CPUC Self-Generation Incentive Program Third-Year Impacts Assessment Report

Submitted to:

The Self-Generation Incentive Program Working Group

Prepared By:

Itron

1104 Main Street, Suite 630
Vancouver, WA 98660

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Executive Summary

This third year impacts assessment of the California Pubic Utilities Commission's Self-Generation Incentives Program (SGIP or Program) includes an assessment of the operational projects from the first two and one-half years of the program (i.e., mid 2001 – 2003). This report summarizes applicant status, available project data, impact analysis results, and related key findings for the Program as of December 31, 2003. Program-level electric peak demand and annual energy impacts were estimated for all known operational projects, regardless of their stage of advancement. Substantial quantities of electric net generator output (E-NGO) data were available for this calendar year 2003 analysis. However, only limited quantities of recovered thermal energy data were available for use in the analysis of cogeneration system performance. Therefore, the cogeneration system efficiency results must be considered preliminary. Metering installation and data collection efforts are ongoing. More definitive results will be available in 2005, given the expected additional metered data from operational projects collected during 2004 and 2005.

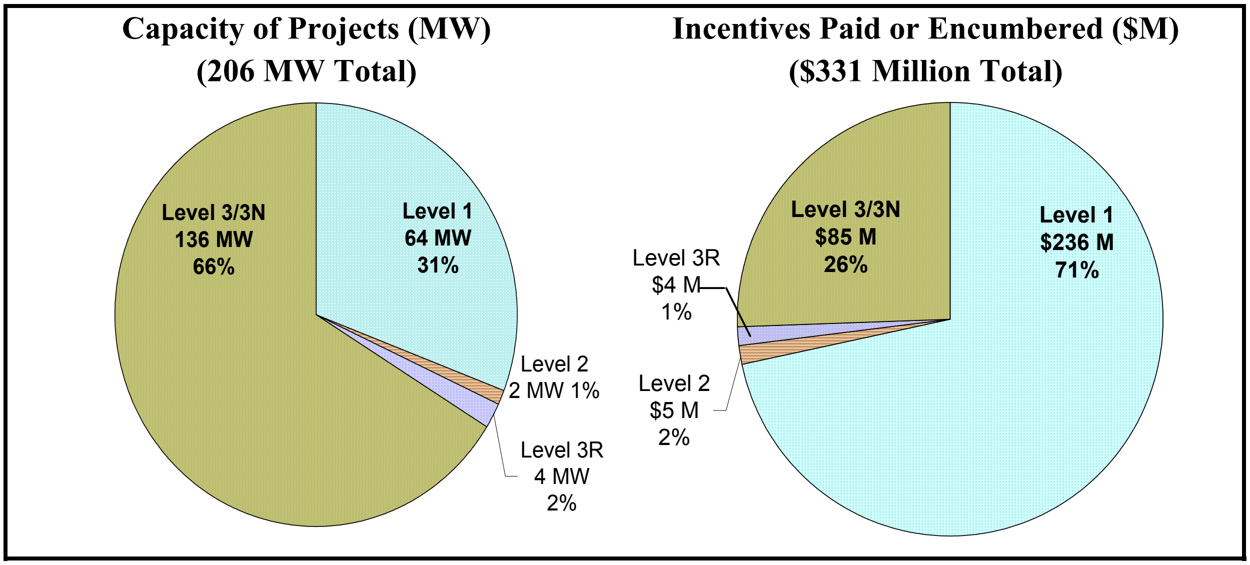
Program Status and Data Availability

The overall status of the Program is summarized in Figure 1-1, which includes projects that either remain active in the program or have advanced entirely through the incentive payment process. Level 1 photovoltaic, fuel cell, and wind projects account for 31% of the project capacity and 71% of the program incentives. Participation volumes for Level 2 fuel cells and Level 3R renewable fuel projects have been modest to date.[1] Cogeneration system applicants under Levels 3/3N account for about 2/3 of the Program's capacity through PY 2003.

The weighted-average incentive level expected to be paid for 206 MW of completed and remaining active projects is $1.60/Watt; while the average incentive paid for the 45.3 MW of completed SGIP projects is $1.41/Watt. The weighted average incentive paid by the Program for 15.2 MW of completed PV projects through 2003 is $3.02/Watt. This true incentive level is about 33% below the $4.50/Watt cap on the Program's Level 1 incentive and does not include incentives that were paid through other PV funding programs (LADWP, USDOE, etc.). The estimated incentive level for the 48.5 MW of remaining active projects is

[1] Incentive Levels 3-N and 3-R did not exist in PY2001. In September 2002, Level 3 was bifurcated into Level 3-R and 3-N depending upon the types of fuels used. Projects which applied for funding prior to this date were classified as Level 3 projects regardless of the type of fuels used.

Figure 1-1: Summary of PY01- PY03 Project Capacity and Incentives by Level



notably higher, at $3.93 /Watt. While there are three remaining active fuel cell projects, only one 0.2 MW Level 2 project incentive at $2.50/Watt was paid as of the end of 2003. Completed Level 3/3N cogeneration projects account for 29.5 MW of installed capacity and correspond to an average incentive of $0.58/Watt, which is 42% below the $1.00/Watt cap on Level 3/3N incentives. As with completed PV projects, the incentive for many of the Level 3/3N cogeneration systems is governed by the maximum 30% of eligible project costs limit for Level 3/3N.

Electric net generator output (E-NGO) data are available for more than half of the operational system capacity over the analysis period of calendar 2003, while only a small quantity of useful thermal energy data (less than 20% of operational capacity) are available to date for this impacts analysis. The vast majority of the thermal energy data were obtained from program participants.

Electric Peak Demand Impacts

Electrical demand and energy impacts for projects that had begun normal operations prior to December 31, 2003 were calculated using available metered data and other system characteristics information from the program tracking systems maintained by the Program Administrators. Therefore, this assessment of the Program's estimated demand and energy impacts on the electric system is necessarily based on a combination of the available metered data and engineering estimates. Overall program-level demand impacts coincident with the 2003 CAISO system peak load are summarized below in Table 1-1. In 2003, the ISO system peak reached a maximum value of 42,581 MW on July 21 during the hour from 3PM to 4 PM. While the total rated capacity of the 195 operational projects exceeded 58 MW, the total impact of the Program that was coincident with the ISO peak load is estimated at just over 35

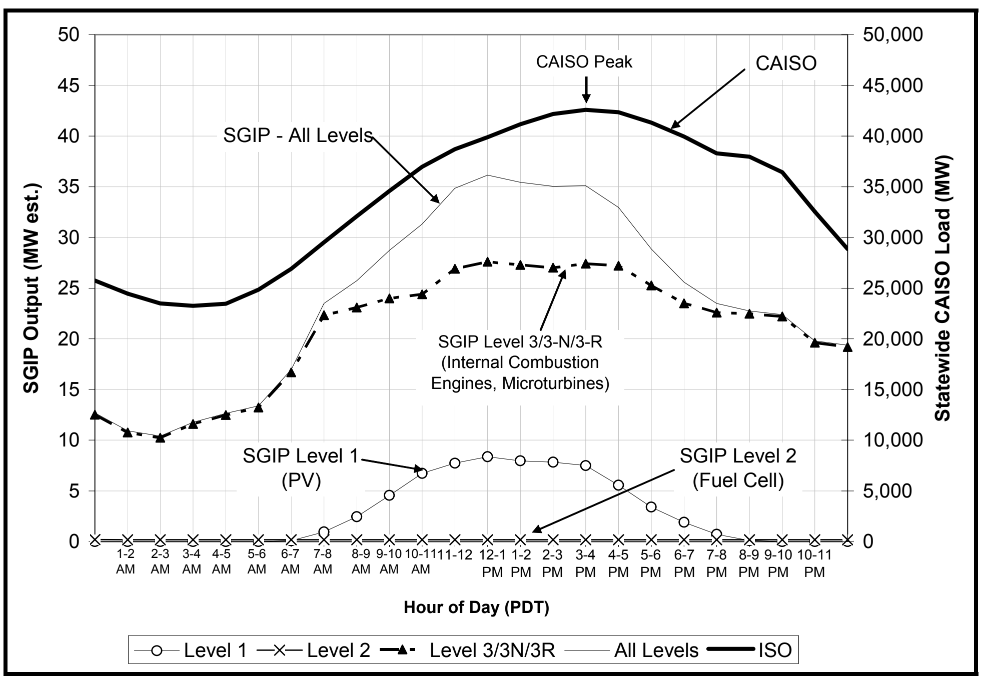
MW. Incentive Level 3/3-N/3-R engines and microturbines account for 78% of this total 2003 peak demand impact.

Table 1-1: Demand Impacts Coincident with 2003 ISO System Peak Load

Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	105	12,671	7,494
Level 2 Fuel Cell	1	200	187
Level 3/3-N/3-R ICE/Turbine	89	46,010	27,410
Total	**195**	**58,881**	**35,091**

The peak-day profiles of the California ISO system load, as well as the estimated SGIP generation, are illustrated in Figure 1-2. While PV system power output was substantial on the day of the CAISO system peak, the PV output curve's shape is relatively more "pointed" than the CAISO daily load's shape. After 1 PM the total output of the 105 operational PV systems began falling, whereas CAISO loads continued to increase for several hours. The shape of the output curve estimated for the 89 operational engines and turbines aligns well with the statewide ISO system peak from 3 to 4 PM, and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak hour).

Figure 1-2: CAISO Peak-Day Loads vs. Total SGIP Generation (MW)



Review of Cogeneration System Efficiency and Heat Recovery

Level 2 fuel cell and Level 3/3N engine/turbine cogeneration system designs are required to demonstrate through engineering calculations the achievement of certain minimum efficiencies on an annual basis.

Available metered thermal data collected from on-line cogeneration projects were used to calculate the overall system efficiency, incorporating both electricity produced as well as useful heat recovered. In some cases, availability of CY2003 data was not sufficient to estimate PUC 218.5 thermal energy proportions or efficiencies due to their annual basis requirement. These sites with insufficient data were not included in Table 1-2 or in the other subsequent summaries of system efficiency results presented in this report. Data were available for one Level 2 fuel cell project, which satisfied the requirements of PUC 218.5(b) with a 218.5(b) efficiency exceeding 50%. However, the results of the analysis for Level 3/3-N projects are not as positive regarding compliance with PUC 218.5 (b) as summarized in Table 1-2. Metered data collected to date suggest that only 2 of the 20 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%[2]. The limited quantities of cogeneration system data available for this impacts analysis suggest the possibility of systematic negative variance between planned system efficiencies and actual system efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn.

Table 1-2: Actual Level 3/3-N Cogeneration System Efficiencies (n=20)

Summary Statistic	218.5 (a) Proportion[1] (5 % Min.)	218.5 (b) Efficiency [2] (42.5 % Min.)	Overall Plant Efficiency = [(Elec+Thermal)/fuel input]
Min	1%	23%	25%
Max	54%	43%	58%
Median	46%	35%	45%
Mean	39%	35%	44%
Std Dev	17%	5%	10%
Coefficient of Variation	0.4	0.1	0.2

[1] 218.5 (a) Portion of the facility's total annual energy output that is in the form of *useful thermal energy*.
[2] 218.5 (b) Annual System Efficiency is calculated as the sum of E-NGO plus one-half of the useful thermal energy, divided by any natural gas energy input.

In general the actual useful heat recovery rates observed in 2003 were less than projected by engineering calculations completed during the design stage of cogeneration system project

[2] See Section 9.7 of this report for a discussion of the PUC 218.5 requirements for minimum useful thermal energy (218.5 a) and minimum system efficiency (218.5 b)

development. The variance is due to numerous factors, including: design problems, operational problems, unanticipated operational conditions, and reliability problems. Information about these problems is being collected as part of the limited-scope process evaluation of the SGIP. The results of this ongoing targeted process assessment will be presented later this year in a separate report, and will help explain the quantitative results presented in this third year impacts report.

Finally, it must be emphasized that the quantity of useful recovered heat data available for this analysis is small. While the total capacity of operational cogeneration systems approached 60 MW at the end of 2003, this analysis included useful recovered heat data for projects totaling less than 10 MW.

2

Introduction

The purpose of this report is to document the Self-Generation Incentive Program's third-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 (D.)01-03-073. Since July of 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, a summary of the second program year impacts evaluation's objectives and key results, an outline of the objectives of the third program year impact evaluation,[2] and presents the organization of the remainder of the report.

2.1 Program Description Update

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 authorized an annual statewide allocation of $125 million for program years 2001 through 2004 for incentives and program administration costs. Since July of 2001, the SGIP has been available to provide financial incentives for the installation of new qualifying

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

[2] The methodology and results for a targeted process evaluation are presented in a separate report entitled the California Self-Generation Incentive Program PY2004 Targeted Process Evaluation Report.

electric generation equipment that will meet all or a portion of the electric needs of an eligible customer's facility.

The SGIP is available to electric and/or gas customers of Southern California Edison, Pacific Gas & Electric, Southern California Gas Company, and San Diego Gas & Electric. Although the Program was intended to accept applications under its current program guidelines through December 31, 2004, it has as of the third quarter of 2004 been fully subscribed under Incentive Levels 1 and 3 within several of the Program Administrator service areas. Even with the strong level of program application activity during the first half of 2004, the Program will continue to accept applications, subject to the availability of Administrator Program Funds.

Assembly Bill 1685, signed into law October 12, 2003, extended the program through December 31, 2007, and requires combustion-based projects using nonrenewable or fossil fuels to satisfy new air emissions requirements. The CPUC will adopt annual statewide allocations for program years 2005 through 2007 before the end of the year..

The Self-Generation Incentive Program is designed to complement the California Energy Commission's (CEC) existing Emerging Renewables Program (CEC Emerging Program). This is accomplished primarily by focusing on the nonresidential market sectors, including commercial, industrial, and agricultural segments and by including select renewable and nonrenewable-fueled self-generation technologies— up to 1,000 kW in generating capacity.[3] Coordination with the CEC Emerging Program occurs through several administrative processes, including CEC participation in the Statewide Self-Generation Incentive Program Working Group and through shared utilization of a statewide Program compliance database to track applicant participation in the two agencies' incentives programs. .

"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. Financial incentives are provided to the targeted distributed generation technologies as summarized in Table 2-1. The CPUC is currently considering proposed modifications to current incentive levels and program requirements.

[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

Program 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[2,3]
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[2,3,4] ■ Internal combustion engines and small gas turbines[2,3,4]

1 Operating on renewable fuel.
2 Operating on non-renewable fuel.
3 Using sufficient waste heat recovery.
4 Meeting reliability criteria.

PG&E, SCE, and SoCalGas administer the Program in their service territories. Within the SDG&E service territory, the San Diego Regional Energy Office (SDREO) administers the Program.

The CPUC authorized a statewide annual budget of $100 million through 2004, allocated equally between Levels 1, 2, and 3. Program Administrators may reallocate incentive funds to Level 1 projects, according to market demand. Level 1 or Level 2 allocations may not be transferred to Level 3-N projects without CPUC approval. Program Administrators may also use administrative funds to pay incentives, if such funds are not required for their original purpose.

2.2 California's Market for Distributed Generation

In order to provide some useful background information regarding the Program's activity and its impacts during the third operational year, a brief overview is presented of the market for distributed generation.

Overview of the 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 residence) to provide a partial alternative to or an enhancement of the utility electric power system. The SGIP provides incentives to projects 1,500 kW or less. Level 1 projects much reach a minimum capacity size of 30 kW.

It is generally accepted that centralized electric power plants will remain the major source of electric power supply for the foreseeable 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 may also allow the electric utility to postpone or avoid the need for transmission and/or distribution system upgrades. Electric utilities have not always favored the use of distributed generation everywhere within the electrical system. Distribution system protection concerns may 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 require distribution planners/system protection engineers address these concerns 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. Site-specific project economics are sensitive to fuel cost, retail electric rates, and the cost of owning and operating distributed generation. Some SGIP participants are analyzing whether it will cost less to use their distributed generation units off-peak or to purchase this off-peak power from the grid.
- ***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.

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

- ***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.
- ***Standby Power:*** used in the event of an outage, as a back up to the electric grid. (While some distributed generation systems are designed to continue operating during a grid outage, most systems installed through the program are not 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. The SGIP requires projects to meet PU Code §218.5 waste heat recovery utilization standards for 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's 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 energy-related technology innovation. In California, the energy crisis of late 2000/early 2001 had a major impact on the development of distributed generation markets. Government policymakers, energy service providers, and energy users continue to consider distributed energy resources 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 during 2002 was extensive. Distributed generation, defined as all generation close to the point of consumption, accounted for nearly 10,000 MW of capacity. Smaller distributed generation resources (5 MW or less) provided over 400 MW of capacity. These figures do not include the sole application of emergency backup generation. For the smallest size classification (<1 MW) it is interesting to compare the total capacity reported in late

2002 (124 MW) to the total SGIP project development activity as of the end of 2003 (161 MW of active projects), and over 45 MW that are completed with the incentives paid.

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 Participants

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 typical host customer cannot easily undertake the planning and analysis of a distributed generation project on their own. 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 company that initially approaches the host electric customer about the SGIP project. These private sector companies then assume a major responsibility for tasks that can include performing cost-effectiveness analysis, applying to the program, permitting, selecting, procuring and installing equipment,. 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. Some municipal electric utility distributed generation incentive programs are interactive with the SGIP. For instance, LADWP's previous photovoltaic program incentive of up to $6.00/watt could 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 2002 dual-incentive effect for Level 1 photovoltaic had a notable impact in the LADWP service area. It remains unclear if other future municipal utility distributed generation programs will have a similar impact on local SGIP markets over the next three years.
- ***Consultants.*** Most customers who install distributed generation do so with help from consultants or other technical/management services for-profit firms. Consultants can help their customers in a 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 and performance testing. 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 and the US Department Of Energy, that promote distributed generation. A few of the participants in one of the CEC programs originally obtained their equipment through a low-interest CEC loan, then subsequently learned about SGIP incentives. The CEC Emerging Renewables Program also offers direct rebate incentives throughout most of same areas of the state, although these CEC program resources are currently available for smaller sized projects (i.e., less than 30 kW), thus minimizing the potential program overlap with the SGIP market.

The level of support that customers require varies widely. ESCOs and other specialty energy firms offering turnkey project development, financing and installation services provide the broadest support to customers. In these cases, distributed generation customers may have relatively little exposure to the sometimes difficult process of project development including participating in the SGIP. They are usually aware of these difficulties in some sense when they occur, insofar as they sign application materials prepared by third parties and they may hear about or be affected by permitting and interconnection issues and related delays. There is little question that third party providers have been instrumental in developing the market for distributed generation in California and the U.S. and to date have been responsible for much of the Program's 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.

Non-bypassable System Charges

Electric utility customers in California who install DG over 1 MW at their facilities pay certain non-bypassable system charges. These charges recover energy procurement costs incurred by the electric utilities and the state on behalf of those customers. In D.03-04-060, the CPUC exempted all SGIP-eligible projects 1 MW or under from these energy procurement related non-bypassable charges. SGIP projects over 1 MW pay some or all non-bypassable charge components, depending on their technology type and other factors.

Incentive Level 1 renewable SGIP projects are fully exempt from all non-bypassable charges. Level 2 and 3 SGIP projects are exempt from most or all non-bypassable charge components, depending on their technology type and other factors.

Impact of Fluctuating Wholesale Electric Costs

The Program was created in response to rapidly escalating wholesale electric costs in California. Many customers experienced rotating blackouts during the summer of 2000 and into early 2001, caused by generators withholding power from the market. As a result, many customers entered the Program with considerable animosity toward their electric company and with uncertainty about future utility rates. Many feel that electric utility rate increases threatened the viability of their business. While escalating electric rates visibly dampened customer enthusiasm for their electric companies, it also motivated them to self-generate and to participate in the SGIP. As the utilities' financial situations improved, electric rates decreased. For example, when SCE completed its cost recovery in July 2003, the CPUC approved the utility's request to reduce most nonresidential electric rates.

2.3 Second-Year Impact Evaluation Objectives and Key Results

The primary objectives of the previously completed second-year impacts assessment included: 1) compile and summarize electrical energy production and demand reduction by specific time periods and 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.

Program participation upon which the second-year impacts assessment was based is summarized in Table 2-2. Due to project development and construction time requirements only 9% of PY01-PY02 projects had been completed as of the end of 2002.

Table 2-2: Program Participation Summary as of End of Year 2002

	Active		Complete		Total	
Incentive Level	**n**	**kW**	**N**	**kW**	**n**	**kW**
1: PV	169	29,166	21	2,310	190	31,476
2: Fuel Cell	2	800	1	200	3	1,000
3/3-N: IC Engines / Microturbines	161	73,077	12	5,457	173	78,534
3-R: IC Engines / Microturbines	8	1,585	0	0	8	1,585
Total Program	**340**	**104,628**	**34**	**7,967**	**374**	**112,595**

Demand impacts estimated for 2002 for the Program and each incentive level are summarized in Table 2-3. 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 2-3: CAISO System Peak Demand Impacts Estimated for 2002

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

Overall Program electrical energy impacts estimated for 2002 are presented in Table 2-4. 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 2-4: Energy Impacts Estimated for 2002 by Quarter (kWh)

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

Data availability constraints imposed significant limitations on the analysis of 2002 operating characteristics for systems installed through the Program. Useful thermal energy data were available for only two projects, and impacts were estimated for the majority of projects using data available for other projects.

2.4 Third-Year Impact Evaluation Objectives

Objectives of the third-year impacts assessment are identical to those of the second-year impacts assessment. However the number of operational projects is now much larger, and the proportion of projects for which at least some metered data are available is notably higher. This current analysis is referred to as the Third-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 statewide program tracking database compiled from each of the four Program Administrators tracking database; 2) investor-owned utility (IOU)/energy service provider electric metering data of net generator electric output; and 3) other required operational data (e.g., recovered thermal energy, natural gas consumption for Level 2 & 3 cogeneration projects) to be collected under the program metering, data collection, and site verification tasks.

2.5 Report Organization

An executive summary, which provides a high-level overview of the key objectives and findings of this third year impacts evaluation, is presented in Section 1 of this report. The remainder of the report is organized 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 and fourth year evaluation activity.
- Section 4 presents a summary of the program status and participant characterization of the active 2001, 2002 and all 2003 participants.
- Section 5 discusses the third-year (and future) impact evaluation sample design issues.
- Section 6 addresses the data collection activities for this assessment.
- 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 summarizes the key results of the Third-Year Program Impacts Evaluation.

3

Evaluation Work Plan Updates

This section of the PY 2003 Impacts Report provides a discussion of the progression of the Self-Generation Incentive Program (SGIP or Program) measurement and evaluation work plan and its current status as of the second quarter of 2004. An overview of the program M&E Plan is discussed in Section 3.1. Key revisions to the previous work plan are addressed in Section 3.2, and the schedule for the upcoming fourth-year evaluation activities are presented in Section 3.3. This work plan update does not address the AB 1685 extension of the SGIP.

3.1 Overview of SGIP Measurement and Evaluation Plan

The initial work plan prepared for this program evaluation effort was derived and refined from a series of tasks that were defined by the SGIP Working Group. 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 Comparative Assessment (Utility vs. non-Utility)
- Prepare Annual Program Evaluation Reports
- Prepare Other Evaluation 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 program's First-Year Process Evaluation Report.

During 2002 changes to the Program affected a few key elements of the M&E work plan. Major Program modifications and clarifications include: 1) clarification of the eligibility of certain electric municipal customers that are also served by an eligible natural gas IOU; 2) allowance for Program 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 for eligible 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.

During 2003 there were several additional changes to the Program, to the regulatory guidelines governing evaluation of its impacts, and to the contractual arrangements enabling evaluation of its impacts. Major Program modifications and clarifications that took place include: 1) extension of the Program for three additional years, to January 1, 2008; 2) initiation of the process leading to revision and extension for two years of the co-funding agreement under which various program evaluation activities are completed; and 3) modification of the schedule for reporting third-year impacts of the program.

These various revisions and clarifications, and their overall impacts on the SGIP M&E plan, are discussed in further detail in Section 3.2 below.

Self-Generation Incentive Program Evaluation Criteria

The Self-Generation Incentive Program was developed to fulfill the requirements laid out in Attachment 1 of CPUC Decision 01-03-073 (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/Objectives" column in Table 3-1. With input from the Program Working Group, Itron developed criteria for assessing achievement of each goal. These criteria are listed in the second column, "Criteria for Meeting Goal", in Table 3-1. The ALJ Gottstein Ruling of April 24, 2002, approved these criteria as well as the schedule of M&E Reports for the Program through April 2005.

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

Goal/Rationale/Objective	CR #	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.

3.2 Revisions to 2001-2002 Evaluation Plan

During 2002 and 2003 there were a number of Program modifications and regulatory oversight clarifications formalized through a series of CPUC Decisions, Interim Orders, and

ALJ Rulings. 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 CPUC actions, three of the Program Administrators decided in March of 2003 to request proposals from the statewide evaluation contractor to provide electric Net Generator Output (E-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 E-NGO metering. These Program Administrators included Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and Southern California Gas Company (SCG). Purchase orders were subsequently executed with two of these Program Administrators, including PG&E and SCG. Recently, a purchase order was also executed with the third Administrator to complete E-NGO metering on certain Level 3 projects that are not affected by the departing load tariff. These E-NGO metering installations for certain Administrators are being performed outside of the Statewide Program Administrator evaluation contract – and implemented directly with the Program Administrator.

As a result of these actions, a two-year work plan addendum was developed that addresses the required and optional M&E tasks that are relevant to the currently-defined incentives program from Program Year (PY) 2003 up to the point of the PY 2004[1] Load Impact Evaluation. Additional work activities that have been incorporated into this work plan addendum include:

i) Procurement and installation of all thermal energy and biogas monitoring systems for sampled PY 2002, PY 2003 and PY 2004 participants, including natural gas meters where required,

ii) Removal of one-half of the thermal energy meters, natural gas meters and biogas monitoring systems upon completion of required M&E,

[1] "Program Year" refers to the period in which an applicant is accepted into the program. Some tasks are necessarily budgeted based upon the active applicants within a program year. For example, a PY 2002 applicant may not become operational or paid until 2003 or later and therefore will not be monitored until operational status is achieved. "Calendar Year" simply refers to a specific 12-month period.

iii) Development of program impacts reports for PY 2003 and PY 2004 operational periods,

iv) An optional process evaluation completed during 2004 if needed, and

v) The added renewable fuel use/cost monitoring and reporting per D. 02-09-051.

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 E-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 M&E 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 Program's Statewide Working Group 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. • Purpose: 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 • Purpose: 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. • Purpose: 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. • Purpose: 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. • Purpose: 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. • Purpose: 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 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 39 percent (144/372) 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. The sample rate for Level 1-R Fuel Use and Level 2 project thermal monitoring is projected to remain at 100 percent through PY 2004.

Table 3-3: Summary of Estimated M&E Thermal /Fuel Use Monitoring Requirements

	Level 1-R	Level 2	Level 3	Total No. Sites
Total Estimated No. Sites Monitored in PY 2001 - 2004	3	5	136	144
Total No. of Est. Active Applicants @ Year-End (PY 2001 – 2004)	3	5	364	372

In addition to the thermal monitoring and data collection discussed above, electric meters are placed on each monitored system to determine net generator kW output on a 15-minute interval basis. Natural gas meters are installed on monitored projects that use natural gas as their primary or secondary fuel source. Table 3-4 summarizes the estimated costs for the electric NGO metering components for each Program Year's applicants, without indicating which party may be responsible for them.

Customer applicants will pay for E-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 guidelines. Those E-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 category).

Table 3-4: Estimated Net Generator Output Metering Costs

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

* 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 total estimated E-NGO metering costs over the four years included within Table 3-4 is $1,919,995.

The scope of work in the initial RER proposal response 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 Program M&E estimated budgets including the original contract and the incremental work plan activity over the PY2003 through PY 2004 period, including each Program Administrator's estimated share of the M&E budget. In addition, expenditures to date are identified for the original work plan and contract through October 31, 2003.

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

Allocation Factors	48%	26%	13.6%	12.4%	100%	
	PG&E Share	**SCE Share**	**SoCalGas Share**	**SDREO Share**	**Total M&E Budget**	**Expenditures to Date (10/31/03)**
Original Contract	878,026	475,597	248,774	226,823	1,829,220	**1,789,600**
Incremental	1,534,394	831,131	434,745	396,385	3,196,655	--
Total Program	2,412,420	1,306,728	683,519	623,208	**5,025,875**	

3.3 Schedule for Fourth-Year Evaluation Tasks

The schedule for all SGIP program evaluation activities currently foreseen over the initial Program duration are summarized in Table 3-6. The Program's fourth-year evaluation reports include: 1) Outline for Fourth Year Program Impact Evaluation Report, 2) Onsite Monitoring Fuel-use Report No. 5, and 3) Fourth Year Program Impact Evaluation Report.

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

Annual & Fuel Use Program Evaluation Reports	Due Date	Compliance
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.*
Onsite Monitoring Fuel-use Report #4	*September 17, 2004*	*Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.*
Third Year Program Impact Evaluation Report	October 18, 2004	Assess energy production and system peak demand reduction impacts occurring during Program Year 2003
Program Cost-Effectiveness Framework	Fall 2004	Addresses (partial) requirement in ALJ Ruling for Energy Division to develop cost-effectiveness assessment of all Load Removal Programs
PY 2004 Targeted Process Evaluation Report	December 15, 2004	Assess specific Program implementation and evaluation issues at the Request of the SGIP Working Group
Outline for Fourth Year Program Impact Evaluation Report	December 15, 2004	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 & Peak Period of 2005??
Program Funding Ends for eligible Applications received by	**December 31, 2007**	

Note: The Evaluation Process 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 statewide for all applicants to the Self-Generation Incentive Program for Program Years 2001, 2002, and 2003 (PY2001, PY2002, and PY2003), based on Program Administrator tracking data available through December 31, 2003.

4.2 Project Status and Stage Classification

Applications to the SGIP were classified according to the calendar year in which the Reservation Request Form was received. For example, if a Reservation Request Form for a project was received in 2001, the project was considered to be a *PY2001* project. The numbers of requests for incentives funding statewide during each program year through the end of 2003 are summarized in Table 4-1. Clearly, there has been an upward trend over this period in the number of requests for Program incentive funds, with an increase in requests of about one-third from PY2002 to PY2003.

Table 4-1: Number of Requests for Funding

Program Year	No. of Requests for Funding
PY2001	261
PY2002	405
PY2003	543
Total	**1,209**

All projects are assigned to one of five Incentive Levels (1, 2, 3, 3-N, or 3-R). The 3-N and 3-R Incentive Levels first appeared in September 2002 when D.02-09-051 instituted different participation conditions for internal combustion engines, microturbines, & small gas turbines depending on fuel type. Additionally, all projects are classified into three general project status categories: active, complete, and inactive.

- ***Active Projects.*** Active projects refer to projects that were not withdrawn, rejected or suspended. Active projects are further classified into four 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 Letter (CRNL), 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 and a Reservation Confirmation and Incentive Claim Form has been issued.
  - **Suspended.** Suspended projects consist of those projects for which the application has been suspended due to project development delays.
  - **Wait List.** Wait-listed projects consist of those projects for which the Program Administrator has suspended further processing of the application pending future availability of funding. Eligible projects are placed upon a wait list for a Program Year once funding for the relevant incentive level has been exhausted for that Program Year.

- ***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 or rejected, 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 are further classified into the following categories according to the latest stage reached:[2]

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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 and PY2003, 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

- **RRF Received.** *Reservation Request Form* received from applicant (i.e., the application is under review).
- **CRN Sent.** *Conditional Reservation Notice* 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* sent to the applicant (i.e., the reservation has been confirmed).
- **OSV Complete.** An *on-site verification* of the system has been conducted.
- **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 4-2 presents the status of all projects from all program years active through December 2003. The majority of these projects were Level 1 projects. The 286 active Level 1 projects also represented the majority of potential installed capacity (48,474 kW) and total potential incentives ($190.5 million). Level 3-N projects represented the next largest share of total active applications, in terms of number of applications (158), total potential installed capacity (89,869 kW), and total potential incentives ($56.2 million). Level 3 projects also represented a substantial share of active projects, with 41 active applications representing 17,031 kW in potential installed capacity and $11.4 million in potential incentives. Additionally, there were a small number of Level 3-R projects active through December 2003, which represented 15 projects with 3,593 kW of potential installed capacity and $3.9 million in total potential incentives. There were only 3 active Level 2 projects through December 2003, which represented 1,800 kW of potential installed capacity and $4.5 million in potential incentives.

Table 4-3 presents the status of the 15 PY2001 projects active through December 2003. The majority of these were Level 3 projects. The 14 Level 3 projects represented 5,194 kW of (potential) installed capacity and $3.3 million in total potential incentives. The single Level 1 project still active through December 2003 represented 35 kW of potential installed capacity and $0.2 million of total potential incentives. There were no Level 2 projects active through December 2003. All PY2001 projects active through December 2003 had advanced beyond the conditional reservation stage.

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.

Table 4-4 presents the status of the 101 PY2002 projects active through December 2003. Level 1 projects (39) accounted for the majority of the total potential incentives reserved ($21.5 million), and accounted for 6,507 kW of potential installed capacity. Level 3-N projects (29) accounted for the majority of potential installed capacity (17,885 kW), and accounted for $10.7 million in potential incentives reserved. Level 3 projects (i.e., prior to determination of “3-N” and “3-R” in September 2002) (27) represented the next largest share of potential installed capacity (11,837 kW) and potential incentives reserved ($8.1 million). Additionally, there were 5 Level 3-R projects active through December 2003, which accounted for 745 kW of potential installed capacity and $0.7 million of potential incentives reserved. The single Level 2 project active through December 2003 represented 600 kW of potential installed capacity and $1.5 million of potential incentives reserved.

Table 4-5 presents the status of the 387 PY2003 projects active through December 2003. Incentive Level 1 projects (246) accounted for the majority of potential incentives reserved ($168.8 million) as well as the next largest share of potential installed capacity (41,933 kW). Level 3-N projects (129) represented the majority of potential installed capacity (71,984 kW) and next largest share of potential incentives reserved ($45.6 million). Additionally, there were 10 Level 3-R projects active through December 2003, which accounted for 2,848 kW of potential installed capacity and $3.1 million of potential incentives reserved. Finally, the two Level 2 projects active through December 2003 represented 1,200 kW of potential installed capacity and $3.0 million of potential incentives reserved.

Table 4-2: Summary of All Active Projects (All Program Years)

Incentive Level	All Active Projects through December 2003 (All Administrators, All Program Years)														
	Reservation Request Form Under Review			Conditional Reservation			Confirmed Reservation			Suspended			Total Active		
	Projects	kW	Incentives ($ 1,000)	Projects	kW	Incentives ($ 1,000)	Projects	kW	Incentives ($ 1,000)	Projects	kW	Incentives ($ 1,000)	Projects	kW	Incentives ($ 1,000)
Level 1	49	11,432	$ 47,014	137	24,289	$ 100,443	90	10,080	$ 34,859	10	2,674	$ 8,193	286	48,474	$ 190,509
Level 2	1	200	$ 500	1	1,000	$ 2,500	1	600	$ 1,500	0	0	$ -	3	1,800	$ 4,500
Level 3	0	0	$ -	0	0	$ -	41	17,031	$ 11,414	0	0	$ -	41	17,031	$ 11,414
Level 3-N	41	22,644	$ 15,528	47	22,559	$ 13,169	67	42,816	$ 26,064	3	1,850	$ 1,519	158	89,869	$ 56,280
Level 3-R	1	968	$ 983	5	1,000	$ 1,197	9	1,625	$ 1,687	0	0	$ -	15	3,593	$ 3,867
Total	**92**	**35,244**	**$ 64,025**	**190**	**48,848**	**$ 117,309**	**208**	**72,152**	**$ 75,524**	**13**	**4,524**	**$ 9,713**	**503**	**160,767**	**$ 266,570**

Note: Incentives are stated in units of thousands of dollars.

Table 4-3: Summary of Active PY2001 Projects[3]

Incentive Level	PY2001 Active Projects through December 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	1	35	$ 157,680	0	0	$ 0	1	35	$ 157,680
Level 2	0	0	$ 0	0	0	$ 0	0	0	$ 0	0	0	$ 0	0	0	$ 0
Level 3	0	0	$ 0	0	0	$ 0	14	5,194	$ 3,299,727	0	0	$ 0	14	5,194	$ 3,299,727
Total	**0**	**0**	**$ 0**	**0**	**0**	**$ 0**	**15**	**5,229**	**$ 3,457,407**	**0**	**0**	**$ 0**	**15**	**5,229**	**$ 3,457,407**

[3] As indicated previously, incentive Levels 3-N and 3-R did not exist in PY2001. In September 2002, Level 3 was bifurcated into Level 3-R and 3-N depending upon the types of fuels used. Projects which applied for funding prior to this date were classified as Level 3 projects regardless of the type of fuels used.

Table 4-4: Summary of Active PY2002 Projects

Incentive Level	PY2002 Active Projects through December 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	2	1,124	$ 4,594,649	37	5,383	$ 16,927,125	0	0	$ 0	39	6,507	$ 21,521,774
Level 2	0	0	$ 0	0	0	$ 0	1	600	$ 1,500,000	0	0	$ 0	1	600	$ 1,500,000
Level 3	0	0	$ 0	0	0	$ 0	27	11,837	$ 8,114,718	0	0	$ 0	27	11,837	$ 8,114,718
Level 3-N	0	0	$ 0	5	975	$ 796,191	24	16,910	$ 9,917,040	0	0	$ 0	29	17,885	$ 10,713,231
Level 3-R	0	0	$ 0	0	0	$ 0	5	745	$ 739,673	0	0	$ 0	5	745	$ 739,673
Total	**0**	**0**	**$ 0**	**7**	**2,099**	**$ 5,390,840**	**94**	**35,475**	**$ 37,198,557**	**0**	**0**	**$ 0**	**101**	**37,574**	**$ 42,589,397**

Table 4-5: Summary of Active PY2003 Projects

Incentive Level	PY2003 Active Projects through December 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	49	11,432	$ 47,014,111	135	23,165	$ 95,847,968	52	4,662	$ 17,774,290	10	2,674	$ 8,193,377	246	41,933	$ 168,829,746
Level 2	1	200	$ 500,000	1	1,000	$ 2,500,000	0	0	$ 0	0	0	$ -	2	1,200	$ 3,000,000
Level 3-N	41	22,644	$ 15,527,955	42	21,584	$ 12,373,071	43	25,906	$ 16,146,514	3	1,850	$ 1,519,138	129	71,984	$ 45,566,678
Level 3-R	1	968	$ 982,500	5	1,000	$ 1,197,394	4	880	$ 946,974	0	0	$ -	10	2,848	$ 3,126,868
Total	**92**	**35,244**	**$ 64,024,566**	**183**	**46,749**	**$ 111,918,433**	**99**	**31,448**	**$ 34,867,778**	**13**	**4,524**	**$ 9,712,515**	**387**	**117,965**	**$ 220,523,292**

In general, a one-year deadline is established for completion of installation of a project receiving funding under the Self-Generation Incentive Program. The one-year deadline is calculated based upon the date the Conditional Reservation Notice is issued. Thus, the original one-year deadlines for all PY2001 and PY2002 projects have passed and no PY2001 or PY2002 projects should still be active through December 2003, absent any extensions. However, program guidelines were modified in PY2002 to allow extensions up to 180 days past the one-year deadline in certain cases. Thus, some PY2001 and PY2002 projects remain active through December 2003.

System Capacity Characteristics by Technology and Incentive Level

Table 4-6 summarizes the system capacity characteristics of all active projects by incentive level, and Table 4-7 through Table 4-9 present system capacity characteristics of active projects by program year and incentive level. As shown, Level 1 PV systems generally display the lowest minimum system size of all technologies (24 kW), followed by Level 3 microturbines (28 kW) and Level 3-R microturbines (30 kW). Level 3 and Level 3N internal combustion engines displayed the largest maximum system sizes of all technologies, at 1.5 MW, the program limit. Level 1 PV systems and wind turbines, Level 2 fuel cells, and Level 3-N microturbines also displayed maximum sizes greater than or equal to 1 MW, the maximum system capacity from which rebates may be calculated for individual systems.

Table 4-6: Installed Capacities of All Active Projects (All Program Years)

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	281	160	24	75	1,008
	Wind Turbine	3	887	710	950	1,000
	Fuel Cell, Renewable Fuel	2	375	250	375	500
Level 2	Fuel Cell, Nonrenewable Fuel	3	600	200	600	1,000
Level 3	IC Engine	30	491	50	375	1,500
	Microturbine	11	211	28	120	600
Level 3-N	IC Engine, Nonrenewable Fuel	110	725	60	678	1,500
	Microturbine, Nonrenewable Fuel	48	211	60	120	1,400
Level 3-R	IC Engine, Renewable Fuel	5	429	95	300	968
	Microturbine, Renewable Fuel	10	145	30	80	300

Table 4-7: Installed Capacities of Active 2001 Projects

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	1	35	35	35	35
Level 2	Fuel Cell, Nonrenewable Fuel	0	N/A	N/A	N/A	N/A
Level 3	IC Engine	5	706	120	990	1,000
	Microturbine	9	185	28	120	600

Table 4-8: Installed Capacities of Active 2002 Projects

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	39	167	30	91	995
Level 2	Fuel Cell, Nonrenewable Fuel	1	600	600	600	600
Level 3	IC Engine	25	447	50	340	1,500
	Microturbine	2	326	180	326	472
Level 3-N	IC Engine, Nonrenewable Fuel	25	638	60	400	1,500
	Microturbine, Nonrenewable Fuel	4	485	60	240	1,400
Level 3-R	IC Engine, Renewable Fuel	1	95	95	95	95
	Microturbine, Renewable Fuel	4	163	70	140	300

Table 4-9: Installed Capacities of Active 2003 Projects

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	241	160	24	75	1,008
	Wind Turbine	3	887	710	950	1,000
	Fuel Cell, Renewable Fuel	2	375	250	375	500
Level 2	Fuel Cell, Nonrenewable Fuel	2	600	200	600	1,000
Level 3-N	IC Engine, Nonrenewable Fuel	85	751	60	750	1,500
	Microturbine, Nonrenewable Fuel	44	186	60	90	1,210
Level 3-R	IC Engine, Renewable Fuel	4	512	280	400	968
	Microturbine, Renewable Fuel	6	133	30	80	300

4.4 Summary of Completed Projects

Table 4-10 presents the status of the 184 projects completed and paid through December 2003. The majority of the projects completed between PY2001 and PY2003 were Level 1 projects. The 117 completed Level 1 projects also represented the largest share of installed incentive dollars awarded ($45.9 million), but only represented the second largest share of system capacity (15,220 kW). Level 3 projects represented the second largest share of completed projects in terms of number of systems (56) and incentive dollars awarded ($15.7 million), but represented the largest share of installed system capacity (26,793 kW). The 9 completed Level 3-N projects accounted for a lesser share of installed system capacity (2,676 kW) and incentive dollars awarded ($1.4 million). The single Level 3-R project completed accounted for 420 kW of installed system capacity, and $0.5 million of incentives, and the single Level 2 project completed accounted for 200 kW of installed system capacity and $0.5 million of incentives.

Table 4-11 presents the status of the 56 PY2001 projects completed and paid through December 2003. The majority of the PY2001 projects completed represented Level 3 technologies. Thirty-five Level 3 projects were completed, which represented $8.2 million of incentives and 13,724 kW of installed system capacity. Due to the differing incentive levels, fewer Level 1 projects were completed (20), while Level 1 applications accounted for the majority of the incentive dollars awarded. Level 1 projects constituted $11.8 million in funding and 3,872 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 4-12 presents the status of the 112 PY2002 projects completed and paid through December 2003. The majority of the PY2002 projects completed were Level 1 technologies. Eighty-two Level 1 projects were completed, which represented 10,278 kW of installed system capacity and $30.0 million in incentives. Twenty-one Level 3 projects were also completed, which represented 13,519 kW of installed capacity and $7.4 million in paid program incentives. Additionally, eight Level 3-N projects were completed, which represented 2,556 kW of installed capacity and $1.2 million in incentives. There were no completed Level 2 projects. The single Level 3-R project that was completed represented 420 kW of installed capacity and $0.5 million of paid program incentives.

Table 4-13 presents the status of all completed PY2003 projects through December 2003. As shown, nearly all of the PY2003 projects completed and paid through December 2003 represented Level 1 technologies. Fifteen Level 1 projects were completed, which represented 1,070 kW of installed capacity and $4.2 million of paid program incentives. The single Level 3-N project that was completed represented 120 kW of installed capacity and $0.1 million in incentives. No Level 2 or Level 3-R projects were completed and paid through December 2003.

Table 4-10: Status of All Completed Projects (All Program Years)

Incentive Level	All Completed Projects through December 2003 (All Administrators, All Program Years)		
	Projects	kW	Incentives ($)
Level 1	117	15,220	$ 45,944,156
Level 2	1	200	$ 500,000
Level 3	56	26,793	$ 15,652,304
Level 3-N	9	2,676	$ 1,356,789
Level 3-R	1	420	$ 485,013
Total	**184**	**45,309**	**$ 63,938,262**

Table 4-11: Status of All Completed PY2001 Projects

Incentive Level	2001 Completed Projects through December 2003 (All Administrators)		
	Projects	kW	Incentives ($)
Level 1	20	3,872	$ 11,763,062
Level 2	1	200	$ 500,000
Level 3	35	13,274	$ 8,248,825
Total	**56**	**17,346**	**$ 20,511,887**

Table 4-12: Status of All Completed PY2002 Projects

Incentive Level	2002 Completed Projects through December 2003 (All Administrators)		
	Projects	kW	Incentives ($)
Level 1	82	10,278	$ 29,967,531
Level 2	0	0	$ 0
Level 3	21	13,519	$ 7,403,479
Level 3-N	8	2,556	$ 1,236,789
Level 3-R	1	420	$ 485,013
Total	**112**	**26,773**	**$ 39,092,811**

Table 4-13: Status of All Completed PY2003 Projects

Incentive Level	PY2003 Completed Projects through December 2003 (All Administrators)		
	Projects	kW	Incentives ($)
Level 1	15	1,070	$ 4,213,563
Level 2	0	0	$ -
Level 3-N	1	120	$ 120,000
Level 3-R	0	0	$ -
Total	**16**	**1,190**	**$ 4,333,563**

System Capacity Characteristics by Technology and Incentive Level

Table 4-14 summarizes the system capacity characteristics of all completed projects by incentive level. As shown, Level 3 internal combustion engines possessed the largest mean system size of all completed projects by technology (676 kW). The single microturbine using renewable fuel displayed the next largest system size of all completed projects (420 kW). Level 3-N internal combustion engines displayed the next largest mean system size of all completed projects (366 kW), followed by the single fuel cell using nonrenewable fuel (200 kW), Level 3-N microturbines (160 kW), Level 1 photovoltaics (130 kW), and Level 3 microturbines (94 kW). There were no completed Level 3-R internal combustion engine projects.

Table 4-15 summarizes the system capacity characteristics of completed PY2001 projects by incentive level and technology. As shown in Table 4-15, Level 3 internal combustion engines possessed the largest mean system size of all completed PY2001 projects (528 kW). The single Level 2 fuel cell project using nonrenewable fuel displayed the next largest system size of all completed projects, at 200 kW, followed by Level 1 photovoltaics (194 kW) and Level 3 microturbines (94 kW).

Table 4-16 summarizes system capacity characteristics of completed PY2002 projects by incentive level and technology. As shown in Table 4-16, Level 3 internal combustion engines possessed the largest mean system size of all completed PY2002 projects (919 kW), followed by Level 3R microturbines (420 kW), Level 3N internal combustion engines (366 kW), Level 3N microturbines (180 kW), Level 1 photovoltaics (125 kW), and Level 3 microturbines (94 kW).

Table 4-17 summarizes system capacity characteristics of the relatively few completed PY2003 projects by incentive level and technology. As shown in Table 4-17, the single Level 3-N microturbine completed displayed a larger installed system capacity (120 kW) than the mean system capacity of the initial 15 completed photovoltaics projects (71 kW).

Table 4-14: Installed Capacities of All Completed Projects (All Program Years)

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	117	130	30	73	1,100
Level 2	Fuel Cell, Nonrenewable Fuel	1	200	200	200	200
Level 3	IC Engine	37	676	60	600	1,495
	Microturbine	19	94	28	90	240
Level 3-N	IC Engine, Nonrenewable Fuel	6	366	60	200	1336
	Microturbine, Nonrenewable Fuel	3	160	120	120	240
Level 3-R	IC Engine, Renewable Fuel	0	0	0	0	0
	Microturbine, Renewable Fuel	1	420	420	420	420

Table 4-15: Installed Capacities of Completed PY2001 Projects

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	20	194	30	81	1,008
Level 2	Fuel Cell, Nonrenewable Fuel	1	200	200	200	200
Level 3	IC Engine	23	528	150	400	1,015
	Microturbine	12	94	28	75	240

Table 4-16: Installed Capacities of Completed PY2002 Projects

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	82	125	30	69	1,100
Level 2	Fuel Cell, Nonrenewable Fuel	0	0	0	0	0
Level 3	IC Engine	14	919	60	1,000	1,495
	Microturbine	7	94	60	100	140
Level 3-N	IC Engine, Nonrenewable Fuel	6	366	60	200	1,336
	Microturbine, Nonrenewable Fuel	2	180	120	180	240
Level 3-R	IC Engine, Renewable Fuel	0	0	0	0	0
	Microturbine, Renewable Fuel	1	420	420	420	420

Table 4-17: Installed Capacities of Completed PY2003 Projects

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	15	71	30	65	203
Level 2	Fuel Cell, Nonrenewable Fuel	0	0	0	0	0
Level 3-N	IC Engine, Nonrenewable Fuel	0	0	0	0	0
	Microturbine, Nonrenewable Fuel	1	120	120	120	120
Level 3-R	IC Engine, Renewable Fuel	0	0	0	0	0
	Microturbine, Renewable Fuel	0	0	0	0	0

4.5 Summary of Inactive Projects

Table 4-18 presents the status of the 301 projects inactive through December 2003. As shown, Level 1 projects constituted the largest share of inactive projects in terms of number of inactive projects (280), but constituted only the second largest share of inactive projects in terms of total potential installed capacity (56,198 kW). Level 3 projects accounted for the second largest share in terms of number of inactive projects (177), but constituted the largest share of inactive projects in terms of total potential installed capacity (85,237 kW). The 53 inactive Level 3-N projects represented 23,009 kW of total potential installed capacity, and the 6 inactive Level 2 projects represented 2,450 kW of total potential installed capacity. Finally, the 4 inactive Level 3-R projects also represented 2,450 kW of total potential installed capacity.

Table 4-19 presents the status of the 188 PY2001 projects inactive through December 2003. As shown, Level 3 projects constituted the majority of inactive projects, both in terms of the number of inactive projects (118) and total potential installed capacity (57,128 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 five inactive Level 2 projects, which represented 1,450 kW of potential installed capacity.

Table 4-20 presents the status of the 192 PY2002 projects inactive through December 2003. As shown in Table 4-20, Level 3 projects accounted for the majority of inactive projects in terms of potential installed capacity (28,109 kW), though the number of Level 3 inactive projects (59) was less than the number of inactive Level 1 projects (106). Level 1 inactive projects accounted for 19,969 kW of potential installed capacity. Level 3-N projects accounted for the next largest share of inactive projects in terms of both number of projects (25) and potential installed capacity (11,399 kW), followed by Level 3-R projects. The two inactive Level 3-R projects accounted for only 420 kW of potential installed capacity. There were no inactive Level 2 projects through December 2003.

Table 4-21 presents the status of the 140 PY2003 projects inactive through December 2003. As shown in Table 4-21, Level 1 projects accounted for the majority of inactive projects both in terms of number of projects (109) and potential installed capacity (19,729 kW). Level 3-N projects accounted for the next largest share of inactive projects, both in terms of number of projects (28) and potential installed capacity (11,610 kW), followed by Level 3-R and Level 2 projects. The two inactive Level 3-R projects accounted for 2,030 kW of potential installed capacity, and the single inactive Level 2 project accounted for 1,000 kW of potential installed capacity.

As noted by the total inactive system capacity, there has been a downward trend of inactive system capacity from PY2001 through PY2003, and this trend is dominated by the Level 3 projects. Although the number of inactive projects has increased, inactive Level 1 photovoltaic project capacity has remained essentially constant over this period.

It should also be noted that the proportion of withdrawn or rejected projects should not be considered a precise indicator of Program activity, since a number of projects that are withdrawn or rejected later reapply to the Program and subsequently progress successfully toward completion.

Table 4-18: Status of All Inactive Projects (All Program Years)

Incentive Level	All Inactive Projects through December 2003 (All Administrators, All Program Years)					
	Withdrawn		Rejected		Total Inactive	
	Projects	kW	Projects	kW	Projects	kW
Level 1	163	34,580	117	21,618	280	56,198
Level 2	3	1,000	3	1,450	6	2,450
Level 3	102	47,130	75	38,107	177	85,237
Level 3-N	30	14,152	23	8,857	53	23,009
Level 3-R	3	1,420	1	1,030	4	2,450
Total	**301**	**98,282**	**219**	**71,062**	**520**	**169,344**

Table 4-19: Status of All Inactive PY2001 Projects

Incentive Level	PY2001 Inactive Projects through December 2003 (All Administrators)					
	Withdrawn		Rejected		Total Inactive	
	Projects	kW	Projects	kW	Projects	kW
Level 1	32	9,120	33	7,680	65	16,800
Level 2	3	1,000	2	450	5	1,450
Level 3	57	26,396	61	30,732	118	57,128
Total	**92**	**36,516**	**96**	**38,862**	**188**	**75,378**

Table 4-20: Status of All Inactive PY2002 Projects

Incentive Level	PY2002 Inactive Projects through December 2003 (All Administrators)					
	Withdrawn		Rejected		Total Inactive	
	Projects	kW	Projects	kW	Projects	kW
Level 1	79	13,502	27	6,167	106	19,669
Level 2	0	0	0	0	0	0
Level 3	45	20,734	14	7,375	59	28,109
Level 3N	13	6,542	12	4,857	25	11,399
Level 3R	2	420	0	0	2	420
Total	**139**	**41,198**	**53**	**18,399**	**192**	**59,597**

Table 4-21: Status of All Inactive PY2003 Projects

Incentive Level	PY2003 Inactive Projects through December 2003 (All Administrators)					
	Withdrawn		Rejected		Total Inactive	
	Projects	kW	Projects	kW	Projects	kW
Level 1	52	11,958	57	7,771	109	19,729
Level 2	0	0	1	1,000	1	1,000
Level 3N	17	7,610	11	4,000	28	11,610
Level 3R	1	1,000	1	1,030	2	2,030
Total	**70**	**20,568**	**70**	**13,801**	**140**	**34,369**

5

Program Impact Evaluation Sample Design

5.1 Introduction

This section addresses sample design issues related to collection of metered data from distributed generation systems receiving incentives from the Self-Generation Incentive Program (SGIP). Sample design is an important element of program evaluation. Evaluation resources are limited and therefore good program evaluation practice requires optimization of expenditure of those limited resources to the extent possible. To achieve this goal, the questions to be answered by the program evaluation are identified and prioritized, and resources are allocated to maximize program evaluation efforts. First, some background information on the sampling approach is presented. Next, sample design strategies for PV and Cogeneration systems are discussed. Actual data collection outcomes are detailed later in this report within Section 8, System Monitoring and Operational Data Collection.

5.2 Background

Several key ideas underlying sample design are summarized above in the Introduction. Put very simply, that summary is akin to the old adage advising against use of a sledgehammer to drive a nail for a picture frame. In the context of system performance metering the adage becomes: 'Don't meter 100% of systems if metering 70% of systems yields data capable of adequately answering the questions targeted by the program evaluation effort'. This conclusion is tempered by the fact that oftentimes there are reasons for requiring accurate impact estimates at the site-specific level. Metering for revenue and billing purposes is a good example. While it would be theoretically possible for a utility company to meter only a sample of customers and collect similar revenues as would be yielded by metering all customers, this approach would create equity problems among the un-metered customers.

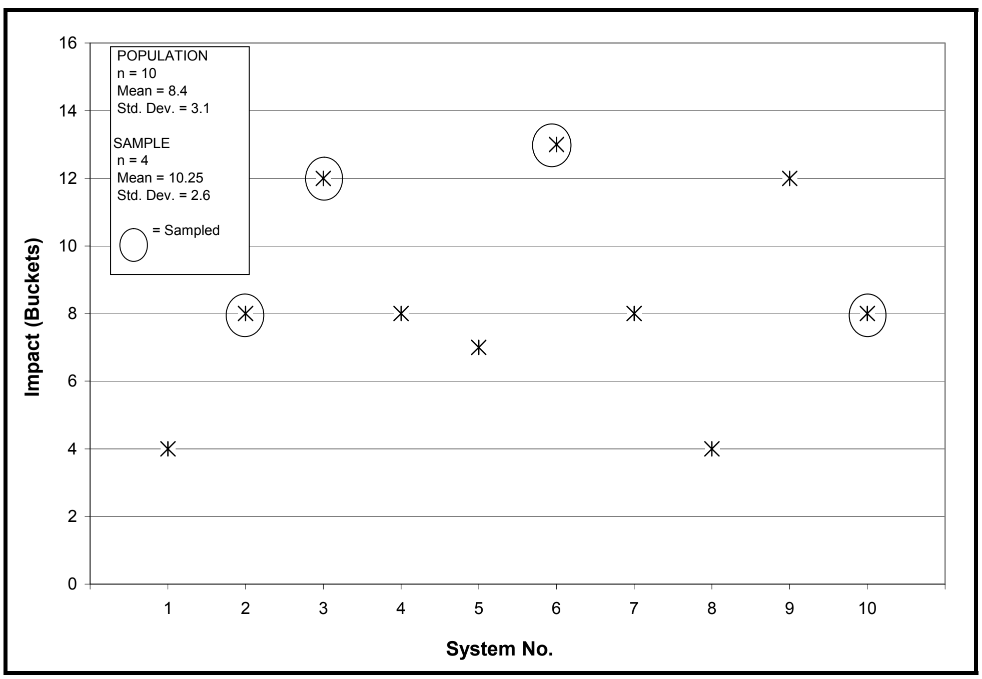
Sample design includes, but is not limited to, selection of physical parameters (e.g., net generator electric output) to be metered. It is also necessary to quantify the effects of sampling on accuracy, select an impacts measurement to serve as the basis for the accuracy assessment, and to define sampling strata. Each of these areas is described below.

Influence of Sampling on Accuracy

Metering sample design is inextricably linked with program impacts evaluation accuracy. Intuitively it is obvious that, all else equal, lower monitoring rates will correspond to higher levels of uncertainty. What may not be intuitively clear is how these tradeoffs are treated quantitatively in metering sample designs. A simple illustrative example is presented below to frame the SGIP-specific material that follows.

In the following discussion, the graphic of Figure 5-1 is used to illustrate several important aspects of sample design[1]. As shown, this example is based on a population of 10 systems with a sample size of 4. First, the sample mean is used to estimate impacts for unsampled systems. Here the sample mean is 10.25 whereas the true population mean is 8.4. If the sample mean were used to estimate the mean for unsampled systems then the resulting estimate of total impacts for the 10 systems would be 102.5 Buckets, whereas the true total is just 84 Buckets. Second, it is customary to express the variance between the estimated total and the true total as a percentage of the true total, and to establish a maximum variance that represents the line between "accurate enough" and "not accurate enough". In this case the variance between the final impact estimate and the true impact is 22%; if the maximum acceptable variance were 10%, then this level of error would be deemed unacceptable. This measure of variance is referred to as precision.

Figure 5-1: Illustrative Sampling Example



[1] For this illustrative example, impacts are expressed in hypothetical units of 'Buckets'.

Finally, the 4-system sample illustrated in Figure 5-1 represents just one of thousands of possible 4-system samples, each of which correspond to a certain level of error between the estimated total and the true total. Assuming random selection without replacement, for large numbers of samples the variance would be less than or equal to 10% for 51% of the samples. For a population of this size exhibiting this variability, one could be 51% confident that a sample size of 4 would yield an estimate of total impacts that was within +/- 10% of the actual total impact of the 10 systems. To increase the confidence level to 90%, the sample size would need to be increased from 4 systems to 8 systems. This illustrative example leads to an important point: If sampling is utilized, the resulting estimate of total impact is of limited usefulness -- if the corresponding levels of precision and confidence are not specified.

Impact Measure of Interest

The illustrative example above expressed impacts in hypothetical units of "Buckets". For the evaluation of electric impacts of the Self-Generation Incentive Program, it is necessary to select a basis upon which to assess accuracy. Several possibilities are listed below:

- AC Power output when CAISO electric system load reaches annual maximum value
- AC Energy production during summertime "on peak" periods as defined in utility tariffs
- AC Energy production for months, seasons, or years

Selection of the impacts measure of interest has implications for sample sizes required to achieve particular levels of accuracy. For example, PV systems with different tilts and azimuths might exhibit substantial variability during single hours, but yield similar quantities of energy over the course of longer periods of time. If a single hour is selected as the impacts measure of interest for purposes of sample design then a larger sample would be required, all else equal.

Sampling Strata

Tradeoffs between metering rates and impact estimate uncertainty levels were discussed previously. Tradeoffs are also encountered when considering definition of subsets (i.e., strata) of the population for purposes of quantifying variability and uncertainty. Such subsets of projects with similar characteristics may be defined either to ensure that impact estimates for particular groups (e.g., individual Program Administrators) achieve accuracy objectives, or to decrease the variability exhibited by data within particular strata.

Stratification for purposes of decreasing intra-strata variability is used to enable achievement of specified population-level accuracy targets with the smallest possible total number of metered sites. For example, if 10 PV systems face west and 10 PV systems face east then at

4 PM the average output of the west-facing PV systems will be substantially greater than that of the east-facing systems. Under these circumstances, the total number of metered sites required to achieve specified population-level (i.e., total impact of east- and west-facing systems) accuracy targets can be minimized by sampling from the two strata separately.

It is important to note that stratification does not *always* reduce overall metering requirements. If the data values in two strata are quite similar then treating them separately will actually *increase* the total number of required metered sites. Sample design thus involves examination of possible stratifying characteristics, and comparison of the net effect of stratifying on overall metering rates required to achieve program impact evaluation objectives.

5.3 Level 1 Solar PV Systems

Initial plans calling for collection of interval-metered electric net generator output (E-NGO) data from all Level 1 PV systems in the Self-Generation Incentive Program were described in the Second Year Impacts Evaluation Report. Since that report was produced, several factors led to the decision to revisit these plans. First and most importantly, the number of PV systems in the program increased substantially. There were approximately 17 times as many PY2003 PV systems as there were PY2001 PV systems. Second, metered data are now available for more systems, and the ability to obtain E-NGO data from Hosts, Applicants, and other third parties is better understood. As a result of these factors, the possibility of sampling PV systems was revisited. The results of that assessment are summarized below.

Impacts Measure of Interest

As noted above, PV metering sample design analysis can be based on a variety of different measures of program impacts. In this analysis, PV AC power output during hours when CAISO loads reached maximum values was selected as the basis for sample design analysis. This basis was selected because a principal objective of the Self-Generation Incentive Program is to deliver generation capacity benefits during system peaking conditions. Furthermore, this treatment is expected to provide a more conservative result than would a sample design analysis based on totalized electric energy production for either seasons or years. This is because output for isolated hours can be greatly affected by a single thunderstorm, a short-term inverter problem, or shade from particular obstructions; the influence of these types of factors will tend to average out over longer periods of time.

Sampling Strata

Electric output of different PV systems during peaking events varies due to numerous factors including: system size, regional weather or climate, PV module orientation, PV system design, and PV module material type. Stratification of the universe of SGIP PV systems could be based on any of these parameters, or numerous others. Discussion with the SGIP Working Group led to an agreement that all of the Program Administrators would continue to ensure that E-NGO data are available for all PV systems sized 300 kW and larger.

This agreement was not driven strictly by program evaluation accuracy considerations. Rather, PV systems of this size represent very large capital investments and the Program Administrators are concerned about the performance of each of the large individual systems. Not surprisingly, all systems of this size encountered to date have been found to already have been equipped with metering equipment by the PV system vendor or owner.

With the large systems removed from consideration for sampling, attention turns to the systems that are <300 kW. The sample design continues to include metering of all PV systems that entered the program in PY2001 or PY2002, regardless of size. The purpose of metering all of these systems is to explore the possibility that performance differences exist between those PV systems already equipped with interval-metering equipment by the PV system supplier and those PV systems that would otherwise include little or no provision for performance monitoring.

Further examination of stratification possibilities is thus limited to PY2003 and PY2004 PV systems that are <300 kW. For these systems, several key stratifying parameters were used in the assessment of sampling on accuracy of impact estimates. These parameters are presented in Table 5-1 and Figure 5-2.

Table 5-1: Stratifying Parameters for PY03 - PY04 PV Systems <300 kW

Parameter	Strata
Program Administrator	PG&E, SCE, SoCalGas, SDREO
PV Orientation	Near-Flat: Module tilts less than 20º (any azimuth) Other: All other tilts (incl. tracking systems)
Location	Coastal: Zones 1 through 7 in Figure 5-2 Inland: Zones 8 through 16 in Figure 5-2

Influence of Sampling on Accuracy

Each of the Program Administrators is in a somewhat different position where collection of E-NGO data from PV systems is concerned. These different positions influence the approaches taken to assess affects of sampling on accuracy of program impact estimates. The PV E-NGO data collection situation for each of the Program Administrators is summarized in Table 5-2.

Figure 5-2: Coastal versus Inland Assignment Map for PV Systems

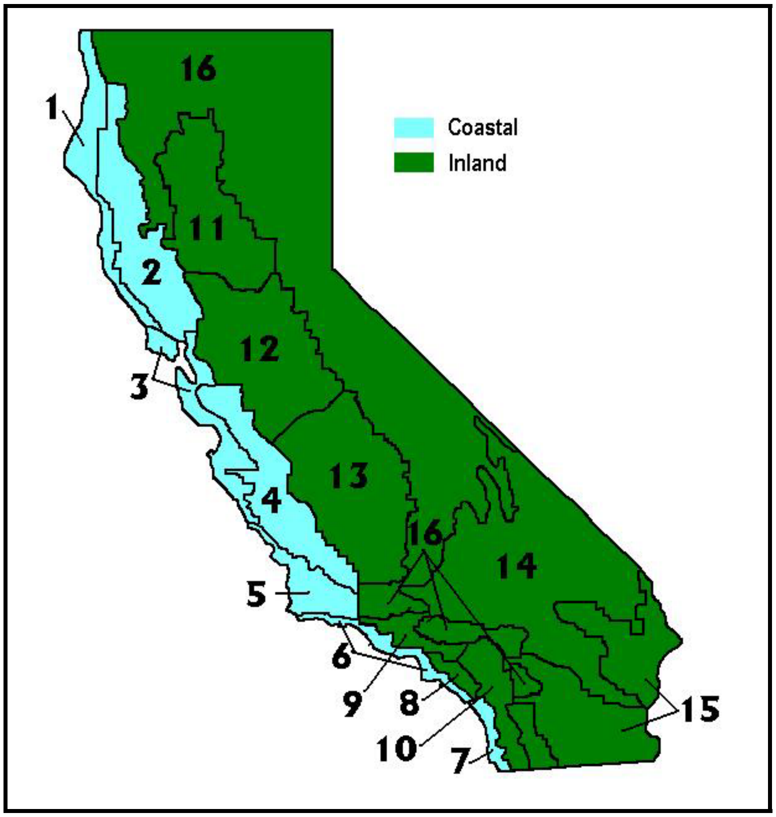


Table 5-2: Sources of E-NGO Data for PY03 - PY04 PV Systems <300 kW

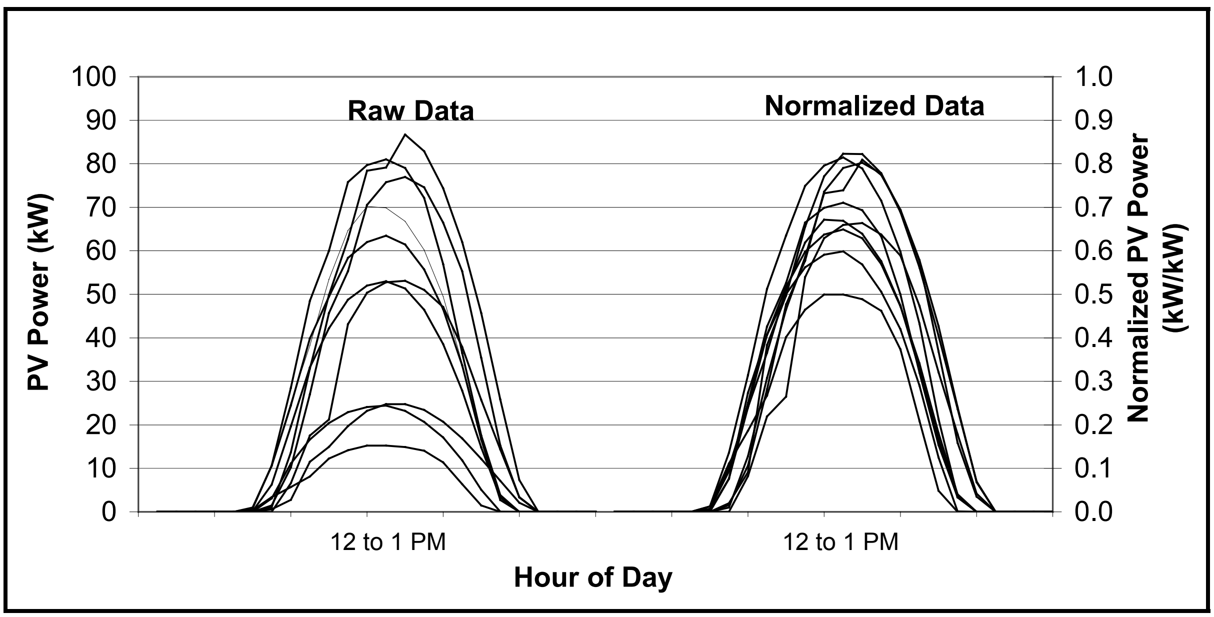
Program Administrator	Sources of PV E-NGO Data	Approximate Data Coverage (%)
PG&E	Hosts, Applicants, & Vendors. PG&E's metering shop is *not* installing electric metering on any PV systems. (PG&E's PV metering subcontractor (Itron) for PY01-PY02 projects has no current plans to install PV E-NGO metering on PY03-PY04 projects.)	≥40%
SCE	SCE's PV metering subcontractor is available to install electric metering for any PV SGIP projects for which SCE is the administrator. The program evaluation contractor will provide SCE with lists of projects recommended for metering.	TBD by Program Evaluation Contractor
SoCalGas	Hosts, Applicants, Vendors, LADWP. Many of the PV system projects for which SoCalGas is the administrator have their output metered by LADWP.	~90%
SDREO	SDG&E's metering shop is installing electric metering for <u>all</u> SGIP projects in its service area. All of SDREO's SGIP projects are in SDG&E's service area.	100%

The summary of E-NGO data collection situations for PY03-PY04 PV systems <300kW suggests several key points. First, data will be available for all of SDREO's PV systems, so the question of affect of sampling on estimates of SDREO impacts is moot. Second, if data available for PG&E projects from existing sources (e.g., Hosts, Applicants, Vendors) are sufficient to yield satisfactory impact estimate accuracy, then the data available for SoCalGas projects from existing sources will be sufficient. Therefore, the influence on accuracy of a 40% sampling rate for PG&E projects was first assessed. These results were used to draw conclusions for SoCalGas projects. Finally, implications of these results for recommendations for metering of SCE PV projects are discussed.

In the example of Section 5.2, variability within the population of values was seen to govern the influence of sampling on accuracy of impact estimates. In the case of PV systems a large portion of the variability is attributable to different system sizes. This is a parameter that is known from Program Administrators' program tracking systems, and that can be accounted for through normalization prior to quantitative assessment of sampling effects. In this instance normalization merely means dividing observed values by system size.

The extent to which system size explains variability is summarized in Figure 5-3, which compares power output data for 10 systems both before and after normalizing. In the case of PV, not only are the raw data collected from metered systems used in the analysis, system size data are also used. Details of the approach used to apply metered data to un-metered sites are explained in detail in Section 9. Due to the details of that analytic approach, the normalized data are used in the assessment of sampling effects.

Figure 5-3: Illustration of Normalization Effects



Metered data available for the hour from 3 to 4 PM (PDT) on August 25, 2003, were used in the sample design analysis. As seen in the demand impacts results presented in Section 9, this was the August 2003 hour when CAISO electric system loads reached their monthly maximum. These August data were used instead of July data because substantially more PV systems were being monitored in August as compared to July. Results of the analysis for PG&E are presented in Table 5-3. A total of 156 PY03-PY04 PV projects <300 kW are currently expected to be completed. Available information suggests that data from existing sources will be available for *at least* 62 of these projects, and that this level of data availability will be adequate for program evaluation purposes.

Table 5-3: PV Sampling Summary – PG&E – <300 kW

Location / Configuration	PY03 Actual Total (n)	PY04 Est. Total (n)	PY03-PY04 Est. Total (n)	PY03-PY04 Existing Sources (n)	PY03-PY04 Required for 90/10 Accuracy (n)
Coast / Near-Flat	23	30	53	21	17
Coast / Other	12	15	27	11	13
Inland / Near-Flat	30	20	50	20	17
Inland / Other	15	11	26	10	13
Total	**80**	**76**	**156**	**62**	**60**

It is important to note that principal interest is focused on estimating accurate impacts for all PV for each PA. Further breakdowns by size, location, and configuration will provide useful information about operational characteristics, however this is not the principal focus of the program evaluation. To put sampling effects in perspective for SGIP projects administered by PG&E the installed capacity of sampled and unsampled PV of all sizes for PY2001-PY2004 are presented together in Table 5-4. Existing sources of data yield reasonably accurate estimates for the individual strata as defined above. Furthermore, what uncertainty there is in the sampled group is small in comparison to overall program activity.

Table 5-4: PG&E PV – Estimated Installed Capacity Summary (PY01-PY04)

Location / Configuration	Unsampled (kW)	Sampled (kW)	Total (kW)
Coast / Near-Flat	9,011	5,353	14,364
Coast / Other	2,545	1,512	4,057
Inland / Near-Flat	9,273	5,508	14,782
Inland / Other	4,367	2,594	6,961
Total	**25,197**	**14,967**	**40,164**

A similar analysis was carried out for SoCalGas PV systems. Because the availability of data from existing sources is substantially higher for SoCalGas PV systems than it is for PG&E,

the conclusion was identical. Namely, data from existing sources are sufficient for purposes of evaluating impacts attributable to PY2003-PY2004 PV systems that are <300 kW and that are administered by SoCalGas. A similar analysis will be completed for SCE PV projects and a list of projects recommended for metering will be developed for the use of SCE and its metering installation contractor. It is expected that this list will include at least 40% of the PY03-PY04 PV projects <300 kW.

5.4 Incentive Level 3 & 3-N Cogeneration Systems

Program evaluation plans continue to include collection of electric net generator output data from all non-PV systems. Whereas sampling of electric metering was the issue for PV, sample design for cogeneration systems differs because in addition to electric production, fuel input and recovery of heat subsequently applied to useful purposes are also of interest. Due to the planned census for E-NGO metering, this sample design assessment for Level 3 and 3-N cogeneration systems is limited to examination of possibilities for fuel and heat metering sampling.

Impact Measure of Interest

Electric impacts considerations for cogeneration systems are identical in kind as those discussed above for PV systems. The principal impact measures of interest that are unique to cogeneration systems include heat recovery rates and several measures of efficiency. These impacts measures are identified and described below in Table 5-5. All four performance measures are very important. Sample designs for cogeneration systems should yield meaningful results for all four system impacts measures.

Table 5-5: Cogeneration System Impacts Measures

Impacts Measure	Importance
PUC 218.5 System Efficiency	Prior to construction, each cogeneration system in the program is required to demonstrate with engineering calculations that system's ability to achieve minimum system efficiencies prescribed by the PUC. This measure is important because it represents a significant program eligibility benchmark.
Overall System Efficiency	In the distributed generation literature it is customary to reference overall system efficiencies achievable when both electricity and useful thermal energy are produced by the system. This measure is important because it represents a significant performance benchmark that can be used to compare cogeneration system performance against the performance of alternative technologies.
Electrical Conversion Efficiency	Electrical conversion efficiency is a particularly important element of the PUC 218.5(b) system efficiency, because in that equation electrical energy is credited at a rate of 100% whereas heat is credited at the lesser rate of 50%. Electrical conversion efficiency is also important because it represents a significant component efficiency that can be used to compare actual performance against expected performance.
Heat Recovery Rate	Expressed in terms of kBtu/kWh, this measure of system performance is particularly important because it is likely to vary across application types (e.g., space heating versus absorption chiller for process cooling), and relatively little field data are currently available.

Each of the impact measures from Table 5-5 could be evaluated either for individual systems or for groups of systems. For groups of systems, the impact measure would represent an average, whereas a site-specific analysis would examine proportions of systems. Representative examples of each type of approach are presented in Table 5-6. While both approaches yield useful information, this sample design analysis focuses on groups of projects because while this program evaluation effort includes development of information regarding operating characteristics, the primary focus is on estimation of impacts at the program level. The average impact measure is well suited for this purpose. It is important to note that this does not preclude development of site-specific operational characteristics information. In fact site-specific operational characteristics are presented and discussed in Section 9 of this report, Impacts and Operating Characteristics.

Table 5-6: Examples of Possible Grouping Bases

Calculation Basis	Statistic	Example
Groups	Mean	Weighted average PUC218.5(b) efficiency actually achieved by operating cogeneration systems.
Individuals	Proportion	Proportion of projects actually achieving PUC218.5(b) efficiencies of at least 42.5%.

Sampling Strata

Specification of sampling strata is dictated in part by factors governing variability. These factors are different for the several key impact measures of interest. Factors influencing variability exhibited by electrical conversion efficiency and heat recovery rate are discussed below. These two impact measures are combined to yield the other system efficiency impact measures.

Electrical Conversion Efficiency. The most important stratifying variable is technology type (i.e., microturbine (MT), internal combustion engine (ICE)). These technologies use fundamentally different power cycles to convert the energy stored in fuel into shaft power that is subsequently transformed into electrical energy. Actual site-specific efficiencies vary according to engine size, percent load, exhaust back pressure, tuning, manufacturer, and other factors. For discussion purposes representative electrical conversion efficiencies can be estimated for microturbines and internal combustion engines. Summary information of this type is presented in Table 5-7.

Table 5-7: Representative Nominal Gross Electrical Conversion Efficiencies

Combustion Technology	Representative Efficiency (%, LHV[2])
Microturbine	28%
Internal Combustion Engine	34%

Source: U.S. EPA, 2002

For the purposes of this project's sample design, technology type was selected as the sole stratifying variable for electrical conversion efficiency.

[2] 'LHV' refers to Lower Heating Value of input fuel. LHV excludes the heat that could be recovered from flue gas if water vapor were condensed out of it. This is a meaningful measure of fuel energy content for manufacturers of equipment designed for non-condensing applications. Utility companies typically express fuel energy content in terms of Higher Heating Value (HHV), which includes the heat that could be recovered from combustion products if water vapor were condensed out of it. As a rule of thumb, LHV is approximately 90% of HHV.

Heat Recovery Rate. Numerous factors could conceivably be used to stratify cogeneration systems for purposes of monitoring useful thermal energy recovery. Several possibilities are listed below.

- End use for heat (space/process heat, space/process cooling)
- Operating schedule (year round, summer only, non-summer only)
- Size of cogeneration system relative to size of facility electrical and heat loads
- Design of heat recovery system (hardware and software)
- Operating effectiveness of heat recovery system (hardware and software)

For this program impacts evaluation project, *no stratification* of cogeneration systems is being performed for purposes of monitoring useful thermal energy recovery. First, there are a large number of potentially significant stratifying factors relative to the total number of available cogeneration systems. Second, the quantity of heat recovery data collected to date is relatively small, and those existing data suggest that recovery of useful heat is quite variable. Therefore, projects will be selected for metering based solely on their operational status. The objective will be to install heat-metering equipment as soon as possible after they become operational, subject to constraints imposed by the program evaluation's overall schedule and budget.

Influence of Sampling on Accuracy

As described above for the assessment of PV sample design, these projects' available metered data are the principal source of information about the actual characteristics (especially variability) of the cogeneration system impact measures of interest. The variability observed to date for the principal factors governing PUC 218.5 (b) efficiency results is summarized in

.

Table 5-8: Summary of Variability Observed in Available Metered Data

PUC 218.5(b) Parameter	n	Mean	Standard Deviation	Coefficient of Variation[3]
Useful Heat Recovery Rate	21	2.4 kBtu/kWh	1.3 kBtu/kWh	0.5
Electrical Conversion Efficiency	22 12	29% (ICE) 23% (MT)	3% (ICE) 2% (MT)	0.1 (ICE) 0.1 (MT)

While the quantity of metered data is small at this time, the data that are available suggest that the relative level of variability exhibited by heat recovery data is *substantially greater* than that exhibited by electrical conversion efficiency. This fact was alluded to earlier in the description of the rationale for not stratifying cogeneration systems for purposes of heat metering sampling. Conversely, relatively modest variability observed in electrical conversion efficiencies to date lead to the recommendation to sample for purposes of estimating this impact measure.

Electrical conversion efficiency is simply the ratio of electrical energy produced to fuel energy consumed. Because E-NGO[4] metered data are being collected from all cogeneration systems the question of sampling simply boils down to fuel metering only. That is, given the census for E-NGO metering, and given the variability observed in electrical conversion efficiencies to date, what degree of fuel metering is required to achieve program evaluation objectives, and are the quantities of metered fuel consumption data available from existing sources sufficient in and of themselves.

To answer these questions the electrical conversion efficiency variability data summarized in

were used to calculate metering rates required for various population sizes to achieve the prescribed levels of accuracy. These rates were then compared to the actual population sizes. Results of this analysis are summarized in Table 5-9. The availability of metered fuel consumption data from existing sources has been averaging approximately 60% to date, which is more than double the average rate required to achieve accuracy levels required for the SGIP impacts evaluation. In many cases, these data are obtained from the local natural

[3] This statistic is simply the ratio of the standard deviation to the mean. Units cancel out of this ratio, which enables direct comparison of variability level for factors with different units of measure. One limitation of the standard deviation as a measure of variability is that it is expressed in the same units as are used for the underlying data (e.g., kBtu/kWh for heat recovery, % for electrical conversion efficiency). This attribute of the standard deviation complicates direct comparison of variability for these two factors. To facilitate comparison of these factors the coefficient of variation is introduced.

[4] Electric net generator output (E-NGO) represents electric gross generator output less parasitic electric loads. Electrical conversion efficiencies presented in Table 5-8 are based on electric gross generator output. In many cases, electric metering captured E-NGO; in these cases, effects of electric parasitic loads were estimated.

gas utility company. This assessment of sampling suggests that fuel use data from existing sources [only] will be sufficient for program impacts evaluation purposes.

Table 5-9: Cogeneration System Fuel Metering Requirements

Program Administrator	Technology	Estimated Population (n)	Fuel Meters Req'd for 90/10 (n)
PG&E	MT	7	3
	ICE	36	6
SCE	MT	7	3
	ICE	11	3
SoCalGas	MT	18	3
	ICE	33	6
SDREO	MT	13	3
	ICE	15	3
Total		**140**	**30**

5.5 Conclusion

Principal conclusions of this updated examination of sample design for metering and associated data collection needs for photovoltaic and cogeneration systems include:

PV. If all systems greater than or equal to 300 kW are metered, then metered data received from Hosts, Applicants, and vendors for smaller PG&E and SoCalGas PV systems will be sufficient to yield impact estimates of sufficient accuracy for program evaluation purposes. Other than occasional spot metering for verification purposes, it is not essential that these Program Administrators have their metering contractors install E-NGO metering on PY2003 and PY2004 PV systems that are less than 300 kW. For SCE PV projects less than 300 kW, a list of projects recommended for metering will be developed for the use of SCE and its metering installation contractor.[5] This list is expected to include at least 40 percent of the PY2003-PY2004 PV projects less than 300 kW.

Cogeneration. Fuel metering effected by utility companies, Hosts, Applicants, and vendors will be sufficient. It is not essential that Program Administrators continue to install additional fuel metering -- solely for program evaluation purposes. Current electric utility plans call for E-NGO metering of all systems for tariff purposes; therefore it is not necessary to examine E-NGO sampling at this time. The current Work Plan calls for metering of useful

[5] Three of the SGIP Program Administrators accepted the Itron Team's recommendation to include data collected by program participants in the impact evaluation. SCE requested that the Team install metering dedicated to program M&E regardless of the availability of metered data from program participants or other non-utility sources, because of concerns about the availability and integrity of data from third parties.

thermal energy for a prescribed number of projects. The possibility of sampling for useful thermal energy metering may be considered when more useful thermal energy data are available for analysis.

5.6 References

Technology Characterization: Microturbines, Prepared by Energy Nexus Group for the US Environmental Protection Agency, Climate Protection Partnership Division, March 2002.

Technology Characterization: Reciprocating Engines, Prepared by Energy Nexus Group for the US Environmental Protection Agency, Climate Protection Partnership Division, February 2002.

6

Third-Year Impact Evaluation Data Collection Activities

This section presents an overview of the range of data collection activities supporting the third-year impact evaluation. A detailed description of metered data collection issues and current status is included in Section 8.

6.1 Administrator Program Tracking Database & Handbook Updates

Administrators provide program evaluators regular updates of their program tracking database files. These files contain information that is essential for planning and implementing data collection activities supporting the impact evaluation. Information of particular importance includes basic project characteristics (e.g., incentive level, technology, size, fuel) and key participant characteristics (e.g., Host & Applicant names, addresses, phone numbers). Itron's initial M&E activities for each project are influenced by the project's technology type, program year, and Program Administrator. The stage in the program of each project is tracked by Itron, and then M&E activities are initiated accordingly. Updated program handbooks are 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 third-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 2003, not all administrators had yet finalized or begun implementing plans for wide-scale installation and operation of net generator output meters. Two administrators retained the statewide evaluation contractor to install E-NGO metering for a portion of their projects in conjunction with useful thermal energy metering installations, however the latter activity was delayed for several months due to an interruption in the contractual arrangements under which the work is performed. This interruption was longer than expected because each of the incremental steps in the contracting process required more time than anticipated. First, Itron developed a revised work plan. Next the Program Administrators worked with the M&E Program Manager to revise their co-funding agreement. Third, a new purchase order between Itron and the statewide M&E Program Manager was negotiated. Finally, contractual agreements between Itron and its subcontractors were negotiated.

In some cases, electric utility metering and data collection problems led to gaps in the data archive, and to delays in availability of the data that were collected. In other cases Hosts or Applicants collect the 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. These issues result in large gaps in the data archive for certain projects. Finally, Applicant concerns about data confidentiality may lead to requests that data be used by the evaluation contractor only.

As a result of the issues described above, the electric net generator output interval data archive is incomplete and has been more difficult and time-consuming to assemble than anticipated. Substantial quantities of E-NGO data for 2003 were ultimately collected, however, as summarized in Section 8.3, System Operational Data Collection. Analytic methodologies used to estimate electric impacts of projects for which E-NGO data were not available are discussed in Section 9. In part as a result of the problems noted above, a targeted third-year process evaluation is now slated for completion in late Fall 2004. One objective of that work will be to improve the E-NGO data collection process by reducing overall costs, while at the same time increasing the completeness of the resulting data archive.

6.3 Useful Thermal Energy Compliance Data Collection

Useful thermal energy data collection typically involves an invasive installation of monitoring equipment (i.e., flow meter, 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 which they are already collecting. This approach minimizes both the cost- and disruption-related risks of installing monitoring equipment. The majority of useful thermal energy data for 2003 were obtained from outside parties in this manner.

The statewide evaluation contractor began installing useful thermal energy and fuel usage metering in the summer of 2003. The first 9 useful thermal energy meters and the first 5 fuel usage meters were installed through December 2003. Metering installation was put on hold for more than 6 months from late-Fall 2003 to Summer 2004 while the several contractual arrangements underlying the work were revised to extend its term. The reasons behind this interruption were identified above in Section 6.2. 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.

Only modest quantities of useful thermal energy data for 2003 were collected, as detailed in Section 8.3, System Operational Data Collection. Fuel usage data were available from gas utilities for a substantial number of projects, however. These data in combination with available E-NGO data enable development of useful information related to electrical conversion efficiencies, which are a key contributor to overall system efficiencies. Analysis of the available data related to heat recovery and system efficiencies is discussed in Section 9.

6.4 On-site Verification Facility Data Collection

During metering and data collection site visits BVA (Itron's 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. As required, the date when the system entered normal operations is determined (or estimated) from the available operations data. This on-site data collection process is further discussed in Section 8.3. Information collected by BVA for Program M&E purposes augments that which is developed by the Program Administrators' installation verification site inspectors. Inspection Reports produced by these independent consultants are provided to the evaluation contractor regularly, and their review typically contributes significantly to the project-level M&E planning efforts.

7

On-Site Field Verification and Inspection Activities

Each of the Program Administrators has retained independent consultants to conduct on-site verification inspections for their SGIP projects. From the perspective of participants, these inspections are one of the last steps in the SGIP process. In early 2003 Itron completed an initial evaluation of the on-site verification process. Results of that work were included in the Second-Year Impacts Evaluation Report. This update of the summary of on-site field verification and inspection activities includes additional detail regarding the use of inspection reports in the program evaluation activities, and minor modifications to the process that have been made to provide additional information for program impacts evaluation purposes.

7.1 On-Site Verification Objectives

CPUC Decision 01-03-073 requires that Program Administrators conduct program verifications 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] On-site inspections are a key part of this verification process. A principal objective of the on-site inspections is to "verify that the funded self-generation systems are actually installed and operating".[2] Other objectives, as described in the program handbook, are to "verify that the project system is operational, interconnected and conforms to the eligibility criteria of the program.[3]" 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

In compliance with the inspection requirement, each of the Program Administrators has retained a third-party engineering firm to conduct on-site field verifications, as shown in Table 7-1. Early in 2002 the inspection procedures and documentation processes, which were still evolving in 2001, were finalized and put into regular practice. The general

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

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

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

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. As of the end of 2003, more than 170 on-site field verification inspection visits had been completed.

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	Rodney R. Hite, PE[4]
Southern California Edison	SCE	AESC
Pacific Gas and Electric	PG&E	KW Engineering[5]

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 system 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.

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 Incentive Claim Form to inspection

[4] Energy Nexus Group was the consultant initially performing on-site verification visits for SoCalGas. In late-2002 this company announced plans to cease operations, however the engineer working on this project continues to provide consulting services under a separate contractual arrangement.

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

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 4: 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.[6]
- Verifying waste heat recovery operation where applicable.[7]
- 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.

[6] Effective January 1, 2002, applicants for Level 3-N technologies must provide manufacturer's specifications at the time of application showing that the systems are capable of operating between 0.95 PF lagging and 0.90 PF leading. During site inspections the installation of controls necessary to affect required PF control is verified where possible.

[7] Applicants for Level 2 and 3-N technologies, which rely on non-renewable fuel, must provide design documentation indicating production of 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 equaling at least 42.5% of fossil fuel inputs.

Step 5: 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 6: 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 7: 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 were interviewed in early-2002. At that time all reported that procedures were 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 2001 and early 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. While inspectors often make an effort to meet with an owner’s representative to obtain project and program feedback from the owner’s perspective, 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.

During 2003 the Itron Team came to rely more heavily on information contained in the on-site verification inspection reports. In cases where the on-site verification visit occurs prior to the M&E Site Visit, the inspection report enables the M&E Site Visit engineer to come up to speed with project details much more quickly, thus increasing the efficiency of the entire process.

In the case of Level 1 photovoltaic projects, the information in inspection reports has a direct bearing on subsequent data collection activity for M&E purposes. Existing provisions for metering and monitoring are documented in inspection reports. This information in combination with the system schematic and related contact information is crucial to enable the Itron Team to collect operating data from existing sources of data for M&E purposes without the need for an additional site visit, thus increasing the efficiency of the entire process.

In the case of Level 3-R projects the information in inspection reports has a direct bearing on subsequent site visit activity for M&E purposes. Level 3-R projects are not subject to the heat recovery or system efficiency requirements of Level 2 and Level 3-N projects. Therefore, the principal purpose of the M&E Site Visit is to develop plans for monitoring compliance with renewable fuel usage guidelines. However, all Level 3-R projects visited to date have relied on renewable fuel exclusively; they have not been designed or constructed to utilize both renewable fuel and fossil fuel. When this fact is documented in on-site verification visit inspection reports, the M&E Site Visit can be eliminated, thus increasing the efficiency of the entire process.

7.4 Summary and Recommendations

The on-site verification processes and forms varied somewhat from area to area in 2002 and 2003, but in all areas appeared to meet the requirements of CPUC 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 2004 without change. However, 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, may provide an extra level of early review to help identify problems at a point in the process when changes in plans are not difficult.

Minor modifications to the inspection report forms were recommended to increase inter-administrator consistency and expand the documentation of PV system characteristics that influence operational performance. Recommended modifications to non-PV forms focused on documentation of existing sources of data. The scope of this area of data collection is summarized in Table 7-2, which is based on the format initially used by one of the inspection contractors. Representative identities of providers of data from existing sources include utility companies, third-party providers of monitoring services, and program Applicants.

Table 7-2: Existing Metering Documentation Format

Measurement Point	Meter #	Source of Data Type / Identity
Site Gas In	______________	☐ Utility ☐ Other ______________
Site Electric In	______________	☐ Utility ☐ Other ______________
Useful Thermal Energy	______________	☐ Utility ☐ Other ______________
Generator Electric Out	______________	☐ Utility ☐ Other ______________
Generator Fuel In	______________	☐ Utility ☐ Other ______________

Additionally, the format recommended for documenting the orientation of PV systems is presented in Figure 7-1.

Figure 7-1: PV Orientation Documentation Format

Which type of mounting system is used to orient the PV array towards the sun?

☐ Fixed

Orientation (i.e., Azimuth): _____ (see Fig. 1)
TILT FROM HORIZONTAL:_____ DEGREES

☐ Manual, Seasonal Adjustment

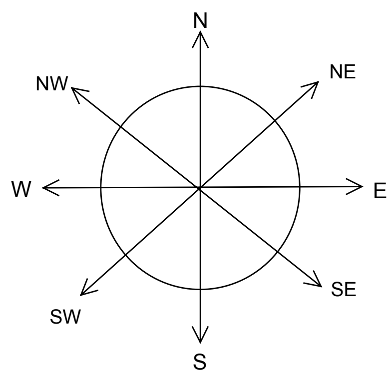
- ☐ Orientation Only – (Tilt fixed at _____ degrees)
- ☐ Tilt Only – (Azimuth fixed at _____ see Fig. 1)
- ☐ Orientation & Tilt adjusted seasonally

☐ Automatic 1-Axis Tracking (e.g., ZomeWorks TrackRack)
Do you manually adjust tilt? Yes / No (circle one)

☐ Automatic 2-Axis Tracking (e.g., WattSun AZ-100)

Notes: ____
____
____

Figure 1: Azimuth Orientations



Note: Pls indicate whether or not azimuth values are true values or magnetic values.

True / Magnetic / Not Applicable
(Circle One)

8

System Monitoring and Operational Data Collection

Sample designs for system monitoring and data collection were discussed previously in Section 5. This section presents the current status of system monitoring and metered data collection activities to date, and addresses plans for future monitoring activities to support evaluation of the Self-Generation Incentive Program. A brief discussion of the purpose and primary objectives of these activities is followed by an overview of the approach that the Itron M&E Team is taking at the program level to monitor and collect system operational data. A detailed description of data collection activities is then presented, both to support the 2003 impact evaluation and moving forward to support future SGIP impact evaluations. Finally, this section presents an overview of quality control procedures implemented by the 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 address: 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 Parameter	Objective	L-1	L-2	L-3R	L-3/3N
1. On-Peak Power Output (kW)	Compare actual on-peak kW contribution 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 ▪ Useful Thermal Energy ▪ System Efficiency	Determine compliance with PUC 218.5 SGIP program requirements (See Table 8-2)		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 (Fuel Cell)		X	

The purpose of monitoring the thermal energy 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), provisions of which are summarized in Table 8-2.

Table 8-2: Public Utilities Code Sec. 218.5 Cogeneration System Requirements

Provision	Minimum Performance (%)	Description
218.5 (a)	5%	Portion of the facility's total annual energy output that is in the form of *useful thermal energy*.
218.5 (b)	42.5%	Cogeneration systems where useful thermal energy follows power production: *Annual System Efficiency* is calculated as the sum of ENGO and one-half the useful thermal energy, divided by any natural gas (and oil)[1] energy input.

These objectives and measurement parameters are a subset of the overall SGIP data collection and evaluation activities that were summarized previously in Table 3-2. SGIP operational data yielded by metering and monitoring activities will be used to assess other specific performance metrics closely related to the Self-Generation Incentive Program's stated goals and eligibility guidelines. These metrics, which vary across technologies and incentive levels, include self-generation system efficiencies, reliability, on-peak availability, and capacity factor. Assessments of these performance metrics require electric, thermal energy, and gaseous fuel metering.

The mandate for implementing 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 SGIP. Since that time, metering and monitoring requirements have been clarified through SGIP Working Group meetings along with formal actions modifying the Program and its M&E requirements at the CPUC[2]. In some instances, program design changes have resulted in modification of metering and monitoring requirements[3]. Although many data collection issues have arisen and been addressed, additional changes and clarifications can be expected for the Program as program implementation and metering and monitoring activities continue.

[1] Only natural gas (and renewable) fueled cogeneration systems are eligible for incentives under the SGIP.
[2] RER Program Metering and Monitoring Plan, Drafts submitted June 10 and September 23, 2002
[3] See RER M&E Response to CPUC Decision 02-09-051, transmitted November 8, 2002

8.2 Overview of Program-Level Monitoring Approach

A defining characteristic of the program-level monitoring approach is the reliance on various diverse meter installers and data providers. The range of meter installers and data providers encountered to date is summarized in Table 8-3. In certain cases, program administrators and/or local utilities, as well as program applicants and/or host customers, may be undertaking electric, fuel, or heat metering and monitoring activities for their own purposes (e.g., billing, research, and/or operations). 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, operations risk and inconvenience, while still ensuring availability of metered data suitable for program evaluation purposes.

Table 8-3: Variety of Meter Installers and Data Providers

ENGO	FUEL	HEAT
PG&E	PG&E	Itron Team
SCE	SoCalGas	Applicants (6)
SDG&E	SDG&E	Vendors (2)
LADWP	Long Beach Energy	
Itron Team	Itron Team	
Applicants (17)	Applicants (5)	
Vendors (3)	Vendors (2)	

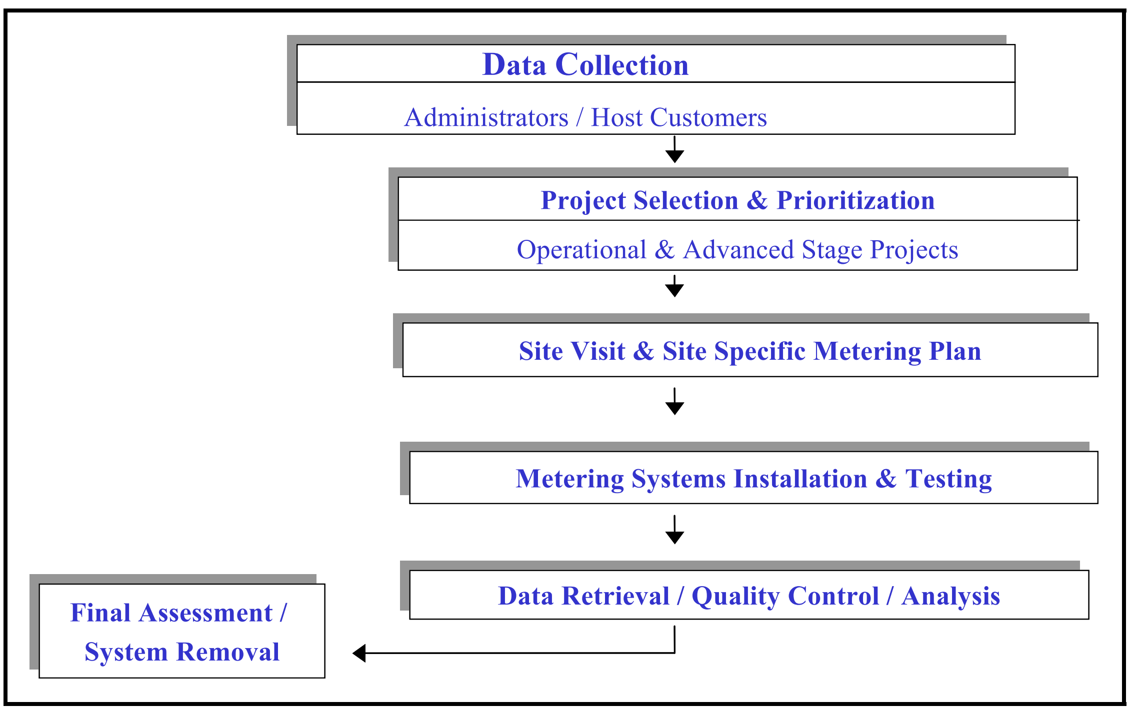
In accordance with the amended Program Evaluation RFP and subsequent discussions with the Working Group prior to and following CPUC Decision 03-04-030 that clarified cost responsibility for *Customer Generation Departing Load* (Exit Fees), the program administrators have retained the primary responsibility for metering and data collection regarding the degree to which SGIP units operate during peak periods. Therefore, the baseline electric interval data collection and transmittal protocol places responsibility for the collection of system electric data in the hands of the four Program Administrators. However, PG&E and SoCalGas contracted directly with Itron to provide electric metering and data collection for certain projects that are not already being monitored by other parties or by the Administrator's own metering shop. Itron is providing this support directly to the Administrator – separate from the M&E resources available through the co-funding agreement between the four Program Administrators. In other instances, electric interval metered data of sufficient quality may be directly available from program applicants or third party vendors who are collecting these data for their own purposes. Note that as a guiding principal, whenever an Administrator is monitoring ENGO, Itron 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.

The total number of unique Applicants and Vendors providing 2003 data was 22, which in addition to the Program Administrators brings the total number of data providers to 29. While utilization of existing data collected by others offers the advantage of decreasing the program's overall metering acquisition and installation costs, it does so at the additional costs of increasing data collection coordination costs, data collection schedule risk, and data validation costs. These factors are discussed in more detail below in the section describing results of the metering installation and data collection efforts to date.

8.3 System Operational Data Collection

Principal metering and monitoring team members include Itron, Brown Vence and Associates, and Environmental Systems Inc. Other equipment-specific installation subcontractors are brought into this process as necessary. As noted above, metering and monitoring activities are not performed solely by the Itron team of program evaluation contractors. Figure 8-1 provides an overview of the monitoring and data collection steps entailed in this SGIP evaluation in the instances where the Itron Team is installing metering and collecting data.

Figure 8-1: Metering and Data Collection Implementation Overview



Measurement Points for Metering & Data Collection

The electric, fuel, and thermal energy measurement points targeted for metering and data collection are described below.

Electric Net Generator Output

Electric net generator output (ENGO) refers to a measure of system output that includes effects of prime mover/generator electric parasitic loads (EPL) (e.g., onsite controls, pumps, fans, compressors, and electrical interconnection gear associated with the fuel systems, prime movers, generators, and heat recovery systems). The basis of ENGO measurements is illustrated with the following equation.

$$ENGO = EGGO - EPL$$

ENGO =	Net generator electric output
EGGO =	Gross generator electric output
EPL =	System Electric parasitic load

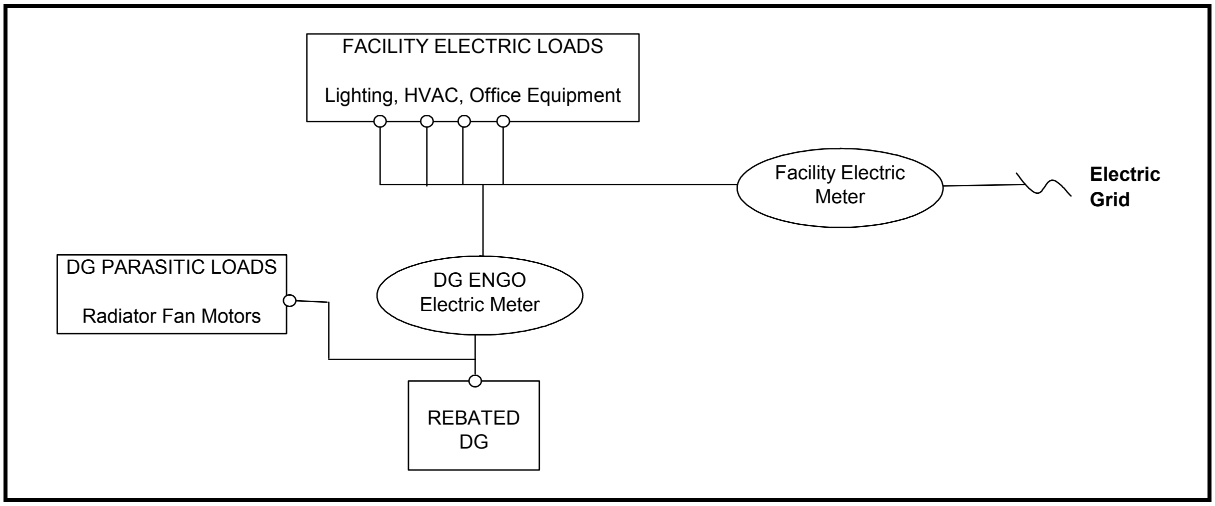
Depending on the physical arrangement of electric circuits it may not be possible to measure ENGO directly with a single meter. If parasitic loads are on a separate circuit then two or more meters are used to measure gross generator electric output (EGGO) and EPL directly, and ENGO is calculated. Alternatively, in some cases EGGO (only) is measured; in these instances EPL are estimated, and ENGO estimates are calculated.

Net generator electric output *interval* metered data (e.g., 15-minute, 60-minute) are required to achieve the objectives of the program evaluation. Hardware and software required to effect this type of metering can be substantially different from the requirements for metering designed to yield only monthly totalized output. These electric generation data will be collected for the majority of program participants, as described in Section 5.

Host Facility Electric Consumption

The ENGO data will be sufficient to determine the electrical production and electrical system demand reduction yielded by all self-generation systems funded through the program. However, a complete assessment of program impacts on individual host customers and utilities would require not only ENGO interval data but also net electric interval consumption data from the energy provider billing meter located on the grid side of the ENGO electric meter. The relationship between ENGO metering and facility metering for billing purposes is depicted graphically in Figure 8-2.

Figure 8-2: Relationship between DG ENGO and Facility Electric Meter



The schematic of Figure 8-2 can also be used to explain the distinction between ENGO and EGGO. In Figure 8-2 the DG electric output metering includes effects of parasitic loads (EPL). Measurements made at this point thus yield ENGO data with a single measurement. If the parasitic loads had been tied in to the facility electric system between the DG ENGO meter and the Facility Electric Meter (instead of between the DG ENGO meter and the Rebated DG system) then either the EPL would need to be metered separately, or their effects would need to be estimated.

The principal use of host facility electric consumption data is in cost-effectiveness analyses from the perspective of program participants or electric utilities. However, to date plans for program cost-effectiveness analysis have not yet been finalized. Collection and analysis of host facility electric consumption data will begin once program cost-effectiveness analysis framework and implementation plans are finalized and approved by the CPUC. The program administrators will make them available to the evaluation consultant in the same format as the ENGO data for incorporation into the program impacts and cost-effectiveness analyses.

Generator Fuel Consumption

Generator fuel consumption data are required to assess actual operating efficiencies (e.g., overall system, electrical conversion) as well as compliance with certain renewable fuel eligibility requirements. When calculating electrical conversion efficiencies, the fuel consumption data are combined with gross generator electrical output data to yield a measure of actual efficiency that can be compared directly with manufacturer performance data.

Fuel consumption metering differs from electric metering in at least one important way. Whereas electric power generation is metered directly, fuel meters measure volumetric flow rates directly and additional calculations are required to arrive at an estimate of fuel energy content. These calculations incorporate measured data or estimates concerning operating pressures, operating temperatures, and fuel heat content. Of particular note is the fact that for utility billing purposes fuel energy measurements typically are expressed in terms of higher heating value (HHV), whereas PUC 218.5 efficiencies and electrical conversion efficiencies typically are expressed in terms of lower heating value (LHV). In cases where utilities provided fuel consumption information in terms of HHV a simple conversion factor was applied to estimate the LHV energy content.

System Useful Thermal Energy Recovery

Participating systems subject to heat recovery requirements use a variety of means to recover heat, as well as a variety of means to utilize recovered heat for useful purposes. Heat recovery is typically accomplished through:

- Engine block via water-to-water heat exchanger;
- Exhaust via air-to-water heat exchanger;
- Exhaust via air-to-air heat exchanger;
- Exhaust via heat recovery steam boiler; or
- Exhaust directly.

Recovered heat must be applied to a useful purpose to be credited to PUC 218.5 and other efficiency measures. Heat utilization is typically accomplished via:

- Use of recovered heat for space heating, water heating, or process heating; and/or
- Use of recovered heat to operate a heat recovery absorption chiller (HRAC);

The variety exhibited by heat capture and heat application approaches necessitates use of a relatively wide variety of types of monitoring approaches. As with the measurement of fuel, the measurement of heat requires monitoring both a flow rate and parameters necessary to calculate estimates of heat content per unit of flow rate. In the case of steam these secondary parameters include steam pressure and temperature, while in the case of hot water applications it is sufficient to measure the change in temperature across the inlet and outlet of the useful application.

Key Issues Influencing Metering & Data Collection

Several key issues influencing metering and data collection plans are discussed below. These issues include:

- Reliance on System Owner/Third Party Monitoring Equipment
- Basis of Generator Electric Output Data
- Treatment of Possible Secondary Impacts

- Treatment of Mixed-Status Systems
- Date Entered Normal Operations (DENO)
- Specification of Basis of Useful Thermal Energy Recovery

Reliance on System Owner/Third Party Monitoring Equipment

In numerous cases the Project Team could rely on metered data collected by the system owner or its data collection agent. This is particularly true in the case of recovered heat monitoring of cogeneration systems and electric generation monitoring of photovoltaic systems, because utilities do not measure these parameters for billing purposes. This approach offers both rewards (i.e., reduced metering installation costs) as well as possible risks. These possible risks include:

- System owner/third party "gaming" of the system in a manner that would overestimate system performance.
- Meter and data acquisition system calibration, operation, and maintenance problems falling outside of the control of the Itron Team.
- Difficulty in obtaining consistent and complete datasets on a regular basis in a timely manner.

After considering the numerous tradeoffs involved in the decision to utilize metered data available from third parties, the Itron Project Team concluded that the advantages outweighed the costs.[4] To mitigate the above risks, the Project Team examines the existing system's monitoring capability during the preliminary monitoring site visit and determines 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. Data obtained in this manner are subjected to systematic validation analyses, and the Itron Team is prepared to conduct short-term validation metering in any cases where accuracy of third-party data is suspect.

Basis of Generator Electric Output Data

The importance of understanding the basis of generator output metered data was discussed above. It is necessary that electric parasitic loads be accounted for in estimates of net generator electric output. Similarly, it is necessary that electric parasitic loads be excluded from estimates of gross generator output used to calculate electrical conversion efficiencies

[4] Three of the SGIP Program Administrators accepted the Itron Team's recommendation to include data collected by program participants in the impact evaluation. SCE requested that the Team install metering dedicated to program M&E regardless of the availability of metered data from program participants or other non-utility sources, because of concerns about the availability and integrity of data from third parties.

that are compared to performance data from manufacturers. In many cases the precise basis of non-PV ENGO data received from utilities to date has been difficult to determine.

Treatment of Possible Secondary Impacts

In cases where recovered heat is used to operate a newly installed heat recovery absorption chiller a strong possibility exists that the absorption chiller's operation will serve to decrease load on an electric chiller (either an existing electric chiller, or a (hypothetical) new electric chiller that would have been installed in the absence of the new DG system and new absorption chiller). Disregarding the question of rebate eligibility, if the absorption chiller would not have been installed in the absence of the rebated generator then process- and economic-related impacts of the absorption chiller's installation ought to be attributed to the program.

Under these circumstances program-attributable unloading of an electric chiller will yield secondary impacts proportional to the quantity of chilled water produced by the absorption chiller. Thermal and electric monitoring approach specifications for Self-Generation Incentive Program Level 3 and Level 3-N projects that include new absorption chillers therefore depend on broader attribution questions. As a result of discussions among the Team and also with the Working Group, the Itron Project Team concluded the following:

- Primary program evaluation emphasis should be placed on assessing compliance with the Program's PUC 218.5 efficiency requirements.
- Secondary electric impacts resulting from displacement of conventional cooling capacity may also be of interest for cost-effectiveness analysis purposes; however, monitoring costs should not be increased substantially to enable measurement of chilled water production.

Based on these conclusions, the following guidelines were established for projects that include new absorption chillers:

- In cases where recovered heat is utilized for both heating and cooling purposes, a single BTU meter will be used to measure total recovery of useful heat. In the analysis assumptions will be made to: 1) distinguish between heating and cooling services yielded by the recovered useful heat, and 2) estimate chilled water production and associated secondary electric impacts.
- Collection of temperature data that will improve estimates of absorption chiller conversion efficiency will be proposed. The cost to install additional equipment necessary to collect these temperature data is expected to be less than $300 per point, and these costs will be identified separately in Monitoring Plans. The temperature of hot water supplied to the chiller is expected to be available in all cases. The ability to cost-effectively monitor the temperature of condenser water supplied to the chiller will depend on site-specific system layout.

- In cases where recovered heat is utilized for cooling purposes only, if the project **IS NOT** expected to exceed the program's 218.5 efficiency requirements by a relatively wide margin then we will use a single BTU meter to measure total recovery of useful heat (i.e., delivery of heat to the absorption chiller). We will propose collection of temperature data that will improve estimates of absorption chiller conversion efficiency.
- In cases where recovered heat is utilized for cooling purposes only, if the project **IS** expected to exceed the program's 218.5 efficiency requirements by a relatively wide margin then we will use a single BTU meter to measure chilled water production. We will propose collection of temperature data that will improve estimates of absorption chiller conversion efficiency (i.e., the temperature of the water delivering heat to the absorption chiller, and the temperature of condenser water supplied to the absorption chiller). We will propose collection of the condenser water supply temperature only if doing so is not substantially more difficult and expensive than is collection of the hot water supply temperature (which should be relatively easy and inexpensive [i.e., approximately $250-$300], because this can be collected in the immediate vicinity of the work being done to install the hot-side temperature sensor for the useful thermal energy meter).

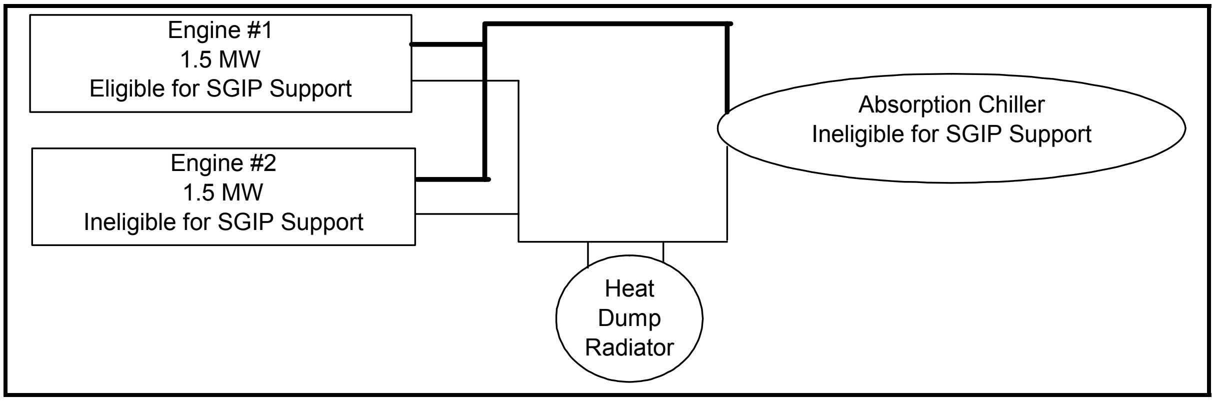
Treatment of 'Mixed-Status' Systems

In certain cases equipment eligible for SGIP financial support is incorporated into larger physical plants in ways that complicate measurement and monitoring for program evaluation purposes. Resulting physical plants can be termed '*mixed status*' from a program eligibility standpoint. This can occur with both PV and non-PV systems.

In the case of PV, non-rebated PV modules may be added to systems originally rebated through the SGIP. In these cases existing ENGO metering does not provide an accurate indication of the performance of the original system, however if the new PV modules are supplying DC power to a rebated inverter then it is reasonable to assume that those extra PV modules would not have been installed in the absence of the SGIP incentive. Under these circumstances the data from existing ENGO metering can be used as-is for purposes of estimating Program impacts.

Treatment of non-PV mixed status systems is less straightforward. A representative example of a non-PV mixed status system is summarized graphically in Figure 8-3. This illustrative system comprises two internal combustion engines contributing heat to a single heat recovery distribution loop feeding a single heat recovery absorption chiller. The SGIP eligibility status of each of the principal components is indicated in the figure.

Figure 8-3: Representative Example of Non-PV Mixed Status Physical Plant



Put simply, the objective of the impacts evaluation is to compare the world observed today to the (hypothetical) baseline world that *would have been* observed today -- if there had never been a SGIP. This latter (hypothetical) world is the baseline against which we compare the actual observed condition in a calculation of program impacts.

The world observed today is obvious; for this representative example it is simply the physical plant depicted schematically in Figure 8-3. What is impossible to always know with certainty is the basis of the true baseline condition. This puzzle can begin to be unraveled by considering the range of possible (hypothetical) baseline scenarios, along with their corresponding impacts. This range for the representative example is summarized in Table 8-4.

Table 8-4: Representative Baseline Hypotheses for Example Case

Baseline Hypothesis	Observed			Baseline Hypothesis			SGIP Impacts		
	ICE Genset	Absorption Chiller	Electric Chiller	ICE Genset	Absorption Chiller	Electric Chiller	ICE Genset	Absorption Chiller	Electric Chiller
1	2	1	0	2	1	0	0	0	0
2	2	1	0	1	0.5	0.5	1	0.5	-0.5
3	2	1	0	0	0	1	2	1	-1

Each of the baseline hypotheses from Table 8-4 is interpreted in Table 8-5. Baseline hypothesis #3 is accepted for purposes of attributing impacts to the SGIP.

Table 8-5: Interpretation of Possible Baseline Hypotheses for Example Case

Interpretation	Baseline Hypothesis #1	Baseline Hypothesis #2	Baseline Hypothesis #3
Description	The customer would have installed precisely the same system as depicted in Figure 8-3.	The customer would have installed only 1 new engine-genset, and 1 new small HRAC. The remaining new cooling load would have been satisfied by 1 new small electric chiller.	The customer would have installed 1 new large electric chiller to satisfy new cooling load. The customer would have continued to rely on the local utility for 100% of its electric power requirements.
Implication	The SGIP had no impact whatsoever on the customer's actions. There are no impacts to attribute to the SGIP.	Installation of 1 engine-genset as well as 1 small HRAC (in lieu of a new electric chiller) is attributed to the SGIP.	Installation of both engine-gensets as well as the HRAC (in lieu of a new electric chiller) is attributed to the SGIP.
Conclusion	Reject Hypothesis	Reject Hypothesis	Accept Hypothesis

Baseline hypothesis #1 is rejected because it corresponds to the assumption that the SGIP had no impacts. This treatment of the issue of free ridership would not be consistent with the treatment being used for all of the other projects covered by the M&E effort.

Baseline hypothesis #2 is rejected for other reasons. If in the absence of the SGIP, only 1 engine-genset would have been installed then it follows that installation of this single [unrebated] engine-genset would have been economic. If this first [unrebated] engine-genset was economic then, due to economies of scale, installation of a second [unrebated] engine-genset at the same time would have been even more financially attractive. If the customer would have installed the first unit on their own in the complete absence of the program, and if installing a second one at the same time would have offered even better financial return, then it is not reasonable to assume that the SGIP is responsible for installation of the second engine-genset, and therefore hypothesis #2 is rejected.

Baseline hypothesis #3 is accepted based on a line of reasoning similar to that presented above for hypothesis #2. It is important to note that any subsequent analysis of program cost-effectiveness should utilize an identical assumption for the hypothetical baseline. While on the surface it may appear overly charitable to attribute the output of an unrebated engine-genset to the SGIP even though no incentive was issued for it, it is important to recognize that both the benefits <u>and the costs</u> are included in the cost-effectiveness analysis. As a practical matter, it is worth noting that the treatment recommended for mixed-status systems involves monitoring plans that are much simpler than other possible approaches designed to allocate recovered heat to particular engine-generator sets. There may however be situations when data are not available for unrebated equipment; these cases may require alternate monitoring approaches.

Date Entered Normal Operations (DENO)

In many cases rebated systems enter normal operations well before an incentive check is issued for the project. The 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 8-6 illustrates the current difference between the number of completed projects using the two approaches.

Table 8-6: DENO - Comparison of Completed Projects

Level	Projects Deemed Complete in Tracking System	PPA Approved or Beyond in PA Tracking Systems	No. of Projects "Operational" per Itron Survey Data
1	117	207	149
2	1	2	1
3N	65	173	115
3R	1	10	2
Total	**184**	**392**	**267**

As Table 8-6 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[5]; but this situation should not necessarily delay the installation of Program monitoring equipment or the assessment of impacts due to the program.

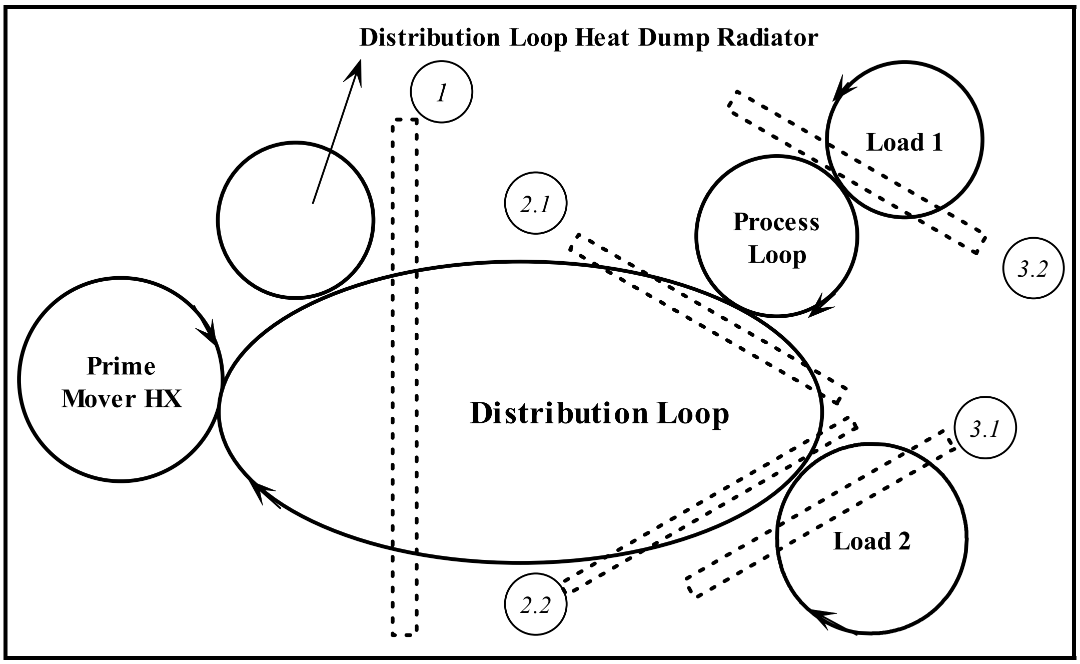
Contact is initiated with an M&E Notification Letter sent to the Applicant and the Host Customer (if different than the applicant), which is followed up with a telephone call to discuss the status of the project and to assess the appropriate time to schedule the metering plan site visit. Assuming the 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.

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

Specification of Basis of Useful Thermal Energy Recovery

In a preceding section the different types of heat recovery methods and different types of useful applications for recovered heat were discussed. Moving from these general terms to specification of detailed measurement and analysis approaches requires systematic definition of useful thermal energy. Numerous different definitions are possible because thermal-mechanical systems typically are composed of several heat transfer loops, as shown in Figure 8-4.

Figure 8-4: Typical Cogeneration System Thermal Energy Distribution



Each of the three (3) principal heat distribution loops of Figure 8-4 are described below:

1. Thermal Energy Distribution Loop: Primary or Primary/Secondary loop (either steam or hydronic) that removes heat from the Prime mover(s) and delivers it to the various thermal 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.

Guidance on a definition of what constitutes Useful Thermal Energy for program evaluation purposes can be taken from the Code of Federal Regulations (18CFR292.202), which states:

(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).

Item h.3 above clearly describes the treatment of absorption chillers. Returning to Figure 8-4, the Code suggests that Useful Thermal Energy be measured at point 2.1 (i.e., across the hot side of the chiller). Due to absorption chiller inefficiencies the quantity of thermal energy services (i.e., cooling) actually provided for the end use load will be substantially less than the quantity of heat defined as Useful Thermal Energy. Application of this convention to the case of heating end uses suggests that Useful Thermal Energy be measured at point 2.2. When site or project conditions dictate measurement of thermal energy at points such as 3.1 or 3.2 engineering estimates of heat exchanger effectiveness (or absorption chiller efficiency) will be used to calculate estimated heat recovery values for points such as 2.1 or 2.2.

Monitoring & Data Collection Requirements by Program Level & Technology

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.

Level 1 Photovoltaic, Wind, & Fuel Cell

Although currently all of the Level 1 projects are photovoltaic or wind energy conversion systems, Incentive Level 1 also includes fuel cells operating on renewable fuel. Interval-metered data requirements of photovoltaic and wind systems will be fully satisfied by the NGO and NGO-connected facility electric interval data for which requirements were 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 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 includes:

- Electric meter with 15-minute interval averaging/storage capabilities to monitor net generator output
  - May be provided by Program Administrator, Program Participant, or local electric utility.
- Electric revenue meter with 15-minute interval averaging/storage capabilities to monitor electric load on the billing meter located on the grid side of the NGO meter
  - Will be provided by local electric utilities in the event that these data are required to complete cost-effectiveness analyses mandated by the CPUC.
- 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.
  - May be provided by Program Administrator, Program Participant, or local natural gas utility.

Level Two Fuel Cell

Whereas electric output interval-metered data and fuel usage data are sufficient to assess the performance of Level 1 fuel cells, Level 2 fuel cells operating on fossil fuels are subject to heat recovery and system efficiency requirements that make additional data collection necessary. Specifically, eligible Level 2 [and Level 3/3-N] SGIP systems must utilize waste heat from the generating facility and meet the cogeneration requirements of Public Utilities Code Sec. 218.5, requirements of which were presented in Table 8-2.

Assessment of actual performance in relation to these program eligibility 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 either from the providing utility or from the program participant.

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 typically provided by the Itron team will include:

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

Additional metering equipment and/or information that is necessary for the impacts evaluation includes:

- Electric meter with 15-minute interval averaging/storage capabilities to monitor net generator output
  - May be provided by Program Administrator, Program Participant, or local electric utility.
- Electric revenue meter with 15-minute interval averaging/storage capabilities to monitor electric load on the billing meter located on the grid side of the NGO meter
  - Will be provided by local electric utilities in the event that these data are required to complete cost-effectiveness analyses mandated by the CPUC.
- Standard natural gas consumption data specifically for the incentivized generator fuel input (MMCF), coupled with reported average gas Btu content for the period (or the equivalent Therms as appropriate) for the fuel cell generator.
  - May be provided by Program Administrator, Program Participant, or local natural gas utility.

Level Three Engines, Turbines, and Microturbines

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 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 thermal energy metering and data collection will be implemented by the Itron monitoring team following the procedures for thermal energy monitoring and data collection previously discussed above for Level 2 Fuel Cells.

Data Collection Status and Schedule

At the end of 2003, 392 projects have achieved Proof of Project Advancement, of which 267 projects are assumed to be *Operational,* with 184 projects identified as *Completed* and *Paid.* The status of collection of 2003 data for the operating projects is summarized on a PA-specific basis in Figure 8-7 through Figure 8-16. The overall status of collection of 2003 data for all four Program Administrators is summarized in Figure 8-5 and Figure 8-6.

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 numerous 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).

The 2003 calendar year (CY2003) ENGO data collection status is summarized at the program level in Figure 8-5 and Figure 8-6. On an overall, program-level basis ENGO data are available for more than half of the operational system capacity.

Figure 8-5: Overall PV ENGO Data Availability for CY2003 (MW)

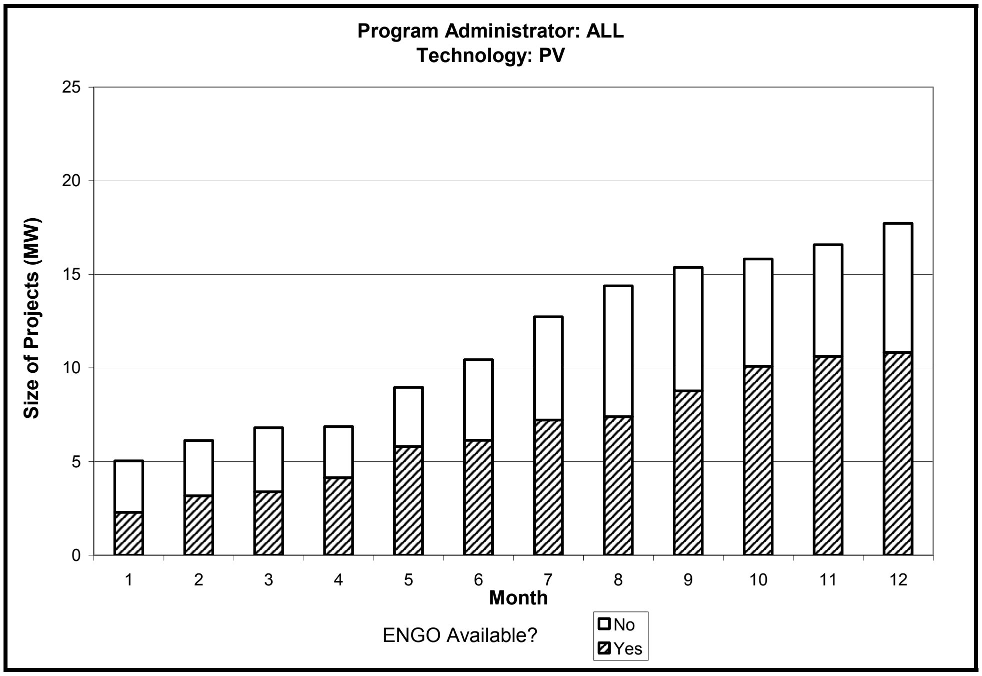
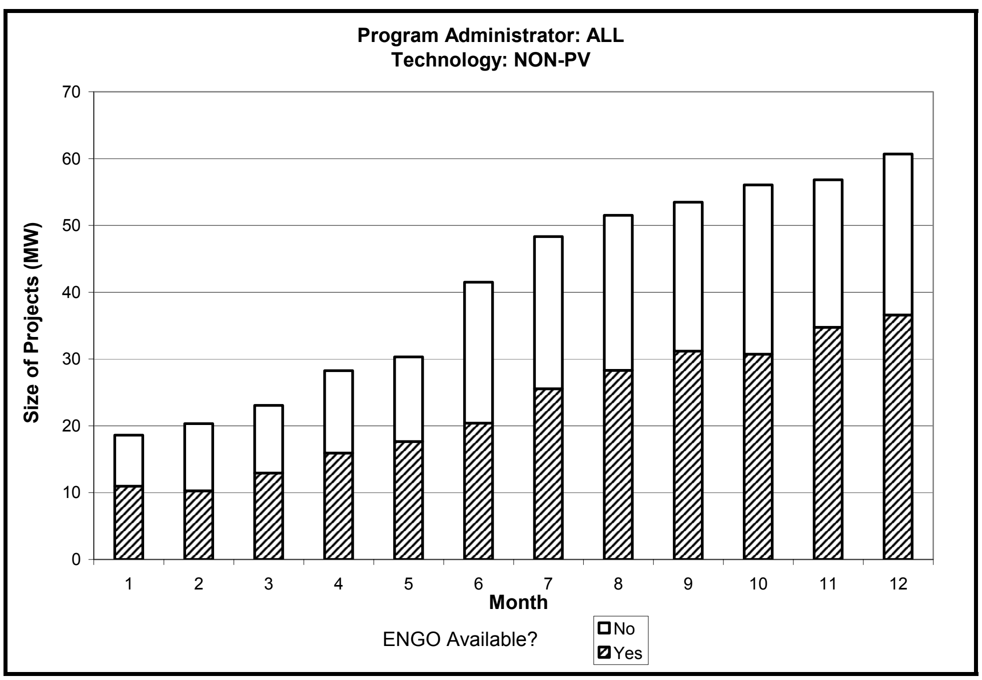


Figure 8-6: Overall Non-PV ENGO Data Availability for CY2003 (MW)



The 2003 calendar year (CY2003) ENGO data collection status for PG&E is summarized in Figure 8-7 and Figure 8-8. The majority of PV ENGO data are being provided by program participants. During summer months ENGO data are available for more than half of operating PV capacity. The majority of Non-PV ENGO data are being provided by PG&E metering.

Figure 8-7: PG&E PV ENGO Data Availability for CY2003 (MW)

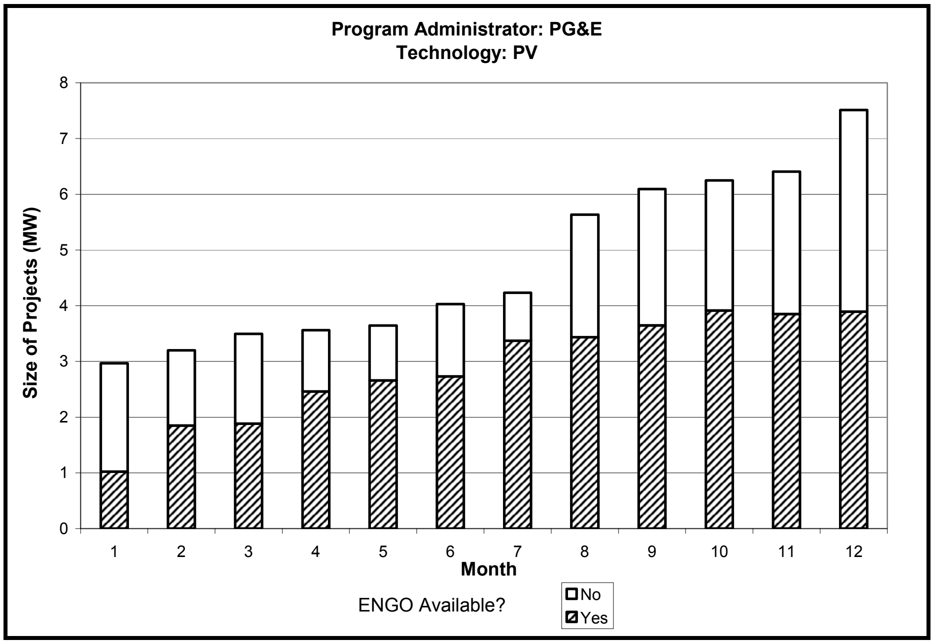
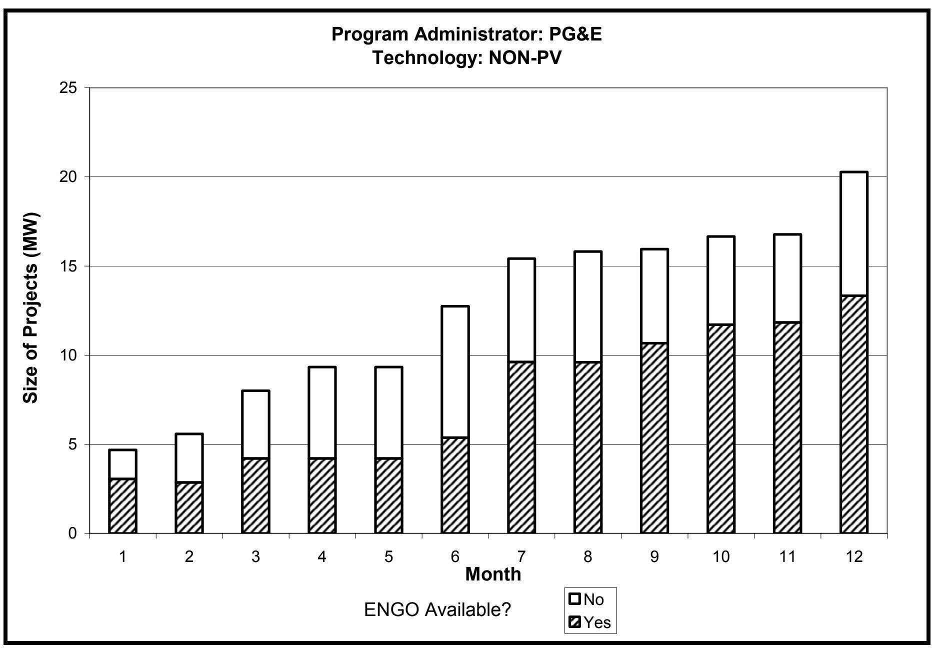


Figure 8-8: PG&E Non-PV ENGO Data Availability for CY2003 (MW)



The CY2003 ENGO data collection status for SCE is summarized in Figure 8-9 and Figure 8-10. The majority of PV ENGO data are being provided by metering being installed for

SCE by a metering vendor. No data were yet available from this source for CY2003; the small quantity of available data were obtained from a program participant. The majority of Non-PV ENGO data are being provided by SCE metering. Data for CY2003 are available for approximately two-thirds of the operating Non-PV capacity.

Figure 8-9: SCE PV ENGO Data Availability (MW)

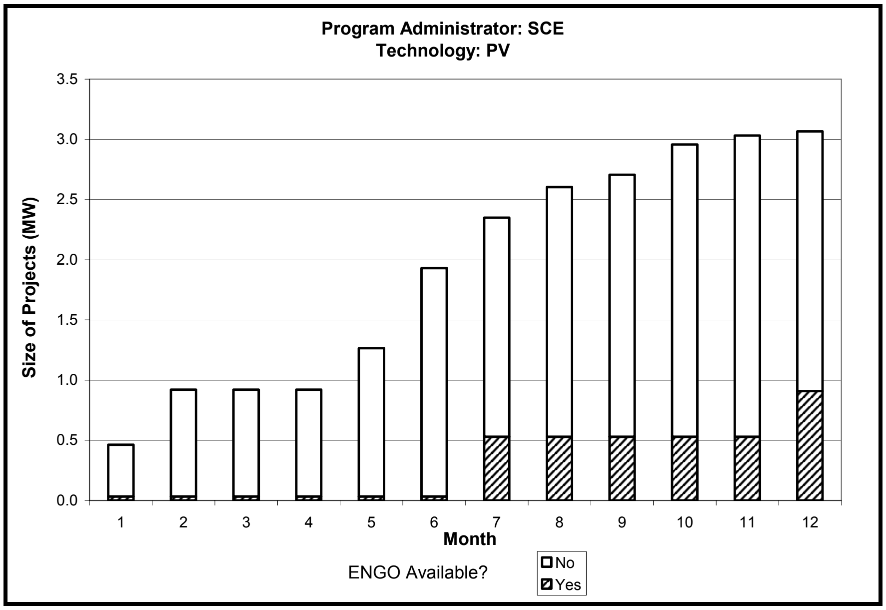
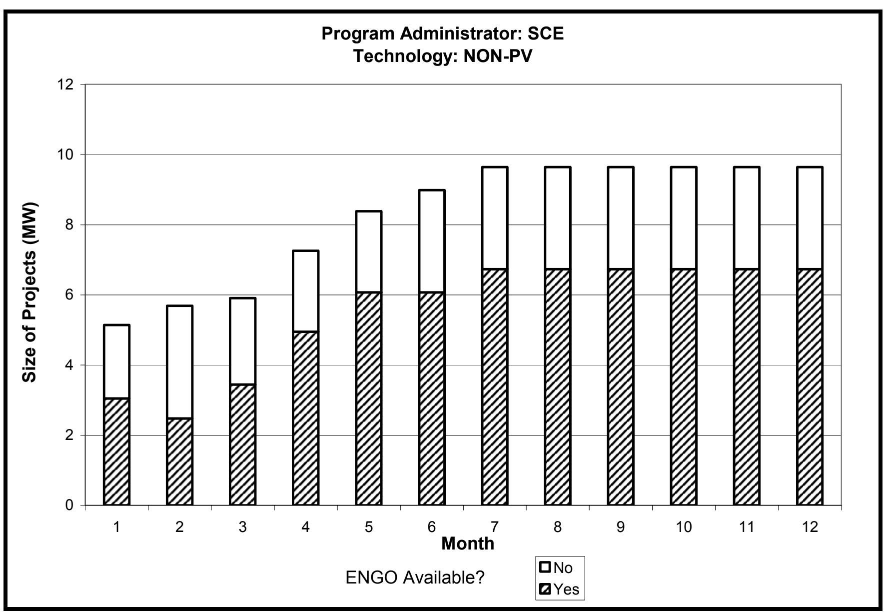


Figure 8-10: SCE Non-PV ENGO Data Availability (MW)



The CY2003 ENGO data collection status for SoCalGas is summarized in Figure 8-11 and Figure 8-12. The majority of PV and Non-PV ENGO data are being provided by the local electric utility as a courtesy. The completeness of the PV ENGO dataset is increasing with time. A substantial quantity of Non-PV ENGO metering will be installed for SoCalGas by a metering vendor at the same time as useful thermal energy metering is installed by the Itron Team.

Figure 8-11: SoCalGas PV ENGO Data Availability (MW)

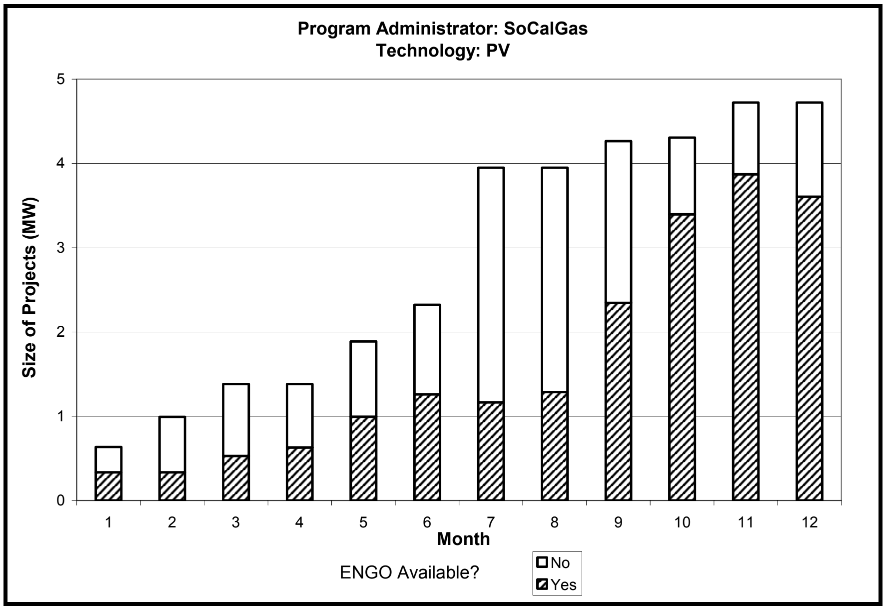
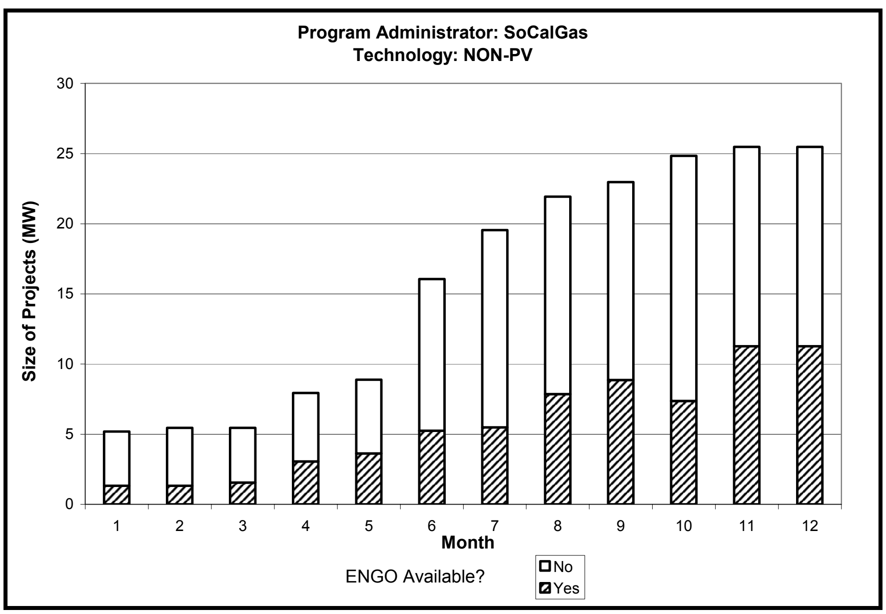


Figure 8-12: SoCalGas Non-PV ENGO Data Availability (MW)



The CY2003 ENGO data collection status for SDREO is summarized in Figure 8-13 and Figure 8-14. All ENGO data for both PV and Non-PV are being provided by the local electric utility. Both datasets are nearly 100% complete. The small quantity of missing PV ENGO data resulted from a site-specific data collection problem.

Figure 8-13: SDREO PV ENGO Data Availability (MW)

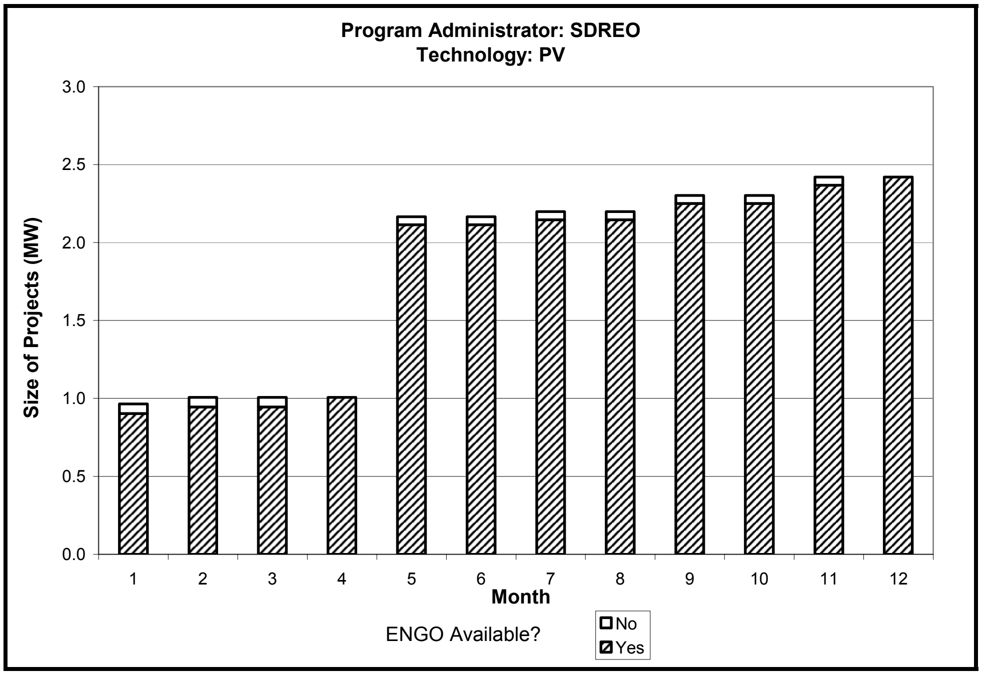
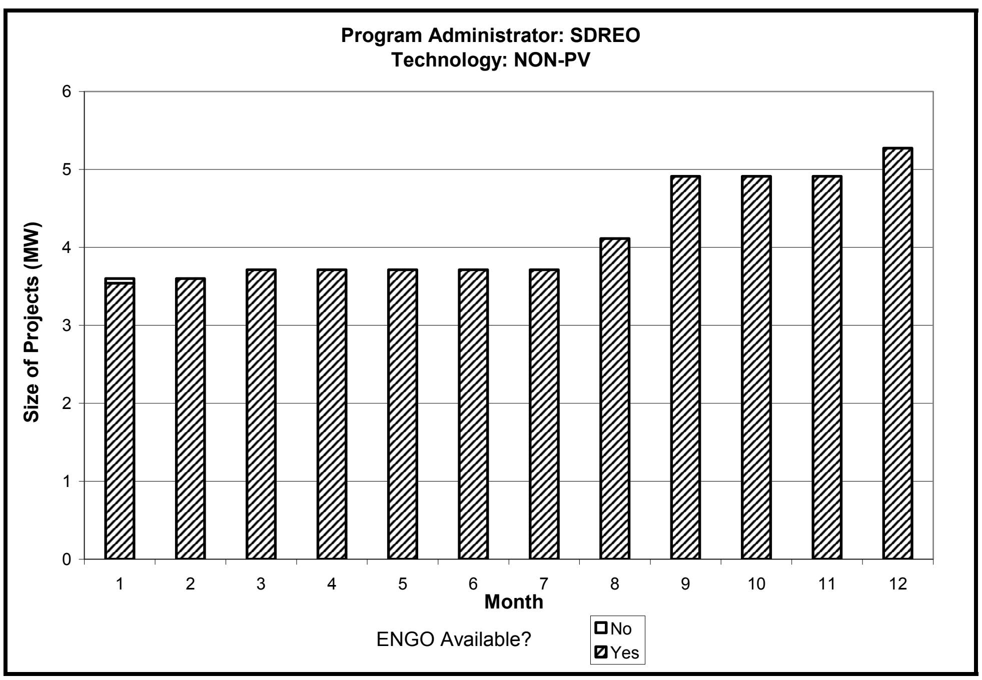


Figure 8-14: SDREO Non-PV ENGO Data Availability (MW)



The CY2003 useful thermal energy data collection status for all four Program Administrators is summarized in Figure 8-15 and Figure 8-16. These summary graphics cover all Level 2 and Level 3-N projects that are subject to heat recovery and system efficiency eligibility requirements during the implementation phase of program participation. To date only a small quantity of useful thermal energy data are available for analysis. The vast majority of these data were obtained from program participants.

Figure 8-15: Cogeneration System Useful Thermal Energy Data Availability (n)

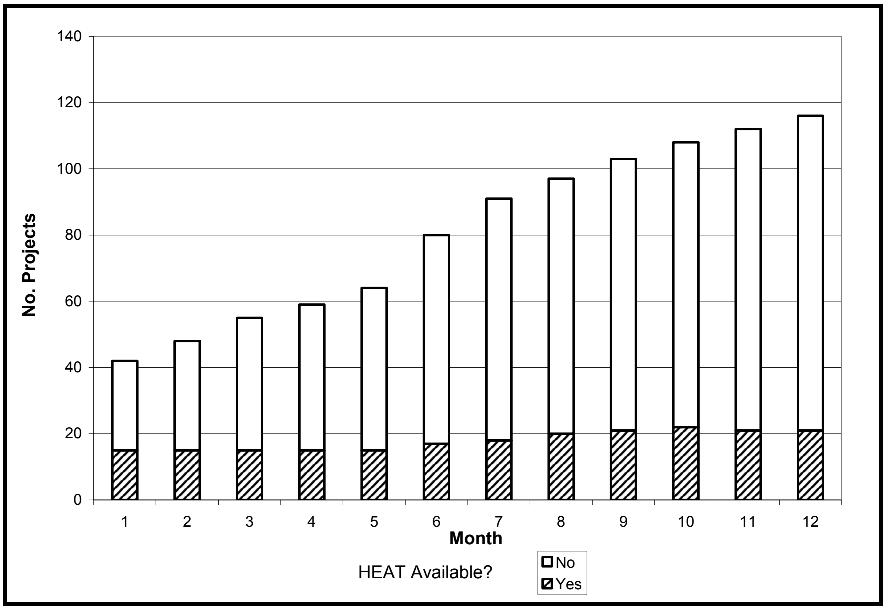
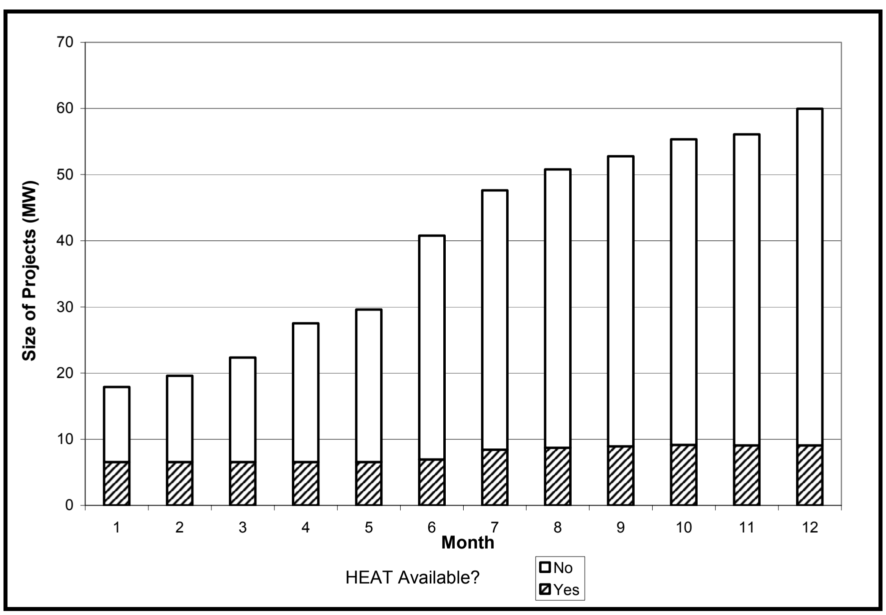


Figure 8-16: Cogeneration System Useful Thermal Energy Data Availability (MW)



8.4 Collection of California ISO Peak Load Data

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) presented the goals of the Self-Generation Incentive Program, and evaluation criteria for meeting those goals were adopted in ALJ Gottstein's April 24, 2002, Ruling on Schedule for Evaluation Reports. One of the key program goals is to "encourage the deployment of distributed generation in California to reduce peak electrical demand". One of the key program evaluation objectives is to assess the degree to which participation in the program has reduced participants' demand for grid power during peak demand periods.

To identify periods of peak electrical demand the project team obtained historical hourly load data for 2003 from the California Independent System Operator (CAISO) Open Access Same-Time Information System (OASIS) web site. From January 1, 2003, to July 10, 2003, actual system load was measured as the instantaneous demand in MW for the CAISO control area, as measured at the beginning of each hour by the energy management system. Beginning July 11, 2003, actual system load was measured as the averaged interval value in MW for the ISO control area integrated over the last five minutes of each hour.

The date and hour of the 2003 CAISO electric system peak was determined by identifying the hour at which actual system load values reached their maximum. Contribution of rebated systems to reduction of load at the time of system peak is discussed further in Section 9. The economic value of demand reduction yielded by the SGIP is not limited to the single hour during which the annual maximum CAISO electric load is observed. One indication that a non-peak period corresponds to relatively tight electric supply conditions is the CAISO's call for Restricted Maintenance Operations (RMO).

The CAISO's call for RMO institutes precautionary restrictions limiting routine work or maintenance in an effort to eliminate avoidable loss of resources. During a RMO day, no work or adjustments may be performed to the power transmission system, system generation, or associated computer control systems without the express permission of the CAISO. RMO days represent days during which available system resources are low relative to current demand, and available resources must be monitored closely to mitigate the possibility of disruption of supply. The contribution of rebated systems during RMO days provides additional information regarding the SGIP's contribution to reducing peak electrical demand. In 2003, March 21-28 and May 28-29 were identified as RMO days. Impacts of rebated systems upon demand reduction during RMO days are presented in further detail in Section 9 of this report.

8.5 Utility Data Exchange Process

In most instances electric and fuel data used for program evaluation purposes will have been collected and provided by a utility company. Utility companies that have provided data to date are listed in Table 8-7.

Table 8-7: Utility Data Providers

Electric	Fuel
PG&E	PG&E
SCE	SoCalGas
SDG&E	SDG&E
LADWP	Long Beach Energy

Exchange of data between the utility company and the Itron M&E Team involves several steps. First, Itron reviews the Program Administrator's Inspection Reports to determine what type of metering is equipped with each system. Second, Data Release requirements are identified based on the identities of the Program Administrator and utility company. Next, Itron requests data for operational projects with utility metering. Lastly, the utility company extracts the data and provides them to Itron for SGIP M&E purposes.

In cases where the utility company providing data is not the administrator for a particular SGIP project, the customer must provide the releasing utility with written authorization to deliver data for their accounts to Itron and the Program Administrator for SGIP M&E purposes. These exchanges of data can be governed by a Data Release Agreement whose content and format were finalized and approved by the Statewide Working Group in February 2002. In some instances the releasing utility's own data release form is used.

Program Administrator: SDREO. All projects require a data release for SDG&E fuel and/or electric metered data. In all but a handful of cases SDREO and SDG&E have worked with the customer to ensure that all necessary data release provisions are completed. In a small number of cases Itron has followed up with the program participant to obtain data releases for SDG&E fuel data.

Program Administrator: SCE. Many cogeneration projects require a data release for fuel metered data. Itron has been responsible for following up with the program participant to obtain data releases for these utility fuel metered data.

Program Administrator: SoCalGas. Most projects require a data release for electric metered data. Itron has been responsible for following up with the program participant to obtain data releases for these utility electric metered data.

Program Administrator: PG&E. To date no SGIP projects have been metered by a utility company other than PG&E. Consequently, there has been no data release activity for this program administrator.

8.6 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, other third-party vendors, or utility companies provide data, Itron initiates the data collection process by requesting that the data provider submit a sample of data in the format they use for their own purposes. The data file is reviewed and a Data Documentation Form is used to systematically document the basis of data received from each of the many providers. After initial review of the sample data file, one or two follow-up e-mails are typically required to complete the Data Documentation Form. The data basis elements covered by the form are described in further detail below.

All Data Documentation Forms are specific to a certain data-provider, and contain certain basic project information, such as SGIP Program Administrator, reservation number, host company and contact name, company name of data provider, and a description of data transfer arrangements (i.e., frequency and method of data delivery and contact information for the data delivery contact). Additionally, all Data Documentation Forms summarize the bases of the raw data, including interval length, units in which AC power is recorded, Daylight Savings Time treatment, and a description of steps taken by the data provider to ensure that the clock settings of the data acquisition system (DAS) remained accurate. All Data Documentation Forms also contain summary excerpts of raw data for each data type provided (i.e., E-NGO, fuel, and thermal) and summarize transformations necessary to convert the raw data to standard format.

Additionally, Data Documentation Forms for PV systems summarize information on system configuration (i.e., tracking, seasonal adjustments, azimuth in degrees from south, and tilt in degrees from horizontal), type of meter used to collect data, and location of E-NGO metering for PV systems equipped with an isolation transformer.

Once the Data Documentation Form for a specific batch of data has been completed, the data is processed and converted to a common format, as described in the following section. Due to the wide variety of formats in which data was received, conversion of raw data to a common format is essential in order to ensure that all data received is treated consistently. Prior to instituting the approach described above Itron initiated the data collection process by providing a written summary of preferred data characteristics and a representative example of a satisfactory file format. These characteristics were presented in the Second Year Program Impacts Report. However, this approach proved impractical. Overall quality and cost of the data collection effort are optimized when the Itron Team's analysts adapt to the norms of the data providers, rather than the other way around. Using data management software these analysts can quickly import and manipulate data files spanning a very wide range of formats.

Convert Raw Data to a Common Format

As mentioned previously, once the bases of the raw data are verified and documented, the raw data are standardized so that they can be systematically stored and processed. 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 the time 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 more straightforward 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, estimated, or calculated based upon a ratio factor developed from other metered data collected at the site).

E-NGO data received in 1-minute format is aggregated and converted to 15-minute format by calculating the average kWh value reported during that period. Hourly E-NGO data is converted to 15-minute format by assuming constant load throughout the hour. For PV systems with E-NGO meters on the inverter side of the transformer rather than the sales meter side of the transformer, a factor is applied when calculating 15-minute E-NGO values to account for transformer losses. All E-NGO data is ultimately stored in 15-minute format, in units of kWh, in the permanent SAS data warehouse.

For cogeneration systems where 15-minute E-NGO data is available, and fuel or thermal data is received in increments larger than 15-minute intervals, 15-minute E-NGO data is used to distribute the fuel or thermal data into the corresponding 15-minute intervals. For monthly fuel data, the transformation is accomplished by assuming a constant electrical efficiency rate for each month. Similarly, for daily heat data, the transformation is accomplished by assuming a constant heat rate for each day. All fuel and thermal data is ultimately stored in 15-minute data, in units of kBtu, in the permanent SAS data warehouse.

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 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 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.

In the case of cogeneration systems, E-NGO, fuel, and thermal data are aggregated to calculate monthly electrical efficiencies, total efficiencies, and PUC 218.5 efficiencies for all months where data are available. Cases where these efficiencies are outside reasonable bounds are flagged for further examination. Additionally, projects displaying atypical variance between monthly total efficiency and monthly electrical efficiency are flagged. In cases where calculated efficiencies appear suspicious, Itron checks with the provider of the data to see if the behavior can be explained. In cases where anomalous behavior cannot be explained, the metered data are not included in the analysis.

Implementation of the data quality control procedures described above has resulted in identification of numerous data quality issues that have been resolved with data providers. Due to the large number of data providers involved with this project, rigorous data QA/QC processes have proved essential.

9

System Impacts and Operational Characteristics

9.1 Introduction

This section of the Program Impacts Assessment addresses the 2003 peak demand and energy impacts of the operational SGIP projects from program years PY2001, PY2002, and PY2003. 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 non-PV projects to be metered, and most PV projects to be metered, as of the end of 2003 about 50% of operational PY2001-PY2003 projects were not yet equipped with generator output electric metering (or data were not yet available to the evaluation contractor from third parties). Consequently, this second impacts assessment relies on a combination of metered data, statistical methods, and engineering assumptions. The data availability situation and corresponding analytic methodologies vary by program level and technology, as 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 were calculated for projects that began normal operations prior to December 31, 2003, 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 operating projects implemented as of the end of 2003. Consequently, this assessment of the Program's demand and energy impacts on the electrical system is based on a combination of metered data and engineering estimates.

Peak Demand Impacts

Overall program demand impacts coincident with 2003 ISO system peak load are summarized below in Table 9-1. In 2003 the ISO system peak reached a maximum value of 42,581 MW on July 21 during the hour from 15:00 to 16:00 (3 to 4 PM) PDT. There were

195 known operational SGIP projects when the ISO experienced this summer peak, but generator electric interval-metered data were available for only 87 of them. While the total on-line capacity of the 195 operational projects exceeded 58 MW, the total impact of the Program coincident with the ISO peak load is estimated at just over 35 MW (35,091 kW). Level 3/3N/3R engines and microturbines account for 78% of the 2003 peak demand impact.

Table 9-1: Program Impacts Coincident with 2003 ISO System Peak Load

Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	**105**	**12,671**	**7,494**
Metered	45	6,561	3,756
Estimated	60	6,110	3,739
Level 2 Fuel Cell	**1**	**200**	**187**
Metered	0	0	0
Estimated	1	200	187
Level 3/3-N/3-R ICE/Turbine	**89**	**46,010**	**27,410**
Metered	42	19,365	11,768
Estimated	47	26,645	15,642
Total	**195**	**58,881**	**35,091**

Energy Impacts

Overall program electrical energy impacts are summarized in Table 9-2. While Level 3 cogeneration systems (i.e., 3/3-N/3-R engines and turbines) accounted for 78% of demand impacts, they account for 91% of total energy impacts.

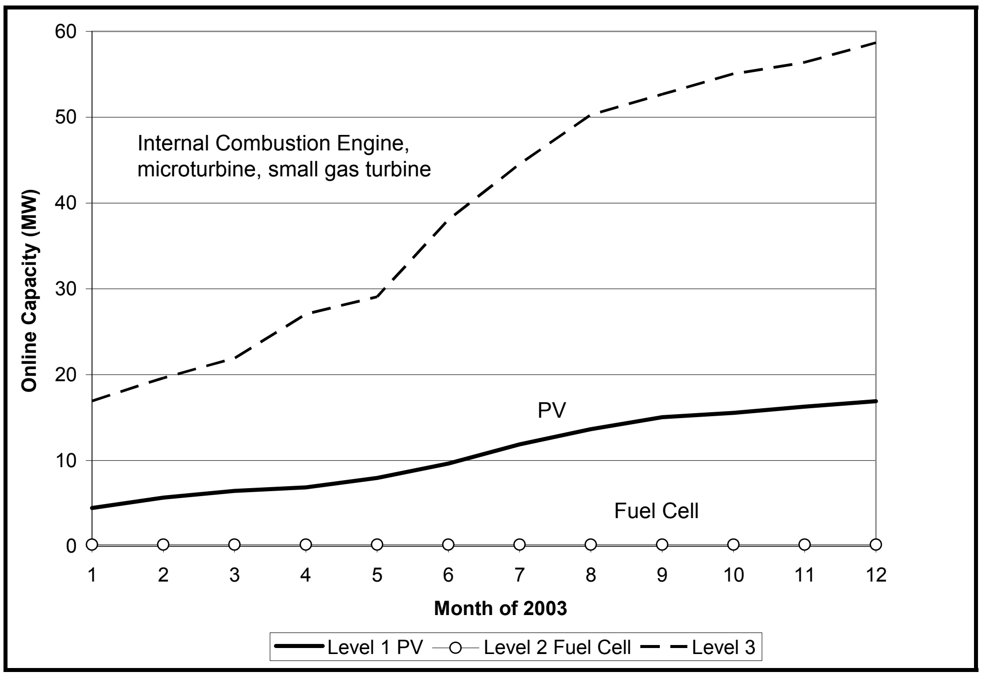
Table 9-2: Program Energy Impacts in 2003 by Quarter (MWh)

Level / Basis	Q1-2003	Q2-2003	Q3-2003	Q4-2003	Total
Level 1 PV	**1,678**	**3,736**	**6,119**	**3,869**	**15,402**
Metered	852	2,173	3,245	2,405	8,676
Estimated	826	1,563	2,874	1,463	6,726
Level 2 Fuel Cell	**396**	**408**	**413**	**418**	**1,635**
Metered	132	0	19	282	433
Estimated	264	408	394	136	1,202
Level 3/3-N/3-R ICE/Turbine	**18,150**	**37,722**	**55,271**	**55,441**	**166,583**
Metered	9,583	19,834	29,967	31,790	91,174
Estimated	8,567	17,888	25,304	23,651	75,410
Total	**20,224**	**41,865**	**61,803**	**59,728**	**183,620**

This difference is due to the fact that the average capacity factor of these incentive Level 3 engines and turbines is greater than that for the Level 1 Solar PV systems. The overall energy production growth rate can be simply characterized by a nearly three fold increase in energy production between Q1 and Q3. This increase is primarily due to additional generation capacity coming on-line during this period, but is also influenced slightly by the seasonal increase in Level 1 PV generation during Q2 and Q3. Due to a seasonal decrease in PV energy production and slowing growth in Level 3 capacity, total energy production in Q4 energy output was similar to that in Q3.

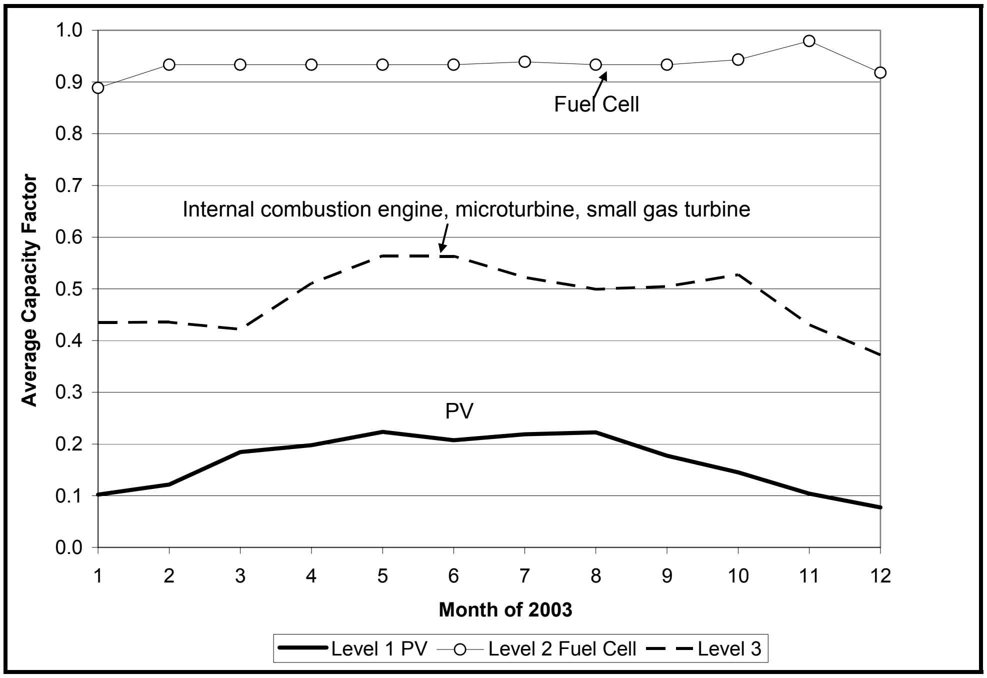
On-line capacity for July 21, 2003, was summarized in Table 9-1. An important factor influencing this program impacts evaluation effort is the fact that additional projects are entering normal operation on a regular basis. The increase in on-line capacity during 2003 is depicted graphically in Figure 9-1. This chart also illustrates the relative quantities of project capacity for the various technologies by incentive level included in the program.

Figure 9-1: On-Line Capacity by Month (2003)



Energy impacts of the program on a quarterly basis were summarized in Table 9-2. In Figure 9-2, the energy production characteristics of the operational systems are expressed on a normalized basis (i.e., monthly capacity factor) to enable comparison of the different distributed generation technologies by Program incentive level. Additional detail concerning these energy production characteristics are discussed in subsequent portions of this section.

Figure 9-2: Average Capacity Factor by Month (2003)



9.3 Level 1 Solar Photovoltaic Systems

The data availability situation for incentive Level 1 PV is summarized in Figure 9-3 and Figure 9-4. As shown in Figure 9-3 the total number of operational PV projects nearly tripled during 2003. Shading in the bars represents the portion of systems (in Figure 9-4 MW capacity) for which metered E-NGO data are available. Due to a variety of factors, complete E-NGO datasets were unavailable for many of the operational PV systems during 2003. The available system output data are used in the analysis directly. These data were also combined with certain known characteristics of projects to estimate peak demand and energy impacts of the unmetered PV systems (e.g., including system location, array tilt and orientation angles, and system size).

Figure 9-3: Solar PV Operational Projects & E-NGO Data Availability (n)

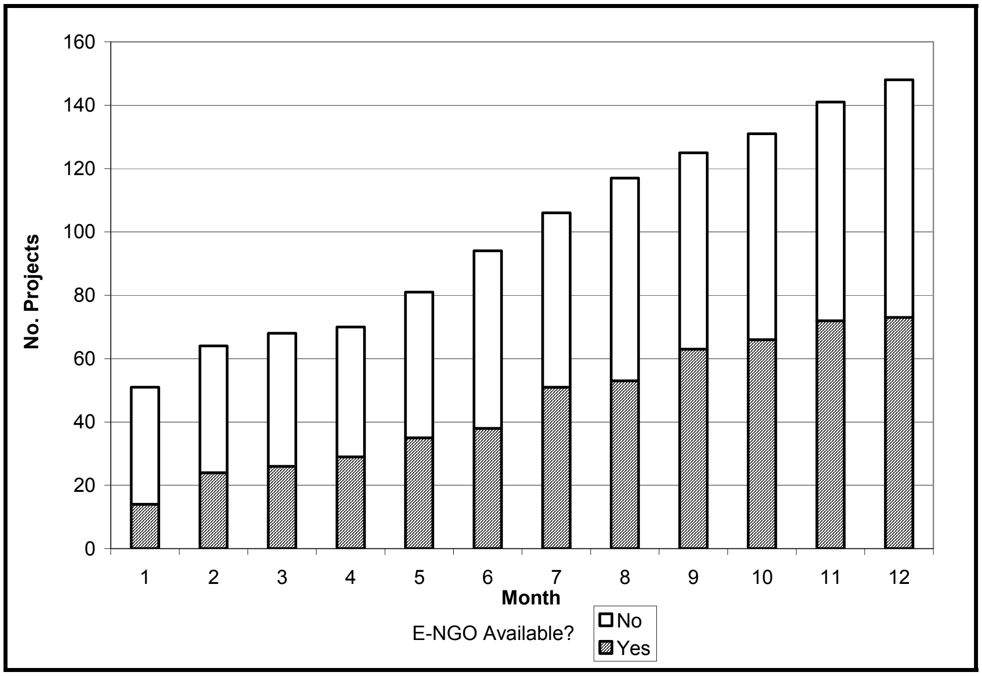
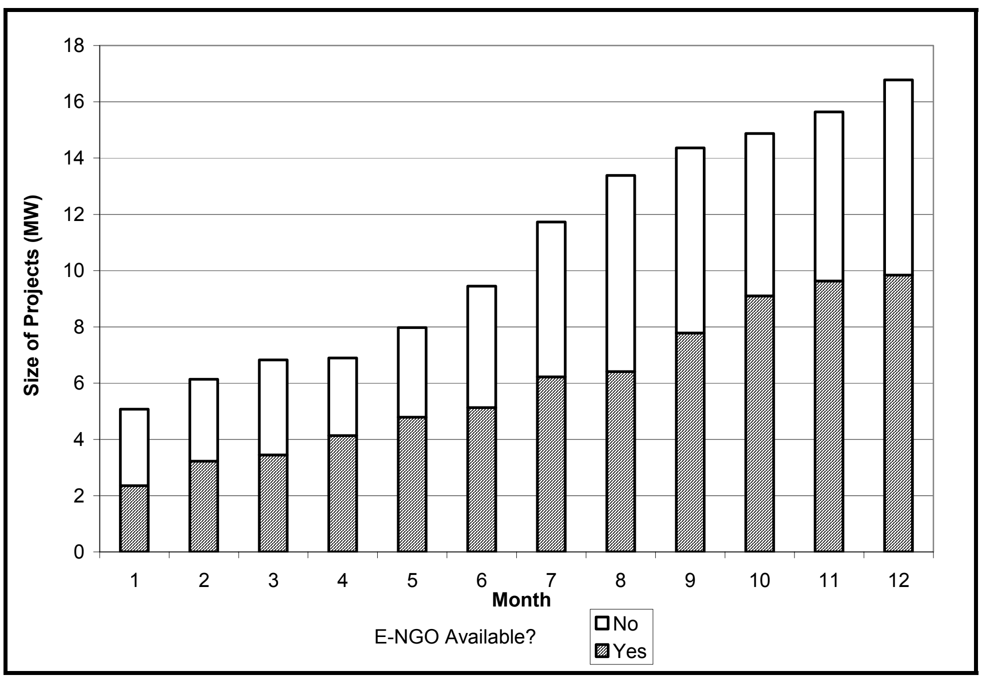


Figure 9-4: Solar PV Operational Projects & E-NGO Data Availability (MW)



Data from the metered projects were used to estimate impacts of the unmetered operational PV systems. Available metered data were used to calculate ratios representing average PV system power output per unit of rebated system capacity. Ratios were calculated separately for each of the sample design strata discussed in Section 5.[1] For periods when no metered data were available, estimates of PV system power output were calculated as:

$$N\hat{G}O_{psdh} = \left(S_{ps}\right)_{Unmetered} \times \left(\frac{\sum NGO_{psdh}}{\sum S_{ps}}\right)_{Metered}$$

Where:

$N\hat{G}O_{psdh}$ = Predicted net generator output for project p in strata s on day d during hour h

Units: kWh
Source: Calculated

S_{ps} = Solar PV system size for project p in strata s

Units: kW
Source: SGIP Tracking System

NGO_{psdh} = Metered net generator output for project p in strata s on day d during hour h

Units: kWh
Source: Net Generator Output Meters

ISO Peak Demand Impacts

In 2003 the statewide ISO system peak occurred on July 21 during the 16th hour (from 3 to 4 PM PDT). During this hour the electrical demand for the CAISO reached 42,581 MW. On this day there were 105 PV systems under the SGIP installed and operating; interval-metered data are available for 45 of them. Resulting estimates of peak demand impacts coincident with the ISO peak load are summarized in Table 9-3. The estimated peak demand impact corresponds to 0.59 kW per 1 kW of PV system size [basis: rebated capacity]. The total program-level system peak demand impact for incentive Level 1 PV systems is estimated to have been 7,494 kW (approximately 7.5 MW).

Table 9-3: Impacts of Level 1 PV Coincident with 2003 ISO Peak

Output Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Metered	45	6,561	3,756
Estimated	60	6,110	3,739
Total	**105**	**12,671**	**7,494**

[1] Due to data availability limitations data available for SCE and SoCalGas PV systems were combined in the 2003 estimation calculations rather than being treated separately. In the future when data collection confirms to the sample design summarized in Section 5, it will not be necessary to combine strata in this manner.

Those unfamiliar with PV system size ratings and PV system operating characteristics may be surprised that the overall weighted-average peak demand impact was not substantially higher than 0.59 $kW_P/kW_{rebated}$. To help put this result in perspective, it can be compared to a simple engineering estimate of peak power output based on published information regarding PV system performance. First, we begin with 1 kW [Basis: rebated size] of horizontal PV system capacity. For purposes of determining rebates, PV system sizes are calculated as the product of cumulative estimated module DC power output under PTC conditions and inverter maximum DC to AC conversion efficiency. The potential influence of several key factors on PV system power output on hot summer afternoons is illustrated in Table 9-4.

Table 9-4: Illustration of Factors Influencing PV System Peak Output

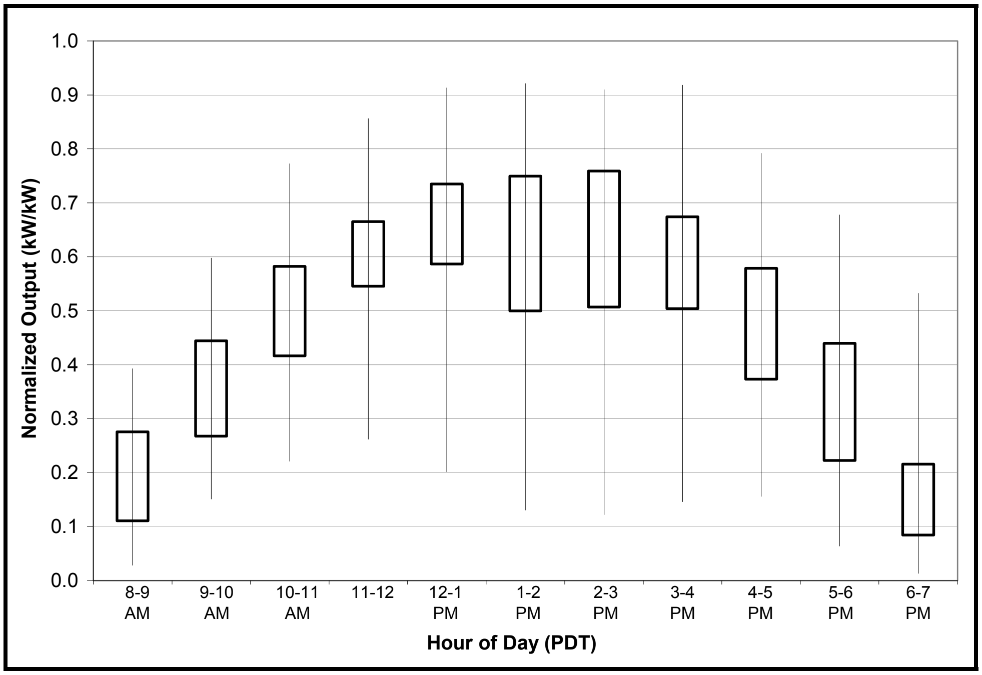
Description	Value	Basis	Summary
Rebated System Size	1.00	Total PTC DC x Inv. Eff.	1.00
Production Tolerance	0.95	PV Design Guide*	0.95
Power output on hot summer afternoon is less than under PTC weather conditions	0.95	CEC research**	0.90
Inverter efficiency at full load is less than rated maximum inverter efficiency	0.95	Assume 95% maximum rated efficiency and 90% full-load efficiency at actual ambient temp.	0.86
Soiling	0.93	PV Design Guide	0.80
Mismatch & wiring	0.95	PV Design Guide	0.76
During late-afternoon hours the sun is not directly overhead	1-2 PM: 1.01 2-3 PM: 0.96 3-4 PM: 0.86	Analysis of hourly TMY data for San Francisco (Summertime, Clear Days)	1-2 PM: 0.77 2-3 PM: 0.73 3-4 PM: 0.65

*A Guide to Photovoltaic (PV) System Design and Installation, Prepared for California Energy Commission Technology Systems Division, Prepared by Endecon Engineering, Publication #500-01-020, June 2001.
**Measured Output for Nineteen Residential PV Systems: Updated Analysis of Actual System Performance and Net Metering Impacts, Boleyn, D.R., Lilly, P., Scheuermann, K., and Miller, S., Proceedings of ASES Annual Conference, American Solar Energy Society, 2002.

For the hour from 3 to 4 PM PDT, a relatively conservative estimate of power output for a horizontal PV system would be 0.65 kW of power output per kW of rebated PV system size, on clear days. The incidence of clouds, shading, or electrical/mechanical problems would result in further decreases of electric power output below the rebated system size.

The peak-day operating characteristics of the 45 PV projects for which peak-day interval-metered data were available are summarized in the box plot of Figure 9-5. System sizes were used to normalize power output values prior to plotting summary statistics of 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 characteristics of PV systems of varying sizes. The vertically oriented boxes represent ranges within which 75% of project-specific values lie. The vertical lines represent the total range (i.e., maximum and minimum) of project-specific values.

Figure 9-5: 2003 ISO Peak Day PV Output Profile Summary



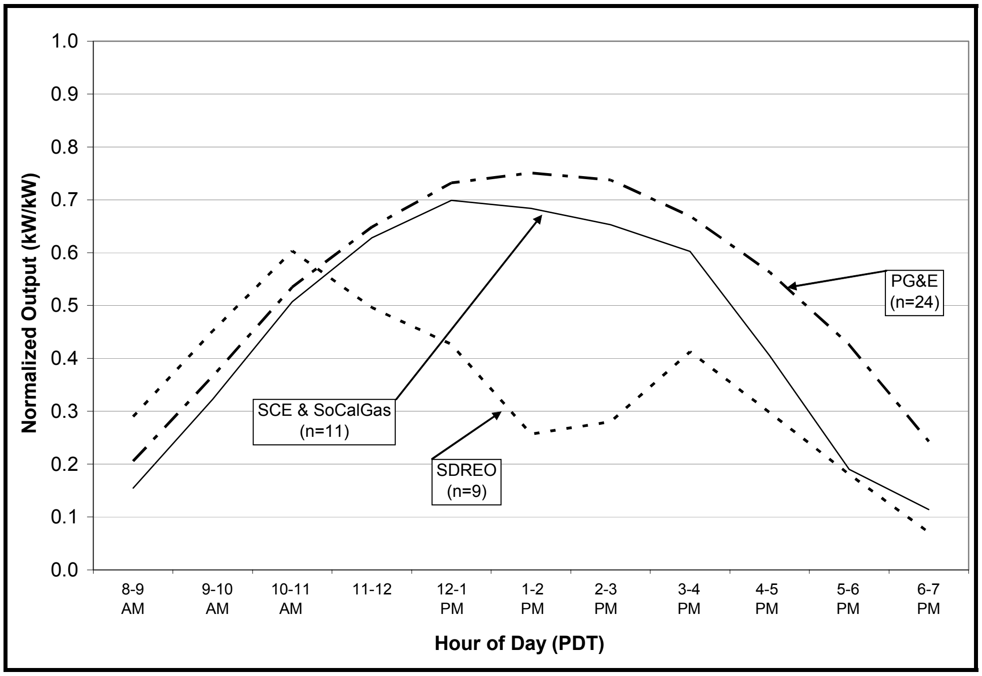
During the hour from 3 to 4 PM three of the 45 metered PV systems produced less than 0.35 $kW/kW_{Rebated}$. These values at the lower end of the range of peak-hour PV system output are significantly lower than what would be expected for a PV system that was operating trouble-free under full-sun conditions. Notes concerning the performance of these three systems are presented in Table 9-5. The PV generation profile depicted in Figure 9-5 reveals an increased degree of variability during the hours from 12 to 3 PM as compared to the hour from 11 AM to 12 PM. Review of weather data and PA-specific generation profiles reveals that cloudy weather in portions of Southern California was largely responsible for this behavior.

Table 9-5: Peak-Hour PV Performance Notes

System Number	Peak-Hour Output ($kW_P/kW_{Rebated}$)	Performance Notes
1	0.15	This system was known to have been experiencing hardware/software problems on this day.
2	0.18	This small system is located approximately 40 miles east of Los Angeles. During the summer of 2003 system output exceeded 0.7 $kW/kW_{Rebated}$ on numerous occasions. On July 21, 2003 power output was 0.48 $kW/kW_{Rebated}$ during the hour from 1 to 2 PM before falling to 0.18 $kW/kW_{Rebated}$ during the hour from 3 to 4 PM. Horizontal solar radiation values measured at a nearby weather station during these two hours were 883 and 307 W/m^2, respectively. Thus, the kW output observed during the hour of the CAISO system peak appears likely to have been strongly influenced by clouds.
3	0.34	This large PV system is located in San Diego near the coast. During other summertime hours this system regularly achieved power output levels of 0.8 $kW/kW_{Rebated}$. Again the output observed during the hour of the CAISO system peak appears likely to have been strongly influenced by either clouds or fog.

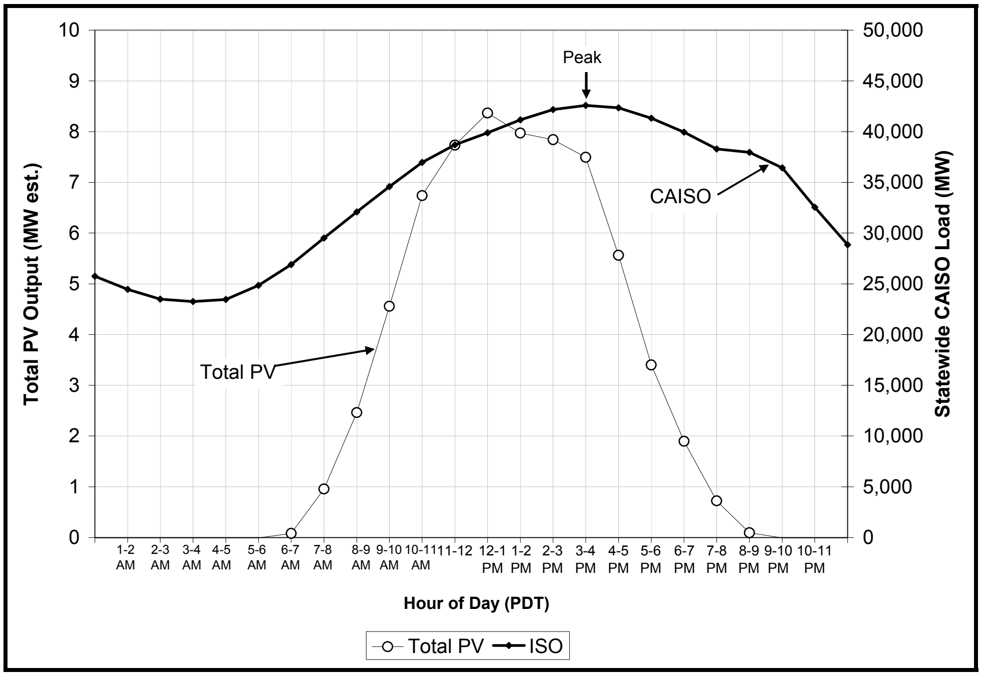
The PA-specific generation profiles are presented in Figure 9-6. These profiles of hourly generation output represent weighted averages calculated as the total power output of the metered systems divided by total cumulative rated size of those systems. For each curve in this graphic the total number of metered sites (n) contributing to the generation profile is identified. These data reveal that on the day of the CAISO 2003 system peak the skies remained relatively clear in the northern portion of the state, whereas regional weather events in the San Diego area resulted in a substantial decrease in PV system power output on July 21, 2003.

Figure 9-6: 2003 ISO Peak Day PV Output Profiles By PA



The peak-day profiles of both ISO system loads and the total of the metered/estimated output of the 105 operational PV systems are illustrated in Figure 9-7. While PV system power output was substantial on the day of the CAISO system peak, the PV output curve's shape is more pointed than the CAISO load's shape. After 1 PM the output of PV systems began falling, whereas CAISO loads continued to increase for several hours.

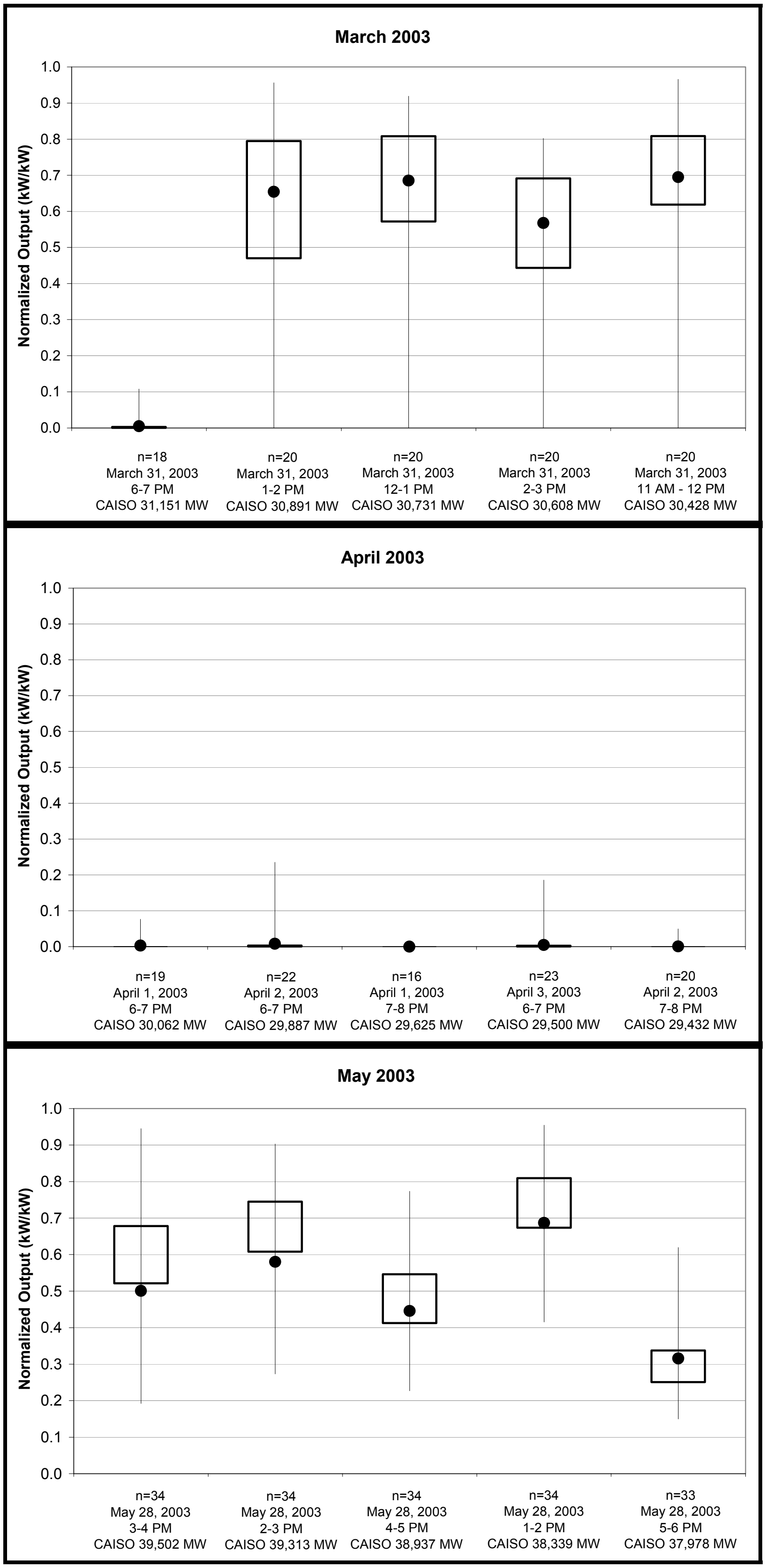
Figure 9-7: 2003 ISO Peak Day System Loads and Total PV Output



To more completely characterize the Program's demand impacts, normalized hourly output of the metered PV systems during fall, summer, and spring hours coincident with the CAISO maximum loads (i.e., 5 peak hours of each month) are summarized in Figure 9-8 through Figure 9-10. In these charts each of the five box plots summarizes power output of metered PV systems during one of the hours during which CAISO maximum loads occurred. The left-most box plot corresponds to the hour when the maximum CAISO load occurred during the month. Remaining box plots are arranged in order of descending CAISO load. CAISO emergency operating conditions are noted where applicable.

Box plots are not provided for winter months because wintertime CAISO loads reached maximum values during evening hours when PV output was small. The weighted average values, depicted in these charts with black circles, were calculated as the total power output of the metered systems divided by total cumulative size of those systems. Weighted averages such as these were calculated and applied to their respective strata in cases where metered data were unavailable and it was necessary to calculate estimates of PV power output.

Figure 9-8: Demand Impacts – PV – Spring



PV output was substantial during four of the five hours when CAISO system loads reached their highest levels. The fifth hour occurred in the evening when average PV output was near zero.

Two of the metered PV systems were not operational on March 31, 2003.

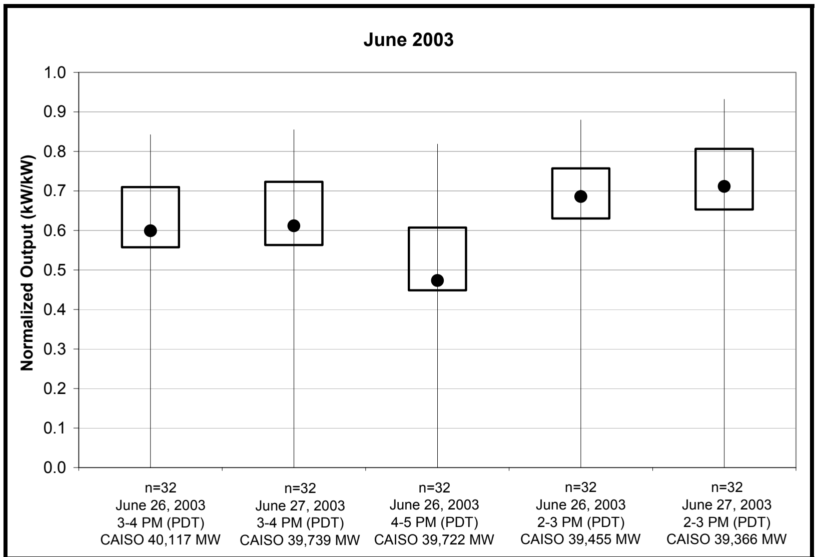
In April 2003 CAISO loads reached maximum values during evening hours when most PV systems were not producing power. Out of a total of 97 system-hours, normalized output exceeded 0.1 kW/kW for only 2 system-hours.

Stage 1 Emergency

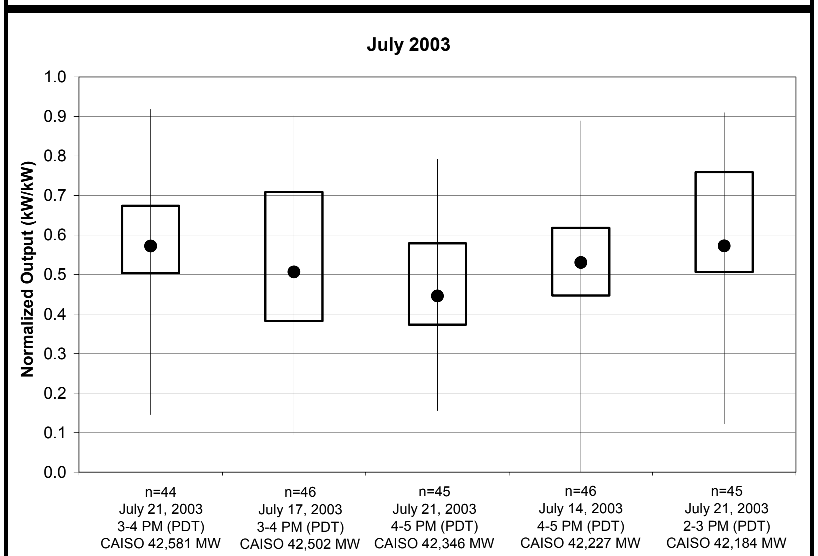
The CAISO declared a Stage 1 Emergency at 4:00 PM PDT on May 28, 2003, when actual generating reserves (6%-7%) fell below required levels. The Emergency event extended to 9:00 PM PDT.

The weighted average value can be outside of the rectangle when a large system's output is either quite high or quite low.

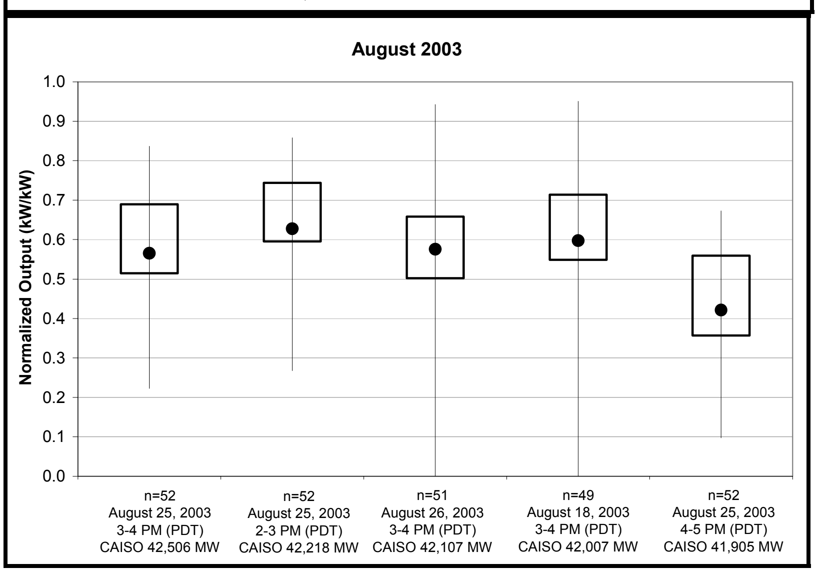
Figure 9-9: Demand Impacts – PV – Summer



One PV system was not operational on June 26 and June 27. This system was off-line for approximately two weeks during summer 2003. This is not one of the two systems identified above as being off-line during a portion of March 2003.

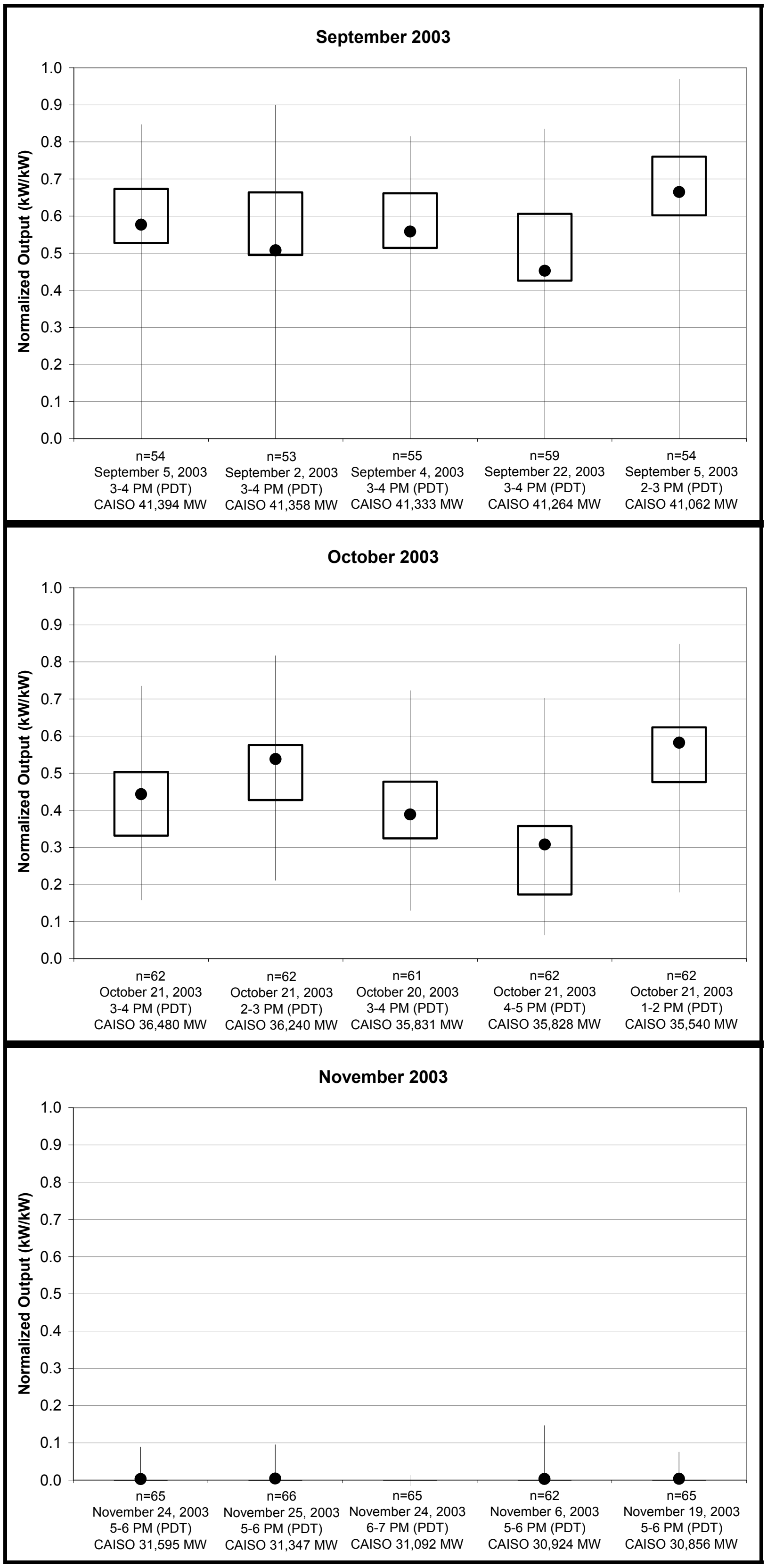


On July 14, 2003, one PV system went off-line in the middle of the day and stayed off for the next two days. This is not one of the three systems identified above as being off-line during a portion of March 2003 or June 2003.



On August 26 one system tripped off during the afternoon hours. This was the only day during summer 2003 that this PV system was off-line. On August 18 a different system was off-line during the hour when CAISO loads reached a high level. The output of this system was erratic for approximately one month; in mid-September its performance appeared to stabilize. These two systems were on-line during the March, June, and July CAISO peak events described above.

Figure 9-10: Demand Impacts – PV - Fall



The system with erratic performance in August continued to experience problems that took it off-line intermittently on September 2, 4, and 5. On September 22 when CAISO loads reached 41,264 MW a 30 kW PV system was off-line. This system was off-line for approximately three weeks in September; it operated normally during all of October.

In October 2003 no metered PV systems were off-line during the five hours when CAISO loads reached their maximum values for the month. During these five hours the weighted average PV output of metered systems ranged from 0.31 to 0.58 kW of power output per kW of rebated PV system capacity.

During November 2003 maximum CAISO loads occurred during evening hours. Several systems produced small quantities of power during these hours; however, the weighted average PV output of metered systems was near zero.

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 9-3 and Figure 9-4, a substantial portion of total Program PV energy production was not captured in interval-metered data. Therefore, energy impacts were estimated in cases where metered data were not available. Metered and estimated energy production (MWh) impact results for Level 1 solar PV systems are summarized by quarter in Table 9-6.

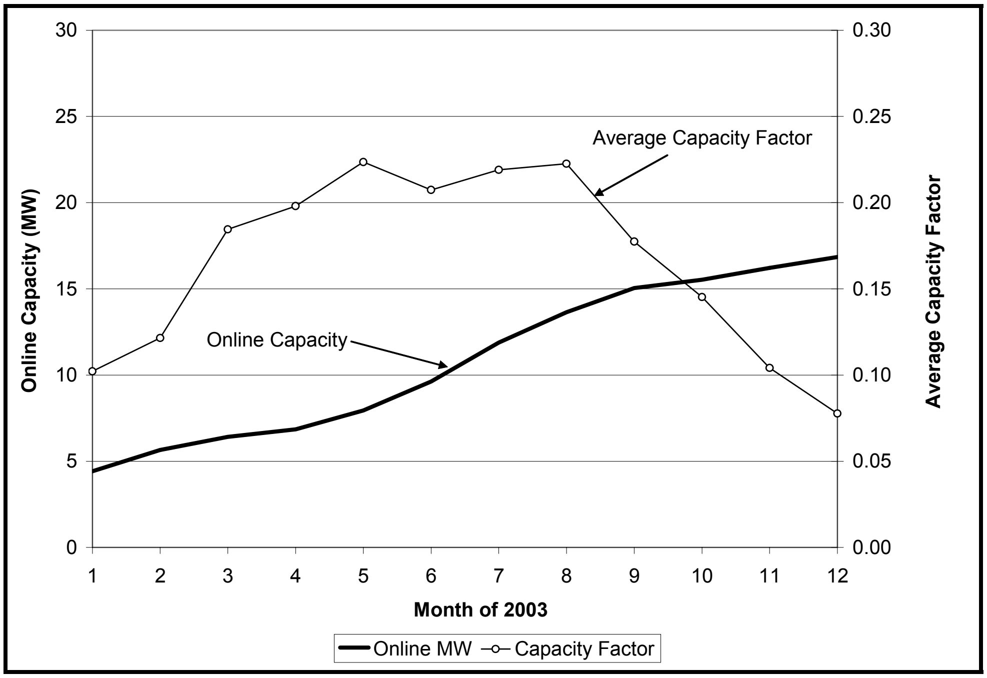
Table 9-6: Energy Impacts of PV in 2003 by Quarter (MWh)

Output Basis	Q1-2003	Q2-2003	Q3-2003	Q4-2003	Total MWh
Metered	852	2,173	3,245	2,405	8,676
Estimated	826	1,563	2,874	1,463	6,726
Total	**1,678**	**3,736**	**6,119**	**3,869**	**15,402**

The quarter-to-quarter variability exhibited in energy impacts results presented in Table 9-6 is largely due to the fact that projects were coming on-line throughout 2003. The project completion trend is summarized in Figure 9-11 (on the left axis). The energy production of the group of metered PV systems varied according to season. In Figure 9-11, normalized energy production by month is illustrated (on the right axis). These values represent the monthly average capacity factor for the on-line PV system capacity.

As expected, normalized energy production levels reach their maximum values in the summer season and decrease towards the winter season as the intensity and duration of incident solar radiation falls off, coupled with increased incidence of storms and other weather disturbances off the Pacific ocean which affect the availability of solar radiation on the PV systems. The arithmetic mean of these monthly values is 17%. The annual average load factor for individual systems, or for years other than 2003, will likely be different.

Figure 9-11: PV On-Line Capacity & Average Capacity Factor (2003)



9.4 Incentive Level 1 Wind Turbine Systems

There were no operating wind systems funded under the program identified during the period of CY2003. Although there have been three such wind project applicants that have applied to the Program. All three applicants have now reached the Proof of Project Advancement (PPA) stage of development.

9.5 Incentive Level 1 & 2 Fuel Cells

As of the end of 2003, no Level 1 fuel cells (renewable fuel) were operational -- although two such projects were in early stages of development. One Level 2 fuel cell project was installed and operating during all of 2003. A limited quantity of metered data is available for this system during the months of January, July, and October through December. An average operating capacity factor of 93% is indicated by the available metered data. This average value was used to estimate demand and energy impacts of the operational fuel cell system during periods when metered data were not available. Estimated 2003 peak demand impacts on the ISO from the operational Level 2 fuel cell project are summarized in Table 9-7.

Table 9-7: Impacts of Level 2 Fuel Cells Coincident with 2003 ISO Peak

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio ($kW_P/kW_{Rebated}$)
Metered	0	0	0	0.00
Estimated	1	200	187	0.93
Total	**1**	**200**	**187**	**0.93**

To estimate energy impacts an average capacity factor of 93% was assumed. The resulting distribution of energy impacts by quarter is summarized in Table 9-8.

Table 9-8: Energy Impacts of Level 2 Fuel Cells in 2003 by Quarter (MWh)

Output Basis	Q1-2003	Q2-2003	Q3-2003	Q4-2003	Total MWh
Metered	132	0	19	282	433
Estimated	264	408	394	136	1,202
Total	**396**	**408**	**413**	**418**	**1,635**

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

The electric NGO data availability situation for Level 3/3-N/3-R internal combustion engines and turbines is summarized in Figure 9-12 (basis: n = number of systems) and Figure 9-13 (basis: kW generation capacity). Shading in the bars represents the portion of systems/capacity for which metered E-NGO data are available. In terms of growth rates, both the total number of operational projects and operational capacity increased by approximately 300% during 2003.

Figure 9-12: Level 3/3-N/3-R Operational Projects & E-NGO Data Availability (n)

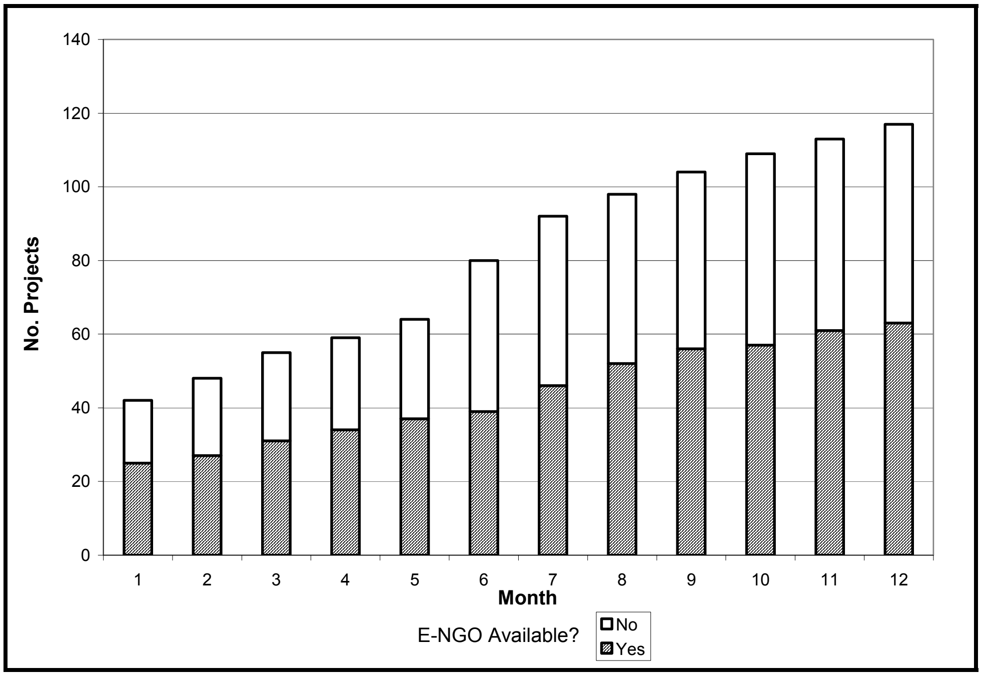
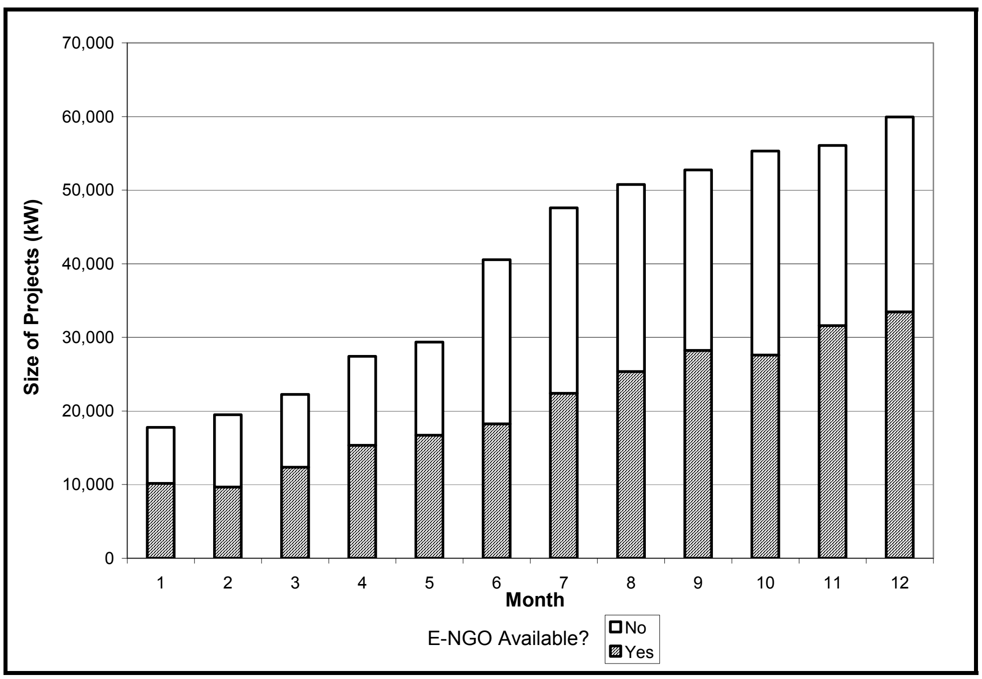


Figure 9-13: Level 3/3-N/3-R Operational Projects & E-NGO Data Availability (kW)



Consistent with the other technologies, data from metered projects were used to estimate impacts of unmetered internal combustion engines, microturbines, and small gas turbines. First, available metered data were used to calculate ratios representing average power output per unit of rebated system capacity. For periods when no metered data were available, estimates of power output were calculated as:

$$N\hat{G}O_{sdh} = \left(S_s\right)_{Unmetered} \times \left(\frac{\sum NGO_{sdh}}{\sum S_s}\right)_{Metered}$$

Where:

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

S_s = System size for system *s*
Units: kW
Source: SGIP Tracking System

NGO_{sdh} = Metered net generator output for system *s* on day *d* during hour *h*
Units: kWh
Source: Net Generator Output Meters

ISO Peak Demand Impacts

In 2003 the statewide ISO system peak occurred on July 21 during the 16th hour (from 3 to 4 PM). During this hour the electrical demand for the ISO reached 42,581 MW. On this day there were 89 engines and turbines under the SGIP installed and operating. Interval-metered data were available for 42 of these Incentive Level 3 systems. Resulting estimates of peak demand impacts on the ISO are summarized in Table 9-9. The estimated demand impact corresponds to 0.60 kW per 1.00 kW of installed system size [Basis: rebated capacity]. The total program-level system peak demand impact for incentive Level 3/3-N/3-R engines and turbines is estimated at approximately 28 MW.

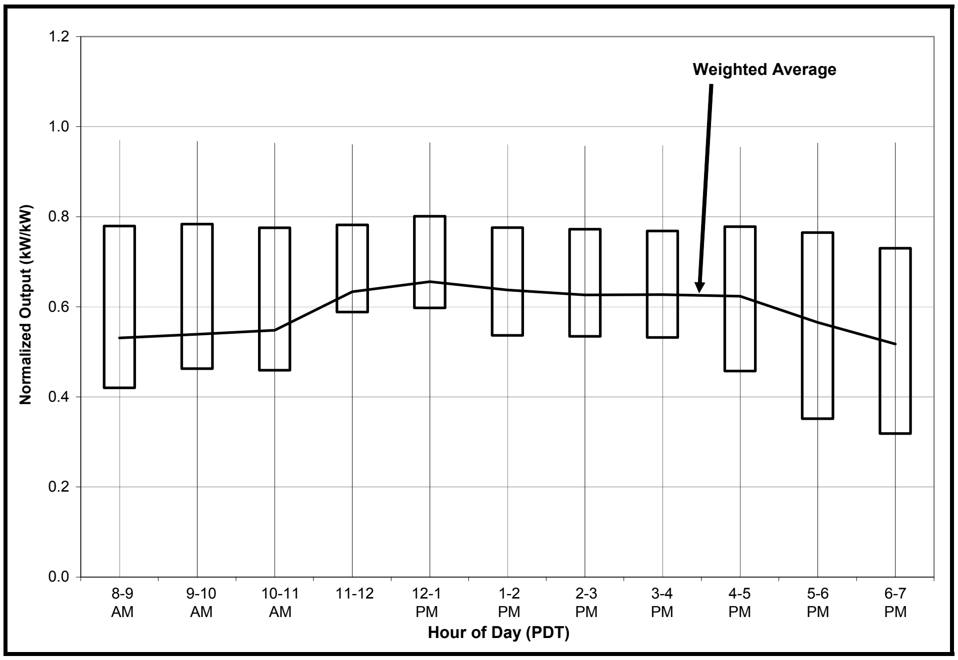
Table 9-9: Impacts of Level 3/3-N/3-R Systems Coincident with 2003 ISO Peak

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Metered	42	19,365	11,768
Estimated	47	26,645	15,642
Total	**89**	**46,010**	**27,410**

The peak-day operating characteristics of the 42 IC engine and turbine projects for which peak-day interval-metered data were available are summarized in the box plot of Figure 9-14. System sizes were used to normalize power output values prior to plotting summary statistics of electric output profiles for individual projects. The normalized values represent power output per unit of system size. Treatment in this manner enables direct comparison of the power output of systems of varying sizes.

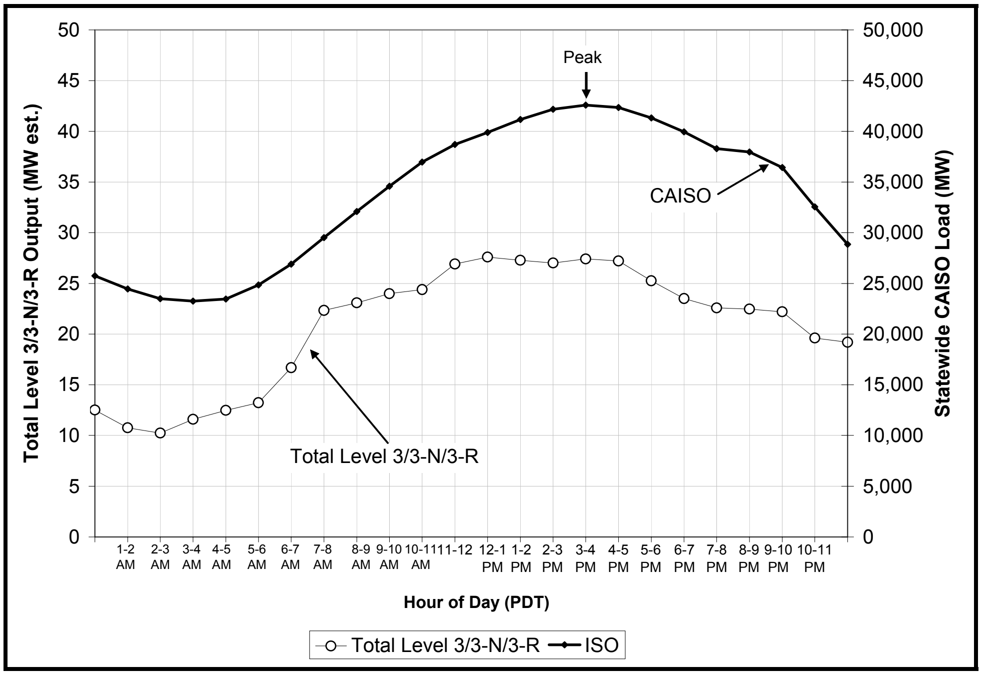
The boxes represent ranges within which 75 percent of project-specific values lie. The vertical lines represent the range of project-specific values (e.g., maximum and minimum normalized output). The weighted average depicted in this graphic with a heavy solid line was calculated as the total power output of the 42 systems divided by total cumulative capacity of those systems. These values were used to estimate output of Level 3/3-N/3-R projects in cases where metered data were unavailable. Two of the systems were idle on this ISO peak day.

Figure 9-14: ISO Peak Day Level 3/3-N Output Profile Summary (July 21, 2003)



The peak-day profiles of both ISO system loads and the total of the metered/estimated output of the 89 operational Level 3/3-N/3-R systems are illustrated in Figure 9-15. The shape of the output curve for engines and turbines aligns well with the statewide ISO system peak from 3 to 4 PM, and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak).

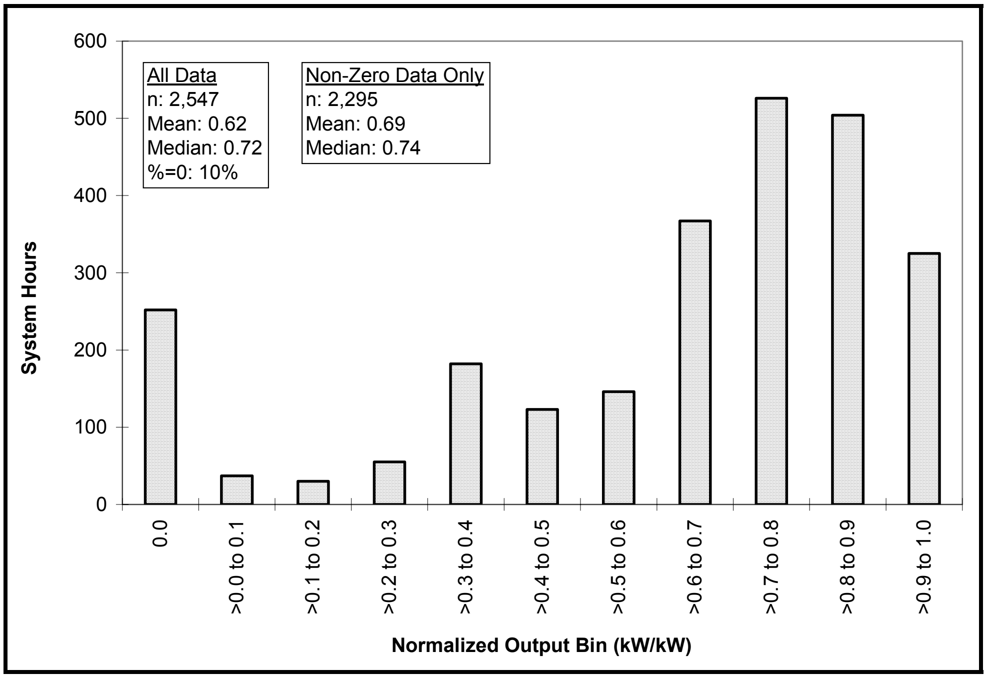
Figure 9-15: ISO 2003 Peak Day Loads & Coincident Total Level 3/3-N/3-R Generation Output



To more completely characterize the Program's demand impacts, normalized hourly output of the metered Level 3 systems during 2003 coincident with the ISO maximum loads (i.e., based on the 5 peak hours of each month) are summarized in Figure 9-16. "System Hours" are based on a given operational hour for each cogeneration system that is "on-line" during a defined period of time. Whereas for PV both intra- and inter-day variability were significant, for Level 3 systems it is more meaningful to consider all 60 ISO-maximum load hours as a single group. These 60 hours correspond to a total of 2,547 system hours (i.e., the average number of "on-line" [but not necessarily operational] systems was 42. As shown in Figure 9-1, on-line capacity increased steadily throughout 2003. For this group, normalized kW output of the monitored Level 3 systems on a weighted average basis was equal to 0.61 kW of power output per kW of rebated system size during the top 5 peak load hours each month over the CY 2003 period of this assessment. This annual average result is identical to the demand impact of metered systems during the single hour of the ISO annual peak.[2]

[2] For several Level 3/3-N projects monthly kWh production data were available instead of interval-metered data. These monthly totals were combined with an assumed generation profile to estimate demand impacts. Consequently, the weighted-average peak demand impact for the group of projects for which demand impacts were estimated is not identical to the weighted-average peak demand impact for the group of projects for which interval-metered data were available.

Figure 9-16: Demand Impacts – Level 3/3-N – Basis: Five Hours each Month when ISO Loads Reach Maximum Levels



The idle units (0.0 kw/kw normalized output) play an important role in reducing the average output of all rebated units during hours when ISO loads reach their maximum values. Several characteristics of these idle-system hours include:

- Among units that were metered during at least 5 of the 60 ISO-maximum hours, none were idle during more than 40% of these metered hours.
- While 42 units were metered on the day of the ISO peak, a total of 64 different systems were metered during at least one ISO-maximum hour (i.e., during the second half of 2003 the number of metered units increased by approximately 50%). Of these 64 systems, only one-third were operational during all of the ISO-maximum hours they were metered.
- The incidence of idle units during summer months was lower than during other months. While 26% of the 2,547 ISO-maximum hours occurred during summer, only 21% of the idle-system hours occurred in summer.
- The incidence of idle units was similar for internal combustion engines and microturbines. Microturbines accounted for 37% of the 2,547 ISO-maximum system hours, but were responsible for 42% of the idle-system hours.
- The incidence of idle units was similar for systems smaller than 200 kW and those 200 kW or larger. Systems <200 kW accounted for 39% of the 2,547 ISO-maximum system hours, but were responsible for 42% of the idle-system hours.
- When normalized output is non-zero but very low, it is likely that the unit operated for only a portion of the hour.

- Many rebated systems comprise multiple generating units. For instance, for a system comprising two units, normalized output equal to 0.5 kW/kW could represent full-load operation of one unit only, or half-load operation of both units. In many instances electric metering captures output of all rebated units, thus limiting ability to infer operational practices directly from the data.
- Cogeneration systems may be operated in a "load following" mode. Depending on the size of the cogeneration system relative to the magnitude and timing of facility loads, this factor could account for some of the system hours corresponding to reduced normalized output levels. The influence of these factors on energy production is discussed in the following section.

A limited-scope process evaluation is being implemented concurrently with the impacts evaluation covered by this report. One important objective of the process evaluation is to collect information about system performance, reliability, and operational practices. Results of the process evaluation will be presented in a separate report.

Energy Impacts

In cases where metered data were available, they were used directly to calculate energy impacts of Level 3/3-N/3-R systems. However, as illustrated above in Figure 9-12 and Figure 9-13, 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. The resulting distribution of energy impacts by quarter is summarized in Table 9-10. The variability in energy production observed across quarters is primarily attributable to systems coming on-line throughout 2003, as illustrated in Figure 9-12 above.

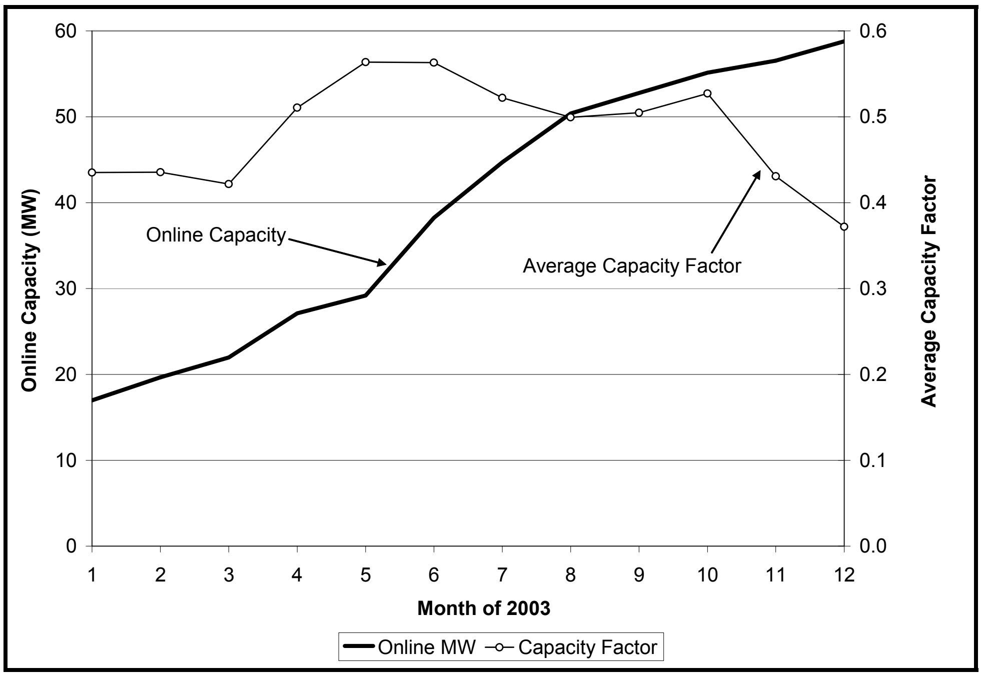
Table 9-10: 2003 Energy Impacts of Level 3/3-N/3-R Systems by Quarter (MWh)

Basis	Q1-2003	Q2-2003	Q3-2003	Q4-2003	Total MWh
Metered	9,583	19,834	29,967	31,790	91,174
Estimated	8,567	17,888	25,304	23,651	75,410
Total	**18,150**	**37,722**	**55,271**	**55,441**	**166,583**

The project completion trend for Level 3/3-N/3-R systems is summarized in Figure 9-17 along with monthly average capacity factor. Whereas for PV systems the pronounced seasonal variability of monthly average capacity factor illustrated in Figure 9-11 was expected, the capacity factor of engines and turbines is influenced by fundamentally different factors. PV system power output is primarily governed by weather, and PV systems in the program are eligible for net-metering tariffs that enable them to produce more power than is consumed by the facility during certain hours.

Engine and turbine power output is primarily governed by on/off switches and the on-site demand for thermal energy, and is generally required to be controlled to a level such that substantial quantities of power are not exported to the grid. Depending on the relative size of the engine or microturbine system, when facility power requirements are low the power output of the distributed generation system might need to be throttled down to prevent export of power to the grid. Consequently, monthly average capacity factor may be strongly influenced by facility operating hours (i.e., 1-, 2-, or 3-shift). The capacity factor data presented in Figure 9-17 are provided for summary purposes only. Because additional metered systems were being added periodically throughout the year, and because the number of complete-year datasets is small, it is not possible to draw any sweeping conclusions from these summary data. They do provide a meaningful reference point for comparison to capacity factors for other technologies however.

Figure 9-17: Level 3/3-N/3-R On-Line MW & Average Capacity Factor (2003)



9.7 Review of Useful Thermal Energy and System Efficiency

Level 2 fuel cells and Level 3/3-N engines/turbines are subject to certain heat recovery and system efficiency requirements during the implementation stage of the Self-Generation Incentive Program. A variety of means are used to recover heat for useful purposes, and to apply that heat to provide various forms of heating and cooling services. The end uses served by recovered useful thermal energy are summarized in Table 9-11, which includes projects that had entered operation through December 2003.

Table 9-11: End Uses Served by Level 2/3/3-N Recovered Useful Thermal Energy

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	71	30,284
Heating & Cooling	14	11,073
Cooling Only	25	12,950
Total	**110**	**54,307**

To assess actual heat recovery and system efficiency performance, useful heat recovery will be monitored. Availability of these data for 2003 is summarized in Table 9-12, which provides the number and capacities of cogeneration projects for which useful thermal energy data for CY2003 were available. In some cases, availability of CY2003 data was not sufficient to estimate PUC 218.5 thermal energy proportions or efficiencies due to their annual basis. These sites with insufficient data were not included in Table 9-12 9-12 or in the subsequent summaries of system efficiency results.

Table 9-12: Level 2/3/3-N Useful Thermal Energy Data Availability (CY2003)

End Use	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	15	4,346
Heating & Cooling	2	1,800
Cooling Only	4	2,400
Total	**21**	**8,546**

Overall Cogeneration System Efficiencies Actually Observed

Level 2 fuel cell and Level 3/3-N engine/turbine cogeneration system designs are required to demonstrate [on paper through engineering design documentation] achievement of the minimum efficiencies presented in Table 9-13.

Table 9-13: Program Required PUC 218.5 Minimum Performance

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

Available metered thermal data collected from these on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results of the analysis for Level 3/3-N projects are summarized in Table 9-14. A complete year of data was available for 13 of the 20 systems. In 6 other cases at least 5 months of data were available for the second half of 2003. While the basis of the PUC 218.5 proportions and efficiencies is annual, when at least 5 months of data from several seasons are available the calculated results are representative of what could be expected on an annual basis.

Table 9-14: Actual Level 3/3-N Cogeneration System Efficiencies (n=20)

Summary Statistic	218.5 (a) proportion	218.5 (b) Efficiency	Overall Plant Efficiency
Min	1%	23%	25%
Max	54%	43%	58%
Median	46%	35%	45%
Mean	39%	35%	44%
Std Dev	17%	5%	10%
Coefficient of Variation	0.4	0.1	0.2

Metered data collected to date suggest that 2 of the 20 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%. The limited quantities of cogeneration system data available for this impacts analysis suggest the possibility of systematic negative variance between planned system efficiencies and actual system efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn. Data were available for one fuel cell project, which satisfied the requirements of PUC 218.5 (a) and achieved a PUC 218.5 (b) system efficiency exceeding 50%.

Electrical Conversion Efficiencies Actually Observed

Results of an analysis of electrical conversion efficiencies are presented in Table 9-15. Gross electric generator output data and engine/turbine fuel usage data were combined in a calculation of engine/turbine electric conversion efficiency. In the case of reciprocating engines (ICE), actual electrical conversion efficiencies below 30% are typical. This typical result is substantially less than electrical conversion efficiencies normally found in published technical specifications by engine-genset manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30%, and sometimes exceed 35%.

Table 9-15: Level 3/3-N Electrical Conversion Efficiency[3]

Summary Statistic	ICE	MT
n	22	12
Min	23%	19%
Max	36%	26%
Median	29%	23%
Mean	29%	23%
Std Dev	3%	2%

Observed electrical efficiencies for microturbines were lower than those for reciprocating engines, as expected. The median efficiency actually observed was 23%. This is lower than nominal microturbine efficiencies typically published by manufacturers. For purposes of comparison, the observed electrical conversion efficiencies are presented in Table 9-16 with the representative nominal efficiencies originally presented in Table 5-7. In the context of PUC 218.5 (b) efficiency calculations, these variances are *relatively more significant* than those on the useful recovered heat side of the equation because only 50% credit is given to the recovered heat in the 218.5 (b) efficiency equation. These factors are discussed in more detail in the following section.

Table 9-16: Representative Nominal Versus Observed Gross Electrical Conversion Efficiencies

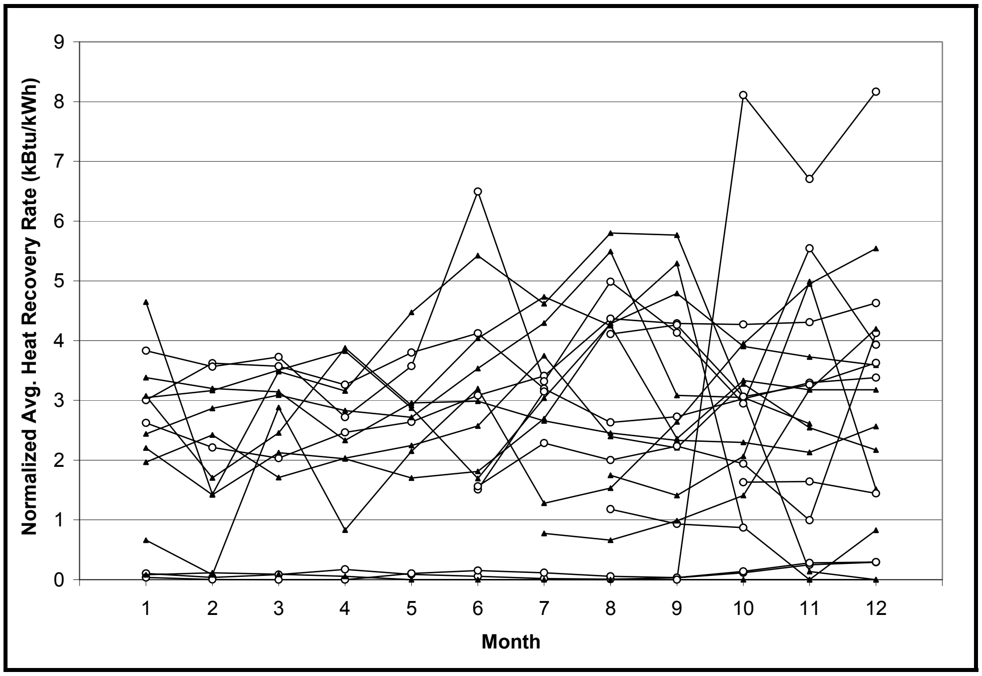
Combustion Technology	Representative Nominal Efficiency (%, LHV)	Median Observed Efficiency (%, LHV)
Microturbine	28%	23%
Internal Combustion Engine	34%	29%

Useful Heat Recovery Actually Observed

Both inter- and intra-system variability exhibited by actual useful heat recovery rates is depicted graphically in Figure 9-18. To enable direct comparison of systems of different sizes the monthly average heat recovery raw data were normalized with respect to net generator electric energy output. Normalized actual useful heat recovery rates are therefore expressed in terms of kBtu of useful recovered heat per kWh of net generator electric energy production.

[3] The electrical conversion efficiencies are calculated as the ratio of gross electric generator output to *lower heating value* of fuel content after converting both to an identical units basis.

Figure 9-18: Actual Useful Heat Recovery by Month (n=21)



The monthly recovered useful thermal energy data of Figure 9-18 are summarized in Table 9-17. For these 21 systems for which 2003 data were available for this analysis, substantial variability among systems was observed in the normalized measure of monthly average heat recovery rate. This variability is reflected in the incidence of several projects with very minimal heat recovery, as well as the considerable variability (i.e., 2 to 5 kBtu/kWh) observed for the projects where appreciable quantities of useful heat were recovered.

Table 9-17: Actual Useful Heat Recovery Rates (n = 21)

Summary Statistic	Value (kBtu/kWh)
Min	0.0
Max	4.0
Median	2.8
Mean	2.4
Std Dev	1.3

In general, the actual useful heat recovery rates observed in 2003 were less than projected by engineering calculations completed during the design stage of cogeneration system project development. The variance is due to numerous factors, including: design problems, operational problems, unanticipated operational conditions, and system or component reliability problems. Information about these problems is being collected as part of the limited-scope process evaluation previously described in this report. Results of the process evaluation will be presented in a separate report, and will help explain the quantitative results presented in this report.

Finally, it must be emphasized that the quantity of useful recovered heat data is very modest. While the total capacity of operational cogeneration systems approached 60 MW at the end of 2003, this analysis included useful recovered heat data for projects totaling less than 10 MW. In addition, for some of these projects less than a complete year's worth of data were available. This monitored group does not represent a statistical sample; rather, it could best be characterized as a monitored group for which useful recovered heat data were available. While results presented in this report for 2003 are suggestive of systematic deviation between planned system efficiency and actual system efficiency, current data availability constraints preclude the drawing of definitive conclusions at this time.

10

Summary of Results and Key Findings

10.1 Introduction

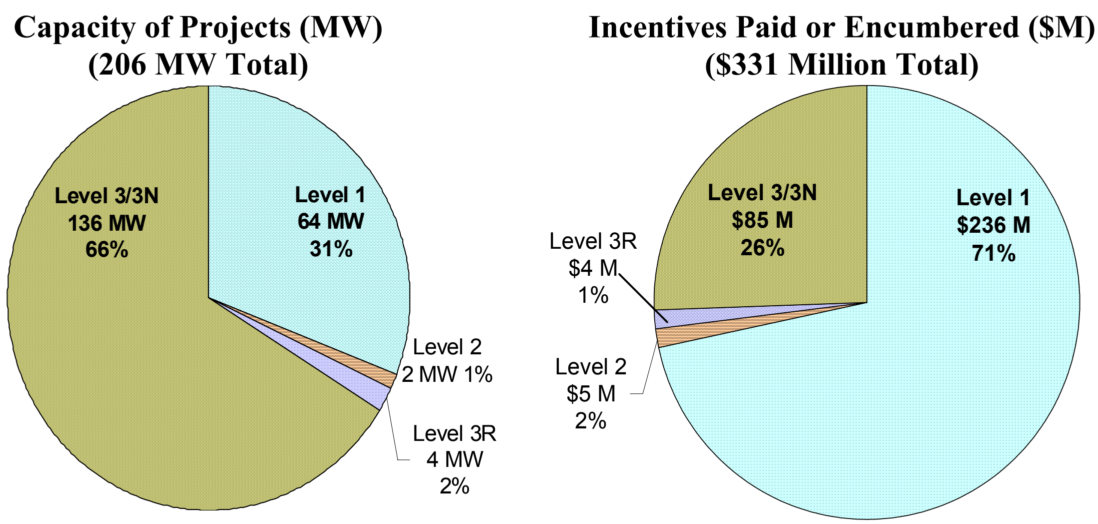
This section of the Program Impacts Assessment summarizes results and key findings for all Self-Generation Incentive Program projects from program years PY01, PY02, and PY03. Electrical demand and energy impacts were estimated for operational projects regardless of their stage of advancement in the program. 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. Substantial quantities of electric net generator output (E-NGO) data were available for analysis. Only limited quantities of useful recovered heat data were available for use in the analysis of cogeneration system performance. These results must be considered preliminary. The metering installation and data collection efforts are ongoing. More definitive results will be available at a future data for operational data collected during 2004 and 2005.

10.2 Summary of Results

Program Status

Overall program status is summarized at a high level in Figure 10-1, which includes projects

Figure 10-1: Summary of PY01- PY03 Project Capacity and Incentives by Level



that either remain active in the program or have advanced in the program through the incentive payment phase. Level 1 photovoltaic, fuel cell, and wind projects account for 31% of the project capacity and 71% of the program incentives. Participation volumes for Level 2 fuel cells and Level 3R renewable fuel projects have been modest to date.[1] Cogeneration systems in Levels 3/3N account for the majority of the program capacity through PY 2003.

Additional project characteristics detail is presented in Table 10-1. The weighted average incentive paid for PV projects completed through 2003 is $3.02/Watt. (All Level 1 projects completed through 2003 were PV projects.) This is 33% less than the $4.50/Watt cap on Level 1 incentives. The incentive for many of the completed PV projects was governed by the maximum 50% of eligible project costs limit.

Level 3/3N projects average 517 kW in size and correspond to weighted average incentives of $0.62/Watt, which is 38% below the $1.00/Watt cap on Level 3/3N incentives. As with completed PV projects, the incentive for many of the Level 3/3N cogeneration systems is governed by the maximum 30% of eligible project costs limit for Level 3/3N.

Table 10-1: Project Characteristics by Status and Level

Level and Status[2]	Projects	Total Capacity (kW)	Average Capacity (kW)	Incentives ($1,000)	Incentives[3] ($/Watt)
Level 1					
Active	286	48,474	169	$190,509	$3.93
Complete	117	15,220	130	$45,944	$3.02
Total	**403**	**63,694**	**158**	**$236,453**	**$3.71**
Level 2					
Active	3	1,800	600	$4,500	$2.50
Complete	1	200	200	$500	$2.50
Total	**4**	**2,000**	**500**	**$5,000**	**$2.50**
Level 3/3N					
Active	199	106,900	537	$67,694	$0.63
Complete	65	29,469	453	$17,009	$0.58
Total	**264**	**136,369**	**517**	**$84,703**	**$0.62**

[1] Incentive Levels 3-N and 3-R did not exist in PY2001. In September 2002, Level 3 was bifurcated into Level 3-R and 3-N depending upon the types of fuels used. Projects which applied for funding prior to this date were classified as Level 3 projects regardless of the type of fuels used.

[2] In this summary "Complete" projects are those projects that have been installed and inspected through an on-site verification and an incentive check has been issued. Some "active" projects are also operational. The total capacities in Table 10-2 are based on program status not operational status.

[3] These $/watt values were calculated as total incentives divided by total capacity. This capacity-weighted average is less than the result that would be yielded by simply taking the arithmetic mean of $/watt values for individual projects.

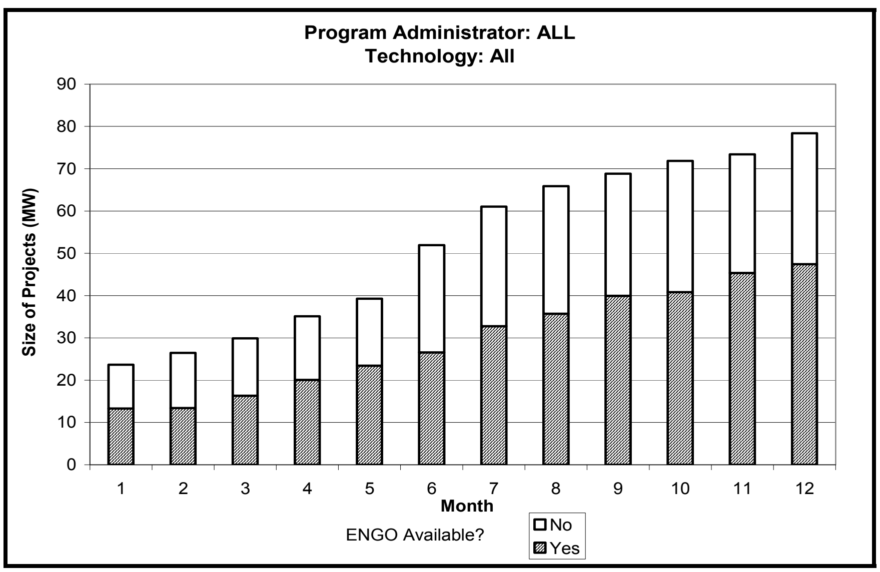
Table 10-1: Project Characteristics by Status and Level (Continued)

Level and Status[4]	Projects	Total Capacity (kW)	Average Capacity (kW)	Incentives ($1,000)	Incentives[5] ($/Watt)
Level 3R					
Active	15	3,593	240	$3,867	$1.08
Complete	1	420	420	$485	$1.15
Total	**16**	**4,013**	**251**	**$4,352**	**$1.08**
All Levels					
Active	503	160,767	320	$266,570	$1.66
Complete	184	45,309	246	$63,938	$1.41
Total	**687**	**206,076**	**300**	**$330,508**	**$1.60**

Metering Sample Design and Data Collection

The 2003 calendar year (CY2003) E-NGO data collection status for all known operational PY01, PY02, and PY03 projects is summarized at the program level in Figure 10-2. E-NGO data are available for more than half of the operational system capacity. An important factor influencing this program impacts evaluation effort is the fact that additional projects are entering normal operation on a regular basis. In Figure 10-3, the CY2003 useful thermal energy data collection status for all four Program Administrators is summarized.

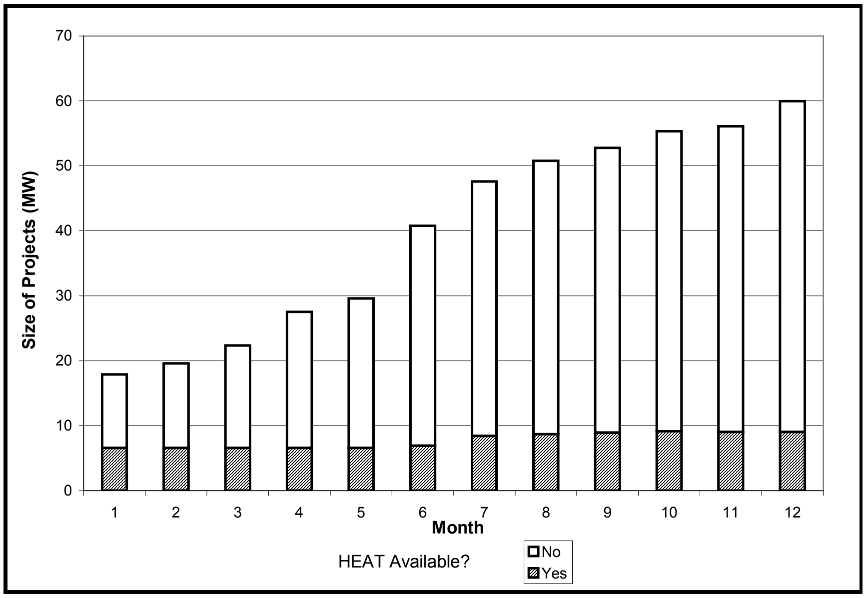
Figure 10-2: E-NGO Data Collection Summary (CY2003)



[4] In this summary "Complete" projects are those projects that have been installed and inspected through an on-site verification and an incentive check has been issued. Some "active" projects are also operational. The total capacities in Table 10-2 are based on program status not operational status.

[5] These $/watt values were calculated as total incentives divided by total capacity. This capacity-weighted average is less than the result that would be yielded by simply taking the arithmetic mean of $/watt values for individual projects.

Figure 10-3: Useful Thermal Energy Data Collection Summary (CY2003)



This summary graphic covers all Level 2 and Level 3-N projects that are subject to heat recovery and system efficiency eligibility requirements during the implementation phase of program participation. To date only a small quantity of useful thermal energy data are available for analysis. The vast majority of these data were obtained from program participants.

An examination of metering-related sample design issues is covered in Section 5 of this report. In the future, a sampling strategy will be employed by three of the Program Administrators for PY03-PY04 PV systems with rebated capacities <300 kW. SDREO will continue 100% E-NGO metering due to its smaller participant count and due to unique circumstances governing metering of PV systems in the SDG&E service area. A census of all other technologies will continue to be subjected to E-NGO metering. Natural gas utilities have been found to be metering fuel consumption of approximately 60% of cogeneration systems in the program. This metering rate is sufficient for program evaluation purposes; in the future it is not expected to be necessary for Program Administrators to install additional natural gas metering expressly for program evaluation purposes.

Electric Demand Impacts

Electrical demand and energy impacts for projects that had begun normal operations prior to December 31, 2003 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 metered data are not yet being collected from all operating projects implemented as of the end of 2003. Consequently, this assessment of the Program's demand and energy impacts on the electrical system is based on a combination of metered data and engineering estimates.

Overall program demand impacts coincident with 2003 ISO system peak load are summarized below in Table 10-2. In 2003 the ISO system peak reached a maximum value of 42,581 MW on July 21 during the hour from 15:00 to 16:00 (3 to 4 PM) PDT. While the total on-line capacity of the 195 operational projects exceeded 58 MW, the total impact of the

Table 10-2: Program Impacts Coincident with 2003 ISO System Peak Load

Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	105	12,671	7,494
Level 2 Fuel Cell	1	200	187
Level 3/3-N/3-R ICE/Turbine	89	46,010	27,410
Total	**195**	**58,881**	**35,091**

Program coincident with the ISO peak load is estimated at just over 35 MW. Level 3/3-N/3-R IC engines and microturbines account for 78% of this total 2003 peak demand impact. The estimated peak demand impact for PV corresponds to 0.59 kW per 1 kW of PV system size [Basis: rebated capacity]. The total program-level system peak demand impact for incentive Level 1 PV systems is estimated to have been approximately 7.5 MW. The estimated demand impact for Level 3/3N/3R systems corresponds to 0.60 kW per 1.00 kW of installed system size. Two of the Level 3/3N/3R systems were idle on this ISO peak day.

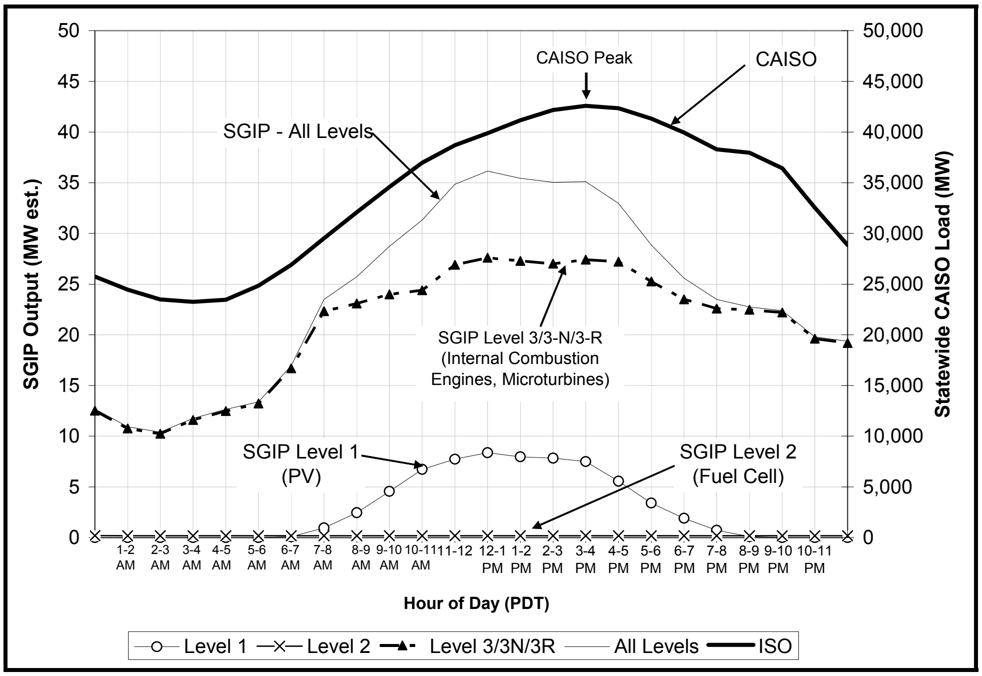
As noted above, each unit of rebated system capacity does not correspond to peak demand impact on a one-to-one basis. An 'effective' incentive level representing the incentive paid per unit of peak demand reduction can be calculated as the incentive paid per unit of rebated capacity divided by the ratio of peak demand reduction to rebated system size. This simple summary approach is illustrated in Table 10-3. In this illustrative example completed project $/kW$_p$ values from Table 10-1 were used to derive the Effective Incentive.

Table 10-3: Influence of Actual Demand Impact on Effective Incentive Level

Level / Basis	Incentive Paid ($\$/kW_r$)	Peak Demand (kW_p/kW_r)	Effective Incentive ($\$/kW_P$)
Level 1 PV	$3.02	0.59	$5.12
Level 2 Fuel Cell	$2.50	0.93	$2.69
Level 3/3-N ICE/Turbine	$0.58	0.60	$0.97

The peak-day profiles of ISO system load, as well as SGIP generation, are illustrated in Figure 10-4. While PV system power output was substantial on the day of the CAISO system peak, the PV output curve's shape is more pointed than the CAISO load's shape. After 1 PM the total output of the 105 operational PV systems began falling, whereas CAISO loads continued to increase for several hours. The shape of the output curve estimated for the 89 operational engines and turbines aligns well with the statewide ISO system peak from 3 to 4 PM, and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak hour).

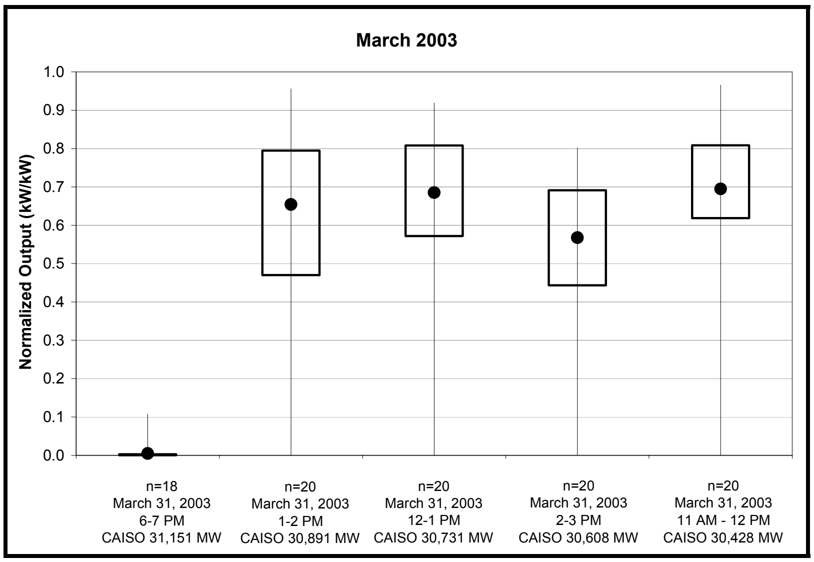
Figure 10-4: ISO 2003 Peak Day Loads & Estimated Total SGIP Generation



To more completely characterize the demand impacts yielded by PV systems, normalized hourly output of the metered PV systems during hours coincident with the CAISO monthly maximum loads (i.e., 5 peak hours of each month) were calculated. Select results of this analysis are presented in Figure 10-5 and Figure 10-6. In these charts each of the five box plots summarizes power output of metered PV systems during one of the hours during which CAISO maximum loads occurred. The left-most box plot corresponds to the hour when the maximum CAISO load occurred during the month. Remaining box plots are arranged in order of descending CAISO load. The weighted average values, depicted in these charts with black circles, were calculated as the total power output of the metered systems divided by total cumulative size of those systems. Weighted averages such as these were calculated and applied to their respective strata in cases where metered data were unavailable and it was necessary to calculate estimates of PV power output.

The PV data for March 2003 presented in Figure 10-5 illustrate at least two important points. First, PV delivers capacity benefits not only during summer months, but during certain spring and fall months also. Second, during spring or fall months the probability that PV output will coincide with the highest monthly CAISO loads is lower than the probability during summer months. Rigorous quantification of the capacity value of PV would require complex power flow modeling and probabilistic loss-of-load analysis; however examination of PV output coincident with monthly maximum CAISO loads provides some indication of the capacity benefit of PV throughout the year.

Figure 10-5: Demand Impacts Per Unit of Rebated Capacity – PV (March 2003)



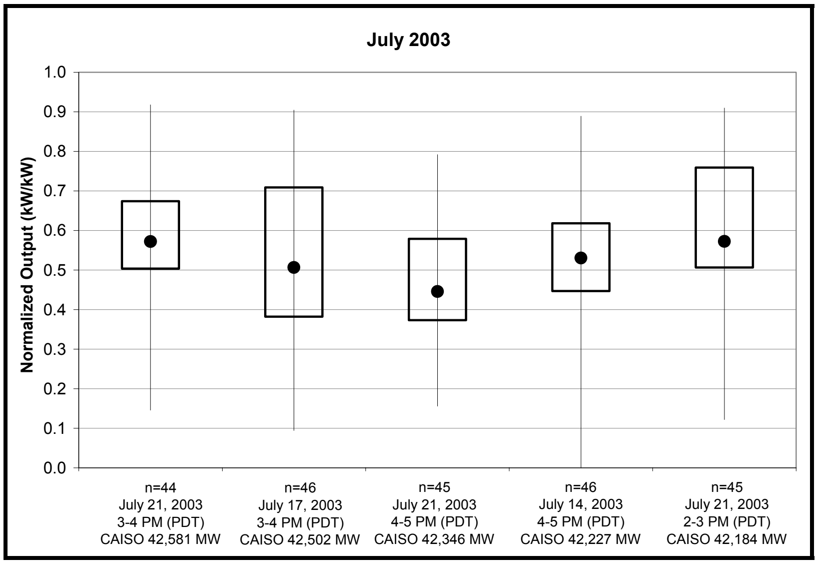
PV output was substantial during four of the five hours when CAISO system loads reached their highest levels. The fifth hour occurred in the evening when average PV output was near zero.

Two of the metered PV systems were not operational on March 31, 2003.

The PV data for July 2003 presented in Figure 10-6 include PV output on July 21, the day when CAISO loads reached their 2003 annual peak value. During the July 2003 hours when CAISO loads reached their five highest values normalized PV output ranged from 0.45 to 0.57 kW of power output per kW of PV system size [Basis: rebated capacity].

PV demand impacts during July 2003 are expressed on a normalized basis in Figure 10-6.

Figure 10-6: Demand Impacts Per Unit of Rebated Capacity – PV (July 2003)

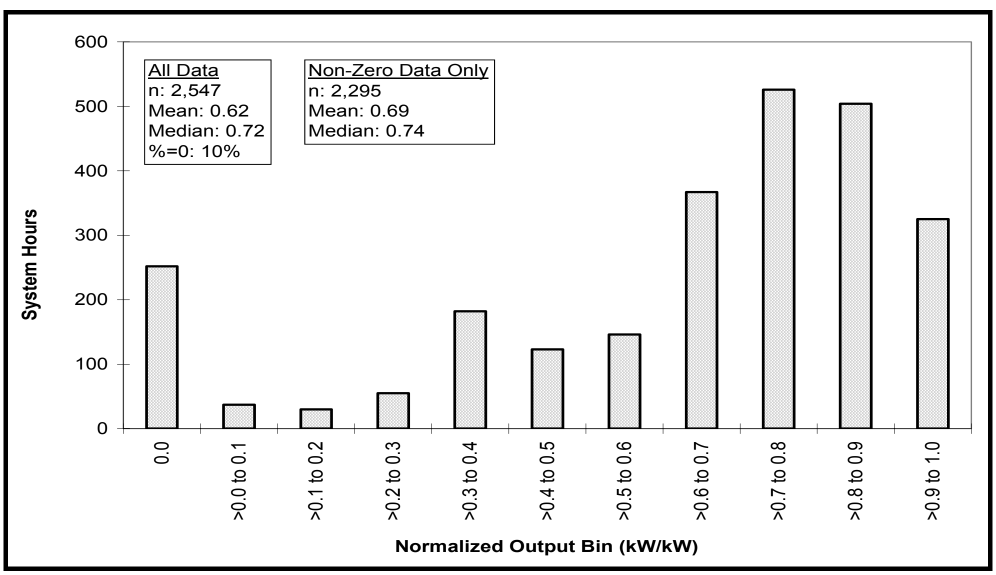


During the hour from 3 to 4 PM on July 21 three of the 45 metered PV systems produced less than 0.35 kW/kW. Notes concerning the performance of these three systems are presented in Section 9.

On July 14, 2003, one PV system went off-line in the middle of the day and stayed off for the next two days. This is not one of the three systems identified above as being off-line during a portion of March 2003 or June 2003.

To more completely characterize the Program's demand impacts, normalized hourly output of the metered Level 3/3N systems during 2003 coincident with the ISO maximum loads (i.e., based on the 5 peak hours of each month) are summarized in Figure 10-7. "System Hours" are based on a given operational hour for each cogeneration system that is "on-line" during a defined period of time. Whereas for PV both intra- and inter-day variability were significant, for Level 3/3N systems it is more meaningful to consider all 60 ISO-maximum load hours as a single group. These 60 hours correspond to a total of 2,547 system hours (i.e., the average number of "on-line" [but not necessarily operational] systems was 42). As shown in Figure 10-2 and Figure 10-3, on-line capacity increased steadily throughout 2003.

Figure 10-7: Demand Impacts Per Unit of Rebated Capacity – Level 3/3-N



For the group of 2,547 ISO-maximum system hours, normalized power output of the monitored Level 3/3N systems on a weighted average basis was equal to 0.61 kW of power output per kW of rebated system size during the top 5 peak load hours each month over the CY 2003 period of this assessment. This annual average result is identical to the demand impact of metered systems during the single hour of the ISO annual peak.[6] The idle units (0.0 kW/kW Normalized Output) play an important role in reducing the average output of all rebated units during hours when ISO loads reach their maximum values. There are many possible explanations for the results presented in Figure 10-7. Several possibilities include: 1) relationships between cogeneration system size and facility electric load magnitude or timing could constrain electric output in some cases; 2) mechanical failure; 3) change in ownership or turnover among operations staff; and 4) uncertainty regarding cogeneration system cost-effectiveness in the face of current gas prices and retail electric rates.

Electric Energy Impacts

Overall program electrical energy impacts are summarized in Table 10-4. While Level 3/3N/3R engines and turbines accounted for 78% of demand impacts, they account for 91% of total energy impacts. This difference is due to the fact that the average capacity factor of Level 3/3-N/3-R IC engines and turbines is greater than that for Level 1 Solar PV. The variability in energy production observed across quarters is primarily attributable to systems coming on-line throughout 2003, as illustrated in Figure 10-2 above. This complicates interpretation and use of absolute measures of program electric energy impacts (i.e., MWh).

Table 10-4: Program Energy Impacts in 2003 by Quarter (MWh)

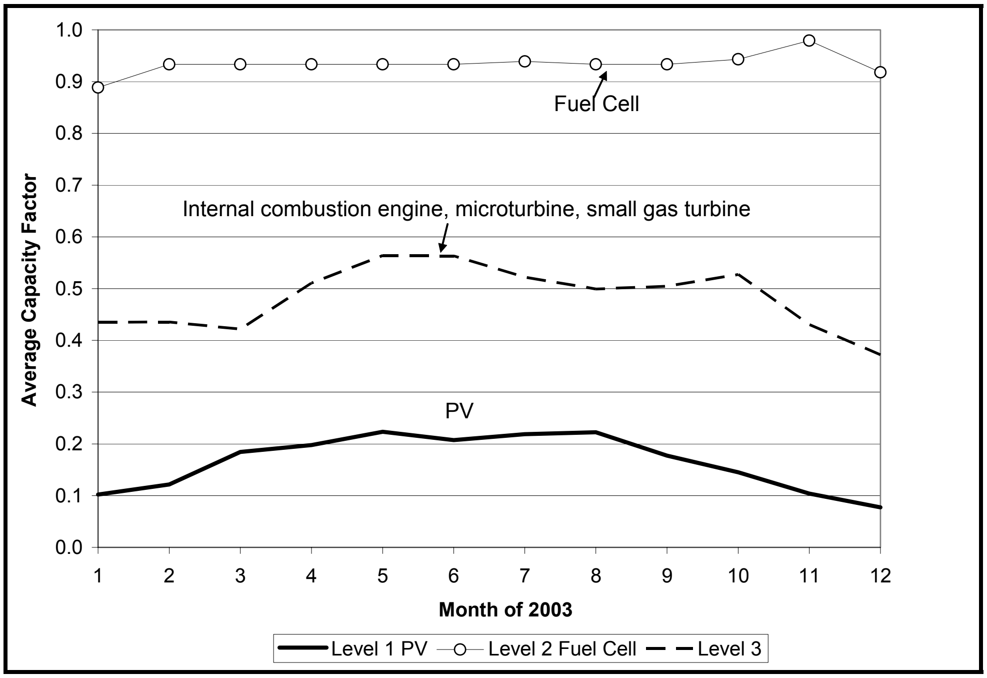
Level / Basis	Q1-2003	Q2-2003	Q3-2003	Q4-2003	Total MWh
Level 1 PV	1,678	3,736	6,119	3,869	15,402
Level 2 Fuel Cell	396	408	413	418	1,635
Level 3/3-N/3-R ICE/Turbine	18,150	37,722	55,271	55,441	166,583
Total	**20,224**	**41,865**	**61,803**	**59,728**	**183,620**

Energy impacts of the program were summarized in Table 10-4. In Figure 10-8 the energy production characteristics of the operational systems are expressed on a normalized basis to enable comparison of the several different distributed generation technologies. As expected, normalized PV energy production levels reach their maximum values in the summer season

[6] For several Level 3/3-N projects monthly kWh production data were available instead of interval-metered data. These monthly totals were combined with an assumed generation profile to estimate demand impacts. Consequently, the weighted-average peak demand impact for the group of projects for which demand impacts were estimated is not identical to the weighted-average peak demand impact for the group of projects for which interval-metered data were available.

and decrease towards the winter season as the intensity and duration of incident solar radiation falls off, coupled with increased incidence of storms and other weather conditions affecting the availability of solar radiation on PV systems. For PV the arithmetic mean of the monthly values is 17%. The annual average load factor for individual systems, or for years other than 2003, could be different. The basis of results presented in Figure 10-8 vary. As summarized in Table 10-2, only 1 Level 2 fuel cell was operational during 2003; the numbers of and capacities of operational Level 1 PV and Level 3/3N cogeneration systems contributing to the results presented in Figure 10-8 were much larger.

Figure 10-8: Average Capacity Factor by Month (CY 2003)



Whereas for PV systems the pronounced seasonal variability of monthly average capacity factor was expected, the capacity factor of engines and turbines is influenced by fundamentally different factors. PV system power output is primarily governed by weather, and PV systems in the program are eligible for net-metering tariffs that enable them to produce more power than is consumed by the facility during certain hours. Engine and turbine power output is primarily governed by thermal demand and on/off switches, and is generally required to be controlled to a level such that substantial quantities of power are not exported to the grid. Depending on the relative size of the engine or microturbine system, when facility power requirements are low - the power output of the distributed generation system might need to be throttled down to prevent export of power to the grid. Consequently, the monthly average capacity factor may be strongly influenced by facility operating hours (i.e., 1-, 2-, or 3-shift). The capacity factor data presented in Figure 10-8 are provided for summary purposes only. Because additional metered systems were being added periodically throughout the year, and because the number of complete-year datasets is small, it is not possible to draw any sweeping conclusions from these summary data. They do however provide a very general reference point for comparison to capacity factors for other technologies.

Cogeneration System Energy Impacts

Level 2 fuel cells and Level 3/3-N engines/turbines are subject to certain heat recovery and system efficiency requirements during the implementation stage of the Self-Generation Incentive Program. A variety of means are used to recover heat for useful purposes, and to apply that heat to provide various forms of heating and cooling services. The end uses served by recovered useful thermal energy are summarized in Table 10-5, which includes projects that had entered operation through December 2003.

Table 10-5: Thermal End Uses Served by Cogeneration Systems

End Use	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	71	30,284
Heating & Cooling	14	11,073
Cooling Only	25	12,950
Total	**110**	**54,307**

To assess actual heat recovery and system efficiency performance, useful heat recovery will be monitored. Availability of these data for 2003 is summarized in Table 10-6, which provides the numbers and capacities of cogeneration projects for which useful thermal energy data for CY2003 were available. In some cases, availability of CY2003 data was not sufficient to estimate PUC 218.5 thermal energy proportions or efficiencies due to their annual basis requirement. These sites with insufficient data were not included in Table 10-6 or in the subsequent summaries of system efficiency results.

Table 10-6: Level 2/3/3N Useful Thermal Energy Data Availability (CY2003)

End Use	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	15	4,346
Heating & Cooling	2	1,800
Cooling Only	4	2,400
Total	**21**	**8,546**

Level 2 fuel cell and Level 3/3N engine/turbine cogeneration system designs are required to demonstrate [on paper through engineering design documentation] achievement of the minimum efficiencies presented in Table 10-7.

Table 10-7: Program Required PUC 218.5 Minimum Performance

Provision	Minimum Performance (%)	Description
218.5 (a)	5%	Proportion of the facility's total annual energy output that is in the form of *useful thermal energy*.
218.5 (b)	42.5%	Cogeneration systems where useful thermal energy follows power production: *Annual System Efficiency* is calculated as the sum of E-NGO and one-half the useful thermal energy, divided by any natural gas (and oil)[7] energy input.

Available metered thermal data collected from these on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results of the analysis for Level 3/3-N projects are summarized in Table 10-8. A complete year of data was available for 13 of the 20 systems. In 6 other cases, at least 5 months of data were available for the second half of 2003. While the basis of the PUC 218.5 proportions and efficiencies is annual, when at least 5 months of data from several seasons are available the calculated results are representative of what could be expected on an annual basis.

Table 10-8: Actual Level 3/3-N Cogeneration System Efficiencies (n=20)

Summary Statistic	218.5 (a) Proportion	218.5 (b) Efficiency	Overall Plant Efficiency
Min	1%	23%	25%
Max	54%	43%	58%
Median	46%	35%	45%
Mean	39%	35%	44%
Std Dev	17%	5%	10%
Coefficient of Variation	0.4	0.1	0.2

Metered data collected to date suggest that 2 of the 20 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%. The limited quantities of cogeneration system data available for this impacts analysis suggest the possibility of systematic negative variance between planned system efficiencies and actual system

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

efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn.

Data were available for one Level 2 fuel cell project, which satisfied the requirements of PUC 218.5 (a) and achieved a 218.5 (b) system efficiency exceeding 50%.

Results of an analysis of electrical conversion efficiencies and average heat recovery rates are presented in Table 10-9. Gross electric generator output data and engine/turbine fuel usage data were combined in a calculation of engine/turbine electric conversion efficiency. In the case of reciprocating engines (ICE), actual electrical conversion efficiencies below 30% are typical. This typical result is substantially less than electrical conversion efficiencies normally found in published technical specifications by engine-genset manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30%, and sometimes exceed 35%.

Table 10-9: Level 3/3-N Electrical Conversion Efficiency[8] and Average Normalized Heat Recovery Rates

Summary Statistic	Elec. Conversion Effic. ICE	Elec. Conversion Effic. MT	Useful Thermal Energy Recovery
n	22	12	21
Min	23%	19%	0.0 kBtu/kWh
Max	36%	26%	4.0 kBtu/kWh
Median	29%	23%	2.8 kBtu/kWh
Mean	29%	23%	2.4 kBtu/kWh
Std Dev	3%	2%	1.3 kBtu/kWh
Coefficient of Variation	0.1	0.1	0.5

Normalization of the recovered useful thermal energy data enables direct comparison of systems of different sizes. Normalized actual useful heat recovery rates are therefore expressed in terms of kBtu of useful recovered heat per kWh of net generator electric energy production. For the 21 systems for which 2003 data were available for this analysis, substantial variability among systems was observed in the normalized measure of heat recovery. This variability in part reflects the incidence of several projects with very minimal heat recovery, as well as the considerable variability (i.e., 2 to 5 kBtu/kWh) observed for the projects where appreciable quantities of useful heat were recovered.

[8] The electrical conversion efficiencies are calculated as the ratio of gross electric generator output to *lower heating value* of fuel content after converting both to an identical units basis.

Observed electrical efficiencies for microturbines were lower than those for reciprocating engines, as expected. The median efficiency actually observed was 23%. This is lower than nominal microturbine efficiencies typically published by manufacturers (i.e., approximately 28%). In the context of PUC 218.5 (b) efficiency calculations, these variances are *relatively more significant* than those on the useful recovered heat side of the equation; because only 50% credit is given to the recovered heat in the 218.5 (b) efficiency equation. These factors are discussed in more detail in the following section.

In general the actual useful heat recovery rates observed in 2003 were less than projected by engineering calculations completed during the design stage of cogeneration system project development. The variance is due to numerous factors, including: design problems, operational problems, unanticipated operational conditions, and reliability problems. Information about these problems is being collected as part of the limited-scope process evaluation described previously. Results of the current targeted process evaluation will be presented in a separate report, and will help explain the quantitative results presented in this report.

Finally, it must be emphasized that the quantity of useful recovered heat data available for this analysis is small. While the total capacity of operational cogeneration systems approached 60 MW at the end of 2003, this analysis included useful recovered heat data for projects totaling less than 10 MW. In addition, for some of these projects less than a complete year of data were available. This monitored group does not represent a statistical sample; rather, it could best be characterized as a monitored group for which useful recovered heat data were available. While results presented in this report for 2003 are suggestive of the possibility of systematic deviation between planned system efficiency and actual system efficiency, data availability constraints preclude drawing definitive conclusions at this time.

10.3 Key Findings

Several key findings of this Program Year 2003 impacts analysis for the Self-Generation Incentive Program include:

Level 3/3-N Demand Impacts

During hours when CAISO system reaches maximum values, there was substantial variability in engine/microturbine output (including substantial portions that were not operating). The weighted average contribution to demand impacts during the hour of the CAISO system peak may be lower than expected (i.e., 0.60 kW per kW of system capacity [Basis: rebated size]).

Level 1 PV Demand Impacts

During hours when CAISO system loads reach monthly maximum values PV delivers demand impact not only in summer months, but also in certain spring and fall months. The weighted average contribution to demand impacts during the hour of the CAISO system peak (i.e., 0.59 kW per kW of system capacity [Basis: rebated size]) may be lower than expected from PV systems. However, as explained in Section 9, this result is largely explained by known factors influencing actual PV system power output, as compared to rated system sizes used for establishing the rebate.

Cogeneration System Actual Operating Efficiencies

The limited quantities of cogeneration system data available for this impacts analysis suggest the possibility of systematic negative variance between planned and actual system efficiencies. Data available to date suggest that only 2 of the 20 monitored Level 3/3-N cogeneration systems appear likely to actually achieve 42.5% PUC 218.5 (b) efficiency on an annual basis.

A limited-scope process evaluation is being performed concurrently with the impacts evaluation addressed by this report. One important objective of the process evaluation is to collect information about system performance, reliability, and operational practices. Results of the targeted process evaluation will be presented in a separate report later this year that will help explain some of the key results of this impacts analysis.