California Self-Generation Incentives Program

Second Year Impacts Evaluation Report

Submitted To:

Southern California Edison

Prepared by:

Itron, Inc.
1104 Main Street, Suite 630
Vancouver, Washington 98660

April 17, 2003

Table of Contents

List of Tables

List of Figures

1

Executive Summary

This program evaluation report addresses the Self-Generation Incentive Program's year 2002 peak load impacts as required under California Public Utility Commission (CPUC) Decision 01-03-073, and includes the evaluation objectives, measurement and monitoring plan procedures, data collection processes, operational characteristics and analysis results.

Distributed (or self-) generation resources are small-scale power generation technologies, typically in the range of 1 kW to 10,000 kW, located where electricity is used (e.g., within a business or residence) to provide a partial alternative to or an enhancement of the utility electric power system. Under the requirements of the California Self-Generation Incentive Program (SGIP or Program), projects are restricted to the middle of this range: 30 kW to 1,500 kW. The Program was adopted on March 27, 2001 by the CPUC under Decision 01-03-073. Since June 29, 2001, the Program has been available to provide financial incentives for the installation of new qualifying electric generation equipment. Under the direction of this CPUC Decision, the Self-Generation Incentive Program is offered and administered on a regional joint-delivery basis through three investor-owned utilities; Southern California Edison (SCE), Pacific Gas & Electric (PG&E), Southern California Gas Company (SoCalGas)—and one non-utility administrator entity, the San Diego Regional Energy Office (SDREO).[1] The Program will continue to accept applications through December 31, 2004, subject to availability of the regional Administrator program funds for their respective geographic areas and funded Incentives Levels.

Initially, the $100 million total Program annual incentive budget is equally allocated amongst Program Incentive Levels 1, 2, and 3. As required according to market demand, the Program Administrators may reallocate these Program incentive budgets, with certain exceptions regarding transfer to Level 3-N nonrenewable technologies. A brief description of the Program, including eligible technologies and the available incentives, is provided in Section 2.1 of this report.

Impact Evaluation Objectives and Approach

The primary objectives of this first Program impacts assessment include: 1) compile and summarize electrical energy production and demand reduction by specific time periods and

[1] SDREO is the Program Administrator for San Diego Gas & Electric customers.

technology-specific factors, 2) determine operating and reliability statistics, 3) determine compliance with thermal energy utilization and system efficiency program requirements, 4) determine compliance of Incentive Level 1 fuel cell systems with the renewable fuel usage requirements, and 5) review available renewable fuel clean-up equipment costs for Level 1-R and Level 3-R systems.

The approach employed for this first program impacts assessment includes the collection of all available operational energy output and related system performance data from all known operational SGIP projects as of December 31, 2002. Due to the limited implementation time to date, there was clearly a lack of generation data for many of the operational SGIP projects in this first Program impacts assessment. As of the time of this assessment, there were no available NGO data for an estimated 20 of the 30 operational SGIP projects. For this subset of projects that were determined to be operational at the time of the ISO system peak day in 2002 without available NGO metered data -- their impacts on the system peak are estimated based upon their generation capacity and the available operational characteristics of their "metered counterpart projects" for the technology. This lack of metered system data clearly limits the accuracy and precision of the results included in this impacts assessment.

Program Status Overview

The Program Administrators have been accepting applications since late June 2001. Table 1-1 presents the status of the 56 PY2001 projects that were active at the end of January 2003. Table 1-2 presents the status of the 284 PY2002 projects that were active at the end of January 2003. Table 1-3 summarizes the generation capacity characteristics of all completed projects as of the end of January 2003.

Second Year Data Collection Activities

Data from all available sources contributed to the compilation and analyses of the SGIP system operational characteristics. These project specific data sources include: 1) the four Administrator's combined program tracking database, 2) participant end-user survey data, 3) investor-owned utility (IOU)/energy service provider electric metering data of net generator output, and 4) other required operational data (i.e., recovered useful thermal energy, natural gas consumption for Level 2 & 3 projects) to be collected under the program metering, data collection, and site verification tasks.

Table 1-1: Summary of Active PY2001 Projects

Incentive Level	PY2001 Active Projects as of January 2003 (All Administrators)														
	Reservation Request Form Under Review			Conditional Reservation			Confirmed Reservation			Suspended			Total Active		
	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)
Level 1	0	0	$ 0	0	0	$ 0	12	2,291	$ 7,979,166	0	0	$ 0	12	2,291	$ 7,979,166
Level 2	0	0	$ 0	0	0	$ 0	1	200	$ 367,632	0	0	$ 0	1	200	$ 367,632
Level 3N	0	0	$ 0	3	554	$ 326,543	40	14,898	$ 9,579,961	0	0	$ 0	43	15,452	$ 9,906,503
Level 3R	0	0	$ 0	0	0	$ 0	0	0	$ 0	0	0	$ 0	0	0	$ 0
Total	**0**	**0**	**$ 0**	**3**	**554**	**$ 326,543**	**53**	**17,389**	**$ 17,926,759**	**0**	**0**	**$ 0**	**56**	**17,943**	**$ 18,253,301**

Table 1-2: Summary of Active PY2002 Projects

Incentive Level	PY2002 Active Projects as of January 2003 (All Administrators)														
	Reservation Request Form Under Review			Conditional Reservation			Confirmed Reservation			Suspended			Total Active		
	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)
Level 1	25	4,937	$ 14,756,552	69	13,085	$ 45,561,767	57	6,591	$ 19,815,142	6	2,263	$ 7,025,368	157	26,875	$ 87,158,828
Level 2	0	0	$ 0	0	0	$ 0	1	600	$ 1,500,000	0	0	$ 0	1	600	$ 1,500,000
Level 3N	23	10,626	$ 5,662,714	64	30,047	$ 17,358,737	28	14,782	$ 9,351,221	3	2,170	$ 1,307,780	118	57,625	$ 33,680,452
Level 3R	1	300	$ 146,600	6	1,145	$ 1,175,833	0	0	$ 0	1	140	$ 140,000	8	1,585	$ 1,462,433
Total	**49**	**15,863**	**$ 20,565,866**	**139**	**44,277**	**$ 64,096,337**	**86**	**21,973**	**$ 30,666,363**	**10**	**4,573**	**$ 8,473,148**	**284**	**86,685**	**$ 123,801,714**

Table 1-3: Installed Capacities of Completed/Paid Projects

Incentive Level	Technology	System Size (kW)				
		N	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	21	110	30	46	521
Level 2	Fuel Cell, Nonrenewable Fuel	1	200	200	200	200
Level 3N	IC Engine, Nonrenewable Fuel	7	716	150	1,000	1,063
	Microturbine, Nonrenewable Fuel	5	89	60	84	120

System Monitoring and Operational Data Collection

Assessment of the impact evaluation performance metrics require that electric, thermal energy, and gaseous fuel metering be performed to provide the needed data to meet the various objectives of this assessment. Table 1-4 provides an overview of the major impacts evaluation related measurement activities and objectives as they apply to the technologies included under each Program incentive level. These measurement activities include: 1) System On-Peak Energy Production, 2) Annual Renewable Energy Production, 3) California Public Utilities Code (PUC) 218.5 Efficiency and useful thermal energy requirements, and 4) Annual Renewable Fuel Usage compliance.

Table 1-4: Overview of Impacts Evaluation Measurement Objectives

Measurement	Objective	L-1	L-2	L-3R	L-3N
1. On-Peak Energy Production (kW)	Compare actual on-peak kW contribution of systems versus rated kW	X	X	X	X
2. Renewable Energy Production (kWh)	Assess total renewable energy kWh contribution of systems for calendar year	X		X	
3. Efficiency/Cogeneration ▪ 5% (Useful Thermal) ▪ 42.5% (Overall)	Determine compliance with PUC 218.5 SGIP program requirements		X		X
4. Renewable Fuel Usage ▪ >75% Annual Renewable Fuel Use	Determine compliance with SGIP renewable fuel usage requirement per D.02-09-051	X (FC)		X	

It is also important to note that metering and monitoring activities by design are not restricted to the RER/Itron team of program evaluation contractors. In some cases, program administrators and/or local utilities as well as program applicants and/or host customers may be undertaking metering and monitoring activities for their own purposes. In these instances, the metering and monitoring team is pursuing opportunities available for utilizing *existing* metering and monitoring capabilities, *thereby minimizing overall data collection cost and host customer inconvenience*, while still ensuring availability of metered data that is suitable for program evaluation purposes.

System Impacts and Operational Characteristics

Electrical system demand and energy impacts for projects that had begun normal operations prior to December 31, 2002 were calculated using available metered data and other system characteristics information from the SGIP tracking systems maintained by the Program Administrators. Electric net generator output (E-NGO) metered data are not yet being collected from all projects during program operational years one and two that were installed and operating as of the end of 2002. Consequently, this initial assessment of demand and energy impacts on the electrical system is based on a combination of metered data and engineering estimates.

Overall estimated program demand impacts on 2002 ISO system peak load are addressed in Section 9 of this report and summarized in Table 1-5 below. During 2002, the ISO system peak reached a maximum value of 42,352 MW on July 10. There were 30 known operational SGIP projects when the ISO experienced this summer peak demand, however interval-metered data were available for only 9 of these 30 SGIP projects. While the total on-line generation capacity of the 30 operational projects was 8.3 MW, the total impact of the Program on the ISO peak demand is estimated at 6.7 MW. Incentive Level 3 IC engine and microturbine systems account for 82% of this total 2002 system peak impact.

Table 1-5: Overall Program 2002 ISO System Peak Demand Impacts

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	11	1,130	790
Level 2 Fuel Cell	2	400	400
Level 3 IC Engines / Microturbines	17	6,752	5,472
Total Estimated Impact	**30**	**8,282**	**6,662**

Energy Impacts

Overall Program electrical energy impacts are presented in Section 9 of this report and are summarized in Table 1-6 below. While Level 3 engines and turbines accounted for 82% of peak demand impacts, they account for 86% of total energy impacts. This difference is due to the fact that the average capacity factor of Level 3 IC engines and turbines is greater than that for Level 1 Solar PV.

Table 1-6: Overall Energy Impacts in 2002 by Quarter (kWh)

Basis	Q1-2002	Q2-2002	Q3-2002	Q4-2002	Total kWh
Level 1 PV	59,899	461,814	679,860	646,822	1,848,394
Level 2 Fuel Cell	410,400	528,580	839,040	839,420	2,617,440
Level 3 IC Engines /Microturbines	2,476,239	4,795,801	7,402,374	13,002,985	27,677,399
Total	**2,946,538**	**5,786,195**	**8,921,274**	**14,489,227**	**32,143,233**

Useful Thermal Energy and System Efficiency Review

Thermal data for only two Level 3 projects were obtained for this analysis – lack of understanding and/or cooperation from third parties minimized the available data, as several Level 3 operational projects that have yet to be paid their SGIP incentive would not agree to provide RER/Itron their operational data in a timeframe for this first-year impacts analysis. Available metered thermal data collected from the on-line Level 3-N projects were used to calculate overall system efficiency incorporating both electricity produced and useful heat recovered. An average of 18.2% of the facilities' total annual energy output is in the form of useful thermal energy delivered to the absorption chillers, which considerably exceeds the PUC 218.5 (a) requirement of 5%. The average overall system efficiency of approximately 43.5% is slightly above the required 42.5% efficiency stipulated in PUC 218.5 (b). Project-specific system efficiencies for both projects on an individual basis exceeded minimum requirements prescribed by PUC 218.5 (b).

Review of Renewable Fuel Cleanup Equipment Costs

Renewable fuel cleanup equipment cost data from Purchase Orders were available for six microturbine projects and one internal combustion engine project utilizing renewable fuel. For the internal combustion engine, the incremental cost for fuel cleanup was reported to be negligible. The range of costs is quite large. The capacity-weighted average, which provides an overall summary of renewable fuel cleanup equipment costs at the program level, was found to be $0.59/Watt for microturbines.

As with the purchase order data, the report clean-up equipment cost ranges corresponding to data from the program tracking system are quite large. The size-weighted average natural gas microturbine total system cost is about $2.70/Watt. Combination of this result with the renewable fuel cleanup equipment cost adder would result in an estimate of total renewable microturbine system cost equal to $3.28/Watt. Based on size-weighted average results, the program tracking system data suggest an incremental cost adder of $0.89/Watt, which exceeds the $0.59/Watt result that was based on analysis of a limited quantity of data from purchase orders.

The existing $1.50/Watt incentive for Level 3-R projects appears to be based on an assumed project cost of $3.74/Watt for microturbine projects utilizing renewable fuel. This value exceeds both the $3.58/Watt or $3.28/Watt figures. However, sample sizes remain small and project-to-project cost variability is substantial. Development of any definitive/general conclusions about the appropriateness of the $3.74/Watt assumption may require additional data representative of completed projects.

2

Introduction

The purpose of this report is to document the Self-Generation Incentive Program's second year peak load impacts evaluation approach, monitoring plan procedures, data collection and analysis results. The Self-Generation Incentive Program was adopted on March 27, 2001 by the CPUC under Decision 01-03-073. Since June 29, 2001, the program has been available to provide financial incentives for the installation of new qualifying electric generation equipment that will meet all or a portion of the electric needs of an eligible customer's facility. Under the direction of the CPUC Decision, the Self-Generation Incentive Program is administered on a regional joint-delivery basis through three investor-owned utilities—Southern California Edison (SCE), Pacific Gas & Electric (PG&E), Southern California Gas Company (SoCalGas)—and one non-utility administrator entity, the San Diego Regional Energy Office (SDREO).[1]

The remainder of this introductory section provides a brief description of the Self-Generation Incentive Program, an overview of the distributed generation market in California, outlines of the objectives of the second year process evaluation and impact evaluation,[2] and presents the organization of the remainder of the report.

2.1 Program Description

Assembly Bill 970 was signed into law September 6, 2000 and required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation program activities. This included a provision for making available financial incentives to eligible customers. The Self-Generation Incentive Program (SGIP or Program) was adopted on March 27, 2001 by the CPUC under Decision 01-03-073. Since June 29, 2001, the SGIP has been available to provide financial incentives for the installation of new qualifying electric generation equipment that will meet all or a portion of the electric needs of an eligible customer's facility.

---

1 SDREO is the Program Administrator for San Diego Gas & Electric customers.

2 The process evaluation methodology and results are presented in a separate report entitled the California Self-Generation Incentives Program Second Year Program Process Evaluation Report.

The Self-Generation Incentive Program is designed to complement the California Energy Commission's existing Emerging Renewables Buydown Program. This is accomplished primarily by focusing on the commercial/industrial/agricultural market sectors and through the inclusion of select renewable and nonrenewable-fueled self-generation technology—up to 1,000 kW in generating capacity.[3] Coordination with the CEC Buydown Program occurs through participation in the Statewide Self-Generation Incentive Program Working Group and through a separately managed statewide self-generation program compliance database.

The SGIP is offered throughout most of the state of California, specifically within the service areas of Southern California Edison, Pacific Gas & Electric, Southern California Gas Company, and San Diego Gas & Electric. The Program will continue to accept applications through December 31, 2004, subject to availability of Administrator Program Funds for their respective Incentives Levels. Decision 01-03-073 authorized an annual statewide allocation of $125 million, including all incentives and program administration costs.

"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 either a portion or all of that customer's electric load. Under the Program, financial incentives are now provided to the targeted distributed generation technologies as summarized in Table 2-1.

3 A subsequent CPUC Ruling increased the allowed maximum system size to 1.500 kW – although the maximum incentives basis remains capped at 1,000 kW.

Table 2-1: Summary of Self-Generation Program Incentive Levels

Incentive Category	Maximum Incentive Offered ($/watt)	Maximum Incentive as a % of Eligible Project Cost	Minimum System Size (kW)	Maximum System Size Incentivized (kW)	Eligible Generation Technologies
Level 1	$4.50	50%	30	1,000	■ Photovoltaics ■ Fuel Cells[1] ■ Wind Turbines
Level 2	$2.50	40%	None	1,000	■ Fuel Cells[2]
Level 3-R	$1.50	40%	None	1,000	■ Microturbines[1] ■ Internal combustion engines and small gas turbines[1]
Level 3-N	$1.00	30%	None	1,000	■ Microturbines[2,3] ■ Internal combustion engines and small gas turbines[2,4]

1 Operating on renewable fuel.
2 Operating on non-renewable fuel.
3 Using sufficient waste heat recovery and meeting reliability criteria.
4 Both utilizing sufficient waste heat recovery and meeting reliability criteria.

PG&E, SCE, and SoCalGas will administer programs in their service territories. Within the SDG&E service territory, the Program is administered (via contractual arrangement) through the San Diego Regional Energy Office (SDREO).

Initially, the $100 million of the statewide annual budget set aside for incentives is allocated equally amongst Program Incentive Levels 1, 2, and 3. As needed, the incentive budgets may be reallocated according to market demand, with the exception that any Level 1 renewable or Level 2 allocations may not be transferred to Level 3-N nonrenewable technologies, without the formal approval of the CPUC via an advice letter filing.

2.2 California's Market for Distributed Generation

Overview of California's Distributed Generation Market[4]

Distributed generation resources are small-scale power generation technologies, typically in the range of 1 kW to 10,000 kW, located where electricity is used (e.g., within a business or

4 This discussion is based principally on the CEC website on distributed generation: www.energy.ca.gov/distgen/.

residence) to provide a partial alternative to or an enhancement of the utility electric power system. Under the requirements of the California Self Generation Incentive Program (SGIP), projects are restricted to a maximum size of 1,500 kW.[5]

It is generally accepted that centralized electric power plants will remain the major source of electric power supply for the near future. Distributed generation, however, can complement central power by providing incremental electric capacity to the utility grid and/or to an end use electric customer. Installing distributed generation at or near the end-user can also in some cases benefit the electric utility by avoiding or reducing the cost of transmission and distribution system upgrades. However, electric utilities have not always necessarily favored the use of distributed generation everywhere within its system. High voltage system protection issues may in some instances require modification of the original distributed generation system interconnection or control systems design. Reverse power flows and system stability of a short-term nature may also be areas of concern that distribution planners/system protection engineers need to review and address with each distributed generation interconnection application.

For the electric power consumer, the potential lower cost, higher service reliability and power quality, increased energy efficiency/lower thermal energy costs, and (partial) energy independence are all reasons for interest in distributed generation in the longer term. The use of renewable distributed generation and “green power purchases” (such as wind, photovoltaic, geothermal or hydroelectric power) can also provide a significant environmental benefit as well as the potential for more stable energy costs over time.

Some of the primary applications for distributed generation include the following.

- ***Low-Cost Energy:*** the use of distributed generation as baseload or primary power that is less expensive to produce locally or on-site than it is to purchase from the electric utility. Although many systems are still passing through an elongated shakedown period, most Level 3 SGIP participants are operating their units most of the time and within 20% of the system rated capacity.
- ***Combined Heat and Power (Cogeneration):*** increases the efficiency of on-site power generation by using the waste heat for existing thermal process. This is a program requirement for all non-renewable energy systems.
- ***Premium Power:*** reduced voltage/frequency variations, voltage transients, power surges, dips or other disruptions.
- ***Peak Shaving:*** the use of distributed generation only during times when electric use and demand charges are the highest. Some SGIP participants are analyzing

[5] Note that SGIP Level 1 technologies (photovoltaic, fuel cells operating on renewable fuels, and wind turbines) are further restricted to a minimum of 30 kW.

whether it will be cheaper to use their distributed generation units off-peak or to purchase this off-peak power from the grid.

- ***Standby Power:*** used in the event of an outage, as a back up to the electric grid. (However, not all distributed generation systems installed through the program are designed to run without the grid.)

These nonresidential users of distributed generation have different power needs and expectations from the program. Hospitals need high reliability (back-up power) and power quality (premium power) due to the sensitivity of their operating requirements and safety regulations regarding some of their end-use equipment. They also may experience lower generation and thermal energy combined costs, although this economic driver may be a secondary motivation. Due to their high energy use intensities, industrial plants typically have high energy bills, long production hours, and thermal processes, and would therefore seek distributed generation applications that include low-cost energy with combined heat and power. Per the Program Handbook, California Public Utilities Code (PUC) 218.5, waste heat recovery utilization is required for any SGIP projects that do not use a renewable energy source. Applications that can integrate waste heat for processing can be particularly advantageous for customers. HVAC and refrigeration system thermal requirements also favor distributed generation applications and are used by many program participants. Computer data centers require steady, high quality, uninterrupted power (premium power). Distributed generation technologies are available now and others are being developed to meet these market needs.

California Distributed Generation Market

California has long been a leader in renewable energy and distributed generation applications, due mostly to favorable state energy policies and to the State's emphasis on technological energy-related innovation. In California, the energy crisis of late 2000/early 2001 has had a major impact on the development of the distributed generation markets. Government policymakers, energy service providers, and energy users continue to consider distributed energy as a contributing solution to the state's energy problems.

As indicated in the following table, the amount of distributed power generation operating in California is extensive. Distributed generation, as defined as all generation close to the point of consumption, accounts for nearly 10,000 MW of capacity. Smaller distributed generation resources (20 MW or less) provide nearly 2,500 MW of capacity. These figures do not include the sole application of emergency backup generation.

Distributed Generation Operating in California

(Totals shown in Megawatts and depend upon assumed size of DG)

	PG&E	SCE	SDG&E	SMUD	Riverside	Total
Generating Facilities of All Sizes	5,443	4,142	216	13	4	9,819
Facilities < 20 MW	1,039	766	58	13	4	1,880
Facilities < 10 MW	472	379	58	13	4	927
Facilities < 5 MW	241	139	28	13	4	426
Facilities < 1 MW	57	38	12	13	4	124

Source: Various utility data responses per Energy Commission reporting requirements.
PG&E Report Date: 7/25/02
SDG&E Report Date: 11/14/02
SCE Report Date: 6/02
SMUD Report Date 12/3/02: www.smud.org/info/powersupply.html
Riverside Public Utilities Presentation 4/10/02

Notes:
1) Estimates do not include merchant plants, utility-retained, or backup generation.
2) Estimates include non-utility cogeneration facilities.
3) Non-utility retailers are not required to report facilities below 1 MW.

Prepared by Scott Tomashefsky - California Energy Commission 12/3/02.

Market Entities

There are a variety of market players involved in the distributed generation arena. This is due not only to the complexity of some distributed generation projects, but the fact that many customers are adopting on-site generating technologies for the first time. The SGIP has encouraged third party providers such as distributed generation-oriented engineering/construction and energy service companies to market the program to host customers, and to help them navigate their project's technical and administrative hurdles.

In many respects, the distributed generation marketplace is still immature. Most host customers are largely unaware of available options and their economic advantages or disadvantages. The technologies are sufficiently complex and specialized that a host customer (with the possible exception of a few photovoltaic customers) cannot easily undertake the planning and analysis of a distributed generation project on their own, even when they are participating in a utility program. Consequently, host customers often choose to work with these third party entities. In most cases, it is the vendor or manufacturer representatives, or energy service companies, that initially approach the host electric customer about the SGIP project. These private sector companies then assume a major responsibility for tasks that can include cost-effectiveness analysis, applying to the program, permitting, selecting/procuring equipment, and installation. Without this third party involvement, many of these distributed generation projects, no matter how viable otherwise, simply would not be developed.

Market entities include customers who install distributed generation at their facilities, as well as electric and natural gas utilities, consultants, performance contractors, leasing companies, financial institutions, equipment manufacturers, installers and other non-utility incentives programs.

- ***Utilities.*** Electric and gas utilities in California play a proactive role through the programs they offer to promote distributed generation. Even customers who install distributed generation outside of utility programs are proportionately impacted by the reduced consumption from the grid and in the near future, potential exit (departing load) fees. Some municipal electric utility distributed generation incentive programs are interactive with the SGIP. For instance, LADWP's solar photovoltaic incentive of up to $6.00/watt now can be applied to a SGIP project by reducing the eligible system cost, with the SGIP incentive picking up 50% of the remaining system cost. This mid-2002 dual-incentive effect for photovoltaic has just begun to have a notable impact in the LADWP service area. It remains unclear whether other existing/future municipal utility distributed generation programs will have a similar impact on local SGIP markets over the next two years.
- ***Consultants.*** Most customers who install distributed generation do so with help from consultants or other for-profit firms. Consultants can help customers in any number of ways, including evaluating the technical and economic feasibility of potential distributed generation projects, assisting with/or obtaining project approvals and permits, locating financing, selecting installation contractors, and supervising construction. Customers actively participating in the SGIP typically rely on experienced consultants to guide them through at least some parts of the project development process.
- ***Performance Contractors.*** Energy service companies (ESCOs) offer host customers the opportunity to obtain distributed generation without any upfront capital outlay. In return, the ESCO will realize much of the savings from the project. Contracts are each structured differently, but in many cases where ownership is not inherent in the contract, the host customer has an option to purchase the equipment after a pre-determined period. ESCOs often provide turnkey services for host customers.
- ***Leasing Companies.*** Some customers choose to avoid all capital outlay by using a leasing company that will purchase the equipment, and the host company will realize the savings and pay on the monthly equipment lease.
- ***Financial Institutions.*** Investment banks and other traditional lenders can be involved by providing mortgages for customers who need to borrow the money for equipment that they choose to own.
- ***Equipment Manufacturers.*** In the distributed generation industry, equipment manufacturers typically assume an active role in the development of the Project, oftentimes including assistance with the SGIP application. They provide support

to customers and other market entities that may resemble services offered by consultants. These services may be provided directly by the manufacturer, or through distribution representatives.

- ***Installers.*** The installation of distributed generation systems is usually contracted to a primary installation contractor that will use subcontractors as needed to complete the job. Often, equipment manufacturers will steer customers toward pre-qualified system installers. If an ESCO or equipment vendor is managing the project, the equipment and the project installation may also be subcontracted to local contractors.
- ***Other Programs.*** There are other non-utility incentive/market development programs, such those offered by the California Energy Commission, that promotes distributed generation. A few of the participants in this CEC program originally obtained their equipment through a low-interest CEC loan, then subsequently learned about SGIP incentives. The Emerging Buydown Program also offers incentives throughout much of the state to renewable distributed generation project owners, although much of these program resources are currently eligible to smaller projects (i.e., less than 30 kW), thus minimizing the overlap with the SGIP market.

The level of support that customers require varies widely. ESCOs and firms offering turnkey installation services provide the broadest support to customers. In these cases, distributed generation customers may have little exposure to the sometimes difficult process of participating in the SGIP. They are usually aware of these difficulties in a vague sense when they occur, insofar as they sign application materials prepared by third parties and they may hear about permitting and interconnection issues and related delays. It seems as though they know just enough to be relieved that they are not directly involved in the process.

There is little question that third party providers have been instrumental in both developing the market for distributed generation in California and the U.S. and are responsible for much of the SGIP activity. This group plays a valuable supporting role in program success—from both a customer satisfaction standpoint and ensuring that potential projects are successfully completed.

Distributed Energy Systems Interface with the Utility Grid

True distributed generation systems are, by their nature, designed to operate in parallel with the utility grid. Therefore, they have the potential to influence the electric system in some fashion. These influences by distributed generation systems can be favorable or unfavorable, depending on many factors. Favorable effects can occur with distributed energy systems that are allowed to feed energy back to the grid (restricted to renewable-fueled generation sources). The favorable effects include local stabilization of voltage and frequency and potential deferral of the need for major distribution system expansion investments (e.g., power transformation equipment and related switchgear). Potentially unfavorable influences can occur if distributed generation systems are not adequately synchronized with the grid when feeding power back to the grid. Also, for safety of utility workers, the distributed generation must be disconnected from the grid during utility local distribution system outages (referred to as "islanding"). To ensure this safety issue is addressed, all program participants are required to install anti-islanding devices.

Although efforts are underway to improve the process, interconnection issues continue to be a significant problem for many program participants. Distributed generation industry groups including the IEEE P-1547 Working Group and the California Energy Commission's Rule 21 Working Group have developed protocols to standardize the requirements for electrical interconnection. The Rule 21-related language was adopted by the CPUC (D.00-12-037 (12/21/00) - CPUC Decision Adopting Interconnection Standards). Despite these efforts, interconnection issues continue to arise at several stages of the SGIP project implementation process:

- During the application for utility interconnection,
- During the utility interconnection inspection, and
- During the local building departments' electrical inspection.

Frequently raised issues reportedly include the failure of utility technicians and electrical inspectors to understand the rules, their lack of familiarity with these rules and the associated distributed generation equipment, and their inexperience or willingness to interface with customers in a positive and proactive way.

Metering requirements are also raised as an issue for distributed generation systems using net metering tariffs. Reported issues include the failure of the electric utility to provide appropriate meters in a timely manner, and master metering requirements. The latter refers to the requirement that the distributed generation host meter their system's output at the point at which the distributed generation is interconnected to the grid. This imposes an additional complication and cost burden on customers/system owners that might otherwise use the self-generated power at several locations within the master-metered site downstream of the interconnection point.

Exit (Departing Load) Fees

Utility customers in California who self-generate—including the participants in the Self-Generation Incentive Program—will likely be required to pay *exit fees* (also called *departing load* fees). Currently under active consideration by the CPUC (Docket R-02-01-011), these proposed exit fees are a mechanism intended to protect ratepayers remaining fully served by the utilities system from bearing an unfair share of the burden for paying the cost of more expensive power purchased during the state's energy crisis of 2000-2001. Exit fees could be imposed on self-generators to cover their portion of the long-term power supply contracts negotiated by the State of California's Department of Water Resources following the 2001 energy crisis. If exit fees are imposed, some or all distributed generation customers would be billed for producing their own electricity.

Although these proposed fees are independent of the program, it has clearly colored customer opinions about the program and their view of the utilities sponsoring the program. In some cases, distributed generation customers were not even aware at the outset of the possibility of exit fees. In this case, new payback calculations can render previously viable projects to be deemed uneconomic. Thus, exit fees could at least partially negate the value of the Self-Generation Incentive Program's incentives.

Because of protests over these exit fees from both renewable energy interests and the distributed generation industry as a whole, the February 2003 date established for settling this matter has been delayed. At the time this evaluation report was prepared, the new plan involves development of alternative proposals. Consequently, the current environment is one of uncertainty over exit fees and deep skepticism about California electric companies.

Drastically Escalating Electric Rates

The program is in its early years and operating in a time of rapidly escalating electric rates in California. In addition, many customers experienced numerous blackouts during the summer of 2000. As a result, many customers are entering the program with considerable animosity toward their electric company and uncertainty towards their future rates. Many feel that these electric rate increases are threatening the viability of their business. While escalating electric rates have visibly dampened customer enthusiasm for their electric companies, it has also motivated them to self-generate and to participate in the SGIP.

2.3 Second Year Process Evaluation Objectives

This second year evaluation of the Self-Generation Incentive Program was performed to fulfill specific requirements identified in CPUC Decision 01-03-073 (Interim Opinion: Implementation of Public Utilities Code Section 399.15(b); Load Control and Distributed Generation Initiatives, March 27, 2001). The second year Process assessment is being conducted and reported under separate cover. This Process evaluation addressed a number of topics, including: program awareness, Program Administrator marketing, ease of application implementation and efficiency, and to the degree they can be addressed given available data, related program design issues. In addition, the second year process evaluation provided analysis on changes in these process issues relative to findings in the first year process evaluation. This comparative analysis is particularly useful to gauge the impact of newly implemented programmatic changes and to track the metrics used to evaluate the program goals. The rationale and evaluation goals of the program as described in Decision 01-03-073 are presented in Table ES-2. Evaluation criteria were then developed for meeting each goal and incorporated into the process evaluation.

2.4 Second Year Impact Evaluation Objectives

This assessment is a parallel effort to determine the Operational Characteristics of systems funded under the Self-Generation Incentives Program. This analysis is referred to as the Second Year Self-Generation Incentive Program Impacts Study (Impacts Study). Data from all available sources will contribute to the compilation and analyses of the funded self-generation system operational characteristics. These data sources include: 1) a program tracking database, 2) participant end-user survey data, 3) investor-owned utility (IOU)/energy service provider electric metering data of net generator output, and 4) other required operational data (i.e., recovered thermal energy, natural gas consumption for Level 1 (renewable fueled) fuel cells, etc.) to be collected under the program metering, data collection, and site verification tasks.

The objectives of this impact study are to compile and summarize electrical energy production and demand reduction by specific time periods and technology-specific factors, determine operating and reliability statistics, determine compliance with thermal energy utilization and system efficiency program requirements, compliance with program reliability criteria, determine compliance of Incentive Level 1 systems with the renewable fuel usage requirements, and review/compare renewable fuel clean-up equipment costs for Level 1-R and Level 3-R systems.

2.5 Report Organization

An executive summary, which provides a high-level overview of the key aspects and findings of this second year impacts evaluation, is presented in Section 1 of this report. The remainder of the report is organized into as described below.

- Section 3 presents the evaluation work plan update, which addresses the revisions for the second year evaluation and the schedule for the third year evaluation.
- Section 4 presents a summary of the program status and participant characterization of the active 2001 and all 2002 participants.
- Section 5 discusses the second year and future Impact Evaluation sample design issues.
- Section 6 addresses the Impact Evaluation data collection activities.
- Section 7 summarizes the field verification and inspection activity.

- Section 8 discusses the system monitoring and operational data collection efforts.
- Section 9 addresses the system impacts and operational characteristics
- Section 10 briefly summarizes the second year program impacts

3

Evaluation Work Plan Updates

This section of the Impacts Report provides a summary of the progression of the SGIP measurement and evaluation work plan and its current status as of the 1st quarter of 2003. An overview of the M&E Plan is discussed in Section 3.1. Key revisions to the first year plan are addressed in Section 3.2, and the schedule for the upcoming third-year evaluation activities are presented in Section 3.3.

3.1 Overview of SGIP Measurement and Evaluation Plan

The initial work plan prepared for this SGIP program evaluation effort was derived and refined from a series of tasks that were defined by the statewide working group of Program Administrators. These M&E support activities included the following:

- Development of the Program Evaluation Plan
- Statistical Methods Assessment and System Sampling
- Program Participant Characterization
- Compile and Summarize CPUC and Other Program Participation
- Determine System Operational Characteristics
- Implement On-Site Monitoring, Data Collection, and Field Verification Inspections
- Develop Program Recommendations to Improve On-Peak Load Impacts
- Program Administrator Impact and Process Assessment (Utility vs. non-Utility)
- Prepare Annual Program Evaluation Reports
- Prepare Other Project Deliverables

There were also several initial goals established by the Statewide Working Group for this program evaluation effort. In addition to the first goal of developing the M&E Plan, the other remaining major M&E related goals include:

- Develop and implement a performance data collection system and reporting framework

- Perform annual process and impact evaluations, as required, reporting Program results
- Develop recommendations regarding potential improvements to the Program

This early M&E planning work, which was coordinated with the Statewide SGIP Working Group, along with the first year clarifications led to the Work Plan that was incorporated as Section 2 of the First-Year Process Evaluation Report. During the past year, there were a number of changes to the Program, and regulatory requests by the CPUC that have affected a few key elements of the M&E work plan. Major Program modifications and clarifications that have taken place during this past year include: 1) clarification of the eligibility of certain electric municipal customers that are also served by an eligible natural gas IOU; 2) Allowance for Incentive carry-forwards for unused incentives budgets from one year to another; 3) ability to borrow forward future incentives funds with CPUC approval for a given Incentive Level when existing funds become fully subscribed; 4) creation of a new Incentive Level 3-R (renewable-fueled) generators that employ Level 3 energy conversion technologies; and 5) implementation in PY 2002 of previously specified reliability criteria for Level 3-N technologies that are greater than 200 kW in generation capacity. These various revisions, clarifications and their overall impacts on the SGIP M&E plan are discussed in further detail in Section 3.2 below.

In addition, the ALJ Gottstein Ruling of April 24, 2002 approved the Evaluation Goals/Rationale/Objectives and their respective criteria and in addition the schedule of M&E Reports for the Program through April 2005.

Self-Generation Incentive Program Evaluation Criteria

The Self-Generation Incentive Program was developed to fulfill the requirements laid out in CPUC Decision 01-03-073 in Attachment 1 of the Decision (i.e., Adopted Programs to Fulfill AB970 Load Control and Distributed Generation Requirements, March 27, 2001).

The original CPUC Decision laid out the program’s objectives, as listed in the “Goals/ Rationale/Objective” column in Table 3-1. With input from the SelfGen Incentive Program Working Group, RER developed the criteria for assessing achievement of each goal. These criteria are listed in the second column, “Criteria for Meeting Goal” in Table 3-1.

Table 3-1: Evaluation Criteria of the SelfGen Incentive Program

Goal/Rationale/Objective		Criteria for Meeting Goal
G1 Encourage the deployment of distributed generation in California to reduce peak electrical demand	**C1.A**	Increased customer awareness of available distributed generation technology and incentive programs
	C1.B	Fully subscribed participation in program (i.e., total installed capacity, number of participants)
	C1.C	Participants' demand for grid power during peak demand periods is reduced
G2. Give preference to new (incremental) renewable energy capacity	**C2.A**	Development and provision of substantially greater incentive levels (both in terms of $ per watt and maximum percentage of system cost)
	C2.B	Provision of fully adequate lead-times for key program milestones (i.e., 90 day and 12 month)
G3 Ensure deployment of clean self-generation technologies having low and zero operational emissions	**C3.A**	Maximum allocation of combined budget allocations for Level 1 and Level 2 technologies
	C3.B	A high percentage of Level 1 and Level 2 projects are successfully installed with sufficient performance
G4 Use an existing network of service providers and customers to provide access to self-generation technologies quickly	**C4.A**	Demonstration of customer delivery channels for program participation to include distributed generation service providers and existing utility commercial/industrial customers networks
G5 Provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just to individual customers	**C5.A**	Demonstrate that the combined incentive level subscription, on an overall statewide program basis (i.e., the participant mix of Levels 1, 2, and 3 across service areas), provides an inherent generation value to the electricity system (avoided generation, capacity, and T&D support benefits).
G6 Help support continued market development of the energy services industry	**C6.A**	Quantifiable program impact on market development needs of the energy services industry
	C6.B	Demonstrated consumer education and program marketing support as needed
	C6.C	Tracking of energy services industry market activity and participation in the program
G7 Provide access through existing infrastructure, administered by the entities (i.e., utilities and SDREO) with direct connections to, and the trust of small consumers	**C7.A**	Ensure that program delivery channels include communications, marketing, and administration of the program, providing outreach support to small consumers
G8 Take advantage of customers' heightened awareness of electricity reliability and cost	**C8.A**	Use existing consumer awareness and interact with other consumer education/marketing support related to past energy issues to market the program benefits.

The Program Evaluation Criteria, Work Plan and schedule of M&E Reports were approved as stated above by CPUC Administrative Law Judge Gottstein on April 24, 2002.

3.2 Revisions to 2001-2002 Evaluation Plan

During the implementation of the First Year Evaluation, there were a number of Program modifications, and clarifications formalized through a series of Decision/Interim Orders and

ALJ Rulings by the CPUC in PY 2002. These include the following formal actions, which have impacted the PY 2002 through PY 2004 evaluation plans:

- Adoption of Decision 02-02-026 (Interim Order dated February 7, 2002)
- ALJ *Gottstein* April 24, 2002 Ruling on Evaluation Criteria, Plan and Schedule of M&E Reporting Activity
- Adoption of Decision 02-09-051, dated September 19, 2002 (Interim Opinion addressing the eligibility of Renewable Fueled Microturbines for SGIP Incentives)

In addition to these formal actions of the CPUC, three of the Program Administrators have decided in March of 2003 to request proposals from the statewide evaluation contractor to provide net generator output (NGO) metering of their operational SGIP systems to address either 1) the net-metered Level 1 Projects, or 2) all of their Level 1, 2 & 3 SGIP projects that are determined to require independent NGO metering. Per the Working Group's request, these NGO metering installations for certain Administrators will be performed outside of the Statewide Program Administrator evaluation contract -- directly with each Program Administrator.

The impacts upon the Evaluation Plan implementation of each of the above Program modifications and clarifications are briefly discussed below.

The adoption of Decision 02-02-026 had the effect of clarifying the inclusion of the natural gas municipal electric customers and addressing the incentive funds *carry-forwar*d and *annual overrun* provisions. This clarification will thus require ongoing coordination with the active electric municipal utilities in the SoCalGas and PG&E service areas regarding NGO and whole-facility metering and associated electric power data collection over the term of the Program. This clarification adds a separate layer of metering and data collection coordination for these two Utilities' projects and expands the number of utilities involved in this process.

The clarification of the incentive funds *carry-forwar*d and *annual overrun* provisions will likely provide greater funding flexibility to the Program and hold all targeted incentives funds for their designated purpose through the term of the Program. This has the potential effect of minimizing the concerns surrounding the allowance for extensions to project applicants that may require more time to meet their 90 day Proof of Project Advancement and one-year completion project milestones. The other stipulations of D. 02-02-026 (increasing the eligible project size to 1.5 MW, and the denial of RealEnergy's petition) have little effect on the evaluation plan.

ALJ *Gottstein's* April 24, 2002 Ruling on evaluation criteria, plan and schedule of evaluation reporting activity directly affected the first year and all subsequent year M&E Plan implementation through the approval of the Evaluation Goals/Rationale/Objectives and their respective criteria presented above in Table 3-1. In addition, this ruling established the associated schedule of M&E related reports for the SGIP Program. For M&E activity budgeting purposes, this ruling also further established the basis for estimating related evaluation costs through the term of the Program – as it laid out all required future reports through April 2005.

The adoption of Decision 02-09-051 on September 19, 2002 perhaps had the most significant impact on the evaluation plan for program years PY 2002 through PY 2004. This Interim Opinion established a new Incentive Level 3 category for renewable-fueled generators (Level 3-R), including internal combustion engines, microturbines and small gas turbines operating on a qualified "renewable fuel" as previously defined by the Program. The Decision also required that Program Administrators (or their consultant) conduct on-site inspections, and monitor, on an ongoing basis, the renewable fuel usage of these Level 3-R projects, including any identified *fuel switching* and report their results to the CPUC Energy Division on a semi-annual basis. Also the required renewable fuel use reports were subsequently added to the program evaluation report schedule approved under the ALJ *Gottstein* April '02 Ruling & Adopted Schedule of M&E Reports.

As a result of these added activities, the responsibilities for the various metering, data collection, analysis and reporting functions were then clarified with the Statewide Working Group of Program Administrators in accordance with Table 3-2 below.

Table 3-2: Summary of SGIP Measurement and Evaluation Responsibilities

Item	Description	Level(s)	Sample Size	Data Collection Responsibility	Data Analysis Responsibility	Reporting to CPUC Responsibility
1. Net Generator Output (NGO)	• Electric interval metering (15-minute) data meeting the format requirements specified by RER. • <u>Purpose</u>: Energy (kWh) and peak load (kW) data to be used as part of program cost-benefit analysis to be performed under the direction of the Energy Division.	All	100%	PA	RER	RER (annually)
2. Host Facility Electric Consumption Data	• *Electric interval metering data of NGO-connected whole facility meeting* format requirements specified by RER • <u>Purpose</u>: Energy (kWh) and peak load (kW) data to be used as part of program cost-benefit analysis to be performed under the direction of the Energy Division	All	100%	PA	RER	RER (annually)
3. Waste Heat Utilization (PU 218.5) Evaluation	• Various measurements pertaining to a system's thermal and electric output. • <u>Purpose</u>: Verify whether projects which meet 218.5 requirements on paper (based on a certain set of assumptions) actually operate in a manner which satisfies the standard over 12-month timeframe(s).	L-2, L-3N	100%[1]	RER/BVA	RER	RER (annually)
4. Renewable Fuel Usage	• Measurement of total BTU contributions of renewable and natural gas (if it is available at the site) to generating system. • <u>Purpose</u>: Verify whether projects receiving the L-3R incentive meet the requirement that no more than 25% of total BTU input over 12-month timeframe(s) comes from natural gas.	L1R/ L3R	100%	PA	PA/RER Annual Impacts Reports	PA (every six months)
5. Renewable Fuel Cleanup Equipment Costs	• Collect costs associated with the fuel cleanup equipment. • <u>Purpose</u>: Evaluate whether or not to limit the amount of allowable cleanup costs (e.g., as a percentage of total project costs) as eligible project costs going forward.	L-3R	100%	PA	RER	RER (second year evaluation report)
6. SGIP Participant Surveys	• Collect information through surveys (in person and over the telephone) from program participants. • <u>Purpose</u>: Evaluate whether changes or improvements are needed to the program going forward and how effectively the program is being managed and delivered.	All	TBD	RER	RER	RER (annually)

PA = Program Administrators, RER = Itron/Regional Economic Research, BVA = Brown, Vence, and Associates

[1] Waste heat utilization evaluations will be conducted on 100% of all L-2 and L-3N projects initially – until such time as an appropriate sample size is reached.

In accordance with the CPUC's request within the Decision, these additional evaluation reporting responsibilities, schedule impacts and metering costs were determined and incorporated into the Program-level M&E budget. The Decision also required that Program Administrators provide an estimated budget for all of the monitoring and evaluation activities required in accordance with the original Program authorized under D.01-03-073 and per the additional requirements contained within D.02-09-051. Table 3-3 provides an overview of the projected number of applicants that will need to be monitored for either thermal energy or renewable fuel use, by incentive level, for the entire four year Program period. Across all incentive levels and technologies, about 34 percent (142/419) of the cogeneration and renewable fuel-fuel cell applicants are expected to be monitored. As noted in the table, the vast majority of these monitored applicants are expected to be Level 3 technologies (IC Engines, microturbines, and small gas turbines). The projected thermal monitoring sample rates are 100 percent in each of the first two years and then drop off to 30 percent and 10 percent respectively, for the Level 3N projects in PY 2003 and PY 2004 applicants. The sample rate for Level 1-R Fuel Use and Level 2 project thermal monitoring is projected to remain at 100 percent through PY 2003 and then decrease to 50 percent in PY 2004.

Table 3-3: Summary of Evaluation Thermal /Fuel Use Monitoring Requirements

	Level 1-R	Level 2	Level 3	Total No. Sites
Total Estimated No. Sites Monitored in PY 2001 - 2004	4	7	131	142
Total No. of Est. Active Applicants @ Year-End (PY 2001 – 2004)	5	10	404	419

In addition to the thermal monitoring and data collection discussed above there is also electric meters placed on each monitored system to determine net generator kW output on a 15-minute interval basis. Natural gas meters will also be installed on monitored projects that use natural gas as their primary or secondary fuel source. Table 3-4 summarizes the estimated costs for these metering components for each Program Year's applicants, without indicating which party may be responsible for them. Customer applicants will pay for Net Generator Output (NGO) electric meters and natural gas meters that are installed to meet utility interconnection and tariff requirements; however, these costs are eligible for a partial rebate under the Program. Those NGO or natural gas meters installed solely to meet M&E requirements of the Program will be paid for entirely by the Program (from the Administrative/M&E budget).

Table 3-4: Estimated Net Generator Output and Natural Gas Metering Costs

Program Applicant Category	Incentive Level 1	Incentive Level 2	Incentive Level 3	Program Applicant Total	Total No. Electric Monitored Sites*	Est. NGO Meter Costs (@ $5,500 per Installation)	Est. NG Meter Costs (@ $1,500 per Installation)
PY2001	24	4	71	99	72	$395,340	$90,000
PY2002	134	0	111	245	123	$676,188	$58,100
PY2003	70	2	111	183	105	$578,600	$52,800
PY2004	72	4	111	187	49	$269,867	$19,600
Total Program Estimated NGO & Natural Gas Metering Costs:						**$1,919,995**	**$220,500**

* PA's will be monitoring the electric output of 100% of program participants who complete their installations. The drop in numbers from Applicants to Monitored Sites assumes a certain level of attrition based on available data.

The combined Program total for the estimated NGO and natural gas metering costs over the four years included within Table 3-4 is $2,140,495.

The scope of work in the RER proposal response that was approved by the Working Group included the evaluation of the first two years of the Program (through Program Year 2002). On April 24, 2002, the "Administrative Law Judge's Ruling on Schedule for Evaluation Reports" (ALJ's Report Ruling) extended the program evaluation deliverables through the fourth year of the Program by requiring that the Program Administrators submit a "Schedule of M&E Deliverables" through Program Year 2004 (PY4). Therefore, this revised scope and estimated budget, provided in response to Decision 02-09-051, include:

- The two-year extension of the evaluation activities, as specified in the ALJ's Report Ruling.
- The added Fuel Clean-up Equipment Cost Review and Fuel Use Monitoring and Reporting requirements in Ordering Paragraphs 7, 8, and 9 of D.02-09-051.

Table 3-5 contains the revised annual Program Year M&E estimated budgets, which are provided by specific evaluation activity, including Process Evaluations, Impact Evaluations, Thermal Monitoring Systems, Administrator Comparison, and the M&E Activities added by D.02-09-051. These estimated costs are shown for each Program Year through 2004. Note that the process evaluation activity is not currently scheduled to be performed after PY 2002 (this year), and that the installation of monitoring systems, data collection and impact evaluation efforts have begun in the second year of the Program and will continue through early 2005 (for PY 2004). The following includes a brief summary description of the evaluation activities represented in each column of Table 3-5.

Table 3-5: Measurement and Evaluation Four-Year Program Estimated Budget

Program Year	Process Evaluations	Impacts Evaluations	Thermal Monitoring Systems	Administrator Comparison	M&E Activities Added by D.02-09-051	Total Annual M & E Budget
PY1 (2001)	$452,038	$0	$544,279	$0	$0	$ 996,317
PY2 (2002)	$250,000	$329,058	$413,456	$90,170	$113,200	$1,195,884
PY3 (2003)	$0	$345,511	$389,898	$0	$130,280	$865,689
PY4 (2004)	$0	$362,786	$153,085	$0	$134,360	$650,231
Subtotals	$702,038	$1,037,355	$1,500,718	$90,170	$377,840	$3,708,121
Total M&E Net Generator Output and Natural Gas Metering Costs (see Table 3-4)						$2,140,495
Total M&E Estimated Budget for the Authorized Program Period:						**$5,848,616**

Process Evaluations: Activities related to gathering information from Program stakeholders (e.g., customer participants and nonparticipants, third-party participants and nonparticipants, program administrators) about how the program was run, in order to provide recommendations on incentive levels and other program design changes that might improve the Program.

Impact Evaluations: Activities related to operational project data collection and related quality control, estimation of customer and ISO peak load reduction, compliance with useful thermal energy requirements, system performance and reliability, renewable fuel use and renewable fuel cleanup cost comparisons (second year impacts report), and program cost-effectiveness[1].

Thermal Monitoring Systems: Activities specifically designed to measure compliance with useful thermal energy requirements, including: site preliminary assessments and metering/data collection plans, specification and installation of metering systems and data loggers/communications interfaces, and system maintenance.

Administrator Comparison: Activities related to collecting information through interviews and surveys of all Program stakeholders, reviewing program databases from the first and second program years, analyzing the information, and reporting the findings in written reports and targeted presentations.

M&E Activities Added by D.02-09-051: The added M&E activity addressing Level 3-R and Level 1 Fuel Cell project begins with the eligible PY 2002 participants and will continue through the term of the Program. This last increment to the Program's prior updated M&E work scope includes the following tasks:

- Collect data on fuel cleanup equipment costs for both Level 3-R combustion technologies and renewable fuel cells (Level 1),
- Examine the fuel cleanup equipment cost data to see if the costs appear unreasonably high,
- Report cost analysis as part of the second year program evaluation report,
- Conduct on-site inspections of all projects that utilize renewable fuels,
- Determine compliance with the renewable fuel use provisions once the projects are operational,
- Determine whether fuel switching has occurred,
- Re-evaluate the renewable incentive categories on a prospective basis, as needed, and
- Submit renewable fuel-use monitoring reports every six months.

[1] Program cost-effectiveness analyses will be performed when the CPUC/Energy Division determines that an appropriate methodology has been developed for all Load Removal programs per Decision 01-03-073.

3.3 Schedule for Third-Year Evaluation Tasks

The schedule for all SGIP program evaluation activities currently foreseen over the Program duration are summarized in Table 3-6. The Program's third-year evaluation reports include: 1) Outline for Third Year Program Impact Evaluation Report, 2) Onsite Monitoring Fuel-use Report No. 3, 3) Third Year Program Impact Evaluation Report, and 4) Onsite Monitoring Fuel-use Report No. 4.

Table 3-6: Summary of SGIP Program Evaluation Deliverables

Annual & Fuel Use Program Evaluation Reports	Due Date	Compliance
First Year Incentives / Program Design Evaluation / Recommendations Report	June 28, 2002	Submitted in lieu of First Year Peak Operations Impacts; recommendations for Program Year 2002
Outline for Second Year Program Impact Evaluation Report	December 18, 2002	Per ALJ Gottstein 4/24/02 Ruling
Outline for Second Year Program Process Evaluation Report	December 25, 2003	Per ALJ Gottstein 4/24/02 Ruling
Onsite Monitoring Fuel-use Report #1	*March 17, 2003*	*Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.*
Outline for Utility / Non-Utility Administrator Comparison Report	April 3, 2003	Per ALJ Gottstein 4/24/02 Ruling
Second Year Program Impact Evaluation Report	April 18, 2003	For energy production and system peak demand reductions occurring during the Program Year 2002
Second Year Program Process Evaluation Report	April 25, 2003	To provide recommendations on incentives or program designs that could improve peak load reduction for Program Year 2003
Utility / Non-Utility Administrator Comparison Report	August 1, 2003	To provide an analysis of the relative effectiveness of the utility and non-utility administrative approaches during years 2001 & 2002
Onsite Monitoring Fuel-use Report #2	*September 17, 2003*	*Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.*
Outline for Third Year Program Impact Evaluation Report	December 16, 2003	Per ALJ Gottstein 4/24/02 Ruling
Onsite Monitoring Fuel-use Report #3	*March 17, 2004*	*Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.*
Third Year Program Impact Evaluation Report	April 16, 2004	For energy production and system peak demand reductions occurring during Program Year 2003
Onsite Monitoring Fuel-use Report #4	*September 17, 2004*	*Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.*
Outline for Fourth Year Program Impact Evaluation Report	December 15, 2003	Per ALJ Gottstein 4/24/02 Ruling
Onsite Monitoring Fuel-use Report #5	*March 17, 2005*	*Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.*
Fourth Year Program Impact Evaluation Report	April 15, 2005	For energy production and system peak demand reductions occurring during Program Year 2004
Program Funding Ends	**December 31, 2004**	

Note: The Evaluation and Impacts Reports cover from January 1 - December 31. First Program Year is 2001.

4

Program Status and Participant Characterization

4.1 Introduction

This section provides a summary level overview of participant characteristics for all applicants to the Self-Generation Incentive Program in Program Years 2001 (PY2001) and 2002 (PY2002), based on tracking data available as of January 31, 2003. This section provides a summary of active, complete, and inactive projects in PY2001 and PY2002.

4.2 Project Status and Stage Classification

Applications to the Self-Generation Incentive Program (SGIP) were classified according to the date on which the Reservation Request Form was received. Thus, if a Reservation Request Form for a project was submitted prior to December 31, 2001, the project was considered to be a PY2001 project. Similarly, if a Reservation Request Form for a project was submitted between January 1, 2002 and December 31, 2002, the project was classified as a PY2002 project. In PY2001, 261 applicants submitted requests for funding from the SGIP in the form of a Reservation Request Form. In PY2002, 402 applicants submitted requests for funding from the program.

All projects were classified by Incentive Level (1, 2, 3N or 3R). This represented a departure from the PY2001 process evaluation, where projects were classified into incentive levels 1, 2, and 3. All technologies are classified accordingly, and Level 3 systems are distinguished by type of fuels (renewable or non-renewable) employed. Additionally, all projects were classified into three general categories by project status: active, complete, and inactive.

- ***Active Projects.*** Active projects refer to projects that were not withdrawn, rejected or suspended. Active projects are further classified into three categories:
  - **Under Review.** Projects considered under review are those for which a Reservation Request Form has been received and remains under review by the Program Administrator.
  - **Conditional Reservation.** Active projects classified into this category consist of those projects that were issued a Conditional Reservation Notice (CRN) letter, but for which applicants have not yet provided Proof of Project Advancement.

  - **Confirmed Reservation.** Active projects classified into this category consist of those projects for which Proof of Project Advancement (PPA) has been submitted.
  - **Suspended.** Suspended projects consist of those projects for which the Program Administrator suspended the application due to lack of sufficient funding or to project development delays.

- ***Complete Projects.*** Completed projects are defined as those projects for which the systems have been installed and inspected through an on-site verification and an incentive check has been issued.
- ***Inactive Projects.*** Inactive projects are defined as those projects that have been withdrawn, rejected, or suspended, and are no longer proceeding in the application process. Thus, inactive projects are classified into the following categories[1]:
  - **Withdrawn.** Withdrawn projects consist of those projects for which the applicant or host customer cancelled the application.
  - **Rejected.** Rejected projects consist of those projects for which the Program Administrator cancelled the application due to failure to meet program requirements.

Active SGIP projects were further classified into the following categories according to the latest stage reached:[2]

- **RRF Received.** Reservation Request Form received from applicant (i.e., the application is under review).
- **CRN Sent.** Conditional Reservation letter sent to applicant (i.e., a conditional reservation has been issued).
- **PPA Received.** Proof of Project Advancement received from applicant.
- **PPA Approved.** Proof of Project Advancement approved by Program Administrator.
- **RCICF Sent.** Reservation Confirmation and Incentive Claim Form received from applicant (i.e., the reservation has been confirmed).
- **OSV Complete.** An on-site verification of the system has been conducted.

---

1 The distinction between withdrawals and rejections is artificial in many cases, since a project could be mutually cancelled by the Program Administrator (since the project did not meet program requirements) and by the applicant or host customer (due to difficulties unrelated to the program).

2 In PY2002, all Program Administrators submitted data for the milestones described herein. Although it was initially proposed that submittal milestones be recorded as the date on which the required form (i.e., Reservation Request Form, Proof of Project Advancement, or Reservation Confirmation and Incentive Claim Form) and all supporting documentation was received by the Program Administrator, most Program Administrators did not track packages in their entirety. Thus, the Program Administrators recorded the date at which an initial submittal was received, whether or not the submittal was complete. Active projects were classified accordingly.

- **Check Issued.** The system has been completed and has passed inspection. An incentive check has been issued to the applicant or host customer.

4.3 Summary of Active Projects

Table 4-1 presents the status of the 56 PY2001 projects that were active at the end of January 2003. Of the three incentive levels for which PY2001 applications remained active, Level 3N had the most active projects as of January 2003 (43), which represented 15,452 kW of (potential) installed capacity, and $9.9 million in total potential incentives reserved. Level 1 projects (12) accounted for the next largest share of active potential installed capacity and total potential incentives reserved, with 2,291 kW of potential installed capacity and $8.0 million of total potential incentives. Only one Level 2 project remained active as of January 2003, which accounted for 200 kW of potential installed capacity and $0.4 million of potential incentives reserved. Additionally, no PY2001 projects were suspended or remained under review, as all of the projects had advanced to a later stage, or were withdrawn or rejected as of January 2003. The 3R incentive level was not created until PY2002.

Table 4-2 presents the status of the 284 PY2002 projects active at the end of January 2003. Level 1 projects (157) accounted for the majority of the total potential incentives reserved ($87.2 million), but only accounted for 26,875 kW of potential installed capacity. Level 3N projects (118) accounted for the majority of potential installed capacity (57,625 kW), and accounted for $33.7 million in potential incentives reserved. Level 3R projects (8) represented the next largest share of potential installed capacity (1,585 kW) and potential incentives reserved ($1.6 million) after the Level 1 and Level 3N categories. There was only one Level 2 project active as of January 2003, which represented 600 kW of potential installed capacity and $1.5 million of potential incentives reserved.

Table 4-1: Summary of Active PY2001 Projects

Incentive Level	PY2001 Active Projects as of January 2003 (All Administrators)														
	Reservation Request Form Under Review			Conditional Reservation			Confirmed Reservation			Suspended			Total Active		
	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)
Level 1	0	0	$ 0	0	0	$ 0	12	2,291	$ 7,979,166	0	0	$ 0	12	2,291	$ 7,979,166
Level 2	0	0	$ 0	0	0	$ 0	1	200	$ 367,632	0	0	$ 0	1	200	$ 367,632
Level 3N	0	0	$ 0	3	554	$ 326,543	40	14,898	$ 9,579,961	0	0	$ 0	43	15,452	$ 9,906,503
Level 3R	0	0	$ 0	0	0	$ 0	0	0	$ 0	0	0	$ 0	0	0	$ -
Total	**0**	**0**	**$ 0**	**3**	**554**	**$ 326,543**	**53**	**17,389**	**$ 17,926,759**	**0**	**0**	**$ 0**	**56**	**17,943**	**$ 18,253,301**

Table 4-2: Summary of Active PY2002 Projects

Incentive Level	PY2002 Active Projects as of January 2003 (All Administrators)														
	Reservation Request Form Under Review			Conditional Reservation			Confirmed Reservation			Suspended			Total Active		
	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)
Level 1	25	4,937	$ 14,756,552	69	13,085	$ 45,561,767	57	6,591	$ 19,815,142	6	2,263	$ 7,025,368	157	26,875	$ 87,158,828
Level 2	0	0	$ 0	0	0	$ 0	1	600	$ 1,500,000	0	0	$ 0	1	600	$ 1,500,000
Level 3N	23	10,626	$ 5,662,714	64	30,047	$ 17,358,737	28	14,782	$ 9,351,221	3	2,170	$ 1,307,780	118	57,625	$ 33,680,452
Level 3R	1	300	$ 146,600	6	1,145	$ 1,175,833	0	0	$ 0	1	140	$ 140,000	8	1,585	$ 1,462,433
Total	**49**	**15,863**	**$ 20,565,866**	**139**	**44,277**	**$ 64,096,337**	**86**	**21,973**	**$ 30,666,363**	**10**	**4,573**	**$ 8,473,148**	**284**	**86,685**	**$ 123,801,714**

In general, a one-year deadline is established for completion of installation of a project receiving funding under the Self-Generation Incentives Program. The one-year deadline is calculated based upon the date the Conditional Reservation Notice is issued. Since PY2001, projects are defined as those projects for which a Reservation Request Form was received on or by December 31, 2001, and applicants may be granted an additional 30 days to furnish any missing information prior to Conditional Reservation Notice issuance. The original one-year deadlines for all PY2001 projects have passed and no PY2001 projects should be active as of January 2003, absent any extensions. However, since extensions to the various project milestones have been granted by the Program Administrators, a substantial percentage of PY2001 projects remain active as of January 2003. Extensions were only granted to PY2001 applicants under extenuating circumstances, based upon the information provided by applicants and the judgment of the individual Program Administrators. More recently, program guidelines have been modified to allow extensions up to 180 days past the one-year deadline in certain cases.

4.4 Summary of Completed Projects

Table 4-3 presents the status of the 21 PY2001 projects complete and paid as of the end of January 2003. The majority of the PY2001 projects that were completed represented Level 3N technologies. Eleven Level 3N projects were completed, which represented $2.4 million of incentives and 4,394 kW of installed system capacity. While fewer Level 1 projects were completed (9), Level 1 applications accounted for the majority of the incentive dollars awarded. Level 1 projects constituted $4.9 million in funding and 1,182 kW of installed system capacity. Only one Level 2 project was completed, which accounted for 200 kW of capacity and $0.5 million of incentives.

Table 4-4 presents the status of all completed PY2002 projects as of the end of January 2003. There were no completed Level 2 or 3R projects. However, 12 Level 1 projects were completed, representing 1,118 kW of installed capacity and $4.5 million in incentives. Additionally, one Level 3N project was completed, which represents 1,063 kW of potential installed capacity and $0.46 million in paid program incentives.

Table 4-3: Status of All Completed PY2001 Projects

Incentive Level	2001 Completed Projects as of January 2003 (All Administrators)		
	Projects	**kW**	**Incentives ($)**
Level 1	9	1,182	$4,894,765
Level 2	1	200	$500,000
Level 3N	11	4,394	$2,410,240
Level 3R	0	0	$0
Total	**21**	**5,776**	**$7,805,005**

Table 4-4: Status of All Completed PY2002 Projects

Incentive Level	2002 Completed Projects as of January 2003 (All Administrators)		
	Projects	**kW**	**Incentives ($)**
Level 1	12	1,118	$4,502,539
Level 2	0	0	$0
Level 3N	1	1,063	$459,880
Level 3R	0	0	$0
Total	**13**	**2,181**	**$4,962,419**

System Capacity Characteristics by Technology and Incentive Level

Table 4-5 summarizes the system capacity characteristics of all completed projects. Completed projects were not classified by program year since so few projects were actually completed that cross-year comparisons would not be very meaningful. As shown in Table 4-5, internal combustion engines possessed the largest mean system size of all completed projects (716 kW). The single fuel cell project using nonrenewable fuel displayed the next largest system size of all completed projects, at 200 kW, followed by photovoltaics (110 kW) and microturbines utilizing non-renewable fuels (89 kW).

Both completed photovoltaics projects and microturbines utilizing non-renewable fuels displayed a lower mean installed capacity than the respective means of potential installed capacities reported for active projects. However, completed internal combustion engines utilizing non-renewable fuels displayed a higher mean installed capacity than the reported mean potential installed capacity of active internal combustion engine systems utilizing non-renewable fuels.

Table 4-5: Installed Capacities of Completed Projects

Incentive Level	Technology	System Size (kW) N	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	21	110	30	46	521
Level 2	Fuel Cell, Nonrenewable Fuel	1	200	200	200	200
Level 3N	IC Engine, Nonrenewable Fuel	7	716	150	1,000	1,063
	Microturbine, Nonrenewable Fuel	5	89	60	84	120

4.5 Summary of Inactive Projects

As shown in Table 4-6, Level 3N projects constituted the majority of the inactive PY2001 projects, both in terms of the number of inactive projects (115) and the total potential installed capacity of the projects (56,359 kW). There were also a substantial number of inactive Level 1 projects (65), which represented 16,800 kW of potential installed capacity. There were only four inactive Level 2 projects, which represented 1,250 kW of potential installed capacity.

Table 4-7 presents the status of the PY2002 projects inactive as of the end of January 2003. Level 3N projects accounted for the majority of inactive projects in terms of potential installed capacity (27,058 kW), though the number of Level 3N inactive projects (50) was less than the number of inactive Level 1 projects (55). Level 1 inactive projects accounted for 8,872 kW of potential installed capacity. There were no inactive Level 2 or Level 3R projects as of the end of January 2003.

Table 4-6: Status of All Inactive PY2001 Projects

Incentive Level	PY2001 Inactive Projects as of January 2003 (All Administrators)					
	Withdrawn		Rejected		Total Inactive	
	Projects	kW	Projects	kW	Projects	kW
Level 1	53	14,965	12	1,835	65	16,800
Level 2	2	800	2	450	4	1,250
Level 3N	71	36,180	44	20,179	115	56,359
Level 3R	0	0	0	0	0	0
Total	**126**	**51,945**	**58**	**22,464**	**184**	**74,409**

Table 4-7: Status of All Inactive PY2002 Projects

Incentive Level	PY2002 Inactive Projects as of January 2003 (All Administrators)					
	Withdrawn		Rejected		Total Inactive	
	Projects	kW	Projects	kW	Projects	kW
Level 1	45	6,258	10	2,614	55	8,872
Level 2	0	0	0	0	0	0
Level 3N	39	19,073	11	7,985	50	27,058
Level 3R	0	0	0	0	0	0
Total	**84**	**25,331**	**21**	**10,599**	**105**	**35,930**

5

Program Impact Evaluation Sample Design

Electric net generator output data will be collected from all projects completed through the Self-Generation Incentive Program. Sample design is therefore not an issue for all-electric projects (i.e., solar PV, wind), or for the electric output of other projects. Fuel consumption monitoring will be necessary in cases where Level 1 fuel cell or Level 3-R combustion technologies are fueled with both renewable and non-renewable fuel. In these dual-fuel situations, a census of the projects will be monitored to assess compliance with program requirements (i.e., at least 75% renewable fuel input). Sample design is therefore not an issue for fuel input monitoring of dual-fueled Level 1 fuel cells and Level 3-R combustion technologies. As described in Section 3, Evaluation Work Plan Updates, a sampling strategy is planned for thermal monitoring of Level 2 and Level 3-N projects. Sample design considerations related to this thermal monitoring activity are discussed in the following sections.

5.1 Selected Basis for Precision and Accuracy

Specification of a sampling strategy for thermal monitoring will have implications on uncertainty corresponding to resulting estimates of program impacts. Quantification of these uncertainty implications first requires identification of the specific program impact parameter(s) for which estimates are being calculated. In the case of thermal monitoring, there are numerous possibilities. For example,

- Percentage of projects satisfying PUC 218.5's efficiency requirements
- Average of PUC 218.5 efficiency estimates calculated for individual projects
- Estimate of aggregate PUC 218.5 efficiencies for groups of projects

The planned sampling strategy first presented in Section 3 is summarized in Table 5-1. Development of this planned thermal monitoring sampling strategy was based on engineering judgement and general budgetary considerations. As additional metered data and impact analysis results for PY2001 and PY2002 program applicants become available, the implications of the planned thermal monitoring sampling rates on impact estimate uncertainty will be reassessed and sampling rates may be adjusted if necessary.

Table 5-1: Planned Thermal Monitoring Sampling Rates for Level 2 and Level 3-N Projects

Program Applicant Category	Level 2 Fuel Cells	Level 3-N Combustion Technologies
PY2001	100%	100%
PY2002	100%	100%
PY2003	100%	30%
PY2004	50%	10%

5.2 Estimation of Participation -- per 2002 Applicant Status

The overall sampling strategy for thermal energy monitoring involves collecting interval metered data from all PY2001 and PY2002 projects, regardless of when they begin operating, and then collecting metered data from a limited sample of PY2003 and PY2004 projects. Participation characteristics, including project stage in the program as of January 2003, were summarized previously in Section 4.

Detailed project status information that were used to develop information in Section 4 were also used to estimate the total number of PY01 and PY02 projects that will eventually be completed and be included in the metering census described above. For this analysis 'Pending' projects were those with project status value equal to RRF_Received, CRN_Sent, PPA_Received, or PPA_Approved. 'Installed' projects were those with project status values equal to RCICF_Received, OSV_Complete, and Check_Issued. Results of this analysis are presented in Table 5-2. This metering needs analysis was performed to support development of E-NGO meter installation proposals provided to several Program Administrators in early 2003. The actual numbers of completed projects will no doubt differ somewhat from the estimates yielded by the assumptions included in this analysis.

Table 5-2: Anticipated Number of Completed PY01/PY02 Projects by Level

Level	Installation Status	Number of Active Projects	Anticipated Number of Completed Projects
1	Pending	148	114
	Installed	36	35
2	Pending	0	0
	Installed	3	3
3-N	Pending	148	110
	Installed	22	18
3-R	Pending	7	5
	Installed	0	0
Total – All Levels		**364**	**285**

5.3 Sample Design for Second Year Evaluation & Monitoring Effort

The sample design originally planned for the second year evaluation and monitoring effort involved collection of metered data from a census of operational PY2001 and PY2002 projects. While this remains the planned approach for these projects, in many cases collection of metered E-NGO and thermal energy data will not begin until 2003. Therefore, 2002 operating data for all operational PY01 and PY02 projects are not available for this year's impacts assessment. These operational data availability issues are examined in more detail in Section 9, System Impacts and Operational Characteristics.

5.4 Planned 3rd Year Evaluation Monitoring & Verification Activities

During PY03, a key area of evaluation monitoring and verification emphasis will be on obtaining electric net generator output data for projects that have entered normal operations. Regardless of whether or not the evaluation contractor is ultimately assigned responsibility for this work or if SCE, PG&E, and SoCalGas find other means of having these meters installed (SDG&E has installed E-NGO meters for all completed projects), to move forward with evaluation activities as they were originally planned will require that the pace of net generator output meter installation accelerate dramatically.

In parallel with the net generator output meter installation activity will be an accelerated rate of installation of Level 3-N thermal energy monitoring systems. As of the end of 2002, a number of M&E Site Visits were completed and Monitoring Plans developed, but no thermal energy meters were installed by the evaluation contractor and its subcontractors. In May and June of 2003 a significant push will be made to install meters and coordinate Host and Applicant data collection activities so that summertime 2003 data are collected from a substantial number of PY01 and PY02 projects that had entered normal operations as of the end of 2002.

6

Second-Year Impact Evaluation Data Collection Activities

6.1 Administrator Program Tracking Database & Handbooks Updates

Administrators have provided program evaluators regular updates of their program tracking database files. Data in these files contain information that is essential for planning and implementing data collection activities supporting the impact evaluation. When projects progress at least to the proof of project advancement (PPA Approved) stage an M&E Notification letter is sent to the program Host and Applicant. This letter introduces the evaluation contractor and describes its activities. In the case of Level 2, Level 3-N, and Level 3-R projects an M&E Site Visit is then scheduled to determine metering and data collection needs. In the case of Level 1 projects, the follow-up involves discussion of availability of electric generation data from the Host or Applicant, or of arrangements for authorizing release of data from an electric utility. If the program evaluation contractor is requested to play a role in installing electric net generator output meters in the future, then a similar notification process will be used to initiate net generator output meter installation activities. Updated program handbooks have been downloaded from the Program Administrators' web sites and used for planning and reference purposes.

6.2 Electric Net Generator Output (E-NGO) Interval Data Collection

Electric net generator output data collection activities for the second-year impact evaluation were aimed at obtaining available data from Hosts, Applicants, and electric utilities. This effort was complicated by several factors. As of the end of 2002 several administrators had not yet finalized or begun implementing plans for wide-scale installation and operation of net generator output meters. In other cases Hosts or Applicants are collecting these data but are reluctant to provide them before they receive their incentive payment. There can be a significant delay between the beginning of normal operations and final satisfaction of all program eligibility requirements. Large gaps in the data archive for certain projects may result. Finally, in at least one instance an Applicant's concerns about data confidentiality led to their request that data be used by the evaluation contractor only.

As a result of the issues described above relatively little electric net generator output interval data were incorporated into the second-year impact evaluation. A more detailed discussion of data availability is included within Section 9. A significant effort is currently underway to ensure that more E-NGO data are available for incorporation into impact evaluations scheduled to be completed in future years. Three of the program administrators recently requested that the evaluation contractor provide proposals covering installation of E-NGO metering equipment. It is anticipated that additional meter installation activity will begin soon after bid decisions are made.

6.3 Useful Thermal Energy Compliance Data Collection

Useful thermal data collection typically involves an invasive installation of monitoring equipment (e.g. flow meters and temperature sensors). Therefore, a significant effort was undertaken to minimize the unnecessary installation of this equipment. Many third parties or host customers had this equipment installed at the time of system installation either as part of their contractual agreement with a third party vendor or for internal process/energy monitoring purposes. Relationships were established with these hosts and third parties that installed monitoring equipment, in an effort to obtain the relevant data they are collecting. This approach minimizes both the cost- and disruption-related risks of installing monitoring equipment.

To date one of the Level 2 projects and four of the thirteen completed Level 3-N projects fall under this scenario. Of these five operational projects for which monitoring equipment is installed, data has been received for two Level 3-N projects. Data for several projects is being withheld until the applicant receives their incentive check or an M&E Site Visit is completed.

Additionally, several projects with monitoring equipment installed have recently been sold and new agreements to access this data are being negotiated. Should these negotiations not result in access to the operational data, the RER M&E Team will install thermal monitoring equipment independently of the third party.

The remaining completed projects for which monitoring equipment has not yet been installed are in the process of monitoring plan preparation and monitoring equipment procurement. Many of the sites are expected to have thermal monitoring equipment in place to observe the 2003 system peak.

6.4 On-site Verification Facility Data Collection

During metering and data collection site visits BVA, the RER/Itron on-site evaluation subcontractor, collects facility information necessary to complete the project-specific metering and data collection plan in support of the impact evaluation. Meter nameplate information is recorded for meters for billing purposes as well as those used for information purposes. The date when the system entered normal operations is also determined or estimated from the available operations data, as required.

This on-site field system data collection process is further discussed in Section 8.3.

7

On-Site Field Verification and Inspection Activities

CPUC Decision 01-03-073 requires that Program Administrators conduct program verifications in order to "ensure that the self-generation units installed at customer sites are installed and operating properly and have the potential to deliver electric generation."[1] A key part of this verification process involves on-site inspections, which are conducted to "verify that the funded self-generation systems are actually installed and operating."[2] In compliance with the inspection requirement, each of the Program Administrators have retained third party engineering firms to conduct on-site field verifications, as shown in Table 7-1. In preparing this process evaluation, we interviewed representatives from each of the on-site inspection contractors, and obtained sample copies of each of their inspection forms and checklists.

Table 7-1: On-Site Verification Inspectors

Program Administrator	Service Area	On-Site Inspector
SD Regional Energy Office	SDG&E	AESC
Southern California Gas	SoCalGas	Energy Nexus
Southern California Edison	SCE	AESC[3]
Pacific Gas and Electric	PG&E	KW Engineering

While initial review of reservation materials began in late 2001, the first self generation installations were not completed and ready for on site inspections until mid-2002. A total of 40 to 45 on-site inspections were conducted statewide during 2002. Over one-half of these inspections were for photovoltaic installations, with most of the remainder for installations of internal combustion engines. On-site inspections also included a small number of micro-turbines and fuel cells.

[1] Decision 01-03-073, pg. 28.

[2] Decision 01-03-073, pg. 19.

[3] AESC also provides review of waste heat calculations in the PG&E area, with KW Engineering providing on-site verification of waste heat operation, where possible.

7.1 On-Site Verification Objectives

As required in CPUC Decision 01-03-073, the overall on-site verification objectives are to ensure that the self generation units are installed and operating properly, and have the potential to deliver electric generation. The specific objective, as described in the program handbook, is to "verify that the project system is operational, interconnected and conforms to the eligibility criteria of the program.[4]" In order to do this, the inspection contractors verify that the as-installed self generation equipment and operation matches the applications, and that, to the extent that they can be verified in the field, the key program requirements have been met.

7.2 Review of Field Verification and Inspection Activities

Summary

Early in 2002 the inspection procedures and documentation processes, which were still evolving in 2001, were finalized and put into regular practice. The general procedures are now largely standard across the state, although inspection contractors each use different forms, and in each case their processes vary somewhat from the steps and details described below.

On-Site Verification Process

Following are the generic steps we identified in the on-site verification process:

Step 1: Verification Contractor Sent Documentation: The on-site verification contractor is first provided by the Program Administrator with documentation of the proposed installation. Generally the verification contractor first becomes aware of the project at the time that the generation is reported to be installed and operational, and at the time an Incentive Claim Form has been submitted by the Applicant. However, in at least one case the verification contractor receives the Reservation Request Form prior to installation and may at that time provide comments to the Program Administrator on the adequacy of the documentation and apparent program eligibility.

At least one Program Administrator employs a different engineering consultant than the field verification visit contractor at an early stage of program participation to review waste heat recovery calculations and other project information. In this case the engineering consultant involved in the earliest stages of project review shares its findings with the on-site verification contractor to assist in the inspection process.

[4] Self-Generation Incentive Program Handbook, Section 4.4.9.

Step 2: Key Information Transferred to On-Site Verification Forms: Prior to conducting the on site inspections the general approach is to transfer key equipment and operation information from the Reservation Request Form and Claim Form to inspection forms. This information will in turn be compared with the equipment and operation found at the site.

Step 3: Site Visits Scheduled: The Applicant is contacted and a time is arranged for the on-site inspection.

Step 3: On-Site Verifications Conducted: The central activity in the process is the on-site inspection. Tasks include:

- Verifying that the equipment model numbers and ratings match those in the application material.
- Verifying that actual quantities (e.g., number of photovoltaic modules) match those in the application.
- Verifying that equipment is operational and permanently installed.
- Going through a checklist to help verify eligibility and document the characteristics of the installation. (These checklists vary significantly among the inspection contractors; although each appears to collect the information needed to help assure compliance.)
- Photographing the generator, other associated equipment, and nameplates (e.g., inverter, switchgear, heat exchanger, metering).
- Verifying outputs at the time of the inspection (kW, and BTU and power factor where metered)
- Verifying power factor control where applicable[5]
- Verifying waste heat recovery operation where applicable.[6]
- Verifying how the generator is controlled (e.g., load following)
- Verifying and documenting monitoring equipment.
- Identifying potential safety hazards.
- Asking clarifying questions of site personnel, when necessary and possible.

[5] Effective January 1, 2002, applicants for Level 3-N technologies must show that the systems are capable of operating between 0.95 PF lagging and 0.90 PF leading.

[6] Applicants for Level 2 and 3-N technologies, which rely on non-renewable fuel, must produce at least 5% of the total output as useful thermal energy, with the total annual power output plus one-half of the useful thermal energy out equaling at least 42.5% of fossil fuel inputs.

Step 4: Analyses Conducted and Reports Prepared: Steps in the analysis stage may include: (1) transferring on-site information to a clean report, (2) using available site data and/or engineering assumptions to estimate waste heat recovery (where required), and (3) using available data and other assumptions to calculate system efficiency (where required).

*Step 5: Report Delivered to Program Administrator***:** At this point the general approach is to prepare a cover letter to the inspection report and to submit the report to the Program Administrator with a finding that the installation has passed inspection or failed for the specified reason(s). In at least one case standard practice when the installation has been inadequate is to first send an e-mail to the Program Administrator describing the problem(s) and suggesting that they be corrected before conducting a follow-up inspection.

Step 6: Follow-up Inspections Performed (When Needed): If problems are found in the initial inspections the Applicant may correct those problems and a follow-up inspection conducted.

7.3 Analysis and Results

On-site verification contractors all report that procedures are now working very well, with one interviewee noting that their role has now become a "well-oiled, flexible process." This is partially because the program changes that took place during 2002 were few and had only limited impact on the inspection process for the majority of sites. Depending on inspection contractor and the technology, such changes included making slight changes to forms, adding heat recovery verification, adding power factor checks, looking closer at instrumentation and readings, performing efficiency calculations, and evaluating renewable fuels.

The only significant problem identified (by two of the contractors) was on occasion setting up inspections and traveling to the site only to find that equipment was not yet fully operational. The most common deficiency has involved incomplete monitoring equipment.

The interviewees were also asked if they perceived that the inspections provided any benefits to the host customers. The general response to that question was "usually not", partly because host customers often are not present during inspections (contractors or equipment suppliers are more likely to attend). However there have been a few cases in which the host customer has benefited, such as one in which the inspector pointed out the incorrect orientation of auxiliary equipment.

7.4 Summary and Recommendations

The on-site verification processes and forms varied somewhat from area to area in 2002, but in all areas appeared to meet the requirements of PUC Decision 01-03-073, including subsequent program specifications and amendments. Therefore, it appears the process is functioning effectively and as intended.

It is believed that the inspection process will meet all verification needs during 2003 without change. However, in order to provide added customer benefits, Program Administrators may wish to forward information to inspection contractors at the Reservation Request stage. Bringing the inspection contractors in at this earlier stage, which is already done in at least one case, can provide an extra level of early review to help identify problems at a point in the process when changes in plans are not difficult.

8

System Monitoring and Operational Data Collection

This section presents system monitoring and metered data collection activities undertaken and planned to support evaluation of the Self-Generation Incentive Program. A brief discussion of the purpose and objectives is followed by an overview of the approach that the RER/Itron Team is taking at the program level to monitor and collect operational data from these systems. A detailed description of data collection activities is then presented, both to support the initial 2002 impact evaluation and moving forward to support future impact evaluations. Finally this section provides an overview of the quality control procedures implemented by the RER/Itron Program M&E Team.

8.1 Purpose & Objectives of System Monitoring and Data Collection

An overview of the major impacts evaluation-related measurement activities and objectives as they apply to the technologies included under each Program incentive level is presented in Table 8-1. These measurement activities cover: 1) System On-Peak Power Output, 2) Annual Renewable Energy Production, 3) PUC 218.5 Efficiency and useful thermal energy requirements, and 4) Annual Renewable Fuel Usage compliance.

Table 8-1: Overview of Evaluation Measurement Objectives

Measurement	Objective	L-1	L-2	L-3R	L-3N
1. On-Peak Power Output (kW)	Compare actual on-peak kW contribution of systems versus rated kW	X	X	X	X
2. Renewable Energy Production (kWh)	Assess total renewable energy kWh contribution of systems for calendar year	X		X	
3. Efficiency/Cogeneration ▪ 5% (Useful Thermal) ▪ 42.5% (OPE)	Determine compliance with PUC 218.5 SGIP program requirements		X		X
4. Renewable Fuel Usage ▪ >75% Annual Renewable Fuel Use	Determine compliance with SGIP renewable fuel usage requirement per D.02-09-051	X (FC)		X	

These measurements and objectives are a subset of the overall SGIP data collection and evaluation activities that were summarized previously in Table 3-2.

The purpose of system monitoring and data collection extends back to the original CPUC Decision authorizing the Program and to RER's September 13, 2001 proposal to provide a specific package of measurement and evaluation services for the Self-Generation Incentive Program (SGIP). Since that time, metering and monitoring requirements have been clarified through SGIP Working Group meetings and formal actions modifying the Program and its M&E requirements at the CPUC[1]. In some instances, program design changes have resulted in modification of metering and monitoring requirements[2]. Although many data collection issues have arisen and been addressed, additional changes and clarifications can be expected for the Program as both program implementation and metering and monitoring activities continue forward.

8.2 Overview of Program-Level Monitoring Approach

SGIP operational data yielded by metering and monitoring activities will be used to assess specific performance metrics related to the Self-Generation Incentive Program's stated goals and eligibility guidelines. These metrics, which vary across technologies and incentive levels, include: 1) on-peak electric system load impacts, 2) overall energy efficiency impacts, 3) renewable/fossil fuel consumption ratio, 4) self-generation system reliability, on-peak availability and capacity factor, and 5) impacts on host customer facility billed electric demand. Assessment of these performance metrics will require electric, thermal energy, and gaseous fuel metering.

Another important aspect of Program-level monitoring is timing. The RER/Itron M&E Team has adopted an approach that identifies projects that are coming on-line more quickly than the utility-provided tracking system generally can allow. The approach is to use the Proof of Project Advancement indicator within the tracking system as a trigger for initiating contact with the Host Customer to assess the status of the project. Some projects will come on-line shortly after this stage, but this will not be reflected in the tracking system data for at least several months. Table 8-2 illustrates the current difference between the number of completed projects using the two approaches.

---

[1] RER Program Metering and Monitoring Plan, Drafts submitted June 10 and September 23, 2002

[2] See RER M&E Response to CPUC Decision 02-09-051, transmitted November 8, 2002

Table 8-2: Comparison of Completed Projects

	Projects Deemed Complete in Tracking System	PPA_ Approved or Beyond in PA Tracking Systems	No. of Projects "Operational" per RER Survey Data
1	24	85	52
2	1	3	1
3N	5	20	15
3R	0	0	0
Total	**30**	**108**	**68**

As Table 8-2 illustrates, the actual number of operating projects falls between the number of projects that show Proof of Project Advancement and the number of projects that have been issued checks. Waiting for projects to receive incentive checks was causing unnecessary delays in the data collection process. Many of these delays are clearly due to situations beyond the control of the Program Administrators per the current Program Handbook requirements, such as air quality permits[3]; but this situation should not necessarily delay the installation of Program monitoring equipment or the assessment of impacts due to the program.

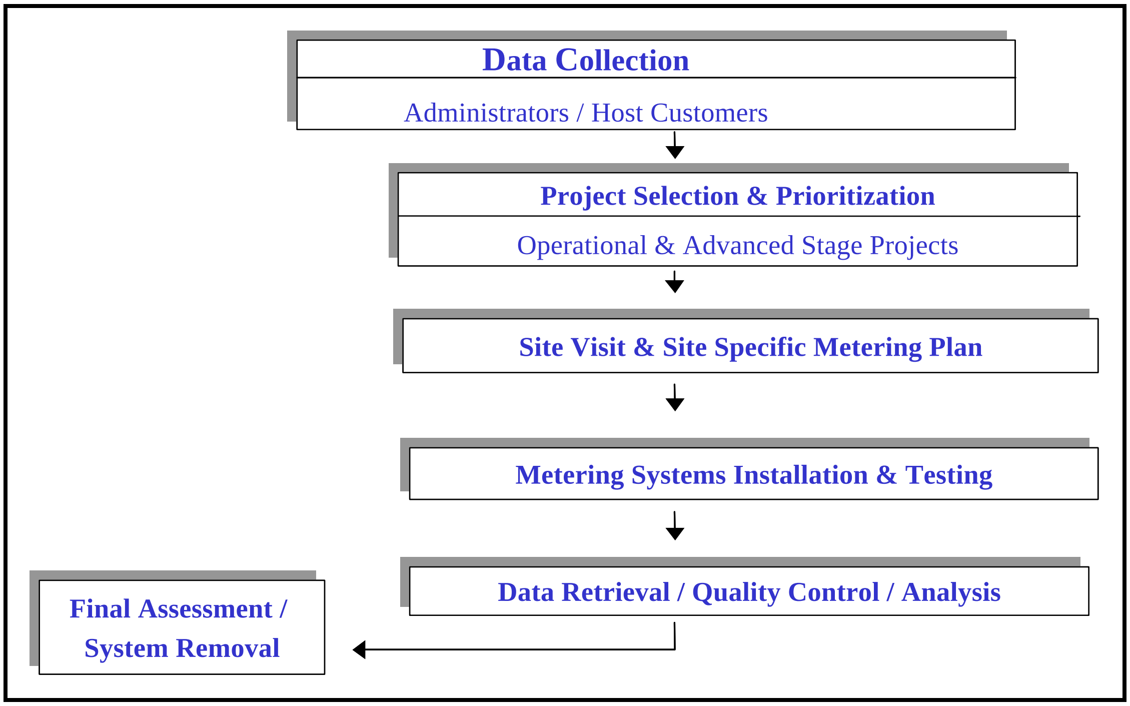
Contact is initiated with an M&E Notification Letter sent to the Applicant and the Host Customer (if different than the applicant), which is followed up with a telephone call to discuss the status of the project and to assess the appropriate time to schedule the metering plan site visit. Assuming the project has been completed, the metering plan site visit is scheduled and conducted. A metering plan is then prepared, reviewed, and submitted to the Program Administrator for approval.

8.3 System Operational Data Collection

Principal metering and monitoring team members include RER/Itron, Brown Vence and Associates, and Endecon Engineering. Other equipment-specific installation subcontractors will be brought into this process as necessary. It is important to note that metering and monitoring activities by design are not restricted to the RER/Itron team of program evaluation contractors. In certain cases, program administrators and/or local utilities as well as program applicants and/or host customers may be undertaking metering and monitoring activities for their own purposes. In these instances the metering and monitoring team is pursuing opportunities available for utilizing *existing* metering and monitoring capabilities, thereby minimizing overall data collection cost and inconvenience, while still ensuring availability of metered data suitable for program evaluation purposes. Figure 8-1 provides an overview of the monitoring and data collection steps entailed in this SGIP evaluation.

[3] See the Self Generation Incentives Program Second Year Process Evaluation for more detail on delays associated with project completion.

Figure 8-1: Metering and Data Collection Overview



Program evaluation data requirements and project-specific data collection approaches unique to each of the eligible technologies/fuel types under Program Incentive Levels 1, 2, and 3 are discussed separately in the following subsections. First, electric data collection activities common to all SGIP technologies and incentive levels are summarized below. Next in this section, we provide the background and technical basis for determining the site-specific approach for Level 2 and Level 3-N thermal energy compliance monitoring.

Net Generator Output Data Collection

In accordance with the revised Program Evaluation RFP and subsequent discussions with the Working Group, the program administrators are responsible for metering and data collection regarding the degree to which self-generation units installed under this program operate during peak periods. This metering activity is expected to yield 15-minute interval electric data. These electric load data will be collected for a census of program participants. For the discussions below, we assume that the stream of 15-minute interval electric data will represent Net Generator Output (NGO). In this context "Net" implies that prime mover/generator "house/auxiliary" loads are included (e.g., onsite controls, pumps, compressors, inverters associated with the fuel preparation/combustion/generators/heat recovery systems).

The baseline electric interval data collection and transmittal protocol places responsibility for collection of electric data in the hands of Program Administrators. However, should an Administrator(s) determine there is a need for the RER evaluation team to either meter or collect electric interval data for certain classes of (or all) completed program participants, RER and its team can provide this support upon request within our available Program M&E resources. In other instances, electric interval metered data of sufficient quality may be directly available from program applicants who are collecting these data for their own purposes. Note that as a guiding principal, whenever an Administrator is monitoring NGO, RER will first use this data source as the basis for determining program impacts. The scope of electric interval metered data collection will be addressed on a case-by-case basis.

Host Facility Electric Consumption Data Collection

A complete assessment of program impacts on host customers and utilities will require not only NGO electric interval data but also net electric interval consumption data from the energy provider billing meter located immediately upstream of the NGO electric meter. Where these data exist, the administrators will provide them to RER in the same format as the NGO data for incorporation into the program impacts and cost-effectiveness analyses.

The utility-supplied electric interval data will be sufficient to determine the electrical production and electrical system demand reduction yielded by all self-generation systems funded through the program. These data, combined with applicant O&M log information will also provide the basis for assessment of generation system operating and reliability statistics.

Useful Thermal Energy Metering & Data Collection

The purpose of monitoring the thermal production of generators in the CPUC Self-Generation Incentive Program is to determine if they meet the requirements of Public Utilities Code Sec. 218.5 Parts a) and b). Part a) of the code requires that at least 5% of a distributed generation system's total annual energy output be in the form of useful thermal energy, while part b) requires that the sum of the useful annual power output and one-half the useful annual thermal energy output equal not less than 42.5% of any fuel input.

Although the Program's PUC 218.5 eligibility requirement is straightforward, issues arise in making the decision of: 1) what constitutes "useful thermal energy", 2) whether or not to use the host applicant's or Third Party's monitoring equipment and 3) where to place additional monitoring equipment, if required (e.g., on what side of the heat exchanger or energy conversion apparatus). This subsection will first provide a discussion of what constitutes *useful thermal energy*, as relevant to the Program, and then discuss our approach to other thermal monitoring issues.

Discussion of "Useful" Thermal Energy

Generally, the purpose of a cogeneration system is to displace energy consumed by existing facility equipment with the waste heat from the cogeneration system prime mover. It is rare, however, that this is a one-for-one displacement. For example, assume a facility has a swimming pool heater with 80 percent combustion efficiency, for every BTU of heat added to the swimming pool; approximately 1.25 BTUs are offset from the facility's natural gas consumption. So, is the useful thermal energy 1.0 or 1.25 BTU? Is this amount of energy then also corrected for the losses in the cogeneration system's distribution loop?

Recommendation: From the Code of Federal Regulations (18CFR292.202):

> *(h) Useful thermal energy output of a topping-cycle cogeneration facility means the thermal energy:*
>
> *(1) That is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water);*
>
> *(2) That is used in a heating application (e.g., space heating, domestic hot water heating); or*
>
> *(3) That is used in a space cooling application (i.e., thermal energy used by an absorption chiller).*

From h.1 above we can infer that energy delivered to a heat exchanger constitutes useful thermal energy and one need not take into account energy displaced. To answer the example question from above, for this program the useful thermal energy would be 1.0 Btu plus any heat exchanger thermal losses.

Thermal Energy Measurement Options

Like any thermal-mechanical system, the heat utilization component(s) of a cogeneration system can be generally broken down into a series of heat transfer loops as shown in Figure 8-2:

1. Thermal Energy Distribution Loop: Primary or Primary/Secondary loop (either steam or hydronic) that removes heat from the Prime mover(s) to the various thermal consuming loads in the facility.
2. Process Loop(s): A piece of equipment or system that consumes energy in one form and releases it in another form. For example, an absorption chiller.
3. Load(s) A piece of equipment or system that directly uses heat from the distribution loop.

Measuring thermal energy to determine "*Useful Thermal Energy*" can be accomplished at the points shown below. However, there are advantages and disadvantages to each option as listed in Table 8-3.

Figure 8-2: Typical Cogeneration System Thermal Energy Distribution

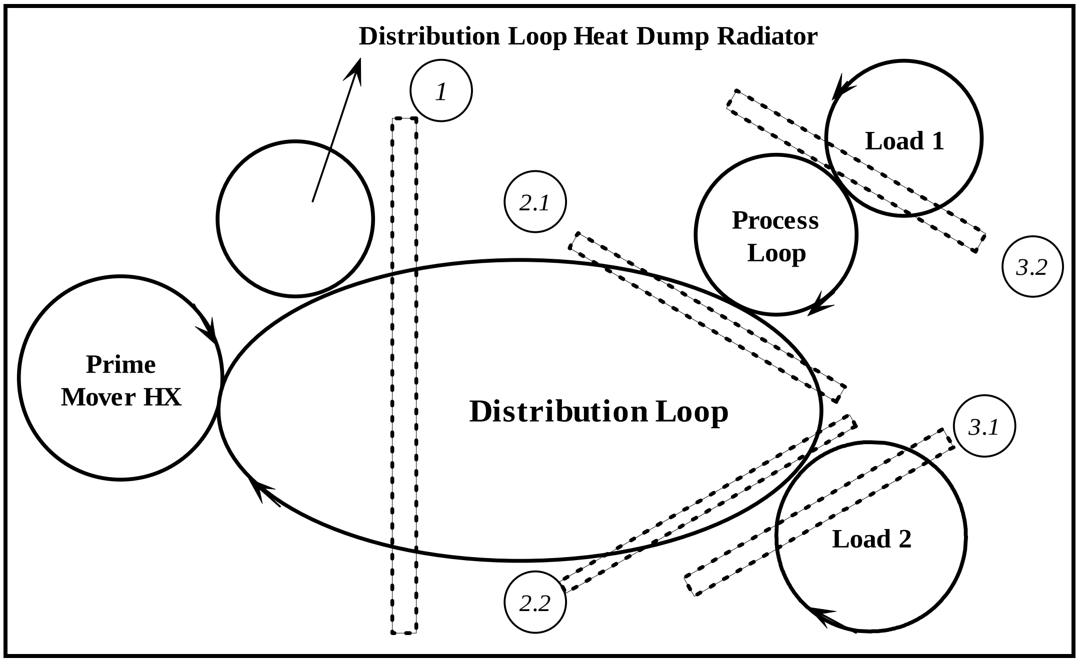


Table 8-3: Advantages and Disadvantages of Measurement Points

Measurement Point	Advantages	Disadvantages
1	▪ Generally easier to measure as it can be installed with the original system. ▪ Often measured already. ▪ Requires only one Btu meter.	▪ Would measure more thermal energy than actually consumed by the load due to thermal losses in the distribution loop and the heat exchangers. However, per our definition of useful thermal energy, this is acceptable.
2.1 (Preferred Method)	▪ Used in conjunction with point 2.2, this could be used to measure loads individually - if an existing Btu meter is measuring at Point 2.2 ▪ Maybe easier to install than Point 1 on some installations due to the type and layout of the piping.	▪ Would meter more thermal energy delivered than actually consumed by the load due to thermal losses of the heat exchanger. However, per our definition of useful thermal energy, this is acceptable. ▪ Could be more costly to install than Point 1 if two Btu meters are required (Points 2.1 and 2.2).
2.2 (Preferred Method)	▪ Similar to 2.1	▪ Similar to 2.1
3.1	▪ Directly measures the heat consumption of the load.	▪ Could be more costly than measuring Point 1 if more than one non-metered load exists. ▪ Would result in less useful thermal energy than allowed per our definition as it does not include heat exchanger losses.
3.2	▪ This point measures on the other side of some thermal process, for example an absorption chiller, and is often already being measured. ▪ Directly measures the heat-supplied to/removed by the load.	▪ Requires a calculation(s) (with operational assumptions as necessary) to back-calculate thermal energy delivered.

Thermal Measurement Implementation Issues

There are several important issues that have been addressed in the course of determining the best available approach and the resulting thermal monitoring system performance and results. These issues are briefly discussed below.

Use of System Owner/Third Party's Monitoring Equipment

In many cases, the Project Team could use the *system owner/third party's* process flow energy measuring equipment to monitor system thermal performance. This approach could be problematic in that the M&E Team members are not in direct control of the monitoring system and associated equipment. Possible issues consist of:

- *System owner/third party's* "*gaming*" the system in a manner that would overestimate the amount of useful energy produced.
- Temp/flow Sensor initial calibration and monitoring system maintenance
- Difficulty having to rely on a third-party to obtain needed operational information on a regular basis

However, using previously installed equipment would clearly be less expensive to the Program M&E budgets and could be as accurate as monitoring systems installed by the RER/Itron team. Also, thermal energy monitoring results would generally be acquired more quickly in the initial year of operation and may result in additional data availability during this period, as the equipment would already have been installed.

To mitigate the above issues, the Team will examine the existing system's monitoring capability during the preliminary monitoring site visit and determine whether or not its characteristics are adequate for use in the SGIP Program Evaluation. If so, arrangements are then made to obtain data from the generator on a regular basis. In addition, spot checks are performed to verify existing monitoring system sensor calibration and related measurements.

Need For Engineering Calculations as Opposed to Direct Thermal Measurement

At several of the sites visited by the RER Team, thermal energy is currently being measured, but on the downstream side of a thermal conversion system, for example an absorption chiller (See Point 3.2 above). It is possible to estimate the thermal energy delivered to the chiller by incorporating an estimate of its Coefficient of Performance (COP), which expresses chiller efficiency in terms of the dimensionless ratio of refrigerant effect to net energy input. This approach effectively captures effects related to thermal end use variability, however effects of chiller performance variability are not completely captured because absorption chiller COP is dependent on numerous factors, including: ambient wet bulb and dry bulb temperatures, the temperature of hot water delivered to the absorption chiller, and load conditions. It is anticipated that in some instances interval- or spot-metered data for one or more of these factors may be available and allow refinement of COP estimates. When the COP method is utilized the sources of data and relevant assumptions will be documented.

From the CFR citation above, energy delivered to an absorption chiller constitutes useful thermal energy, therefore no calculations comparing to displaced energy are necessary. From Issue #2 above, we utilize a generator's monitoring equipment if, in the judgment of the engineer visiting the site, it is of acceptable quality. The issue therefore boils down to whether or not an assumed chiller/process device COP should be used. A direct monitoring approach will be utilized in cases where this is the preference of the program administrator. In other cases a preliminary assessment is made to determine how close the facility is to meeting the PUC Section 218.5 requirements. If utilizing conservative assumptions on the COP indicates that there is little chance that they will not meet 218.5, existing metering (on the chilled water side of the absorber) will be used with the conservative COP estimate. This can be checked periodically, and monitoring equipment added in the future if it is apparent that the system is not meeting 218.5 based on the conservative COP assumptions.

Summary Of Thermal Energy Monitoring Process & Procedures

In summary, the RER M&E Team is implementing the following process and procedures in determining 1) whether to install and 2) the exact location of thermal monitoring systems to be placed at selected SGIP Incentive Level 2 and 3-N sites:

- Useful energy can be measured on either side of a heat exchanger, so long as it is net of energy returned to the prime mover(s) (i.e., hot water return or steam condensate energy is subtracted from hot water supply or supply steam energy).
- The evaluation team will use system owner's/third party installed monitoring equipment when, in the opinion of the Professional Engineer visiting the site, there is a high level of confidence that the site-specific results will be reasonably accurate. This will in come cases require spot-checking to verify initial - and perhaps ongoing - sensor calibration.
- Every selected cogeneration system installed under the SGIP will be equipped with the capability to monitor useful thermal energy.
- Using an appropriate COP (or other rated performance factor) to back-calculate the useful thermal energy produced by a system shall be acceptable when, in the opinion of the Professional Engineer visiting the site, there is a high level of confidence that the results will be reasonably accurate -- and the potential for not meeting the Program eligibility requirements of PUC Section 218.5 is minimal.

Level One Technology Monitoring & Data Collection

Although currently all of the Level 1 projects are photovoltaic systems, Incentive Level 1 includes photovoltaic systems, wind energy conversion systems, and fuel cells operating on renewable fuel with an aggregate generation capacity of 30 kW or more. Interval-metered data requirements of photovoltaic and wind systems will be fully satisfied by the NGO and NGO-connected facility electric interval data requirements previously described above. To determine if Level 1 fuel cells operating on a combination of renewable and nonrenewable fuels meet the renewable fuel requirements, DG electric energy production figures and natural gas (or any other nonrenewable fuel) metered consumption or bills, along with an estimate of fuel cell conversion efficiency, will typically be used. When dual-fuel systems are installed, the Administrator will request that the local gas utility install a separate natural gas meter to monitor the DG gas consumption separately. This approach will generally provide sufficient accuracy to determine compliance with the *renewable fuel* definition. In certain cases where unusual fuel cell performance variation is found to occur, it may be necessary to install a biogas (or other renewable) fuel meter in order to determine compliance with the renewable fuel requirements contained in D.02-09-051.

At this time detailed performance monitoring of Level 1 Fuel Cell, PV, and Wind systems is not expected to be performed on SGIP Level 1 projects, per the request of the Statewide Working Group. Detailed performance monitoring would entail collection of select environmental data (i.e., plane of array solar insolation, ambient/module temperatures, wind speed/direction) coincident with photovoltaic or wind system electric power output, or development of detailed electric performance information (e.g., module/system conversion efficiency, power factor, harmonics, etc.).

In summary, Level 1 metering equipment and/or information that is necessary for the impacts evaluation and that is expected to be provided by either the Program Administrators and/or local utility includes:

- Electric revenue meter with 15-minute interval averaging/storage capabilities to monitor net generator output,
- Electric revenue meter with 15-minute interval averaging/storage capabilities to monitor electric load on the billing meter located immediately upstream of the NGO meter, and
- For Level 1 fuel cells only, standard natural gas revenue meter billing data, specifically for the incentivized generator fuel input (MMCF), coupled with reported average gas Btu content for the billing period (or the equivalent billed Therms as appropriate) for the fuel cell generator.

Level Two Fuel Cell Monitoring

Whereas electric interval data are sufficient to assess the performance of Level 1 fuel cells, Level 2 fuel cells operating on fossil fuels are subject to system efficiency requirements that will make additional data collection necessary. Specifically, eligible Level 2 [and Level 3] SGIP systems must utilize waste heat from the generating facility and meet the cogeneration requirements of Public Utilities Code Sec. 218.5. Public Utilities Code Sec. 218.5 defines the following requirements: a) at least five 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)[4] energy input. Assessment of compliance with these Program requirements will require monitoring of waste heat utilization and incorporation of natural gas consumption data. Level 2 fuel cell natural gas input volume and average energy content will be obtained from the providing utility

Thermal energy meters and data loggers with remote communications capabilities will be installed to monitor waste heat utilization. Equipment installations will typically be permanent or long term in nature. Impact to the customer should be limited to a few hours of down time for equipment installation and removal. Only under the conditions where a host customer's production/thermal process disruption is a significant factor and monitoring of a short-term nature proves to be a reasonable approach, will non-invasive, ultrasonic flow and surface temperature measurements be used to speed installation and removal and to minimize the project's impact on the customer and their DG system.

The key Level 2 monitoring system components will include:

- Data logger, modem, and accessories
- Btu meter
- Telephone line

Additional metering equipment and/or information that is necessary for the impacts evaluation and that is expected to be provided by either the Program Administrators and/or local utility includes:

- Electric revenue meter with 15-minute interval averaging/storage capabilities to monitor net generator output,
- Electric revenue meter with 15-minute interval averaging/storage capabilities to monitor electric load on the billing meter located immediately upstream of the NGO meter, and

[4] Only natural gas (and renewable) fueled cogeneration systems are eligible for incentives under the SGIP.

- Standard natural gas revenue meter billing data, specifically for the incentivized generator fuel input (MMCF), coupled with reported average gas Btu content for the billing period (or the equivalent billed Therms as appropriate) for the generator.

Level Three Technology Monitoring

Incentive Level 3 includes microturbines, internal combustion engines, and small gas turbines operating on either fossil or renewable fuel. Following D.02-09-051, Level 3 projects are further classified according to their fuel type. Systems utilizing renewable fuel are classified as Level 3-R, while those operating on non-renewable fuel are classified as Level 3-N. The data requirements and data collection approaches for Incentive Level 3-R technologies mirror those defined previously for Level 1 fuel cells. For these systems the impacts assessment will incorporate metered electric and fuel data necessary to assess both electric impacts as well as compliance with renewable fuel input requirements. As a general rule, both of these data elements will be provided by the Program Administrator (or through the local utility).

The requirements and approach for Level 3-N technologies will generally parallel those of the Level 2 Fuel Cells. For these cogeneration systems the impacts analysis will include metered electric, thermal, and fuel data necessary to assess both electric impacts, as well as compliance with system overall efficiency requirements. As a general rule, metered electric and fuel data will be provided by the Administrator or utility and metered thermal energy data will be implemented and collected by the RER monitoring team following the procedures for thermal energy monitoring and data collection previously discussed in Section 1.4.

Data Collection Status and Schedule

At the end of 2002, 108 projects have achieved Proof of Project Advancement, of which 68 projects are assumed to be *Operational*, with 30 projects identified as *Completed* and *Paid.* To date, the RER/Itron/BVA Team has conducted 27 metering plan site visits and have prepared 13 metering and data collection (M&DC) plans. RER/Itron has reviewed 12 of these plans and 9 have been submitted to the Program Administrator for their review and approval. Thermal data for two sites have been received by RER and these data have been analyzed for the impacts report. Analysis results for these Incentive Level 3 sites are presented in Section 9. The next steps that are currently underway include finalizing submitted metering plans and installing on-site data acquisition related to currently operational projects. This data gathering effort will remain an ongoing M&E task activity throughout the course of this Program M&E effort. Verbal agreements are also in place to obtain thermal data for several operational projects that have already installed their own monitoring equipment. This metering and data collection effort will continue on an ongoing basis throughout the Program operational period (i.e., for a sample of PY 2004 projects installed in 2005).

8.4 Utility Data Exchange Process

To date utility data have been received from SDG&E for projects administered by SDREO. For these projects, SDREO has had customers sign a data release prior to providing the data to RER/Itron for program evaluation purposes. Utility data provided in these transmittals have included electric net generator output meter, electric billing meter, and natural gas billing meter interval data. In numerous instances, per the Metering and Monitoring Plan, the collection of this metered data has begun well before payment of a program incentive.

No metered data have yet been received from SCE. In the future, it appears that E-NGO metered data will be collected from Level 2 and Level 3-N projects by SCE and provided to the Project Team, while collection of E-NGO metered data from other types of rebated systems may be handled by the evaluation contractor. RER/Itron anticipates that in cases where SCE is collecting metered data for evaluation purposes, that it will also make any necessary data release provisions with customers.

In addition, no data from utility-owned meters have yet been received from PG&E for their completed projects. In the future, for those projects without customer-installed metering deemed adequate for evaluation purposes, it appears that E-NGO metered data will be collected from Level 2 and Level 3-N projects by PG&E and provided to the Project Team, while collection of E-NGO metered data from Level 1 rebated systems may be handled by the evaluation contractor. RER/Itron anticipates that in all cases where it is directly collecting metered data for evaluation purposes, that it will also make any necessary data release provisions with customers.

Depending on where the host customers are located, customers with projects being administered by SoCalGas will receive their electric service from one of several electric utilities, including: SCE, LADWP, or another municipal utility. Exchange of data between these other electric utilities and SoCalGas and RER/Itron will be governed by a Data Release Agreement, the content and format of which was finalized by the Statewide Working Group in February 2002. This Data Release Agreement specifies terms governing the transfer of data between different utilities for purposes of SGIP program evaluation.

The Data Release Agreement may be used to facilitate transfer of both E-NGO as well as billing metered data. In numerous instances E-NGO data are being collected from Level 1 PV systems by municipal utilities. For these systems, after a project advances at least to the PPA_Approved stage an M&E Notification letter will be sent to both the Host and Applicant.

RER/Itron will follow up with program participant and obtain a Data Release signature that will enable the electric utility to release metered data for program evaluation purposes.

No billing meter data were incorporated into this round of impact analysis. In the future, however, these data will be obtained from electric utilities. While the Energy Division has yet to take actions necessary to cause cost-effectiveness analytic methodologies to be developed, it is anticipated that this will occur in the future and result in the need to estimate billed demand impacts and project cost-effectiveness from the regional/societal and customer's perspectives. This will be particularly interesting for solar PV projects because their output is sensitive to weather and while the coincidence of PV system output with billed demand events has been subject to considerable speculation, very little metered data are available from actual systems and their impacted customer electric accounts.

8.5 Quality Control Procedures and Results

Utilization of metered data from numerous different sources increases the importance of quality control procedures in ensuring validity of metered data used in impacts analyses. The process being employed to ensure data quality involves three principal steps that are summarized below. The three steps include:

- Document the basis of received data
- Convert raw data to a common format
- Review data and seek clarification as necessary

Document the Basis of Data

In cases where Program Hosts or Applicants are providing data, RER/Itron initiates the data collection process by providing a written summary of preferred data characteristics and a representative example of a satisfactory file format. Preferred file format details included in the summary are listed below.

- File Format: ASCII Text
- Field Delimiter: Tab
- Time Basis: Standard Time (i.e., no adjustment during Daylight Savings Time)
- Recording Interval: 15 minutes
- Month Begin/End
  - Preferred: Calendar month
  - Alternate: Billing cycle
- Data Identifiers Contained <u>Within</u> Each File
  - Self-Gen Incentive Program application number

  - Meter identifier unique to the application
  - Channel identifier unique to the meter
  - Unit of measure (e.g., kW, kWh)

- Delivery Frequency/Mode
  - Preferred: Monthly/Email
  - Alternate: Quarterly/CD (if large file sizes preclude email transmission)

- File Naming: [Application #]_[type]_[Data ID #]_[last data date].ext
  where *type* = elec, NG, or thermal, *Data ID#* typically is = 1, but could be 2 or 3 if multiple channels/meters are necessary to capture all metered data of a particular type), and *last data date* = the date of the last record in the file (i.e., mmddyyyy).

Convert Raw Data to a Common Format

Upon receipt of a data file, it is first opened and quickly reviewed simply to confirm that the file can be opened and that it contains data. The data are reviewed and its bases are documented. The data are then converted to a common basis so that they can be stored and processed systematically. This data manipulation is accomplished using SAS statistical analysis software. For each project, the SAS software is used to build a data "backbone" onto which the metered data from one or more sources are merged. The data backbone consists of a complete list of date-time records beginning with when a project first entered normal operations. This approach is used for two reasons. First, it makes it possible to quickly check to see if there are any gaps in the metered data. Second, it makes it easy to fill any gaps using statistical or engineering analytic methods. A data basis flag is used to keep track of the basis of data values for each metered parameter and interval (i.e., metered or estimated).

Review Data & Seek Clarification as Needed

All data files are reviewed graphically to help identify dates when systems entered normal operation, and also to identify any periods of time where data are suspicious (e.g., solar PV system power output at night) or where trends suggested by the data abruptly change. Separate graphs of power output versus hour of data are produced for each day. These graphs are produced in SAS, where it is possible to review them sequentially in a manner that facilitates review of trends embedded in large quantities of data. In cases where suspicious data or abrupt changes are observed RER/Itron will check with the provider of the data to see if the behavior can be explained.

In the case of solar PV systems, metered data are normalized such that energy production per unit of system capacity can be reviewed and compared against results for other similar systems. This data review step is helpful for confirming that the values contained in the data files accurately correspond to the particular hardware that was rebated.

Implementation of the data quality control procedures described above has resulted in identification of several data issues that will be resolved with data providers. Due to the dearth of metered data available to the PY2002 impacts analysis, the approach described above enabled efficient expansion of available data to the periods of time for which no data were available. In some cases problems with the data received from Hosts or Applicants were identified. In at least one case the Applicant is working on a fix that should result in cleaner data files in the future. Progress will be monitored as data collection and analysis continues into the future.

9

System Impacts and Operational Characteristics

9.1 Introduction

This section of the Program Impacts Assessment addresses the 2002 peak demand and energy impacts of the operational Self-Generation Incentive Program projects. Electrical demand and energy impacts were estimated for operational projects regardless of their stage of advancement in the program. Impact estimates are therefore based on projects for which SGIP incentives have already been disbursed, as well as on operational projects that have yet to complete the SGIP process.

While the sample design calls for all operational PY2001 and PY2002 projects to be metered, as of the end of 2002 a majority of these operational PY2001-2002 projects were not yet equipped with energy meters (or data were not yet available to the evaluation contractor from third parties). Consequently, this first impacts assessment incorporates a combination of metered data, statistical methods, and engineering assumptions. The data availability situation and corresponding analytic methodologies varies by program level and technology, and is described in subsections 9.3 through 9.7 below following the summary of program-level peak demand and energy impacts.

9.2 Overall Program Impacts

Electrical demand and energy impacts for projects that had begun normal operations prior to December 31, 2002 were calculated using available metered data and other system characteristics information from the program tracking systems maintained by the Program Administrators. As described in a previous section of this report, electric net generator output (E-NGO) metered data are not yet being collected from all projects during program operational years one and two that were installed and operating as of the end of 2002. Consequently, this initial assessment of demand and energy impacts on the electrical system is based on a combination of metered data and engineering estimates.

ISO Peak Demand Impacts

Overall program demand impacts on 2002 ISO system peak load are summarized below in Table 9-1. In 2002 the ISO system peak reached a maximum value of 42,352 MW on July

10 during the hour from 2 to 3 PM. There were 30 operational SGIP projects when the ISO experienced this summer peak, but interval-metered data were available for only 9 of the 30 projects. While the total on-line capacity of the 30 operational projects was 8.3 MW, the total impact of the Program on the ISO peak demand is estimated at 6.7 MW. Level 3 IC engines and microturbines account for 82% of this total 2002 peak demand impact.

Table 9-1: Overall Impacts on 2002 ISO System Peak Demand

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	**11**	**1,130**	**790**
Metered	3	248	173
Estimated	8	882	616
Level 2 Fuel Cell	**2**	**400**	**400**
Metered	0	0	0
Estimated	2	400	400
Level 3 IC Engines / Microturbines	**17**	**6,752**	**5,472**
Metered	6	1,377	1,118
Estimated	11	5,375	4,354
Total Estimated Impact	**30**	**8,282**	**6,662**

Energy Impacts

Overall program electrical energy impacts are summarized in Table 9-2. While Level 3 engines and turbines accounted for 82% of demand impacts, they account for 86% of total energy impacts. This difference is due to the fact that the average capacity factor of Level 3 IC engines and turbines is greater than that for Level 1 Solar PV.

Table 9-2: Overall Energy Impacts in 2002 by Quarter (kWh)

Basis	Q1-2002	Q2-2002	Q3-2002	Q4-2002	Total
Level 1 PV	**59,899**	**461,814**	**679,860**	**646,822**	**1,848,394**
Metered	0	10,603	179,554	343,315	533,472
Estimated	59,899	451,211	500,306	303,507	1,314,923
Level 2 Fuel Cell	**410,400**	**528,580**	**839,040**	**839,420**	**2,617,440**
Metered	0	0	0	0	0
Estimated	410,400	528,580	839,040	839,420	2,617,440
Level 3 IC Engines /Microturbines	**2,476,239**	**4,795,801**	**7,402,374**	**13,002,985**	**27,677,399**
Metered	458,909	1,065,162	1,458,229	2,145,189	5,127,489
Estimated	2,017,330	3,730,639	5,944,146	10,857,796	22,549,911
Total	**2,946,538**	**5,786,195**	**8,921,274**	**14,489,227**	**32,143,233**

9.3 Level 1 Solar PV Systems

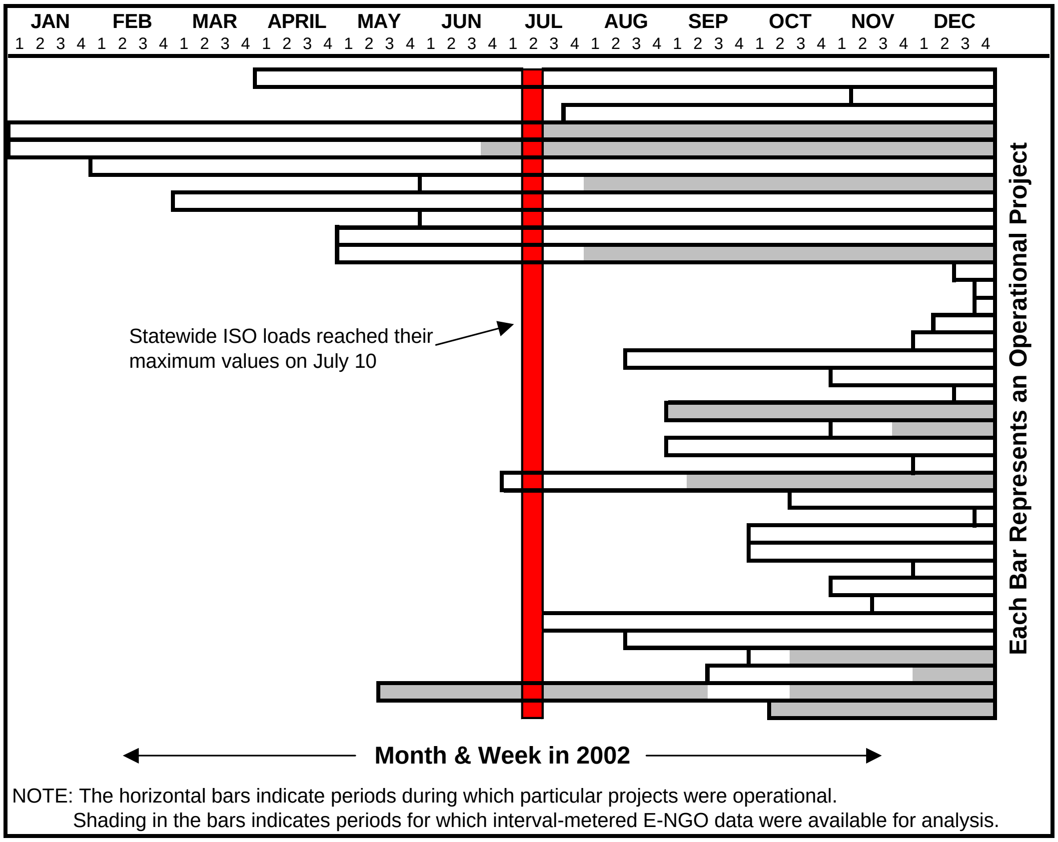
The data availability situation for incentive Level 1 PV is summarized in Figure 9-1. The horizontal bars represent periods of time that particular PV systems were operational in 2002. Shading in the bars represents periods of time for which E-NGO data are available. The vertical bar illustrates the timing of the ISO electrical system 2002 peak (i.e., July 10, 2002).

Direct calculation of impacts of PV systems relies exclusively on E-NGO data. Due to a variety of factors, complete E-NGO datasets were unavailable for most of the operational PV systems during PY2001 and 2002. The data that were available are used in the analysis directly. These data were also combined with weather data from secondary sources, and with known characteristics of projects (e.g., location and system size), to estimate peak demand and energy impacts of unmetered PV systems.

ISO Peak Demand Impacts

In 2002 the statewide ISO system peak occurred on July 10 during the 14th hour (from 2 to 3 PM). During this hour the electrical demand for the ISO reached 42,352 MW. On this day there were 11 PV systems under the SGIP installed and operating; interval-metered data are available for three of them. These metered data were used to calculate peak demand impacts on the ISO directly, as summarized in Table 9-3.

Figure 9-1: Solar PV Operational Projects & E-NGO Data Availability



For these projects, the demand impact corresponded to 0.7 kW of demand impact per 1 kW of PV system size [basis: rebated capacity]. A rough estimate of demand impacts for projects for which data were not available was calculated as the product of this ratio and total unmetered system capacity. The total program-level system peak demand impact for incentive Level 1 PV systems is estimated equal to 790 kW.

Table 9-3: Impacts of Operational Level 1 PV on 2002 ISO System Peak Demand

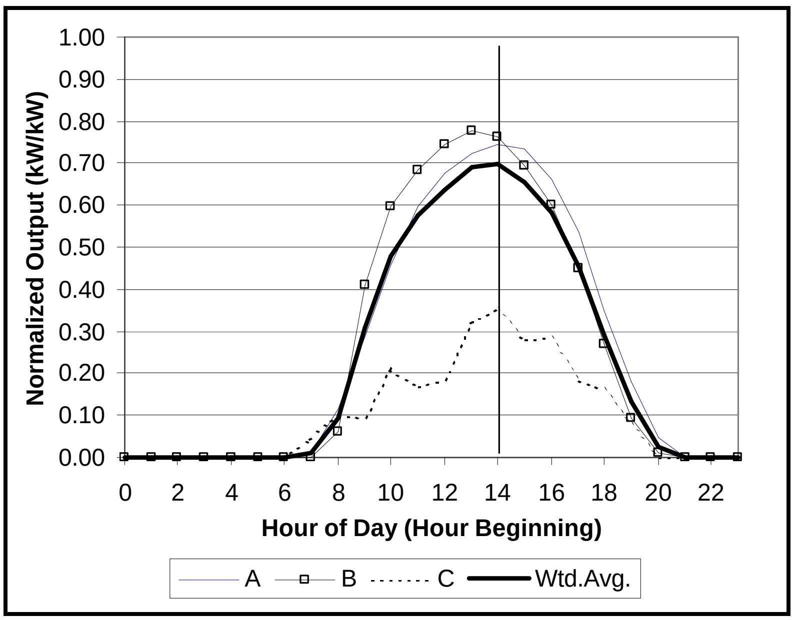
Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio (kW_P/kW)
Metered	3	248	173	0.7
Estimated	8	882	616	0.7
Total	**11**	**1,130**	**790**	**0.7**

The peak-day operating characteristics of the three PV projects for which peak-day interval-metered data are available are summarized in Figure 9-2. System sizes were used to normalize power output values prior to plotting PV output profiles for individual projects.

The normalized values represent PV power output per unit of system size. Treatment in this manner enables direct comparison of the power output of systems of varying sizes. The weighted average indicated in this graphic was calculated as the total power output of the three systems divided by total system size of the three systems.

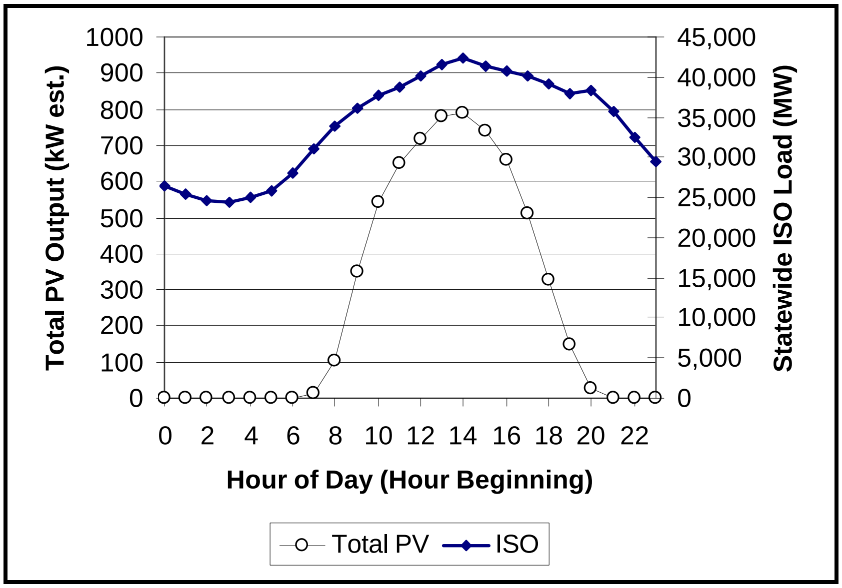
The output of one of the three metered systems was substantially lower than the other two on July 10, 2002. On most days in July 2002 the output of this system during this time of the day was considerably higher. In July 2002 during the hour from 2 to 3 PM the average output was 62% of rebated system capacity, which is nearly twice the output observed on July 10 during the peak hour. This system is located near the coast in southern California. Weather data for this day suggest that this area may have experienced foggy or cloudy conditions during much of July 10.

Figure 9-2: 2002 ISO Peak Day PV Output Profiles (July 10, 2002)



The peak-day profiles of both ISO system loads and the total of the metered/estimated output of the 11 operational PV systems are illustrated in Figure 9-3. The shape of the PV output curve aligns well with the statewide ISO system peak from 2 to 3 PM. The output of PV drops off more rapidly than the ISO system load, however.

Figure 9-3: 2002 ISO Peak Day Loads and Est. Total PV Output



Energy Impacts

In cases where metered data were available they were used directly to calculate energy impacts of PV systems. However, as illustrated above in Figure 9-1, a substantial portion of total energy production was not captured in interval-metered data. Energy impacts were estimated in cases where metered data were not available.

To estimate PV system energy production solar radiation data collected in northern and southern California were incorporated into the analysis. First, all PV projects were assigned to either northern or southern California. Second, available metered data were used to calculate average energy production per unit of solar radiation and system size as:

$$R = \frac{\sum NGO_{srdh}}{\sum\left(S_{sr} \times \frac{GHR_{rdh}}{1{,}000}\right)}$$

Where:

R = Average solar PV system energy production per unit of system size and incident solar radiation

Value: 0.92
Units: kWh/kW/(kWh/m^2)
Source: Calculated

NGO_{srdh} = Actual metered net generator output for system *s* in region *r* on day *d* during hour *h*

Units: kWh
Source: Net Generator Output Meters

S_{sr} = Solar PV system size for system *s* in region *r*
Units: kW
Source: SGIP Tracking System

GHR_{rdh} = Global horizontal radiation in region *r* on day *d* during hour *h*
Units: Wh/m^2
Source: California Irrigation Management Information System data for Irvine and Oakland Foothills weather stations

1,000 = Conversion Factor
Units: Wh/kWh

Next, in cases where metered data were unavailable the per-unit energy production result was combined with observed weather data and system size information to calculate estimates of energy production as:

$$\hat{NGO}_{sdh} = S_{sr} \times \frac{GHR_{rdh}}{1{,}000} \times R$$

Where:

$\hat{NGO}_{sdh}$ = Predicted net generator output for system *s* in region *r* on day *d* during hour *h*
Units: kWh
Source: Calculated

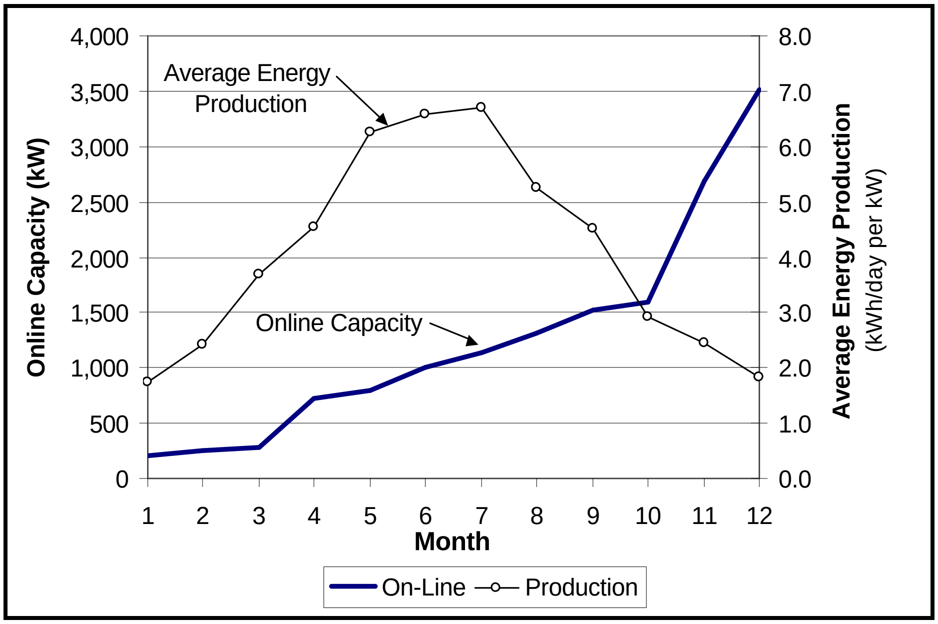
Metered and estimated energy impact results for Level 1 solar PV systems are summarized by quarter in Table 9-4.

Table 9-4: Energy Impacts of PV in 2002 by Quarter (kWh)

Basis	Q1-2002	Q2-2002	Q3-2002	Q4-2002	Total
Metered	0	10,603	179,554	343,315	533,472
Estimated	59,899	451,211	500,306	303,507	1,314,923
Total	**59,899**	**461,814**	**679,860**	**646,822**	**1,848,394**

The quarter-to-quarter variability exhibited in energy impacts results presented in Table 9-4 is largely due to the fact that projects were coming on-line throughout 2002. The project completion trend is summarized in Figure 9-4. The energy production of particular PV systems varied according to season. In Figure 9-4, normalized energy production by month is illustrated. These values represent the average daily energy production per unit of on-line PV system capacity. As expected, normalized energy production values reach maximum values in the summertime.

Figure 9-4: PV On-Line Capacity & Normalized Energy Production (2002)



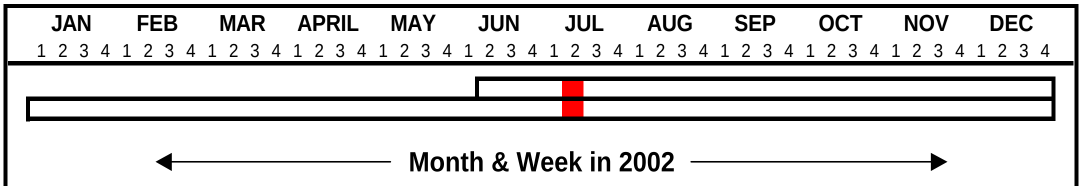
9.4 Wind Turbine Generators

As of the end of 2002, no program applications for wind turbine generators had been received.

9.5 Incentive Level 1 & 2 Fuel Cells

As of the end of 2002, no program applications for Level 1 fuel cells had been received. Two Level 2 fuel cell projects are installed and operating. As illustrated in Figure 9-5, while both of the fuel cell projects were in normal operation at the time of the ISO system peak, metered E-NGO data are available for neither of the systems.

Figure 9-5: Level 2 Fuel Cell Operational Projects & E-NGO Data Availability



NOTE: The horizontal bars indicate periods during which particular projects were operational.
Shading in the bars indicates periods for which interval-metered E-NGO data were available for analysis.

Demand and energy impacts of the Level 2 fuel cells were estimated. Each of the systems was assumed to have been operating at full load during the hour of the system peak. Table 9-5 summarizes the estimated 2002 peak demand impacts on the ISO from operational Level 2 fuel cell projects

Table 9-5: Impacts of Level 2 Fuel Cells on 2002 ISO System Peak Demand

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio (kW_P/kW)
Metered	0	0	0	N/A
Estimated	2	400	400	1.00
Total	**2**	**400**	**400**	**1.00**

To estimate energy impacts an average capacity factor of 95% was assumed. The resulting distribution of energy impacts by quarter is summarized in Table 9-6.

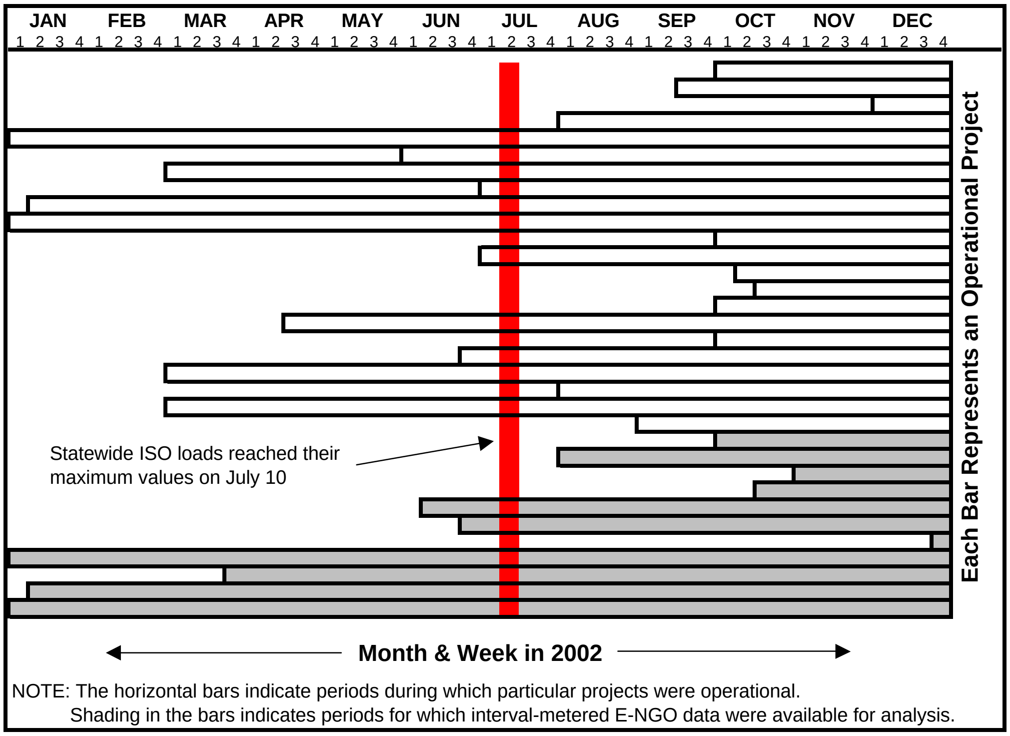
Table 9-6: Energy Impacts of Level 2 Fuel Cells in 2002 by Quarter (kWh)

Basis	Q1-2002	Q2-2002	Q3-2002	Q4-2002	Total
Metered	0	0	0	0	0
Estimated	410,400	528,580	839,040	839,420	2,617,440
Total	**410,400**	**528,580**	**839,040**	**839,420**	**2,617,440**

9.6 Incentive Level 3-N: Microturbines, IC Engines, and Small Gas Turbines

The electric NGO data availability situation for Level 3 internal combustion engines and turbines is summarized in Figure 9-6. The horizontal bars represent periods of time that SGIP systems were operational. Shaded bars represent periods of time for which E-NGO data are available for this analysis. The vertical bar illustrates the timing of the ISO electrical system 2002 peak (i.e., July 10, 2002).

Figure 9-6: Level 3-N Operational Projects & E-NGO Data Availability



ISO Peak Demand Impacts

On July 10, 2002, seventeen Level 3-N engine and turbine projects were on-line. On that ISO system peak day, metered E-NGO data are available for six of these systems. For these six projects, during the hour from 2 to 3 PM the net system power output (i.e., demand impact) was 0.81 kW per kW of system capacity [basis: rebated system size]. This ISO peak ratio was applied to system size information for unmetered systems that were on-line on the day of the ISO system peak. The estimate of total Level 3-N ISO peak demand impact is equal to 5,472 kW.

Table 9-7: Impacts of Level 3-N Systems on 2002 ISO System Peak Demand

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio (kW_P/kW)
Metered	6	1,377	1,118	0.81
Estimated	11	5,375	4,354	0.81
Total	**17**	**6,752**	**5,472**	**0.81**

Energy Impacts

In cases where metered data were available they were used directly to calculate energy impacts of Level 3-N systems. However, as illustrated above in Figure 9-6, a substantial portion of total energy production was not captured in interval-metered data. Energy impacts were estimated in cases where metered data were not available.

To estimate Level 3-N system energy production metered data available for the analysis were used to calculate an average Capacity Factor expressing the Level 3-N system average power output per unit of system size:

$$CF = \frac{\sum NGO_{sdh}}{\sum (S_s \times H_s)}$$

Where:

CF = Capacity factor representing the ratio of actual metered energy production to total energy that would have been produced had the system operated continuously at the rebated power output level

Value: 0.43
Units: kWh/kWh
Source: Calculated

NGO_{sdh} = Actual metered net generator output for system *s* on day *d* during hour *h*

Units: kWh
Source: Net Generator Output Meters

S_s = Level 3-N system size for system *s*

Units: kW
Source: SGIP Tracking System

H_s = Total hours system *s* was available for operation

Units: Hours
Source: Net Generator Output Meters

For hours where metered electric net generator output data were not available for the analysis the average capacity factor from above was combined with system size to calculate estimates of Level 3-N system power output as:

$$\hat{NGO}_{sdh} = S_s \times CF$$

Where:

$\hat{NGO}_{sdh}$ = Predicted net generator output for system *s* on day *d* during hour *h*
Units: kWh
Source: Calculated

The resulting distribution of energy impacts by quarter is summarized in Table 9-8. The variability observed across quarters is primarily attributable to systems coming on-line throughout 2002, as illustrated in Figure 9-6 above.

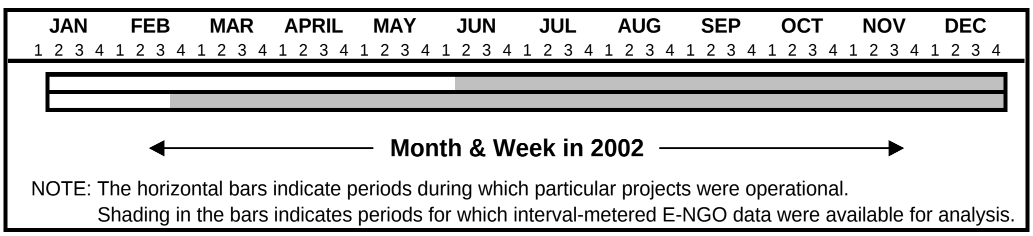
Table 9-8: Energy Impacts of Level 3-N Systems in 2002 by Quarter (kWh)

Basis	Q1-2002	Q2-2002	Q3-2002	Q4-2002	Total
Metered	458,909	1,065,162	1,458,229	2,145,189	5,127,489
Estimated	2,017,330	3,730,639	5,944,146	10,857,796	22,549,911
Total	**2,476,239**	**4,795,801**	**7,402,374**	**13,002,985**	**27,677,399**

Review of Useful Thermal Energy and System Efficiency

Thermal data for two Level 3-N projects were obtained for this analysis. Figure 9-7 illustrates the availability of this data for 2002.

Figure 9-7: Level 3-N Thermal Data Availability Summary



Available metered thermal data collected from these on-line Level 3-N projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results of the analysis are summarized in Table 9-9. An average of 18.2% of the facilities' total annual energy output is in the form of useful thermal energy delivered to the absorption chillers, exceeding the PUC 218.5 (a) requirement of 5%. The resulting average overall system efficiency of approximately 43.5% is slightly above the required 42.5% efficiency stipulated in PUC 218.5 (b). Project-specific efficiencies for both projects on an individual basis exceeded minimum requirements prescribed by PUC 218.5 (b).

An assumed chiller COP of 0.7 was used in this analysis. Although the manufacturer's nominal rated efficiency is slightly higher, chillers typically operate somewhere below the optimal efficiency for most of their operating hours. Using the California Title 24 standard COP of 0.7 accounts for variations in actual operating efficiency. An important implication of applying an assumed efficiency to available chilled water ton-hours supplied by the absorption chiller is that the lower the chiller COP, the higher the estimate of PUC 218.5 (b) overall system efficiency. Both systems were found to comply with PUC 218.5.

Table 9-9: Thermal Efficiency of Level 3-N Systems

Project ID	218.5 (a) Percent Thermal Energy	218.5 (b) Overall System Efficiency
Project A	17.8%	42.9%
Project B	18.7%	44.4%
Total	**18.2%**	**43.5%**

9.7 Incentive Level 3-R: Renewable fueled Microturbines, IC Engines, and small gas turbines

Level 3-R engine and turbine projects operating on renewable fuel are eligible for larger incentives and are subject to fewer requirements than Level 3-N engines and turbines. The 3-R incentive level was created with the adoption of Decision 02-09-051 dated September 19, 2002. As of the end of 2002, no Level 3-R projects were yet on-line.

9.8 Renewable Fuel Cleanup Equipment Costs

The September 2002 Decision 02-09-051 that made Level 3 incentive levels dependent on fuel type was based in part on the limited renewable fuel cleanup equipment cost data available to the Energy Division prior to the decision. In its decision the CPUC specified that this second year program impacts report include compilation and examination of available data on these costs for both Level 3-R combustion technologies and Level 1 fuel cells. To date no Level 1 fuel cell projects have applied for funding through the program. An assessment of available renewable fuel cleanup equipment cost data for Level 3-R combustion technologies is presented below.

Data Sources

Renewable fuel cleanup equipment cost data from two sources were included in the analysis. First, Total Eligible Project Costs reported for all projects on Reservation Request Forms. Second, more detailed fuel cleanup equipment cost data from Purchase Orders. Included in the September 2002 decision was a new requirement for inclusion of this detailed fuel cleanup equipment cost information in Proof of Project advancement submittals for Level 3-R projects.

The Total Eligible Project Cost data were available from the program tracking system data files provided by the program adminstrators on a monthly basis. Program administrators provided renewable fuel cleanup equipment cost data from purchase orders submitted to satisfy Proof of Project Advancement requirements.

Analysis & Results

Renewable fuel cleanup equipment cost data from Purchase Orders were available for six microturbine projects and one internal combustion engine project utilizing renewable fuel. For the internal combustion engine the incremental cost for fuel cleanup was reported to be negligible. For this project the special consideration attributable to renewable fuel utilization was limited to modification of a fuel filter specification.

In Table 9-10 cost data for the microturbine projects are summarized. The range of costs is quite large. The capacity-weighted average, which provides an overall summary of renewable fuel cleanup equipment costs at the program level, was found to be $0.59/Watt for microturbines.

Table 9-10: Renewable Fuel Cleanup Equipment Costs (Microturbine Purchase Orders)

Project	($/W)
Small (Size < 100 kW)	0.45
Small (Size < 100 kW)	0.46
Medium (100 kW ≤ Size < 300 kW)	0.89
Medium (100 kW ≤ Size < 300 kW)	1.63
Large (300 kW ≤ Size < 500 kW)	0.33
Large (300 kW ≤ Size < 500 kW)	0.33
Minimum	0.33
Maximum	1.63
Median	0.45
Average	0.68
Size-Weighted Average	**0.59**

Results of analysis of program tracking system data for microturbine total project costs are summarized in Table 9-11. The number of renewable fuel projects included in this table is larger than the number of projects for which information from purchase orders was available. This is explained by the fact that purchase order submittal is not required until Proof of

Table 9-11: Microturbine Total System Costs (Program Tracking System)

Statistic	Microturbine Renewable Fuel ($/W)	Microturbine Natural Gas ($/W)
n	10	50
Minimum	2.43	0.95
Maximum	9.81	7.35
Median	3.58	2.51
Average	4.12[1]	2.79[2]
Size-Weighted Average	**3.58**	**2.69**

Project Advancement is documented, and numerous projects have not yet reached that stage of development.

As with the purchase order data, the ranges corresponding to data from the program tracking system are quite large. The size-weighted average natural gas microtubine total system cost is about $2.70/Watt. Combination of this result with the renewable fuel cleanup equipment cost adder from Table 9-10 would result in an estimate of total renewable microturbine system cost equal to $3.28/Watt. Based on size-weighted average results, the program tracking system data suggest an incremental cost adder of $0.89/Watt, which exceeds the $0.59/Watt result that was based on analysis of a limited quantity of data from purchase orders.

The existing $1.50/Watt incentive for Level 3-R projects appears to be based on an assumed project cost of $3.74/Watt for microturbine projects utilizing renewable fuel. This value exceeds both $3.58/Watt or $3.28/Watt. However, sample sizes remain small and project cost variability is substantial. Development of definitive/general conclusions about the appropriateness of the $3.74/Watt assumption may require additional data for actual projects.

[1] The average value reported in Appendix A to Attachment 1 of the September 2002 Decision 02-09-051 for 4 projects was $3.33/Watt. The revised median, average, and size-weighted average results exceed $3.33/Watt.

[2] The average value reported in Appendix A to Attachment 1 of the September 2002 Decision 02-09-051 for 30 projects was virtually identical: $2.77/Watt.