e.g., phone-to-RF), PakBus® routing, or scheduled data collection; LoggerNet software is recommended for those applications.

Campbell Scientific offers the following three LoggerNet Software Packages:

- **LoggerNet**, the standard package, is recommended for those who have datalogger networks that do not require the more advanced features offered in LoggerNet Admin. It consists of a server application and several client applications integrated into a single product. This software provides all of PC400's capabilities as well as support for combined communication options (e.g., phone-to-RF), PakBus® routing, and scheduled data collection

- **LoggerNet Admin** is intended for customers who have large networks. Besides providing better tools for managing large networks, LoggerNet Admin allows you to remotely manage a datalogger network over TCP/IP, and to remotely and automatically distribute data to other computers.

- **LoggerNetRemote** includes LoggerNet Admin clients to administer a running LoggerNet Admin server via TCP/IP from a remote PC. This software does not include the LoggerNet server.

LoggerNet provides a way to accomplish almost all the tasks you'll need to complete when using a datalogger.

Applications

The measurement precision, flexibility, long-term reliability, and economical price of the CR1000 make it ideal for scientific, commercial, and industrial applications.

Meteorology

The CR1000 is used in long-term climatological monitoring, meteorological research, and routine weather measurement applications.

Our rugged, reliable weather station measures meteorological conditions at St. Mary's Lake, Glacier National Park, MT.

Sensors the CR1000 can measure include:

- cup, propeller, and sonic anemometers
- tipping bucket rain gages
- wind vanes
- pyranometers
- ultrasonic distance sensors
- thermistors, RTDs, and thermocouples
- barometric pressure sensors
- RH sensors
- cooled mirror hygrometers

Data is output in your choice of units (e.g., wind speed in miles per hour, meters per second, or knots). Standard CR1000 outputs include wind vector averaging, sigma, theta, histograms, saturation vapor pressure, and vapor pressure from wet/dry bulb temperatures.

Agriculture and Agricultural Research

The versatility of the CR1000 allows measurement of agricultural processes and equipment in applications such as:

- plant water research
- canopy energy balance
- machinery performance
- plant pathology
- crop management decisions
- food processing/storage
- frost prediction
- irrigation scheduling
- integrated pest management

This vitaculture site in Australia integrates meteorological, soil, and crop measurements.

Wind Profiling

Our data acquisition systems can monitor conditions at wind assessment sites, at producing wind farms, and along transmission lines. The reliability of these systems ensures data collection, even under adverse conditions. Wide operating temperature ranges and weatherproof enclosures allow our systems to operate reliably in harsh environments.

The CR1000 makes and records measurements, controls electrical devices, and can function as PLCs or RTUs. Because the datalogger has its own power supply (batteries, solar panels), it can continue to measure and store data and perform control during power outages.

Typical sensors for wind assessment applications include, but are not limited to:

- sonic anemometers
- three-cup and propeller anemometers (up to 10 anemometers can be measured by using two LLAC4 peripherals)
- wind vanes
- temperature sensors (air, water, and equipment)
- barometric pressure
- wetness
- solar radiation

Photo courtesy npower renewables

A Campbell Scientific system monitors an offshore wind farm in North Wales.

For turbine performance applications, the CR1000 can monitor electrical current, voltage, wattage, stress, and torque.

Soil Moisture

The CR1000 is compatible with the following soil moisture measurement technologies:

- **Soil moisture blocks** are inexpensive sensors that estimate soil water potential.
- **Matric water potential sensors** also estimate soil water potential but are more durable than soil moisture blocks.
- **Time-Domain Reflectometry Systems (TDR)** use a reflectometer controlled by a CR1000 to accurately measure soil water content. Multiplexers allow sequential measurement of a large number of probes by one reflectometer, reducing cost per measurement.
- **Self-contained water content reflectometers** are sensors that emit and measure a TDR pulse.
- **Tensiometers** measure the soil pore pressure of irrigated soils and calculate soil moisture.

Air Quality
The CR1000 can monitor and control gas analyzers, particle samplers, and visibility sensors. It can also automatically control calibration sequences and compute conditional averages that exclude invalid data (e.g., data recorded during power failures or calibration intervals).

Road Weather/RWIS
Our fully NTCIP-compliant Environmental Sensor Stations (ESS) are robust, reliable weather stations used for road weather/RWIS applications. A typical ESS includes a tower, CR1000, two road sensors, remote communication hardware, and sensors that measure wind speed and direction, air temperature, humidity, barometric pressure, solar radiation, and precipitation. The CR1000 can also measure soil moisture and temperature sensors, monitor bridge vibrations, and control external devices.

Water Resources/Aquaculture
Our CR1000 is well-suited to remote, unattended monitoring of hydrologic conditions. Most hydrologic sensors, including SDI-12 probes, interface directly to the CR1000. Typical hydrologic measurements:

- **Water level** is monitored with incremental shaft encoders, double bubblers, ultrasonic level transducers, resistance tapes, or strain gage or vibrating wire pressure transducers. Some shaft encoders require a QD1 Interface. Vibrating wire transducers require an AVW1, AVW4, or AVW100 Interface.
- **Well draw-down tests** use a pressure transducer measured at logarithmic intervals or at a rate based on incremental changes in water level.
- **Ionic conductivity measurements** use one of the switched excitation ports from the CR1000.
- **Samplers** are controlled by the CR1000 as a function of time, water quality, or water level.
- **Alarm and pump actuation** are controlled through digital I/O ports that operate external relay drivers.

A turbidity sensor was installed in a tributary of the Cedar River watershed to monitor water quality conditions for the city of Seattle, Washington.

Vehical Testing
This versatile, rugged datalogger is ideally suited for testing cold and hot temperature, high altitude, off-highway, and cross-country performance. The CR1000 is compatible with our SDM-CAN interface, GPS16-HVS receiver, and DSP4 Heads Up Display.

Vehicle monitoring includes not only passenger cars, but locomotives, airplanes, helicopters, tractors, buses, heavy trucks, drilling rigs, race cars, and motorcycles.

The CR1000 can measure:

- **Suspension—**strut pressure, spring force, travel, mounting point stress, deflection, ride
- **Fuel system—**line and tank pressure, flow, temperature, injection timing
- **Comfort control—**ambient and supply air temperature, solar radiation, fan speed, ac on and off, refrigerant pressures, time-to-comfort, blower current
- **Brakes—**line pressure, pedal pressure and travel, ABS, line and pad temperature
- **Engine—**pressure, temperature, crank position, RPM, time-to-start, oil pump cavitation
- **General vehicle—**chassis monitoring, road noise, vehicle position and speed, steering, air bag, hot/cold soaks, wind tunnels, traction, CANbus, wiper speed and current, vehicle electrical loads

Other Applications
- Eddy covariance systems
- Wireless sensor/datalogger networks
- Mesonet systems
- Avalanche forecasting, snow science, polar, high altitude
- Fire weather
- Geotechnical
- Historic preservation

CR1000 Specifications

Electrical specifications are valid over a -25° to +50°C range unless otherwise specified; non-condensing environment required. To maintain electrical specifications, Campbell Scientific recommends recalibrating dataloggers every two years.

PROGRAM EXECUTION RATE

10 ms to 30 min. @ 10 ms increments

ANALOG INPUTS

8 differential (DF) or 16 single-ended (SE) individually configured. Channel expansion provided by AM16/32 and AM25T multiplexers.

RANGES, RESOLUTION AND TYPICAL INPUT NOISE: Basic resolution (Basic Res) is the A/D resolution of a single conversion. **Resolution of DF measurements with input reversal is half the Basic Res.** Noise values are for DF measurements with input reversal; noise is greater with SE measurements.

		Input Referred Noise Voltage	
Input Range (mV)	*Basic Res (µV)*	*250 µs Int. (µV RMS)*	*50/60 Hz Int. (µV RMS)*
±5000	1330	385	192
±2500	667	192	95.9
±250	66.7	19.2	19.2
±25	6.7	2.3	1.9
±7.5	2	0.62	0.58
±2.5	0.67	0.34	0.19

ACCURACY[1]:
±(0.06% of reading + offset), 0° to 40°C
±(0.12% of reading + offset), -25° to 50°C
±(0.18% of reading + offset), -55° to 85°C (-XT only)

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

MINIMUM TIME BETWEEN VOLTAGE MEASUREMENTS: Includes the measurement time and conversion to engineering units. For voltage measurements, the CR1000 integrates the input signal for 0.25 ms or a full 16.66 ms or 20 ms line cycle for 50/60 Hz noise rejection. DF measurements with input reversal incorporate two integrations with reversed input polarities to reduce thermal offset and common mode errors and therefore take twice as long.

250 µs Analog Integration: ~1 ms SE
1/60 Hz Analog Integration: ~20 ms SE
1/50 Hz Analog Integration: ~25 ms SE

COMMON MODE RANGE: ±5 V

DC COMMON MODE REJECTION: >100 dB

NORMAL MODE REJECTION: 70 dB @ 60 Hz when using 60 Hz rejection

SUSTAINED INPUT VOLTAGE W/O DAMAGE: ±16 Vdc max.

INPUT CURRENT: ±1 nA typical, ±6 nA max. @ 50°C; ±90 nA @ 85°C

INPUT RESISTANCE: 20 Gohms typical

ACCURACY OF BUILT-IN REFERENCE JUNCTION THERMISTOR (for thermocouple measurements):
±0.3°C, -25° to 50°C
±0.8°C, -55° to 85°C (-XT only)

ANALOG OUTPUTS

3 switched voltage, active only during measurement, one at a time.

RANGE AND RESOLUTION: Voltage outputs programmable between ±2.5 V with 0.67 mV resolution.

ACCURACY: ±(0.06% of setting + 0.8 mV), 0° to 40°C
±(0.12% of setting + 0.8 mV), -25° to 50°C
±(0.18% of setting + 0.8 mV), -55° to 85°C (-XT only)

CURRENT SOURCING/SINKING: ±25 mA

RESISTANCE MEASUREMENTS

MEASUREMENT TYPES: The CR1000 provides ratiometric measurements of 4- and 6-wire full bridges, and 2-, 3-, and 4-wire half bridges. Precise, dual polarity excitation using any of the 3 switched voltage excitations eliminates dc errors.

RATIO ACCURACY[1]: Assuming excitation voltage of at least 1000 mV, not including bridge resistor error.

$$\pm(0.04\% \text{ of reading} + \text{offset})/V_{ex}$$

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

Offset values are reduced by a factor of 2 when excitation reversal is used.

PERIOD AVERAGING MEASUREMENTS

The average period for a single cycle is determined by measuring the average duration of a specified number of cycles. The period resolution is 192 ns divided by the specified number of cycles to be measured; the period accuracy is ±(0.01% of reading + resolution). Any of the 16 SE analog inputs can be used for period averaging. Signal limiting are typically required for the SE analog channel.

INPUT FREQUENCY RANGE:

Input Range	*Signal (peak to peak)[2] Min*	*Max*	*Min. Pulse W.*	*Max[3] Freq.*
±2500 mV	500 mV	10 V	2.5 µs	200 kHz
±250 mV	10 mV	2 V	10 µs	50 kHz
±25 mV	5 mV	2 V	62 µs	8 kHz
±2.5 mV	2 mV	2 V	100 µs	5 kHz

[2]The signal is centered at the datalogger ground.
[3]The maximum frequency = 1/(Twice Minimum Pulse Width) for 50% of duty cycle signals.

PULSE COUNTERS

Two 24-bit inputs selectable for switch closure, high frequency pulse, or low-level ac.

MAXIMUM COUNTS PER SCAN: 16.7×10^6

SWITCH CLOSURE MODE:
Minimum Switch Closed Time: 5 ms
Minimum Switch Open Time: 6 ms
Max. Bounce Time: 1 ms open w/o being counted

HIGH FREQUENCY PULSE MODE:
Maximum Input Frequency: 250 kHz
Maximum Input Voltage: ±20 V
Voltage Thresholds: Count upon transition from below 0.9 V to above 2.2 V after input filter with 1.2 µs time constant.

LOW LEVEL AC MODE: Internal ac coupling removes dc offsets up to ±0.5 V.

Input Hysteresis: 16 mV @ 1 Hz
Maximum ac Input Voltage: ±20 V
Minimum ac Input Voltage:

Sine wave (mV RMS)	*Range (Hz)*
20	1.0 to 20
200	0.5 to 200
2000	0.3 to 10,000
5000	0.3 to 20,000

DIGITAL I/O PORTS

8 ports software selectable, as binary inputs or control outputs. C1-C8 also provide edge timing, subroutine interrupts/wake up, switch closure pulse counting, high frequency pulse counting, asynchronous communications (UART), SDI-12 communications, and SDM communications.

HIGH FREQUENCY MAX: 400 kHz

SWITCH CLOSURE FREQUENCY MAX: 150 Hz

OUTPUT VOLTAGES (no load): high 5.0 V ±0.1 V; low <0.1

OUTPUT RESISTANCE: 330 ohms

INPUT STATE: high 3.8 to 5.3 V; low -0.3 to 1.2 V

INPUT HYSTERISIS: 1.4 V

INPUT RESISTANCE: 100 kohms

SWITCHED 12 V

One independent 12 V unregulated sources switched on and off under program control. Thermal fuse hold current = 900 mA @ 20°C, 650 mA @ 50°C, 360 mA @ 85°C.

SDI-12 INTERFACE SUPPORT

Control ports 1, 3, 5, and 7 may be configured for SDI-12 asynchronous communications. Up to ten SDI-12 sensors are supported per port. It meets SDI-12 Standard version 1.3 for datalogger mode.

CE COMPLIANCE

STANDARD(S) TO WHICH CONFORMITY IS DECLARED: IEC61326:2002

CPU AND INTERFACE

PROCESSOR: Hitachi H8S 2322 (16-bit CPU with 32-bit internal core)

MEMORY: 2 Mbytes of Flash for operating system; 2 Mbytes of battery-backed SRAM for CPU usage, program storage and data storage; 4 Mbytes optional

SERIAL INTERFACES: CS I/O port is used to interface with Campbell Scientific peripherals; RS-232 port is for computer or non-CSI modem connection.

PARALLEL INTERFACE: 40-pin interface for attaching data storage or communication peripherals such as the CFM100 module

BAUD RATES: Selectable from 300 bps to 115.2 kbps. ASCII protocol is one start bit, one stop bit, eight data bits, and no parity.

CLOCK ACCURACY: ±3 min. per year

SYSTEM POWER REQUIREMENTS

VOLTAGE: 9.6 to 16 Vdc

TYPICAL CURRENT DRAIN:
Sleep Mode: ~0.6 mA
1 Hz Scan (8 diff. meas., 60 Hz rej., 2 pulse meas.)
w/RS-232 communication: 19 mA
w/o RS-232 communication: 4.2 mA
1 Hz Scan (8 diff. meas., 250 µs integ., 2 pulse meas.)
w/RS-232 communication: 16.7 mA
w/o RS-232 communication: 1 mA
100 Hz Scan (4 diff. meas., 250 µs integ.)
w/RS-232 communication: 27.6 mA
w/o RS-232 communication: 16.2 mA

EXTERNAL BATTERIES: 12 Vdc nominal; reverse polarity protected.

PHYSICAL SPECIFICATIONS

MEASUREMENT & CONTROL MODULE SIZE: 8.5" x 3.9" x 0.85" (21.6 x 9.9 x 2.2 cm)

CR1000WP WIRING PANEL SIZE: 9.4" x 4" x 2.4" (23.9 x 10.2 x 6.1 cm); additional clearance required for serial cable and sensor leads.

WEIGHT: 2.1 lbs (1 kg)

WARRANTY

Three years against defects in materials and workmanship.

CAMPBELL SCIENTIFIC, INC.
815 West 1800 North • Logan, Utah 84321-1784 • (435) 753-2342 • Fax (435) 750-9540
Offices also located in: Australia • Brazil • Canada • England • France • Germany • South Africa • Spain

AirLink COMMUNICATIONS

RAVEN

> APPLICATIONS

UTILITIES
- Natural Gas Wellhead Monitoring
- C&I Meters
- Transmission Line Flow Meters
- Energy Management Systems

TRANSPORTATION
- Traffic Measurement
- Traffic Control
- Variable Message Signs

ATMOSPHERIC/ENVIRONMENTAL
- Weather Monitoring
- Irrigation Control
- Seismic Monitoring
- Water Level Monitoring

PRIMARY/REDUNDANT CONNECTIVITY
- Automated Teller Machines
- Routers
- Enterprise Servers

> APPLICATION INTERFACES

Standard interfaces include:
- AT command set
- Host TCP/IP stack communicates with Raven via PPP.
- Windows 95/98/2000/NT/XP Dial Up Networking communicates with Raven using PPP.

> SPECIAL FEATURES

- Class I Div 2 certified
- High speed data transfer rate
- Full duplex transceiver
- Low power consumption
- Proven technology
- Compact size
- Rugged aluminum case
- LEDs show status of network operation
- Optional mounting brackets

The AirLink Raven CDMA is a rugged, intelligent wireless data platform designed to enable real-time, two-way communications with remote assets.

THE ALEOS PLATFORM

The AirLink Embedded Operating System (ALEOS) is the power inside the Raven. ALEOS has its own embedded TCP/IP stack which enables transmission of date from non-IP devices. ALEOS enables several functions including remote configuration and diagnostics, packet assembly and dis-assembly for UDP and TCP, and dynamic IP management. The unique intelligence within ALEOS enables virtually any type of remote device to connect via the public wireless data network.

ALEOS
AirLink Embedded Operating System

FEATURES
- Integrated IP stack
- Standard AT commands
- Remote configuration, downloads, troubleshooting
- Telemetry protocols
- Encryption and security
- Dynamic DNS
- Network Address Translation
- Simple firewall to filter unauthorized IP adresses

BENEFITS
- Common ALEOS code used across all AirLink intelligent devices
- Provides a common experience to customers regardless of the network technology
- Allows customers to migrate to next generation networks with no change to their applications
- Over-the-air updates

HEAT Equipment Specification Sheets—Legacy

• SYSTEM-10-BAC-IP BTU METER •
BACnet/IP COMPATIBLE

ONICON INCORPORATED

DESCRIPTION

The System-10 BTU Meter provides highly accurate thermal energy measurement in chilled water, hot water and condenser water systems based on signal inputs from two matched temperature sensors (included) and any of ONICON's insertion or in-line flow meters (ordered separately). The System-10-BAC-IP provides energy flow and temperature data on a local alphanumeric display and to the BACnet/IP network via the BACnet/IP communications driver. An optional auxiliary input is also available to totalize pulses from another device and communicates the total directly to the BACnet/IP network.

APPLICATIONS

Chilled water, hot water and condenser water systems for:

- Commercial office tenant billing
- Central plant monitoring
- University campus monitoring
- Institutional energy cost allocation
- Performance/efficiency evaluations
- Performance contracting energy monitoring

FEATURES

BACnet Compatible Serial Communications - Provides complete energy, flow and temperature data to the control system through a single BACnet/IP network connection, reducing installation costs.

Simple Installation and Commissioning - Factory programmed and ready for use upon delivery. All process data and programming functions are accessible via front panel display and keypad.

Single Source Responsibility - One manufacturer is responsible for every aspect of the energy measurement process, ensuring component compatibility and overall system accuracy.

N.I.S.T. Traceable Calibration with Certification - Each Btu measurement system is individually calibrated using application specific flow and temperature data and is provided with calibration certifications.

Precision Solid State Temperature Sensors - Custom calibrated and matched to an accuracy better than ±0.15° F over calibrated range.

A Variety of Accurate Flow Meters - ONICON has flow meters for every application. In the most demanding applications, the F-3000 series in-line electromagnetic meters offer accuracies of ± 0.2% of reading in limited straight pipe runs. Insertion turbine meters offer outstanding value with ± 1.0% of reading accuracy and are priced independent of pipe size. F-2000 series in-line vortex meters offer ± 1.0% of reading accuracy for very high temperature applications.

Complete Installation Package - All mechanical installation hardware, color coded interconnecting cabling and installation instructions are provided to ensure error-free installation and accurate system performance.

ORDERING INFORMATION

The System-10 BTU Meter is sold complete with temperature sensors and standard thermowells. Flow Meters are purchased separately.

ITEM #	DESCRIPTION
SYSTEM-10-BAC-IP	System-10 BTU Meter BACnet/IP compatible
SYSTEM-10-OPT1	Add for 6" and larger pipes
SYSTEM-10-OPT2	Add for 2.5" - 3" copper tube
SYSTEM-10-OPT3	Add for 4" copper tube
SYSTEM-10-OPT4	Upgrade to outdoor thermowells (pair)
SYSTEM-10-OPT5	Upgrade to hot tap thermowells (pair)
SYSTEM-10-OPT8	High temperature sensors (over 200° F)
SYSTEM-10-OPT9	Add one analog output
SYSTEM-10-OPT10	Add four analog outputs
SYSTEM-10-OPT11	Auxiliary pulse input
Choose from the following flow meters:	
F-1100/F-1200	Insertion Turbine Flow Meter (1¼"-72")
F-1300	Inline Turbine Flow Meter (¾" - 1")
F-2000 Series	Full Bore Vortex Flow Meter
F-3000 Series	Full Bore Electromagnetic Flow Meter
Refer to catalog for flow meter installation kits. Consult with ONICON for additional flow meter types.	

UL LISTED
PROCESS CONTROL EQUIPMENT
3GF5

1500 North Belcher Road, Clearwater, Florida 33765 Tel (727) 447-6140 Fax (727) 442-5699
www.onicon.com E-mail: sales@onicon.com

SYSTEM-10-BAC-IP BTU METER SPECIFICATIONS

CALIBRATION

Flow meter and temperature sensors are individually calibrated, followed by a complete system calibration.
Field commissioning is also available.

ACCURACY

Differential temperature accuracy ±0.15° F over calibrated range
Computing nonlinearity within ±0.05%

PROGRAMMING

Factory programmed for specific application
Field programmable via front panel interface

MEMORY

Non-volatile EEPROM memory retains all program parameters and totalized values in the event of power loss.

DISPLAY

Alphanumeric LCD displays total energy, total flow, energy rate, flow rate, supply temperature and return temperature
Alpha: 16 character, 0.2" high; Numeric: 6 digit, 0.4" high

OUTPUT SIGNALS

BACnet/IP Points List (Complies with Annex J)

Name	BACnet Object Type	Units
Total Energy	Analog Value	Btu, kW-hrs or ton-hrs
Energy Rate	Analog Input	Btu/hr, kW or tons
Total Flow	Analog Value	gallons, liters or meters³
Flow Rate	Analog Input	gpm, gph, mgd, l/s, l/m, l/hr or m³/hr
Supply Temperature	Analog Input	°F or °C
Return Temperature	Analog Input	°F or °C
Delta T	Analog Input	°F or °C
Energy Total Reset	Binary Value	Not applicable
Flow Total Reset	Binary Value	Not applicable
Auxiliary Input Total	Analog Value	Pulse Accumulator
Auxiliary Input Reset	Binary Value	Not applicable

Network Connection: 10BaseT, 10Mbps, RJ45 connection
Isolated solid state dry contact for energy total
Contact rating: 100 mA, 50V
Contact duration: 0.5, 1, 2, or 6 sec
Optional Analog Output(s) (4-20 mA, 0-10 V or 0-5 V):
One or four analog output(s) available for flow rate, energy rate, supply/return temps, or delta-T.

LIQUID FLOW SIGNAL INPUT

0-15 V pulse output from any ONICON flow meter.

TEMPERATURE SENSORS

Solid state sensors are custom calibrated using N.I.S.T. traceable temperature standards.
Current based signal (mA) is unaffected by wire length.

TEMPERATURE RANGE

Liquid temperature range:	32° to 200° F
Optional liquid temperature range:	122° to 302° F
Ambient temperature range:	40° to 120° F

MECHANICAL

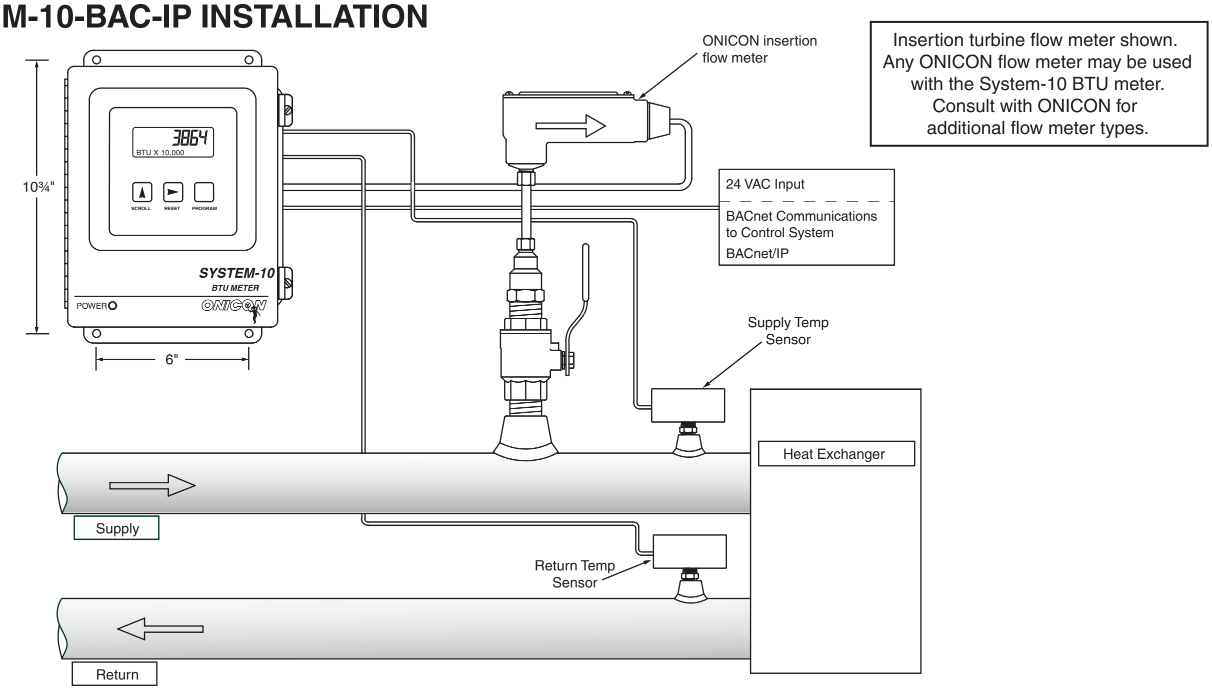
ELECTRONICS ENCLOSURE:
Standard: Steel NEMA 13, wall mount, 8"x10"x4"
Optional: NEMA 4 (Not UL listed)
Approximate weight: 12 lbs.
TEMPERATURE THERMOWELLS:
Standard: ½" NPT brass thermowells (length varies with pipe size) with junction box
Note: 6" pipes and larger require SS thermowell option
Optional:
- ½" NPT stainless steel thermowells
- Outdoor junction box with thermal isolation
- Hot tap thermowells with isolation valves are available in plated brass or stainless steel

ELECTRICAL

INPUT POWER*:
Standard: 24 VAC 50/60 Hz, 300 mA
Optional: 120 VAC 50/60 Hz, 200 mA
230 VAC, 50 Hz, 150 mA
*Based on Btu meters configured for network connection without the optional analog outputs
INTERNAL SUPPLY:
Provides 24 VDC at 200 mA to electronics and flow meter
WIRING:
Temperature signals: Use 18 - 22 ga twisted shielded pair
Flow signals: Use 18 - 22 ga shielded - see flow meter specification sheet for number of conductors

NOTE: Specifications are subject to change without notice.

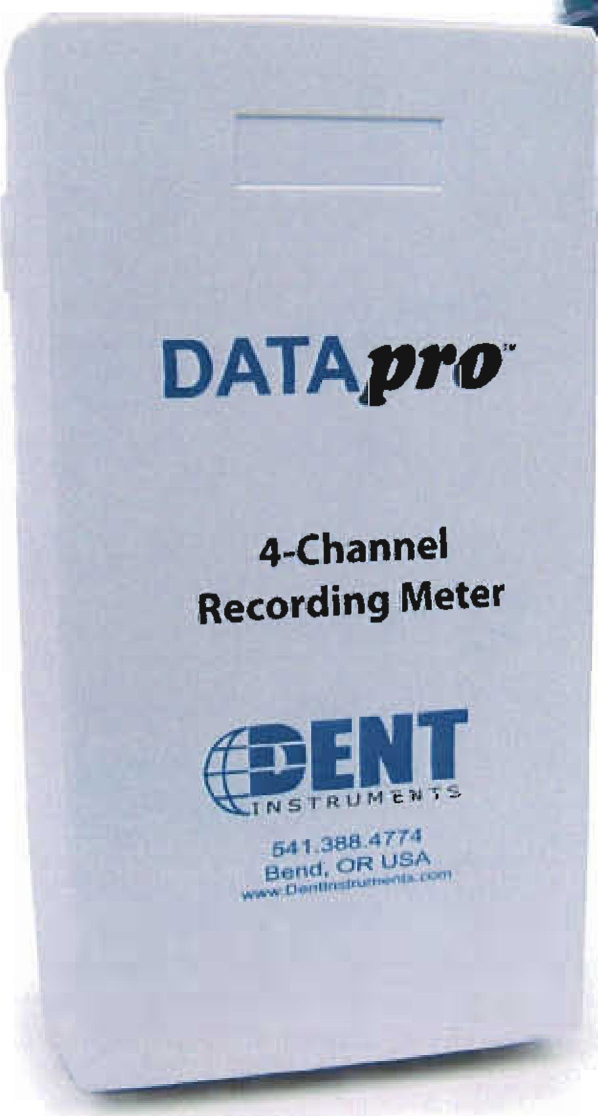
TYPICAL SYSTEM-10-BAC-IP INSTALLATION



1500 North Belcher Road, Clearwater, Florida 33765 Tel (727) 447-6140 Fax (727) 442-5699
www.onicon.com E-mail: sales@onicon.com
6-22-07

Measure, log and analyze almost anything!

Count pulses, or measure temperature, control & process signals, AC current and much more.



(Actual Size)

One DATApro™ is right for you

Who can use the DATA*pro*? Virtually anyone with a measuring problem. The DATA*pro* series can monitor, store and analyze data from a variety of common sensors, allowing you to make the right decision for your application. Production managers, security supervisors, facilities managers, architects, building owners, meteorologists, researchers, waste management supervisors, and engineers of all types are discovering new applications every day that one of the DATA*pro* Recording Meters can address. It's that versatile!

Applications

A growing family of DATA*pro* models is available to meet almost any measuring need. Virtually any utility – gas, water, electric, steam, HVAC, compressed air, solid or liquid waste – can be recorded. One DATA*pro* model will correlate utility consumption with inside or outside temperature, while others can measure and record data from manufacturing processes or environmental changes. With the ability to accept pulses and inputs such as 4-20mA, 0-10VDC, temperature, or AC current, one DATA*pro* model is right for you.

DENT INSTRUMENTS
www.DentInstruments.com

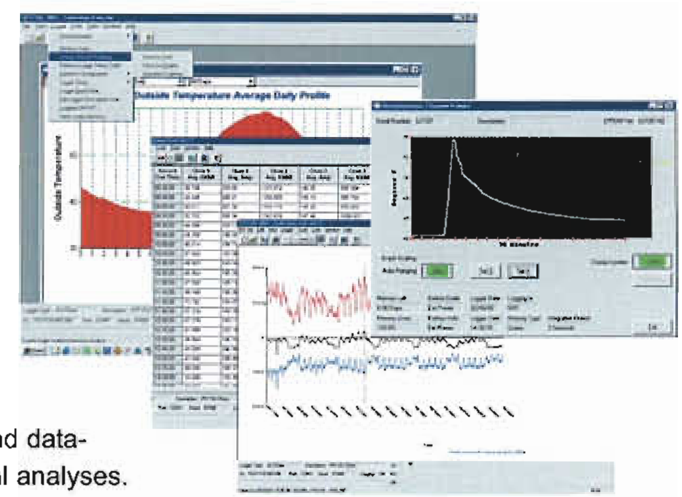
Multi-Purpose Recording Meter

Easy Installation

Installation and connection are both a breeze. Magnetic strips on the housing facilitate mounting on metal cabinets, and a simple 8-position port connects all external inputs. You supply the sensor; we supply the Recorder.

State of the Art Software

The ELOG software is used to program the meter, display metered values, retrieve and analyze the data. The Windows™ software graphically displays recorded data, performs analyses and allows automatic, remote data collection. Data is also easily exported to popular spreadsheets and databases for special analyses.



Versatile Options

A variety of options will suit your situation:

Modem - For long-term monitoring applications an internal modem is available. The modem can be programmed to automatically download data or used to read real-time values.

Weatherproof - A custom housing is dust and liquid resistant, allowing the unit to operate in harsh, wet and outdoor environments.

High Memory - This is the option you want when recording lots of data. Capacity is quadrupled to store up to 100,000 records between downloads.

4 Channel DATA*pro* Models

4V - 4 Voltage channels (0-10 Vdc)

4C - 4 Current channels

4P - 4 Pulse channels

4T - 4 Temperature channels

1T/3P - 1 Temperature, 3 pulse

2T/2P - 2 Temperature, 2 pulse

4M - 4 Milliamp (4-20mA or 0-25mA)

There's a DATApro model for every application

Specifications

Inputs	4 channels of AC current, DC voltage, DC milliamps, pulse count, or temperature
Measurements	Min, Max, Average, Total
Frequency	10 Hz (pulse) and 50 or 60 Hz (current)
Accuracy	<1% of reading, exclusive of sensor accuracy
Baud Rate	Up to 57,600 (direct) or 14,400 (modem)
Resolution	Better than .1% FS for all parameters; 12 bit A/D (1 part in 4,096)
Memory	128kB (25,000 readings) or 512kB (100,000 readings)
Sampling Frequency	7.68 kHz (128 points per current waveform) or 10 Hz, interrupt driven
Recording Intervals	3, 15, 30 seconds; 1, 2, 5, 10, 15, 20, 30 minutes and 1, 12, 24 hrs.
Real Time Clock	Crystal controlled, true calendar, 20 ppm accuracy (<1 min/month)
Battery Life	3 years @ 1 min. sampling, LED indicator of low battery
Operating Temp.	-7 to 60 °C (20 to 140 °F)
Operating Humidity	5% to 95% non-condensing
Dimensions	8 x 15 x 6 cm (3.2" x 5.9" x 2.4")
Weight	340 gm (12 ounces)

DENT INSTRUMENTS
64 NW Franklin Ave. • Bend, OR 97701-2906 USA • Phone: 541.388.4774 • Fax: 541.385.9333

• F-1211 DUAL TURBINE •
INSERTION FLOW METER
ISOLATED ANALOG OUTPUT

Made in the USA

DESCRIPTION

ONICON insertion turbine flow meters are suitable for measuring electrically conductive water-based liquids. The F-1211 model provides isolated 4-20 mA and 0-10 V analog output signals that are linear with the flow rate.

APPLICATIONS

- Chilled water, hot water, condenser water, and water/glycol/brine for HVAC
- Process water and water mixtures
- Domestic water

GENERAL SPECIFICATIONS

ACCURACY
± 0.5% OF READING at calibrated velocity
± 1% OF READING from 3 to 30 ft/s (10:1 range)
± 2% OF READING from 0.4 to 20 ft/s (50:1 range)

SENSING METHOD
Electronic impedance sensing
(non-magnetic and non-photoelectric)

PIPE SIZE RANGE
2½" through 72" nominal

SUPPLY VOLTAGE
24±4 V AC/DC at 100 mA

LIQUID TEMPERATURE RANGE
Standard: 180˚ F continuous, 200˚ F peak
High Temp: 280˚ F continuous, 300˚ F peak
Meters operating above 250˚ F require
316 stainless steel construction option

AMBIENT TEMPERATURE RANGE
-5 to 160˚ F (-20 to 70˚ C)

OPERATING PRESSURE
400 PSI maximum

PRESSURE DROP
Less than 1 PSI at 20 ft/s in 2½" pipe,
decreasing in larger pipes and lower velocities

OUTPUT SIGNALS PROVIDED:

ANALOG OUTPUT (ISOLATED)
Voltage output: 0-10 V (0-5 V available)
Current output: 4-20 mA

FREQUENCY OUTPUT
0-15 V peak pulse, typically less than 300 Hz

(continued on back)

CALIBRATION

Every ONICON flow meter is wet-calibrated in our flow laboratory against primary volumetric standards directly traceable to NIST. Certification of calibration is included with every meter.

FEATURES

Unmatched Price vs. Performance - Custom calibrated, highly accurate instrumentation at very competitive prices.

Excellent Long-term Reliability - Patented electronic sensing is resistant to scale and particulate matter. Low mass turbines with engineered jewel bearing systems provide a mechanical system that virtually does not wear.

Industry Leading Two-year "No-fault" Warranty - Reduces start-up costs with extended coverage to include accidental installation damage (miswiring, etc.). Certain exclusions apply; see our complete warranty statement for details.

Installation Flexibility - Patented dual turbine models deliver outstanding accuracy in short pipe runs.

Simplified Hot Tap Insertion Design - Standard on every insertion flow meter. Allows for insertion and removal by hand without system shutdown.

OPERATING RANGE FOR
COMMON PIPE SIZES
0.17 TO 20 ft/s
± 2% accuracy begins at 0.4 ft/s

Pipe Size (Inches)	Flow Rate (GPM)
2½	2.5 - 230
3	4 - 460
4	8 - 800
6	15 - 1800
8	26 - 3100
10	42 - 4900
12	60 - 7050
14	72 - 8600
16	98 - 11,400
18	120 - 14,600
20	150 - 18,100
24	230 - 26,500
30	360 - 41,900
36	510 - 60,900

1500 North Belcher Road, Clearwater, Florida 33765 Tel (727) 447-6140 Fax (727) 442-5699
www.onicon.com E-mail: sales@onicon.com

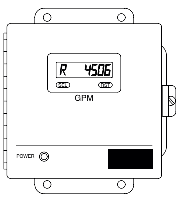
F-1211 SPECIFICATIONS cont.

MATERIAL
Wetted metal components
Standard: Electroless nickel plated brass
Optional: 316 stainless steel

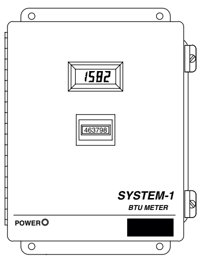
ELECTRONICS ENCLOSURE
Standard: Weathertight aluminum enclosure
Optional: Submersible enclosure

ELECTRICAL CONNECTIONS
4-wire minimum for 4-20 mA or 0-10 V output
Second analog output and/or frequency output requires additional wires
Standard: 10' of cable with ½" NPT conduit connection
Optional: Indoor DIN connector with 10' of plenum rated cable

ALSO AVAILABLE



Display Modules



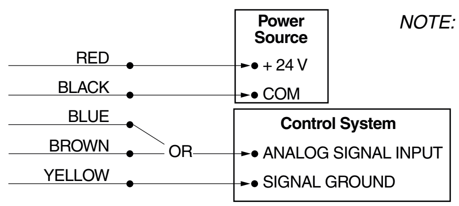
BTU Measurement Systems

F-1211 Wiring Information

WIRE COLOR CODE		NOTES
RED	(+) 24 V AC/DC supply voltage, 100 mA	Connect to power supply positive
BLACK	(–) Common ground (Common with pipe ground)	Connect to power supply negative
GREEN	(+) Frequency output signal: 0-15 V peak pulse	Required when meter is connected to local display or BTU meter
BLUE	(+) Analog signal: 4-20 mA (isolated)	Use yellow wire as (–) for these signals. Both signals may be used independently.
BROWN	(+) Analog signal: 0-10 V (isolated)	
YELLOW	(–) Isolated ground	Use for analog signals only
DIAGNOSTIC SIGNALS		
ORANGE	Bottom turbine frequency	These signals are for diagnostic purposes - connect to local display or BTU Meter
WHITE	Top turbine frequency	

F-1211 Wiring Diagram

Flow Meter into Control System (No Display or BTU Meter)

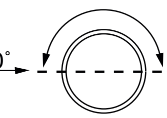


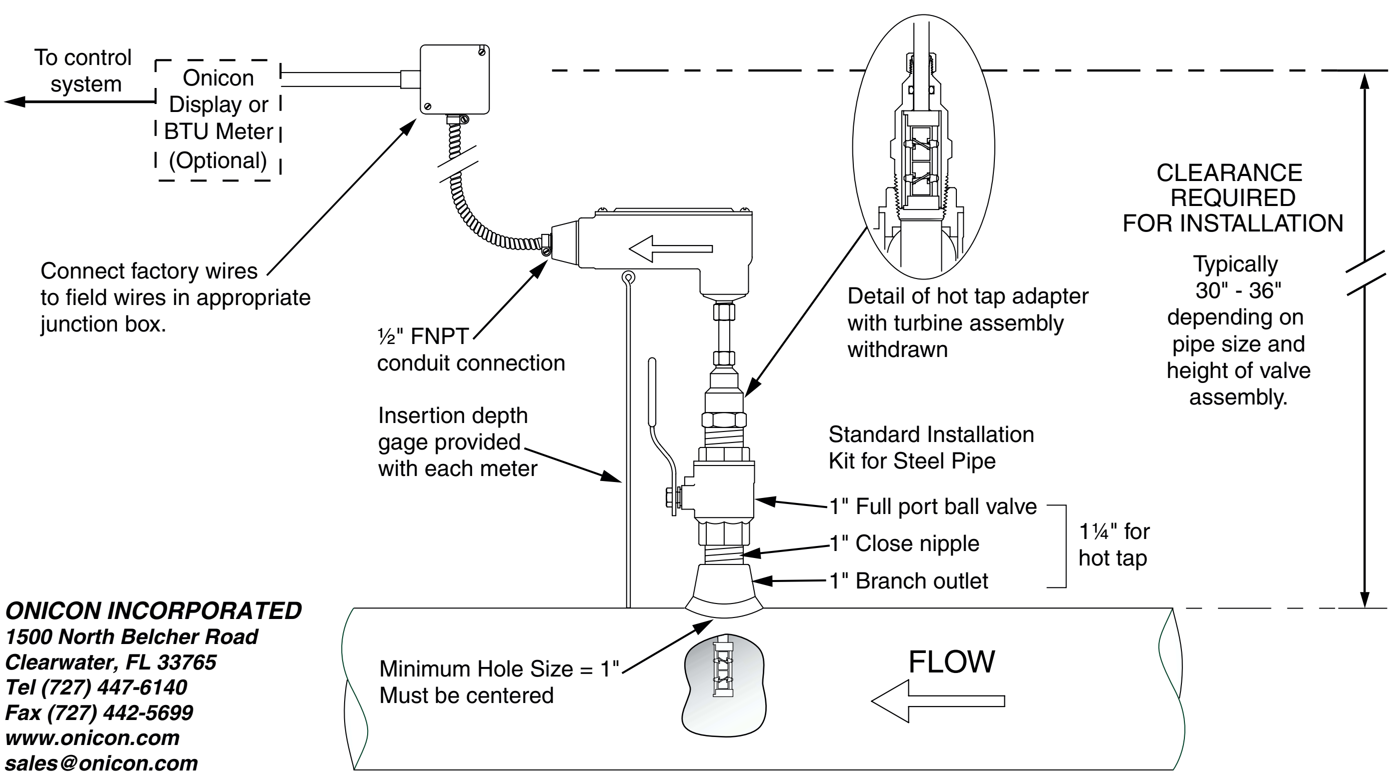
NOTE: 1. Black wire is common with the pipe ground (typically earth ground).
2. Frequency output required for ONICON display module or BTU meter, refer to wiring diagram for peripheral device.

Typical Meter Installation

(New construction or scheduled shutdown)

- Acceptable to install in vertical pipe
- Position meter anywhere in upper 180˚ for horizontal pipe





ONICON INCORPORATED
1500 North Belcher Road
Clearwater, FL 33765
Tel (727) 447-6140
Fax (727) 442-5699
www.onicon.com
sales@onicon.com

Note: Installation kits vary based on pipe material and application. For installations in pressurized (live) systems, use "Hot tap" 1¼ inch installation kit and drill hole using a 1 inch wet tap drill.

Appendix F

Legislation and Regulation

Assembly Bill 578

BILL NUMBER: AB 578 CHAPTERED
BILL TEXT

CHAPTER 627
FILED WITH SECRETARY OF STATE SEPTEMBER 30, 2008
APPROVED BY GOVERNOR SEPTEMBER 30, 2008
PASSED THE SENATE AUGUST 22, 2008
PASSED THE ASSEMBLY AUGUST 28, 2008
AMENDED IN SENATE AUGUST 18, 2008
AMENDED IN SENATE JULY 14, 2008
AMENDED IN SENATE JULY 12, 2007
AMENDED IN ASSEMBLY JUNE 1, 2007
AMENDED IN ASSEMBLY APRIL 16, 2007
AMENDED IN ASSEMBLY APRIL 9, 2007

INTRODUCED BY Assembly Members Blakeslee and Levine

FEBRUARY 21, 2007

An act to amend Section 25783 of the Public Resources Code, and to add Section 321.7 to the Public Utilities Code, relating to energy.

LEGISLATIVE COUNSEL'S DIGEST

AB 578, Blakeslee. Energy: distributed energy generation: study.
(1) Existing law requires the State Energy Resources Conservation and Development Commission (Energy Commission), in consultation with the Public Utilities Commission (PUC), to evaluate the costs and benefits of having an increased number of operational solar energy systems as part of the electrical system.
This bill would delete this requirement.
(2) Under the existing Public Utilities Act, the PUC is required to report to the Legislature by July 15, 2009, and triennially thereafter, on the energy efficiency and conservation programs overseen by the PUC, as specified.
This bill would require the PUC, on or before January 1, 2010, and biennially thereafter, in consultation with the Independent System Operator and the Energy Commission, to study, and submit a report to the Legislature and the Governor, on the impacts of distributed energy generation on the state's distribution and transmission grid. The bill would require the PUC to specifically assess the impacts of the California Solar Initiative program, the self-generation incentive program, and the biogas customer-generator net energy metering pilot program.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Section 25783 of the Public Resources Code is amended to read:
25783. The commission shall do all the following:
(a) Publish educational materials designed to demonstrate how builders may incorporate solar energy systems during construction as well as energy efficiency measures that best complement solar energy systems.
(b) Develop and publish the estimated annual electrical generation and savings for solar energy systems. The estimates shall vary by climate zone, type of system, size, life cycle costs, electricity

prices, and other factors the commission determines to be relevant to a consumer when making a purchasing decision.

(c) Provide assistance to builders and contractors. The assistance may include technical workshops, training, educational materials, and related research.

(d) The commission shall annually conduct random audits of solar energy systems to evaluate their operational performance.

SEC. 2. Section 321.7 is added to the Public Utilities Code, to read:

321.7. (a) On or before January 1, 2010, and biennially thereafter, the commission, in consultation with the Independent System Operator and the State Energy Resources Conservation and Development Commission, shall study, and submit a report to the Legislature and the Governor, on the impacts of distributed energy generation on the state's distribution and transmission grid. The study shall evaluate all of the following:

(1) Reliability and transmission issues related to connecting distributed energy generation to the local distribution networks and regional grid.

(2) Issues related to grid reliability and operation, including interconnection, and the position of federal and state regulators toward distributed energy accessibility.

(3) The effect on overall grid operation of various distributed energy generation sources.

(4) Barriers affecting the connection of distributed energy to the state's grid.

(5) Emerging technologies related to distributed energy generation interconnection.

(6) Interconnection issues that may arise for the Independent System Operator and local distribution companies.

(7) The effect on peak demand for electricity.

(b) In addition, the commission shall specifically assess the impacts of the California Solar Initiative program, specified in Section 2851 and Section 25783 of the Public Resources Code, the self-generation incentive program authorized by Section 379.6, and the net energy metering pilot program authorized by Section 2827.9.

Assembly Bill 970

BILL NUMBER: AB 970 CHAPTERED
BILL TEXT

CHAPTER 329
FILED WITH SECRETARY OF STATE SEPTEMBER 7, 2000
APPROVED BY GOVERNOR SEPTEMBER 6, 2000
PASSED THE SENATE AUGUST 31, 2000
PASSED THE ASSEMBLY AUGUST 31, 2000
AMENDED IN SENATE AUGUST 31, 2000
AMENDED IN SENATE AUGUST 7, 2000
AMENDED IN SENATE JUNE 26, 2000
AMENDED IN SENATE JULY 6, 1999
AMENDED IN ASSEMBLY APRIL 27, 1999

INTRODUCED BY Assembly Members Ducheny, Battin, and Keeley
(Principal coauthor: Assembly Member Baugh)
(Coauthors: Assembly Members Aanestad, Ackerman, Baldwin, Bates, Brewer, Campbell, Cardoza, Cox, Davis, Dickerson, Gallegos, Granlund, House, Kaloogian, Leach, Machado, Maddox, Maldonado, Margett, Nakano, Olberg, Oller, Rod Pacheco, Pescetti, Runner, Strickland, Thompson, and Zettel)
(Coauthors: Senators Alpert, Bowen, and Kelley)

FEBRUARY 25, 1999

An act to add and repeal Section 12078 of the Government Code, to add and repeal Section 42301.14 of the Health and Safety Code, to add Chapter 6.5 (commencing with Section 25550) to Division 15 of, and to repeal Sections 25550, 25552, and 25555 of, the Public Resources Code, and to amend Section 372 of, and to add Section 399.15 to, the Public Utilities Code, relating to energy resources, making an appropriation therefor, and declaring the urgency thereof, to take effect immediately.

LEGISLATIVE COUNSEL'S DIGEST

AB 970, Ducheny. Electrical energy: thermal powerplants: permits.

Existing law provides for the restructuring of California's electric power industry so that the price for the generation of electricity is determined by a competitive market.

Under existing law, air pollution control districts, air quality management districts, and the State Energy Resources Conservation and Development Commission issue permits for the operation of powerplants.

This bill would authorize those districts to issue a temporary, expedited, consolidated permit for a thermal powerplant if specified conditions are met, and would require the commission to establish a process for the expedited review of applications to construct and operate powerplants and thermal powerplants and related facilities.

This bill would require the Public Utilities Commission to identify and undertake certain actions to reduce or remove constraints on the electrical transmission and distribution system, and adopt specified energy conservation initiatives and undertake efforts to revise, mitigate, or eliminate specified policies or actions of the Independent System Operator for which the Public Utilities Commission or Electricity Oversight Board make a specified finding.

The bill would appropriate $57,500,000 from the General Fund for purposes of the bill. Of that amount, $5,200,000 would be allocated to fund specified staff resources to implement specified programs at the commission, the agencies, boards, and departments within the California Environmental Protection Agency, and the Resources Agency; $2,300,000 would be allocated to the Public Utilities Commission to fund specified staff resources, and $50,000,000 would be allocated to the commission to implement energy conservation and demand-side energy programs.

The bill would declare that it is to take effect immediately as an urgency statute.

Appropriation: yes.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. This act shall be known, and may be cited, as the California Energy Security and Reliability Act of 2000.

SEC. 2. The Legislature finds and declares as follows:

(a) In recent years there has been significant growth in the demand for electricity in the state due to factors such as growth in population and economic activities that rely on electrical generation.

(b) In the past decade, efforts to construct and operate new, environmentally superior and efficient generation facilities and to promote cost-effective energy conservation and demand-side management have seriously lagged.

(c) As a result, California faces potentially serious electricity shortages over the next two years, which necessitates immediate action by the state.

(d) The purpose of this act is to provide a balanced response to the electricity problems facing the state that will result in significant new investments in new, environmentally superior electricity generation, while also making significant new investments in conservation and demand-side management programs in order to meet the energy needs of the state for the next several years.

(e) It is further the intent of this act to provide assistance to persons proposing to construct electrical generation facilities without in any manner compromising environmental protection.

SEC. 3. Section 12078 is added to the Government Code, to read:

12078. (a) There is hereby established the Governor's Clean Energy GREEN TEAM, which shall consist of a chairperson and not more than 15 members as follows:

(1) The Chair of the Electricity Oversight Board.

(2) The President of the California Public Utilities Commission.

(3) The Chair of the Energy Resources Conservation and Development Commission.

(4) The Secretary for Environmental Protection.

(5) The Secretary of the Resources Agency.

(6) The Secretary of the Trade and Commerce Agency.

(7) The director of the Governor's Office of Planning and Research.

(8) Representatives from the United States Environmental Protection Agency, the United States Fish and Wildlife Service, and other affected federal agencies appointed by the Governor.

(9) Representatives of local and regional agencies, including, but not limited to, air pollution control districts and air quality management districts appointed by the Governor.

(b) Within 90 days of the effective date of this section, the

GREEN TEAM shall do all of the following:

(1) Compile and, upon request, make available to persons proposing to construct powerplants, all available guidance documents and other information on the environmental effects associated with powerplants proposed to be certified pursuant to Division 15 (commencing with Section 25000) of the Public Resources Code, and including state-of-the-art and best available control technologies and air emissions offsets that could be used to mitigate those environmental effects.

(2) Upon request, provide assistance to persons proposing to construct powerplants in obtaining essential inputs, including, but not limited to, natural gas supply, emission offsets, and necessary water supply.

(3) Upon request, provide assistance to persons proposing to construct powerplants pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code in identifying the environmental effects of such powerplants and any actions the person may take to mitigate those effects.

(4) Upon request, provide assistance to persons proposing to construct powerplants in working with local governments in ensuring that local permits, land use authorizations, and other approvals made at the local level are undertaken in the most expeditious manner feasible without compromising public participation or environmental protection.

(5) Develop recommendations for low- or zero-interest financing programs for renewable energy, including distributed renewable energy for state and nonprofit corporations.

(c) This section shall remain in effect only until January 1, 2004, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2004, deletes or extends that date.

SEC. 4. Section 42301.14 is added to the Health and Safety Code, to read:

42301.14. (a) To the extent permitted by the federal Clean Air Act (42 U.S.C. Sec. 7401 et seq.), and notwithstanding Section 65950 of the Government Code, a district may issue a temporary, expedited, consolidated permit, as provided by Sections 42300.1 and 42301.3, for a powerplant within 60 days after the date of certification of an environmental impact report, within 30 days after the adoption of a negative declaration, or within 30 days after the date of a determination that the project is exempt from Division 13 (commencing with Section 21000) of the Public Resources Code, if all of the following conditions are met:

(1) The powerplant will emit less than 5 parts per million of oxides of nitrogen averaged over a three-hour period.

(2) The powerplant will operate exclusively under the terms of a contract entered into with the Independent System Operator and approved by the Electricity Oversight Board established pursuant to Article 2 (commencing with Section 334) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code.

(3) The owner or operator of the powerplant shall demonstrate that the powerplant, on average, will displace electrical generation that produces greater air emissions in the same air basin or in a basin that causes air pollution transport into that basin.

(4) The powerplant will be interconnected to the grid in a manner that the Public Utilities Commission, in consultation with the Electricity Oversight Board, has determined will allow the powerplant to provide service to a geographical area of the state that is urgently in need of generation in order to provide reliable electric service. However, nothing in this paragraph affects the authority of

the Energy Resources Conservation and Development Commission over powerplants pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code.

(5) The powerplant will be operated at a location that has the necessary fueling and electrical transmission and distribution infrastructure for its operation.

(6) The owner or operator of the powerplant enters into a binding and enforceable agreement with the district, and where applicable, with the Energy Resources Conservation and Development Commission, which demonstrates either of the following:

(A) That the powerplant will cease to operate and the permit will terminate within three years.

(B) That the powerplant will be modified, replaced, or removed within a period of three years with a combined-cycle powerplant that uses best available control technology and offsets, as determined at the time the combined-cycle plant is constructed, and that complies with all other applicable laws and regulations.

(7) Where applicable, the owner or operator of the powerplant will obtain offsets or, where offsets are unavailable, pay an air emissions mitigation fee to the district based upon the actual emissions from the powerplant, to the district for expenditure by the district pursuant to Chapter 9 (commencing with Section 44275) of Part 5, to mitigate the emissions from the plant.

(8) It is the intent of the Legislature in this section to encourage the expedited siting of cleaner generating units to address peaking power needs. It is further the intent of the Legislature to require local air quality management districts and air pollution control districts to recognize the critical need for these facilities and the short life span of these facilities in exercising their discretionary authority to apply more restrictive air quality regulations than would otherwise be required by law.

(b) This section may be utilized for the purpose of expediting the siting of electrical generating facilities pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code.

(c) This section shall remain in effect only until January 1, 2004, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2004, deletes or extends that date.

SEC. 5. Chapter 6.5 (commencing with Section 25550) is added to Division 15 of the Public Resources Code, to read:

CHAPTER 6.5. EXPEDITED SITING OF ELECTRICAL GENERATION

25550. (a) Notwithstanding subdivision (a) of Section 25522, and Section 25540.6 the commission shall establish a process to issue its final certification for any thermal powerplant and related facilities within six months after the filing of the application for certification that, on the basis of an initial review, shows that there is substantial evidence that the project will not cause a significant adverse impact on the environment or electrical system and will comply with all applicable standards, ordinances, or laws. For purposes of this section, filing has the same meaning as in Section 25522.

(b) Thermal powerplants and related facilities reviewed under this process shall satisfy the requirements of Section 25520 and other necessary information required by the commission, by regulation, including the information required for permitting by each local, state, and regional agency that would have jurisdiction over the proposed thermal powerplant and related facilities but for the exclusive jurisdiction of the commission and the information required for permitting by each federal agency that has jurisdiction over the proposed thermal powerplant and related facilities.

(c) After acceptance of an application under this section, the commission shall not be required to issue a six-month final decision on the application if it determines there is substantial evidence in the record that the thermal powerplant and related facilities may result in a significant adverse impact on the environment or electrical system or does not comply with an applicable standard, ordinance, or law. Under this circumstance, the commission shall make its decision in accordance with subdivision (a) of Section 25522 and Section 25540.6, and a new application shall not be required.

(d) For an application that the commission accepts under this section, all local, regional, and state agencies that would have had jurisdiction over the proposed thermal powerplant and related facilities, but for the exclusive jurisdiction of the commission, shall provide their final comments, determinations, or opinions within 100 days after the filing of the application. The regional water quality control boards, as established pursuant to Chapter 4 (commencing with Section 13200) of Division 7 of the Water Code, shall retain jurisdiction over any applicable water quality standard that is incorporated into any final certification issued pursuant to this chapter.

(e) Thermal powerplants and related facilities that demonstrate superior environmental or efficiency performance shall receive priority in review.

(f) With respect to a thermal powerplant and related facilities reviewed under the process established by this chapter, it shall be shown that the applicant has a contract with a general contractor and has contracted for an adequate supply of skilled labor to construct, operate, and maintain the plant.

(g) With respect to a thermal powerplant and related facilities reviewed under the process established by this chapter, it shall be shown that the thermal powerplant and related facilities complies with all regulations adopted by the commission that ensure that an application addresses disproportionate impacts in a manner consistent with Section 65040.12 of the Government Code.

(h) This section shall not apply to an application filed with the commission on or before August 1, 1999.

(i) To implement this section, the commission may adopt emergency regulations in accordance with Chapter 3.5 (commencing with Section 11340) of Part 2 of Division 3 of Title 2 of the Government Code. For purposes of that chapter, including without limitation, Section 11349.6 of the Government Code, the adoption of the regulations shall be considered by the Office of Administrative Law to be necessary for the immediate preservation of the public peace, health, safety, and general welfare.

(j) This section shall remain in effect until January 1, 2004, and as of that date is repealed unless a later enacted statute, that is enacted before January 1, 2004, deletes or extends that date.

25552. (a) The commission shall implement a procedure, consistent with Division 13 (commencing with Section 21000) and with the federal Clean Air Act (42 U.S.C.A. Sec. 7401 et seq.), for an expedited decision on simple cycle thermal powerplants and related facilities that can be put into service on or before August 1, 2001, including a procedure for considering amendments to a pending application if the amendments specify a change from a combined cycle thermal powerplant and related facilities to a simple cycle thermal powerplant and related facilities.

(b) The procedure shall include all of the following:

(1) A requirement that, within 15 days of receiving the application or amendment to a pending application, the commission shall determine whether the application is complete.

(2) A requirement that, within 25 days of determining that an application is complete, the commission shall determine whether the application qualifies for an expedited decision pursuant to this section. If an application qualifies for an expedited decision pursuant to this section, the commission shall provide the notice required by Section 21092.

(c) The commission shall issue its final decision on an application, including an amendment to a pending application, within four months from the date on which it deems the application or amendment complete, or at any later time mutually agreed upon by the commission and the applicant, provided that the thermal powerplant and related facilities remain likely to be in service before or during August 2001.

(d) The commission shall issue a decision granting a license to a simple cycle thermal powerplant and related facilities pursuant to this section if the commission finds all of the following:

(1) The thermal powerplant is not a major stationary source or a modification to a major stationary source, as defined by the federal Clean Air Act, and will be equipped with best available control technology, in consultation with the appropriate air pollution control district or air quality management district and the State Air Resources Board.

(2) The thermal powerplant and related facilities will not have a significant adverse effect on the environment as a result of construction or operation.

(3) With respect to a project for a thermal powerplant and related facilities reviewed under the process established by this section, the applicant has a contract with a general contractor and has contracted for an adequate supply of skilled labor to construct, operate, and maintain the thermal powerplant.

(e) In order to qualify for the procedure established by this section, an application or an amendment to a pending application shall be complete by October 31, 2000, satisfy the requirements of Section 25523, and include a description of the proposed conditions of certification that will do all of the following:

(1) Assure that the thermal powerplant and related facilities will not have a significant adverse effect on the environment as a result of construction or operation.

(2) Assure protection of public health and safety.

(3) Result in compliance with all applicable federal, state, and local laws, ordinances, and standards.

(4) A reasonable demonstration that the thermal powerplant and related facilities, if licensed on the expedited schedule provided by this section, will be in service before August 1, 2001.

(5) A binding and enforceable agreement with the commission, that demonstrates either of the following:

(A) That the thermal powerplant will cease to operate and the permit will terminate within three years.

(B) That the thermal powerplant will be modified, replaced, or removed within a period of three years with a combined-cycle thermal powerplant that uses best available control technology and obtains necessary offsets, as determined at the time the combined-cycle thermal powerplant is constructed, and that complies with all other applicable laws, ordinances, and standards.

(6) Where applicable, that the thermal powerplant will obtain offsets or, where offsets are unavailable, pay an air emissions mitigation fee to the air pollution control district or air quality

management district based upon the actual emissions from the thermal powerplant, to the district for expenditure by the district pursuant to Chapter 9 (commencing with Section 44275) of Part 5 of Division 26 of the Health and Safety Code, to mitigate the emissions from the plant. To the extent consistent with federal law and regulation, any offsets required pursuant to this paragraph shall be based upon a 1:1 ratio, unless, after consultation with the applicable air pollution control district or air quality management district, the commission finds that a different ratio should be required.

(7) Nothing in this section shall affect the ability of an applicant that receives approval to install simple cycle thermal powerplants and related facilities as an amendment to a pending application to proceed with the original application for a combined cycle thermal powerplant or related facilities.

(f) This section shall remain in effect only until January 1, 2003, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2003, deletes or extends that date except that the binding commitments in paragraph (5) of subdivision (e) shall remain in effect after that date.

25553. Notwithstanding any other provision of law, on or before 120 days after the effective date of this section or on the earliest feasible date thereafter, the commission shall take both of the following actions:

(a) Update its assessment in trends in energy consumption pursuant to Section 25216 in order to provide the Governor, the Legislature, and the public with accurate information on the status of electricity supply, demand, and conservation in the state and to recommend measures that could be undertaken to ensure adequate supply and energy conservation in the state.

(b) Adopt and implement updated and cost-effective standards pursuant to Section 25402 to ensure the maximum feasible reductions in wasteful, uneconomic, inefficient, or unnecessary consumption of electricity.

25555. (a) In consultation with the Public Utilities Commission, the commission shall implement the peak electricity demand reduction grant programs listed in paragraphs (1), (2), and (3). The commission's implementation of these programs shall be consistent with guidelines established pursuant to subdivision (b). The award of a grant pursuant to this section is subject to appeal to the commission upon a showing that factors other than those adopted by the commission were applied in making the award. Any action taken by an applicant to apply for, or to become or remain eligible to receive, a grant award, including satisfying conditions specified by the commission, does not constitute the rendering of goods, services, or a direct benefit to the commission. Awards made pursuant to this section are not subject to any repayment requirements of Chapter 7.4 (commencing with Section 25645). The peak electricity demand programs the commission shall implement pursuant to this section shall include, but not be limited to, the following:

(1) For San Francisco Bay Area and San Diego region electricity customers, the peak electricity demand program shall include both of the following:

(A) Incentives for price responsive heating, ventilation, air conditioning, and lighting systems.

(B) Incentives for cool communities.

(2) For statewide electricity customers, the peak electricity demand program shall include all of the following:

(A) Incentives for price responsive heating, ventilation, air conditioning, and lighting systems.

(B) Incentives for cool communities.

(C) Incentives for energy efficiency improvements for public universities and other state facilities.
(D) Funding for state building peak reduction measures.
(E) Incentives for light-emitting diode traffic signals.
(F) Incentives for water and wastewater treatment pump and related equipment retrofits.
(3) Renewable energy development, except hydroelectric development, for both onsite distributed energy development and for commercial scale projects through which awards may be made by the commission to reduce the cost of financing those projects.
(b) In consultation with the Public Utilities Commission, the commission shall establish guidelines for the administration of this section. The guidelines shall enable the commission to allocate funds between the programs as it determines necessary to lower electricity system peak demand. The guidelines adopted pursuant to this subdivision are not regulations subject to the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code.
(c) The commission may choose from among one or more business entities capable of supplying or providing goods or services that meet a specified need of the commission in carrying out the responsibilities for programs included in this section. The commission may select an entity on a sole source basis if the cost to the state will be reasonable and the commission determines that it is in the state's best interest.
(d) The commission shall contract with one or more business entities for evaluation of the effectiveness of the programs implemented pursuant to subdivision (a). The contracting provisions specified in subdivision (c) shall apply to these contracts.
(e) For purposes of this section, the following definitions shall apply:
(1) "Low-rise buildings" means one and two story buildings.
(2) "Price responsive heating, ventilation, air conditioning, and lighting systems" means a program that provides incentives for the installation of equipment that will automatically lower the electricity consumption of these systems when the price of electricity reaches specific thresholds.
(3) "Light-emitting diode traffic signals" means a program to provide incentives to encourage the replacement of incandescent traffic signal lamps with light-emitting diodes.
(4) "Cool communities" means a program to reduce "heat island" effects in urban areas and thereby conserve energy and reduce peak demand.
(5) "Water and wastewater treatment pump retrofit" means a program to provide incentives to encourage the retrofit and replacement of water and wastewater treatment pumps and equipment and installation of energy control systems in order to reduce their electricity consumption during periods of peak electricity system demand.
(f) The commission may expend no more than 3 percent of the amount appropriated to implement this section, for purposes of administering this section.
(g) This section shall remain in effect only until January 1, 2004, and as of that date is repealed, unless a later enacted statute, which is enacted before January 1, 2004, deletes or extends that date.
SEC. 6. Section 372 of the Public Utilities Code is amended to read:
372. (a) It is the policy of the state to encourage and support the development of cogeneration as an efficient, environmentally beneficial, competitive energy resource that will enhance the

reliability of local generation supply, and promote local business growth. Subject to the specific conditions provided in this section, the commission shall determine the applicability to customers of uneconomic costs as specified in Sections 367, 368, 375, and 376. Consistent with this state policy, the commission shall provide that these costs shall not apply to any of the following:

(1) To load served onsite or under an over the fence arrangement by a nonmobile self-cogeneration or cogeneration facility that was operational on or before December 20, 1995, or by increases in the capacity of such a facility to the extent that such increased capacity was constructed by an entity holding an ownership interest in or operating the facility and does not exceed 120 percent of the installed capacity as of December 20, 1995, provided that prior to June 30, 2000, the costs shall apply to over the fence arrangements entered into after December 20, 1995, between unaffiliated parties. For the purposes of this subdivision, "affiliated" means any person or entity that directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common on control with another specified entity. "Control" means either of the following:

(A) The possession, directly or indirectly, of the power to direct or to cause the direction of the management or policies of a person or entity, whether through an ownership, beneficial, contractual, or equitable interest.

(B) Direct or indirect ownership of at least 25 percent of an entity, whether through an ownership, beneficial or equitable interest.

(2) To load served by onsite or under an over the fence arrangement by a nonmobile self-cogeneration or cogeneration facility for which the customer was committed to construction as of December 20, 1995, provided that the facility was substantially operational on or before January 1, 1998, or by increases in the capacity of such a facility to the extent that the increased capacity was constructed by an entity holding an ownership interest in or operating the facility and does not exceed 120 percent of the installed capacity as of January 1, 1998, provided that prior to June 30, 2000, the costs shall apply to over the fence arrangements entered into after December 20, 1995, between unaffiliated parties.

(3) To load served by existing, new, or portable emergency generation equipment used to serve the customer's load requirements during periods when utility service is unavailable, provided such emergency generation is not operated in parallel with the integrated electric grid, except on a momentary parallel basis.

(4) After June 30, 2000, to any load served onsite or under an over the fence arrangement by any nonmobile self-cogeneration or cogeneration facility.

(b) Further, consistent with state policy, with respect to self-cogeneration or cogeneration deferral agreements, the commission shall do the following:

(1) Provide that a utility shall execute a final self-cogeneration or cogeneration deferral agreement with any customer that, on or before December 20, 1995, had executed a letter of intent (or similar documentation) to enter into the agreement with the utility, provided that the final agreement shall be consistent with the terms and conditions set forth in the letter of intent and the commission shall review and approve the final agreement.

(2) Provide that a customer that holds a self-cogeneration or cogeneration deferral agreement that was in place on or before December 20, 1995, or that was executed pursuant to paragraph (1) in the event the agreement expires, or is terminated, may do any of the

following:
(A) Continue through December 31, 2001, to receive utility service at the rate and under terms and conditions applicable to the customer under the deferral agreement that, as executed, includes an allocation of uneconomic costs consistent with subdivision (e) of Section 367.
(B) Engage in a direct transaction for the purchase of electricity and pay uneconomic costs consistent with Sections 367, 368, 375, and 376.
(C) Construct a self-cogeneration or cogeneration facility of approximately the same capacity as the facility previously deferred, provided that the costs provided in Sections 367, 368, 375, and 376 shall apply consistent with subdivision (e) of Section 367, unless otherwise authorized by the commission pursuant to subdivision (c).
(3) Subject to the fire wall described in subdivision (e) of Section 367 provide that the ratemaking treatment for self-cogeneration or cogeneration deferral agreements executed prior to December 20, 1995, or executed pursuant to paragraph (1) shall be consistent with the ratemaking treatment for the contracts approved before January 1995.
(c) The commission shall authorize, within 60 days of the receipt of a joint application from the serving utility and one or more interested parties, applicability conditions as follows:
(1) The costs identified in Sections 367, 368, 375, and 376 shall not, prior to June 30, 2000, apply to load served onsite by a nonmobile self-cogeneration or cogeneration facility that became operational on or after December 20, 1995.
(2) The costs identified in Sections 367, 368, 375, and 376 shall not, prior to June 30, 2000, apply to any load served under over the fence arrangements entered into after December 20, 1995, between unaffiliated entities.
(d) For the purposes of this subdivision, all onsite or over the fence arrangements shall be consistent with Section 218 as it existed on December 20, 1995.
(e) To facilitate the development of new microcogeneration applications, electrical corporations may apply to the commission for a financing order to finance the transition costs to be recovered from customers employing the applications.
(f) To encourage the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources, to improve system reliability for consumers by retaining existing generation and encouraging new generation to connect to the electric grid, and to increase self-sufficiency of consumers of electricity through the deployment of self-generation and cogeneration, both of the following shall occur:
(1) The commission and the Electricity Oversight Board shall determine if any policy or action undertaken by the Independent System Operator, directly or indirectly, unreasonably discourages the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid.
(2) If the commission and the Electricity Oversight Board find that any policy or action of the Independent System Operator unreasonably discourages, the connection of existing self-generationor cogeneration or new self-generation or cogeneration to the grid, the commission and the Electricity Oversight Board shall undertake all necessary efforts to revise, mitigate, or eliminate that policy or action of the Independent System Operator.

SEC. 7. Section 399.15 is added to the Public Utilities Code, to read:

399.15. Notwithstanding any other provision of law, within 180 days of the effective date of this section, the commission, in consultation with the Independent System Operator, shall take all of the following actions, and shall include the reasonable costs involved in taking those actions in the distribution revenue requirements of utilities regulated by the commission, as appropriate:

(a) (1) Identify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, including, but not limited to, reconductoring of transmission lines, the addition of capacitors to increase voltage, the reinforcement of existing transmission capacity, and the installation of new transformer banks. The commission shall, in consultation with the Independent System Operator, give first priority to those geographical regions where congestion reduces or impedes electrical transmission and supply.

(2) Consistent with the existing statutory authority of the commission, the commission shall afford electrical corporations a reasonable opportunity to fully recover costs it determines are reasonable and prudent to plan, finance, construct, operate, and maintain any facilities under its jurisdiction required by this section.

(b) In consultation with the State Energy Resources Conservation and Development Commission, adopt energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods. Those initiatives shall include, but not be limited to, all of the following:

(1) Expansion and acceleration of residential and commercial weatherization programs.

(2) Expansion and acceleration of programs to inspect and improve the operating efficiency of heating, ventilation, and air-conditioning equipment in new and existing buildings, to ensure that these systems achieve the maximum feasible cost-effective energy efficiency.

(3) Expansion and acceleration of programs to improve energy efficiency in new buildings, in order to achieve the maximum feasible reductions in uneconomic energy and peak electricity consumption.

(4) Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during peak electricity demand period.

(5) Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.

(6) Incentives for load control and distributed generation to be paid for enhancing reliability.

(7) Differential incentives for renewable or super clean distributed generation resources.

(8) Reevaluation of all efficiency cost-effectiveness tests in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility.

(c) In consultation with the Energy Resources Conservation and Development Commission, adopt and implement a residential, commercial, and industrial peak reduction program that encourages electric customers to reduce electricity consumption during peak power periods.

SEC. 8. The sum of fifty seven million five hundred thousand dollars ($57,500,000) is hereby appropriated from the General Fund to the State Controller for the following purposes:

(a) Five million two hundred thousand dollars ($5,200,000) to fund temporary staff resources, including, but not limited to, limited term positions, not to exceed four years, at the Energy Resources Conservation and Development Commission, the agencies, boards, and departments within the California Environmental Protection Agency, and the Resources Agency, with jurisdiction over electrical powerplant siting and conservation and demand side management programs, for the exclusive purpose of implementing programs pursuant to this act.

(1) Prior to the expenditure of funds pursuant to this subdivision, the commission shall prepare and submit an expenditure plan to the Governor and the Legislature that specifies those agencies and positions for which those funds will be expended.

(2) It is the intent of the Legislature that these funds for staff resources be expended exclusively to implement programs that achieve the maximum feasible cost-effective energy conservation and efficiency while providing the necessary staff resources to expedite siting of electrical powerplants that meet the criteria established pursuant to the act adding this section.

(b) Two million three hundred thousand dollars ($2,300,000) to the Public Utilities Commission, to fund temporary staff resources, including limited term positions not to exceed four years, and to implement the programs established pursuant to this act.

(c) Fifty million dollars ($50,000,000) to the Energy Resources Conservation and Development Commission, to implement cost-effective energy conservation and demand-side management programs established pursuant to Section 25555 of the Public Resources Code, as enacted by this act. The commission shall prioritize conservation and demand-side management programs funded pursuant to this subdivision to ensure that those programs that achieve the most immediate and cost-effective energy savings are undertaken as a first priority.

SEC. 9. Nothing in this act shall, in any way, apply to a pending application for the certification of the Metcalf Energy Center, which was filed with the State Energy Resources Conservation and Development Commission by Calpine and Bechtel under Docket No. (99-AFC-3).

SEC. 10. This act is an urgency statute necessary for the immediate preservation of the public peace, health, or safety within the meaning of Article IV of the Constitution and shall go into immediate effect. The facts constituting the necessity are:

Due to the shortage of electric generation capacity to meet the needs of the people of this state and in order to limit further impacts of this shortage on the public health, safety, and welfare, it is necessary that this act take effect immediately.

Assembly Bill 1470

BILL NUMBER: AB 1470 CHAPTERED
BILL TEXT

CHAPTER 536
FILED WITH SECRETARY OF STATE OCTOBER 12, 2007
APPROVED BY GOVERNOR OCTOBER 12, 2007
PASSED THE SENATE SEPTEMBER 10, 2007
PASSED THE ASSEMBLY SEPTEMBER 12, 2007
AMENDED IN SENATE SEPTEMBER 5, 2007
AMENDED IN SENATE AUGUST 31, 2007
AMENDED IN SENATE JULY 10, 2007
AMENDED IN SENATE JUNE 26, 2007
AMENDED IN ASSEMBLY JUNE 1, 2007
AMENDED IN ASSEMBLY MAY 2, 2007
AMENDED IN ASSEMBLY APRIL 12, 2007

INTRODUCED BY Assembly Member Huffman
(Principal coauthor: Assembly Member Leno)
(Coauthors: Assembly Members Beall, Carter, DeSaulnier, Krekorian, Laird, Wolk, and Saldana)
(Coauthors: Senators Corbett, Florez, Kuehl, Romero, Scott, and Wiggins)

FEBRUARY 23, 2007

An act to add the heading of Article 1 (commencing with Section 2851) to, and to add and repeal Article 2 (commencing with Section 2860) of, Chapter 9 of Part 2 of Division 1 of, the Public Utilities Code, relating to solar energy.

LEGISLATIVE COUNSEL'S DIGEST

AB 1470, Huffman. Solar energy: Solar Water Heating and Efficiency Act of 2007.

(1) Under existing law, the Public Utilities Commission has regulatory authority over public utilities, including gas corporations. The commission is required to implement elements of the California Solar Initiative, which modifies the self-generation incentive program for distributed generation resources and provides incentives to customer-side photovoltaics and solar thermal electric projects under one megawatt. The commission is required to award monetary incentives for up to the first megawatt of alternating current generated by solar energy systems that meet the eligibility criteria established by the State Energy Resources Conservation and Development Commission (Energy Commission). The commission is required to adopt a performance-based incentive program for solar energy photovoltaic systems and is authorized to award monetary incentives for solar thermal and solar water heating devices in a total amount up to $100,800,000.

This bill would establish the Solar Water Heating and Efficiency Act of 2007. The bill would make findings and declarations of the Legislature relating to the promotion of solar water heating systems and other technologies that reduce natural gas demand. The bill would define several terms for purposes of the act. The bill would require the commission to evaluate the data available from a specified pilot program, and, if it makes a specified determination, to design and implement a program of incentives for the installation of 200,000 solar water heating systems in homes and businesses throughout the state by 2017.

The bill would require the commission, in consultation with the Energy Commission and interested members of the public, to establish eligibility criteria for the solar water heating systems receiving gas customer funded incentives. The commission would be required to establish conditions on those incentives. The bill would specify that, except for the Solar Water Heating Pilot Program in San Diego, only solar water heating technologies that displace electricity are eligible for a portion of California Solar Initiative funds, as determined by the commission.

The commission would be required to allocate not less than 10% of the overall funds for installation of solar water heating systems for specified low-income residential housing . The bill would extend eligibility for funding pursuant to this program to include residential housing occupied by specified ratepayers. The bill would specify that no moneys be diverted from any existing programs for low-income ratepayers. The bill would specify that the consumer rebates decline over time and be structured to reduce the cost of solar water heating technologies. The Energy Commission, in coordination with the commission, would be required to consider, when appropriate, coupling rebates for solar water heating systems with complementary energy efficient technologies. The commission would be required to report to the Legislature, not later than July 1, 2010, on the effectiveness of the program. The bill would repeal these provisions on August 1, 2018.

(2) Existing law establishes a surcharge on all natural gas consumed in the state to fund certain low-income assistance programs, cost-effective energy efficiency and conservation activities, and public interest research and development. Existing law requires a public utility gas corporation, as defined, to collect the surcharge from natural gas consumers, as specified. The moneys from the surcharge are deposited in the Gas Consumption Surcharge Fund and are continuously appropriated to specified entities, including to the commission, or to an entity designated by the commission, to fund low-income assistance programs, cost-effective energy efficiency and conservation activities, and public interest research and development not adequately provided by the competitive and regulated markets.

This bill would require the commission to fund the program of the Solar Water Heating and Efficiency Act of 2007, for the service territories of the gas corporations, through a surcharge applied to gas customers in those service territories based on the amount of natural gas consumed, not to exceed $250,000,000 over the course of the 10-year program. The bill would require the commission to annually establish a surcharge rate for each class of gas customers. The bill would exempt from that surcharge those gas customers participating in the California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA) programs. The bill would require that the program be administered by the gas corporations or 3rd party administrators, as determined by the commission, and subject to the supervision of the commission.

(3) The bill would require the governing body of each publicly owned utility providing gas service to retail end-use gas customers, to adopt, implement, and finance a solar water heating system incentive program meeting certain requirements, thereby imposing a state-mandated local program.

(4) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The heading of Article 1 (commencing with Section 2851) is added to Chapter 9 of Part 2 of Division 1 of the Public Utilities Code, to read:

Article 1. Solar Energy Systems

SEC. 2. Article 2 (commencing with Section 2860) is added to Chapter 9 of Part 2 of Division 1 of the Public Utilities Code, to read:

Article 2. Solar Water Heating Systems

2860. This article shall be known, and may be cited, as the Solar Water Heating and Efficiency Act of 2007.

2861. As used in this article, the following terms have the following meanings:

(a) "Energy Commission" means the State Energy Resources Conservation and Development Commission.

(b) "Gas customer" includes both "core" and "noncore" customers, as those terms are used in Chapter 2.2 (commencing with Section 328) of Part 1, that receive retail end-use gas service within the service territory of a gas corporation.

(c) "kWth" means the kilowatt thermal capacity of a solar water heating system, measured consistent with the standard established by the SRCC.

(d) "kWhth" means kilowatthours thermal as measured by the number of kilowatts thermal generated, or displaced, in an hour.

(e) "Low-income residential housing" means either of the following:

(1) Residential housing financed with low-income housing tax credits, tax-exempt mortgage revenue bonds, general obligation bonds, or local, state, or federal loans or grants, and for which the rents of the occupants who are lower income households, as defined in Section 50079.5 of the Health and Safety Code, do not exceed those prescribed by deed restrictions or regulatory agreements pursuant to the terms of the financing or financial assistance.

(2) A residential complex in which at least 20 percent of the total units are sold or rented to lower income households, as defined in Section 50079.5 of the Health and Safety Code, and the housing units targeted for lower income households are subject to a deed restriction or affordability covenant with a public entity that ensures that the units will be available at an affordable housing cost meeting the requirements of Section 50052.5 of the Health and Safety Code, or at an affordable rent meeting the requirements of Section 50053 of the Health and Safety Code, for a period of not less than 30 years.

(f) "New Solar Homes Partnership" means the 10-year program, administered by the Energy Commission, encouraging solar energy systems in new home construction.

(g) "Solar heating collector" means a device that is used to collect or capture heat from the sun and that is generally, but need not be, located on a roof.

(h) "Solar water heating system" means a solar energy device that has the primary purpose of reducing demand for natural gas through water heating, space heating, or other methods of capturing energy from the sun to reduce natural gas consumption in a home, business, or any building receiving natural gas that is subject to the surcharge established pursuant to Section 2860, or exempt from the surcharge pursuant to subdivision (c) of Section 2863, and that meets or exceeds the eligibility criteria established pursuant to Section 2864. "Solar water heating systems" do not include solar pool heating systems.

(i) "SRCC" means the Solar Rating and Certification Corporation.

2862. The Legislature finds and declares all of the following:

(a) California is heavily dependent on natural gas, importing more than 80 percent of the natural gas it consumes.

(b) Rising worldwide demand for natural gas and a shrinking supply create rising and unstable prices that can harm California consumers and the economy.

(c) Natural gas is a fossil fuel and a major source of global warming pollution and the pollutants that cause air pollution, including smog.

(d) California's growing population and economy will put a strain on energy supplies and threaten the ability of the state to meet its global warming goals unless specific steps are taken to reduce demand and generate energy cleanly and efficiently.

(e) Water heating for domestic and industrial use relies almost entirely on natural gas and accounts for a significant percentage of the state's natural gas consumption.

(f) Solar water heating systems represent the largest untapped natural gas saving potential remaining in California.

(g) In addition to financial and energy savings, solar water heating systems can help protect against future gas and electricity shortages and reduce our dependence on foreign sources of energy.

(h) Solar water heating systems can also help preserve the environment and protect public health by reducing air pollution, including carbon dioxide, a leading global warming gas, and nitrogen oxide, a precursor to smog.

(i) Growing demand for these technologies will create jobs in California as well as promote greater energy independence, protect consumers from rising energy costs and result in cleaner air.

(j) It is in the interest of the State of California to promote solar water heating systems and other technologies that directly reduce demand for natural gas in homes and businesses.

(k) It is the intent of the Legislature to build a mainstream market for solar water heating systems that directly reduces demand for natural gas in homes, businesses, and government buildings. Toward that end, it is the goal of this article to install at least 200,000 solar water heating systems on homes, businesses, and government buildings throughout the state by 2017, thereby lowering prices and creating a self-sufficient market that will sustain itself beyond the life of this program.

(l) It is the intent of the Legislature that the solar water heating system incentives created by the act should be a cost-effective investment by gas customers. Gas customers will recoup the cost of their investment through lower prices as a result of avoiding purchases of natural gas, and benefit from additional system stability and pollution reduction benefits.

2863. (a) The commission shall evaluate the data available from the Solar Water Heating Pilot Project conducted by the California Center for Sustainable Energy. If, after a public hearing, the commission determines that a solar water heating program is cost effective for ratepayers and in the public interest, the commission shall do all of the following:

(1) Design and implement a program applicable to the service territories of a gas corporation, to achieve the goal of the Legislature to promote the installation of 200,000 solar water heating systems in homes and businesses throughout the state by 2017.

(2) The program shall be administered by gas corporations or third-party administrators, as determined by the commission, and subject to the supervision of the commission.

(3) The commission shall coordinate the program with the Energy Commission's New Solar Homes Partnership to achieve the goal of building zero-energy homes.

(b) (1) The commission shall fund the program through the use of a surcharge applied to gas customers based upon the amount of natural gas consumed. The surcharge shall be in addition to any other charges for natural gas sold or transported for consumption in this state.

(2) The commission shall impose the surcharge at a level that is necessary to meet the goal of installing 200,000 solar water heating systems, or the equivalent output of 200,000 solar water heating systems, on homes and businesses in California by 2017. Funding for the program established by this article shall not, for the collective service territories of all gas corporations, exceed two hundred fifty million dollars ($250,000,000) over the course of the 10-year program.

(3) The commission shall annually establish a surcharge rate for each class of gas customers. Any gas customer participating in the California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA) programs shall be exempt from paying any surcharge imposed to fund the program designed and implemented pursuant to this article.

(4) Any surcharge imposed to fund the program designed and implemented pursuant to this article shall not be imposed upon the portion of any gas customer's procurement of natural gas that is used or employed for a purpose that Section 896 excludes from being categorized as the consumption of natural gas.

(5) The gas corporation or other person or entity providing revenue cycle services, as defined in Section 328.1, shall be responsible for collecting the surcharge.

(c) Funds shall be allocated for the benefit of gas customers to promote utilization of solar water heating systems.

(d) In designing and implementing the program required by this article, no moneys shall be diverted from any existing programs for low-income ratepayers or cost-effective energy efficiency programs.

2864. (a) The commission, in consultation with the Energy Commission and interested members of the public, shall establish eligibility criteria for solar water heating systems receiving gas customer funded incentives pursuant to this article. The criteria should specify and include all of the following:

(1) Design, installation, and energy output or displacement standards. To be eligible for rebate funding, a residential solar water heating system shall, at a minimum, have a SRCC OG-300 Solar Water Heating System Certification. Solar collectors used in systems for multifamily residential, commercial, or industrial water heating shall, at a minimum, have a SRCC OG-100 Solar Water Heating System Certification.

(2) Require that solar water heating system components are new and unused, and have not previously been placed in service in any other location or for any other application.

(3) Require that solar water heating collectors have a warranty of not less than 10 years to protect against defects and undue degradation.

(4) Require that solar water heating systems are in buildings connected to a natural gas utility's distribution system within the state.

(5) Require that solar water heating systems have meters or other kWhth measuring devices in place to monitor and measure the system's performance and the quantity of energy generated or displaced by the system. The criteria shall require meters for systems with a capacity for displacing over 30 kWth. The criteria may require meters for systems with a capacity of 30 kWth or smaller.

(6) Require that solar water heating systems are installed in conformity with the manufacturer's specifications and all applicable codes and standards.

(b) No gas customer funded incentives shall be made for a solar water heating system that does not meet the eligibility criteria.

2865. (a) The commission shall establish conditions on gas customer funded incentives pursuant to this article. The conditions shall require both of the following:

(1) Appropriate siting and high-quality installation of the solar water heating system based on installation guidelines that maximize the performance of the system and prevent qualified systems from being inefficiently or inappropriately installed. The conditions shall not impact housing designs or densities presently authorized by a city, county, or city and county. The goal of this paragraph is to achieve efficient installation of solar water heating systems and promote the greatest energy production or displacement per gas customer dollar.

(2) Appropriate energy efficiency improvements in the new or existing home or commercial structure where the solar hot water system is installed.

(b) The commission shall set rating standards for equipment, components, and systems to ensure reasonable performance and shall develop standards that provide for compliance with the minimum ratings.

2866. (a) The commission shall provide not less than 10 percent of the overall funds for installation of solar water heating systems on low-income residential housing.

(b) The commission may establish a grant program or a revolving loan or loan guarantee program for low-income residential housing consistent with the requirements of Chapter 5.3 (commencing with Section 25425) of Division 15 of the Public Resources Code. All loans outstanding as of August 1, 2018, shall continue to be repaid in a manner that is consistent with the terms and conditions of the program adopted and implemented by the commission pursuant to this subdivision, until repaid in full.

(c) The commission may extend eligibility for funding pursuant to this section to include residential housing occupied by ratepayers participating in a commission approved and supervised gas corporation Low-Income Energy Efficiency (LIEE) program and who either:

(1) Occupy a single-family home.

(2) Occupy at least 50 percent of all units in a multifamily dwelling structure.

(d) The commission shall ensure that lower income households, as defined in Section 50079.5 of the Health and Safety Code, and, if the commission expands the program pursuant to subdivision (c), ratepayers participating in a LIEE program, that receive gas service at residential housing with a solar water heating system receiving incentives pursuant to subdivision (a), benefit from the installation of the solar water heating systems through reduced or lowered energy costs.

(e) No later than January 1, 2010, the commission shall do all of the following to implement the requirements of this section:

(1) Maximize incentives to properties that are committed to continuously serving the needs of lower income households, as defined in Section 50079.5 of the Health and Safety Code, and, if the commission expands the program pursuant to subdivision (c), ratepayers participating in a LIEE program.

(2) Establish conditions on the installation of solar water heating systems that ensure properties on which solar water heating systems are installed under subdivision (a) remain low-income residential properties for at least 10 years from the time of installation, including property ownership restrictions and income rental protections, and appropriate enforcement of these conditions.

(f) All moneys set aside for the purpose of funding the installation of solar water heating systems on low-income residential housing that are unexpended and unencumbered on August 1, 2018, and all moneys thereafter repaid pursuant to subdivision (b), except to the extent that those moneys are encumbered pursuant to this section, shall be utilized to augment cost-effective energy efficiency measures in low-income residential housing that benefit ratepayers.

2867. (a) The rebates provided through this program shall decline over time. They shall be structured so as to drive down the cost of the solar water heating technologies, and be paid out on a performance-based incentive basis so that incentives are earned based on the actual energy savings, or on predicted energy savings as established by the commission.

(b) The commission shall consider federal tax credits and other incentives available for this technology when determining the appropriate rebate amount.

(c) The commission shall consider the impact of rebates for solar water heating systems pursuant to this article on existing incentive programs for energy efficiency technology.

(d) In coordination with the commission, the Energy Commission shall consider, when appropriate, coupling rebates for solar water heating systems with complementary energy efficiency technologies, including, but not limited to, efficient hot water heating tanks and tankless or on demand hot water systems that can be installed in addition to the solar water heating system.

2867.1. Not later than July 1, 2010, the commission shall report to the Legislature as to the effectiveness of the program and make recommendations as to any changes that should be made to the program. This report shall include justification for the size of the rebate program in terms of total available incentive moneys as well as the anticipated benefits of the program in its entirety. To facilitate the understanding of how solar water heating systems compare with other clean energy and energy efficiency technologies, all documents related to and rebates provided by this program shall be measured in both kWhth and therms of natural gas saved.

2867.2. Except for the Solar Water Heating Pilot Program in San Diego, solar water heating technologies shall not be eligible for California Solar Initiative (CSI) funds, pursuant to Section 2851, unless they also displace electricity, in which case only the electricity displacing portion of the technology may be eligible under the CSI program, as determined by the commission.

2867.3. In order to further the state goal of encouraging the installation of 200,000 solar water heaters by 2017, the governing body of each publicly owned utility providing gas service to retail end-use gas customers shall, after a public proceeding, adopt, implement, and finance a solar water heating system incentive program that does all the following:

(a) Ensures that any solar water heating system receiving monetary incentives complies with eligibility criteria adopted by the governing body. The eligibility criteria shall include those elements contained in paragraphs (1) to (6), inclusive, of subdivision (a) of Section 2864.

(b) Includes minimum ratings and standards for equipment, components, and systems to ensure reasonable performance and compliance with the minimum ratings and standards.

(c) Includes an element that addresses the installation of solar water heating systems on low-income residential housing. If deemed appropriate in consultation with the California Tax Credit Allocation Committee, the governing board may establish a grant program or a revolving loan or loan guarantee program for low-income residential housing consistent with the requirements of Chapter 5.3 (commencing with Section 25425) of Division 15 of the Public Resources Code.

2867.4. This article shall remain in effect only until August 1, 2018, and as of that date is repealed, unless a later enacted statute, that is enacted before August 1, 2018, deletes or extends that date.

SEC. 3. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act, within the meaning of Section 17556 of the Government Code.

Assembly Bill 1613

BILL NUMBER: AB 1613 CHAPTERED
BILL TEXT

CHAPTER 713
FILED WITH SECRETARY OF STATE OCTOBER 14, 2007
APPROVED BY GOVERNOR OCTOBER 14, 2007
PASSED THE SENATE SEPTEMBER 11, 2007
PASSED THE ASSEMBLY SEPTEMBER 12, 2007
AMENDED IN SENATE SEPTEMBER 7, 2007
AMENDED IN SENATE SEPTEMBER 4, 2007
AMENDED IN SENATE AUGUST 20, 2007
AMENDED IN SENATE JULY 10, 2007
AMENDED IN SENATE JUNE 27, 2007
AMENDED IN ASSEMBLY JUNE 1, 2007
AMENDED IN ASSEMBLY MAY 1, 2007
AMENDED IN ASSEMBLY APRIL 17, 2007

INTRODUCED BY Assembly Member Blakeslee
(Coauthors: Assembly Members Adams, Emmerson, Huffman, Parra, and Torrico)

FEBRUARY 23, 2007

An act to add Chapter 8 (commencing with Section 2840) to Part 2 of Division 1 of the Public Utilities Code, relating to energy.

LEGISLATIVE COUNSEL'S DIGEST

AB 1613, Blakeslee. Energy: Waste Heat and Carbon Emissions Reduction Act.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations, as defined. Existing law authorizes the PUC to fix the rates and charges for every public utility, and requires that those rates and charges be just and reasonable. The existing Public Utilities Act requires the PUC to review and adopt a procurement plan for each electrical corporation in accordance with specified elements, incentive mechanisms, and objectives. The act additionally requires the PUC, in consultation with the Independent System Operator, to establish resource adequacy requirements for all load-serving entities, as defined, in accordance with specified objectives.

The existing Warren-Alquist State Energy Resources Conservation and Development Act establishes the State Energy Resources Conservation and Development Commission (Energy Commission) and requires it to undertake a continuing assessment of trends in the consumption of electricity and other forms of energy and to analyze the social, economic, and environmental consequences of those trends and to collect from electric utilities, gas utilities, and fuel producers and wholesalers and other sources, forecasts of future supplies and consumption of all forms of energy.

This bill would enact the Waste Heat and Carbon Emissions Reduction Act. The bill would state the intent of the Legislature: (A) to dramatically advance the efficiency of the state's use of natural gas by capturing unused waste heat, (B) to reduce wasteful consumption of energy through improved residential, commercial, institutional, industrial, and manufacturer utilization of waste heat whenever it is cost effective, technologically feasible, and environmentally beneficial, particularly when this reduces emissions of carbon dioxide and other carbon-based greenhouse gases, and (C) to support and facilitate both customer- and utility-owned combined heat and power systems.

This bill would authorize the PUC to require an electrical corporation to purchase excess electricity, as defined, delivered by a combined heat and power system, as defined, that complies with certain sizing, energy efficiency, and air pollution control requirements, but would authorize the PUC to establish a maximum kilowatthours limitation on the amount of excess electricity that an electrical corporation is required to purchase if the PUC finds that the anticipated excess electricity generated has an adverse effect on long-term resource planning or the reliable operation of the grid. The bill would require the PUC to establish, in consultation with the Independent System Operator, tariff provisions that facilitate the provisions of the act and the reliable operation of the grid. The bill would require every electrical corporation to file a standard tariff with the PUC for the purchase of excess electricity from an eligible customer-generator, as defined, would require the electrical corporation to make the tariff available to eligible customer-generators within the service territory of the electrical corporation upon request, and would authorize the electrical corporation to make the terms of the tariff available in the form of a standard contract. The bill would require that the costs and benefits associated with any tariff or contract be allocated to benefiting customers, as defined. The bill would require the PUC to establish for each electrical corporation, a pay-as-you-save pilot program, meeting certain goals, for eligible customers, as defined, to finance all of the upfront costs for the purchase and installation of combined heat and power systems. The bill would require the PUC, in approving an electrical corporation's procurement plan, to require the plan to assess the reliability of incorporating combined heat and power solutions to the maximum degree that is cost effective compared to other competing forms of wholesale generation, technologically feasible, and environmentally beneficial, particularly as it pertains to reducing emissions of carbon dioxide and other greenhouse gases. The bill would authorize the PUC to modify or adjust the requirements of the act for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.

This bill would require a local publicly owned electric utility serving retail end-use customers to establish a program that allows retail end-use customers to utilize combined heat and power systems that reduce emissions of greenhouse gases by achieving improved efficiencies utilizing heat that would otherwise be wasted in separate energy applications and that provides a market for the purchase of excess electricity generated by a combined heat and power system, at a just and reasonable rate, to be determined by the governing body of the utility. By placing additional requirements upon local publicly owned electric utilities, the bill would impose a state-mandated local program.

This bill would require the Energy Commission, by January 1, 2010, to adopt guidelines that require combined heat and power systems be designed to reduce waste energy, be sized to meet the eligible customer-generator's thermal load, operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat, and are cost effective, technologically feasible, and environmentally beneficial. The bill would authorize the Energy Commission to adopt temporary guidelines for combined heat and power systems prior to January 1, 2010. The bill would require an eligible customer-generator's combined heat and power system to meet certain efficiency and emissions requirements. The bill would require an eligible customer-generator to adequately maintain and service the combined heat and power system so that during operation, the system continues to meet or exceed the efficiency and emissions requirements.

(2) The existing California Global Warming Solutions Act of 2006, requires the State Air Resources Board (state board) to adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with the reporting and verification program, as specified, and requires the state board to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020. The act requires the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective reduction in emissions of greenhouse gases and authorizes the state board to adopt market-based compliance mechanisms, as defined, meeting specified requirements. Existing law requires the PUC, by February 1, 2007, through a rulemaking proceeding and in consultation with the Energy Commission and the state board, to establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities.

This bill would require that a combined heat and power system comply with the greenhouse gases emission performance standard established by the PUC.

(3) This bill would require the state board to report to the Governor and the Legislature by December 31, 2011, on the reduction in emissions of greenhouse gases resulting from the increase of new electrical generation that utilizes excess waste heat through combined heat and power systems and recommend policies that further the goals of the bill.

(4) Existing law makes any public utility, as defined, and any corporation other than a public utility, that violates or that fails to comply with any part of any order, decision, rule, direction, demand, or requirement of the PUC, guilty of a crime.

Because certain provisions of the bill would require PUC action to implement and a violation or failure to comply with any part of any order, decision, rule, direction, demand, or requirement of the PUC would be a crime, the bill would impose a state-mandated local program by creating a new crime.

(5) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Chapter 8 (commencing with Section 2840) is added to Part 2 of Division 1 of the Public Utilities Code, to read:

CHAPTER 8. ENERGY EFFICIENCY SYSTEMS

Article 1. Waste Heat and Carbon Emissions Reduction Act

2840. This article shall be known and may be cited as the Waste Heat and Carbon Emissions Reduction Act.

2840.2. For purposes of this article, the following terms have the following meanings:

(a) "Combined heat and power system" means a system that produces both electricity and thermal energy for heating or cooling from a single fuel input that meets all of the following:

(1) Is interconnected to, and operates in parallel with, the electric transmission and distribution grid.

(2) Is sized to meet the eligible customer-generator's onsite thermal demand.

(3) Meets the efficiency standards of subdivisions (a) and (d), and the greenhouse gases emissions performance standard of subdivision (f) of Section 2843.

(b) "Eligible customer-generator" means a customer of an electrical corporation that meets both of the following requirements:

(1) Uses a combined heat and power system with a generating capacity of not more than 20 megawatts, that first commences operation on or after January 1, 2008.

(2) Uses a time-of-use meter capable of registering the flow of electricity in two directions. If the existing electrical meter of an eligible customer-generator is not capable of measuring the flow of electricity in two directions, the eligible customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is able to measure electricity flow in two directions. If an additional meter or meters are installed, the electricity flow calculations shall yield a result identical to that of a time-of-use meter.

(c) "Electrical corporation" has the same meaning as defined in Section 218.

(d) "Energy Commission" means the State Energy Resources Conservation and Development Commission.

(e) "Excess electricity" means the net electricity exported to the electrical grid, generated by a combined heat and power system that is in compliance with Section 2843.

(f) "Greenhouse gas" or "greenhouse gases" includes all of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

2840.4. The Legislature finds and declares all of the following:

(a) Combined heat and power systems produce both electricity and thermal energy from a single fuel input, thus achieving much greater efficiency than the usual separate systems for producing these forms of energy, and reducing consumption of fuel.

(b) Combined heat and power systems recover heat that would otherwise be wasted in separate energy applications, and use this heat to avoid consumption of fuel that would otherwise be required to produce heat.

(c) Gigawatthours of potential useful electricity and millions of British thermal units of thermal energy could be derived from unused waste heat that is currently being vented into the atmosphere.

2840.6. (a) It is the intent of the Legislature that state policies dramatically advance the efficiency of the state's use of natural gas by capturing unused waste heat, and in so doing, help offset the growing crisis in electricity supply and transmission congestion in the state.

(b) It is the intent of the Legislature to reduce wasteful consumption of energy through improved residential, commercial, institutional, industrial, and manufacturer utilization of waste heat whenever it is cost effective, technologically feasible, and environmentally beneficial, particularly when this reduces emissions of carbon dioxide and other carbon-based greenhouse gases.

(c) It is the intent of the Legislature to support and facilitate both customer- and utility-owned combined heat and power systems.

(d) This article does not apply to, and shall not impact, combined heat and power systems in operation prior to January 1, 2008, or combined heat and power systems with a generating capacity greater than 20 megawatts.

2841. (a) The commission may require an electrical corporation to purchase from an eligible customer-generator, excess electricity that is delivered to the grid that is generated by a combined heat and power system that is in compliance with Section 2843. The commission may establish a maximum kilowatthours limitation on the amount of excess electricity that an electrical corporation is required to purchase if the commission finds that the anticipated excess electricity generated has an adverse effect on long-term resource planning or reliable operation of the grid. The commission shall establish, in consultation with the Independent System Operator, tariff provisions that facilitate both the provisions of this chapter and the reliable operation of the grid.

(b) (1) Every electrical corporation shall file with the commission a standard tariff for the purchase of excess electricity from an eligible customer-generator.

(2) The tariff shall provide for payment for every kilowatthour delivered to the electrical grid by the combined heat and power system at a price determined by the commission.

(3) The tariff shall include flexible rates with options for different durations, not to exceed 10 years, and fixed or variable rates relative to the cost of natural gas.

(4) The commission shall ensure that ratepayers not utilizing combined heat and power systems are held indifferent to the existence of this tariff.

(c) The commission, in reviewing the tariff filed by an electrical corporation, shall establish time-of-delivery rates that encourage demand management and net generation of electricity during periods of peak system demand.

(d) Every electrical corporation shall make the tariff available to eligible customer-generators that own, or lease, and operate a combined heat and power system within the service territory of the electrical corporation, upon request. An electrical corporation may make the terms of the tariff available to an eligible customer in the form of a standard contract.

(e) The costs and benefits associated with any tariff or contract entered into by an electrical corporation pursuant to this section shall be allocated to all benefiting customers. For purposes of this section "benefiting customers" may, as determined by the commission, include bundled service customers of the electrical corporation, customers of the electrical corporation that receive their electric service through a direct transaction, as defined in subdivision (c) of Section 331, and customers of an electrical corporation that receive their electric service from a community choice aggregator, as defined in Section 331.1.

(f) The physical generating capacity of the combined heat and power system shall count toward the resource adequacy requirements of load-serving entities for purposes of Section 380.

(g) The commission shall adopt or maintain standby rates or charges for combined heat and power systems that are based only upon assumptions that are supported by factual data, and shall exclude any assumptions that forced outages or other reductions in electricity generation by combined heat and power systems will occur simultaneously on multiple systems, or during periods of peak electrical system demand, or both.

(h) The commission may modify or adjust the requirements of this article for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.

2841.5. A local publicly owned electric utility serving retail end-use customers shall establish a program that does both of the following:

(a) Allows retail end-use customers to utilize combined heat and power systems that reduce emissions of greenhouse gases by achieving improved efficiencies utilizing heat that would otherwise be wasted in separate energy applications.

(b) Provides a market for the purchase of excess electricity generated by a combined heat and power system, at a just and reasonable rate, to be determined by the governing body of the utility.

2842. The commission, in approving a procurement plan for an electrical corporation pursuant to Section 454.5, shall require that the electrical corporation's procurement plan incorporate combined heat and power solutions to the extent that it is cost effective compared to other competing forms of wholesale generation, technologically feasible, and environmentally beneficial, particularly as it pertains to reducing emissions of carbon dioxide and other greenhouse gases.

2842.2. The commission shall ensure that an electrical corporation utilizes long-term planning and a reliability assessment for upgrades to its transmission and distribution systems and that any upgrades are not inconsistent with promoting combined heat and power systems that are cost effective, technologically feasible, and environmentally beneficial, particularly as those combined heat and power systems reduce emissions of greenhouse gases.

2842.4. (a) The commission shall, for each electrical corporation, establish a pay-as-you-save pilot program for eligible customers.

(b) For the purposes of this section, an "eligible customer" means a customer of an electrical corporation that meets the following criteria:

(1) The customer uses a combined heat and power system with a generating capacity of not more than 20 megawatts that is in compliance with Section 2843.

(2) The customer is a nonprofit organization described in Section 501(c) (3) of the Internal Revenue Code (26 U.S.C. Sec. 501(c) (3)), that is exempt from taxation under Section 501(a) of that code (26 U.S.C. Sec. 501(a)).

(c) The pilot program shall enable an eligible customer to finance all of the upfront costs for the purchase and installation of a combined heat and power system by repaying those costs over time through on-bill financing at the difference between what an eligible customer would have paid for electricity and the actual savings derived for a period of up to 10 years.

(d) The commission shall ensure that the reasonable costs of the electrical corporation associated with the pilot program are recovered.

(e) All costs of the pay-as-you-save program or financing mechanisms shall be borne solely by the combined heat and power generators that use the program or financing mechanisms, and the commission shall ensure that the costs of the program are not shifted to the other customers or classes of customers of the electrical corporation.

(f) Each electric corporation shall make on-bill financing available to eligible customers until the statewide cumulative rated generating capacity from pilot program combined heat and power systems in the service territories of the three largest electrical corporations in the state reaches 100 megawatts. An electrical corporation shall only be required to participate in the pilot program until it meets its proportionate share of the 100-megawatt limitation, based on the percentage of its peak demand to the total statewide peak demand within the service territories of all electrical corporations.

2843. (a) The Energy Commission shall, by January 1, 2010, adopt guidelines that combined heat and power systems subject to this chapter shall meet, and shall accomplish all of the following:

(1) Reduce waste energy.

(2) Be sized to meet the eligible customer-generator's thermal load.

(3) Operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat.

(4) Are cost effective, technologically feasible, and environmentally beneficial.

(b) It is the intent of the Legislature that the guidelines do not permit customers to operate as de facto wholesale generators with guaranteed purchasers for their electricity.

(c) Notwithstanding any other provisions of law, the guidelines required by this section shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code. The guidelines shall be adopted at a publicly noticed meeting offering all interested parties an opportunity to comment. At least 30 days' public notice shall be given of the meeting required by this section, before the Energy Commission initially adopts guidelines. Substantive changes to the guidelines shall not be adopted without at least 10 days' written notice to the public.

(d) Prior to January 1, 2010, the Energy Commission may adopt temporary guidelines for combined heat and power systems that comply with the parameters set forth in subdivision (a).

(e) (1) An eligible customer-generator's combined heat and power system shall meet an oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100-percent load.

(2) An eligible customer-generator's combined heat and power system that meets the 60-percent efficiency standard may take a credit to meet the applicable NOx emissions standard of 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British thermal units of heat recovered.

(f) An eligible customer-generator's combined heat and power system shall comply with the greenhouse gases emission performance standard established by the commission pursuant to Section 8341.

(g) An eligible customer-generator shall adequately maintain and service the combined heat and power system so that during operation, the system continues to meet or exceed the efficiency and emissions standards established pursuant to subdivisions (a), (d), and (f).

2845. The State Air Resources Board shall report to the Governor and the Legislature by December 31, 2011, on the reduction in emissions of greenhouse gases resulting from the increase of new electrical generation that utilizes excess waste heat through combined heat and power systems and recommend policies that further the goals of this article.

SEC. 2. No reimbursement is required by this act pursuant to

Section 6 of Article XIII B of the California Constitution because certain costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

With respect to certain other expenses, no reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act, within the meaning of Section 17556 of the Government Code.

Assembly Bill 1685

BILL NUMBER: AB 1685 CHAPTERED
BILL TEXT

CHAPTER 894
FILED WITH SECRETARY OF STATE OCTOBER 12, 2003
APPROVED BY GOVERNOR OCTOBER 12, 2003
PASSED THE ASSEMBLY SEPTEMBER 11, 2003
PASSED THE SENATE SEPTEMBER 8, 2003
AMENDED IN SENATE SEPTEMBER 4, 2003
AMENDED IN SENATE AUGUST 18, 2003
AMENDED IN SENATE JULY 16, 2003
AMENDED IN ASSEMBLY MAY 13, 2003
AMENDED IN ASSEMBLY APRIL 24, 2003
AMENDED IN ASSEMBLY APRIL 10, 2003

INTRODUCED BY Assembly Member Leno
(Coauthors: Assembly Members Hancock, Jackson, and Koretz)

FEBRUARY 21, 2003

An act to amend Sections 353.2 and 379.5 of, and to add Section 379.6 to, the Public Utilities Code, relating to energy.

LEGISLATIVE COUNSEL'S DIGEST

AB 1685, Leno. Energy: self-generation incentive program: peak reduction.

Existing law requires the Public Utilities Commission on or before March 7, 2001, and in consultation with the Independent System Operator, to take certain actions, including, in consultation with the State Energy Resources Conservation and Development Commission (Energy Commission), adopting energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods, including, but not limited to, differential incentives for renewable or superclean distributed generation resources. Pursuant to this requirement, the commission has developed a Self Generation Incentive Program to encourage customers of electrical corporations to install distributed generation that operates on renewable fuel or contributes to system reliability. Existing law defines "ultra-clean and low-emission distributed generation" as an electric generation technology that produces zero emissions during operation or that produces emissions that are equal to or less than limits established by the State Air Resources Board, if the electric generation technology commences operation between January 1, 2003, and December 31, 2005.

This bill would require the commission, in consultation with the Energy Commission, to administer, until January 1, 2008, a self-generation incentive program for distributed generation resources in the same form that exists on January 1, 2004, but would require that combustion-operated distributed generation projects using fossil fuels commencing January 1, 2005, meet a NOx emission standard, and commencing January 1, 2007, meet a more stringent NOx emission standard and a minimum efficiency standard, to be eligible for incentive rebates under the program. The bill would establish a credit for combined heat and power units that meet a certain efficiency standard.

The bill would revise the definition of an ultra-clean and low-emission distributed generation to include electric generation technologies that commence operation prior to December 31, 2008.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The Legislature finds and declares each of the following:

(a) Increasing California's reliance on renewable energy resources, particularly solar, "ultra-clean," and "low-emission" electricity generation, promotes stable electricity prices, protects public health, improves environmental quality, stimulates sustainable economic development, creates new employment opportunities, and reduces reliance on imported fuels.

(b) The development of renewable energy resources, particularly nonpolluting solar electricity generation, ameliorates air quality problems throughout the state and improves public health by reducing the burning of fossil fuels and the associated environmental impacts.

(c) The Self Generation Incentive Program administered by the Public Utilities Commission and established pursuant to Section 379.5 (Decision 01-03-073, March 27, 2001), has been a critically important subsidy for the growth of solar electricity generation in California, but is set to expire at the end of 2004.

(d) The Legislature intends that the commission continue the Self Generation Incentive Program in order to subsidize solar electricity generation.

SEC. 2. Section 353.2 of the Public Utilities Code is amended to read:

353.2. (a) As used in this article, "ultra clean and low emission distributed generation" means any electric generation technology that meets both of the following criteria:

(1) Commences initial operation between January 1, 2003, and December 31, 2008.

(2) Produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60-percent system efficiency on a higher heating value.

(b) In establishing rates and fees, the commission may consider energy efficiency and emissions performance to encourage early compliance with air quality standards established by the State Air Resources Board for ultra clean and low emission distributed generation.

SEC. 3. Section 379.5 of the Public Utilities Code is amended to read:

379.5. Notwithstanding any other provision of law, on or before March 7, 2001, the commission, in consultation with the Independent System Operator, shall take all of the following actions, and shall include the reasonable costs involved in taking those actions in the distribution revenue requirements of utilities regulated by the commission, as appropriate:

(a) (1) Identify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, including, but not limited to, reconductoring of transmission lines, the addition of capacitors to increase voltage, the reinforcement of existing transmission capacity, and the installation of new transformer banks. The commission shall, in consultation with the Independent System Operator, give first priority to those geographical regions where congestion reduces or impedes electrical transmission and supply.

(2) Consistent with the existing statutory authority of the commission, afford electrical corporations a reasonable opportunity to fully recover costs it determines are reasonable and prudent to plan, finance, construct, operate, and maintain any facilities under its jurisdiction required by this section.

(b) In consultation with the State Energy Resources Conservation and Development Commission, adopt energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods. Those initiatives shall include, but not be limited to, all of the following:

(1) Expansion and acceleration of residential and commercial weatherization programs.

(2) Expansion and acceleration of programs to inspect and improve the operating efficiency of heating, ventilation, and air-conditioning equipment in new and existing buildings, to ensure that these systems achieve the maximum feasible cost-effective energy efficiency.

(3) Expansion and acceleration of programs to improve energy efficiency in new buildings, in order to achieve the maximum feasible reductions in uneconomic energy and peak electricity consumption.

(4) Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during a peak electricity demand period.

(5) Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.

(6) Incentives for load control and distributed generation to be paid for enhancing reliability.

(7) Differential incentives for renewable or super clean distributed generation resources pursuant to Section 379.6.

(8) Reevaluation of all efficiency cost-effectiveness tests in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility.

(c) In consultation with the Energy Resources Conservation and Development Commission, adopt and implement a residential, commercial, and industrial peak reduction program that encourages electric customers to reduce electricity consumption during peak power periods.

SEC. 4. Section 379.6 is added to the Public Utilities Code, to read:

379.6. (a) The commission, in consultation with the State Energy Resources Conservation and Development Commission, shall until January 1, 2008, administer a self-generation incentive program for distributed generation resources, in the same form as exists on January 1, 2004.

(b) Notwithstanding subdivision (a), the self-generation incentive program shall do all of the following:

(1) Commencing January 1, 2005, require all combustion-operated distributed generation projects using fossil fuels to meet an oxides of nitrogen (NOx) emissions rate standard of 0.14 pounds per megawatthour to be eligible for self-generation rebates.

(2) Commencing January 1, 2007, require all combustion-operated distributed generation projects using fossil fuels to meet an oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent, to be eligible

for self-generation rebates. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100 percent load.

(3) Combined heat and power units that meet the 60 percent efficiency standard may take a credit to meet the applicable oxides of nitrogren (NOx) emission standard of 0.14 pounds per megawatthour or 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British Thermal Units (BTUs) of heat recovered.

(4) Provide the commission with flexibility in administering the self-generation incentive program, including, but not limited to, flexibility with regard to the amount of rebates, inclusion of other ultra clean and low emission distributed generation technologies, and evaluation of other public policy interests, including, but not limited to, ratepayers, and energy efficiency and environmental interests.

Assembly Bill 2267

BILL NUMBER: AB 2267 CHAPTERED
BILL TEXT

CHAPTER 537
FILED WITH SECRETARY OF STATE SEPTEMBER 28, 2008
APPROVED BY GOVERNOR SEPTEMBER 28, 2008
PASSED THE SENATE AUGUST 29, 2008
PASSED THE ASSEMBLY AUGUST 31, 2008
AMENDED IN SENATE AUGUST 22, 2008
AMENDED IN SENATE JUNE 26, 2008
AMENDED IN ASSEMBLY APRIL 23, 2008
AMENDED IN ASSEMBLY APRIL 3, 2008

INTRODUCED BY Assembly Member Fuentes
(Coauthors: Assembly Members Blakeslee, Caballero, Price, and Salas)

FEBRUARY 21, 2008

An act to amend Sections 25620 and 25620.5 of the Public Resources Code, and to amend Section 379.6 of the Public Utilities Code, relating to energy.

LEGISLATIVE COUNSEL'S DIGEST

AB 2267, Fuentes. California-based entities: self-generation incentive program.

(1) Existing law establishes the Public Interest Research, Development, and Demonstration Fund in the State Treasury, and provides that the money collected by the public goods charge to support cost-effective energy efficiency and conservation activities, public interest research and development not adequately provided by competitive and regulated markets, be deposited in the fund for use by the State Energy Resources Conservation and Development Commission (Energy Commission) to develop, implement, and administer the Public Interest Research, Development, and Demonstration Program to develop technologies to improve environmental quality, enhance electrical system reliability, increase efficiency of energy-using technologies, lower electrical system costs, or provide other tangible benefits.

This bill would state that public interest energy research, demonstration, and development projects should provide economic benefits for California by promoting California-based technology firms, jobs, and businesses. The bill would require the Energy Commission to give priority to California-based entities in making awards pursuant to the program. The bill would define a California-based entity.

(2) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations and gas corporations, as defined. Existing law requires the PUC, in consultation with the Energy Commission, to administer, until January 1, 2012, a self-generation incentive program for distributed generation resources. The program is applicable to all eligible technologies, as determined by the PUC and subject to certain air emissions and efficiency standards, until January 1, 2008, except for solar technologies, which the PUC is required to administer separately, after January 1, 2007, pursuant to the California Solar Initiative. Commencing January 1, 2008, until

January 1, 2012, existing law limits eligibility for nonsolar technologies to fuel cells and wind distributed generation technologies that meet or exceed emissions standards adopted by the State Air Resources Board (state board). Existing law authorizes the PUC, in administering the program, to adjust the amount of rebates, include other ultraclean and low-emission distributed generation technologies, as defined, and evaluate other public policy interests and energy efficiency and environmental interests. Pursuant to decisions of the PUC, Pacific Gas and Electric Company, Southern California Edison, and Southern California Gas Company are the program administrators throughout their respective service territories and the Center for Sustainable Energy is the program administrator for the San Diego Gas and Electric Company service territory.

The existing California Global Warming Solutions Act of 2006 requires the State Air Resources Board (state board) to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990, to be achieved by 2020. Existing law prohibits any load-serving entity, as defined, and any local publicly owned electric utility, as defined, from entering into a long-term financial commitment, as defined, unless any baseload generation, as defined, complies with a greenhouse gases emission performance standard. Existing law requires the commission, in consultation with the Energy Commission and the state board, to establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities.

This bill would require the commission to provide from existing program funds an additional incentive of 20% for the installation of eligible distributed generation resources from a California supplier, as defined.

This bill would require the Energy Commission to update its evaluation and recommendations by November 1, 2011.

(3) This bill incorporates amendments to Section 25620 of the Public Resources Code proposed by both this bill and SB 1760, which would only become operative if both bills are enacted and become effective on or before January 1, 2009, each bill amends Section 25620 of the Public Resources Code, and this bill is enacted after SB 1760.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. (a) It is the intent of the Legislature that California' s leadership in energy efficiency and greenhouse gas emission reductions translate into economic benefits for California through job creation, workforce training and retraining, manufacturing retention and development, and the development of a green technology industry in the state by using the state's existing investments, incentives, and support for clean and greenhouse gas emission reducing technologies and applications that assist the state in meeting its greenhouse gas emission reduction targets.

(b) It is further the intent of the Legislature that the State Air Resources Board, the State Energy Resources Conservation and Development Commission, and the Public Utilities Commission provide additional consideration, priority, or preference to projects that result in job creation and economic benefits in California in administering incentive programs for energy efficiency, including renewable energy, and the reduction of greenhouse gas emissions, to the maximum extent feasible and consistent with the provisions of law governing these incentive programs.

SEC. 3. Section 25620 of the Public Resources Code is amended to read:

25620. The Legislature hereby finds and declares all of the following:

(a) It is in the best interests of the people of this state that the quality of life of its citizens be improved by providing environmentally sound, safe, reliable, and affordable energy services and products.

(b) To improve the quality of life of this state's citizens, it is proper and appropriate for the state to undertake public interest energy research, development, and demonstration projects that are not adequately provided for by competitive and regulated energy markets.

(c) Public interest energy research, demonstration, and development projects should advance energy science or technologies of value to California citizens and should be consistent with the policies of this chapter.

(d) It is in the best interest of the people of California for the commission to positively contribute to the overall economic climate of the state within the roles and responsibilities of the commission as defined by statute, regulation, and other official government authority, including, but not limited to, providing economic benefits to California-based entities.

SEC. 3.5. Section 25620 of the Public Resources Code is amended to read:

25620. The Legislature hereby finds and declares all of the following:

(a) It is in the best interests of the people of this state that the quality of life of its citizens be improved by providing environmentally sound, safe, reliable, and affordable energy services and products.

(b) To improve the quality of life of this state's citizens, it is proper and appropriate for the state to undertake public interest energy research, development, and demonstration projects that are not adequately provided for by competitive and regulated energy markets.

(c) Public interest energy research, demonstration, and development projects should advance energy science or technologies of value to California citizens and should be consistent with the policies of this chapter.

(d) It is in the best interest of the people of California for the commission to positively contribute to the overall economic climate of the state within the roles and responsibilities of the commission as defined by statute, regulation, and other official government authority, including, but not limited to, providing economic benefits to California-based entities.

(e) Public interest energy research, demonstration, and development projects should be coordinated with other related state programs and research needs to meet overall state policy objectives related to energy efficiency, environmental protection, greenhouse gas emission reduction, clean technology job creation, and climate change adaptation in the most efficient manner possible.

SEC. 4. Section 25620.5 of the Public Resources Code is amended to read:

25620.5. (a) The commission may solicit applications for awards, using a sealed competitive bid, competitive negotiation process, commission-issued intradepartmental master agreement, the methods for selection of professional services firms set forth in Chapter 10 (commencing with Section 4525) of Division 5 of Title 1 of the Government Code, interagency agreement, single source, or sole source method. When scoring teams are convened to review and score proposals, the scoring teams may include persons not employed by the commission, as long as employees of the state constitute no less than 50 percent of the membership of the scoring team. A person participating on a scoring team may not have any conflict of interest with respect to the proposal before the scoring team.

(b) A sealed bid method may be used when goods and services to be acquired can be described with sufficient specificity so that bids can be evaluated against specifications and criteria set forth in the solicitation for bids.

(c) The commission may use a competitive negotiation process in any of the following circumstances:

(1) Whenever the desired award is not for a fixed price.

(2) Whenever project specifications cannot be drafted in sufficient detail so as to be applicable to a sealed competitive bid.

(3) Whenever there is a need to compare the different price, quality, and structural factors of the bids submitted.

(4) Whenever there is a need to afford bidders an opportunity to revise their proposals.

(5) Whenever oral or written discussions with bidders concerning the technical and price aspects of their proposals will provide better results to the state.

(6) Whenever the price of the award is not the determining factor.

(d) The commission may establish interagency agreements.

(e) The commission may provide awards on a single source basis by choosing from among two or more parties or by soliciting multiple applications from parties capable of supplying or providing similar goods or services. The cost to the state shall be reasonable and the commission may only enter into a single source agreement with a particular party if the commission determines that it is in the state's best interests.

(f) The commission, in accordance with subdivision (g) and in consultation with the Department of General Services, may provide awards on a sole source basis when the cost to the state is reasonable and the commission makes any of the following determinations:

(1) The proposal was unsolicited and meets the evaluation criteria of this chapter.

(2) The expertise, service, or product is unique.

(3) A competitive solicitation would frustrate obtaining necessary information, goods, or services in a timely manner.

(4) The award funds the next phase of a multiphased proposal and the existing agreement is being satisfactorily performed.

(5) When it is determined by the commission to be in the best interests of the state.

(g) The commission may not use a sole source basis for an award pursuant to subdivision (f), unless both of the following conditions are met:

(1) The commission, at least 60 days prior to taking an action pursuant to subdivision (f), notifies the Joint Legislative Budget Committee and the relevant policy committees in both houses of the Legislature, in writing, of its intent to take the proposed action.

(2) The Joint Legislative Budget Committee either approves or does not disapprove the proposed action within 60 days from the date of notification required by paragraph (1).

(h) The commission shall give priority to California-based entities in making awards pursuant to this chapter.

(i) The provisions of this section are severable. If any provision of this section or its application is held to be invalid, that invalidity does not affect other provisions or applications that can be given effect without the invalid provision or application.

For purposes of this Section and Section 25620, "California-based entity" means either of the following:

A corporation or other business form organized for the transaction of business that has its headquarters in California and manufactures in California the product that qualifies for the incentive or award, or a corporation or other business form organized for the transaction of business that has an office for the transaction of business in California and substantially manufactures in California the product that qualifies for the incentive or award, or substantially develops within California the research that qualifies for the incentive or award, as determined by the agency issuing the incentive or award.

SEC. 5. Section 379.6 of the Public Utilities Code is amended to read:

379.6. (a) (1) The commission, in consultation with the State Energy Resources Conservation and Development Commission, shall administer, until January 1, 2012, the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000.

(2) Except as provided in paragraph (3), the extension of the program pursuant to Chapter 894 of the Statutes of 2003, as amended by Chapter 675 of the Statutes of 2004 and Chapter 22 of the Statutes of 2005, shall apply to all eligible technologies, as determined by the commission, until January 1, 2008.

(3) The commission shall administer solar technologies separately, after January 1, 2007, pursuant to the California Solar Initiative adopted by the commission in Decision 06-01-024.

(b) Commencing January 1, 2008, until January 1, 2012, eligibility for the program pursuant to paragraphs (1) and (2) of subdivision (a) shall be limited to fuel cells and wind distributed generation technologies that meet or exceed the emissions standards required under the distributed generation certification program requirements of Article 3 (commencing with Section 94200) of Subchapter 8 of Chapter 1 of Division 3 of Title 17 of the California Code of Regulations.

(c) Eligibility for the self-generation incentive program's level 3 incentive category shall be subject to the following conditions:

(1) Commencing January 1, 2007, all combustion-operated distributed generation projects using fossil fuel shall meet an oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100 percent load.

(2) Combined heat and power units that meet the 60-percent efficiency standard may take a credit to meet the applicable NOx emissions standard of 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British thermal units (Btus) of heat recovered.

(3) Notwithstanding paragraph (1), a project that does not meet the applicable NOx emissions standard is eligible if it meets both of the following requirements:

(A) The project operates solely on waste gas. The commission shall require a customer that applies for an incentive pursuant to this paragraph to provide an affidavit or other form of proof, that specifies that the project shall be operated solely on waste gas. Incentives awarded pursuant to this paragraph shall be subject to refund and shall be refunded by the recipient to the extent the project does not operate on waste gas. As used in this paragraph, "waste gas" means natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

(B) The air quality management district or air pollution control district, in issuing a permit to operate the project, determines that operation of the project will produce an onsite net air emissions benefit, compared to permitted onsite emissions if the project does not operate. The commission shall require the customer to secure the permit prior to receiving incentives.

(d) In determining the eligibility for the self-generation incentive program, minimum system efficiency shall be determined either by calculating electrical and process heat efficiency as set forth in Section 218.5, or by calculating overall electrical efficiency.

(e) In administering the self-generation incentive program, the commission may adjust the amount of rebates, include other ultraclean and low-emission distributed generation technologies, as defined in Section 353.2, and evaluate other public policy interests, including, but not limited to, ratepayers, and energy efficiency and environmental interests.

(f) On or before November 1, 2008, the State Energy Resources Conservation and Development Commission, in consultation with the commission and the State Air Resources Board, shall evaluate the costs and benefits, including air pollution, efficiency, and transmission and distribution system improvements, of providing ratepayer subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation," as defined in Section 353.2, as part of the integrated energy policy report adopted pursuant to Chapter 4 (commencing with Section 25300) of Division 15 of the Public Resources Code. The State Energy Resources Conservation and Development Commission shall include recommendations for changes in the eligibility of technologies and fuels under the program, and whether the level of subsidy should be adjusted, after considering its conclusions on costs and benefits pursuant to this subdivision.

(g) (1) In administering the self-generation incentive program, the commission shall provide an additional incentive of 20 percent from existing program funds for the installation of eligible distributed generation resources from a California supplier.

(2) "California supplier" as used in this subdivision means any sole proprietorship, partnership, joint venture, corporation, or other business entity that manufactures eligible distributed generation resources in California and that meets either of the following criteria:

(A) The owners or policymaking officers are domiciled in California and the permanent principal office, or place of business from which the supplier's trade is directed or managed, is located in California.

(B) A business or corporation, including those owned by, or under common control of, a corporation, that meets all of the following criteria continuously during the five years prior to providing eligible distributed generation resources to a self-generation incentive program recipient:

(i) Owns and operates a manufacturing facility located in California that builds or manufactures eligible distributed generation resources.

(ii) Is licensed by the state to conduct business within the state.

(iii) Employs California residents for work within the state.

(3) For purposes of qualifying as a California supplier, a distribution or sales management office or facility does not qualify as a manufacturing facility.

SEC. 5.5. Section 3.5 of this bill incorporates amendments to Section 25620 of the Public Resources Code proposed by both this bill and SB 1760. It shall only become operative if (1) both bills are enacted and become effective on or before January 1, 2009, (2) each bill amends Section 25620 of the Public Resources Code, and (3) this bill is enacted after SB 1760, in which case Section 3 of this bill shall not become operative.

SEC. 6. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

Assembly Bill 2768

BILL NUMBER: AB 2768 CHAPTERED
BILL TEXT

CHAPTER 541
FILED WITH SECRETARY OF STATE SEPTEMBER 28, 2008
APPROVED BY GOVERNOR SEPTEMBER 28, 2008
PASSED THE SENATE AUGUST 5, 2008
PASSED THE ASSEMBLY AUGUST 7, 2008
AMENDED IN SENATE JUNE 16, 2008

INTRODUCED BY Assembly Member Levine

FEBRUARY 22, 2008

An act to amend Section 2851 of the Public Utilities Code, relating to solar energy.

LEGISLATIVE COUNSEL'S DIGEST

AB 2768, Levine. Energy: solar energy systems: pricing.

Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. A decision of the PUC adopted the California Solar Initiative. Existing law requires the PUC to undertake certain steps in implementing the California Solar Initiative, including requiring time-variant pricing for all ratepayers with a solar energy system, as defined, pursuant to a time-variant tariff developed by the PUC. Existing law authorizes the PUC to delay implementation of time-variant pricing for ratepayers with a solar energy system, until the effective date of the rates established in the next general rate case of the state's 3 largest electrical corporations. If the commission delays implementation of time-variant pricing, existing law requires that ratepayers required to take service under time-variant pricing between January 1, 2007, and January 1, 2008, and that would otherwise qualify for flat rate pricing, be given the option to take service under flat-rate or time-variant pricing.

This bill would delete that authorization to delay implementation and revise those time-variant pricing provisions by deleting the requirement to impose time-variant pricing on ratepayers with a solar energy system and, instead, authorizing the commission to develop a time-variant tariff.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Section 2851 of the Public Utilities Code is amended to read:

2851. (a) In implementing the California Solar Initiative, the commission shall do all of the following:

(1) The commission shall authorize the award of monetary incentives for up to the first megawatt of alternating current generated by solar energy systems that meet the eligibility criteria established by the State Energy Resources Conservation and Development Commission pursuant to Chapter 8.8 (commencing with Section 25780) of Division 15 of the Public Resources Code. The commission shall determine the eligibility of a solar energy system, as defined in Section 25781 of the Public Resources Code, to receive monetary incentives until the time the State Energy Resources

Conservation and Development Commission establishes eligibility criteria pursuant to Section 25782. Monetary incentives shall not be awarded for solar energy systems that do not meet the eligibility criteria. The incentive level authorized by the commission shall decline each year following implementation of the California Solar Initiative, at a rate of no less than an average of 7 percent per year, and shall be zero as of December 31, 2016. The commission shall adopt and publish a schedule of declining incentive levels no less than 30 days in advance of the first decline in incentive levels. The commission may develop incentives based upon the output of electricity from the system, provided those incentives are consistent with the declining incentive levels of this paragraph and the incentives apply to only the first megawatt of electricity generated by the system.

(2) The commission shall adopt a performance-based incentive program so that by January 1, 2008, 100 percent of incentives for solar energy systems of 100 kilowatts or greater and at least 50 percent of incentives for solar energy systems of 30 kilowatts or greater are earned based on the actual electrical output of the solar energy systems. The commission shall encourage, and may require, performance-based incentives for solar energy systems of less than 30 kilowatts. Performance-based incentives shall decline at a rate of no less than an average of 7 percent per year. In developing the performance-based incentives, the commission may:

(A) Apply performance-based incentives only to customer classes designated by the commission.

(B) Design the performance-based incentives so that customers may receive a higher level of incentives than under incentives based on installed electrical capacity.

(C) Develop financing options that help offset the installation costs of the solar energy system, provided that this financing is ultimately repaid in full by the consumer or through the application of the performance-based rebates.

(3) By January 1, 2008, the commission, in consultation with the State Energy Resources Conservation and Development Commission, shall require reasonable and cost-effective energy efficiency improvements in existing buildings as a condition of providing incentives for eligible solar energy systems, with appropriate exemptions or limitations to accommodate the limited financial resources of low-income residential housing.

(4) Notwithstanding subdivision (g) of Section 2827, the commission may develop a time-variant tariff that creates the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently. In developing the time-variant tariff, the commission may exclude customers participating in the tariff from the rate cap for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, as required by Section 80110 of the Water Code. Nothing in this paragraph authorizes the commission to require time-variant pricing for ratepayers without a solar energy system.

(b) Notwithstanding subdivision (a), in implementing the California Solar Initiative, the commission may authorize the award of monetary incentives for solar thermal and solar water heating devices, in a total amount up to one hundred million eight hundred thousand dollars ($100,800,000).

(c) (1) In implementing the California Solar Initiative, the commission shall not allocate more than fifty million dollars ($50,000,000) to research, development, and demonstration that explores solar technologies and other distributed generation technologies that employ or could employ solar energy for generation or storage of electricity or to offset natural gas usage. Any program that allocates additional moneys to research, development, and demonstration shall be developed in collaboration with the Energy Commission to ensure there is no duplication of efforts, and adopted by the commission through a rulemaking or other appropriate public proceeding. Any grant awarded by the commission for research, development, and demonstration shall be approved by the full commission at a public meeting. This subdivision does not prohibit the commission from continuing to allocate moneys to research, development, and demonstration pursuant to the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000, as modified pursuant to Section 379.6.

(2) The Legislature finds and declares that a program that provides a stable source of monetary incentives for eligible solar energy systems will encourage private investment sufficient to make solar technologies cost effective.

(3) On or before June 30, 2009, and by June 30th of every year thereafter, the commission shall submit to the Legislature an assessment of the success of the California Solar Initiative program. That assessment shall include the number of residential and commercial sites that have installed solar thermal devices for which an award was made pursuant to subdivision (b) and the dollar value of the award, the number of residential and commercial sites that have installed solar energy systems, the electrical generating capacity of the installed solar energy systems, the cost of the program, total electrical system benefits, including the effect on electrical service rates, environmental benefits, how the program affects the operation and reliability of the electrical grid, how the program has affected peak demand for electricity, the progress made toward reaching the goals of the program, whether the program is on schedule to meet the program goals, and recommendations for improving the program to meet its goals. If the commission allocates additional moneys to research, development, and demonstration that explores solar technologies and other distributed generation technologies pursuant to paragraph (1), the commission shall include in the assessment submitted to the Legislature, a description of the program, a summary of each award made or project funded pursuant to the program, including the intended purposes to be achieved by the particular award or project, and the results of each award or project.

(d) (1) The commission shall not impose any charge upon the consumption of natural gas, or upon natural gas ratepayers, to fund the California Solar Initiative.

(2) Notwithstanding any other provision of law, any charge imposed to fund the program adopted and implemented pursuant to this section shall be imposed upon all customers not participating in the California Alternate Rates for Energy (CARE) or family electric rate assistance (FERA) programs as provided in paragraph (2), including those residential customers subject to the rate cap required by Section 80110 of the Water Code for existing baseline quantities or usage up to 130 percent of existing baseline quantities of electricity.

(3) The costs of the program adopted and implemented pursuant to this section may not be recovered from customers participating in the

California Alternate Rates for Energy or CARE program established pursuant to Section 739.1, except to the extent that program costs are recovered out of the nonbypassable system benefits charge authorized pursuant to Section 399.8.

(e) In implementing the California Solar Initiative, the commission shall ensure that the total cost over the duration of the program does not exceed three billion three hundred fifty million eight hundred thousand dollars ($3,350,800,000). The financial components of the California Solar Initiative shall consist of the following:

(1) Programs under the supervision of the commission funded by charges collected from customers of San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company. The total cost over the duration of these programs shall not exceed two billion one hundred sixty-six million eight hundred thousand dollars ($2,166,800,000) and includes moneys collected directly into a tracking account for support of the California Solar Initiative and moneys collected into other accounts that are used to further the goals of the California Solar Initiative.

(2) Programs adopted, implemented, and financed in the amount of seven hundred eighty-four million dollars ($784,000,000), by charges collected by local publicly owned electric utilities pursuant to Section 387.5. Nothing in this subdivision shall give the commission power and jurisdiction with respect to a local publicly owned electric utility or its customers.

(3) Programs for the installation of solar energy systems on new construction, administered by the State Energy Resources Conservation and Development Commission pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, and funded by nonbypassable charges in the amount of four hundred million dollars ($400,000,000), collected from customers of San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company pursuant to Article 15 (commencing with Section 399).

Assembly Bill 2778

BILL NUMBER: AB 2778   CHAPTERED
BILL TEXT

CHAPTER 617
FILED WITH SECRETARY OF STATE SEPTEMBER 29, 2006
APPROVED BY GOVERNOR SEPTEMBER 29, 2006
PASSED THE SENATE AUGUST 31, 2006
PASSED THE ASSEMBLY AUGUST 31, 2006
AMENDED IN SENATE AUGUST 28, 2006
AMENDED IN SENATE AUGUST 23, 2006
AMENDED IN SENATE AUGUST 9, 2006
AMENDED IN SENATE AUGUST 7, 2006
AMENDED IN SENATE JUNE 15, 2006
AMENDED IN ASSEMBLY MAY 26, 2006

INTRODUCED BY Assembly Member Lieber
(Coauthor: Assembly Member Saldana)

FEBRUARY 24, 2006

An act to amend Section 379.6 of the Public Utilities Code, relating to electricity.

LEGISLATIVE COUNSEL'S DIGEST

AB 2778, Lieber Electricity: self-generation incentive program.

Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. Existing law requires the commission, in consultation with the State Energy Resources Conservation and Development Commission (Energy Commission), to administer, until January 1, 2008, a self-generation incentive program for distributed generation resources in the same form that exists on January 1, 2004, subject to certain air emissions and efficiency standards. In a decision, the PUC adopted the California Solar Initiative, which modified the self-generation incentive program for distributed generation resources and provides incentives to customer-side photovoltaics and solar thermal electric projects under one megawatt.

This bill would require the commission, in consultation with the Energy Commission, to administer, until January 1, 2012, a self-generation incentive program for distributed generation resources. The program in its currently existing form, would be applicable to all eligible technologies, as determined by the commission, until January 1, 2008, except for solar technologies, which the commission would be required to administer separately, after January 1, 2007, pursuant to the California Solar Initiative. The bill, commencing January 1, 2008, until January 1, 2012, would limit eligibility for nonsolar technologies to fuel cells and wind distributed generation technologies that meet or exceed the emissions standards required under the distributed generation certification program adopted by the State Air Resources Board. The bill would require the Energy Commission, on or before November 1, 2008, in consultation with the commission and the board, to evaluate the costs and benefits of providing ratepayer subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation," as defined, as part of the Energy Commission's integrated energy policy report.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Section 379.6 of the Public Utilities Code is amended to read:

379.6. (a) (1) The commission, in consultation with the State Energy Resources Conservation and Development Commission, shall administer, until January 1, 2012, the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000.

(2) Except as provided in paragraph (3), the extension of the program pursuant to Chapter 894 of the Statutes of 2003, as amended by Chapter 675 of the Statutes of 2004 and Chapter 22 of the Statutes of 2005, shall apply to all eligible technologies, as determined by the commission, until January 1, 2008.

(3) The commission shall administer solar technologies separately, after January 1, 2007, pursuant to the California Solar Initiative adopted by the commission in Decision 06-01-024.

(b) Commencing January 1, 2008, until January 1, 2012, eligibility for the program pursuant to paragraphs (1) and (2) of subdivision (a) shall be limited to fuel cells and wind distributed generation technologies that meet or exceed the emissions standards required under the distributed generation certification program requirements of Article 3 (commencing with Section 94200) of Subchapter 8 of Chapter 1 of Division 3 of Title 17 of the California Code of Regulations.

(c) Eligibility for the self-generation incentive program's level 3 incentive category shall be subject to the following conditions:

(1) Commencing January 1, 2007, all combustion-operated distributed generation projects using fossil fuel shall meet an oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100 percent load.

(2) Combined heat and power units that meet the 60-percent efficiency standard may take a credit to meet the applicable NOx emissions standard of 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British thermal units (Btus) of heat recovered.

(3) Notwithstanding paragraph (1), a project that does not meet the applicable NOx emissions standard is eligible if it meets both of the following requirements:

(A) The project operates solely on waste gas. The commission shall require a customer that applies for an incentive pursuant to this paragraph to provide an affidavit or other form of proof, that specifies that the project shall be operated solely on waste gas. Incentives awarded pursuant to this paragraph shall be subject to refund and shall be refunded by the recipient to the extent the project does not operate on waste gas. As used in this paragraph, "waste gas" means natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

(B) The air quality management district or air pollution control district, in issuing a permit to operate the project, determines that operation of the project will produce an onsite net air emissions benefit, compared to permitted onsite emissions if the project does not operate. The commission shall require the customer to secure the permit prior to receiving incentives.

(d) In determining the eligibility for the self-generation incentive program, minimum system efficiency shall be determined either by calculating electrical and process heat efficiency as set forth in Section 218.5, or by calculating overall electrical efficiency.

(e) In administering the self-generation incentive program, the commission may adjust the amount of rebates, include other ultraclean and low-emission distributed generation technologies, as defined in Section 353.2, and evaluate other public policy interests, including, but not limited to, ratepayers, and energy efficiency and environmental interests.

(f) On or before November 1, 2008, the State Energy Resources Conservation and Development Commission, in consultation with the commission and the State Air Resources Board, shall evaluate the costs and benefits, including air pollution, efficiency, and transmission and distribution system improvements, of providing ratepayer subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation," as defined in Section 353.2, as part of the integrated energy policy report adopted pursuant to Chapter 4 (commencing with Section 25300) of Division 15 of the Public Resources Code. The State Energy Resources Conservation and Development Commission shall include recommendations for changes in the eligibility of technologies and fuels under the program, and whether the level of subsidy should be adjusted, after considering its conclusions on costs and benefits pursuant to this subdivision.

CPUC Decision 01-03-073

Decision 01-03-073 March 27, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Proposed Policies and Programs Governing Energy Efficiency, Low-Income Assistance, Renewable Energy and Research Development and Demonstration.	Rulemaking 98-07-037 (Filed July 23, 1998)

INTERIM OPINION: IMPLEMENTATION OF PUBLIC UTILITIES CODE SECTION 399.15(b), PARAGRAPHS 4-7; LOAD CONTROL AND DISTRIBUTED GENERATION INITIATIVES

TABLE OF CONTENTS

INTERIM OPINION: IMPLEMENTATION OF PUBLIC UTILITIES CODE SECTION 399.15(b), PARAGRAPHS 4-7; LOAD CONTROL AND DISTRIBUTED GENERATION INITIATIVES

1. Summary

By today's decision, we adopt the Energy Division's program proposals for load control and distributed generation initiatives, pursuant to Pub. Util. Code § 399.15(b), with certain modifications and clarifications. We authorize a total of $137.8 million in funding for these programs, on an annual basis through December 31, 2004.

As discussed in this decision, we cannot raise electric utility rates until the Commission has determined that the rate freeze is over, or unless the Legislature specifically authorizes us to impose an additional charge during the freeze to recover these program costs. Nor can we ignore the Legislature's clear direction to include the cost of these programs in distribution revenue requirements. We recognize that SDG&E's rate freeze is over, although there is a rate cap on SDG&E's generation-related rate component. However, SDG&E is also subject to performance-based ratemaking (PBR) for its distribution revenue requirements. It would be inconsistent with the PBR framework to address the level of SDG&E's distribution revenue requirements and rates on a piecemeal basis. Instead, SDG&E should address the costs of these programs within the context of the PBR mechanism in its next PBR and cost-of-service proceeding. For PG&E and SCE, where the rate freeze is still in effect, we direct them to increase their distribution revenue requirements, without modifying current rates, to reflect today's authorized budgets.

Within 15 days, PG&E and SCE shall file Advice Letters increasing their electric distribution revenue requirements, without modifying current rates, for

this purpose. SDG&E shall address the funding of these programs in its next PBR and cost-of-service proceeding. On the gas side, PG&E, SDG&E and Southern California Gas Company (SoCal) should include the costs of these programs in their next gas rate recovery proceeding, e.g., the Biennial Cost Adjustment Proceeding. In the interim, all program costs should be tracked in memorandum accounts, and the utilities should establish such accounts for this purpose.

By directing this Commission to adopt new utility programs to reduce demand for electricity within six months of the passage of AB 970, the Legislature clearly stated its intent to proceed expeditiously with the deployment of these initiatives. Accordingly, PG&E, SDG&E, SCE and SoCal, collectively referred to as "the utilities," are directed to implement these programs without delay.

Under the adopted programs, SDG&E will administer a demand-responsiveness pilot program, targeted to reach 5,000 residential customers in its service territory. SCE will administer a similar pilot program, targeted to 5,000 small commercial customers. SDG&E and SCE will provide financial incentives to customers who agree to set their thermostats at pre-specified levels. Through an internet interface, the utility will monitor and verify actual interruption of loads at the customer site and provide interactive information to customers about their electric usage, in order to encourage peak demand reduction. Within certain parameters, customers will have the flexibility to override the thermostat settings, subject to pre-specified penalties.

We also authorize a pilot program to provide interactive consumption and cost information to small customers, such as historical energy bill information, representative energy usage and cost information for common appliances, and tariff options. PG&E will contract with an independent web designer to develop a website that provides customer online access to this information. Our goal is to reach 10,000 to 15,000 customers in PG&E's service territory. The program will be targeted to residential customers with relatively high monthly energy consumption, residential customers with swimming pools, homes and small businesses in the San Francisco peninsula or in Silicon Valley, and/or rural residences and small businesses.

We also authorize today a self-generation program across all the utility service territories. "Self-generation" refers to distributed generation technologies (microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells and internal combustion engines) installed on the customer's side of the utility meter that provide electricity for a portion or all of that customer's electric load. Under the program, financial incentives will be provided to distributed generation technologies as follows:

Incentive category	**Incentive offered**	**Maximum percentage of project cost**	**Minimum system size**	**Maximum system size**	**Eligible Technologies**
Level 1	$4.50/W	50%	30 kW	1 MW	▪ Photovoltaics ▪ Fuel cells operating on renewable fuel ▪ Wind turbines
Level 2	$2.50/W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery
Level 3	$1.00/W	30%	None	1 MW	▪ Microturbines utilizing sufficient

					waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing sufficient waste heat recovery and meeting reliability criteria

For SDG&E's service territory, the program will be administered (via contractual arrangement) through the San Diego Regional Energy Office. PG&E, SCE and SoCal will administer programs in their service territories.

All program administrators are required to outsource to independent consultants or contractors all program evaluation activities, and are encouraged to outsource as many other aspects of program implementation as possible. Independent contractors, and not program administrators[1], will perform all installation of technologies (hardware and software) at customer sites. We encourage the program administrators to coordinate and work closely with local governments, community-based organizations and business associations to recruit and contact interested customers.

[1] SDG&E would not be precluded from bidding to perform installations, since it will not be serving as program administrator.

Attachment 1 describes the authorized programs and funding levels in greater detail.

2. Background

AB 970, signed by the Governor on September 6, 2000, requires the Commission to initiate certain load control and distributed generation activities within 180 days. By ruling dated October 17, 2000, we assigned the implementation of Pub. Util. Code § 399.15(b) (codifying AB 970), paragraphs 4 through 7 to this proceeding. The relevant excerpts from the statute are as follows:

4. Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during peak electricity demand period.
5. Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.
6. Incentives for load control and distributed generation to be paid for enhancing reliability.
7. Differential incentives for renewable or super clean distributed generation resources.

In the same October 17, 2000 ruling, we directed the Energy Division to "develop specific program plans for implementing load control and distributed generation initiatives per § 399.15(b) for our consideration." We also consulted with the California Energy Commission (CEC) during the development of these programs.

The Energy Division report on recommended programs was issued for comment on January 31, 2001. The following organizations responded: Cannon Technologies, Capstone Turbine Corporation (Capstone), CEC, California Independent System Operator (ISO), California Retailers Association, Natural

Resources Defense Council (NRDC), Office of Ratepayer Advocates (ORA), PG&E, SDG&E/SoCal (jointly), SCE, Solar Development Corporation, The Utility Reform Network (TURN) and Xenergy, Inc. (Xenergy).

3. Energy Division's Program Recommendations

Below, we briefly summarize Energy Division's January 31, 2001 program proposals. For all programs, Energy Division recommends extensive outsourcing of installation, outreach, and as many aspects of program administration as possible. Energy Division also recommends that all program evaluation activities be outsourced to independent consultants or contractors.

For each program type and utility distribution company, the table below presents Energy Division's recommended annual collections and budgets through the end of 2004, which is the sunset period of AB 970.[2]

Utility	**Demand Responsiveness Budget ($ million)**	**Self Generation Budget ($ million)**	**Total Annual Budget ($ million)**
PG&E	$3.0	$60.0	$63.0
SCE	$5.9	$32.5	$38.4
SDG&E	$3.9	$15.5	$19.4
SoCal	NA	$17.0	$17.0
Total	**$12.8**	**$125.0**	**$137.8**

3.1 Demand-Responsiveness Programs

Energy Division proposes three pilot programs to implement demand-responsiveness initiatives pursuant to AB 970. SDG&E is designated to

[2] The comments appear to reflect some confusion on this point. We clarify that the program designs, budgets and annual funding levels are authorized through the end of 2004, consistent with the sunset period of AB 970, unless further modified by subsequent Commission decision.

administer the residential sector pilot, SCE to administer a small commercial sector pilot, and PG&E to implement an internet information test pilot reaching both residential and small commercial customers.

3.1.1 Residential Demand-Responsiveness Pilot Program

The residential pilot program proposed in the Energy Division report calls for installing remotely controlled thermostats using an internet-based communication link. This approach differs from existing "direct control" air-conditioning (A/C) cycling programs in that it uses internet technology as the means to communicate and monitor customer demand responsiveness. It also allows participants to maintain control over their equipment and even override the remote signal, if so desired, via the internet connection.

Energy Division recommends that the program be designed for a pool of 5,000 customers in SDG&E's service territory. Program participants would receive the equipment and installation free of charge from the utility. In addition, Energy Division recommends that the customer receive an incentive of $100 at the end of each year of program participation.[3] The incentive would be reduced by $2 each time the default thermostat setting is overridden, although it would never be less than $0.

Under Energy Division's proposal, SDG&E would target three distinct customer groups: 1) residential customers whose average monthly electricity consumption is greater than 250 kWh; 2) residential customers residing in geographical areas in SDG&E's service territory known to have high

[3] Several parties interpret Energy Division's recommendations to mean that only a one-time incentive would be offered at the end of the first year. This was not the intent, and Attachment 1 clarifies that incentives would be available for the entire duration of the pilot period, i.e., through the end of 2004.

electric consumption due to climate; and 3) customers residing in known limited- to moderate-income areas. Energy Division's preliminary estimates indicate that the program will save approximately $6.6 million over ten years (1.68 benefit-cost ratio).

3.1.2 Small Commercial Demand-Responsiveness Pilot Program

Energy Division recommends that 5,000 small commercial customers in SCE's service territory receive the same demand-responsiveness technology described above. These customers would be paid $250 at the end of each year of program participation. The incentive would be reduced by $5 each time the default thermostat setting is overridden.

SCE would administer the pilot and target commercial customers 1) with high average consumption in the summer, 2) with high consumption due to climate, and/or 3) located in small cities or rural areas. Energy Division estimates that the program will produce $13.1 million in savings over ten years (2.22 benefit-cost ratio).

3.1.3 Interactive Consumption and Cost Information For Small Customers Pilot Program

Energy Division recommends that PG&E contract with an independent web designer to develop a website that provides customer online access to historical energy bill information and presents information on tariff options, representative energy usage and cost information for common appliances, and other information to better support the needs of small customers. Energy Division proposes to reach 10,000 to 15,000 customers under this pilot, targeted to: 1) residential customers with monthly consumption of more than 250 kWh, 2) residential customers known to have swimming pools, 3) homes and small businesses in the San Francisco peninsula or in Silicon Valley, and/or 4) rural residences and small businesses.

Energy Division recommends that PG&E provide an incentive to a customer for actually logging onto the web site and accessing their own energy profile. The incentive could be in the form of a gift certificate of approximately $20 for a home improvement center, appliance store, or a particular product, such as a compact fluorescent lamp. Energy Division does not present a projection of expected energy savings in its report, due to the difficulty in generating such an estimate at this time.

3.2 Self-Generation Program

In its report, Energy Division defines "self-generation" as "distributed generation (DG) installed on the customer's side of the utility meter, which provides electricity for a portion or all of that customer's electric load." (Report, p. 5.) DG units sited on the utility-side of the customer's meter or owned by the distribution utility or a publicly-owned utility would not be eligible for incentives under Energy Division's proposal.

For the purpose of this program, Energy Division defines DG technologies as internal combustion engines, microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells, and combined heat and power or cogeneration. A subset of these technologies is considered renewable and eligible for differential incentives, as required by § 399.15(b) paragraph (7), including wind turbines, photovoltaics and fuel cells. Diesel-fired DG resources and emergency or backup systems would not be eligible under the program.

Energy Division proposes to limit the AB970 initiatives to renewable self-generation technologies that are 30 kW or greater in capacity. The proposed program offers incentives of $4.50 per watt of installed on-site renewable generation capacity, up to a maximum of 50% of total installation costs. Non-renewable self-generation (of any capacity) would also be eligible under the program, but with a lower incentive: $1.00 per watt of on-site generation, up to 30% of total costs.

In addition, Energy Division recommends that the utilities be required to waive interconnection and standby fees for any self-generation units installed through this program, as well as through the CEC renewables buy-down program.

Energy Division estimates program costs at $125 million, and projects benefits of $1.12 billion over the life of the units (benefit-cost ratio of 9.98).

4. Discussion

The comments we received on Energy Division's proposals were extensive and generally very constructive. In the following sections, we concentrate on the chief points of contention, and do not try to summarize every nuance in the comments.

4.1 Cost Recovery and Ratemaking

Pub. Util. Code § 399.15 specifies that the Commission shall "include the reasonable costs involved…in the distribution revenue requirements of utilities regulated by the commission, as appropriate."

To implement this provision, Energy Division recommends that funding for the proposed programs be collected from ratepayers through a non-bypassable usage-based charge, similar to the public goods charge. Energy Division assigns some of the program costs for self-generation to gas ratepayers; however, the majority of program costs are allocated to electric ratepayers. Energy Division recommends that program expenditures be tracked in a balancing account until ratemaking can be formally addressed in each electric utility's next cost of service/performance-based ratemaking proceeding, and SoCal's next biennial cost adjustment proceeding.

The utilities strongly object to Energy Division's recommendations to track costs until future rate recovery proceedings, arguing that such an approach would further jeopardize their already fragile financial position. SDG&E and SoCal take the positions that the entire public, and not just utility ratepayers, should be responsible for funding these programs.

TURN contends that most of the private benefits of the self-generation program accrue to non-residential program participants, and argues that residential customers should probably not subsidize these program costs at all. TURN requests that we track all program costs and benefits by customer class before adopting a specific cost allocation.

Until we have determined that the electric rate freeze is over for PG&E and SCE,[4] or until there is specific Legislative authority to impose an additional charge to recover these costs, we cannot consider granting the rate relief requested by the utilities, particularly not in this rulemaking proceeding. Nor can we ignore the Legislature's clear direction to include the cost of these programs in distribution revenue requirements. We recognize that SDG&E's rate freeze is over, although there is a rate cap on SDG&E's generation-related rate component. However, SDG&E is also subject to PBR for its distribution revenue requirements. It would be inconsistent with the PBR framework to address the level of SDG&E's distribution revenue requirements and rates on a piecemeal basis. Instead, SDG&E should address the costs of these programs within the context of the PBR mechanism in its next PBR and cost-of-service proceeding. For PG&E and SCE, where the rate freeze is still in effect, we direct them to

[4] We are examining this issue in A.00-11-038 et al.

increase their distribution revenue requirements, without modifying current rates, to reflect today's authorized budgets.

Should general fund appropriations be made available for demand-responsiveness and self-generation programs through subsequent Legislative action, we will consider augmenting today's approved programs. As described further below, the Energy Division's proposed programs consist of a focused set of pilots that can be broadened to encompass additional market sectors, technologies and system sizes, if and when appropriate.

Within 15 days, PG&E and SCE shall file Advice Letters increasing their electric distribution revenue requirements, without modifying current rates, for this purpose. SDG&E shall address the funding of these programs in its next PBR and cost-of-service proceeding. On the gas side, PG&E, SDG&E and Southern California Gas Company (SoCal) should include the costs of these programs in their next gas rate recovery proceeding, e.g., the Biennial Cost Adjustment Proceeding. In the interim, all program costs should be tracked in memorandum accounts, and the utilities should establish such accounts for this purpose. We will address specific cost allocation issues, including the one raised by TURN, when we address the rate recovery for these programs. In the meantime, the utilities should track all program costs and benefits by customer class, as TURN recommends.

Several parties request clarification regarding the allocation of costs for the self-generation program between electric and gas customers of the combined utilities. As discussed in the Energy Division report, some of the program costs for self-generation are assigned to gas ratepayers, as well as electric ratepayers, to reflect the public benefits (e.g., environmental) that will accrue to gas ratepayers as well. (Report, p. 7.) To establish the budget for each individual utility, Energy Division allocated the total costs for the self-generation program (developed on a statewide basis) to each service territory based on the relative proportion of costs currently allocated to each utility for energy efficiency programs. In our opinion, this represents a reasonable proxy for the allocation of benefits between gas and electric customers that we can expect from the self-generation program. In the Advice Letter filings described above, PG&E and SDG&E should present the specific factors they use to allocate costs between their electric and gas customers, for the purpose of increasing their electric distribution revenue requirements.

4.2 Size and Scope of AB 970 Initiatives

The comments reflect divergent opinions concerning the appropriate size and scope of the AB 970 demand-responsiveness and self-generation initiatives. ORA, for example, recommends a much larger overall program funded at $300 million per year, whereas other parties, such as PG&E, express concerns that the level of ratepayer funding proposed by the Energy Division may be too ambitious at the proposed $138 million annual level.

Parties also differ with respect to the scope of technologies and applications that should be eligible under the proposed programs. Whereas the Energy Division recommends that all customer sectors be eligible under the self-generation initiatives, ORA recommends limiting the incentives to non-public sector retrofit applications for residential and small/medium businesses. CEC recommends expanding eligibility to cover installations of DG systems on either side of the customer's meter, rather than only on the customer side, as recommended by Energy Division. Capstone recommends that the eligibility of renewable technologies be expanded by lowering the proposed size minimum of 30kW to 10kW, while PG&E and SDG&E recommend that self-generation units be subject to specific size limits.

With respect to the demand-responsiveness pilots, several parties propose significant expansions in scope to include additional options and technologies. For example, CEC recommends that the demand-responsiveness pilots include load curtailment options that address lighting (e.g., dimmable ballasts), metering technologies and market-based rate designs. CEC also recommends that the internet information test pilot be expanded to encompass full-scale deployment of metering systems that provide real-time usage data feedback through internet-based systems to customers. Cannon Technologies recommends that the pilots be expanded to include additional peak reduction technologies that allow the utilities to interrupt load on a one-way basis. Along these lines, TURN recommends that the Commission authorize expansions in the utilities' existing direct load control air-conditioning cycling programs as part of the AB 970 initiatives.

It is clear from the comments that the AB 970 initiatives could be expanded to greatly exceed the $138 million annual budget developed by Energy Division, by including a wider array of technologies, system sizes and applications. However, we are not persuaded that such expansion is in the public interest at this time. Instead, we concur with Energy Division that the § 399.15(b) initiatives should encompass a specific set of programs that can be tested on a pilot basis, without risking major investment of ratepayer funding on a full-scale statewide rollout. In this way, we will complement, rather than duplicate, initiatives for peak-demand reductions that are being explored in the Commission's rulemaking into the operation of interruptible programs (Rulemaking (R.) 00-10-002), proceeding on real-time pricing (Application (A.) 00-07-055), as well as programs being implemented under the CEC's AB 970 demand-responsiveness grant programs and renewables programs.

We believe that Energy Division's proposal for overall program size and scope best accomplishes this goal. Although several parties critique various aspects of the Energy Division's preliminary cost-benefit analysis, no party presents convincing argument or analysis to indicate that the level of proposed funding represents an unreasonable investment in demand-responsiveness and self-generation, relative to expected benefits.[5] We find that Energy Division's proposed annual funding level of $137.8 million for the § 399.15(b) demand-responsiveness and self-generation initiatives to be reasonable. Should additional funding become available via legislative action, we may consider expanding today's adopted demand-responsiveness and self-generation initiatives in a subsequent decision. We may also consider future funding increases for these programs via distribution rates, in this rulemaking, as we gain further experience with the programs adopted today.

SCE requests that we clarify the relationship between the programs adopted in this rulemaking and those being considered in the interruptible rulemaking, R.00-10-002. Nothing in this decision is intended to preclude or prejudge the Commission's consideration of additional initiatives involving interruptible programs (for all customer groups including the residential and small commercial sector) in that proceeding.

Although we generally concur with the Energy Division's proposed size and general scope of program initiatives, we do lower the minimum size requirement for receiving renewables incentives and make specific

---

[5] ORA presents an analysis of program cost-effectiveness that produces a benefit cost ratio for self-generation of 2:1, which is significantly less than Energy Division's preliminary analysis, but still comparable to the energy efficiency portfolios of the combined utilities. See ORA's comments, p. 5.

improvements to design and implementation parameters, in response to parties' comments. These modifications are discussed below, by general category and specific program initiative.

4.3 Program Administration

In its report, Energy Division assumes that the utilities will administer these programs "for the purposes of expediency," at least for 2001. (Report, p. 6.) SDG&E, SCE and SoCal concur with this approach, and recommend that the Commission affirmatively state now that the utilities will serve as the administrators through at least 2004. PG&E suggests that the Commission consider alternatives to utility administration, particularly if the expectation is to have utilities gear up for only a one-year assignment of program administration.

Although TURN does not propose a specific alternative to utility administration, it recommends that the Commission "find any other entity, private, non-profit or government, whose interest is more aligned with program success" to administer the self-generation program. In TURN's view, the utilities have presented positions in the distributed generation rulemaking (R.99-10-025) that reflect their perception that self-generation will reduce distribution revenues.

ORA expresses similar concerns, and recommends that SDG&E contract with the San Diego Regional Energy Office to provide administrative services for the self-generation programs in SDG&E's service territory. For the longer-term, ORA urges the Commission to establish a statewide network of Commission- certified regional energy offices to become administrators of both energy efficiency public purpose programs and self-generation programs.

ORA's proposal to designate the San Diego Regional Energy Office as program administrator for self-generation in SDG&E's service territory provides us with an opportunity to explore non-utility administration on a limited basis. We believe that such exploration will be valuable, given the concerns raised by parties regarding utility administration in this proceeding. The independent evaluation of the self-generation program should include an examination of the relative effectiveness of the two administrative approaches we adopt today.

Today's decision is not the appropriate forum for addressing the administrative structure of energy efficiency and self-generation programs for the longer-term, as proposed by ORA, and we will not adopt ORA's recommendation to establish regional energy offices for this purpose. However, nothing in today's decision precludes the Commission from considering alternatives to utility administration for future demand-responsiveness or self-generation program initiatives, based on our evaluation of the § 399.15(b) pilot results or other relevant information.

We direct the utilities to administer today's adopted pilot programs through the funding period, i.e., through December 31, 2004, with the exception of the self-generation program in SDG&E's service territory. For this program, SDG&E shall contract with the San Diego Regional Energy Office at the full budget amount specified herein ($15.5 million) to provide administrative services.

Energy Division recommends that the self-generation program be administered through the utility's existing standard performance contract (SPC) program. The SPC programs rely on third parties such as energy service companies to install equipment at customer facilities. Contractors then follow an established program procedure to install the equipment, measure and verify the equipment's impact on on-site consumption, and collect payment from the utility.

SDG&E/SoCal point out in their joint comments that SoCal does not currently administer an SPC program for energy efficiency. Therefore, SoCal requests flexibility to utilize other approaches for implementing the self-generation program. Xenergy also comments that their knowledge from conducting the statewide SPC program evaluations suggests that there may be other equally viable, and potentially less burdensome, program delivery choices. Like SoCal, the San Diego Regional Energy Office also does not have an existing SPC program. Given this, we will grant the program administrators flexibility in program delivery mechanisms, as long as they meet the following basic requirements:

- Available incentive funding (dollars per watt or percentage of system cost) is fixed on a statewide basis at the levels described below. (See table in Section 4.6.1.)
- Inspections are conducted to verify that the funded self-generation systems are actually installed and operating.
- The measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period. (See also Section 4.6.2 below.)
- As discussed below, the target expenditures for program administration be limited to 5% of program funding, with the exception of measurement and verification activities.

Finally, we clarify our expectations regarding outsourcing by program administrators. While we afford administrators the flexibility to select the manner of outsourcing (e.g., competitive bidding, sole source contracting) for these pilot programs, we do require program administrators to outsource to independent consultants or contractors all program evaluation activities. This requirement, coupled with the role of Energy Division in the evaluation process (see Section 4.8 below), will ensure that the programs are independently evaluated. In addition, all installation of technologies (hardware and software) at customer sites shall be performed by independent contractors and not utility personnel (for those utilities that will administer their own programs), or agency personnel (in the case of the San Diego Regional Energy Office). This requirement will ensure that market actors other than the program administrators are involved in program delivery, consistent with the manner in which we implement energy efficiency and low-income assistance programs.

Program administrators should also outsource other aspects of program administration and implementation, to the extent feasible. In particular, the majority of program marketing and outreach activities should be outsourced, to the extent feasible, although the program administrator should actively participate and assist contractor efforts for this purpose. We also encourage the program administrators to coordinate and work closely with local governments, community-based organizations, business associations and other entities to recruit and contact interested customers.

4.4 Budget Allocations and Fund Shifting Flexibility

In its January 31, 2001 report, Energy Division recommends that administrative expenses be limited to 5% of total program funding, for each program, and estimates a 3% budget allocation for certain evaluation activities in developing the overall funding levels.[6] Based on the comments of Xenergy and others, we believe that the administrators should be afforded some flexibility in allocating the authorized budget for each program (e.g., $3.9 million for the residential demand-responsiveness pilot) among the various cost categories

---

[6] See Energy Division Report, p. 6 and program budgets on pp. 15 and 21.

(administration, program evaluation, installation, service and operation costs, customer incentives). We agree with Energy Division that contract administration, marketing and regulatory reporting should be undertaken as cost-efficiently as possible by program administrators, so that proportionately more funds are available for hardware installations and customer incentives. However, we also recognize that it is difficult to estimate at the outset precisely what the appropriate allocation across cost categories should be for these programs. For this reason, we are establishing are target of administering these programs at a cost no greater than 5% of program funds, with the exception of measurement and evaluation activities. In any event, the actual cost of administration must be reasonable.

We will provide some flexibility, enabling the utilities to shift funds across cost categories within the overall budgeted amounts for each of the four programs (i.e., residential demand-responsiveness, small commercial demand-responsiveness, interactive information for small customers and self-generation programs), with the following exceptions. First, utilities may not shift any funds between the demand-responsiveness and self-generation programs that they administer without first obtaining Commission authorization. Second, one-third of the self-generation incentive funds is initially allocated to each of the self-generation categories. Although the utilities may exercise full discretion in moving funds from non-renewable self-generation categories to the renewable category, a utility must seek approval through advice letter prior to shifting additional funds into either of the non-renewable categories. The utilities shall not unreasonably withhold funds that could be used to deploy a greater amount of renewable self-generation. Finally, with the exception of measurement and evaluation activities, administrators must obtain Commission authorization to allocate more than 5% of program funds to "administrator costs" (i.e., contract administration, marketing, and regulatory reporting) within each program budget, for either demand-responsiveness or self-generation programs. Such authorization may be requested via Advice Letter. The funds authorized today are designated exclusively for approved § 399.15(b) demand-responsiveness and self-generation activities, and shall not be used for other purposes.

4.5 Design Parameters For Demand-Responsiveness Pilot Programs

As discussed above, Energy Division proposed a specific set of customer incentive levels and selected a particular load control technology to test under the residential and small commercial demand-responsiveness pilot programs. Several parties argue that the effectiveness of these programs, which are intended to induce customer behavioral changes, will best be achieved by allowing some flexibility and experimentation in the design of customer incentives, marketing approaches, technology type and other design parameters.

We agree that the effectiveness of these pilot programs will be enhanced by allowing some flexibility in their implementation. In particular, within the overall program funding levels authorized for each pilot, we will allow the utilities to experiment with alternative incentive designs. This may involve higher annual customer incentives and override penalties, or other signals that will differentiate usage of air conditioning during peak periods, as some parties suggest. Similarly, for the interactive consumption and cost information pilot, PG&E should have the flexibility to select the design and amount of the incentive, as suggested in its comments. (PG&E Comments, p. 4.)

We also will allow some flexibility in the overall number of pilot participants, as recommended by Xenergy and others. The utility administrators should consider the 5,000 participant level (for the residential and small commercial) and 10,000-15,000 participant level (for the small customer information pilot) as general targets, rather than strict requirements. In this way, the utility administers will be able to make reasonable modifications to other program design parameters (e.g., incentive levels) and also accommodate within the authorized program budgets any additional costs (e.g., equipment) that exceed the Energy Division's preliminary estimates.

SDG&E and others comment that the 250 kWh threshold for residential customers, as suggested in the Energy Division report, may not be an appropriate level for targeting higher electric load residences. We will afford SDG&E and SCE flexibility in establishing monthly consumption threshold levels in order to define a target group of participants with high average consumption.

However, we will not retreat from Energy Division's recommendation that the residential pilot also target limited- to moderate-income areas. In its comments, SDG&E argues that these customers are unlikely to use central air conditioning, an assertion that appears nonsensical given the high summer temperature climate zones within SDG&E's service territory. SDG&E and TURN also suggest in their comments that many limited- to moderate-income customers do not use personal computers (with internet access), and therefore cannot effectively participate in the residential pilot program. This reflects a basic misunderstanding of the "internet connectivity" referred to in Energy Division's report. Customers are not required to have internet capability via a personal computer, although this is one technology option. Rather, at a minimum, the thermostat equipment itself needs to be capable of internet interface, an option that does not require the customer to own or operate a personal computer. As discussed below, the utilities may elect to employ more than one technology in implementing the pilots, and we expect them to take into consideration the targeted market in making such choices.

Finally, we clarify our intent to allow some flexibility with respect to the specific technologies employed in the residential and small commercial demand-responsiveness pilot programs, and encourage the utilities to solicit multiple bids for this purpose. However, such flexibility is not intended to alter the focus of the pilot program recommended by Energy Division in its January 31, 2001 report. Consistent with those recommendations, we will not test technologies that simply allow the utility to interrupt load on a one-way basis. More specifically, any technology installed for the demand-responsiveness pilot programs must include the following features:

(1) Allow each customer some level of control over its own HVAC equipment (over-ride, etc.),

(2) Provide interactive information for consumers to make consumption decisions (e.g., via the thermostat or a computer internet connection), and

(3) Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

With respect to the interactive consumption and cost information pilot, Xenergy seeks to ensure that PG&E pursues other methods of providing customers with information on their energy usage profile and the benefits of various rate options, including mail out audits, telephone approaches and other alternatives. We do not intend this pilot to replace or diminish other effective methods that PG&E might also employ to provide energy information to smaller customers. However, we are not persuaded that including several, very different information dissemination approaches in a single pilot program, as suggested by Xenergy, would enhance the effort. We therefore retain the focus of the pilot, which is to implement and test the website approach proposed by the Energy Division.

4.6 Design Parameters For Self-Generation Program

Parties provided extensive comments on the various aspects of this proposed program, including incentive design, warranty requirements and the waiver of interconnection fees and standby charges. We summarize the main areas of contention in the following sections, and describe the modifications we adopt to Energy Division's proposal.

4.6.1 Technology Categories, Incentive Levels and Size Limits

Energy Division proposed two categories of self-generation technologies and associated incentives, based on a consideration of various system dimensions, including air emissions characteristics, fuel type, and system cost. After considering parties' comments, we modify certain aspects of Energy Division's proposal, as discussed below.

Several parties argue that incentives are not required or warranted for non-renewable self-generation systems. They argue against funding these systems because they are less efficient and more polluting than combined cycle technologies without waste heat recovery. We find merit in these concerns. Section 399.15(b) requires the Commission to establish both "incentives for… distributed generation to be paid for enhancing reliability" as well as "differential incentives for renewable and super clean distributed generation resources." We agree with PG&E that many fossil fuel applications would fail to satisfy any of these criteria.

As NRDC and TURN have pointed out, some micro-turbines operating on natural gas may be cleaner than large central station fossil generators, but combustion turbines and other small natural gas generators may actually be more polluting than modern central station facilities. While we have not created an exhaustive record in this proceeding from which to reach a firm conclusion, there is nothing to suggest that these technologies offer "super clean" generation, and when run on natural gas, certainly are not renewable.[7] Thus, to qualify for incentives, a fossil facility must serve to enhance system reliability.

Since all new generation could arguably add incrementally to the reliability of available generation, the language of § 399.15(b) suggests that the Legislature had in mind some other contribution to system reliability. In order to qualify for incentives, a fossil-fired facility must make a demonstrable contribution to the reliability of the transmission or distribution system. We

---

[7] We note that neither the Energy Division report nor the applicable statute provide a definition for "super clean" generation and find that the information before us does not provide a basis for declaring that any particular fuel-burning technology fits in such a category.

expect the utilities to work with those customers seeking incentives for fossil-fueled facilities to determine whether a proposed facility will enhance transmission or distribution reliability and document those benefits prior to approving an incentive payment.

We note Capstone's suggestion that micro-turbines be allowed to qualify for renewable incentive levels if they utilize renewable fuels. While it is logical to consider such facilities as providing renewable power, the incentives, that we are offering here, relate to capital cost. Capstone has not suggested that micro-turbines using renewable fuels would be appreciably more expensive to install a unit using renewable fuel than it would to install one using fossil fuels. However, it would be appropriate to enable such a facility to qualify for a normal micro-turbine incentive payment without meeting a "system reliability" test. We will consider expanding the program to include renewable-fuel micro-turbines once we determine what comprises a renewable fuel and are persuaded that a facility that once qualifies for a "renewable fuel" incentive would not later switch to fossil fuel. We seek the Energy Division's assistance in answering these questions and ask the staff to report back to us.

In addition, we will modify Energy Division's proposal, as recommended by TURN and ORA, to require that non-renewable technologies utilize waste heat recovery at the customer site. This further mitigates concerns over providing incentives to nonrenewable technologies. Accordingly, we modify the technology categories to require that fuel cells utilizing non-renewable fuels, microturbines, and internal combustion engines, be installed in combined heat and power applications, in order to be eligible for incentives under the self-generation program.[8] However, this requirement only becomes meaningful if the opportunity for heat recovery and reuse is meaningful. We ask the Energy Division to work with interested parties to develop heat recovery standards and to submit those standards to us for subsequent consideration.

Further the CEC recommends creation of an additional category for fuel cells operating on a non-renewable fuel source, stating that these systems do not yield the same benefits as fuel cells operating on renewable fuels. We agree that this distinction is warranted, and establish a $2.50 per watt incentive for this category, up to a maximum of 40% of project cost.

NRDC points out that a small number of very large units could easily use up most or all of the available funding, and suggests that the Commission consider adopting a size limit. PG&E specifically recommends limiting the size of units eligible for funding to 10 MW or less, because PG&E generally does not interconnect any project larger than 10 MW to its distribution system.

We believe that a size limitation is reasonable in order to provide options to assist in the installation of self-generation systems for as many California customers as possible. We prefer adopting a size limit to specifying a maximum percentage of available budget that can be paid to a single customer or system, which is an approach often used in program design. Use of such a mechanism in this case, however, would result in widely varying system size

---

[8] This modification also makes moot Energy Division's proposal to pay additional incentives for energy savings from the installation of combined heat and power systems.

limitations across service territories, because of differing budget allocations for the various administrators.

In our judgment, a system size limit of 1 MW will effectively address the concerns raised by NRDC and others. This size represents a fairly large installation for a single customer site and, at the same time, will not use up an unreasonable amount of program funding. We note that one system of this maximum size would only receive about one-third of the available funding in SDG&E's service territory, which is the smallest budgeted program. Individual customers may apply for incentives for more than one system, as long as the combined size does not exceed 1 MW.

In addition, we will preserve the funds available for use in this program by adjusting incentive payments to complement those offered by the CEC, rather than to compete with them. We discuss this change in Section 4.9, below.

Finally, CEC and NRDC express concern over potential overlap between Energy Division's proposed self-generation program and CEC's renewables buy-down program, even with the 30 kW minimum size requirement. We note that only seven systems above 30 kW have been installed under CEC's renewables buy-down program (from a total of 332 systems installed, or 2%) since its inception. Out of 176 additional systems that CEC has approved, but are not yet installed, only nine (5%) represent systems greater than 30 kW.[9] With the higher incentive level offered under today's adopted program,

---

[9] Source: From "Appendix C: Emerging Renewable Resources Account" in "Renewable Energy Program: Annual Project Activity Report to the Legislature", CEC publication nos. P500-00-004 (March 2000) and P500-00-021 (December 2000). Available online at

Footnote continued on next page

we believe that this market can be effectively reached, and will allow customers to participate in both programs, subject to the requirements set forth below.

With the modifications described above, we adopt the following incentive structure for the self-generation program:

Incentive category	Incentive offered	Maximum percentage of project cost	Minimum system size	Maximum system size	Eligible Technologies
Level 1	$4.50/W	50%	30 kW	1 MW	Photovoltaics Fuel cells operating on renewable fuel Wind turbines
Level 2	$2.50/W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3	$1.00/W	30%	None	1 MW	▪ Microturbines utilizing waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing waste

http://www.energy.ca.gov/reports/2000-12-04_500-00-004.PDF and http://www.energy.ca.gov/reports/2000-12-04_500-00-021.PDF.

					heat recovery and meeting reliability criteria

Based on California Retailers Association's comments, we clarify that hybrid DG systems that incorporate technologies from different incentive categories will receive payments based on the appropriate category. For example, a 100 kW system that utilizes 60 kW of microturbines and 40 kW of photovoltaics may receive $1.00/W for the 60 kW microturbine system and $4.50/W for the photovoltaic system. The program administrators shall provide for multiple technologies to be included in the customer's program application.

We require that program administrators keep the incentive levels fixed on a statewide basis throughout the program period. This requirement differs from the flexibility afforded to the administrators in the demand responsiveness programs for several reasons. First, the self-generation program is not designed to induce or monitor changes in consumer behavior, but rather to encourage the purchase of equipment. We believe that considerable flexibility in designing incentive levels is warranted in the former instance, but not necessarily in the latter. Moreover, a program design that varies the incentive payment levels may confuse consumers, or cause them to wait for the possibility of higher incentives before installing self-generation systems. In addition, we believe that the incentive payment for this program should be uniform statewide, as the market for self-generation technologies is not limited to or differentiated by a particular region or utility territory.

4.6.2 Monitoring Peak Demand Reductions

Energy Division's proposal for the self-generation program does not impose operating requirements or establish differential incentives related to on-peak operation. As a result, SDG&E/SoCal argue that the proposed program design does not ensure that generation units will contribute to peak demand reduction. PG&E also requests that we clarify whether units are required to operate during peak.

We are not persuaded that it is necessary or reasonable to impose operating requirements or incentives related to on-peak operation for this program. We believe that customers willing to invest in self-generation already have sufficient economic incentive from energy prices to employ time-of-use meters to measure their usage and to operate their self-generation systems during peak periods. Moreover, the system output for solar technologies is generally coincident with afternoon system peak without any operating requirements. In addition, a per-watt or percentage of system cost up-front payment is already employed through the CEC's Emerging Renewables Buy-Down Program ("renewables buy-down program"). Maintaining that approach should help minimize market confusion and disruption.

However, for program evaluation purposes, we will require program administrators to monitor the extent to which self-generation units installed under this program operate during peak periods. Program administrators should direct their independent evaluation consultants or contractors to develop a process for monitoring and collecting this data from program participants. At the end of the first program year, administrators should report to the Commission on peak operation from the program, and continue this reporting in subsequent years. By the end of the second program year, the consultants or contractors should present recommendations on incentive or program designs that could improve on-peak load reduction from self-generation.

It is not the intent of this evaluation process to penalize customers for not running their self-generation during peak periods. Nor may the program administrators use the collected information in any way to penalize or restrict the ability of customers to run their self-generation systems. Rather, the purpose of this information is to assist us in identifying potential improvements in program design and incentive mechanisms for self-generation programs in the future.

We offer an example of how this operational data might be obtained for evaluation and ongoing program design purposes. If the self-generation unit does not already have built-in logging capability for this purpose, then the unit could be outfitted with a low-cost single-channel datalogger and sensor (such as a relay switch) which would at least enable the utility to determine when the unit is operating and producing electrical output. Program administrators should develop and disseminate the specific requirements for system installations and monitoring capabilities required for program evaluation. The costs of the required monitoring equipment should be paid from program funds.

4.6.3 Warranty Requirements

Under Energy Division's proposal, self-generation systems must be covered by a warranty of not less than three years. CEC recommends a warranty period of five years for eligible systems, consistent with the requirements under CEC's renewables buy-down program and industry practices. We concur with the CEC's recommendation, and adopt a five-year warranty requirement for technologies in Levels 1 and 2 above.

For Level 3 technologies, however, we adopt a different requirement, based on SDG&E's observation that equipment manufacturers for these technologies typically offer warranties of only three to 12 months. In our opinion, a three-year warranty period is sufficient to ensure the continued operation and reliability of these systems and will encourage manufacturers and vendors to offer high quality products. We will adopt SDG&E's recommendation that the customer installing these self-generation systems purchase a three-year (minimum) maintenance contract from the manufacturer or vendor in order to comply with this requirement, if the system does not already include the required warranty. The customer may include the cost of this warranty in the system cost, for purposes of calculating their program incentive, up to the maximum percentage levels specified.

4.6.4 Waiver of Interconnection Fees and Standby Charges

The utilities strongly object to Energy Division's recommendation that interconnection fees and standby charges be waived for any self-generation units installed through the program. They argue that this recommendation is not justified and would ignore the Commission's recent decision on interconnection standards (Decision (D). 00-12-037) as well as the record developed in R.99-10-025 on standby charges. California Retailers Association, on the other hand, supports this recommendation and urges the Commission to adopt it.

We conclude that the appropriate forum for addressing interconnection fees and standby charges for distributed generation is R.99-10-025. We will not prejudge the issues still being considered in that proceeding, or modify prior Commission decisions regarding interconnection fees in designing the § 399.15(b) programs we adopt today. However, we do clarify that the interconnection fees (as defined in D.00-12-037) should be included in total installation costs for the purpose of determining the maximum size of the self-generation incentive. In this way, program dollars can be used to defray a portion of those costs.

4.7 Cost-Effectiveness

AB 970 directs the Commission to reexamine the methodologies used for cost-effectiveness, and revise them in "in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility." (§ 399.15(b)(8).) In its January 31, 2001 report, Energy Division proposes refinements to existing cost-effectiveness testing for this purpose, on a preliminary basis. Energy Division applied this new methodology to estimate the benefits and costs of the proposed self-generation and demand-responsiveness programs.

In their comments, the utilities and CEC contend that Energy Division's estimates for certain cost-effectiveness parameters (e.g., avoided transmission and distribution costs, reliability benefits) are overstated, and that the analysis does not take into account all of the costs associated with DG. ORA presents its own cost-effectiveness test results that it contends is more consistent with the approach (and inputs) used by the Commission to evaluate demand-side management programs.

Despite criticisms of certain aspects of Energy Division's analysis, none of the parties present convincing argument or facts to indicate that Energy Division's recommended programs will not produce sizeable public benefits.[10] They do recommend, however, that we continue to refine our cost-effectiveness

---

10 ORA presents an analysis of program cost-effectiveness that produces a benefit cost ratio for self-generation of 2:1, which is significantly less than Energy Division's preliminary analysis, but still comparable to the energy efficiency portfolios of the combined utilities. See ORA's comments, p. 5.

methods for the future. We concur with this recommendation, and clarify that the cost-effectiveness inputs and methods applied to the Energy Division proposals are limited only to these pilots.

An appropriate cost-effectiveness method for future, longer-term programs still needs to be developed. Energy Division's proposal to hire an independent consultant to perform such a task, utilizing funds appropriated for implementation of AB 970, is a reasonable approach. The scope of work should encompass the development of methodologies, input assumptions and forecasts for addressing § 399.15(b)(8) and other cost-effectiveness issues. In particular, we seek to develop a cost-effectiveness methodology that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation.

Energy Division should submit the final consultant report no later than December 31, 2002, and serve a notice of its availability to all appearances and the state service list in this proceeding (or its successor). Energy Division may hold public workshops with the consultant and interested parties during the development of this methodology, as it deems appropriate. The schedule for comments on the final report will be established by Assigned Commissioner or Administrative Law Judge ruling.

4.8 Program Evaluation

The programs adopted today will be evaluated during and after the program period, consistent with Energy Division's recommendations. For the residential and small commercial demand-responsiveness pilot programs, SDG&E and SCE will each conduct a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002. For the interactive and cost information pilot program, PG&E or its evaluation contractor will contact site users and non-users to discuss their satisfaction with the information on the site and suggest potential improvements. Program administrators for the self-generation program are required to perform program evaluations and load impact studies to verify energy production and system peak demand reductions, as described in greater detail in Section 4.6.2. They are also required to conduct an independent analysis of the relative effectiveness of the utility and non-utility administrative approaches we adopt today. (See Section 4.3.)

As discussed above, program administrators are required to outsource to independent consultants or contractors these evaluation activities. Energy Division shall assist program administrators in the development of the scope of work, selection criteria and the evaluation of submitted proposals to perform these program evaluations. The assigned Administrative Law Judge, in consultation with Energy Division and the program administrators, shall establish a schedule for filing the required evaluation reports. Energy Division should hold a workshop with program administrators as soon as practicable to develop scheduling proposals for this purpose.

4.9 Coordination and Eligibility Issues

Several parties commented on coordination and eligibility issues, particularly with respect to the CEC's programs. In particular, CEC and NRDC express concern over potential overlap between Energy Division's proposed self-generation program and CEC's renewables buy-down program. As the CEC points out, the CEC's program currently offers payments to renewable self-generators at a level lower than that approved in this order. The CEC argues that rather than add to the over-all deployment of renewable resources, a parallel program, offering larger incentives, would drive participants away from CEC program altogether. This would not be a sensible result.

We encourage the CEC to consider adopting a rebate level equal to that adopted in this order. However, as long as the CEC does not reduce its "buy-down" levels, it is appropriate for those receiving CEC incentives to also receive incremental payments from the utilities, bringing the total incentive payments up to the level approved in this order. Of course, this process must be carefully monitored to ensure that no customer can play one program off against another, to achieve exorbitant incentive payments.

It is unlikely that these programs can be successfully coordinated unless there is a common application process for involvement in either program. Thus, we direct the utilities and the Energy Commission to work with the CEC to develop a one-step application process, for use by all customers seeking a CEC renewables "buy-down" or utility renewable self-generation incentive payment.

Energy Division's program proposals for both demand-responsiveness and self-generation state that customers receiving incentives from these programs cannot also participate in any other interruptible or curtailable rate programs. Some parties, including TURN, argue that this prohibition should be eliminated. We agree with the Energy Division that participation in multiple programs could potentially allow an individual customer to receive multiple incentive payments for taking a single action. For example, a commercial customer could be receiving an interruptible rate discount, while at the same time utilizing incentives from the self-generation program to assist in the purchase of on-site generation for use during interruption periods. However, we do not find it necessary to prohibit customers from participating in an interruptible program with load that is not displaced by self-generation receiving incentives through this program.

In its comments, the CEC refers to the guidelines already in place for CEC's renewables buy-down program. Although we do not specifically adopt the CEC guidelines today, we do agree with the CEC that the administrators of these new self-generation programs should take advantage of the work already done by the CEC in developing appropriate program details to encourage self-generation. Those program parameters are available at http://www.energy.ca.us/greengrid/. In order to ensure that the new self-generation program is available as consistently as possible on a statewide basis, we direct SoCal to take the lead in convening a working group including PG&E, SCE, SDG&E, and the San Diego Regional Energy Office to select final program details for statewide implementation. These details may include eligibility criteria for heat recovery levels or system efficiency.

We note that SoCal and SCE generally serve the same service territory and customers. Accordingly, SCE and SoCal must coordinate their marketing and tracking of program incentives very carefully in order to ensure that customers do not receive incentives for the same self-generation equipment from both utilities. In the alternative, as ORA proposes, SoCal may administer the self-generation program for the combined geographic region, if SCE and SoCal so agree.

We recognize that additional incentives for self-generation and demand-responsiveness programs may be authorized by the Legislature in the coming months. As several parties point out, additional issues regarding eligibility and coordination may need to be addressed at that time. We delegate to the Assigned Commissioner the task of clarifying these and other implementation issues by ruling, if and when such a need arises.

5. Comments on Draft Decision

The draft decision of Commissioner Lynch and Administrative Law Judge Gottstein in this matter was mailed to the parties in accordance with Section 311(g)(3) of the Public Utilities Code and Rule 77.7(f)(9) of the Rules of Practice and Procedure. AB 970 requires that these programs be implemented in March 2001. In order to meet this goal, we must reduce the 30-day period for public review and comment. As defined in Rule 77.7(f)(9), the public necessity of adopting this order outweighs the public interest in having the full 30-day period for review and comment. We therefore shorten the comment period to seven days. Comments were filed on March 9, 2001 by SCE, SDG&E/SoCal, PG&E, ORA, NRDC, TURN, and Caterpillar, Inc. In response to the comments, we make minor corrections and clarifications to the draft decision and attached report, but do not make substantive changes to the program or ratemaking directives contained therein.

Findings of Fact

1. Energy Division's proposed programs to comply with Pub. Util. Code § 399.15(b), as modified by this decision, are expected to produce sizeable public benefits in the form of electric peak-demand reductions, environmental and other benefits, relative to their cost. Some of these benefits (e.g., environmental) are expected to accrue to gas, as well as electric, ratepayers.

2. The Commission has not yet determined that the electric rate freeze has ended for SCE and PG&E. The electric rate freeze is over for SDG&E, although there is a rate cap on SDG&E's generation-related rate component and SDG&E is also subject to PBR for its distribution revenue requirements.

3. The self-generation programs adopted today will produce significant public (e.g., environmental) benefits for all ratepayers, including gas ratepayers.

4. The Legislature has not authorized an additional charge, above current electric rate freeze levels, to recover the costs of § 399.15(b) programs. The current allocation of energy efficiency funding between gas and electric customers, on a percentage basis, is a reasonable proxy for the allocation of benefits between these customers that we can expect from the self-generation program.

5. Energy Division's proposed programs, as modified by this decision, encompass a specific set of initiatives that can be tested on a pilot basis, without risking major investment of ratepayer funding on a full-scale rollout. The proposed programs complement, rather than duplicate, initiatives for peak-demand reductions that are being explored in other Commission proceedings, as well as programs being implemented by the CEC.

6. ORA's proposal to designate the San Diego Regional Energy Office as program administrator for the self-generation program in SDG&E's service territory provides us with an opportunity to explore non-utility administration on a limited, pilot basis.

7. ORA's proposal to establish non-utility administrators for energy-efficiency and self-generation programs for the longer-term is beyond the scope of the issues related to § 399.15(b) implementation and Energy Division's report.

8. Energy Division's requirement that the self-generation program be administered through the utility's existing SPC program for energy efficiency poses implementation problems because SoCal and the San Diego Regional Energy Office do not currently administer such a program. There may also be equally viable, and potentially less burdensome, program delivery choices.

9. Requiring administrators to outsource program evaluation, and involving Energy Division in the process, will ensure that the programs authorized today are independently evaluated. Requiring that the installation of technologies at

customer sites be performed by independent contractors ensures that market actors other than the program administrators are involved in the programs. These requirements are consistent with the manner in which Commission-authorized energy efficiency and low-income assistance programs are implemented.

10. Because the programs we authorize today are new, it is difficult at this time to establish budget allocations across individual cost categories (e.g., administration, evaluation) that will not be unduly restrictive to program administrators. At the same time, affording program administrators unlimited flexibility in allocating the program budgets will not ensure that an appropriate level of funding is available for hardware installations and customer incentives.

11. The effectiveness of Energy Division's proposed demand-responsiveness programs will be enhanced by allowing some flexibility and experimentation in the design of customer incentives, marketing approaches, technology selections and other design parameters, within the guidelines described in this decision.

12. There is no evidence to support SDG&E's contention that limited- to moderate-income residential customers in its service territory are unlikely to use central air conditioning.

13. The residential and commercial demand-responsiveness programs require only that the thermostat itself is capable of internet interface, an option that does not require the customer to own or operate a personal computer.

14. Including several, very different information dissemination approaches in the interactive consumption and cost information pilot would detract from the focus of the pilot, i.e., to test a specific website approach, and would not enhance the effort.

15. Categorically excluding non-renewable technologies from the self-generation program adopted today would not be consistent with the legislative

intent reflected in Pub. Util. Code § 399.15 (b), which also allows technologies to qualify if they enhance system reliability.

16. Without waste heat recovery, certain non-renewable self-generation technologies may be less efficient and more polluting than combined cycle technologies. Requiring that these technologies utilize waste heat recovery at the customer site mitigates these concerns and is consistent with our goal of improving the overall efficiency of the electrical generation system.

17. Creating an additional category under the self-generation program for fuel cells operating on a non-renewable fuel source recognizes that these systems do not yield the same benefits as those that operate on renewable fuels.

18. Without some form of size or funding limitation, a small number of very large self-generation units could easily use up most or all of the available program budget. This problem can be addressed by 1) establishing a unit size limit or 2) specifying a maximum percentage of funding that can be paid to a single customer or system. The latter approach, however, would result in widely varying system size limitations across service territories because of differing budget allocations.

19. A system size limit of 1 MW for self-generation projects represents a fairly large installation for a single customer site and, at the same time, will not use up an unreasonable amount of program funding.

20. Affording program administrators flexibility to design the self-generation incentive levels for their individual programs may confuse consumers, or cause them to wait for the possibility of higher incentives before installing self-generation systems. In addition, a uniform, statewide incentive for this program recognizes that the market for self-generation technologies is not limited to or differentiated by a particular region or utility service territory.

21. Establishing on-peak/off-peak operating requirements or differential financial incentives for self-generation systems may not be necessary or reasonable because:

1) It is likely that customers willing to invest in self-generation already have sufficient economic incentive from energy prices to operate their systems during peak periods,

2) The system output for solar technologies is already generally coincident with afternoon system peak, without any further requirements, and

3) The incentive approach (dollars per watt installed) proposed by Energy Division is consistent with the CEC's renewables buy-down program and maintaining that approach should help minimize market confusion and disruption.

22. Monitoring the extent to which self-generation units installed under the program operate during peak periods will assist us in improving program design and incentive mechanisms for self-generation programs in the future.

23. Requiring a five-year manufacturer's warranty for technologies eligible under CEC's renewables buy-down program is consistent with CEC's program requirements and industry practice for those technologies.

24. Manufacturers of other distributed generation equipment (e.g., microturbines) typically offer warranties of only three to 12 months. Requiring a three-year warranty, either from the equipment manufacturer or through a maintenance contract, is sufficient to ensure continued operation and reliability of the system, and will encourage manufacturers and vendors to offer high quality products.

25. Any determinations in this decision regarding the waiver of interconnection fees or standby charges could prejudge the issues being considered and addressed in R.99-10-025.

26. The cost-effectiveness methods and inputs applied to Energy Division's proposals are preliminary and limited only to these pilot programs. An appropriate cost-effectiveness method for future, longer-term programs still needs to be developed.

27. Participation in multiple load control and self-generation programs would potentially allow an individual customer to receive multiple incentive payments for taking a single action. For example, a commercial customer could be receiving an interruptible rate discount, while at the same time utilizing incentives from the self-generation program to assist in the purchase of on-site generation for use during interruption periods.

28. Careful coordination is required to ensure that consumers are not "double dipping" and inappropriately receiving incentives from more than one program, whether sponsored by this Commission, CEC, the ISO or other state agencies. Coordination is particularly needed between SoCal and SCE in implementing the self-generation program, since they generally serve the same service territory and customers.

Conclusions of Law

1. Energy Division's proposed programs and annual funding levels for the implementation of Pub. Util. Code § 399.15(b), as modified by this decision and described in Attachment 1, are reasonable and should be adopted.

2. Until the Commission determines that the electric rate freeze has ended for SCE and PG&E, or until there is specific Legislative authority to impose an additional charge to recover the costs of § 399.15(b) programs, we cannot grant the rate relief requested by the utilities. Although the rate freeze has ended for SDG&E, it would be inconsistent with the PBR framework to address the level of

SDG&E's distribution revenue requirements and rates on a piecemeal basis, rather than within the PBR context in its next PBR/cost-of-service proceeding.

3. The utilities should proceed with today's authorized programs without further delay and establish memorandum accounts to track all program costs. As discussed in this decision, the utilities should also track all program costs and benefits by customer class.

4. It is reasonable that program administrators for the demand-responsiveness programs should have flexibility to design the customer incentive and pilot program according to the guidelines established in this decision and within the adopted program funding levels.

5. The residential demand-responsiveness pilot program should also target limited to moderate-income areas, as recommended by Energy Division.

6. The interactive consumption and cost information pilot should implement and test the website approach recommended by Energy Division, and not be expanded to include other information dissemination approaches. However, nothing in today's decision is intended to diminish or replace other effective methods that PG&E might also employ to provide energy information to smaller customers.

7. Given the concerns raised by parties regarding utility administration of self-generation programs, it is reasonable to explore a non-utility administrative option, on a limited basis, during the implementation of today's adopted programs. For this purpose, ORA's proposal to designate the San Diego Regional Energy Office as program administrator for SDG&E's self-generation program is a reasonable approach and should be adopted.

8. Program administrators should have flexibility in selecting program delivery mechanisms for the self-generation program, as long as they meet the basic requirements described herein.

9. In implementing today's adopted pilot programs, program administrators should outsource program implementation and administrative activities according to the guidelines established in this decision.

10. It is reasonable to establish fund-shifting rules that provide program administrators with sufficient flexibility to manage program costs, while ensuring that an appropriate proportion of funding goes to hardware installations and customer incentives.

11. It is reasonable to require that certain distributed generation technologies also employ waste heat recovery, as a prerequisite for funding under the self-generation program.

12. It is reasonable to establish a third category of technology and incentive level under the self-generation program for fuel cells operating on non-renewable fuel.

13. The incentive structure described in this decision for the self-generation program is reasonable and should be adopted.

14. Hybrid self-generation systems that incorporate technologies from different incentive categories should receive payments based on the appropriate category, as described in this decision.

15. The self-generation incentive levels we adopt today should be fixed and applied uniformly on a statewide basis throughout the program period, unless modified by subsequent Commission decision.

16. It is reasonable to require a warranty period of five-years for Level 1 and 2 technologies. For Level 3 technologies, it is reasonable to require a warranty

period of three years. The customer installing the self-generation system should purchase a minimum of a three-year warranty from the manufacturer or a vendor in order to comply with this requirement, if the system does not already include the required warranty. The customer may include the cost of this warranty in the system cost, for purposes of calculating their program incentive, up to the maximum percentage levels specified.

17. The appropriate forum for considering Energy Division's proposal to waive interconnection fees and standby charges is R.99-10-025, and not this proceeding. However, it is reasonable to use program funds to defray a portion of a project's interconnection fees (as defined in D.00-12-037) by including these fees in the total installation costs when determining the maximum size of the self-generation incentive.

18. As described in this decision, Energy Division should hire an independent consultant to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation.

19. The programs authorized today should be evaluated during and after the program period, as described in this decision.

20. Customers installing self-generation systems eligible for the CEC buy-down program should be allowed to augment the funding received from that program with funding available from today's adopted self-generation program, up to the maximum incentive limits.

21. It is reasonable that administrators of today's adopted self-generation programs should take advantage of the work already done by the CEC in developing appropriate program details to encourage self-generation.

22. SCE and SoCal should carefully coordinate their marketing and tracking of program incentives very carefully in order to ensure that customers do not receive incentives for the same self-generation equipment from both utilities. In the alternative, SoCal may administer the self-generation program for the combined geographic region, if SCE and SoCal so agree.

23. As discussed in this decision, the Assigned Commissioner may further clarify eligibility and other implementation issues by ruling, if and when such a need arises.

24. Public necessity, as defined in Rule 77.7(f)(9) requires that the usual 30-day review and comment period on the draft decision be shortened to seven days.

25. In order to implement today's adopted programs as expeditiously as possible, this order should be effective today.

INTERIM ORDER

1. The programs and annual budgets described in Attachment 1 are approved through December 31, 2004. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCal), collectively referred to as "the utilities," shall implement these programs without delay, consistent with today's decision.

2. The annual program budgets approved today are as follows:

Utility	Demand Responsiveness Budget	Self Generation Budget ($ million)	Total Annual Budget ($ million)
PG&E	$3,000,000	$60,000,000	$63,000,000
SCE	$5,940,000	$32,500,000	$38,440,000

SDG&E	$3,930,000	$15,500,000	$19,430,000
SoCal	NA	$17,000,000	$17,000,000
Total	**$12,870,000**	**$125,000,000**	**$137,870,000**

Within 15 days of the effective date of this decision, PG&E and SCE shall file Advice Letters increasing their electric distribution revenue requirements, without modifying current rates, to include today's authorized program budgets. SDG&E shall address the funding of these programs in its next PBR and cost-of-service proceeding. PG&E, SDG&E and SoCal shall include the costs of the programs allocated to gas customers in their next gas rate recovery proceeding, e.g., the Biennial Cost Adjustment Proceeding. In these filings, PG&E and SDG&E shall present the specific factors they use to allocate self-generation program budgets between their electric and gas customers. These factors shall reflect the current allocation of energy efficiency programs between these customers, as discussed in this decision. The utilities shall establish memorandum accounts to track program costs, and shall also track all program costs and benefits by customer class.

3. The utilities shall be the program administrators for the demand-responsiveness programs described in Attachment 1. For the self-generation program authorized in SDG&E's service territory, SDG&E shall contract with the San Diego Regional Energy Office to provide administrative services at the full budgeted amount for that program ($15.5 million). PG&E, SCE and SoCal shall administer the self-generation programs in their service territories. However, as discussed in this decision, SoCal and SCE may assign to SoCal the administration of self-generation programs for their combined service territories.

4. In implementing today's adopted programs, program administrators shall outsource program implementation and administrative activities as directed below:

- Program administrators shall outsource to independent consultants or contractors all program evaluation activities.
- All installation of technologies (hardware and software) at customer sites shall be done by independent contractors and not utility personnel (or agency personnel, in the case of the San Diego Regional Energy Office).
- Program administrators shall also outsource as many other aspects of program administration and implementation as feasible. In particular, the majority of program marketing and outreach activities should be outsourced, to the extent feasible, although the program administrator shall actively participate and assist contractor efforts for this purpose.
- Program administrators shall have the flexibility to select the manner of outsourcing (e.g., competitive bidding, sole source contracting) for the programs adopted today.

5. Under the self-generation program authorized today, program administrators shall offer the following incentives on a uniform, statewide basis:

Incentive category	**Incentive offered**	**Maximum percentage of project cost**	**Minimum system size**	**Maximum system size**	**Eligible Technologies**
Level 1	$4.50/watt (W)	50%	30 kilowatt (kW)	1 megawatt (MW)	▪ Photovoltaics ▪ Fuel cells operating on renewable fuel ▪ Wind turbines
Level 2	$2.50/W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3	$1.00/W	30%	None	1 MW	▪ Microturbines utilizing waste

					heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing waste heat recovery and meeting reliability criteria

6. As described in this decision, hybrid self-generation systems that incorporate multiple technologies shall be eligible for payments based on the appropriate incentive category, and the program applications should provide for these systems.

7. Interconnection fees for systems funded under the self-generation program shall be included in the total installation costs when determining the maximum size of the self-generation incentive. Today's decision does not address or adopt policies regarding the waiver of these fees or of standby charges for distributed generation technologies.

8. Level 1 and 2 technologies installed under the self-generation program shall be covered by a warranty of not less than five years, consistent with the requirements of the California Energy Commission's (CEC) Emerging Renewables Buy-Down Program. Level 3 technologies shall be covered by a warranty period of not less than three years. The customer installing the Level 3 system shall purchase a minimum of a three-year maintenance contract from the manufacturer or a vendor in order to comply with this requirement, if the system

does not already include the required warranty. The customer may include the cost of this warranty in the system cost, for purposes of calculating the program incentive, up to the maximum percentage levels allowed.

9. As described in this decision, program administrators shall have flexibility in selecting program delivery mechanisms for the self-generation program, subject to the following requirements:

- Available incentive funding (dollars per watt or percentage of system cost) is fixed on a statewide basis at the levels authorized in today's decision.
- Inspections are conducted to verify that the funded self-generation systems are actually installed and operating.
- The measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period.

10. Program administrators shall have flexibility to reallocate and shift funds within the authorized program budgets as described in this decision.

11. As described in this decision, program administrators for the demand-responsiveness programs shall have flexibility within the adopted program funding levels to 1) select the design and level of customer incentive, 2) establish monthly consumption threshold levels for defining the high consumption target groups, and 3) select the specific technologies employed in the residential and small commercial demand-responsiveness programs. However, any technology installed for these programs must include the following features:

- Provide customers some level of control (e.g., thermostat setting override) over their own heating, ventilation and air-conditioning equipment.

- Provide interactive information for consumers to make consumption decisions (e.g., via the thermostat or a computer internet connection), and

- Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

12. The programs authorized today shall be evaluated during and after the program period, as follows:

- For the residential and small commercial demand-responsiveness pilot programs, SDG&E and SCE shall each conduct a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002.
- For the interactive and cost information pilot program, PG&E shall contact site users and non-users to discuss their satisfaction with the information on the site and suggest potential improvements.

- Program administrators for the self-generation program shall perform program evaluations and load impact studies to verify energy production and system peak demand reductions. In particular, program administrators shall monitor the extent to which self-generation units installed under this program operate during peak periods. The costs of monitoring equipment installed for this purpose shall be paid from program funds. Program administrators shall direct their independent evaluation consultants or contractors to develop a process for monitoring and collecting this data from program participants. At the end of the first program year, administrators shall report to the Commission on peak operation from the program, and continue this reporting in subsequent years. By the end of the second program year, the consultants or contractors shall present recommendations on incentive or program designs that could improve on-peak load reduction from self-generation.

- Program administrators for the self-generation program shall also conduct an independent analysis of the relative effectiveness of the utility and non-utility administrative approaches we adopt today.

13. Program administrators shall outsource to independent consultants or contractors all program evaluation activities. Energy Division shall assist program administrators in the development of the scope of work, selection criteria and the evaluation of submitted proposals to perform these program evaluations. The assigned Administrative Law Judge, in consultation with Energy Division and the program administrators, shall establish a schedule for filing the required evaluation reports. Energy Division shall hold a workshop with program administrators as soon as practicable to develop scheduling proposals for this purpose.

14. As described in this decision, Energy Division shall hire an independent consultant to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Energy Division shall utilize funds appropriated for the implementation of AB 970 for this purpose.

The scope of work shall encompass the development of methodologies, input assumptions and forecasts for addressing § 399.15(b)(8) and other cost-effectiveness issues. Energy Division shall submit the final consultant report no later than December 31, 2002, and serve a notice of its availability to all appearances and the state service list in this proceeding (or its successor) . Energy Division may hold public workshops with the consultant and interested parties during the development of this methodology, as it deems appropriate. The Assigned Commissioner or Administrative Law Judge shall establish a schedule for comments on the final report.

15. Customers installing self-generation systems eligible for the CEC Emerging Renewables Buy-Down Program may augment the funding received

from that program with funding available from today's adopted self-generation program, up to the maximum incentive limits. Program administrators shall work with the CEC to ensure the appropriate tracking and accounting of who receives funding, so that an applicant can be easily crosschecked to make sure that there is no duplication.

16. Program administrators should take advantage of the work already done by the CEC in developing appropriate program details to encourage self-generation, and SoCal shall convene a working group including PG&E, SCE, SDG&E, and the San Diego Regional Energy Office to select final program details for statewide implementation, as soon as practicable.

17. SCE and SoCal shall coordinate their marketing and tracking of program incentives very carefully in order to ensure that customers do not receive incentives for the same self-generation equipment from both utilities. In the alternative, SoCal may administer the self-generation program for the combined geographic region, if SCE and SoCal so agree.

18. The Energy Division shall work with the respondent utilities and the California Energy Commission (CEC) to develop reliability criteria for fossil generators participating in the self-generation program and to ensure coordination with CEC programs as discussed in this decision.

This order is effective today.

Dated March 27, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
CARL W. WOOD
GEOFFREY F. BROWN
Commissioners

I dissent.

/s/ HENRY M. DUQUE
Commissioner

I dissent.

/s/ RICHARD A. BILAS
Commissioner

Attachment 1

Adopted Programs to Fulfill AB970 Load Control and Distributed Generation Requirements

(Public Utilities Code Section 399.15(b))

(Paragraphs 4 through 7)

March 26, 2001

Table of Contents

DEMAND - RESPONSIVENESS PROGRAMS

Residential Demand-Responsiveness Pilot Program

Overview

Brief description

This pilot program is designed to test the viability of a new approach to residential load control and demand-responsiveness through the use of internet technology and thermostats to affect HVAC energy use. This program is designed to include approximately 5,000 residential customers in the San Diego Gas & Electric service territory, representing an estimated 4 MW in peak demand reduction, to produce savings before the end of 2002. Consumers will be provided with the necessary technology installation and a small incentive for program participation.

Rationale

We prefer this program to other residential load control program options for the following reasons:

- Potential for peak demand reduction through control of residential and small commercial HVAC appliances
- Probability of customer acceptance
- Utilization of internet platform, which ensures likelihood of forward compatibility of technology
- Data collection ability for measurement and evaluation purposes
- Ability to test residential customer response to energy market demand and price fluctuations.

SDG&E will be the administrator of this pilot program.

Objectives

The main objective of this program is to fulfill the statutory requirement of AB970 contained in PU Code 399.15(b) paragraph 5. This paragraph requires the PUC to undertake the following activity: "Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals."

This pilot program will accomplish this directive, while simultaneously testing other assumptions of interest to the PUC including:

- Consumer participation and behavior patterns in the program
- Consumer satisfaction with newer interactive load control technologies
- Responsiveness of residential customer load to price or system demand signals
- Ability of such programs to deliver reliable and verifiable energy and demand savings.

Administrative responsibility

Commission role

For this pilot program, the Commission will perform traditional oversight of program design, roll out, and implementation. In addition, the Commission will post program information on its web site, so that consumers and other interested parties may learn about the program.

Utility role

SDG&E's functions for this pilot program include:

- Collecting and accounting for program funding from electric distribution customers
- Fine tuning program design and implementation
- Contracting with a third party for program services and equipment
- Acting as a contract administrator for program delivery
- Conducting customer recruiting for program participation, including posting information on utility web site
- Providing marketing assistance and facilitation to contractor(s) providing program delivery
- Performing regulatory reporting functions for the program
- Contracting with independent evaluator(s) to conduct a process evaluation beginning in 2001 and a load impact evaluation after 2002 and at the end of the pilot period (or another schedule established by the Commission).

Third party role

The third party (or parties) for this program will be equipment and service providers. These third parties will provide:

- Connected HVAC programmable thermostats for residential customers
- Data services and software
- Installation services
- System administration
- Communications services
- Settlements and/or reporting of program activity.

The utility will also be required to hire an independent contractor to perform the program evaluations and load impact studies to verify energy savings and peak demand reductions produced by this pilot program.

Eligibility

Participant

For purposes of this pilot program, SDG&E will target three distinct residential customer groups to test program concept viability for each. These include: 1) residential customers whose average monthly electricity consumption is greater than average for their customer class, with the exact specified consumption level to be determined by SDG&E; 2) residential customers residing in geographical areas in SDG&E service territory known to have high electricity consumption due to climate; and 3) customers residing in known limited- to moderate-income areas.

Technology

SDG&E has flexibility to select the exact nature of the technology utilized for this program, based on bids received from technology suppliers. The preferred technologies eligible to be included in this program should be programmable HVAC (connected) thermostats with two-way internet connectivity. SDG&E should not consider technologies that simply allow the utility to interrupt load on a one-way basis. At a minimum, the technology selected must have the following characteristics:

- Allow each customer some level control over its own HVAC equipment (override, etc.)
- Provide interactive information for consumers to make consumption decisions (e.g. via the thermostat or a computer internet connection), and
- Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

Program Expenditures

Budget

The table below includes initial estimates of annual program costs. These will be further refined once the utility issues a request for proposal and receives bids from contractors for exact costs.

Item and assumptions	Estimated Cost
Administrative Costs	
Contract administration, marketing, and regulatory reporting, and program evaluation (admin. and marketing may not exceed 5% of total budget)	$786,000
Installation, service, and operation costs	
Includes hardware, software, installation costs, communications costs, and customer incentives	$3,144,000
Total Annual Program Budget	**$3,930,000**

Incentive Structure

All program participants will receive the equipment and installation free of charge from the utility. In addition, the customer should receive an incentive at the end of each year of program participation. The program administrator shall set a program incentive, which may include an annual program incentive, override penalties, and/or on-peak interruption bonuses.

Verification

Purpose

The purpose of verification in the context of this program is to ensure that the technologies installed in residential homes through the program are installed and operating properly, and have the potential to deliver energy and peak demand savings. Verification should also produce the information necessary to estimate the energy and peak demand savings delivered at each customer site. Evaluation of the aggregate energy and demand savings achieved by the program should be the responsibility of the independent evaluator hired by the utility.

Responsibility

Responsibility for verification of installation of technologies and program operation should be retained by the utility. The utility should verify that the third party hired to deliver the program to consumers has installed operating equipment at residential customer sites. Site inspections should be done on a random sample of at least 10% of homes participating in the program. The utility or its agents should be responsible for these verification inspections.

Procedures or protocols

The hardware and software offered by the delivery contractor for this program should have the capability for periodic reporting of thermostat settings and consumer behavior, for payment settlement purposes. This information should also be made available to the program evaluator hired by the utility in order to estimate aggregate energy savings and peak demand reduction impacts of the pilot program.

Program process

The first step in the program process for this residential pilot is for the utility to issue an RFP and select a contractor or team of contractors to handle technology installation at customer sites, as well as software setup at the utility site. The contractor or contractors should be competitively selected through an open solicitation process. Once this contractor is selected, the utility and contractor can jointly begin to recruit residential customers for program participation.

Application

No application from individual customers should be required for this program, except a signed affidavit from the customer agreeing to have the equipment installed at their home and that they understand the terms and conditions of the pilot program. The contractor should have the authority to interact with the customer to make sure the necessary paperwork and program understanding is accomplished with each and every participating residential customer.

Installation

The contractor should also coordinate with individual consumers to arrange installation and setup of equipment. The utility may either manage this process or ask that the contractor handle the scheduling and coordination of equipment installations.

Operation

Once equipment has been installed at the customer's home, the program can be operated by setting a customer's thermostat to a preset default, the exact nature of which should be determined at the outset of the program by SDG&E. SDG&E should define what will be considered an "event." A maximum number of events during an annual program period should be set. A customer should have the ability to override the thermostat setting at any time during an event, with some loss of incentive. The program operators may wish to vary the thermostat settings and/or the numbers of hours over which each event occurs to test consumer tolerance and reactions to different operating procedures or schedules.

Payment

Customers should receive free equipment and installation at the beginning of program participation. At the end of each year of participation, the customer should receive from the utility for the amount set by the applicable incentive program.

Evaluation

The utility should contract with a third party consultant to conduct both a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002, and thereafter on a schedule to be set by the Commission.

Marketing and Promotion

At a minimum, information about the program should be made available to target households through the utility web site and bill inserts. Community-based organizations should also be involved in program marketing and outreach, to the extent feasible. In addition, utility representatives should work with the program delivery contractor to contact and recruit interested customers.

The CPUC will also include information about the program on its web site, and include links or contact information at the utility where consumers can request more information.

Small Commercial Demand-Responsiveness Pilot Program

Overview

Brief description

This pilot program is designed to test the viability of a new approach to small commercial load control and demand-responsiveness through the use of internet technology and thermostats to affect HVAC energy use. This program is designed to include approximately 5,000 small commercial customers in the Southern California Edison service territory, representing an estimated 4 MW in peak demand reduction, to produce savings before the end of 2002. Consumers will be provided with the necessary technology installation and a small incentive for program participation.

Rationale

We chose this program over other small commercial load control program options for the following reasons:

- Potential for peak demand reduction through control of small commercial HVAC appliances
- Probability of customer acceptance
- Utilization of internet platform, which ensures likelihood of forward compatibility of technology
- Data collection ability for measurement and evaluation purposes
- Ability to test customer response to energy market demand and price fluctuations.

We direct that SCE implement this pilot program.

Objectives

The main objective of this program is to fulfill the statutory requirement of AB970 contained in PU Code 399.15(b) paragraphs 4, 5, and 6 to "equip commercial buildings with the capacity to automatically control thermostats…", "evaluate installation of local infrastructure," and provide "incentives for load control." This pilot program will accomplish these directives, while simultaneously testing other assumptions of interest to the PUC including:

- Consumer participation and behavior patterns in the program

- Consumer satisfaction with newer interactive load control technologies
- Responsiveness of small commercial customer load to price or system demand signals
- Ability of such programs to deliver reliable and verifiable energy and demand savings

Administrative responsibility

Commission role

For this pilot program, the Commission will perform traditional oversight of program design, roll out, and implementation. In addition, the Commission will post program information on its web site, so that consumers and other interested parties may learn about the program.

Utility role

SCE's functions for this pilot program include:

- Collecting and accounting for program funding from electric distribution customers
- Fine tuning program design and implementation
- Contracting with a third party for program services and equipment
- Acting as a contract administrator for program delivery
- Conducting customer recruiting for program participation, including posting information on utility web site
- Providing marketing assistance and facilitation to contractor(s) providing program delivery
- Performing regulatory reporting functions for the program
- Contracting with independent evaluator(s) to conduct a process evaluation in 2001 and a load impact evaluation after 2002, and annually thereafter (exact schedule to be determined).

Third party role

The third party (or parties) for this program will be equipment and service providers. These third parties will provide:

- Connected HVAC programmable thermostats for small commercial customers
- Data services and software
- Installation services
- System administration
- Communications services

- Settlements and/or reporting of program activity.

The utility will also be required to hire an independent contractor to perform the program evaluations and load impact studies to verify energy savings and peak demand reductions produced by this pilot program.

Eligibility

Participant

For purposes of this pilot program, we recommend targeting three distinct small commercial customer groups, to test program concept viability for each: 1) small commercial customers with high average monthly consumption in the summer; 2) small commercial customers in geographical areas in SCE service territory known to have high electricity consumption due to climate; and 3) customers located in small cities or rural areas. Small commercial customers are precluded from participating in both the §399.15(b) demand responsiveness programs and other demand responsiveness programs offered by other state agencies or the interruptible programs being considered in R.00-10-002.

Technology

SCE has flexibility to select the exact nature of the technology utilized for this program, based on bids received from technology suppliers. The preferred technologies eligible to be included in this program should be programmable HVAC (connected) thermostats with two-way internet connectivity. SCE should not consider technologies that simply allow the utility to interrupt load on a one-way basis. At a minimum, the technology selected must have the following characteristics:

- Allow each customer some level control over its own HVAC equipment (override, etc.)
- Provide interactive information for consumers to make consumption decisions (e.g. via the thermostat or a computer internet connection), and
- Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

Program Expenditures

Budget

The table below shows initial estimates of annual program costs. These will be further refined once the utility issues a request for proposal and receives bids from contractors for exact costs.

Item and assumptions	Estimated Cost
Administrator Costs	
Contract administration, marketing, and regulatory reporting, and program evaluation (admin and marketing limited to a maximum of 5% of budget)	$1,188,000
Installation, service, and operation costs	
Includes hardware, software, installation costs, communications, and customer incentives	$4,752,000
Total Annual Program Budget	$5,940,000

Incentive Structure

All customers participating in the program should receive the equipment and installation free of charge from the utility. In addition, the customer should receive a one-time incentive payment at the end of each year of program participation. The program administrator shall set a program incentive, which may include an annual program incentive, override penalties, and/or on-peak interruption bonuses.

Verification

Purpose

The purpose of program verification is to ensure that the technologies installed at small commercial sites through the program are installed and operating properly, and have the potential to deliver energy and peak demand savings. Verification should also produce the information necessary to estimate the energy and peak demand savings delivered at each customer site. Evaluation of the aggregate energy and demand savings achieved by the program should be the responsibility of the independent evaluator hired by the utility.

Responsibility

The utility will have responsibility for verification of technology installation and program operation. The utility should verify that the third party hired to deliver the program to consumers has installed operating equipment at small commercial customer sites. Site inspections should be conducted on a random sample of at least 10% of small businesses participating in the program. The utility or its agents will be responsible for these verification inspections.

Procedures or protocols

The hardware and software offered by the delivery contractor for this program should have the capability for periodic reporting of thermostat settings and consumer behavior, for payment settlement purposes. This information should also be made available to the program evaluator hired by the utility in order to estimate aggregate energy savings and peak demand reduction impacts of the pilot program.

Program process

The first step in the residential pilot program process is for the utility to issue an RFP and select a contractor or team of contractors to handle technology installation at customer sites, as well as software setup at the utility site. The contractor or contractors should be competitively selected through an open solicitation process. Once this contractor is selected, the utility and contractor can jointly begin to recruit small commercial customers for program participation.

Application

No application from individual customers should be required for this program, except a signed affidavit from the customer agreeing to have the equipment installed at their site and that they understand the terms and conditions of the pilot program. The contractor should have the authority to interact with the customer to make sure the necessary paperwork and program understanding is accomplished with each and every participating small commercial customer.

Installation

The contractor should also coordinate with individual consumers to arrange installation and setup of equipment. The utility may either manage this process or ask that the contractor handle the scheduling and coordination of equipment installations.

Operation

Once equipment has been installed at the customer's site, the program can be activated by setting a customer's thermostat to a preset default for a maximum time period to be determined at the outset of the program. Each interruption period will be considered an "event." A maximum number of events during an annual program period should also be determined at the beginning of the program and communicated to the customer. A customer should have the ability to override the thermostat setting at any time during an event. The program operators may also wish to vary the thermostat settings and/or the numbers of hours over which each event occurs to test consumer tolerance and reactions to different operating procedures or schedules.

Payment

Customers will receive free equipment and installation at the beginning of program participation. At the end of each year of participation, the utility should pay the applicable program incentive to the customer.

Evaluation

The utility must contract with a third party consultant to conduct both a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002. Other evaluation schedules will be set by the Commission.

Marketing and Promotion

At a minimum, information about the program should be made available to target small commercial customers through the utility web site and bill inserts. Community-based organizations and small business associations should also be involved in program marketing and outreach, to the extent feasible. In addition, utility representatives should work with the program delivery contractor to contact and recruit interested customers.

The CPUC will also include information about the program on its web site, and include links or contact information at the utility where consumers can request more information.

Interactive Consumption and Cost Information for Small Customers

Overview

Description

The purpose of this program is to provide small, less sophisticated electric customers with access to high-quality information about the changing electricity market. This program requires PG&E to hire a web-site designer to develop a pilot site to test internet support for the needs of small customers. In addition to market information, including prices and costs, customers should be able to access their demand and consumption profiles, to help them understand better how their electric bills are (or will be) influenced by their load profiles.

Rationale

In this rapidly changing electricity market, many consumers, especially small ones, require access to dependable and straightforward information about electricity prices and costs. Missing from many press and public agency accounts of the crisis is the link between activities of the FERC, ISO, PUC, Legislature, Governor, or utility and the customer’s own energy profile. This pilot program will explore how provision of this type of information to smaller consumers can be tailored to help close the information gap.

Objectives

The program objectives are:

- Link market information with customer consumption information
- Test costs and benefits of this approach to consumer outreach (in addition to more traditional audit programs PG&E already offers)
- Link information contained on this site to customer solutions, including equipment and appliance manufacturers that provide high-efficiency products and services
- Explore the nexus of utility and third party services to consumers.

Administrative Responsibility

Commission role

The Commission will oversee program design and implementation. The Commission will also post announcements of this pilot on its web site.

Utility role

We nominate PG&E to administer this program, because we find their current online customer services already more advanced than those of the other utilities. We do not, however, recommend that PG&E develop this web site in-house. Instead, we recommend that PG&E take on the role of marketing the new site to a select group of customers. PG&E should also hire an independent web design consultant to develop the site. PG&E should hire an independent evaluation contractor to study customer reaction to the site and recommend changes and improvements before more widespread deployment of the strategy. We understand that several similar efforts have been ordered in various Commission decisions and that the utilities are already working on a joint statewide website. This effort is intended to be more robust and go beyond those activities.

Third party role

As discussed above, an independent web design contractor should develop and host the site linked from the PG&E main web site. Since the site will contain individual customer data, the web developer will likely be required to sign a confidentiality agreement to protect consumer usage data.

PG&E should hire a separate contractor to evaluate the program concept and customer reaction.

Eligibility

Participant

We recommend targeting this program at approximately 10,000-15,000 selected residential and small commercial customers in PG&E's service territory. Targeted customers could be any or all of the following:

- Residential customers with higher than average monthly consumption for their customer class (the exact specified amount is to be determined by PG&E)
- Residential customers known to have swimming pools
- Homes and small businesses on the San Francisco peninsula or in Silicon Valley
- Rural residences and small businesses

Technology

The site developed should be located on the web, hosted by an independent web site developer, and contain the following information, at a minimum:

- Up-to-date information about the structure of the California electricity market and how it affects small customers
- Information about how electricity is priced
- Rate tariff options for residential customers, explained in simple terms (not simply copies of tariff schedules)
- Customer online access to their own historical energy bill information
- Representative energy usage and cost information for common appliances, including refrigerators, ovens, dishwashers, clothes washers, dryers, televisions, and computers
- Links to manufacturers or retailers of high-efficiency appliances, tailored to the appliance or equipment needs of the individual
- Information about low-cost efficiency options and how much energy and bill savings they could produce, tailored to customer's geographic area
- Information about renewable self-generation options, costs, and benefits
- Links to manufacturers or retailers of self-generation equipment.

Program Expenditures

Budget

The table below gives preliminary annual budget information for planning purposes. Actual expenditures will likely vary, depending on the bids received by PG&E for web development and hosting services, as well as for program evaluation.

Item and assumptions	Estimated Cost
Administrator Costs	
Contract administration, marketing, and regulatory reporting, and program evaluation (admin. & marketing limited to 5% of total budget)	$600,000
Service and Operation Costs	
Includes web development and hosting, including secure access to customer confidential historical billing data, plus incentives for consumers	$2,400,000
Total Annual Program Budget	**$3,000,000**

Incentives

We recommend that PG&E provide a small incentive to a customer for actually logging onto the web site and accessing their own energy profile. This incentive could be in the form of a gift certificate of approximately $20 for a home improvement center, appliance store, or a particular product, such as a compact fluorescent lamp. This small bonus is intended to produce initial interest in viewing the site. Our intention is to provide customers with useful information on the site so that they will return to the site to further increase their energy consumption knowledge.

Verification

Purpose

In the case of this program, the purpose of verification is to determine how many customers access the web site, what kinds of information they look at once there, and if they make repeat visits. "Click-through" rates to sites of appliance manufacturers or retailers should also be tracked.

Responsibility

The web development consultant and hosting contractor will be responsible for verification. Verification information should be reported by PG&E in its periodic reporting to the Commission.

Program Process

Development

The first step is for PG&E to issue an RFP to hire a web development consultant to develop the web site. Development of the information aspects of the site should proceed first so all utility customers can use it. Customer-specific data, including secure access over the web, should be developed second.

Monitoring

The web-hosting contractor should perform periodic statistical analysis of site usage. The contractor should also provide PG&E with information about which customers have accessed the site. This will allow PG&E to send that customer their incentive coupon or gift certificate.

Payment

When the web site contractor notifies PG&E that a customer has access their own energy profile on-line, PG&E should process the incentive/gift and send it directly to the customer.

Evaluation

PG&E should hire an independent evaluation contractor to contact site users and non-users to discuss their satisfaction with the information on the site and suggest potential improvements.

Marketing and Promotion

While the site is under development, PG&E should select customers for receipt of program marketing materials encouraging testing of the site. Bill inserts should be sent to those eligible customers explaining the features of the site and offering the incentive gift certificate or coupon.

SELF - GENERATION PROGRAM

Self-Generation Program

Overview

Description

This program is intended to encourage installation of several types of self-generation technologies, both renewable and non-renewable, as detailed below. The installations may occur at any type of customer site in California. This proposal is designed to complement the current CEC buy-down program, which tends to fund smaller renewable units, while capturing the significant benefits of larger distributed generation units. Such benefits include: greater reduction of grid-supplied electricity, lower installation cost per kW, and, in the case of renewable installations, greater environmental benefits for all Californians.

This program targets photovoltaic, wind, and renewable fuel cell installations of 10 kW or greater. Customers installing units beginning January 1, 2001 should be eligible for program incentives regardless of when they become available.

This program offers differential incentives for self-generation technologies, differentiated by their fuel type, air emissions characteristics, and system costs. Photovoltaics, wind turbines, and fuel cells using renewable fuels are eligible for $4.50 per watt of installed on-site renewable generation capacity, up to a maximum of 50% of total installation costs. Nonrenewable fuel cells utilizing waste heat recovery and meeting reliability criteria may receive $2.50 per watt, up to a maximum of 40% of system cost. Any type of microturbine or internal combustion engine utilizing waste heat recovery may qualify for $1.00 per watt of on-site generation, up to 30% of total project costs. Administrators will administer this program through their existing energy efficiency standard performance contract (SPC) programs and/or similar program approaches. Contractors and energy service companies participating in this program will also be eligible to receive incentives on behalf of customers.

Rationale

In AB 970, the California legislature demonstrated that renewable technologies and self-generation are a policy priority. Self-generation and the use of renewables can provide significant benefits to Californians by improving the quality and reliability of the state's electricity distribution network, which is critical to the state's economic vitality, while protecting the environment and developing "green" technologies. The statute directs the Commission to adopt incentives for distributed generation to be paid for enhancing reliability, and differential incentives for "renewable or super-clean distributed generation resources."[11]

The self-generation incentives provided through this programs are intended to:

- encourage the deployment of distributed generation in California to reduce the peak electric demand;[12]
- give preference to new renewable energy capacity; and
- ensure deployment of clean self-generation technologies having low and zero operational emissions.

Given the high prices experienced over the last year, the transmission constraints that will persist in California for the near future, air quality considerations, California's residents and businesses are more receptive than ever to thinking about alternative generation resources. The biggest drawback is cost. It is in the best interest of all Californians to reduce the strains on infrastructure, economy, and environment, by actively promoting renewable and super-clean technologies.

Objectives

The main objectives of this program are to fulfill the requirements of PU Code §399.15 (b) paragraph 6 and 7, which call for "incentives for distributed generation to be paid for enhancing reliability" and "differential incentives for renewable or super clean distributed generation resources." This program also meets the following additional objectives:

- Utilize an existing network of service providers and customers to provide access to self-generation technologies quickly
- Provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just individual consumers
- Help support continuing market development of the energy services industry
- Provide access through existing infrastructure, administered by the entities with direct connections to and trust of small consumers

---

[11] AB970 contained in PU Code 399.15(b) paragraphs 6 and 7.

[12] For this reason, self-generators installed primarily as backup or emergency power are not eligible for the program.

- Take advantage of customers' heightened awareness of electricity reliability and cost.

Administrative Responsibility

Commission role

The Commission will oversee program design, roll out, and program implementation. In addition, the Commission will post program information on its web site, so that consumers and other interested parties may learn about the program.

Administrator role

PG&E, SCE and SoCalGas will administer the program in their own service territories, while SDG&E should contract with the San Diego Regional Energy Office (SDREO) to implement the program in its territory. We ask SoCalGas to lead a working group of all five entities to refine program design and ensure statewide consistency in program delivery. The utilities will be responsible for collecting and accounting for funding collected from their distribution customers. All administrators (including SDREO) will be responsible for the following:

- Fine tuning program design and implementation
- Modifying program forms and administrative procedures
- Verifying, or hiring a contractor to verify, installation of systems at customer sites
- Dispersing payment for installed systems after verification of installation
- Working with contractors and energy service companies participating in other energy efficiency programs to conduct customer recruiting for program participation
- Posting program information, including application form, on the internet
- Performing regulatory reporting functions for the program
- Contracting with independent evaluator(s).

Third party role

The third party (or parties) may be energy service companies or general contractors who install self-generation systems at eligible customer sites. The administrator will be required to hire an independent contractor to perform the program evaluations and load impact studies to verify energy production and system peak demand reductions produced by this program.

Eligibility

Participant

Any customer of an investor-owned distribution company in California is eligible to receive incentives from this program. In addition, contractors or energy service companies who install self-generation units at these customers' sites are also eligible to receive program incentives in lieu of customer receipt of the incentives, as long as the customer agrees.

The following entities are not eligible for incentives under this program:

- Customers who have entered into contracts for DG services (e.g. DG installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services; (this does not include power purchase agreements, which are allowed)
- Customers who are participating in utility interruptible or curtailable rate schedules or programs
- Customers who are participating in any other state agency-sponsored interruptible, curtailable, or demand-responsiveness program
- Utility distribution companies themselves or their facilities.

Technology Eligibility and Incentive Structure

For purposes of this program, renewable and non-renewable self-generation technologies will be eligible for incentives according to the following structure:

Incentive category	Incentive offered	Maximum percentage of project cost	Minimum system size	Maximum system size	Eligible Technologies
Level 1	$4.50/W	50%	30 kW	1 MW	▪ Photovoltaics ▪ Fuel cells operating on renewable fuel ▪ Wind turbines
Level 2	$2.50/W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3	$1.00/W	30%	None	1 MW	▪ Microturbines utilizing waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing waste heat recovery and meeting reliability criteria

Systems installed under Levels 1 and 2 must be covered by a warranty of not less than five years. Systems installed under Level 3 must be covered by a warranty of not less than three years. Where those Level 3 systems are not warrantied by the manufacturer for at least three years, customers should purchase a minimum of a three-year service contract from the manufacturer or a vendor in order to comply with this requirement. The customer may include the cost of this warranty in the system cost, for purposes of calculating their program incentive, up to the maximum percentage levels specified.

"Hybrid" self-generation systems that incorporate technologies from different incentive categories will receive payments based on the appropriate category. Diesel-fired systems are ineligible for participation in this program.

In addition, applicants to the program will be allow to consider interconnection fees charged by the utilities as part of the cost of the system, for purposes of calculating the incentive.

Program Expenditures

Budget

The table below gives annual estimates of program costs for each administrator.

Item and Assumptions	PG&E	SCE	SoCalGas	SDREO
Administrator Costs				
Incremental design, contract administration, marketing, regulatory reporting, and program evaluation (admin. and marketing not to exceed 5%)	$12,000,000	$6,500,000	$3,400,000	$3,100,000
Incentives				
Maximum available for all types of systems	$48,000,000	$26,000,000	$13,600,000	$12,400,000
Total Program Budget	**$60,000,000**	**$32,500,000**	**$17,000,000**	**$15,500,000**

Verification

Purpose

The purpose of program verification is to ensure that the self-generation units installed at customer sites are installed and operating properly, and have the potential to deliver electric generation. Safety of electrical connections and interconnection (if applicable) should be an important priority of the verification process.

Responsibility

As with the current SPC programs, the responsibility for measurement and verification of energy savings rests with the applicant to the program. The administrator or its independent contractors should be responsible for inspection of installations, but not verification of energy production from self-generation systems.

Procedures or protocols

The existing SPC programs have protocols and procedures designed to measure energy savings from energy efficiency measures. These protocols should be modified and updated to include measurement and verification of energy production from self-generation and cogeneration units, as well as any associated gas or electric efficiency gains. Although the administrator has discretion to utilize other non-SPC program delivery, any program design must include a protocol for estimating the energy production of the self-generation units through a consistent and accepted methodology (using monitoring, statistical sampling techniques, etc.). The administrators are responsible for designing, or hiring a contractor to design, the exact protocols required by the self-generation programs.

Program process

The preferred approach is to operate the self-generation program through existing SPC program rules and procedures, where possible. The administrators, through the working group led by SoCalGas, should finalize all program details prior to program launch in each service territory. Additional requirements related to self-generation installations are included below.

Application

The applicant must provide copies of the following information as proof of installation and parallel operation with the utility distribution grid:

- the final purchase invoice of the self-generation system;
- affidavit signed by the installer of the system and customer stating that the system has been purchased and installed, and that an administrator representative or contractor will be allowed to inspect or monitor the system;
- the building permit showing final inspection signoff;
- an interconnection agreement executed with the utility for the system (if applicable).

Marketing and Promotion

Program marketing should be conducted through existing networks of SPC program service providers. Administrators are also required to provide information about this program to professional organizations representing distributed generation manufacturers, vendors, potential customers, and other interests. Examples of such organizations are the Distributed Power Coalition of America (DPCA) and the California Alliance for Distributed Energy Resources (CADER). Promotion should also be conducted through bill inserts, Internet (e.g. PUC, utility, and industry additional web sites), and other media.

CPUC Decision 04-12-045

Decision 04-12-045 December 16, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Generation and Distributed Energy Resources.	Rulemaking 04-03-017 (Filed March 16, 2004)

ORDER TO MODIFY THE SELF GENERATION INCENTIVE PROGRAM AND IMPLEMENT ASSEMBLY BILL 1685

TABLE OF CONTENTS

ORDER TO MODIFY THE SELF GENERATION INCENTIVE PROGRAM AND IMPLEMENT ASSEMBLY BILL 1685

1. Summary

This decision adopts modifications to the Self Generation Incentive Program (SGIP), which provides incentives to businesses and individuals who invest in distributed generation. We implement the provisions of Assembly Bill (AB) 1685, eliminate the maximum percentage payment limits, and reduce the incentive payments for several technologies, including Level 1 solar projects, which we reduce to $3.50 per watt, effectively immediately. We also eliminate the "maximum percentage payment limits," which have caused considerable administrative complexity. We direct the SGIP program administrators to expand opportunities for public input in three Working Group activities: developing a declining rebate schedule, developing an exit strategy, and adapting a data release format.

Program costs will continue to be included in utility distribution revenue requirements. The utilities will track these costs in the SGIP memorandum accounts created by Decision (D.) 01-03-073 for recovery in their respective general rate cases or other authorized proceedings.

2. Background

The Commission adopted certain load control and distributed generation initiatives on March 29, 2001, pursuant to AB 970. We authorized a total budget of $137.8 million annually through 2004: $12.8 million for load control, and $125 million for self generation. Under the self generation program adopted in D.01-03-073 and modified in D.02-09-051, certain entities qualify for financial incentives to install three different categories (or levels) of clean and renewable distributed generation used to serve some portion of a customer's onsite load:

Level 1: The lesser of 50% of project costs or \$4.50/watt for photovoltaics, wind turbines, and fuel cells operating on renewable fuels;

Level 2: The lesser of 40% of project costs or \$2.50/watt for fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery,

Level 3:

- 3-R: The lesser of 40% of projects costs or \$1.50/watt for microturbines, internal combustion engines, and small gas turbines utilizing renewable fuel.
- 3-N: The lesser of 30% of project costs or \$1.00/watt for the above combustion technologies operating on non-renewable fuel, utilizing sufficient waste heat recovery and meeting certain reliability criteria.

The Commission recognized that certain events, such as legislation, market activity, or outcomes of the SGIP program evaluation process, could require modifications to the SGIP during the course of the program. In subsequent orders, the Commission took actions to refine the program, such as adopting a reliability requirement, developing renewable fuel criteria, and increasing the maximum eligible size from 1 MW to 1.5 MW.

On October 12, 2003, the Governor signed AB 1685. The legislation adopts emissions and efficiency requirements that fossil-fueled DG projects must meet in order to be eligible for SGIP rebates, and extends the SGIP through December 31, 2007. The new emissions standards go into effect in two phases: January 1, 2005, and January 1, 2007.

On September 27, 2004, the Governor signed AB 1684. This law makes projects that operate on waste gas eligible for incentives, subject to certain requirements in the law.

On December 10, 2003, an Administrative Law Judge (ALJ) ruling issued in Rulemaking (R.) 98-07-037 requested comments to the evaluation reports prepared by Itron, as well as on other SGIP-related issues.

On July 9, 2004, the ALJ issued a ruling seeking comments on an Energy Division report that recommended program modifications.

The following organizations responded to one or both ALJ rulings: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company and San Diego Gas & Electric (Sempra), California Solar Energy Industry Association (CALSEIA), The Center for Energy Efficiency and Renewable Technologies (CCERT), Distributed Energy Strategies (DES), Joint Parties Interested in Distributed Generation[1] (JPIDG), Powerlight Inc. (Powerlight), RWE Scott Solar Inc., MegaWatt Inc., Sacramento Municipal Utility District (SMUD), The City and County of San Francisco (San Francisco), the City of Oakland/Rahus Institute, Prevalent Power, Uni-Solar, Occidental Power, Borrego Solar Systems Inc.,[2] and the California Fairs Alliance of Western Fairs Association (Western /Fairs). This decision resolves the issues addressed in Energy Division's report.

3. Discussion

3.1 Incentive Levels and Size Limits

Under the current structure, incentives are based on a project's generating capacity, measured in watts. The incentive payment is capped at a certain

---

[1] JPIDG membership includes Capstone Turbine Corporationems Inc., Chevron Energy Solutions, Cummins Cal-Pacific, Cummins, Inc., next.edge, Inc., Northern Power Systems, Inc., Real Energy Inc., Simax Energy, and Solar Turbines, Inc.

[2] Borrego represents Eco Energies, Inc., Sun Light and Power, Quality Solar, and CC Energy.

percentage of eligible installed costs. Both the per-watt payment and the percentage cap vary by technology level. For example, a solar panel project receives $4.50 per watt of capacity, up to a maximum of 50% of eligible installed project costs.

The Working Group and program applicants have described the time-consuming process to prepare and review hundreds of pages of itemized project costs to determine whether the costs are eligible under the incentive cap. Energy Division proposes to remove the maximum percentage cap, and to set incentives according to installed capacity. Energy Division believes this approach would be simpler and less costly for program administrators and applicants, would accelerate the rebate payment process, and provide an incentive for developers to reduce project costs. As an alternative, CALSEIA and Capstone propose to allow applicants to select one of two approaches, either a dollar per watt or percentage cap structure, on a project-by-project basis. We find that it is reasonable to adopt the Energy Division's recommendation and will set incentives according to installed capacity. Streamlining the SGIP program is in the public interest. In addition, we reduce the per-watt incentive, as discussed below.

The Energy Division report also recommends the Commission adopt CALSEIA's proposal to reduce Level 1 incentives from $4.50 per watt to $4.05 per watt. Program administrators have exceeded their allocated Level 1 budgets for 2004, and have transferred funds from other categories in an effort to meet

Level 1 demand. Both PG&E and SDREO created waiting lists to ensure an orderly reservation process once additional funding becomes available.

While parties agree that the Commission must reduce incentive payments, most believe CALSEIA's proposed incentive payment is too high. To support this claim, PG&E provides an analysis which indicates some projects would actually receive higher incentive payments under the combined effect of eliminating maximum percentage limits and instituting rebates of $4.05 per watt. The Working Group supports reducing Level 1 incentives for solar projects to $3.00 per watt and eliminating the maximum percentage cap, which is the CEC's current model for similar projects.

The Working Group also recommends reducing per-watt incentives for wind turbines and Level 3-R projects to reflect the decrease of installed costs for these technologies, maintaining Level 3-R incentive levels for internal combustion engines, and increasing incentives for microturbines utilizing renewable fuel.

We agree that the incentives must be reduced in order to meet the demand for incentives in 2004 and in light of the limited funding available to solar projects over 30 kW. Reducing the incentives would help meet the short-term need to assure the broadest dispersion of funds. Moreover, some of the incentives are too high relative to known technology costs.

Since most program administrators have exhausted their 2004 funds, we believe changes in incentive levels must occur simultaneously and immediately. As of the effective date of this decision, the new incentive structure for Level 1 wind and solar projects will apply to those projects that have not received a conditional reservation letter, including those projects on waiting lists. Level 1 projects will receive incentive payments of $3.50 per watt. We will order that this level be reduced to $3.00 effective January 1, 2006. Incentive payments for renewable fuel cells will remain at $4.50 per watt. We change several other incentive levels while concurrently eliminating the maximum percentage payment limits. We adopt those recommendations of the Working Group for changed incentive levels, which they developed considering the Itron report and program experience. The combination of reducing some incentives with removing the maximum percentage payment limits will reduce administrative complexity and free up funds for additional projects while better recognizing the costs of each technology.

We make no changes to per-watt incentives for Level 1 and Level 2 fuel cells, as these projects have not yet achieved market penetration levels that would likely lead to lower production and project installation costs. We clarify that maximum percentage caps are lifted for all levels, including fuel cells.

We agree with PG&E that at some point, the Level 1, Level 2, and Level 3 categories may no longer be the most practical method to group disparate technologies. However, because we do not modify the budget allocations assigned to various technologies, we retain the current categories for purposes of tracking budget allocations, reallocations, and incentive availability.

Effective immediately, the new incentive payments for each category are as follows:

	Technology	Incentive (per watt)
Renewable	Level 1 • Fuel Cells • Photovoltaics Level 3-R • Microturbines • Wind Turbines • Internal Combustion Engines	 $4.50 $3.50, decreasing to $3.00 on 1/1/2006 $1.30 $1.00 $1.00 $1.00
Non-renewable	Level 2 • Fuel Cells Level 3 • Microturbines and Gas Turbines • Internal Combustion Engines	 $2.50 $0.80 $.060

PG&E requests that the Commission determine how to treat applications on waiting lists at the end of December 2004. Under current SGIP rules, program administrators must carry over any unused funds to the next program year. The rules also require projects that remain on a waiting list at the end of the year to reapply the following year. As of July 23, 2004, PG&E's waiting list had 109 solar projects requesting $76.6 million, despite repeated reallocations to Level 1. PG&E closed the waiting list on August 1, 2004. It is unlikely PG&E or SDREO will have funds to carry over to 2005. Under the current budget and program structure, if PG&E were to fund the wait-listed projects immediately with 2005 funds, PG&E could once again be oversubscribed in early 2005.

We agree with PG&E that these vendors should not have to submit new applications on January 1, 2005. A combination of the programmatic changes we adopt today: the reduced incentives and elimination of the maximum cap will optimize funding availability for viable projects. We direct the Working Group to develop a process whereby applicants whose projects are on waiting lists at the end of the year will not need to reapply in 2005.

Decision 01-03-073 adopted a maximum project capacity size to 1 MW for all eligible technologies, and set a minimum size of 30 KW for Level 1 projects. A subsequent decision increased the project size cap to 1.5 MW, but retained the 1 MW payment cap. Several parties suggest the Commission could increase the maximum capacity requirement again without raising the incentive payment beyond 1 MW. Proposals range from 2MW to 20 MW. DES asserts that allowing larger projects to participate will add substantial new capacity without claiming excessive funds or reducing the number of projects that can participate. PG&E raises concerns over the potential for "free ridership," for example, financially viable large projects that would be constructed without incentives. We adopt Energy Division's proposal to increase maximum eligible capacity size to 5 megawatts, effective January 1, 2005. Increasing capacity size will allow developers, customers, utilities, and ratepayers to receive cost savings achieved by larger projects. However, we will continue to limit incentive payments to 1 MW of capacity. We share PG&E's concern that increasing incentive payments from 1 MW to 5MW would allow only a few projects, particularly Level 3 technologies, to receive incentives before depleting a program administrator's entire annual budget.

The incentive levels we adopt today are based on the best available information we have at this time. We may revisit these levels following our adoption of a cost-benefit methodology in Phase 2 of this proceeding. A cost-benefit methodology for distributed generation projects will permit us to determine an appropriate level of incentives, whether higher or lower, and on the basis of a comparison of DG projects with other energy resources.

3.2 Administrative Budget

The administrative budget adopted in D.01-03-073 authorizes each Program Administrator to allocate up to 20% of the SGIP budget toward administrative costs. These costs include, but are not limited to measurement, verification, and evaluation activities, marketing, outreach, and regulatory reporting.

As discussed in Section 3.1, we anticipate that removing the maximum percentage caps will reduce administrative costs. The Working Group proposes to reduce the total administrative budget to 10%, which would allow 90% of the SGIP budget to be paid out in rebates. We concur with this approach and herein adopt it.

3.3 Incentives from other Sources

The Working Group makes the observation that current rules permit projects to receive funding from multiple sources. Such incentives are available from several agencies and organizations. Because we herein eliminate the maximum percent of eligible project costs, we need to address how the incentives adopted herein will be calculated where a project receives other funding. We agree with the Working Group's recommendations to calculate the SGIP as a "last rebate" applied after taking into account any other rebates and that total rebates cannot exceed the payments made by the system owner to purchase the system. We also agree that where a project accepts payments based on future performance, the project should not be granted SGIP payments. These restrictions are intended to protect ratepayers from paying projects more than they cost, and to assure that funding is available to promote as many projects as possible. We ask the Working Group to monitor SGIP payments to projects that receive other incentives, and to recommend changes, if any, to the rules that protect ratepayers and funding sources while continuing to promote development of good projects.

3.4 Treatment of Program and Project Data

The scoping memo in this proceeding discusses a number of issues related to DG data collection and dissemination, including but not limited to data collected under the SGIP. Today's decision does not address options to streamline collection and availability of data related to interconnection, net metering, and cost responsibility surcharge exemptions. These issues will be addressed later in the proceeding.

In the meantime, we adopt Energy Division's recommendation to create a data release format that resembles the format used by the California Energy Commission (CEC) Emerging Renewables Incentive Program. Although the categories of data of the two programs may differ to some extent, we direct the Working Group to develop a common format that provides similar project information, including but not limited to:

- Seller, installer, developer, or applicant, as appropriate;
- City and zip code;
- Utility name;
- Technology (including model and manufacturer);
- Capacity size;
- Installed price; and
- Inverter model and manufacturer, where applicable.

The Working Group has already made substantial progress toward releasing this information, as demonstrated by a review of the program administrator websites.

We direct the Working Group to develop and circulate proposed formats for discussion among Working Group members and interested parties. The Working Group may also designate one or more program administrator to confer with interested parties in order to obtain broader input for developing the format. Each program administrator should post the required information to its website within 30 days of the effective date of the decision.

We also direct program administrators to post certain program information to their websites, including the amount of funds reserved, paid, and available in each level, funds transferred between levels, and installed and reserved generating capacity. The format should be consistent among administrators.

3.5 Declining Rebates and Exit Strategy

A report written for the Commission by Itron titled "Second Year Impacts Report," raises concerns regarding the impacts an abrupt termination of the SGIP program would have on markets for renewable and clean DG. Itron recommends the Commission adopt an exit strategy based on a declining incentive structure to ensure a smooth transition to a market no longer supported by SGIP rebates. The Energy Division and parties unanimously support the recommendation.

We agree that a declining incentive structure will gradually reduce the market's reliance on a subsidy. This incentive structure should be predictable and transparent, with a specific schedule, rather than applying program milestones such as dollars expended or capacity installed. We herein direct the Working Group to propose a plan to phase out the incentives in a predictable way. However, we are not prepared to state intent to terminate the program at the end of 2007. The requirements set forth in AB 1685 for the Commission to implement the SGIP end at that time. The Commission, however, is thereafter within its authority to continue funding for and implementation of the program. The state has expressed a strong commitment to distributed generation and renewable energy technologies, for example, in the Energy Action Plan, and three additional years of program funding may not be adequate to assure optimal development of those energy resources. The Working Group's recommended incentive phase-out should therefore anticipate a continuation of the program through the end of 2014.

The Working Group shall file a proposed exit plan, which includes specific calendar dates and a table of incentive levels, within 90 days of the effective date of this order. The declining schedule may vary by technology, if appropriate. The Working Group shall organize at least one open meeting with industry participants and interested parties to obtain broader input on these issues, prior to submitting its proposed plan.

After Commission review and approval of a phase-out plan, the program administrators should post the plan elements on their websites and include the schedule in the program handbook.

3.6 Program Evaluation and Cost Effectiveness

The Commission is considering several DG-related evaluation activities in this and other proceedings. While parties unanimously support a cost-effectiveness study of the SGIP, others seek clarification regarding the purpose of seemingly duplicative cost benefit work, and whether these activities could be consolidated. We describe the evaluation, cost benefit, and cost effectiveness issues under review.

In D.01-03-073, we directed the program administrators to evaluate program success and conduct load impact studies to verify energy production and system peak demand reduction. As observed by Itron and others, many projects that applied for incentives in 2001 were not completed until 2003 or later. Accordingly, Itron had very little production data available for analysis. With over 72 MW installed to date, the program is now better situated for the monitoring, data collection, and evaluation activities envisioned by D.01-03-073. Itron filed the Program Year 2003 evaluation report in October 2004. We intend to address subsequent evaluation plans in a future decision.

Decision 01-03-073 also directed the Energy Division to retain a consultant to study and develop recommendations concerning cost-effectiveness assumptions used to evaluate energy efficiency, demand response, or distributed generation projects and programs. A subsequent decision, D.03-04-055, refined the scope of work to update the avoided costs and externality adders presently used to evaluate energy efficiency programs. These avoided costs and externality adders constitute some, but not all, of the required inputs to the Standard Practice Manual (SPM) cost effectiveness tests. The firm, Energy and Environmental Economics, Inc. (E3) prepared and submitted a report to the Commission in January 2004. The E3 report was finalized on October 25, 2004, and its potential application will be closely examined in R.04-04-025, which is reviewing avoided costs. In that rulemaking, the Commission intends to develop a common avoided cost methodology, consistent input assumptions, and updating procedures for avoided costs which would apply in all resource-related decision-making, such as those applying to qualifying facilities, energy efficiency, and DG.

In R.04-03-017, we intend to develop an overall DG cost-benefit methodology. We indicated we would, to the extent possible, consider other cost effectiveness tests, such as those described in the E3 report, the SPM, and input assumptions from the E3 report. As part of the SGIP evaluation process, Itron is preparing a report that will address the applicability of these and other methodologies for the purpose of assessing the cost-effectiveness of the SGIP. Itron's proposed cost-effectiveness framework is expected to be issued for comment before the end of the year. Based on the proposed framework and parties' comments, Itron will prepare and submit the SGIP cost-effectiveness study for comment. The August 6, 2004 Assigned Commissioner's Scoping Memo issued in this proceeding directed parties to propose cost-benefit methodologies in testimony due October 4, 2004, scheduled hearings for November 2004 and anticipates a proposed decision on a DG cost-benefit methodology by February 2005. Because of the timing of the Itron report and its obvious tie-in with the issues scheduled to be addressed in hearings, the ALJ recently rescheduled hearings on cost-benefit issues so the parties and the Commission may consider the findings and conclusions of the Itron report in hearings and a subsequent Commission order. We also intend to closely coordinate the modeling efforts in this proceeding with those in the proceeding in which we review energy avoided costs, R.04-04-025.

Ideally, we would adopt a cost benefit methodology prior to an analysis of SGIP cost-effectiveness. However, these two related efforts can be conducted concurrently, and updated as necessary. Itron intends to submit an interim SGIP cost-effectiveness report by February 15, 2005, and update the report in

December 2006, if necessary, to reflect the methodology ultimately adopted by the Commission. We intend to proceed to adopt a final cost-benefit methodology following hearings.

3.7 Program Administration Through 2007

Consistent with D.01-03-073, Itron also prepared and submitted a report that compares utility and non-utility program administration. The report did not recommend one approach or the other, concluding that both types of administrators brought strengths and weaknesses to the program.

SDREO's contract with SDG&E expires on December 31, 2004, which coincides with the end of SGIP adopted in D.01-03-073. Since AB 1685 requires the SGIP to continue through 2007, SDREO seeks to continue SGIP administration in San Diego. SDG&E prefers to perform the administrative function within the utility, and to allow SDREO's contract to expire.

Energy Division recommends that the Commission continue to retain SDREO to administer the SGIP in SDG&E's service territory through 2007, approve SDREO's request for interval disbursement of program funds from SDG&E, and direct SDG&E to eliminate duplicative administrative functions. Staff recommends SDG&E update its contractual arrangements with SDREO to reflect these provisions.

SDREO asks the Commission to clarify the purpose of third-party administration, asserting that SDG&E duplicates the review and approval functions performed by SDREO on SGIP projects. SDREO contends that these duplicative efforts delay issuance of incentive payments. SDREO believes that under the current contract arrangement, SDREO is not a truly independent, non-utility administrator.

SDG&E replies that the utility, not SDREO, is the entity ultimately held accountable by the Commission. SDG&E points out that Itron's evaluation of utility and non-utility administration concludes that SDREO's administrative costs per kW achieved through the program were almost double of one or more utility administrators. SDG&E seeks utility administration, but at a minimum, requests recovery of utility costs for incremental activities such as interconnection safety, contract management, and responsibility for program administrator expenses.

The interval between issuance of the conditional reservation and the incentive payment is typically 12 months or more. This is due primarily to the amount of time required for project design, construction and installation. SDG&E disburses funds to SDREO based on the amount of incentive payments each month, and posts the amount in a memorandum account. SDG&E argues that ratepayers would shoulder significantly higher costs if the SGIP budget is disbursed to SDREO annually.

PG&E points out that SDREO has provided valuable contributions over the first three program years, and that only three years of the program remain. PG&E recommends that the Commission address larger questions concerning third-party administration of utility programs in other dockets and programs.

SDG&E does not provide an estimate of the incremental costs associated with annual disbursement. The Itron administrator comparison report, as well as the impacts and process reports, do not identify which utility administrator is associated with specific program measures. It is difficult, if not impossible, to assess the strengths and weaknesses of each program administrator. Subsequent reports should clearly identify all program administrators, and address the performance of each.

By D.01-03-073, we decided to explore non-utility administration of the SGIP "on a limited basis."[3] We did so in response to comments on Energy Division's report and, in particular, concerns raised by TURN and others about the utilities' motivation to aggressively pursue self-generation projects at that time.[4] Accordingly, we directed SDG&E to contract with SDREO to provide administrative services for the self-generation programs in SDG&E's service territory. However, we also acknowledged that D.01-03-073 was not the appropriate forum for addressing the administrative structure of energy efficiency and self-generation programs for the longer-term, and reserved judgment on these issues.

We are currently in the process of carefully evaluating the policy and legal issues associated with program administration alternatives in our energy efficiency rulemaking, R.01-08-028. Although we have not made our final determinations in that proceeding, we do note that the contractual arrangements we adopted for administrative services in D.01-03-073 places SDG&E in the role

---

[3] D.01-03-073, mimeo. p. 17.

[4] *Ibid.*, pp. 17-18. In its report, Energy Division considered utility administration to be the expedient approach through at least 2001, and SDG&E, SCE and SoCal recommended that utility administration be established through 2004. PG&E suggested that the Commission consider alternatives to utility administration if the expectation was to have utilities gear up for only a one-year assignment. ORA, on the other hand, recommended that SDG&E contract with SDREO to provide administrative services for the program in SDG&E's service territory and, for the longer-term, that the Commission establish a network of Commission-certified regional energy offices to become administrators of both energy efficiency and self-generation programs. TURN recommended that alternatives to utility administration be pursued because, in its view, the utilities presented positions in the distributed generation rulemaking (R.99-10-025) that reflected their perception that self-generation would reduce distribution revenues.

of overseeing a contract with a third-party deliverer (SDREO) of administrative services for the SGIP program. In that role, we expect SDG&E to exercise prudent oversight to ensure that SDREO performs administrative services effectively and consistent with program guidelines. At the same time, SDG&E's oversight should not entail unreasonable duplication of effort (*e.g.*, re-reviewing in detail every single SGIP application that SDREO has processed) or unreasonably delay payments of incentives to qualified projects or to SDREO for administrative services rendered. We are extremely concerned about the timeliness of rebates to projects, as well as the additional cost associated with a duplicative review process. Thus, we believe that SDG&E and SDREO should be able to negotiate modified contract terms that allow for periodic progress payments or other similar provision, subject to random auditing or cross-checking by SDG&E. Energy Division should continue to mediate between SDREO and SDG&E on these issues.

Until we have fully addressed the legal and policy issues related to program administration in R.01-08-028, we believe that directing SDG&E to extend its administrative services contract with SDREO through 2007 is the best course of action. This approach enables the SGIP program to move forward without disruption to current program administration arrangements for the authorized funding period. At the same time, it does not preclude us from reevaluating the administrative structure for SGIP if funding continues past 2007. We authorize the program administrators to direct their consultant to update the September 2, 2003 comparative assessment report with data collected from June 2003 through May 2006 for submission by September 15, 2006. As directed above, the report should clearly identify all program administrators, and address the performance of each. We will then be in a better position to consider how best to administer the SGIP program beyond 2007, based on this report, our final determinations regarding program administration in R.01-08-028, and other relevant information.

We reject SDG&E's argument that the utility should receive additional funds to provide SDREO with interconnection and other utility expertise. Utility program administrators receive internal technical support; SDREO must receive similar treatment.

3.8 Emission and Efficiency Requirements

Currently, the Commission requires a Level 3 applicant to submit a permit to operate or other documentation issued by their local air district, approving the unit for operation. Air permitting requirements vary by location.

The Commission also requires Level 3 projects operating on nonrenewable fuel to meet a cogeneration efficiency of 42.5%, as specified in Pub. Util. Code § 218.5. A unit's anticipated efficiency is calculated as the sum of electricity produced and 50% of utilized output, divided by fuel input, based on the unit's average annual consumption.

Assembly Bill 1685 requires combustion-operated fossil-fueled DG projects to meet statewide emissions criteria to qualify for SGIP incentives. Projects must not emit over 0.14 pounds of nitrogen oxides (NOx) per MWh (ppMWh) as of January 1, 2005. By January 1, 2007, units must reduce emissions to 0.07 ppMWh, and achieve a minimum efficiency of 60%. Efficiency is to be calculated as useful energy output divided by fuel input, based on 100% load.

Units that do not meet the 2007 emissions standard may receive "extra credit" for meeting the 60% efficiency standard. [5]

To date, the California Air Resources Board (CARB) has certified just two technologies, microturbines and fuel cells, as able to meet the 2007 air emissions limit.

Energy Division's report recommends program administrators verify a DG unit's compliance with AB 1685 in one of two ways. The unit is automatically eligible for the SGIP if it is certified by CARB. If the unit is not certified by CARB, an applicant may demonstrate eligibility through the existing process, by submitting manufacturer emission specifications, a permit to operate, and project-specific efficiency calculations.

The staff proposal is the most practical approach for applicants to demonstrate compliance with AB 1685 compliance until CARB certifies additional technologies. As suggested by some parties, we clarify several related issues here. First, we agree with the Working Group that the term "commencing" as the term is used in Section 379.6 of AB 1685 should refer to the date on which a program administrator receives an SGIP reservation request form from a project proponent. Therefore, all projects which submit such forms on or after January 1, 2005 shall meet the new emissions standards.

Second, we interpret Section 379.6 (3), enacted by AB 1685, to require that the "credit to meet the applicable oxides of nitrogen" refers to both Section 379.6(1) and (2).

---

[5] The credits specified in AB 1685 should not be confused with emissions trading credits, which is a different process not regulated by the CPUC.

Third, we find that in enacting Section 379.6, AB 1685 did not intend projects to be exempt from the preexisting thermal efficiency requirements of Section 218.5. Moreover, we believe those thermal efficiency requirements are reasonable and serve the public interest. Therefore, in order for projects to qualify for SGIP funding, the requirements of both Section 379.6 and Section 218.5 must be fulfilled.

The Working Group presented a model for how the eligibility process should work for fossil fuel projects, which we agree is a reasonable interpretation of the statute. Specifically, for the period 2005-06, a project is eligible if it either (1) meets the .14 NOx standard or (2) meets the 60% thermal efficiency standard and meets the .14 NOx standard with a NOx credit. In 2007 and thereafter, projects would need to either (1) meet the .07 NOx standard and the 60% thermal efficiency level or (2) meet the 60% thermal efficiency requirement and meet the .07 NOx standard with a NOx credit.

We direct the Working Group to modify the program handbook to reflect the AB 1685 emissions and eligibility requirements, as described herein, and the options we adopt for demonstrating compliance.

3.9 Participation in the SGIP Working Group

The purpose of the Working Group is to ensure program implementation in accordance with Commission policies. It is comprised of SCE, SDG&E, SoCalGas, PG&E, the Commission's Energy Division, CEC, and SDREO. In D.03-08-013, we adopted a process whereby market participants may meet with the Working Group to propose specific program modifications for the Commission's consideration.

The Energy Division's report recommended a process for expanding membership in the Working Group's activities, should the Commission determine that such expansion was appropriate. However, based on parties' comments and our prior determinations regarding Working Group structure, we still find that the Working Group membership is appropriate to its purpose. Nonetheless, we believe the Working Group's development of a proposed exit strategy, declining rebate schedule and common data release format would benefit from broader public input. As discussed above, we direct the Working Group to consult with interested parties in developing recommendations on these issues for our consideration. We also direct the Working Group to consult with interested parties as it incorporates changes to the program handbook to reflect today's determinations.

3.9.1 Program Eligibility

Decision 01-03-073 prohibited utility distribution companies from receiving SGIP incentives. The Working Group seeks clarification as to which distribution companies are excluded from the program.

We clarify that public and investor-owned gas or electricity distribution utilities which generate or purchase electricity or natural gas for wholesale or retail sales, are not eligible to receive incentives.

4. Other Issues

4.1 Corporate Parent Limits

Powerlight contends that projects located on county fairgrounds should be subject to the annual 1 MW corporate/government parent cap per utility service territory. Powerlight states that the fairgrounds are not independent entities, but are overseen by California's State and County Fairgrounds, the Division of Fairs and Expositions, and the California Construction Authority.

Western Fairs and Vote Solar argue that each county fair is a unique, separate, and self-funded entity similar to a school district. Each has its own board of directors, and different legal structures. Most are District Agricultural Associations. Some are non-profits, and others are county organizations. None are state agencies. Moreover, Vote Solar states that average project costs for these solar installations are $4.64 per watt, which is considerably lower than the average SGIP rebate.

DES and JPIDG seek to expand MW eligibility under the parent cap. Capstone questions why the Commission restricts the entities most likely to install DG: a statewide network of grocery stores and other retail chains. We agree that putting caps on funding for government and corporate parents hinder the goal of increasing DG capacity to reduce peak demand, and may inflate project costs to artificially high levels. We do not rule today whether or not county fairgrounds are subject to a cap. Rather, we remove the 1 MW per service territory parent cap that limits funding for the university system, other state and federal agencies, corporations, and other entities formerly subject to the cap. We clarify that the SGIP will not pay incentives for capacity over 1 MW per location through the life of the program.

4.2 Reservation Requests

CALSEIA suspects that certain project developers submit incentive reservation requests for “phantom” projects, in order to reserve funds for undeveloped future projects. CALSEIA states that these practices allow developers to tie up substantial funding that could be reserved for legitimate projects.

Under current program rules, an applicant must provide proof-of-project documentation within 90 days of receiving a conditional reservation request. A program administrator may grant an extension based on project circumstances.

CALSEIA recommends the Commission adopt additional mechanisms to deter phantom projects, such as requiring a nominal fee when an application is submitted, refundable upon project completion. We are not opposed to such a mechanism, provided it does not place an undue financial burden on smaller projects. We delegate to the Working Group the task of developing appropriate procedural or financial mechanisms to deter inappropriate reservation requests.

5. Comment on Draft Decision

The draft decision of the Administrative Law Judge in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on November 8, 2004, and reply comments were filed on November 15, 2004. This decision includes several corrections and changes from the draft decision to reflect reasonable concerns of the parties with regard to the Working Group, the interim use of Itron modeling and administration by SDREO. It also modifies some of the incentive levels and clarifies the requirements for meeting AB 1685 air quality standards.

6. Assignment of Proceeding

Michael Peevey is the Assigned Commissioner and Kim Malcolm is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The demand for incentives in 2004, combined with limited funding for projects over 30 kW created a situation where DG projects did not receive funding. This limitation on funding for viable projects would be mitigated by reducing the incentive payment levels.

2. Eliminating the maximum percentage payment caps would reduce the administrative costs of the program and simplify it.

3. Several incentive programs are available for distributed generation projects and may provide a single project with incentives that exceed costs.

4. Reducing incentives for some types of projects and eliminating the maximum percentage cap for all projects would increase the incentives available for viable projects. The existing $4.50 per watt incentive payment for renewable fuel cells does not need to be changed to address a shortage of funding for such projects.

5. No useful purpose is served by requiring projects on SGIP waiting lists to reapply for funds in subsequent funding cycles.

6. Increasing the maximum eligible capacity size to 5 megawatts, but retaining incentive payments up to 1 megawatt, would promote more cost-effective projects to the benefit of ratepayers and utility operations while maintaining enough funds to provide incentives to a number of viable projects.

7. Developing a data release format that resembles that used by the CEC for its Emerging Renewable Incentives Program and requiring developers to make project information available at their websites would improve the usefulness of information related to DG.

8. An incentive structure that predictably declines over time would promote a smooth transition to a market unsupported by SGIP rebates.

9. Developing a cost-benefit methodology for DG projects will assist in the evaluation of the program and related projects. SDG&E is expected to exercise prudent oversight of its contract with SDREO for administrative services to ensure that SDREO is performing those services effectively and consistent with program guidelines. At the same time, SDG&E's oversight should not entail unreasonable duplication of effort or unreasonably delay payments of incentives to qualified projects or to SDREO for administrative services rendered. SDG&E

and SDREO should negotiate additional contract terms to mitigate these issues. Energy Division should continue to mediate between SDREO and SDG&E on these issues.

10. Directing SDG&E to extend its administrative services contract with SDREO through 2007 enables the SGIP program to move forward without disruption to current program administration arrangements for the authorized funding period. At the same time, it does not preclude the Commission from reevaluating the administrative structure for SGIP if funding continues past 2007.

11. Project proponents may demonstrate air emissions compliance with AB 1685 with a certificate from CARB or by presenting relevant documentation regarding facility operational characteristics.

12. Decision 01-03-073 prohibited utility distribution companies from receiving SGIP incentives.

13. The current caps on funding for government agencies and corporate parent companies hinder the goal of increasing DG capacity and may artificially inflate project costs.

14. As discussed in this decision, the Working Group's development of a proposed exit strategy, a declining rebate schedule and a common data release format would benefit from broader public input.

Conclusions of Law

1. The SGIP incentives should be reduced for certain types of projects as set forth herein and the maximum percentage cap for such projects should be eliminated. The SGIP incentive payment of $4.50 per watt for renewable fuel cells should be retained.

2. The SGIP rules should be modified to eliminate the requirement that proponents of projects reapply for incentives in the subsequent funding cycle, according to a process developed by the Working Group.

3. The SGIP rules should account for multiple incentives that may be available for a single project and preserve existing funding resources for maximum disbursal.

4. The SGIP rules should be modified to increase the maximum eligible capacity size to 5 megawatts, but retain incentive payments only up to 1 megawatt.

5. The data release format should be modified to resemble that used by the CEC for its Emerging Renewable Incentives Program.

6. Program administrators should be required to make project information available at their websites.

7. SGIP incentives should be structured so that they predictably decline over a ten-year period. The Working Group should be directed to develop a plan to that end and the final elements of that plan should be subject to Commission approval.

8. As discussed in this decision, SDG&E should extend its contract with SDREO for program administrative services through 2007.

9. AB 1685 provides the Commission with flexibility to make changes to the SGIP, including changes in the annual program budget.

10. AB 1685 requires combustion-operated fossil-fueled DG projects to meet specified statewide emissions criteria to qualify for SGIP incentives. The program handbook should reflect these emissions and eligibility requirements and the option for project proponents to certify compliance either with documentation from the California Air Resources Board or by submitting

manufacturer emission specifications, a permit to operate, and project-specific efficiency calculations. Utilities should implement related provisions of AB 1685 as set forth herein.

11. D.01-03-073 intended that SGIP funds should not be awarded to public or investor-owned gas or electricity distribution utilities that generate or purchase electricity or natural gas for wholesale or retail sales.

12. SGIP rules should be modified to remove the restrictions limiting funding for the California state university system, other state agencies and corporate parents.

O R D E R

IT IS ORDERED that:

1. The Self Generation Incentive Program (SGIP) incentives are hereby modified as set forth herein and the maximum percentage cap for such projects is hereby eliminated. The SGIP incentive payment of $4.50 per watt for renewable fuel cells is retained.

2. SGIP incentives for all levels shall be based on installed capacity rather than a maximum percentage cap, consistent with this order.

3. The Working Group shall, within 60 days of the effective date of this order and following consultation with interested parties, develop data release formatting and publication protocols as set forth herein, and implement them within 90 days of the effective date of this order.

4. Program administrators shall post required information at their respective websites within 30 days of the effective date of this order, as set forth herein.

5. The SGIP rules are hereby modified to increase the maximum eligible capacity size to 5 megawatts, except that incentive payments are retained at the 1-megawatt level.

6. The Working Group shall, within 90 days of the effective date of this order and following consultation with interested parties, file a proposal to modify the incentive structure so that incentive amounts decline gradually over the next ten years. This exit plan shall not go into effect without subsequent Commission approval and following an opportunity for parties to comment on the Working Group filing.

7. SDG&E shall, within 30 days of the effective date of this order, submit to Energy Division, an extension to the administrative services contract with SDREO through 2007.

8. The Working Group shall, within 30 days of the effective date of this order, modify the program handbook to (1) assure a method for certification by project proponents of compliance with the air emissions standards required by AB 1685 as set forth herein; (2) eliminate the requirement that proponents of projects reapply for incentives in the subsequent funding cycle; (3) clarify the program handbook to provide that SGIP funds may not be awarded to public or investor-owned gas or electricity distribution utilities that generate or purchase electricity or natural gas for wholesale or retail sales; (4) raise from one to 4 MW the annual restrictions on funding for the California University system, other state agencies and corporations; (5) include procedural or financial mechanisms to deter inappropriate reservation requests; and (6) grant projects with multiple funding sources as set forth herein.

9. Program administrators are authorized to direct their consultant to update the September 2, 2003 comparative assessment report with data collected from

June 2003 through May 2006, for submission by September 15, 2006. The report shall clearly identify all program administrators and address the performance of each.

10. For good cause, the Assigned Commissioner or Administrative Law Judge may modify the due dates set forth in this decision.

This order is effective today.

Dated December 16, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

ATTACH A TO KLM R0403017

CPUC Decision 08-04-049

 Date of Issuance 4/25/2008

Decision 08-04-049 April 24, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 08-03-008 (Filed March 13, 2008)

OPINION GRANTING IN PART PETITION BY FUELCELL ENERGY TO MODIFY DECISION 04-12-045

1. Summary

In Rulemaking (R.) 08-03-008, the Commission transferred the petition of FuelCell Energy (FCE) to modify Decision (D.) 04-12-045 to the Commission's new distributed generation rulemaking to be handled in the above-captioned proceeding.

This decision grants in part the petition by FCE to raise the cap on incentives to individual projects that apply for incentives through the Commission Self-Generation Incentive Program (SGIP). During 2008 and 2009 only, this decision allows program administrators of SGIP to use any carryover funds from prior budget years to pay incentives up to 3 megawatts (MW) for qualifying fuel cell or wind distributed generation (DG) projects. Incentives over 1 MW will be paid at a lower rate.

2. Background

In D.01-03-073, the Commission authorized the SGIP to encourage the development and commercialization of new DG technologies.[1] Under the SGIP, certain entities qualify for financial incentives to install DG to serve some portion of a customer's onsite load. In subsequent orders, the Commission refined the program, taking actions such as adopting a reliability requirement, developing renewable fuel criteria, and increasing the maximum project size eligible for incentives.

With regard to project size, the Commission initially limited both the size of eligible projects and incentives to 1 MW, reasoning that the size limit "represents a fairly large installation for a single customer site and, at the same time, will not use up an unreasonable amount of program funding." (D.01-03-073, at 29.) In a subsequent order, the Commission increased the project size eligible to participate up to 5 MW to "allow developers, customers, utilities and ratepayers to receive cost savings achieved by larger projects." (D.04-12-045 at 9.) Despite raising this maximum project size, the Commission retained the cap on incentives at 1 MW due to concerns about depleting limited SGIP budgets. (*Id.*)

---

[1] "Self-generation" refers to distributed generation technologies (microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells and internal combustion engines) installed on the customer's side of the utility meter that provide electricity for a portion or all of that customer's electric load. In D.06-01-024, the Commission directed that starting in 2007, photovoltaic self-generation projects would be separately funded through the California Solar Initiative, rather than the SGIP.

For 2008, the SGIP budget is $ 83 million, as set forth by the Commission in D.08-01-029. In addition, the SGIP is limited by Pub. Util. Code § 379.6 to funding only wind and fuel cell DG projects, effective January 1, 2008.

3. Petition for Modification

On July 25, 2007, FCE filed its petition requesting the Commission modify D.04-12-045 to increase the limit of incentive payments available under the SGIP program from the current cap of 1 MW to 3 MW.[2] Although projects up to 5 MW are eligible for participation in SGIP, incentives are limited to 1 MW. FCE contends this has suppressed participation by larger fuel cell projects in the program. FCE argues an increase in the incentive cap to 3 MW is needed to stimulate the much needed market transformation for affordable fuel cell technology and other renewable distributed generation applications that are only economic at a larger scale. FCE also maintains that the modification would result in new projects that would deliver substantial reductions in greenhouse gases.

In its petition, FCE contends the market for fuel cells in California is significantly constrained, particularly in the waste treatment market, by the 1 MW limit. Based on feedback from operators of industrial facilities and wastewater treatment plants, FCE reasons the modification will result in significant deployments of new fuel cell power plants at these sites. The most

---

[2] FCE's petition was filed in R.04-03-017, the docket in which D.04-12-045 was issued, and also served on parties to R.06-03-004. Service to both lists was completed on July 31, 2007, which extended the filing date for comments on the petition to August 30, 2007. The two dockets, R.04-03-017 and R.06-03-004, were consolidated for purposes of resolving this petition. The petition was transferred to this docket by R.08-03-008 and is resolved herein.

prominent emerging market sector is municipal wastewater treatment. Specifically, FCE contends that fuel cells' high electrical efficiency enables them to deliver almost twice the electrical output for each unit of gas consumed. In a declaration filed with its petition, FCE's witness states that wastewater treatment plant operators have expressed an interest in fuel cell technology as an alternative to combustion technologies. Further, the witness states that he has had conversations with wastewater treatment plant owners who have tried but failed to cost-justify installation of fuel cells at larger facilities without incentives.

FCE further justifies its modification request with the reasoning that raising the incentive cap will result in new projects that would deliver substantial greenhouse gas (GHG) reductions in addition to peak electricity demand reductions. According to FCE, renewable fuel cells can provide high GHG reduction by capturing and using biogas in lieu of its use in either flares or combustion. Thus, FCE argues, larger fuel cell projects, particularly at municipal wastewater plants, could benefit ratepayers by maximizing returns on local tax dollars and increasing the reduction in combustion emissions, with associated environmental benefits. Moreover, FCE contends that increasing the cap on SGIP incentives from 1 to 3 MW could lead to reduced product costs via larger production volumes, thus enabling market transformation for fuel cells.

FCE maintains the only down side to its request is the potential that program funds could be depleted more rapidly than they would otherwise. To offset this concern, FCE suggests the Commission authorize additional SGIP funding to support more projects, or consider other measures to ensure participation by small projects.

According to Rule 16.4(d) of the Commission's Rules of Practice and Procedure, petitions for modification must be filed within one year of a

Commission decision. FCE states that its petition, filed more than two years after issuance of D.04-12-045, is based on experience gained, particularly with larger customers, over the six-year history of SGIP, and therefore could not have been filed earlier. UTC Power Corporation (UTC) objects to FCE's late-filed petition to modify, asserting that FCE has not adequately justified its late submission because potential customers of every size have existed since SGIP's inception. We find that FCE has adequately justified the late filing of its petition because information pertaining to larger customers and the market demand for fuel cells is newly available. Thus, we will address FCE's petition on its merits.

4. Comments on Petition

Responses to the petition were filed by California Center for Sustainable Energy (CCSE), Center for Energy Efficiency and Renewable Technologies (CEERT), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and UTC. In addition, responses were filed by Alliance Power Inc., ApolloPower Inc., California State University Northridge, Carollo Engineers P.C., Chevron Energy Solutions Company (CES), Gills Onions Rio Farms, HydroGen Corporation, Manuel Bros., Inc., Marubeni Corporation, MISCO, National Fuel Cell Research Center, Powerhouse Energy LLC, Silverwood Energy Inc., and Starwood Hotels and Resorts Worldwide Inc. We refer to this latter group collectively as the "fuel cell supporters" because though the comments were filed individually, they were strikingly similar, and in some cases identical to each other.

The fuel cell supporters state strong support for the petition, contending the increase in project size eligible for incentives is needed to cost-effectively develop the biogas market for fuel cell technology at waste treatment plants, landfills, and other host facilities that need larger scale projects. They allege that raising the incentive cap for both natural gas and renewable biogas supplied fuel cell technologies will allow larger users of electric and thermal energy to implement more efficient technologies which utilize less fuel. They contend there is an increasing market demand for DG between 1 and 3 MW to meet the requirements of end user customers. According to the fuel cell supporters, if the Commission raised the incentive cap to 3 MW, this would help encourage innovation and expansion of DG applications at a time when the state needs renewable DG and efficient use of fuel stocks. These parties claim the current 1 MW cap on incentives deters larger installations because they are uneconomic and too risky to develop.

Moreover, these parties contend that large fuel cell projects provide benefits to utility systems in California such as decreasing GHG emissions per megawatt hour of baseload electricity and thermal load supplied, reducing transmission and distribution grid constraints, reducing the need for new generation capacity, and eliminating emissions from combustion-fired power generation that would otherwise be used if renewable biogas or natural gas supplied fuel cell projects are not implemented. The fuel cell supporters further contend that if the Commission is concerned that raising the incentive cap will negatively affect SGIP participation by smaller DG projects, the Commission can monitor this, allocate money between large and small projects, or increase the SGIP budget.

UTC opposes FCE's petition, arguing that the Commission has denied past requests to raise the 1 MW cap on the basis that an increase might cause large projects to deplete the SGIP budget. UTC contends the 1 MW cap should be maintained to ensure the broad distribution of SGIP funds. According to UTC, increasing the cap beyond 1 MW would minimize the overall number of projects funded by SGIP, in opposition to the Commission's earlier stated goal of making SGIP funds available to a broad range of projects and customers.

Moreover, UTC contends the SGIP is successful at current incentive levels, with program data provided by FCE in its petition indicating that 2006 saw the highest level of fuel cell participation in SGIP to date.[3] Thus, UTC concludes that maintaining current incentive levels will support more projects and increase fuel cell market penetration. UTC argues that the overall number of fuel cells manufactured promotes economies of scale that lead to price reductions. Thus, a higher number of smaller projects promote competition and innovation in clean energy more than incentives limited to a few large projects.

CEERT supports the petition as it relates to renewable fuel cells, and supports the recommendation for increased SGIP funding. CEERT also proposes that to ensure smaller installations receive incentives, the Commission could require installations over 1 MW to wait until the close of the fiscal year to receive incentives for the portion of their project over 1 MW. In reply, FCE opposes this request as creating too much uncertainty for fuel cell developers and undermining the ability to obtain project financing.

CCSE, PG&E and SCE support the petition, but only with respect to fuel cells operating on renewable fuel. SCE contends that raising the incentive cap for non-renewable technologies risks depleting program funds. PG&E suggests a lower incentive level of $2.50/watt for incentives over the first MW to extend the SGIP budget, and it also recommends permitting the increased incentive cap

---

[3] UTC cites statistics provided by FCE on p. 4 of its July 25, 2007 petition.

on a two-year pilot basis. CCSE also supports a tiered incentive approach to prevent a small group of large customers from monopolizing program funds.

In response to UTC, FCE states that the current 1 MW cap inhibits development of the market for larger installations. FCE proposes consideration of conditions to ensure funds are fairly allocated to large and small DG, such as budget allocations between large and small customer classes with corresponding discretion to shift funds, or scaled incentives as suggested by PG&E and CCSE. FCE supports the suggestion that any increase in the incentive cap should apply to renewable projects only.

5. Amended Petition

On February 8, 2008, FCE filed an amended petition containing further information in support of its petition and amending its initial request. FCE now asks that the Commission raise the 1 MW incentive cap solely for renewable fuel projects, establish tiered incentives for capacity over 1 MW, and approve the increased incentives on a two-year pilot basis, with extension only upon Commission review.

The amended petition includes two additional declarations containing financial information and analysis on the need for incentives to encourage development of larger fuel cell projects, the efficiencies and economies of scale of fuel cell projects larger than 1 MW, GHG emissions benefits, and financial impacts of tiered incentives. In its amended petition, FCE provides information on two potential projects larger than 1 MW it is working to develop, and it claims incentives are required up to 3 MW to make the payback period for these projects acceptable to potential customers. FCE contends larger projects are better able to deliver cost-effective solutions for wastewater treatment operators because the cost of the fuel treatment system and other external costs of the fuel cell, including mechanical and electric systems and installation, become less significant as project size increases. (FCE Amended Petition, 2/8/08, Declaration of Jeff Cox.) The amended petition also includes data from the SGIP Sixth Year Impact Evaluation, dated August 2007, to support FCE's contention that renewable fuel cells attain the highest net GHG reductions of any participating SGIP technology. (*Id.*, p. 13.)

The following parties filed comments on the amended petition: Californians for Renewable Energy (CARE), CCSE, Debenham Energy LLC (Debenham), SCE, TechNet,[4] and UTC. SCE and CCSE support FCE's amended petition, although SCE suggests the Commission dedicate a percentage of SGIP funds to projects below 1 MW.

CARE, TechNet and UTC oppose the amended petition. UTC comments that the benefits claimed by FCE in its amended petition are inaccurate. UTC disputes FCE's claim that increased funding to large projects will result in market transformation for fuel cell technology. In addition, UTC maintains the mechanisms suggested in the amended petition to preserve funds do not mitigate UTC's concern about budget depletion and lack of funding for small DG projects. CARE echoes this concern that raising the incentive cap to 3 MW will deplete SGIP funds more quickly and benefit a few large companies rather than encourage development of the industry as a whole. TechNet contends that retaining the 1 MW cap on incentives will allow more Californians to benefit from the program, fostering greater competition, innovation, and cost reduction. TechNet urges the Commission to promote fuel cell competition in a technology

[4] TechNet is a bipartisan political network of chief executive officers and senior executives that promote the growth of technology and innovation in the economy.

neutral fashion rather than allowing a vast portion of the SGIP budget to benefit only a few large projects.

In a ruling dated February 14, 2008, the Administrative Law Judge (ALJ) asked for comment on whether the Commission should consider increasing the cap on incentives for eligible wind DG projects as well as renewable fuel cells, as requested in the amended petition. SCE opposes increasing the incentive cap for wind projects without additional information. Debenham, a renewable energy consulting firm, supports the idea, arguing that wind projects need a higher incentive cap for technology-specific reasons. Specifically, Debenham contends the intermittent nature of wind technology is constrained by the 1 MW incentive cap designed to favor to photovoltaics, and this has put a damper on wind participation in SGIP. Further, Debenham supports an incentive cap increase so that fuel cells and wind can share equally in SGIP benefits. CCSE echoes the comments of Debenham that wind projects have experienced difficulty in the below 1 MW sizing range and raising the incentive cap could stimulate projects greater than 1 MW.

6. Discussion

The key issue raised by FCE's petition is whether the Commission should deviate from prior decisions that created and retained a 1 MW cap on incentives to any one project. If we raise the incentive limit beyond 1 MW, as FCE requests, this could allow a large portion of each utility's SGIP budget to go towards a single project, or at most, a few large projects. On the other hand, parties suggest mechanisms to preserve program funds, such as raising the incentive cap for only renewable fuel cell projects, reducing incentives for projects over 1 MW, and lifting the 1 MW cap on a pilot basis.

FCE and CCSE, point out that the SGIP currently has $96 million in unused funds from prior years.[5] CCSE contends that unused funds indicate potential shortcomings in the eligible technology market, the incentive rates, and/or program execution. PG&E and CCSE note that fuel cell participation in SGIP has not been high. CCSE states it has funded only $21.1 of $506.7 million in incentives to wind and fuel cell projects, or just 4%, and only 8.9 MW of 278.1 MW, or 3.2% of installed capacity. PG&E claims the renewable fuel cell market needs stimulation because no renewable fuel cell projects have been completed in its service territory, although five such projects (representing 4.7 MW in capacity) are currently pending. Our Energy Division reviewed SGIP data and found that although SGIP funded a total of 233.8 MW in 2005 through 2007, there were only 32 fuel cell project applications in SGIP in those years. Nine of the 32 projects have been completed, with a capacity of 5.7 MW. Three of the 32 applications pertained to renewable fuel cells, for a total capacity of 2.62 MW. There were five wind turbine project applications over the same period, for 3.8 MW in capacity, and none have been completed. Moreover, only six fuel cell and wind SGIP applications during that period were for projects over 1 MW, with a maximum size of 1.5 MW, and none have been completed. The fact that SGIP has not funded a completed wind or fuel cell project greater than 1 MW from 2005 to the present is consistent with the notion that the existing incentive cap is effectively functioning as a cap on wind and fuel cell project size, despite the fact that projects up to 5 MW are eligible to participate in SGIP.

---

[5] FCE and CCSE cite the SGIP administrators' website as the source of this figure. The Commission's Energy Division has corroborated this figure.

CCSE maintains that providing incentives to larger installations, coupled with a tiered incentive structure that pays less than the full incentive over 1 MW, can provide for the installation of more MW of renewable fuel cell DG projects for fewer incentive dollars. In their example, the current 1 MW cap for CCSE allows them to fund 5.4 MW of renewable fuel projects. If the incentive cap were raised to 3 MW, coupled with tiered incentives, CCSE's budget could fund 8.6 MW with the same budget of $23.4 million.

In support of its petition, FCE argues the market for fuel cells is constrained by the 1 MW limit and that "larger projects are better able to deliver cost-effective solutions to the wastewater operator." (FCE Petition, 7/25/07, p. 6.) FCE also suggests that increasing the incentive cap will allow fuel cell manufacturers to reduce product costs via larger production volumes as they realize economies of scale in raw material procurement and production labor when a higher volume of fuel cells are manufactured and sold. (*Id.*, p. 8.) FCE's amended petition attempts to bolster these assertions with additional data about fuel cell project costs and production efficiencies. UTC disputes FCE's assertions regarding production efficiencies and economies of scale.

Without relying on the disputed claims of production efficiencies and economies of scale, we find the argument by CCSE compelling that unspent funds and the low participation rates for fuel cell and wind projects suggests modifications to the current SGIP structure may be warranted. If we increase the incentive cap for both wind and fuel cell DG projects, coupled with decreased incentives for installations over 1 MW, we can attempt to install more MW with the same budget. Moreover, the existence of $96 million in unspent funds allows us to test FCE's assertions on a pilot basis. The possibility that the 1 MW incentive cap is inhibiting larger scale wind and fuel cell project development, coupled with significant unspent SGIP funds, provides sufficient reason to raise the incentive cap on a trial basis for 2008 and 2009 using carryover funds. As noted above, the original reason for the incentive cap was to prevent a few large projects from depleting SGIP funds, thus excluding broad program participation. At this juncture, given the magnitude of unsubscribed funds, it is reasonable to allow carryover funds to be used to fund larger projects.

Moreover, to the extent there is latent demand that may have been suppressed due to a lack of incentives above 1 MW, we believe it is reasonable to raise the incentive cap for all SGIP-qualifying technologies. Although FCE requests increasing the cap for renewable technologies only, we see no reason not to extend this proposal to all technologies currently supported by SGIP. Policy preferences for a given technology, as well as differences in the underlying economics, are currently reflected in SGIP through the incentive levels and Commission rules on allocation of funds between renewable and non-renewable projects. (See D.01-03-073.) We will allow all SGIP eligible technologies to apply for carryover funds, and prior Commission orders regarding allocation of funds between renewable and non-renewable (i.e., Level 2 and Level 3) incentive categories are unchanged and apply equally to carryover funds.

Thus, we will grant FCE's petition in part and allow the SGIP administrators to use carryover funds from prior budget years to provide incentives up to 3 MW to qualifying projects up to 5 MW during 2008 and 2009. We will not grant a permanent change to SGIP rules, and we will only allow projects to receive incentives over 1 MW to the extent carryover funding is available. Program administrators should adhere to all prior Commission orders regarding allocation of funds between renewable and non-renewable incentive levels. Projects applying for incentives up to a maximum of 1 MW will be funded according to standard SGIP rules from each program administrator's annual budget allocation.[6] Projects applying for incentives greater than 1 MW, if approved, will receive all of their funding from carryover funds, as available. This preserves the current year's SGIP budget of $83 million for projects receiving incentives up to 1 MW. Any incentives paid over 1 MW will decline in tiers, as suggested in the amended petition. We will adopt CCSE's proposed tiering structure, because it is most conservative and will maximize the use of the carryover funds. Plus, CCSE's proposal is easily applicable to all current SGIP incentives, which vary by technology, as the tiers are based on a percentage of the current incentive. We adopt incentive levels for projects that receive incentives up to 3 MW as follows:

Table 1: Tiered Incentive Rates[7]

Capacity	Incentive Rate
0-1 MW	100%
1 MW – 2 MW	50%
2 MW – 3 MW	25%

In addition, we will allow eligible projects under review larger than 1 MW to be deemed eligible to apply for carryover incentive funding as set forth in this

[6] If the annual budget is fully subscribed with applications meeting standard program rules, the SGIP program administrators may use carryover funds to support these projects as well.

[7] Current SGIP incentive levels were set by Commission order and are $1.50/watt for Level 2 renewable wind projects, $4.50/watt for Level 2 renewable fuel cell projects, and $2.50/watt for Level 3 non-renewable fuel cell projects.

order, up to 3 MW, without the need to reapply. The program administrators should notify all such applicants to whom this might apply to determine if they wish to be considered for additional incentives. Completed projects that seek additional funding for an expansion will need to reapply.

Although we initially issued a proposed decision to deny FCE's petition, the new information regarding unspent SGIP funds and low participation rates for fuel cells and wind convinces us that we should consider testing program modifications. Therefore, we will grant FCE's amended petition in part, for all qualifying wind and fuel cell DG projects, with tiered incentives as set forth in Table 1. The increase in the incentive cap to 3 MW and tiered incentives shall apply on a pilot basis for two years, i.e., SGIP program years 2008 and 2009, and projects that apply for incentives over 1 MW, if approved, will be funded entirely from SGIP carryover funds, as available. The increased incentive cap may continue past 2009 only upon further order of this Commission, which we expect would follow a review of program participation and budgets.

Some parties suggest raising the SGIP total budget. We will not consider an increase in the annual SGIP budget at this time, in light of recent legislative restrictions that limit us to funding only wind and fuel cell DG projects through SGIP. Rather, we will use SGIP carryover funds to allow expanded program eligibility.

7. Motion for Confidentiality

Along with its Amended Petition, FCE filed a motion requesting confidential treatment of Appendix C, Attachment 1 to its filing. According to FCE, this document contains commercially sensitive production cost data and cost projections associated with FCE's products, that qualify as "trade secrets" under Government Code Section 6254.7(d). This information involves production data known only to certain individuals and which gives its user an opportunity to obtain a business advantage over its competitors, as discussed in the Government Code defining trade secrets. If revealed, this information would subject FCE to competitive disadvantage with respect to other fuel cell manufacturers. FCE contends the competitive retail environment in which FCE competes necessitates confidential treatment of this information. Debenham opposes the motion for confidentiality, arguing FCE has failed to state any valid legal reason for granting the motion.

We disagree with Debenham and find FCE has stated a valid legal reason to grant confidentiality. FCE's production cost data and cost projections in its filing are commercially sensitive trade secrets under Government Code Section 6254.7(d) and would place FCE at a disadvantage if revealed to competitors. We have granted similar requests for confidential treatment of commercially sensitive business data, and will do so here as well.

8. Comments on Proposed Decision

The proposed decision of Commissioner Michael R. Peevey in this matter was initially mailed to the parties on January 15, 2008, in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by FCE, PG&E, SCE, and UTC. Reply comments were filed by CCSE, SCE, and UTC. The proposed decision was subsequently withdrawn from the Commission's agenda following the filing of FCE's amended petition.

The proposed decision was mailed for comment a second time, following the filing of FCE's amended petition on February 8, 2008. Comments were filed by CCSE, Debenham, FCE, PG&E, SCE, jointly by San Diego Gas & Electric Company and Southern California Gas Company (SDG&E/SoCalGas), and UTC.

Reply comments were filed by CCSE, Debenham, FCE, SCE, and UTC. The comments generally support the proposed decision, and minor modifications as suggested by the comments have been incorporated into the decision. Specifically, PG&E and CCSE request that the Commission clarify that eligible projects larger than 1 MW that are currently under review should not have to cancel their application and reapply to be considered for additional incentives. This clarification has been added to the order.

UTC requests that the augmented incentives be limited to the current $96 million in carryover funds. We decline this suggestion, preferring to allow any additional SGIP carryover funds that may become available over the course of 2008 and 2009 to be used as described in this order. SDG&E/SoCalGas ask for several clarifications on administration of carryover funding, such as how to handle add-ons to existing projects, roll-over of the budget if insufficient to fund a project greater than 1 MW, guidelines for budget transfers, a cap on the amount of carryover funds spent in one year, and wording to allow all eligible technologies to receive augmented incentives. We specifically decline to limit the amount of carryover funding spent in one year, and we decline the wording change to refer to "all eligible technologies." If legislation changes the SGIP eligibility, we can address extension of this program at that time. With regard to the other proposals, we will not address this level of administrative detail in the order, preferring to let our Energy Division work with the SGIP program administrators on appropriate resolution of issues such as these, as they arise, in keeping with the overall guidance set forth in this order.

9. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Dorothy J. Duda is the assigned ALJ for this portion of this proceeding.

Findings of Fact

1. Under the SGIP, projects up to 5 MW in size can apply for incentives, but incentives will be given only up to 1 MW.

2. The Commission has denied requests to increase the 1 MW incentive limit on the basis that this could deplete the SGIP budget.

3. There are $96 million in unspent SGIP funds from prior program years.

4. There has been low participation by fuel cells and wind projects in the SGIP.

Conclusions of Law

1. Increasing the SGIP 1 MW incentive limit without restriction would decrease the number of projects funded by SGIP.

2. Raising the incentive cap to 3 MW for qualifying SGIP wind and fuel cell projects, coupled with tiered incentives over 1 MW, will allow more MW of DG to be installed for the same dollars.

3. Given the large amount of unspent SGIP funds from prior years, the Commission should raise the cap for incentives to 3 MW for qualifying wind and fuel cell projects. Projects applying for incentives up to a maximum of 1 MW will be funded from the annual SGIP budget. Projects applying for incentives greater than 1 MW, if approved, will be funded entirely from SGIP carryover funds, as available.

4. Incentives paid beyond 1 MW should be reduced according to Table 1 and available only for 2008 and 2009.

5. Production cost data and cost projections in Appendix C, Attachment 1 to FCE's filing should be granted confidentiality as trade secrets under Government Code Section 6254.7(d).

O R D E R

IT IS ORDERED that:

1. The petition to modify Decision (D.) 04-12-045 filed by FuelCell Energy (FCE) on July 25, 2007, and amended on February 8, 2008 is granted in part as set forth herein.

2. D.04-12-045 is modified to allow Self-Generation Incentive Program administrators to pay qualifying distributed generation projects incentives up to 3 megawatts (MW) from prior years' carryover funds, with incentives over 1 MW reduced as set forth in Table 1, and with all prior Commission orders regarding allocation of funds to renewable and non-renewable incentive categories applying to the use of carryover funds.

3. This modification shall apply for the SGIP in 2008 and 2009 only, unless modified by further order of this Commission.

4. The motion for confidentiality filed by FCE on February 8, 2008 is granted for two years from the date of this order. During that period, the information shall not be made accessible or disclosed to anyone other than Commission staff, except upon execution of an appropriate non-disclosure agreement with FCE, or on the further order or ruling of the Commission, the assigned Commissioner, the assigned Administrative Law Judge (ALJ), or the ALJ then designated as Law and Motion Judge.

5. If FCE believes that further protection of the information filed under seal is needed, it may file a motion stating the justification for further withholding of the information from public inspection, or for such other relief as the Commission rules may then provide. This motion shall be filed no later than one month before the expiration date of today's order.

6. This decision shall be served on the service list for Rulemaking (R.) 04-03-017 and R.06-03-004.

7. This order is effective today.

Dated April 24, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

CPUC Decision 08-11-044

COM/MP1/jt2 **Date of Issuance 11/24/2008**

Decision 08-11-044 November 21, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 08-03-008 (Filed March 13, 2008)

DECISION ADDRESSING ELIGIBLE TECHNOLOGIES UNDER THE SELF-GENERATION INCENTIVE PROGRAM (SGIP) AND MODIFYING THE PROCESS FOR EVALUATING SGIP PROGRAM CHANGE REQUESTS

1. Summary

This decision addresses several requests to modify the self-generation incentive program (SGIP), and revises the process for evaluating future SGIP program modification requests. The SGIP provides financial incentives for qualified self-generation equipment, which, when installed on the customer's side of the utility meter, provides electricity for either a portion or all of that customer's onsite electric load. This decision provides that advanced energy storage systems that meet certain technical parameters and are coupled with eligible SGIP technologies, currently wind and fuel cell technologies, will receive an incentive of $2 per watt of installed capacity. Appendix A to this decision outlines the revised process for the review of the SGIP program modification requests.

2. Background and Procedural History

The Commission established the SGIP in Decision (D.) 01-03-073 pursuant to Pub. Util. Code § 399.15(b).[1]

Initially, the SGIP provided financial incentives to distributed generation (DG) technologies,[2] including micro-turbines, small gas turbines, solar photovoltaics, wind turbines, fuel cells, and internal combustion engines at certain levels. Assembly Bill (AB) 2778[3] removed all incentives for photovoltaic systems from the SGIP as of January 2007, and provided incentives for photovoltaics through the California Solar Initiative. Thus, as of January 1, 2007, the SGIP provided incentives only to non-solar renewable and non-renewable DG technologies.

AB 2778 further amended Pub. Util. Code § 379.6 relating to SGIP and limited program eligibility for SGIP incentives to qualifying wind and fuel cell DG technologies, beginning January 1, 2008 through January 1, 2012.

---

1 All statutory references are to the Public Utilities Code unless otherwise noted.

2 DG is a parallel or stand-alone electric generation unit generally located within the electric distribution system at or near the point of consumption. *See* Rulemaking (R.) 04-03-017, p. 6.

3 Chapter 617, Statutes of 2006.

The following table reflects the changes to the SGIP pursuant to AB 2778:[4]

Incentive Levels	Eligible Technologies	Incentive Offered ($/watt)	Minimum System Size	Maximum System Size	Maximum Incentive Size
Level 2 Renewable	Wind Turbines	$1.50/watt	30 kW	5 MW	1 MW
	Renewable Fuel Cells	$4.50/watt	30 kW		
Level 3 Non-Renewable	Non-Renewable Fuel Cells	$2.50/watt	None	5 MW	1 MW

By D.08-04-049, the Commission changed the incentive rates during 2008 and 2009 only. During these years, the Program Administrators (PAs) are to use any carryover funds from prior budget years to pay incentives up to 3 megawatts (MW) for qualifying fuel cell or wind DG projects. Incentives over 1 MW are to be paid at a lower rate.

In addition, D.08-04-049 established a tiered incentive structure for wind and fuel cells as follows:

Capacity	Incentive Rate
0-1 MW	100%
1MW-2 MW	50%
2 MW-3 MW	25%

2.1. Evaluation of Program Modification Requests

In D.03-08-013, the Commission established a multi-stepped evaluation process to consider requests to add technologies to the SGIP or evaluate related

[4] D.08-01-029, p. 8.

program changes which are referred to as Program Modification Requests (PMR).[5] Below is a summary of the evaluation process set forth in D.03-08-013:

1. An applicant contacts a PA[6] and develops a PMR package for submittal to the SGIP Working Group.[7]
2. The proposal is distributed to the SGIP Working Group for evaluation.
3. The applicant or the sponsoring PA will present the proposal to the SGIP Working Group.
4. The SGIP Working Group develops recommendations on the eligibility of the new technology or program rule modification.
5. The applicant has five days to comment on the SGIP Working Group's final recommendations to the assigned Commissioner.
6. The Energy Division will submit the SGIP Working Group's final recommendations and the Energy Division's recommendation to the assigned Commissioner within 90 days after the proposal is presented at the SGIP Working Group meeting.
7. The assigned Commissioner will issue a ruling requesting comments within 15 days and replies within five days on the Energy Division/Working Group recommendations. A Commission decision will address the recommendations and the public comments raised by the Assigned Commissioner's Ruling (ACR).

---

[5] This decision presents only a summary of the evaluation process. *See* D.03-08-013 for full text of the adopted evaluation process and guidelines.

[6] SGIP Program Administrators are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), and the California Center for Sustainable Energy (CCSE), San Diego Gas & Electric Company (SDG&E), and the Energy Division of the California Public Utilities Commission.

[7] The SGIP Working Group consists of SCE, PG&E, SoCalGas, CCSE, and SDG&E.

Since D.03-08-013, several applicants submitted PMRs to the Working Group. The SGIP Working Group reviewed the PMRs and pursuant to the requirements in D.03-08-013 submitted its recommendations to the Energy Division. On March 21, 2008, the Energy Division submitted the SGIP Working Group's recommendations along with its own recommendation to the assigned Commissioner for further consideration.[8] In addition, the Energy Division submitted a proposal to modify the PMR evaluation process that was established in D.03-08-013.

On April 4, 2008, pursuant to the procedures set forth in D.03-08-013, the assigned Commissioner issued an ACR soliciting comments from interested parties on the SGIP Working Group's recommendations and the Energy Division's recommendations for the seven PMRs, and on the proposal by the Energy Division to modify the PMR review process.[9]

Comments were filed by the SGIP Working Group, UTC Power (UTC), and StrateGen Consulting LLC (StrateGen) and VRB Power Systems Inc. (VRB), and reply comments were filed by VRB on April 28, 2008. Because VRB's reply contained new information that was not available when the parties submitted their comments, the Administrative Law Judge (ALJ) issued a ruling on July 1, 2008, providing the parties an opportunity to respond to VRB's reply. Chevron Energy Solutions Company (Chevron Energy) and the SGIP PAs filed responses.

---

[8] Energy Division's recommendation addresses only the PMRs that were eligible under SGIP in 2007. Several PMRs address either technologies that were not eligible for SGIP in 2007 or SGIP rules that are no longer relevant. As such, those PMRs are moot. For a list of those PMRs see Appendix B of the ACR, dated April 4, 2008.)

[9] See Appendix B of the ACR for a list of the seven PMRs and the proposed PMR process.

Concurrent with its reply, VRB also filed a motion for Leave to file confidential material under seal and for protective order. An ALJ ruling, dated July 1, 2008 granted VRB's request.

3. Discussion

3.1. Program Modification Requests

Six of the seven PMRs request to include new technologies into SGIP (PMRs Numbers 1 through 6). PMR Number 7 requests to modify the existing 12-month deactivation period requirement for existing generation systems prior to being eligible for SGIP participation. Energy Division recommends we deny PMRs 1 through 5 due to program ineligibility and accept PMR 7, the deactivation rule modification. There is no opposition to these recommendations and the Energy Division's recommendations are reasonable given the limitation on program eligibility. We adopt the Energy Division's recommendations to deny PMR Numbers 1 though 5 and accept PMR number 7. Below, we discuss PMR Number 6, which has opposing views among parties.

3.2. Advanced Energy Storage (AES) Systems

3.2.1. Adding AES Technology as a New SGIP Technology

StrateGen and VRB submitted PMR Number 6 requesting to include AES systems as a new technology into SGIP. Specifically, they submit information for an AES system developed by VRB that converts chemical energy into electrical energy using a vanadium redox battery system (VRB ESS) that consists of two electrolyte tanks connected by a regenerative fuel cell. They request an incentive of $2.5 per watt (W) for a stand-alone AES system and recommend that we adopt a number of operating and performance parameters defining AES system.

Energy Division and the PAs support adding AES to SGIP with certain conditions. In comments to the ALJ ruling, the PAs clarify that despite their earlier disagreement, they do recommend AES be eligible for SGIP incentives if coupled with an eligible technology (fuel cell or wind). Energy Division also recommends adding AES into SGIP, if coupled with wind or fuel cell technology, and recommends an additional incentive of $2/W of installed AES capacity. VRB increased its $2.5/W request to $3.0/W in its reply to the ACR.

We agree that due to program ineligibility, AES systems cannot be added to the SGIP as a stand-alone technology, but when coupled with wind or fuel cell, AES could increase the value of wind and fuel cell and support the goals of SGIP for peak demand reduction. When so coupled, it would be appropriate to allow such AES facility to qualify for SGIP incentives. Accordingly, we adopt the recommendation that AES systems receive SGIP incentives if coupled with an eligible distributed generation technology under the SGIP, currently wind or fuel cell technology. As SGIP PAs have requested in their comments to the proposed decision, we clarify that an AES system must be coupled with an "as current" eligible distributed generation technology under the SGIP. This means that in the future if other technologies are added to the SGIP, then an AES system coupled with those eligible technologies will also be eligible to receive the incentive adopted here.[10] Likewise, if any of the currently eligible SGIP technologies (wind or fuel cell) is removed from the SGIP, then an AES system coupled with those technologies will no longer be eligible to receive SGIP incentives.

[10] Such AES system must still meet the required technical and operation criteria.

In comments to the proposed decision, the SGIP PAs request that we clarify whether the revisions apply to new or existing projects. We clarify that any SGIP project that is currently an eligible technology (wind or fuel cell), including previously installed SGIP projects, will be eligible to receive AES incentives if coupled with an eligible AES system.

3.2.2. Appropriate Incentive Level

With respect to the level of incentives for AES systems, the Working Group raises several issues and suggests the Commission conduct a workshop to address them.

First, the Working Group raises the question of whether the AES incentive should be paid on capacity kilowatt (KW) or energy (kilowatt-hour or KWh) basis. The Working Group argues that there is value to the length of discharge for an AES system, and suggests a per-KWh incentive may be more appropriate.

We adopt the recommendation that AES, if coupled with wind or fuel cell technology, should receive incentives on a per-KW basis. Wind and fuel cell technologies receive SGIP incentives on a per KW basis. Since AES technologies are required to couple with either wind or fuel cell technology, it would make sense to apply the same incentive structure to AES systems. In addition, we have noted above that an AES system coupled with wind or fuel cell technology contributes to the SGIP goal of peak demand reduction. In that context, a capacity or a per KW basis incentive is more appropriate.

We also adopt a $2/W incentive amount for AES systems when coupled with wind or fuel cell technology. While this is slightly less than that originally requested by VRB, it provides an appropriate level of incentive for AES coupled with a currently eligible SGIP technology. VRB's original PMR requested a $2.50/W incentive for a stand-alone AES system. However, the data provided in

VRB's reply indicates that the economics of an AES system would improve when AES is coupled with an eligible SGIP technology. Since we are only authorizing funding when AES systems are coupled with wind or fuel cell technology, a reduction in the requested incentive level is justified. VRB's argument that a \$3/W incentive is necessary for market adoption of AES is not persuasive. VRB provides an analysis based on an 11% rate of return on investment for a 400 kW AES system, with four-hour discharge, coupled with distributed wind. VRB's analysis assumes a very specific case that is not representative of all applications that would qualify for SGIP and does not sufficiently justify the need for a \$3/W incentive.

3.2.3. Appropriate Incentive Structure

The Working Group also raises a series of questions related to whether there should be a size cap on the AES incentives, and if so, whether the capping metrics should be based on a KW or kWh basis. The Working Group also asks whether the tiered incentive structure that was adopted in D.08-04-049 for SGIP technologies should apply here.

We require that the size of the AES system not exceed the capacity of the accompanying SGIP generation.

In the proposed decision we required that the SGIP PAs apply the tiered incentive structure that was adopted in D.08-04-049 on a pilot basis for 2008 and 2009, to projects containing an AES system up to 3 MW in size. We noted that applying the same tier structure to projects containing AES systems would be reasonable because AES is a supportive technology to wind and fuel cell systems. We also noted that under this approach, the SGIP eligible technology and the AES system would each receive 100% of their respective incentive rates for the 0 to 1 MW of capacity, followed by 50% of their incentive rates for the 1 to

2 MW of their capacity and 25% for the 2 to 3 MW of their capacity. We also required that a single project consisting of an eligible SGIP generation technology, coupled with an AES system, may not receive incentives for more than 3 MW of total capacity.

In comments to the proposed decision, the SGIP PAs contend that the incentive structure is too complicated and may have the unintended consequence of acting as a barrier to AES participation in SGIP. They provide an example of a 3 MW renewable fuel cell project coupled with a 1 MW AES system structure, indicating that under the proposed incentive structure, the AES system would not be given an incentive since the incentives for the fuel cell system at all tiered levels will be higher than incentives for the AES system. Instead, the SGIP PAs recommend we cap the AES incentive at 1 MW. VRB, in reply comments to the proposed decision, urges us to reject the SGIP PAs proposal and recommends that we adopt the proposed decision as written, but increase the maximum incentive per project from 3 MW to 5 MW only for combined AES and SGIP projects.

While the example in the PA's comments is representative of only one specific scenario, it does indicate that applying the tiered structure while capping the incentives at 3 MW may become difficult to apply. To avoid complex implementation of the incentive structure, we remove the 3 MW incentive cap and the 5 MW size limit that we imposed in the proposed decision and clarify that for the purpose of calculating the incentive amount, the AES incentive system will be added to the accompanying SGIP generation incentive. Thus, the requirements for an eligible SGIP technology that is coupled with an AES system will be as follows:

- The size of the AES system may not exceed the capacity of the accompanying SGIP generation.
- The tiered incentive structure that was adopted in D.08-04-049 shall apply, on a pilot basis during 2008 and 2009, to eligible SGIP projects as well as the accompanying AES systems.

Table 1 below indicates the amount of incentives for all currently eligible SGIP technologies and AES systems:

Table 1: Tiered Incentive Rates[11]

System Size	Incentive structure	Renewable Fuel Cell	Non-renewable fuel cell	Wind	AES
0-1 MW	100%	$4.50	$2.50	$1.50	$2.00
1-2 MW	50%	$2.25	$1.25	$0.75	$1.00
2-3 MW	25%	$1.125	$0.625	$0.375	$0.50

Based on the above, a hypothetical 3 MW renewable fuel cell SGIP project coupled with a 2 MW AES system, would receive incentives for the renewable fuel cell at all three tiered levels (1 MW through 3 MW) as well as incentives for the first and the second level (1 MW and 2 MW) for an AES system.

3.2.4. Funding Source

The PAs request guidance from the Commission on which funds to use to pay for AES incentives if other than the funds in the SGIP annual incentives budgets. Because the AES supports wind or fuel cell technology, it is reasonable to require that it would be funded out of the same budget that provides

[11] The tiered incentive rates for renewable and non-renewable fuel cell, and wind were adopted in D.08-04-049.

incentives to those technologies.[12] Accordingly, we direct the PAs to fund AES incentives from SGIP budgets.

3.2.5. Operating Parameters

The Working Group raises concerns with the VRB's proposed language to the text of the SGIP Handbook to implement inclusion of AES in the SGIP. Specifically, the Working Group cautions the Commission against making decisions regarding program eligibility strictly based on information provided by VRB.

We have determined that an AES system is eligible for SGIP incentives if coupled with wind or fuel cell technology. We have also noted that this eligibility should not be limited to the AES system proposed by VRB, but rather, all eligible AES systems should receive the same incentive. Thus, it is necessary to define "qualified advanced energy storage."

VRB has proposed a number of minimum technical operating parameters to define an AES system.

These include:

- Ability to be used daily in concert with an on-site wind resource, and still meet its 20-year lifetime requirement. The qualifying AES system must thus have the ability to handle hundreds of partial discharge cycles each day.
- Ability to be discharged for at least four hours of its rated capacity to fully capture peak load reductions in most utility service territories (required AES duration of discharge will depend on each customer's specific load shape, and the duration of its peal demand during peak utility periods).

---

[12] This would require applying the unspent SGIP budget for SGIP technologies as described in D.08-04-049 to the accompanying AES system.

- Ability to meet Institute of Electrical and Electronics Engineers, Inc. interconnection standards.
- Ability to operate in distributed, customer sited locations and comply with all local environmental and air quality requirements.

We adopt the technical parameters proposed by VRB, but lower the proposed 20-year minimum warranty requirement. We find it unreasonable to require a 20-year warranty term for AES, while under the SGIP, wind and fuel cell technologies are required to have only a five-year warranty. Furthermore, the PAs recommend that we "select a minimum warranty term that encourages the greatest success in roll-out of the AES technology."[13] A 20-year warranty term seems unnecessarily excessive. Therefore, we require a five-year warranty for AES systems, consistent with the warranty requirements for wind and fuel cell technologies. We believe that the adopted definition is generic enough to allow all qualified AES systems to participate in SGIP. However, because the likelihood exists that our definition maybe overly restrictive, and in regard to the Working Group's concern, we require the PAs to monitor AES applications and report to the Commission if they find the adopted parameters are creating unfair advantages, or adversely impacting the ability of qualified AES systems to participate. In particular, as part of the SGIP measurement and evaluation, PAs should report if the definition of AES precludes AES technologies other than VRB ESS from participating.

---

13 *See* Comments of SGIP PAs, dated July 11, 2008.

3.3. PMR Evaluation Process

The Working Group and UTC generally agree with the proposed changes, but offer some modifications to the proposed evaluation process. The Working Group recommends all PMRs be submitted in writing 10 business days prior to the SGIP Working Group meeting or roll over to the next meeting. UTC urges the Commission to provide clear guidance on the timing of the review and allow applicant the opportunity to provide additional data or supplement the original requests in response to the Working Group's questions. UTC also recommends we modify the process by which the Working Group's recommendation is submitted to the Commission.

We adopt the Working Group's recommendation for a 10-day advance notice requirement. This would create a firm deadline for the submittal of a PMR, provide automatic notification to the applicant of the timing of the review of the PMR, and provide the Working Group reasonable amount of time to examine the PMR and ask follow up questions prior to the Working Group's meeting.

Similarly, we allow the applicant the opportunity to respond to questions and make a follow up presentation if the Working Group determines additional information is needed. However, we do not limit the timeframe in which the applicant should provide additional data to the next Working Group meeting, but leave that determination to the Working Group. We expect the Working Group to consider the extent and nature of the information requested of each applicant and allow an appropriate amount of time for a response while reasonably moving the review process for each PMR forward.

We reject UTC's suggestion to modify the process by which the Working Group's recommendation is submitted to the Commission. UTC suggests that the applicant prepare a "summary of the Working Group's recommendation" and submit that for Commission review, instead of having the Working Group submit its own recommendation directly to the Commission. UTC suggests the "summary of the recommendation" be vetted by the Working Group for accuracy and completeness before it is submitted to the Commission. UTC's proposal adds no benefits to the Working Group's recommendation submittal process. Instead, it would add an extra step that could increase the complexity of or delay the process. We maintain the existing process for the submittal of the Working Group's recommendation. Appendix A to this decision outlines the adopted PMR process.

PAs shall file an advice letter requesting appropriate revisions to the handbook in accordance with the requirements of this decision. Prior to filing the advice letters, PAs should discuss the specific revisions to the handbook with the Working Group.

4. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 12, 2008, by VRB, Chevron Energy and the SGIP PAs, and reply comments were filed on November 17, 2008 by VRB.

The comments generally support the proposed decision. Some modifications as suggested by the comments have been incorporated into the decision.

Specifically, we have clarified the discussion in Section 3.2.1 to provide that if technologies other than wind or fuel cells are added to the SGIP, then an AES system coupled with those eligible technologies will be eligible to receive the incentives discussed in this decision. We also clarify that any SGIP project that is currently an eligible technology will be eligible to receive AES incentives if coupled with an eligible AES system.

We also modify Section 3.2.3 to remove the 3 MW incentive cap and the 5 MW size limit imposed by the proposed decision. We also make minor changes to improve the discussion and correct typographical errors.

Several comments merit further discussion. Specifically, Chevron Energy states that "it is pleased that the Commission has recognized the importance of AES technology as a new SGIP technology"14 and requests a review by both the Commission staff and the SGIP PAs after 12 months of program operation to help determine whether the incentive level for AES is sufficient to achieve the desired goals. We are concerned from this comment that there may be confusion about AES system eligibility under SGIP, and therefore clarify that we are not adding an AES system as a new technology under SGIP. As noted above, AES systems cannot be added to the SGIP as a stand-alone technology. Rather, we are allowing eligible SGIP technologies, currently wind and fuel cell systems, that are coupled with AES systems to receive incentives for AES. We also decline Chevron's suggestion for a 12-month review of the AES incentives. We prefer such reviews to take place as part of the Commission's ongoing SGIP program evaluation process.

The SGIP PAs request that we remove the advice letter requirement for implementing the SGIP program revisions. Instead, the PAs suggest convening a workshop in December to give them an opportunity to vet the changes required

[14] See Chevron Energy's comments to the proposed decision.

by the decision among themselves and with the industry and to implement the SGIP program changes with the release of 2009 SGIP Program Handbook, scheduled to be published approximately on February 1, 2009.

We do not require a workshop for implementation of the revisions to the SGIP ordered in this decision. However, because of the technical nature of the revisions, we allow more time for the PAs to prepare their implementation advice letters. The SGIP PAs shall submit the advice letters within 60 days of the effective date of this decision. We also allow the PAs to incorporate the changes to the SGIP program in the 2009 SGIP Handbook, which is currently scheduled for February 1, 2009, if the advice letter is approved by the Energy Division.

5. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Maryam Ebke is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The SGIP is limited to wind and fuel cell technologies.
2. There are no protests to the Energy Division's recommendation regarding PMRs Numbers 1 through 5 and PMR number 7.
3. As a stand-alone technology, AES is not eligible for SGIP incentives.
4. When coupled with wind or fuel cell technology, AES system supports the goals of SGIP for peak demand reduction.
5. $2/W is an appropriate incentive for AES coupled with a currently eligible SGIP technology (wind or fuel cell technology).
6. It is logical and consistent with Commission past practice for projects containing an AES system to not exceed the capacity limitations of SGIP.
7. It is reasonable to apply the tiered incentive structure that was adopted in D.08-04-049 to SGIP projects with an AES system.

8. Because AES supports wind and fuel cell technologies, it is reasonable to require that it be funded out of the SGIP budget.

9. Except for the 20-year minimum warranty requirement, the technical parameters proposed by VRB are broad enough to allow all qualified AES to participate in SGIP.

10. A five-year warranty for AES is consistent with the SGIP warranty requirements for wind and fuel cell technologies and is reasonable.

11. It is reasonable for PMRs to be submitted at least 10 business days before the SGIP Working Group meeting

12. The existing process for the submittal of the Working Group's recommendation for PMRs is reasonable.

Conclusions of Law

1. Due to program ineligibility, PMRs Numbers through 5 should be denied.

2. PMR Number 6 should be adopted.

3. When coupled with a currently eligible SGIP technology, namely wind or wind fuel cell technology, AES systems should receive incentives.

4. AES systems, if coupled with wind or fuel cell technology, should receive incentives on a per KW basis.

5. A $2/W incentive should be adopted for AES systems that are coupled with wind or fuel cell technology.

6. The size of the AES should not exceed the capacity of the accompanying generation.

7. During 2008 and 2009, and on a pilot basis, the tiered structure adopted in D.08-04-049 should apply to SGIP projects with AES systems.

8. Any SGIP project that is currently an eligible technology (wind or fuel cell) should be eligible to receive AES incentives if coupled with an eligible AES system.

9. AES incentives should be funded from SGIP budgets.

10. With the exception of the 20-year warranty term, the technical parameters to define AES in the context of SGIP proposed by VRB should be adopted.

11. A five-year warranty for AES should be adopted.

12. PAs should monitor AES applications and report to the Commission if they find the adopted parameters adversely impact the ability of some qualified AES to participate.

13. The proposed changes to the PMR evaluation process with modifications as described in Appendix A should be adopted.

14. This decision should be effective immediately so that the PAs can implement it expeditiously.

O R D E R

IT IS ORDERED that:

1. Advanced energy storage systems that are coupled with one of the eligible self generation technologies, namely wind or fuel cell technology, and meet the technical and operational criteria established in this decision shall receive a $2/watt incentive.

2. Appendix A is adopted.

3. Within 60 days from the date of this decision, the Self-Generation Incentive Program (SGIP) Administrators shall file an advice letter implementing the revisions to the SGIP in accordance with the requirements of this decision and Appendix A. Prior to filing the advice letter, PAs should discuss the specific revisions to the handbook with the SGIP Working Group.

4. Rulemaking 08-03-008 remains open.

This order is effective today.

Dated November 21, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

D0811044 Appendix A

APPENDIX A

Revised Program Modification Request (PMR) Process

1. All Program Modification Requests (PMRs) must be submitted in writing, using the current PMR format, to the SGIP Working Group for review at least 10 business days prior to the SGIP Working Group meeting or the request will roll over to the next SGIP Working Group meeting.

2. All parties desiring a program modification will be required to meet with the SGIP Working Group at the monthly SGIP Working Group meeting to determine if the Working Group would support the PMR.

3. The SGIP Working Group will first determine whether or not the proposed PMR requires a modification to a prior Commission order.

4. **If the PMR is minor and non-substantive, and does not require modifications to prior Commission orders, then:**

    a) The Working Group will review the PMR. If accepted, the Working Group will make the appropriate changes to the Handbook.
    b) If the Working Group needs more information, the party proposing the PMR would have the opportunity to present at the following Working Group meeting with additional information which supports its request for a program change.[1]
    c) The Working Group will make a decision to accept or deny the PMR based on the new information presented in the follow-up presentation.
    d) The proposed program change and the Working Group recommendation(s) and rationale will be captured in the Working Group meeting minutes.
    e) If the party objects to the Working Group's decision to deny the PMR, the party may write a letter to Energy Division stating why their program change should be included in SGIP. Information that supports the party's reasons to accept the program change must be included in the letter.
    f) Energy Division will then make a final decision on whether to approve the PMR.
    g) Energy Division will report its final decision at the following SGIP Working Group meeting, which will be captured in the SGIP Working Group meeting minutes.
    h) If the PMR is accepted, appropriate revisions to the Handbook will be made to capture the change.

[1] The Working Group will determine the timeframe in which the applicant should provide additional information at the following Working Group meeting.

5. If the proposed change requires modification to a prior Commission order or if the PMR addresses large programmatic or substantive issues, then:

a) The Working Group will review the PMR and make a recommendation to support or oppose the PMR in the same meeting.

b) The proposed program change, the Working Group recommendation and rationale will be captured in the Working Group meeting minutes.

c) Subsequent to the meeting, the Working Group will write up a summary of the discussion of the PMR at the Working Group meeting, a list of comments in support or against the PMR, as well as the Working Group's overall recommendation with rationale, which will be presented to the applicant.

d) The party proposing the PMR has the choice to move forward and submit a petition to modify (PTM) for Commission review regardless of the Working Group's recommendation, but the Working Group's summary must be included in the PTM.

e) The Energy Division participates in Working Group meetings and is welcome to participate in the discussion related to the PMR as well as in generating the "list of issues". The Energy Division does not need to participate in the "recommendation" portion of the Working Group's PMR review.

f) Once the PTM is filed with the Commission, the normal PTM process will transpire, only it will have the benefit of the idea being somewhat vetted before submittal. All parties have a chance to comment on PTMs according to the Commission's Rules of Practice and Procedure.

g) The Commission will review and address the PTM in a decision.

(END OF APPENDIX A)

CPUC Decision 09-01-013

Decision 09-01-013 January 29, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 08-03-008 (Filed March 13, 2008)

DECISION ADOPTING SELF-GENERATION INCENTIVE PROGRAM BUDGET FOR 2009 AND OTHER OPERATION DETAILS FOR 2009 THROUGH 2011

Summary

This decision adopts a budget of $83 million for the Commission's Self Generation Incentive Program (SGIP) in 2009. The SGIP budget for 2010 and 2011 will be set later in 2009 after the Commission performs further review of prior years' unspent SGIP funds and program participation rates. Other aspects of SGIP operation, including the administrative budget, budget allocations between the utilities, and allocation of funds between renewable and non-renewable projects, will continue unchanged based on previous Commission guidance. Finally, the decision directs San Diego Gas & Electric Company to extend its contract with the California Center for Sustainable Energy for SGIP administration in the San Diego area through December 31, 2011.

Background

The Commission established the SGIP in 2001 to provide incentives to businesses and individuals who invest in distributed generation (DG), i.e., generation installed on the customer's side of the utility meter that provides electricity for a portion or all of that customer's electric load. (*See* Decision (D.) 01-03-073.) The program is available to customers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas). The program is administered by these same utilities, except that the California Center for Sustainable Energy (CCSE) administers the program in SDG&E's service territory.

Since its inception in 2001, the Commission's SGIP has resulted in over 1200 completed and on-line distributed generation projects within the territories of the four utilities, and the four utilities have paid approximately $488 million in incentives to these completed projects.[1]

The SGIP budget was initially $125 million per year, with cost responsibility allocated across the four energy utilities noted above. With the creation of the California Solar Initiative (CSI) in 2006, the Commission redirected the portion of the SGIP budget supporting solar incentives to the CSI program. (*See* D.06-01-024.) As a result, the SGIP budget was reduced to $83 million per year for 2007 and 2008 to reflect that solar incentives are now funded through CSI. (*See* D.06-12-033 and D.08-01-029.)

Also in 2006, Assembly Bill 2778[2] amended Pub. Util. Code § 379.6 to limit program eligibility for SGIP incentives to qualifying wind and fuel cell distributed generation technologies, beginning January 1, 2008 through January 1, 2012.

---

1 *See "CPUC Self-Generation Incentive Program, Seventh Year Impact Evaluation,"* prepared by Itron, Inc., September 2008.

2 Chapter 617, Statutes of 2006.

In a ruling of September 10, 2008, the assigned Administrative Law Judge (ALJ) asked parties to comment on the SGIP budget, details of the continuing operation of SGIP through December 31, 2011, and whether CCSE should continue in its role of administrator for SGIP in the SDG&E territory. Comments were filed on September 30, 2008, by the California Clean DG Coalition (CCDC), CCSE, the National Association of Energy Service Companies (NAESCO), PG&E, SCE, jointly by SoCalGas and SDG&E, The Utility Reform Network (TURN), and UTC Power. Replies were filed on October 7, 2008, by the Commission's Division of Ratepayer Advocates (DRA), PG&E, SCE, SoCalGas/SDG&E, TURN, and jointly by Bloom Energy and Fuel Cell Energy (Bloom/FCE).

SGIP Budget and Program Operation issues

The Commission must decide whether to direct the Program Administrators to continue to operate the SGIP through 2011 with essentially the same program parameters as prior years. Parties were asked to comment on continuation of SGIP in accordance with previous Commission direction regarding the annual budget, the carry over of unspent funds, and other program implementation details.

The comments by the parties indicate general consensus regarding the details of the continued operation of SGIP through 2011 with the main debate, or area of disagreement, involving the level of the annual budget and the use of carryover funding for this program. Given the consensus on most operational issues, we will first provide direction to the Program Administrators to continue to implement SGIP in accordance with all previous direction from the Commission, including but not limited to budget allocations between the four energy utilities in the same percentages as in 2008, a 10% administrative budget, and allocation of funds between renewable and non-renewable projects.

We now turn to the debate concerning the annual budget and carryover funding. NAESCO, CCDC, CCSE, PG&E, SoCalGas/SDG&E, UTC, and Bloom/FCE all support the budget of $83 million, along with provisions for carryover of unspent funds to future program years. NAESCO supports the carryover to maintain a reserve fund for use during times of extraordinary or unanticipated demand. UTC Power contends that confidence in the availability of SGIP funding from year to year is essential to customers considering clean energy investments, particularly because the customer decision process for fuel cell investments is generally longer than one year. CCDC and CCSE request that the Commission allow flexibility to increase the SGIP budget if the Legislature modifies the eligible SGIP technologies beyond wind and fuel cells. PG&E supports continuation of the program budget at $83 million as an interim measure for 2009, until the Commission can review the use of carryover funds for projects in the 1 megawatt (MW) to 3 MW range, as allowed by D.08-04-049.

SCE supports the continued operation of SGIP through 2011, but it requests flexibility to return SGIP overcollections to ratepayers. SCE explains that it expects an overcollection of $110 million in its SGIP memorandum account by the end of 2008, due to carryover of unspent funds from prior year's budgets. SCE requests an advice letter process to reduce or delay SGIP collections while current over-collected funds are used to fund the program operation. SoCalGas/SDG&E support SCE's suggestion for a mechanism to provide flexibility and allow the utilities to suspend SGIP collections, if justified based on program demand.[3] PG&E states it does not have a large overcollection because it

[3] SoCalGas/SDG&E provide no information on whether either utility has an overcollection of SGIP funds.

has not actually collected from ratepayers its entire authorized budget from 2001 to the present. PG&E supports the carryover of unspent funds but asks for clarification whether it should carryover budget dollars or dollars actually collected from ratepayers.[4]

TURN opposes continuing the current budget level of $83 million without a thorough review of program demand. It argues that if the Commission can meet all program obligations while collecting less money from ratepayers, it should do so now. TURN echoes PG&E's comment that the Commission review SGIP budget and eligibility criteria towards the end of 2009, when more information on the demand for carryover funds is available. TURN contends the Commission should gather additional program data on unspent funds from prior budget years, the ratemaking treatment of SGIP revenues, and the status of applications, and wait until the end of 2009 to determine the long-term SGIP budget. SCE disagrees with TURN on the need for further proceedings and data gathering before setting the SGIP budget.

DRA questions why excess funds are accumulating in the SGIP, and whether this is due to lack of demand, technology limitations, or lack of program marketing. DRA supports the concept of truing up the memorandum accounts on an annual basis if balances exceed a Commission determined minimum balance. DRA agrees a positive balance should be kept in the account for the cyclical fluctuations in program demand, but that there should be a limit to the

---

[4] From 2001 to 2005, "PG&E spent more on SGIP incentives than it collected from ratepayers, and it has not yet trued up that difference, since in more recent years, it has collected more than it has spent." (PG&E Comments, 9/30/08, p. 3.) PG&E notes the amounts should be trued up "so ratepayers pay no more and no less than the amounts spent on this program." (*Ibid.*)

carryover. DRA suggests the Commission adopt an annual true-up a process similar to the one for energy efficiency shareholder incentive claims, as adopted in D.07-09-043.

Discussion

There are three main issues the Commission must decide at this time. First, we must decide what budget level to authorize for SGIP for 2009, 2010, and 2011. Second, we must address whether to continue the practice of allowing unspent funds to be carried over to current budget years. Third, we should address SCE's request for flexibility in its collections so that it can use its current overcollection to fund current program activities.

On the first issue, we find merit to continuing the SGIP budget at the $83 million level for 2009, but we will gather further information before deciding on the proper budget level for 2010 and 2011. We have only recently authorized in D.08-04-049 the payment of SGIP incentives up to 3 MW, instead of the prior limit of 1 MW. In addition, the Commission recently expanded SGIP in D.08-11-044 to allow payment of incentives to advanced energy storage systems that are coupled with eligible SGIP technologies. We should not reduce the program budget until we can gauge the demand for these incentives. We should continue the program at the current funding level to provide market participants certainty when deciding whether to apply for these funds.

The 2009 budget shall be allocated across the utilities as follows:

SGIP Budget for 2009

Investor-Owned Utility	Percentage	2009 SGIP Budget (in millions)
PG&E	44%	$36
SCE	34%	$28
SDG&E	13%	$11
SoCalGas	9%	$8
TOTAL	**100%**	**$83**

We find it is premature to establish a budget for 2010 and 2011. As TURN and DRA suggest, we should assess the participation rate and demand for SGIP funds before establishing a future program budget. We agree with TURN that more information is needed on unspent funds, the ratemaking treatment of SGIP revenues, and the status of applications. We will direct the SGIP program administrators to provide this information, as discussed further below, so we can make future decisions for this program. We also need to retain budget flexibility in the event pending or contemplated legislation alters the technologies eligible for this program. There have been recent legislative proposals on this issue, and we expect further consideration of these proposals in 2009.

The second issue is unspent funds from prior budget years. We will continue the practice of allowing the program administrators to carryover these funds to their 2009 budget. In other words, if a program administrator did not spend its entire authorized budget in prior program years, it can augment its current budget by this amount. As we stated in D.08-01-029, this carryover includes unspent funds from non-PV applications that have dropped out or withdrawn. Unspent SGIP funds from PV applications prior to January 1, 2007 were either transferred to CSI on December 31, 2006, as directed in D.06-12-033, or should be transferred to CSI in the manner described in D.06-12-033 if and when these older PV applications drop out. (See D.06-12-033, pp. 33-34, and D.08-01-029, p. 7.)

Again, because of our recent decision in D.08-04-049 to fund incentives up to 3 MW, and in D.08-11-044 to pay incentives to advanced energy storage, we may see increased demand for the incentives and we want carryover funds to be available for this purpose in 2009. This will also allow us to gather information on the unspent funds from prior years and demand for the funds in 2009, to assess whether to continue this practice for 2010 and 2011.

The third issue is the utilities' requests for flexibility in how they collect SGIP funds from ratepayers. We discern from the comments that the utilities are not necessarily handling collections and accounting for SGIP in a consistent manner. It appears SCE collects its authorized budget annually regardless of demand for the program, and it now has approximately $110 million in unspent funds. Conversely, PG&E has apparently only collected from ratepayers after the fact based on the funds it committed each program year. At some point, however, PG&E switched to collecting its authorized budget annually. It is also unclear how much money each utility has amassed in carryover funds, either those funds it has collected from ratepayers but not spent, or funds that were budgeted but never collected. We need a better understanding of the authorized budget each utility has actually spent in each program year.

It is important to distinguish the authorized budget for SGIP from ratepayer collections. We have authorized an SGIP budget amount for each program year. It is up to the utilities either to collect it in advance from ratepayers or fund the money themselves and get reimbursed through ratepayer collections after the fact. It does not appear that previous SGIP decisions specified how the utilities were to handle this. Previous Commission orders authorized the carryover of unspent funds, but did not specify whether this was carryover of the authorized budget or carryover of money collected but not spent. It was also not clear if the practice of carrying over unspent funds would augment the budget in any given year, or merely offset the need to collect the current year's budget from ratepayers.

We clarify that we are authorizing the carryover of unspent budgeted amounts from prior program years to the 2009 SGIP budget, and this is meant to augment the current year's budget. We will gather information on the exact amounts of funds spent in each prior program year, determine the amount of cumulative carryover, and then determine whether we should continue to authorize the spending of this carryover budget for 2010 and 2011.

SCE, SDG&E/SoCalGas, and TURN urge us to return unspent funds to ratepayers, or suspend collection of future funds. We will not return unspent funds at this time because the demand for funding for projects up to 3 MW and advanced energy storage is unknown at this time. We do not know how much of the carryover funding from prior years will be needed in 2009, and it is unclear if some of this overcollection is actually reserved for specific projects that are not yet completed. Several parties remind us that DG investment decisions can take a long time. We agree that the market for DG investments needs some certainty about the amount of funds available for incentives. To decrease the funding source while customers may still be contemplating an investment could exacerbate market uncertainty. Nevertheless, we will allow SCE the flexibility to use its current overcollection to fund its 2009 SGIP budget rather than SCE collecting additional funds from its ratepayers at this time. SCE's carryover is large enough to fund its 2009 budget of $28 million and still have funds left for projects up to 3 MW or advanced energy storage, if needed. If demand for SGIP incentives in SCE's territory increases dramatically in 2009, SCE may need to collect its $28 million budget for 2009 at a later date.

Part of the reason there is uncertainty about carryover funds is due to the fact that there are incomplete projects from prior years for which funds are reserved. We are aware that in some cases, there are PV projects from 2006 or earlier, prior to the start of CSI in 2007, which have funds reserved under SGIP but have applied for extensions to keep their application in the system. The same is true for certain DG projects that applied in 2006 and 2007, before the program was limited to wind and fuel cell technologies as of January 1, 2008. The practice of granting extensions ties up budget funds, sometimes at outdated and higher incentive rates, and makes it difficult to assess the current budget picture for the program.

We will direct the SGIP administrators to provide information on all pending SGIP applications so we can understand the scope and dollar amounts related to projects that have been receiving such extensions. By this order, we notify the SGIP administrators that all pending applications for projects filed in 2006 or earlier must be completed and paid or rejected by December 31, 2009. After December 31, 2009, pending applications for incomplete PV projects may reapply under CSI, and pending applications for DG projects that are not based on wind or fuel cell technologies and were filed prior to January 1, 2007, will be rejected.

In summary, the SGIP shall continue to operate through 2011, and program administrators should follow the directions previously given by this Commission in all regards, including but not limited to the administrative budget, funding allocations, and allocation of funds between renewable and non-renewable projects. We adopt a budget for 2009 of $83 million. We direct the utilities[5] to each file in this proceeding, no later than June 1, 2009, the following information (current to May 1, 2009) for each calendar year they have operated the SGIP, beginning in 2001:

- Authorized Budget
- Dollar amount of incentive applications (i.e., the amount of the budget "reserved")
- Dollar amount of SGIP budget collected from ratepayers
- Dollar amount paid to completed projects
- Unspent Budget (carryover)
- Status of pending applications (i.e., date filed, dollar amount, reason for extension)
- Dollar amount of SGIP carryover funds transferred to CSI on 12/31/06 or thereafter.

Program Administration Issues

In D.01-03-073, the Commission designated CCSE (formerly known as the San Diego Regional Energy Office) as program administrator for SGIP in the SDG&E territory. At that time, the Commission reasoned this would allow the Commission to explore non-utility program administration on a limited basis. (D.01-03-073, p. 17.) In D.04-12-045, the Commission directed SDG&E to extend its administrative contract with CCSE through 2007. (D.04-12-045, p. 19.) Although the Commission extended CCSE's role as administrator, the Commission discussed reevaluation of the SGIP administrative structure if funding continued past 2007. The decision notes an expected September 2006 comparative assessment report on program administration to aid in that

[5] SDG&E should coordinate with its program administrator, CCSE, to make this filing.

reevaluation. (*Id.*) In D.08-01-049, the Commission directed SDG&E to extend CCSE's contract for SGIP administration through 2008.

The SGIP Program Administrator Comparative Assessment Report (Report) was filed in April 2007.[6] The Report states that "the differences between program administrators are nuances of strengths and weaknesses rather than questions of capability or incapability." (Report, p. 2.) Our review of the Report indicates that CCSE's administration of SGIP compared favorably in many respects to that of its utility counterparts.[7] We also note the report shows that CCSE outperformed its counterparts in certain marketing and outreach activities, such as promoting SGIP case studies, counseling prospective applicants on appropriate system sizing, and its website, which the report described as the most comprehensive of all the program administrators. (*Id.*, p. 70.) The report also discusses improved coordination between CCSE and SDG&E, which has resulted in improved administrative efficiency since the first Comparative Assessment was filed in September 2003. (*Id.*)

In response to the ALJ's ruling, no party opposed CCSE's continued role as program administrator. CCSE expressed its willingness to continue in the role and highlights efforts it has made to be an efficient and effective administrator, using less than 60% of its potential administrative budget to promote installation of more than 37 MW of clean distributed generation. SDG&E stated that although it would prefer to be the program administrator in its territory, it

---

[6] The Report, prepared by Summit Blue, can be found at: http://sdreo.org/uploads/SGIP_M&E_PA_Comparative_Assessment_Report_April_25_2007.pdf.

[7] See the Report's discussion of administrative cost (pp. 42-43), application processing time (p. 40), and applicant experience (p. 59).

appears reasonable to allow CCSE to continue as program administrator at this time. SDG&E states it looks forward to a continued partnership with CCSE to ensure customers are able to access and benefit from SGIP. NAESCO supports CCSE as program administrator, as long as the Commission continually monitors the performance of the administrators. SCE states it is not opposed to the extension of CCSE's contract.

From our review of the Comparative Assessment Report and the statements of the parties, we find it reasonable to allow CCSE to continue to administer SGIP in the SDG&E territory. Therefore, we direct SDG&E to extend its contract with CCSE for SGIP Program Administration in the SDG&E territory through December 31, 2011.

Comments on Proposed Decision

The proposed decision of President Michael R. Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by Bloom Energy, CCDC, CCSE, PG&E, and SCE. There were no reply comments. The comments generally support the proposed decision as written. The only modification based on the comments is to direct the utilities to file SGIP information one month earlier on June 1, 2009 rather than June 30, 2009, as suggested by PG&E.

Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Dorothy J. Duda is the assigned ALJ for this portion of the proceeding.

Findings of Fact

1. In D.08-04-049, the Commission authorized SGIP incentives up to 3 MW.
2. SCE has an SGIP overcollection of approximately $110 million.

3. DG investment decisions can take a long time.

4. There are incomplete SGIP projects from prior years for which budget funds are reserved.

5. The Commission designated CCSE as SGIP administrator in the SDG&E territory, through 2008.

6. The SGIP Program Administrator Comparative Assessment Report indicates CCSE's administration compares favorably to its utility counterparts.

Conclusions of Law

1. The SGIP administrators should continue to implement SGIP in accordance with all previous Commission direction, including but not limited to budget allocations, administrative budget, and allocation of funds between renewable and non-renewable projects.

2. A SGIP budget for 2009 of $83 million, allocated across the four utilities in the same percentages as in 2008, is reasonable.

3. The program administrators should continue to carryover unspent non-PV authorized budgets from prior program years to their 2009 budgets. Unspent funds related to PV applications that drop out should transfer to CSI as directed in D.06-12-033.

4. The Commission requires further information on program participation and unspent funds before it can set the SGIP budget for 2010 and 2011 or decide whether to return unspent funds.

5. SCE may use its overcollection to fund its 2009 SGIP Budget.

6. All pending SGIP applications filed in 2006 or earlier must be completed and paid, or else rejected, by December 31, 2009.

7. It is reasonable to allow CCSE to continue to administer SGIP in the SDG&E territory.

O R D E R

IT IS ORDERED that:

1. The Self Generation Incentive Program (SGIP) budget for 2009 is $83 million, as set forth in this order.

2. Southern California Edison Company (SCE) may use the overcollection in its SGIP memorandum account to fund its 2009 SGIP Budget, rather than collect additional funds from its ratepayers.

3. Pacific Gas and Electric Company, SCE, Southern California Gas Company and San Diego Gas & Electric Company (SDG&E), in cooperation with the California Center for Sustainable Energy (CCSE), shall file in this proceeding, no later than June 1, 2009, the following information (current as of May 1, 2009) for each calendar year they have operated the SGIP, beginning in 2001:

- Authorized Budget
- Dollar amount of incentive applications (i.e., the amount of the budget "reserved")
- Dollar amount of SGIP budget collected from ratepayers
- Dollar amount paid to completed projects
- Unspent Budget (carryover)
- Status of pending applications (i.e., date filed, dollar amount, reason for extension)
- Dollar amount of SGIP carryover funds transferred to the California Solar Initiative on December 31, 2006 or thereafter.

4. SDG&E shall extend its contract with CCSE for SGIP administration through December 31, 2011.

5. For good cause, the assigned Commissioner or Administrative Law Judge may modify the due dates set forth in this decision.

6. Rulemaking 08-03-008 remains open

This order is effective today.

Dated January 29, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

Public Utilities Code 216

WAIS Document RetrievalCALIFORNIA CODES
PUBLIC UTILITIES CODE
SECTIONS 216-218

216. (a) "Public utility" includes every common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, where the service is performed for, or the commodity is delivered to, the public or any portion thereof.

(b) Whenever any common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, or heat corporation performs a service for, or delivers a commodity to, the public or any portion thereof for which any compensation or payment whatsoever is received, that common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, or heat corporation, is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part.

(c) When any person or corporation performs any service for, or delivers any commodity to, any person, private corporation, municipality, or other political subdivision of the state, that in turn either directly or indirectly, mediately or immediately, performs that service for, or delivers that commodity to, the public or any portion thereof, that person or corporation is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part.

(d) Ownership or operation of a facility that employs cogeneration technology or produces power from other than a conventional power source or the ownership or operation of a facility which employs landfill gas technology does not make a corporation or person a public utility within the meaning of this section solely because of the ownership or operation of that facility.

(e) Any corporation or person engaged directly or indirectly in developing, producing, transmitting, distributing, delivering, or selling any form of heat derived from geothermal or solar resources or from cogeneration technology to any privately owned or publicly owned public utility, or to the public or any portion thereof, is not a public utility within the meaning of this section solely by reason of engaging in any of those activities.

(f) The ownership or operation of a facility that sells compressed natural gas at retail to the public for use only as a motor vehicle fuel, and the selling of compressed natural gas at retail from that facility to the public for use only as a motor vehicle fuel, does not make the corporation or person a public utility within the meaning of this section solely because of that ownership, operation, or sale.

(g) Ownership or operation of a facility that has been certified by the Federal Energy Regulatory Commission as an exempt wholesale generator pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (Chapter 2C (commencing with Section 79) of Title 15 of the United States Code) does not make a corporation or person a public utility within the meaning of this section, solely due to the ownership or operation of that facility.

(h) The ownership, control, operation, or management of an electric plant used for direct transactions or participation directly or indirectly in direct transactions, as permitted by subdivision (b) of Section 365, sales into the Power Exchange referred to in Section 365, or the use or sale as permitted under subdivisions (b) to (d), inclusive, of Section 218, shall not make a corporation or person a public utility within the meaning of this section solely because of that ownership, participation, or sale.

216.2. Notwithstanding Section 216, "public utility" does not include a motor carrier of property.

216.4. "Cable television corporation" shall mean any corporation or firm which transmits television programs by cable to subscribers for a fee.

216.6. "Cogeneration" means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards:

(a) At least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy.

(b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

216.8. "Commercial mobile radio service" means "commercial mobile service," as defined in subsection (d) of Section 332 of Title 47 of the United States Code and as further specified by the Federal Communications Commission in Parts 20, 22, 24, and 25 of Title 47 of the Code of Federal Regulations, and includes "mobile data service," "mobile paging service," "mobile satellite telephone service," and "mobile telephony service," as those terms are defined in Section 224.4.

217. "Electric plant" includes all real estate, fixtures and personal property owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, or furnishing of electricity for light, heat, or power, and all conduits, ducts, or other devices, materials, apparatus, or property for containing, holding, or carrying conductors used or to be used for the transmission of electricity for light, heat, or power.

218. (a) "Electrical corporation" includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is

generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others.

(b) "Electrical corporation" does not include a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for any one or more of the following purposes:

(1) Its own use or the use of its tenants.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto, unless there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent property and one or more of the following applies:

(A) The real property on which the electricity is generated and the immediately adjacent real property is not under common ownership or control, or that common ownership or control was gained solely for purposes of sale of the electricity so generated and not for other business purposes.

(B) The useful thermal output of the facility generating the electricity is not used on the immediately adjacent property for petroleum production or refining.

(C) The electricity furnished to the immediately adjacent property is not utilized by a subsidiary or affiliate of the corporation or person generating the electricity.

(3) Sale or transmission to an electrical corporation or state or local public agency, but not for sale or transmission to others, unless the corporation or person is otherwise an electrical corporation.

(c) "Electrical corporation" does not include a corporation or person employing landfill gas technology for the generation of electricity for any one or more of the following purposes:

(1) Its own use or the use of not more than two of its tenants located on the real property on which the electricity is generated.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

(3) Sale or transmission to an electrical corporation or state or local public agency.

(d) "Electrical corporation" does not include a corporation or person employing digester gas technology for the generation of electricity for any one or more of the following purposes:

(1) Its own use or the use of not more than two of its tenants located on the real property on which the electricity is generated.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

(3) Sale or transmission to an electrical corporation or state or local public agency, provided, however, that the sale or transmission of the electricity service to a retail customer shall only be provided through the transmission system of the existing local publicly owned electric utility or electrical corporation of that retail customer.

(e) The amendments made to this section at the 1987 portion of the 1987-88 Regular Session of the Legislature do not apply to any corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity that physically produced electricity prior to January 1, 1989, and furnished that electricity to immediately adjacent real property for use thereon prior to January 1, 1989.

218.3. "Electric service provider" means an entity that offers electrical service to customers within the service territory of an electrical corporation, as defined in Section 218, but does not include an entity that offers electrical service solely to service customer load consistent with subdivision (b) of Section 218, and does not include an electrical corporation, as defined in Section 218, or a public agency that offers electrical service to residential and small commercial customers within its jurisdiction, or within the service territory of a local publicly owned electric utility. "Electric service provider" includes the unregulated affiliates and subsidiaries of an electrical corporation, as defined in Section 218.

Appendix G

Cumulative System Cost and Incentive Trends

Table G-1: Cumulative System Cost and Incentive Trends

Technology	Cost Component	PY01 (M$)	PY02 (M$)	PY03 (M$)	PY04 (M$)	PY05 (M$)	PY06 (M$)	PY07 (M$)
FC	Eligible Cost	$3.60	$7.86	$18.74	$47.17	$99.82	$205.90	$384.26
	Incentive	$0.50	$2.00	$5.88	$13.95	$30.22	$67.96	$121.01
	Leverage Ratio	**6.20**	**2.93**	**2.19**	**2.38**	**2.30**	**2.03**	**2.18**
GT	Eligible Cost	N/A	$3.73	$8.42	$19.34	$44.80	$84.64	$160.94
	Incentive	N/A	$0.81	$1.81	$3.62	$7.29	$14.13	$27.67
	Leverage Ratio	N/A	**3.61**	**3.65**	**4.34**	**5.14**	**4.99**	**4.82**
IC Engine	Eligible Cost	$30.71	$111.84	$223.88	$427.96	$847.52	$1,663.07	$3,304.99
	Incentive	$9.04	$29.72	$60.29	$115.91	$227.00	$447.31	$889.27
	Leverage Ratio	**2.40**	**2.76**	**2.71**	**2.69**	**2.73**	**2.72**	**2.72**
MT	Eligible Cost	$8.14	$16.55	$42.11	$84.29	$162.71	$319.44	$633.70
	Incentive	$2.22	$4.54	$11.54	$23.37	$44.53	$87.92	$174.22
	Leverage Ratio	**2.67**	**2.64**	**2.65**	**2.61**	**2.65**	**2.63**	**2.64**
PV	Eligible Cost	$25.31	$147.22	$324.14	$831.75	$1,434.91	$3,216.92	N/A
	Incentive	$11.92	$56.04	$138.04	$366.27	$617.92	$1,312.49	N/A
	Leverage Ratio	**1.12**	**1.63**	**1.35**	**1.27**	**1.32**	**1.45**	N/A
WD	Eligible Cost	N/A	N/A	$5.38	$5.38	$5.38	$5.38	$5.38
	Incentive	N/A	N/A	$2.63	$2.63	$2.63	$2.63	$2.63
	Leverage Ratio	N/A	N/A	**1.04**	**1.04**	**1.04**	**1.04**	**1.04**
	Total Eligible Cost	$67.76	$287.20	$622.66	$1,415.90	$2,595.14	$5,495.34	$4,489.25
	Total Incentive	$23.68	$93.11	$220.20	$525.76	$929.59	$1,932.44	$1,214.79
	Leverage Ratio	**1.86**	**2.08**	**1.83**	**1.69**	**1.79**	**1.84**	**2.70**