SELF-GENERATION INCENTIVE PROGRAM

MARKET FOCUSED PROCESS EVALUATION

SUBMITTED TO:

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E. EXECUTIVE SUMMARY

This executive summary highlights the major findings and recommendations from the Market Focused Process Study of the Self-Generation Incentive Program (SGIP). The SGIP was first launched in March 2001 by the California Public Utilities Commission (CPUC). The SGIP operates in the service areas of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas (SCG), and the San Diego Gas and Electric Company (SDG&E). The SGIP is administered by PG&E, SCE, and SCG in their respective territories. The California Center for Sustainable Energy administers the SGIP in SDG&E's territory. This organization recently changed its name from the San Diego Regional Energy Office (SDREO). Because most of the researchable issues in this work are retrospective in nature, the SDREO acronym is used in this report. Future research reports on this program will shift to the use of the administrator's new name.

The CPUC directed the Program Administrators (PAs) to conduct the evaluation work contained in this study. A research plan for this study was developed by Summit Blue Consulting and its research partners, Energy Insights and RLW Analytics (hereafter referred to as the Summit Blue team) through meetings with the SGIP Working Group and with the input and oversight of the Measurement and Evaluation Committee (M&E Committee) of the Working Group.[1] That research plan also covers three additional related studies — the completed Program Administrator Comparative Assessment,[2] and the Market Characterization Study and the Retention Study, both of which are due later in 2007. The SGIP Working Group consists of representatives from each of the PAs, as well as representatives from SDG&E, the California Energy Commission (CEC) staff associated with the Emerging Renewables Program, and the Energy Division of the CPUC. The intended audience of this study is the SGIP Working Group and the California Public Utilities Commission.

E.1 Market Focused Process Evaluation Research Objectives

The main research objectives of the Market Focused Process Evaluation were defined to:

- Identify how the SGIP works with the market.
- Identify potential improvements in program processes to meet market needs.
- Review the effect of the application fee.
- Review how public entities interface with the program.
- Identify other relevant social and economic factors affecting how the program processes are experienced.
- Review the decline in cogeneration systems in light of program processes.

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[1] Summit Blue Consulting. "Self-Generation Incentive Program Market Focused Process, Market Characterization, Retention and Program Administrator Comparative Assessment Studies, Final Research Plan." January 26, 2007.

[2] Cooney, K., P. Thompson, Summit Blue Consulting, Energy Insights, RLW Analytics. "Self-Generation Incentive Program: Program Administrator Comparative Assessment." Report to the SGIP Working Group. April 25, 2007.

- Review the impact of the California Solar Initiative (CSI) on the program.

E.2 Evaluation Methods

The evaluation methods used included:

- A review of program participation records and reports submitted to the CPUC through December 2006 from all PAs.
- In-depth interviews with staff from each PA, with project developers across the state, and with CPUC and CEC staff.
- Surveys of program host customers and non-host customers.
- In-depth interviews with program host customers and non-participants.
- Focus groups with SGIP host customers in each of the PAs' territories.
- Review of applicable literature sources, relevant industry documents, and Internet sources.
- Quantitative analyses using data regression methods to explain the relationship between project indices – e.g., the effect of gas prices and declining incentives on cogeneration application rates.

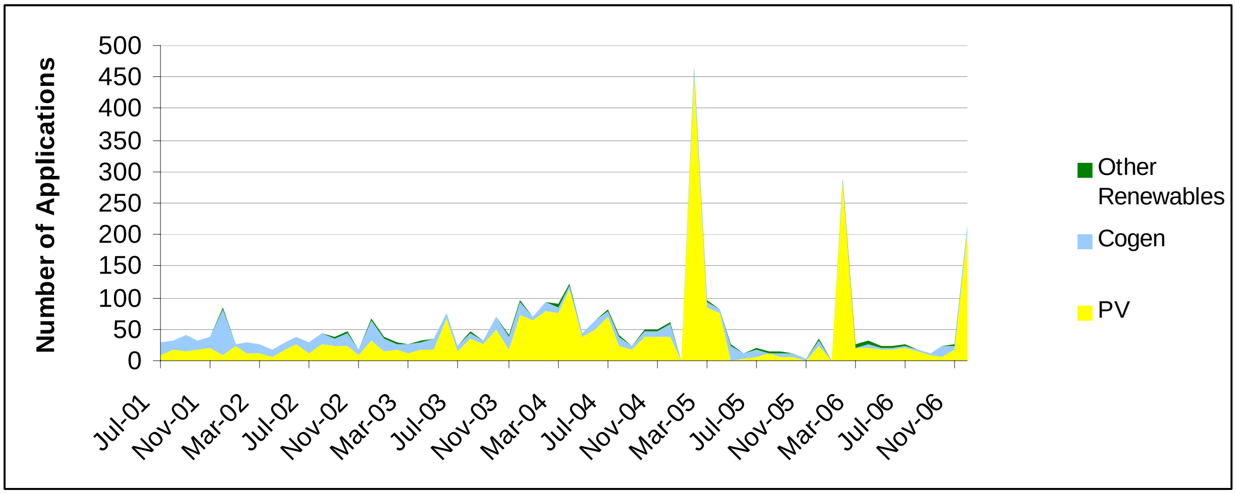
E.3 Key Findings

Key findings from the evaluation are presented below.

SGIP Participation and Market Context

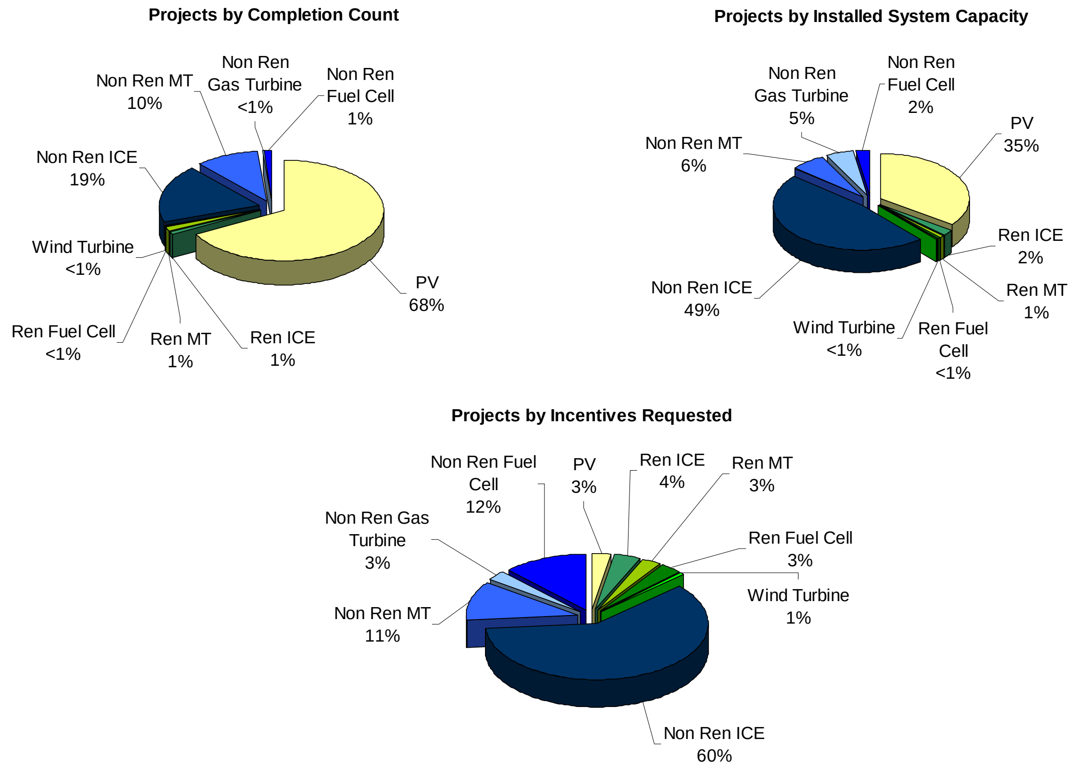
The Self Generation Incentive Program began in 2001. Over its lifetime, program applications have been dominated by solar photovoltaic technology and host customers have applied to the SGIP in some waves (Figure E- 1).

Figure E- 1. SGIP Program Application by Month and Technology



The SGIP has disbursed over $403 M in incentives for 234 MW of capacity since its inception through December 2006. This represents 948 on-site generation projects (638 solar photovoltaic, 7 renewable internal combustion engine, 13 renewable microturbines, 2 renewable fuel cell, 1 wind turbine, 176 non-renewable internal combustion engine, 97 non-renewable microturbines, 4 non-renewable gas turbine and 10 non-renewable fuel cell projects). Figure E- 2 below shows the breakdown of projects by completion count, installed system capacity, and incentives requested.

Figure E- 2. Project Breakdown by Completion Count, Installed System Capacity, and Incentives Requested

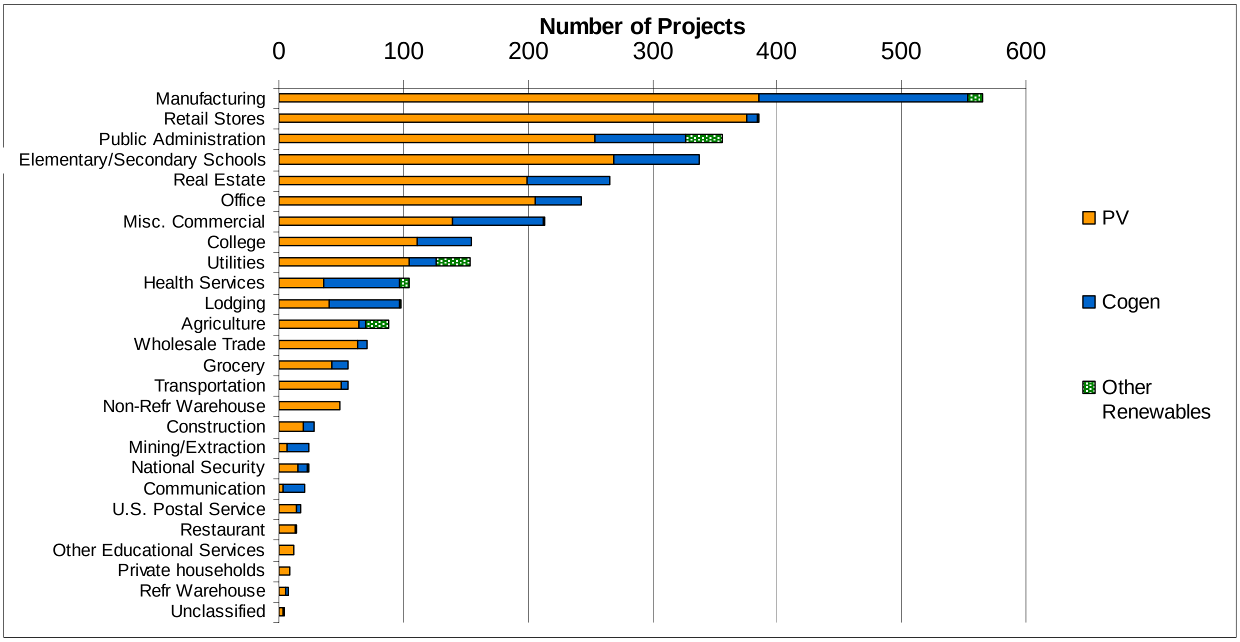


- Average total incentives per completed projects have increased due in part to the changing mix of technologies applying to the SGIP over time.

- Host customers in the SGIP find three factors more compelling in the decision to participate than their non-participant counterparts: utility bill reduction, concern for the environment, and peak demand reduction. Non-participants thought that the desire for back up power would be an important factor, but few SGIP participants agreed.

- Ten market sectors applying to the SGIP account for most applications (80%). Manufacturing dominates with 16% of the total number of program applications. Other sectors, while not dominant in terms of total applications can represent a significant proportion of applications of specific technologies, e.g., lodging applications for cogeneration or the utilities segment in “other renewables” technology types (e.g., renewable fuel cell, renewable internal combustion engine, renewable microturbine, wind turbine). (See Figure E- 3.)

Figure E- 3. Applications to the SGIP by Sector and Technology



Participant Experiences

- Overall program satisfaction is high (80% of survey respondents with active/completed projects and 50% of withdrawn or rejected projects were satisfied or very satisfied).

- Satisfaction with the SGIP was initially low for host customers that applied in 2001: 48% of host customers were satisfied or very satisfied with the program. During 2002-2005, satisfaction was relatively high and constant, ranging from 81% to 90%. However, for those host customers that applied in 2006, only 58% were satisfied or very satisfied with the program.

- Overtime, fewer host customers are completing forms themselves, from 76% of those that applied in 2001 saying they did complete the forms themselves to 13% of those that applied in 2006. This decrease has been a steady decline from 2001 to 2006.

- Most program processes have stayed consistently easy or difficult for host customers over time. One process of note is the ease of submitting proof of project advancement to the program. Forty percent of host customers felt this was easy or very easy in 2001, rising to 79% of host customers that applied in 2004 feeling this way, then decreasing to 54% of host customers that applied in 2006 feeling that submitting the proof of project advancement was easy or very easy.

- Consistent with the SGIP's stated approach, most applicants rely on project developers in some fashion (about 80%) to participate in the SGIP. A significant fraction of applicants take a "hands off" approach to the application process (40%), and a similar percentage are involved, but rely on developers to handle forms. Public entities are almost twice as likely to apply without assistance of a third party on paperwork.

- Of those having a negative experience, paperwork and bureaucracy were typical complaints.

- In terms of navigating the stage gates, both withdrawn and completed projects had difficulty with financing the project, but withdrawn or rejected projects also had more difficulty with appropriate technology selection. However, business case and contracting type issues were cited more often. Air permitting was a significant burden to projects for which these permits must be obtained.

- Participants and developers complained about frequent changes to the programs, making it harder to plan for projects in their budget cycles.

- Extensions during the process are granted relatively often, but there seems to be some confusion amongst participants as to when extensions can be expected.

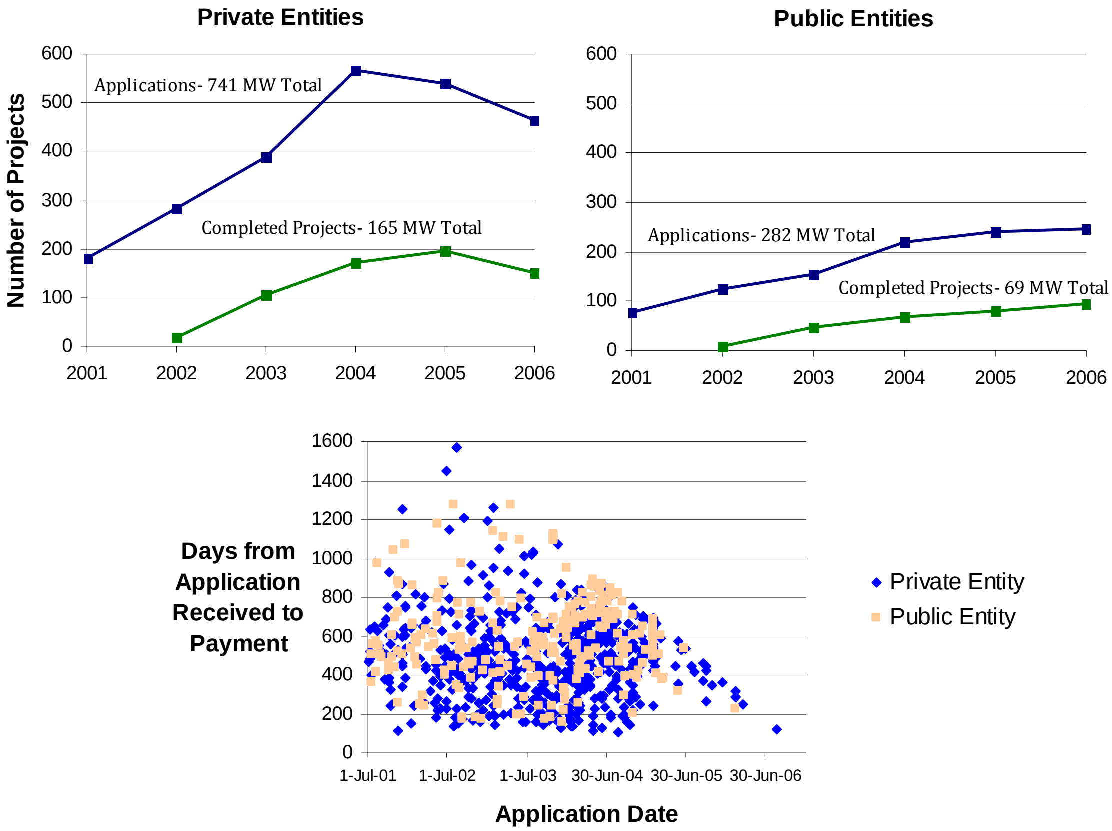
- Drop out rates in the program are relatively constant over time with some increase in 2005.

- The dominant reason reported for withdrawing from the SGIP by far is that system costs relative to rebates are too high (27%). Application process issues were cited by some (10%) and other business reasons such as project financing, internal business priorities changing or problems obtaining or installing equipment and investment uncertainty represented a significant fraction in sum as well (25% in total).

Public versus Private Entity

- Public entity participation is robust and has grown steadily over the SGIP while private entity participation is beginning to decline from the high in 2004. Public entity satisfaction is comparable to private entity satisfaction with the SGIP (Figure E- 4).

Figure E- 4. Public and Private Applications and Days to Complete the SGIP Process



- Public entities do have different decision making and contracting needs, which make the SGIP timeframes somewhat difficult to navigate (e.g., 50% of public entities find proof of project advancement difficult or very difficult while only about 20% of private firms find it that difficult). However, aggregate analysis indicates this differential in time needed to complete the SGIP process has the potential to be overstated.

- Public entity participants are more focused on green image than private counterparts and energy costs, while important to both, are somewhat less important for public entities. However, completion rates for both types are roughly the same. Public entities also see it as their responsibility to provide sites for technical demonstration of projects.

- Public entities are more likely to complete all application forms by themselves and are less likely to outsource in a turnkey manner. This may account for some of their relatively greater difficulty in the interconnection process. Additional consideration of tax consequences of outsourcing by public entities could help them obtain some of the tax benefits otherwise unavailable to them.

Application Fees

- The institution of the application fee is generally seen by most participants, developers and PAs as a success in deterring phantom or premature project application. However, the forfeited fees are significant and some developers appear to be taking the risk for some premature projects.

Transition Issues – Cogeneration, Incentives and CSI

- PAs, participants and developers indicate that cogeneration applications to the program have been declining due to a number of reasons: decreasing incentives, increasing natural gas prices, more stringent air regulations, difficulty meeting waste heat requirements and softening of retail electricity rates from historic 2002 highs. Regression analysis of participation data indicates that incentive reductions have had a greater dampening effect than increasing natural gas prices.

- With regard to PBI and the CSI transition, many are concerned that the transition to PBI will not be an improvement though more are not sure. Concerns voiced reflected worries about mandatory TOU requirements (survey fielded before change) and difficulty obtaining financing or making the business case in the absence of an upfront incentive. Experienced participants also have some continuing concerns about equipment reliability and malfunction.

- There is a general concern about how to bring new technologies into the SGIP. Some think that the PMG guidelines could be used. However, because no applications using the PMG process have resulted directly in a program modification – stakeholders are not confident in this approach.

E.4 Recommendations

Recommendations from the research and analyses are summarized below:

General Recommendations

- Maintain the current project milestone framework that allows more time for public-entity projects, and continue to allow extensions to both public and private entities where good cause is shown. In the program handbook, define (or at least provide examples of) what constitutes "good cause" to ensure that extensions are granted on a consistent basis.

- Host customers that completed projects were significantly more focused on environmental benefits than non-host utility customers surveyed with regard to the "value proposition" of the SGIP. It follows that additional case studies emphasizing environmental leadership could assist those entities with similar mission statements or value constructs. As the market value of RECs becomes clearer, there may be more information desired on this topic. The Working Group should direct the M&E Committee to develop case studies that highlight this value.

- Retention to the project could be improved by continuing to provide *accessible* information about technology performance.

- Continue to provide support to applicants and the interconnection group at utilities, so as to improve the number of applicants that get interconnection right the first time.

- As the program continues to mature, make changes judiciously as the market participants are frustrated by a steady diet of changes.

Recommendations Specific to Public Entities

- Because public entities are more likely to file their paperwork (including interconnection agreements) without benefit of an energy services company, they may need more frequent follow up or specialized outreach efforts.

- Consider developing a compilation of known tax and other incentives as a program resource to various entities, to maximize the program's value and minimize the cost to both public and private entities searching for such information. This could include a set of case studies and/or description of alternative ownership strategies for public entities.

Cogeneration-Related Recommendations

- Do not further reduce the incentive levels for cogeneration projects, as in-depth analysis shows that this is the dominant reason cogeneration applications have dropped off, more so than declining natural gas prices.

- If cogeneration is reinstated, the program should continue to consider biogas and landfill gas resources as eligible for incentives.[3]

Incentive Levels

- The market prefers and is used to rebate-style incentives as being more certain and simple, though a performance-based incentive is not alien and some market actors (particularly those PV applicants that switched from SGIP to CSI) do prefer such a program design. To ease transition effects, the Working Group could consider recommending a hybrid approach that retains some rebate aspects but conditions full payout on quality assurance and performance standards.

- Do not further reduce incentive levels at this time. Undertake a continuing review of equipment cost trends, payback implications, and market adoption rates to determine at what point incentive levels should be changed (up or down).

Application Fee

- In retrospect, the application fee appears to have been a qualified success. It appears to be an appropriate mechanism to reduce phantom projects, though problematic for public entities. Where finite amounts of incentive dollars are available in a technology category, application fees could still serve to reduce immature project sign up.

Program Modification Process

- The program modification process could be improved by creating a delegation mechanism to the Working Group on a limited basis, or by creating a required response time on the part of the CPUC to requests for program modification.

E.5 Recommendations for Future Research

Business models are evolving in the state to serve on-site generating markets. The extent to which PV project developers have used incentives that they may have captured through higher pre-rebate system prices as an investment in their business capabilities, may be driving new partnerships or helping them

[3] This may be particularly worth of investigation given that the targeting of methane capture from landfills is one of the Governor's discrete early action measures under AB 32. See e.g., California EPA, Air Resources Board, Proposed Early Actions to Mitigate Climate Change in California, April, 20, 2007. Available at http://www.climatechange.ca.gov/climate_action_team/reports/2007-04-20_ARB_early_action_report.pdf.

create new delivery methods for marketing, selling and installing systems. The upcoming market study will make an initial review of the evolving market to deliver SGIP services.

Some additional topics that may warrant investigation:

- Review data on regional variations in market appetite for on-site generation, i.e., are there climate differences, and/or social circumstances that may explain participation differences across various regions and locales in California?

- Review regulatory mechanisms required to delegate more authority to the Working Group for program modifications.

- Review how tariff issues affect market participation and specifically projects that decide not to produce power in some instances.

- Conduct further research on total installation cost. For example, does geography determine the "street price"[4] of an installed system? GIS mapping of projects may help determine whether social effects in neighborhoods or communities where installations may be clustered are influencing customer decisions. There were some indications from focus group participants that the visual impact of other local PV systems, and/or communications with peers in their market sector may have influenced their decision to participate. This research would explore whether the data indicate if early adopters of self generation technologies influence others to participate because of proximity.

Conduct further research on how program marketing expenditures and support, particularly PA account representative support, may have affected participation rates.

[4] Wiser, R., M. Bolinger, P. Cappers, R. Margolis. "Analyzing Historical Cost Trends in California's Market for Customer-Site Photovoltaics." Report Prog. Photovolt. Res. Appl. 15. 69-85. June 2005. Some variation in costs between Northern and Southern California are shown in this work.

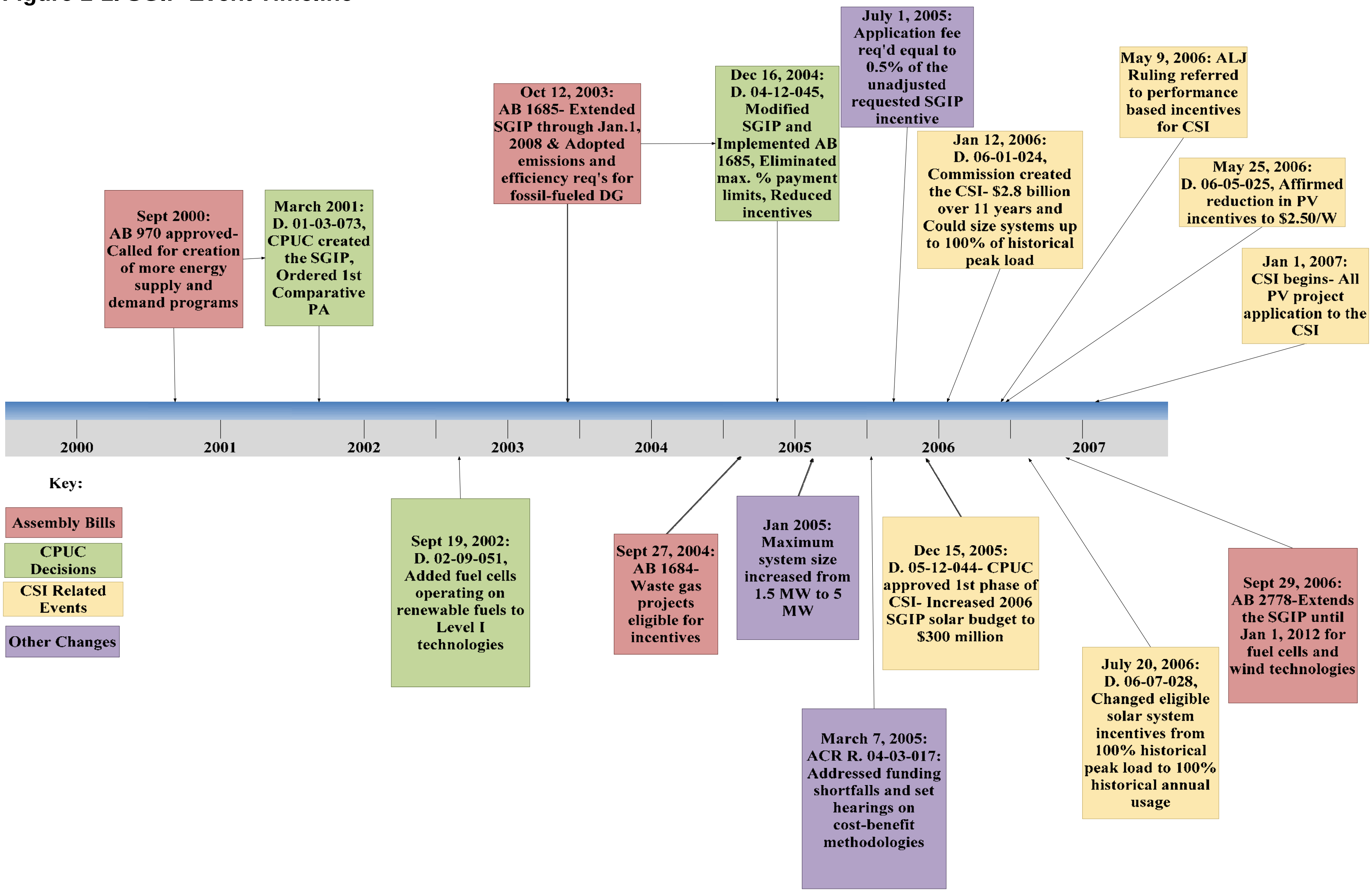
1. BACKGROUND

The SGIP was first launched in March 2001 by the California Public Utilities Commission (CPUC). The SGIP operates in the service areas of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas (SCG), and the San Diego Gas and Electric Company (SDG&E). The SGIP is administered by PG&E, SCE, and SCG, in their respective territories. The California Center for Sustainable Energy administers the SGIP in SDG&E's territory. This organization recently changed its name from the San Diego Regional Energy Office (SDREO). Because most of the researchable issues in this work are retrospective in nature, the SDREO acronym is used in this report. Future research reports on this program will shift to the use of the administrator's new name.

Over time the SGIP has been modified in a number of ways. A brief overview of key events in the history of the SGIP is presented below in Figure 1-1.

Decision D.01-03-073 along with the CPUC's Energy Division directed the Self-Generation Incentive Program Administrators (PAs) to file plans for evaluation activities. On March 6, 2006 in a responsive Joint Motion, an M&E Plan for the SGIP was proposed that described a PA Comparative Assessment update, a Market Focused Process Evaluation, a Market Characterization Study, and a Retention Study. In a ruling dated May 18, 2006, the Administrative Law Judge approved the M&E plan with minor modifications: marketing and outreach was added as an element to the PA Comparative Assessment, and an analysis of the impact of the transition of applications for photovoltaic (PV) systems from this program to the California Solar Initiative (CSI) was added to the Process Study. The first of these studies, the PA Comparative Assessment, was completed and filed with the CPUC on April 25, 2007.

Figure 1-1. SGIP Event Timeline



1.1 Research Objectives

The Market Focused Process Evaluation (Process Study) is unique in that it not only looks at the program processes, but also reviews the interaction between these processes and the current market needs. The Process Study focuses on how the market responds to the SGIP, and how SGIP processes or requirements can be refined or modified to better meet the needs of the various market actors. The Process Study addresses the following specific issues:

- the success of the application fee;
- SGIP involvement by public entities and other complex decision-making organizations;
- the correlation between incentive levels and equipment costs;
- the social and economic factors relating to SGIP involvement;
- the decline in the number of cogeneration systems installed under the SGIP; and
- the impact on customers of the transition from the SGIP to the California Solar Initiative.

Finally, to the extent possible, key results are compared with those from prior Process Studies.[5]

1.2 Description of the Market Focused Process Evaluation Approach

The Process Study is the second of four major studies to be conducted on the SGIP by the Summit Blue team. The other studies are: the Program Administrator Comparative Assessment (completed), the Market Characterization Study, and the Retention Study. These studies will broaden and deepen the research database available to the Process Study.

The data collection activities and analyses associated with these four studies have significant overlap, as illustrated in Figure 1-2. Table 1-1 summarizes the data collection activities for all four studies.

Table 1-2 presents more detail for the activities of the Process Study — a mapping of the key objectives of the Process Study to various data sources. A single *X* indicates that a particular data source may yield useful information for addressing the corresponding objective, while *XX* indicates that the data source will be critical to addressing the objective.

Suggested future research is presented in Section 4.2.

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[5] Itron. “CPUC Self-Generation Incentive Program, 2004 Targeted Process Assessment, Final Report.” April 19, 2005; RER. “Self-Generation Incentive Program, Second Year Process Evaluation.” April 25, 2003.

Figure 1-2. Conceptual Overlap of SGIP Research Studies

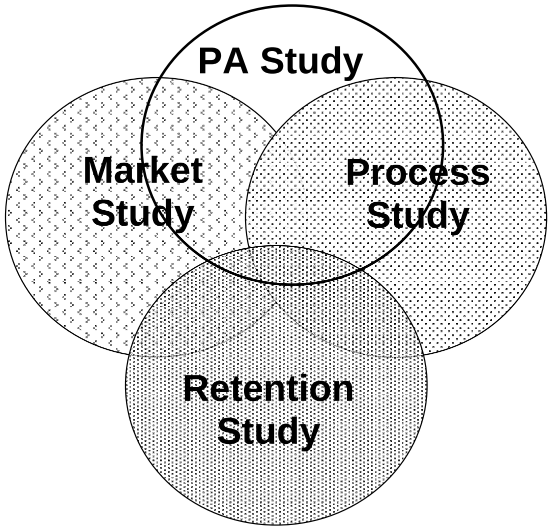

Table 1-1. Summary of Research Efforts for all Studies

Information Source	Approximate Number of Interviews, etc.	Timing (All 2007)
PA and SGIP Staff In-depth Interviews	8 (minimum of 2 sets with each PA)	January
Working Group (CPUC and CEC) In-depth Interviews	2-3	January
Informational Interviews with non-SGIP utility staff (interconnection) and external variation sources (air boards)	27	January and February
Follow on Informational Interviews as needed throughout the remainder of Evaluation	40	Ongoing
Developer In-depth Interviews	26	January
Host Customer Focus Groups	4* (one per PA territory)	February
Host Customer Telephone Surveys	323	March to April
Non-Participant Telephone Surveys	260	May
Participant In-depth Interviews	45	April-May
Non-Participant In-depth Interviews	25	May-June
Review of Itron M&E Database	Iterative	Ongoing

.

Table 1-2. Process Study Research Objectives and Information Sources

Topic Areas	Issues Within Topic Areas	Information Source							
		Host customer Surveys	Non-participant Surveys	PA Interviews	Host customer Interviews	Non-participant Interviews	Focus Groups	Developer Interviews	Program Document & Collateral
SGIP Interface to Market	What is the market for self-generation?	XX	XX		XX	XX	XX	X	
Improvement in Processes to Meet Market Needs	What are the processes? Host customers, non-host customers and other market actors' experiences?	X	X	X	XX	X	X	XX	XX
Application fee (and economic needs)	Opinions about the application fee? Number of host customers with application fee versus without fee?	X	X	X	XX	X	X	XX	X
Public Entities	Process for public versus private customers? Is process too complex? Does EPAct impact?	XX	XX	XX	XX	X	X	XX	XX
Social and Economic Factors	Do applicants understand eligibility is? Why do some projects drop out? Do vendors and DG services contractors experience the program differently?	X	X	X	XX	X	XX	XX	X
Cogen Systems	Explore natural gas prices, difficulty in meeting waste heat req's, market sector trends?	XX		X	XX		XX	XX	
Impact of CSI	Will customers wait for the CSI? Do the performance-based incentives rather than installed-based incentives affect the market?		X	XX		X	X	X	

2. METHODOLOGY

This section provides a review of the data collection methodologies used to gather information for this report, as well as a discussion of potential biases and possible shortcomings related to each methodology.

2.1 Review of Program Data

The Summit Blue team submitted a data request on November 29, 2006 to the PAs through the evaluation project manager. The request asked for contact information, databases, business demographic information, marketing collateral examples, and other documentation. A number of other data items (for example, pointers to sites where systems are known to have been removed or the property has been sold since project development) were discussed during the in-depth PA interviews (see Section 2.2). In some cases, these interviews led to follow-on data requests for additional, administrator-specific information.

For purposes of this report, the team has used program records submitted to the CPUC up through December 2006 from each of the four PAs: PG&E, SCE, SCG, and SDREO. These records include two reports per month: the Monthly Project List and the Monthly Budget Status Report. The Monthly Project List includes a list of projects by year and a list of cumulative projects to date. For each project the List shows, among other items, the project ID, incentive level received, system type, and fuel type. The Monthly Budget Status Report contains program data on budget allocations, reallocations, program expenditures, program definitions, and rebate amounts. A summary of application statistics by year and incentive level is also included in the Budget Status Reports.

The PAs also provided additional internal program records, where available, on outreach activities, public presentations and attendance lists. In addition, internal tracking forms and approaches used by the administrators[6] helped the team conduct a preliminary evaluation of the PAs' processes.

2.2 Surveys

2.2.1 Overview of Survey Process

Host customer telephone surveys were conducted by RLW Analytic's California office. Experienced RLW Analytics staff conducted the telephone data collection. All survey personnel hold college degrees in Energy Management and have the experience and education to speak and interact knowledgeably with survey respondents. Non-participant surveying was conducted by The Dieringer Research Group.

Surveys were pre-tested prior to the main data collection effort. Surveyors for the host customer survey were briefed on the SGIP nomenclature and survey goals prior to any calls. After approximately five surveys, the instrument was reviewed with the Summit Blue team to suggest improvements. All survey calls were tracked, and refusals or incomplete responses were recorded. Results of the completed surveys were entered into an electronic database designed by the project analyst. The data were reviewed by the RLW project manager to ensure quality control. Host customer calls were made from RLW's California office. At the end of this data collection task, a survey disposition report was prepared to document the outcome of each contact attempt, and the possibility of non-response bias was considered.

[6] For example SDREO was able to provide an internal procedures manual for their approach to the SGIP.

A discussion of the sampling strategy is presented in the next section, but first, a few comments about non-respondents are presented. Table 2-1 below summarizes the results of every participant survey contact attempted. Of the 948 attempts to contact a host customer about a specific project, only 26 resulted in firm refusals to participate in the survey (verbally declined or hung up). There was a substantial proportion of contact information that was no longer accurate, e.g., due to changes in personnel or company reorganization, and many unreturned phone calls. Note that the Summit Blue team did attempt to locate correct contact information via the web, and the PAs also were able to provide some updated contact information.

Table 2-1. Participant Survey Disposition Report

	Number of Projects where Contact was Attempted				
Result of Contact Attempt	**PG&E**	**SCE**	**SDREO**	**SCG**	**Total**
Completed survey	163	63	28	69	**323**
Verbally declined to participate*	14	3	4	2	**23**
Hung up on interviewer*	0	2	1	0	**3**
Said to call back later**	21	12	4	10	**47**
Took message, but did not return call**	184	55	11	64	**314**
Language Barrier***	1	2	0	0	**3**
No one currently with the company qualified to answer***	29	20	4	24	**77**
Busy signal***	8	5	0	4	**17**
No answer***	21	6	1	11	**39**
Wrong number***	22	16	3	18	**59**
Number no longer in service***	16	12	1	14	**43**
Total	**479**	**196**	**57**	**216**	**948**

**These represent a clear refusal to participate in the survey.*
***These may represent a "soft" refusal to participate, or may simply represent scheduling difficulties that precluded their participation during the survey period.*
****These are issues that effectively prevented the interviewers from reaching the proper respondent and determining if they were willing to be surveyed. Many of these relate to the limitations of the participant contact information available from the program administrators.*

If we were to calculate the response rate for the participant survey as the number of projects surveyed divided by the number of projects where contact was attempted, the overall response rate would be 34%. As a measure of the willingness of host customers to participate in the survey; however, this is inadequate because it fails to account for the cases where bad phone numbers, corporate reorganizations, etc. made it impossible to reach an appropriate respondent.

Excluding those cases (marked *** in Table 2-1) yields a more appropriate definition of response rate as the number of projects surveyed divided by the number of projects where some contact with the host customer was made. By this definition the overall response rate was 45%, ranging from a low of 43% among PG&E projects to a high of 58% among SDREO projects. These response rates are comparable to response rates from other telephone surveys especially in light of the fact that approximately 80% of applicants relied on ESCOs or developers in a significant fashion for SGIP application assistance. [7]

A comparison of the firmographics of responders and non-responders (e.g., SIC, PA territory, size, technology, active vs. withdrawn) found no evidence of systematic biases between these two groups. Of the 23 who verbally refused to complete the survey, 12 provided a reason. Five of these had no interest in participating, three had no time, two had no availability during the survey period, and two cited legal issues. The latter reason included one host customer who simply referred the interviewer to their attorney, and one who mentioned ongoing litigation concerning the project.

2.2.2 Host Customer Survey

We spoke with 289 host customers, representing 323 projects that have participated in the SGIP process — 204 projects that were active or completed, and 119 projects that were withdrawn, rejected or suspended. Appendix B contains supporting information pertaining to the host customer survey including the number of host customers, number of projects, and number of MW represented. In many cases there was one decision maker that was responsible for multiple sample points. We collected information on the primary sample (defined by the Summit Blue team) and then attempted to capture information on additional projects where the technology, PA, or status differed from the primary sample point, or we captured information on additional projects, if there was some other substantial difference between the projects.

Table 2-2 shows the total number of projects in the sample. The sample was stratified by project characteristics of research interest – PA, technology, and project status. In addition, an effort was made to ensure a good mix of coastal and non-coastal participants in the PV sample.[8] Specific goals were set to obtain a varying amount of surveys from projects in coastal and non-coastal areas.

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[7] In the previous process study on the SGIP, Itron was able to complete the planned interviews with host customers, however the target was an order of magnitude less (32 completes as opposed to 289 customers representing 323 projects in the Summit Blue sample). Itron, CPUC Self-Generation Incentive Study, 2004 Targeted Process Assessment, April 19, 2005. p. 3-3. More recently, ODC completed a survey and attempted to contact 100 people based on a sample frame of 140 completed PV customers but were only able to reach 30. Therefore, Summit Blue's response rate was comparable and survey fatigue within the population is suspected.

[8] For this effort California's climate zones were grouped as coastal and non-coastal. The latter included the inland, mountain and desert climates.

Table 2-2. Sample Frame for Host Customer Surveys[9]

	PG&E		SCE		SCG		SDREO		
	Active/ Complete	**Withdrawn/ Suspended/ Rejected**	**Active/ Complete**	**Withdrawn/ Suspended/ Rejected**	**Active/ Complete**	**Withdrawn/ Suspended/ Rejected**	**Active/ Complete**	**Withdrawn/ Suspended/ Rejected**	**Total**
Solar Photovoltaics	625	574	161	375	56	149	46	59	2,045
Reciprocating engines/turbines	91	114	14	52	54	63	4	5	397
Microturbines	40	20	12	14	33	28	10	2	159
Fuel Cells	9	4	2	3	5	10	0	0	33
Wind	1	5	2	5	1	0	0	0	14
Total	766	717	191	449	149	250	60	66	2,648
By PA	**1483**		**640**		**399**		**126**		

[9] The sample was drawn from all projects as of December 2006. Program participants were not included if they had already been touched by other surveys, such as the California Solar Initiative survey conducted by ODC on behalf of SCE's CSI Program. For further discussion, see Section 2.2.2. In addition, four withdrawn/rejected SCG projects from 2001 for which the technology was not originally listed were excluded from the sampling frame.

Table 2-3 shows the distribution of the 323 host customer surveys by PA, technology, and status.

Table 2-3. Completed Surveys for Host Customers

	PG&E		SCE		SCG		SDREO		
	Active/ Complete	**Withdrawn/ Suspended/ Rejected**	**Active/ Complete**	**Withdrawn/ Suspended/ Rejected**	**Active/ Complete**	**Withdrawn/ Suspended/ Rejected**	**Active/ Complete**	**Withdrawn/ Suspended/ Rejected**	**Total**
Solar Photovoltaics	86	20	14	32	10	14	9	11	**196**
Reciprocating engines/turbines	24	15	2	3	18	3	2	3	**70**
Microturbines	9	2	5	3	11	3	3	0	**36**
Fuel Cells	6	0	1	1	3	6	0	0	**17**
Wind	0	1	0	2	1	0	0	0	**4**
Total	**125**	**38**	**22**	**41**	**43**	**26**	**14**	**14**	**323**
by PA	**163**		**63**		**69**		**28**		

Table 2-4 shows the breakout of PV surveys completed by coastal and non-coastal. This table along with information from RLW reflects that the team met or came fairly close to meeting most of the coastal/non-coastal goals.

Table 2-4. Completed PV Surveys, by Coastal and Non-Coastal

Program Administrator	Active/Complete				Withdrawn/Suspended/Rejected			
	Coastal	Non-Coastal	Unknown	Total	Coastal	Non-Coastal	Unknown	Total
PG&E	51	34	1	86	18	1	1	20
SCE	1	2	11	14	16	8	8	32
SCG	4	2	4	10	10	2	2	14
SDREO	4	1	4	9	7	2	2	11
Total	60	39	20	119	51	13	13	77

The sample plan represented a compromise between the desire for large enough sample sizes in each major stratum to yield high levels of statistical confidence and the reality that in many strata the number of projects available for sampling was quite limited. This was particularly true for SCE projects, where the number of available sample points was reduced by an ongoing CSI surveying effort. Project managers for this effort were rightfully concerned about survey fatigue and asked that these customers be eliminated from the SGIP survey. Because many of those host customers were multiple site host customers (e.g., one host customer that received incentives for projects in multiple locations), this had a greater effect on available sample frame than was originally appreciated. As a result, PV surveys in SCE territory are significantly underrepresented in the final survey numbers. Moreover, because the CSI survey effort focused on completed projects, most of the completed SCE PV projects were excluded from the sample frame for the SGIP host customer survey. So, the data captured from SCE PV projects cannot be viewed as representative of all PV active/completed PV projects in SCE territory. To ameliorate this effect, SCE is providing the Summit Blue team with the CSI survey data results. For the most part, the results of this survey are comparable to the findings presented in this report.

Although the nature of the SCE PV sample unquestionably raises concerns about how one should interpret those data points, these concerns have no real bearing on the analyses and conclusions set forth in this report. The reason is that we did not analyze or report results *at the level of a specific technology within a specific PA territory.* The findings for all SCE projects were compared with all PG&E, SDREO, and SCG projects, and the results for all PV projects (across PAs) were compared with the results for other technologies, but it was never the intent to look with statistical rigor at PV projects within SCE territory. The potentially compromised sample cell (active/completed PV projects in SCE territory) accounts for only 7% of all SGIP projects, and only 9% of all SGIP PV projects. As such, it is the opinion of the Summit Blue team that the conclusions presented in this report are statistically valid.

The sample design allowed us to cut the resulting data in a variety of ways while maintaining "90/10 confidence" (90% confident that the true value is within ±10% of the estimate) within each cut. Examples of cuts that provided this level of confidence include:

- Projects broken out by PA for PG&E, SCE, and SCG; the confidence level for SDREO projects is +/- 14% at the 90% confidence interval;
- Projects by status (active/completed vs. withdrawn/rejected);
- Projects by technology (PV vs. recip/turbine); and
- PV projects by status.

The smaller number of microturbines, fuel cells and wind turbine projects available for sampling meant that the Summit Blue team was not able to attain the same level of statistical confidence for these technologies. Likewise, while the Summit Blue team was able to attain 90/10 confidence for recips/turbines as a group, we were not able to attain this level of precision when breaking recips/turbines out by project status.

Because the sample design deliberately over-sampled some types of projects in an effort to obtain statistical precision around PA, status, and technology, simply reporting the unweighted survey responses would give a misleading picture of the views of host customers as a whole. To correct for this, we applied survey weights to the data before reporting results. The weight for each host customer was calculated by dividing the number of projects in the appropriate cell of the sample frame by the number of completed surveys in the same cell. For example, since there were 625 active/completed PV projects by PG&E

available to be sampled (see Table 2-5), and 86 completed surveys with this sub-group (Table 2-6), each completed survey in this sub-group was given a weight of 7.3 (625 divided by 86). Essentially, each of these 86 respondents represents seven and a quarter projects of the same PA, technology, and status. When weighted in this fashion, the survey results provide an accurate representation of the likely responses of all SGIP host customers, had it been feasible to survey them all.

Table 2-5 and Table 2-6 show the breakdown of the completed surveys by technology, program administrator and the type of entity.

Table 2-5. Host Customer Surveys- Active/Completed- 204 Surveys Total

Technology	Number of Completed Surveys
PV	119
Ren ICE	4
Ren MT	6
Ren Fuel Cell	6
Wind Turbine	1
Non Ren ICE	39
Non Ren MT	22
Non Ren Gas Turbine	3
Non Ren Fuel Cell	4
Program Administrator	
PG&E	125
SCE	22
SCG	43
SDREO	14
Type of Entity	
Private	136
Public	68

Table 2-6. Host Customer Surveys- Withdrawn/Rejected/Suspended- 119 Surveys Total

Technology	Number of Completed Surveys
PV	77
Ren ICE	4
Ren MT	1
Ren Fuel Cell	4
Wind Turbine	3
Non Ren ICE	19
Non Ren MT	7
Non Ren Gas Turbine	1
Non Ren Fuel Cell	3
Program Administrator	
PG&E	38
SCE	41
SCG	26
SDREO	14
Type of Entity	
Private	83
Public	36

2.2.3 Non-Participant Survey

In addition to the host customer surveys, 260 telephone surveys were conducted with qualified nonresidential customers who have not participated in the SGIP process. These surveys were stratified by PA, with 65 completes targeted from non-host customers in each of the four PA territories to provide the research team with 90/10 statistical confidence around the data for each PA's non-participant sample.

The sample frame for non-participant surveys included:

- Non-participating members of customer segments that are well-represented among program host customers (allowing us to explore the barriers to increasing program participation among segments that have already embraced the program), and

- Non-participating members of other large/growing segments with the technical capacity to adopt self-generation technologies.

This approach to defining the non-participant sample frame permits an exploration of barriers to increasing program penetration both among those segments that have already embraced the program and among those segments that have not embraced the program, but that have the technical potential to do so. The non-participant surveys also provide a measure of awareness of the SGIP program among the broader customer base. The sample was purchased by SIC and zip codes from Dunn and Bradstreet and compared to the list of program host customers to identify sample that had not already applied to the SGIP.

2.3 In-depth and Informational Interviews

A variety of qualitative, in-depth interviews as well as shorter, less formal informational interviews were conducted to capture data for the different studies. Thus far, in-depth interviews have been conducted with staff from each PA, project developers across the state, the CEC and CPUC staff, host customers and non-participating customers. PA interviews were substantially conducted in-person along with follow-on telephone discussions with senior staff from the Summit Blue team. Developer and participating customer interviews were conducted by Energy Insights by telephone at scheduled times convenient to the respondent and, with the permission of the respondent, many were tape-recorded for note-taking purposes.

In total, 26 in-depth interviews were conducted with SGIP project developers, representing the experience of 25 companies. There are almost 500 different project developers who have participated in the SGIP process, but only 49 that have done ten or more projects. These top 49 program host customers account for 64% of all completed projects to date.[10] The selections of best interview candidates were based on creating a good balance of interviews with: major developers, important niche players, developers that are more active in certain PA territories, and developers that represent each major self-generation technology type. In addition, at least one interview was conducted with a developer that had gone out of business to help understand reasons for project failure. For each PA, the interviewed developers represented between 21% and 35% of all completed projects.

Draft interview guides were prepared for comment and review by the SGIP M&E committee. Final interview guides are located in Appendix A. Each survey instrument was designed to capture information needed to understand variations in PA procedures and were focused on those data elements unique to each respondent group (rather than duplicating effort with other data collection activities). The developers interviewed and the number of completed projects by PA is contained in Table 2-7 below.

[10] For those projects for which a developer is listed, as of November of 2006.

Table 2-7. Developers Interviewed and Number of Completed Projects by PA

Company Name	PG&E	SCE	SCG	SDREO	Technologies Covered
3rd Rock Systems and Technologies	5			5	PV
Advanced Energy Systems	3				I/C
Alliance Star Energy				1	Fuel cells
Allied Energy Services					I/C (Non-RE Fuel), Fuel cells, Microturbines
California Construction Authority	8	8			PV
California Power Partners	4	5	2	4	Microturbines
Chevron Energy Solutions	18	2	7	3	PV, I/C, Fuel cells, Microturbines
DER (The Distributed Energy Resource Group)					(I/C, PV, Fuel cells, Microturbines)
DG Energy Solutions, LLC	1		4	1	I/C
D&J Electric (recently merged with SunTechnics)	4			1	PV
EI Solutions (formerly Prevalent Power)	7	1			PV
Ingersoll-Rand	2				Microturbines
Northern Power Systems	1			1	I/C
Pacific Power Management	13				PV
PowerHouse Energy	1	3	5		Microturbines, I/C
PowerLight Corp.	59	6	11	3	PV
RealEnergy	3	4		2	I/C
Renewable Technologies	8				PV, Fuel cells
Solar Power Systems	4				PV
SolarCraft Services	5				PV
SolarGen Properties	1				PV
Spectrum Energy	3				PV
SPG Solar, Inc.	2			1	PV
Sun Edison/New Vision Technologies	3	37	1	7	PV
WorldWater Holdings	2	1	1	3	PV
Total	157	67	31	32	--
Percent of complete projects	35.8	27.6	21.2	26.7	

In-depth interviews were also conducted with selected program host customers and non-host customers as follow-up to the telephone surveys.

In total, 45 in-depth interviews with host customers were completed. These interviews were conducted by Energy Insights and Summit Blue staff as follow-up discussions with host customers who already completed a quantitative survey (described earlier in Section 2.2.2). The interviews allowed the research team to probe much more deeply into the role that specific factors played in leading to successful or less successful installations than would have been possible in the more structured telephone survey. Each follow-up interview was tailored to focus on the factors identified in the initial telephone survey as most important to the specific installation in question. Respondents for the follow-up interviews were recruited at the time of the initial telephone survey, as part of the closing. To ensure an adequate cooperation rate, each respondent was offered a $100 contribution to the charity of their choice for the completion of a follow on interview. This yielded a cooperation rate (percent of survey respondents who were asked to do a follow on interview who said yes) of 61% for active/completed projects and 63% for withdrawn/rejected projects. An overview of the host customers interviewed is contained in Table 2-8.[11]

Table 2-8. Host Customer In-depth Interviews by Technology and PA

Technology	Number of Interviews
PV	21
Cogen	18
Other renewables	6
Program Administrator	
PG&E	18
SCE	5
SCG	17
SDREO	5

An additional 25 interviews were completed with non-participant utility customers. These interviews were follow-up discussions with non-host customers who completed a quantitative survey. Conducted by Energy Insights and The Dieringer Group, they probed much more deeply into why customers have not pursued self-generation opportunities. These interviews were intended to help understand whether there are some sites or business types for which self-generation is simply not a workable option, or if some non-participants had considered the SGIP but failed to apply and why. Respondents for the follow-up interviews were recruited at the time of the initial telephone survey, as part of the closing. To ensure an adequate cooperation rate, each respondent was offered a $100 contribution to the charity of their choice for interview completion. The resulting cooperation rate for non-participants (32%) was lower than the participant cooperation rate. Given the fact that non-participants were both less invested in the SGIP program and had less to say in general, this cooperation rate is neither unexpected nor problematic.

[11] As described in section 2.2.2 the sample frame (from which in depth interviews were recruited) were constrained by the CSI survey, thus the relatively low number of in depth interviews with SCE customers.

2.4 Quantitative Analyses

This section describes the data regression methods used to analyze the role of the incentive in the decision to file an application. In general, the regression analyses used ordinary least squares techniques to explain the number of applications in a month as a function of the price of natural gas, the incentive level that month, the season, the year, and other market characteristics. All data from the regression analyses were derived from the monthly project reports from 2001 to the present and other relevant project data and reports.

Attempts to investigate the role of the application fee in the decision to file an application were not successful due to the limited amount of post-fee completion data. Thus, there were not sufficient data points to separate the effect of the application fee from other market effects.

2.5 Focus Groups

Traditional “behind-glass” focus groups were held in February 2007 with SGIP host customers to gather feedback about their perspectives of the program and experience with the program. The focus groups took place in February 2007 with SGIP host customers in the programs administered by SCG (Feb .7), SCE (Feb. 8), SDREO (Feb. 12), and PG&E (Feb. 13). Focus groups provided a means to investigate how the program outreach and processes are being received by host customers, and to allow the PAs to observe what their program host customers think about the program.

Focus groups are particularly useful at helping to understand host customer motivations and their reactions to program rules, processes, and communications. Relative to other research techniques, focus groups are particularly effective for understanding host customer motivations (e.g., regarding adoption of new or different products or ideas, such as grid-connected distributed generation). Statistical research methodologies can be less effective for studying complex decision-making processes such as new product adoption, and one-on-one interviews, while very effective at eliciting input, do not allow for the group dynamic that may be critical in understanding motivation. Topics studied in the focus groups are enumerated in the Research Objectives and Information Sources table above (Table 1-1).

The Summit Blue team provided the M&E Committee an opportunity to review and comment on the focus group discussion guide which is contained in the SGIP Program Administrator Comparative Assessment Report.[12] A review of the recruitment process and possible sources of selection bias are presented below.

Recruitment Process. One focus group facility was reserved in each PA territory. Potential recruitment lists of program host customers were developed that included program host customers within a 30-mile radius of the chosen facility. Only those host customers that had a complete or substantially complete project were accepted for recruitment. Calls and e-mails were sent to those on the recruitment list. Prospective host customers were screened to ensure that host customers had sufficient project experience

[12] Cooney, K., P. Thompson, Summit Blue Consulting, Energy Insights, RLW Analytics. “Self-Generation Incentive Program: Program Administrator Comparative Assessment.” Report to the SGIP Working Group. April 25, 2007. Despite the training provided to focus group facilitators, at least one observer from SDREO expressed concern that host customers sometimes use the term SDG&E and SDREO interchangeably, and expressed a desire for more probing on this issue.

to understand the decision-making process that the host customer's company conducted regarding the program. Host customers were compensated with a cash incentive to participate.[13]

Host Customer Satisfaction. During the recruitment process, the Summit Blue team discovered that those who expressed a negative experience with the program appeared less likely to be willing to attend the focus groups.

Host Customer Involvement. Many host customers in the SGIP hired a contractor or developer who handled most of the interaction with the PA for the host customer, including applying for the rebates through the SGIP. Because having a substantial role in the application, installation, financial analysis, and decision-making processes was a selection criterion for the groups, a substantial number of host customers who had little direct involvement in the program were excluded.

Public Entity Involvement. During the recruitment process, the team found that contacting host customers involved with public entities was, in general, easier than contacting host customers with private firms. As a result, the representation of public entities in the focus groups was generally slightly higher than in the program (see Table 2-9).

Table 2-9. Public Entity Involvement in the Focus Groups

	PAs			
	PG&E	**SCE**	**SCG**	**SDREO**
Completed Public Entity SGIP *Projects*	37%	26%	16%	44%
Public Entity Focus Group *Host customers**	33%	25%	29%	58%

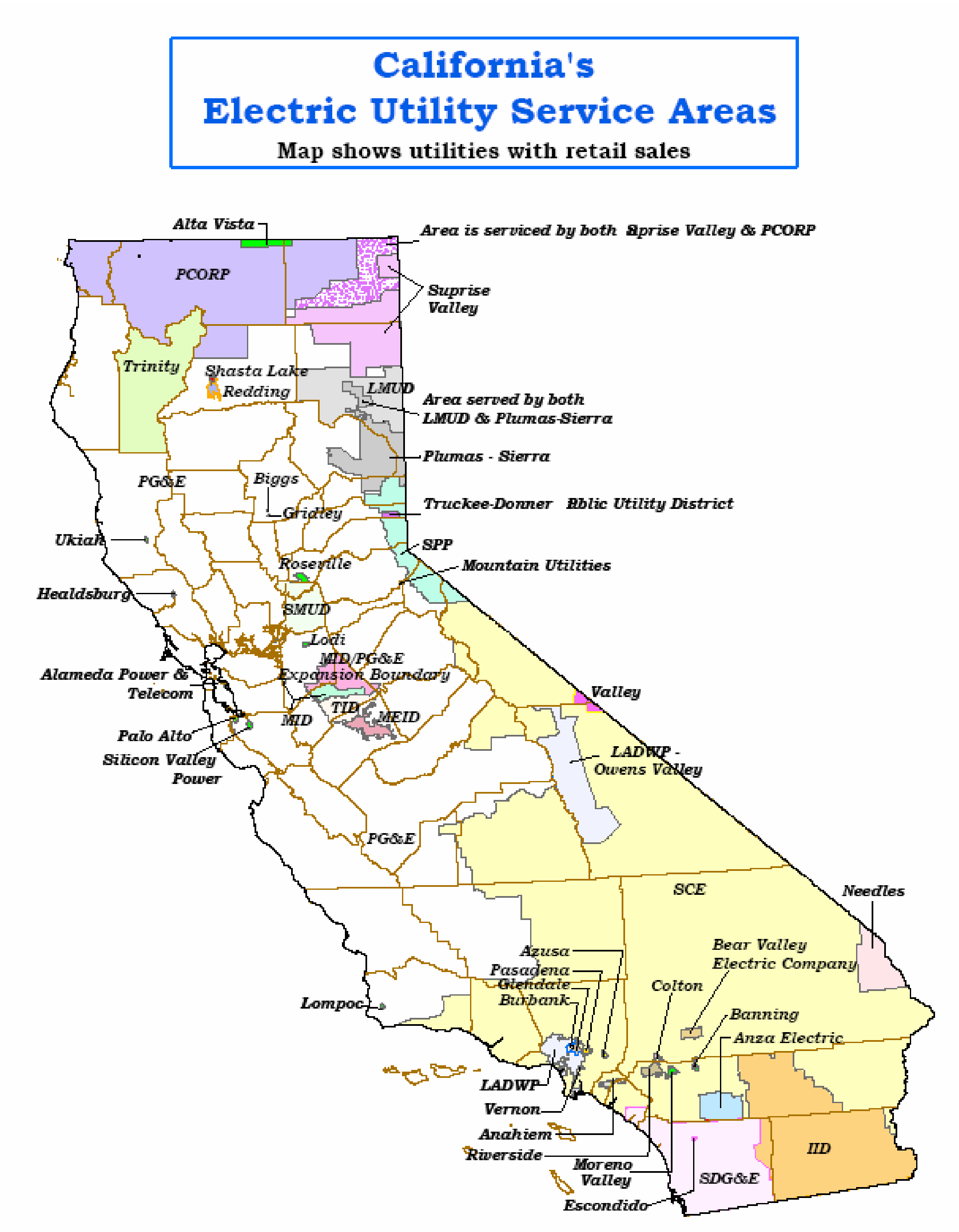
** Some host customers represented several projects.*

Host Customer Stage in the Process. Because a goal of the focus groups was to gain feedback on the SGIP, the team recruited only those host customers who either had completed projects or projects that had almost reached the completed stage. Therefore, host customers with projects that did not receive a confirmed reservation letter, and thus did not make it past the Proof of Project Advancement (PPA) stage, were not recruited for the focus groups. The host customers with projects that did not receive a confirmed reservation letter may have had different comments and suggestions about the SGIP than those who passed this stage gate.

Focus Group Facility Locations. Recruitment lists for each focus group facility location in each PA territory were created and sorted based on host customers whose zip code or city stated in the program records was within approximately a 30-mile radius of the focus group facility location. The focus group facilities used were located in densely populated areas, in Pasadena, Irvine (both located in the greater Los Angeles area), San Diego, and San Francisco. Therefore, the projects represented by the focus groups do not include dairies or landfills, or other less urban types of SGIP host customers. This is relevant as PG&E, SCG, and SCE's territories extend far into low-density population centers with SDREO's (SDG&E) territory also extending somewhat outside the highly populated region near the coast (see Figure 2-1 and Figure 2-2).

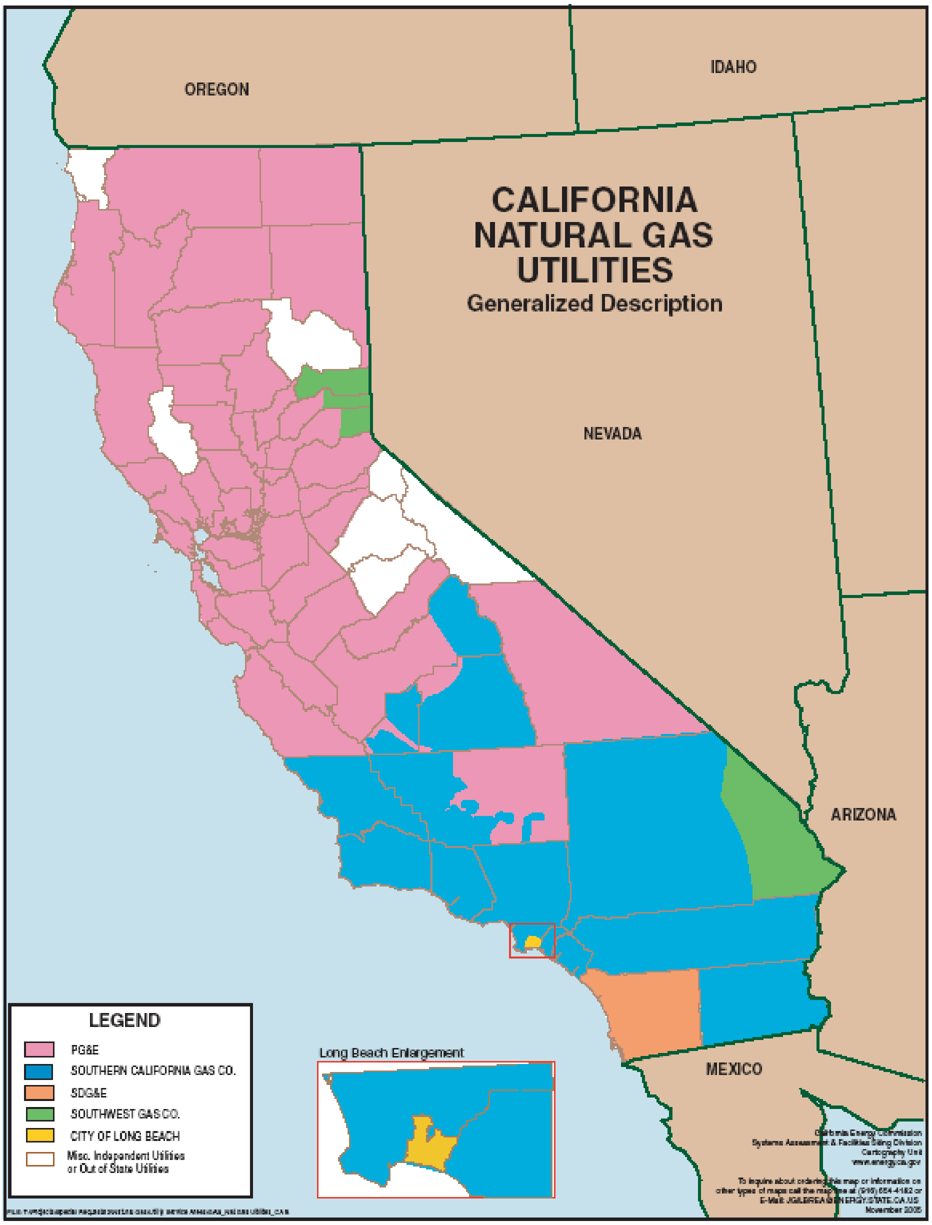
[13] At least two host customers in the SDREO focus group did not accept the cash thank-you. Instead, the cash thank-you was donated to a charity of their choice.

Figure 2-1. California's Electric Utility Service Areas



Source: California Energy Commission, California On-Line Energy Maps, http://www.energy.ca.gov/maps/utility_service_areas.html.

Figure 2-2. California Natural Gas Utility Service Map



Source: California Energy Commission, California On-Line Energy Maps, *http://www.energy.ca.gov/naturalgas/gasmap.html*

2.6 Secondary Data

The review of secondary literature and data is summarized in a table of best practices in program design, with particular emphasis on issues of concern to the SGIP. The results of this review may be found in Appendix C of the PA Study.

3. FINDINGS

The evaluation findings are presented in this section. The section begins with an overview of the program logic and a summary of program participation across time, by technology, and kW capacity. Findings on the program's interface with the market and host customers' experience with the program follow, including customers' satisfaction with the program's processes, their overall satisfaction with the program and important concerns they have.

Survey, interview, and focus group findings are then summarized from various perspectives. Findings on the program process as viewed from the public and private entity perspectives is presented, to ferret out distinctions of potential program importance between these types of entities because of the differing nature of their motivations and decision making. Findings on the effect of the application fee are then presented, as are findings regarding process-related cogeneration project dynamics. The critical effects of incentive levels and equipment costs are addressed next. Finally, the section concludes with a presentation of research findings regarding the transition to the California Solar Initiative.

3.1 Program Logic and Participation Overview

A high-level program logic model was created for the SGIP (Figure 3-1). This diagram is based on key activities and logic elements derived from program-specific documents and related program information. The logic model contains the following components:

1. **Resources**: The human, financial, and material resources that the program needs to operate.
2. **Activities**: The planned actions to successfully implement the program.
3. **Outputs**: The direct results of the program activities that occur in the short term.
4. **Outcomes**: Long-term goals for the program, including changes in the program and changes in host customers' behavior.

The program goals for the SGIP were then mapped to some of the outcomes for the model.

3.1.1 Program Goals/Rationale/Objectives for the SGIP [14]

Goals included in the Logic Model

G1. Encourage the deployment of distributed generation in CA to reduce peak electrical demand.

G2. Give preference to new (incremental) renewable energy capacity.

G3. Ensure deployment of clean self-generation technologies having low and zero operational emissions.

G6. Help support continued market development of the energy services industry.

[14] The program goals were presented in Decision 01-03-073.

Goals not included in the Logic Model

G4. Use an existing network of service providers and customers to provide access to self-generation technologies quickly.

G5. Provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just to individual customers.

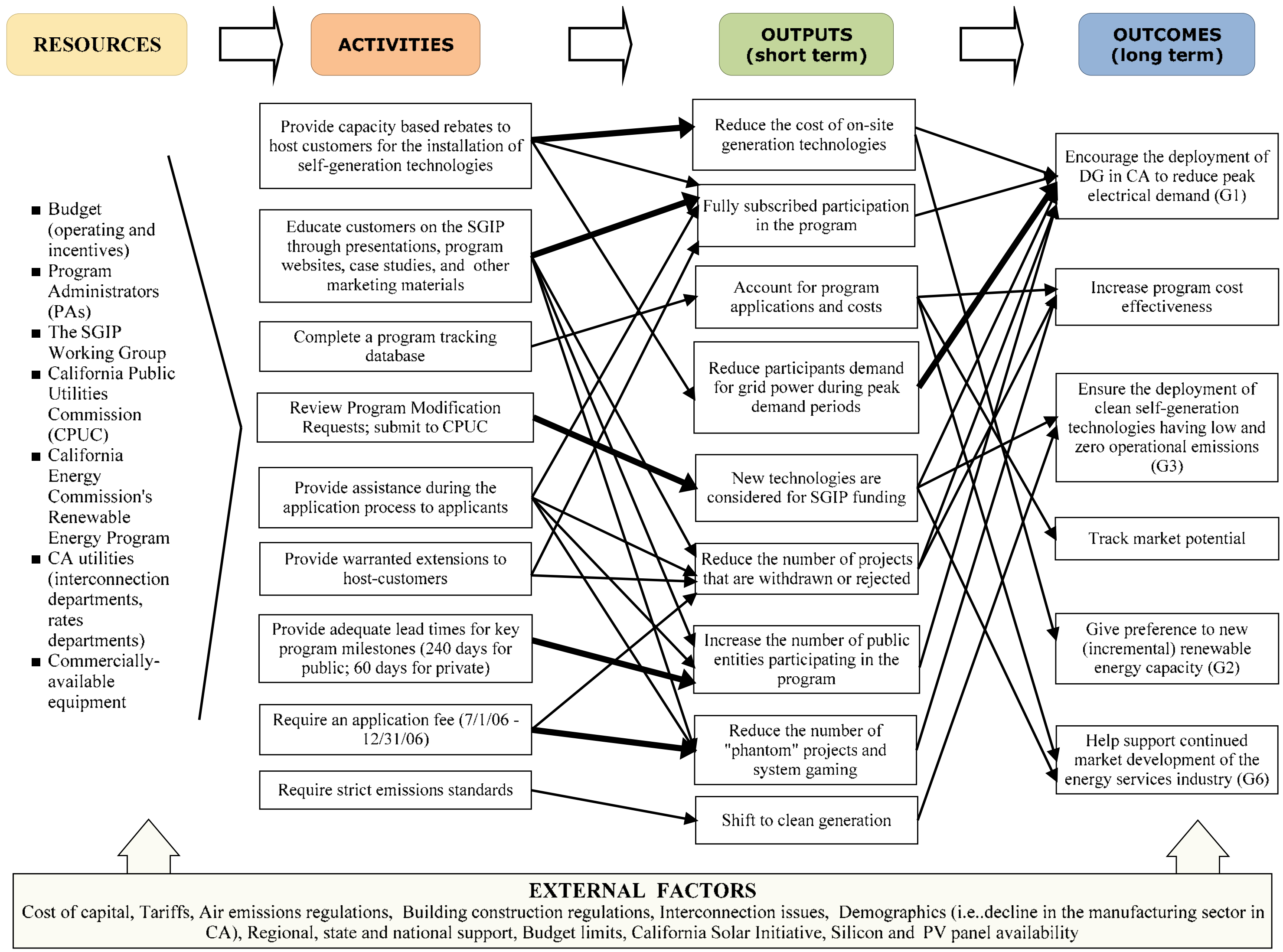
G7. Provide access through existing infrastructure, administered by the entities [i.e., utilities and SDREO] with direct connections to and the trust of small consumers.

G8. Take advantage of customers' heightened awareness of electricity, reliability and cost.

Four of the eight goals are located on the program logic model. These goals are labeled within their respective box as G1, G2, G3 or G6, corresponding to the goal labeling above. The Summit Blue team did not feel that the other four goals could be used as traditional program "outcomes" but rather were better characterized as underlying actions of the program. Goal 8 appears to be neither a goal nor an action of the program and should be considered for removal if the program is reauthorized.

The program logic model can be read from left to right as a series of "If-then" statements. For example, if a specific activity takes place, then the output should occur. If the output occurs, then the outcome should become a reality. The intentions of the SGIP are shown in the logic model, rather than the actual known outputs or outcomes. Thicker lines represent relative logic effectiveness. This logic model is used as a guide throughout the remainder of the report to help identify areas of strengths and weaknesses with the SGIP process.

Figure 3-1. The SGIP Program Logic Model



3.2 Participation Summary

Under the Self-Generation Incentive Program from 2001-2006, Californians have:

- Completed 948 on-site generation projects— 638 solar photovoltaic, 7 renewable internal combustion engine, 13 renewable microturbine, 2 renewable fuel cell, 1 wind turbine, 176 non-renewable internal combustion engine, 97 non-renewable microturbine, 4 non-renewable gas turbine and 10 non-renewable fuel cell projects.

- Developed about 234 MW of expected distributed capacity for California.

- Received over $403M in incentives.

Figure 3-2 presents a summary of the SGIP to-date graphically, and includes the total completed projects under the SGIP by completion count, installed system capacity, and incentives requested. Solar photovoltaics comprise the largest percentage of completions by count (about 68%). However, non-renewable internal combustion engines (ICE) comprise the largest installed system capacity (about 49%), with solar photovoltaics following at about 35% of total installed system capacity. Furthermore, the majority of incentives requested are for non-renewable internal combustion engines (about 60%).

Figure 3-2. Project Capacity, Number Completed, and Incentives - by Technology

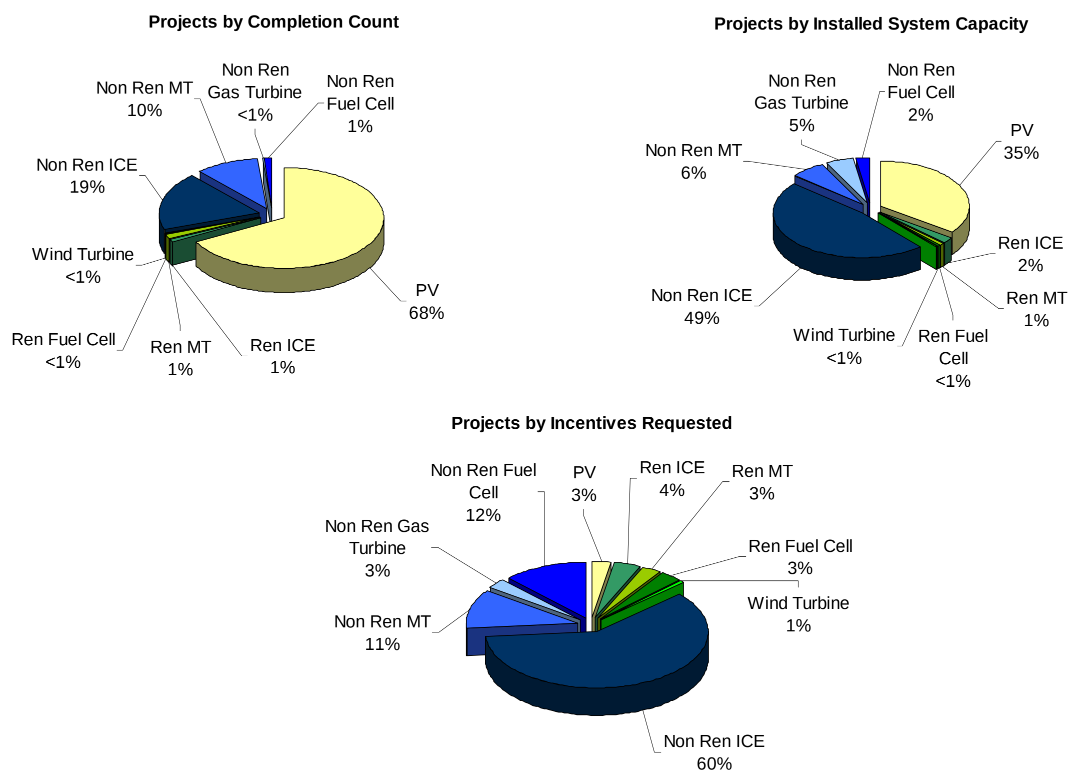


Table 3-1 presents an annual summary of projects completed as of December 2006. The number of completed projects has steadily increased since the program's beginning in 2001. For Program Years

(PY) 2005 and 2006, these numbers appear lower than in earlier years because many of the systems that applied in 2005 and 2006 are not yet complete.

Table 3-1. Summary of Impacts by Technology and Year

Year Received	Technology	Completion Count	System Capacity (kW)	Incentives ($)
2001	PV	21	3,487	11,920,740
	Non Ren ICE	27	14,656	9,042,042
	Non Ren MT	21	2,816	2,215,713
	Non Ren Fuel Cell	1	200	500,000
		70	**21,159**	**23,678,496**
2002	PV	117	14,829	44,163,986
	Ren MT	2	720	632,293
	Non Ren ICE	51	35,930	20,213,769
	Non Ren MT	15	2,268	1,696,130
	Non Ren Gas Turbine	1	1,383	810,156
	Non Ren Fuel Cell	1	600	1,500,000
		187	**55,730**	**69,016,334**
2003	PV	161	18,846	71,824,485
	Ren ICE	2	800	785,247
	Ren MT	5	990	1,228,488
	Ren Fuel Cell	2	750	3,375,000
	Wind Turbine	1	875	993,171
	Non Ren ICE	50	35,274	19,981,157
	Non Ren MT	33	4,068	3,595,552
	Non Ren Gas Turbine	1	1,210	1,000,000
		255	**62,813**	**102,783,100**
2004	PV	291	36,716	144,517,500
	Ren ICE	1	160	64,663
	Ren MT	5	470	663,000
	Non Ren ICE	39	17,489	12,791,732
	Non Ren MT	23	4,751	4,112,219
	Non Ren Fuel Cell	3	2,250	5,577,173
		362	**61,836**	**167,726,286**
2005	PV	43	7,390	24,864,817
	Ren ICE	3	2,340	2,340,000
	Ren MT	1	280	364,000
	Non Ren ICE	9	7,910	2,832,000
	Non Ren MT	5	840	672,000
	Non Ren Gas Turbine	2	9,100	1,052,129
	Non Ren Fuel Cell	5	2,700	5,642,500
		68	**30,560**	**37,767,446**
2006	PV	5	520	1,441,198
	Ren ICE	1	970	970,000
		6	**1,490**	**2,411,198**
Grand Total		**948**	**233,587**	**403,382,861**

As of December 2006, there were 658 currently active projects in the SGIP. The stage of these active projects is varying and is shown in Table 3-2. Though there are fewer active projects than completed projects (658 and 948, respectively), the total incentive amount for the active projects is greater than for the completed projects ($441 M and $402 M, respectively). The larger total incentive amount for a smaller number of projects is due partly to the fact that renewable-fueled projects (PV, renewable fuel cells, renewable internal combustion engines, renewable microturbines, and wind turbines) comprise 84% the active projects. Whereas, about 70% of the completed projects were renewable-fueled projects. Because current and past incentive levels have been higher for renewable-fueled projects compared to their non-renewable counterparts and overall,[15] the smaller number of active projects with a higher percent of renewable-fueled projects amount to a larger total incentive amount. Before 2005, the SGIP paid only a maximum percentage of the project cost depending on the technology. In 2005 and 2006, the SGIP did not limit payment to a maximum percentage of project cost. This also increased allowable incentive payment per project and results in a greater total incentive amount for the active projects (the majority of which applied in 2005 or 2006) than for completed projects.

[15] In 2006, the incentives were $2.25-$2.80/W for PV, $1.50/W for wind, $4.50/W for renewable fuel cells (compared to $2.50/W for non-renewable fuel cells), $1.30/W for renewable microturbines (compared to $0.80/W for non-renewable microturbines), and $1.00/W for renewable internal combustion engines (compared to $0.60/W for non-renewable internal combustion engines).

Table 3-2. Summary of Active Projects by Year

Year Received	Status	Projects	System Capacity (kW)	Incentives ($)
2002	Pending Payment	3	600	459,749
		3	**600**	**459,749**
2003	Advancement	1	750	696,412
	Pending Payment	4	1,341	438,869
		5	**2,091**	**1,135,281**
2004	Advancement	2	1,055	3,376,837
	Approved	1	732	3,293,258
	Pending Payment	14	8,918	8,932,687
	Suspended	2	1,877	4,840,038
		19	**12,582**	**20,442,819**
2005	Advancement	180	44,332	101,305,141
	Approved	5	1,533	2,354,594
	Pending Payment	18	4,692	11,398,424
	Reserved	3	1,382	3,522,453
	Suspended	10	5,938	7,382,894
		216	**57,877**	**125,963,505**
2006	Advancement	121	30,797	63,903,372
	Approved	46	15,547	39,116,182
	Pending Payment	4	522	749,138
	Reserved	68	21,636	55,388,145
	Suspended	36	12,904	33,917,534
	Under Review	140	70,216	99,501,090
		415	**151,622**	**292,575,461**
Grand Total		**658**	**224,772**	**440,576,816**

3.3 SGIP Interface with the Market

The Summit Blue team conducted host customer and non-participant telephone surveys, along with follow-up interviews with some respondents of both these surveys and with project developers, as described in Section 2. This information was utilized to provide the following overview of how the SGIP interacts with the existing market for on-site generation.

A dominant factor in considering on-site generation installation amongst non-participants, or those that do not actively participate in the SGIP, is a desire to reduce utility bills. Most of the respondents (79%) in the non-participant survey indicated that “utility bill reduction” would be influential or very influential in a decision to install on-site generation. However only 60% would find “concern for the environment” influential and 52% would find “peak demand reductions” influential. By comparison, 87% percent of those who participated in the SGIP indicated that utility bill reduction was influential or very influential, 75% reported participating for environmental reasons, and 64% for peak demand reduction (see Table 3-3 for comparisons). Further discussion on bill-reduction and total project economics is provided in (Section

3.8), where it is shown that the decline in cogeneration application rates is also strongly correlated with incentive reductions.

Environmental reasons were a varying dominant factor for host customers with different technologies. Eighty-two percent of host customers with PV projects, along with 77% of host customers with other renewable projects, felt that environmental reasons were very influential or influential to their participation. Conversely, only 47% of host customers with cogeneration projects cited environmental reasons as influential to their participation in the SGIP. Therefore, other factors like economics and reliability are relatively more influential with project participants.

Other decision making factors greatly varied between host customers and non-participants. Having a backup system to improve the overall reliability of the electric system was considered influential for 52% of non-participants as compared to 15% of host customers. Also, improving the business image with green marketing was reported to be more influential to host customers (64%) than to non-participants (38%). Section 3.5 discusses these decision-making factors for host customers in greater depth by comparing private and public entity decision making factors.

Table 3-3. Influential Factors in Decision to Install On-Site Generation

Influential Factors	Non-Participants	Host Customers
Wanted to reduce utility bills	79%	87%
Concern for the environment	60%	75%
Wanted to reduce peak demand	52%	64%
Wanted a backup system to improve the overall reliability of our electric supply	52%	15%
Energy supply independence	50%	43%
Improve our business image- green marketing	38%	66%
Provide technical demonstration	31%	41%

Across all market segments tested, approximately 25% of non-participants reported having heard of the SGIP, and most of these heard of the program from a utility representative (62%).[16] The segments with the greatest familiarity (e.g., 40-50% of those surveyed) included Construction, Chemical or Pharmaceuticals Manufacturing, Water or Waste-water Treatment Plants, Hotels/Motels, and other private sector services. Those that already have stand-by power systems are significantly more likely to have heard about the SGIP (46%). Market segments that report a low familiarity with the SGIP include some manufacturing sub-segments that tend not to have long batch cycles (such as industrial machinery, transportation equipment manufacturing) or market segments that typically do not believe energy is a core

[16] The non-participant survey included both the “utility representative” and the “regional energy office” as options for how the respondents heard about the SGIP. About five percent of non-participants who had heard of the SGIP had heard about it from the regional energy office.

business issue (such as restaurants). Not surprisingly, these segments do not contribute to SGIP application counts significantly.

A brief review of SGIP participation data by market segment and technology is presented next to provide market context for the process study findings. As shown in the figures below, the SGIP is currently reaching and interfacing with a wide range of market sectors. But generally, the top 10 sectors applying to the program account for 80% of program applications. Of these sectors, Manufacturing far exceeds the other segments in terms of applications, with 16% of the total number of program applications (Figure 3-3a). However other sectors, while not dominant in terms of total application numbers, do contribute a significant proportion of applications to specific technologies (Figure 3-4b). For example, the Lodging segment favors cogeneration applications, and the Utilities segment accounts for a significant fraction of “other renewables” technology types (e.g., renewable fuel cell, renewable internal combustion engine, renewable microturbine, wind turbine).

Figure 3-3a. Applications by Sector[17]

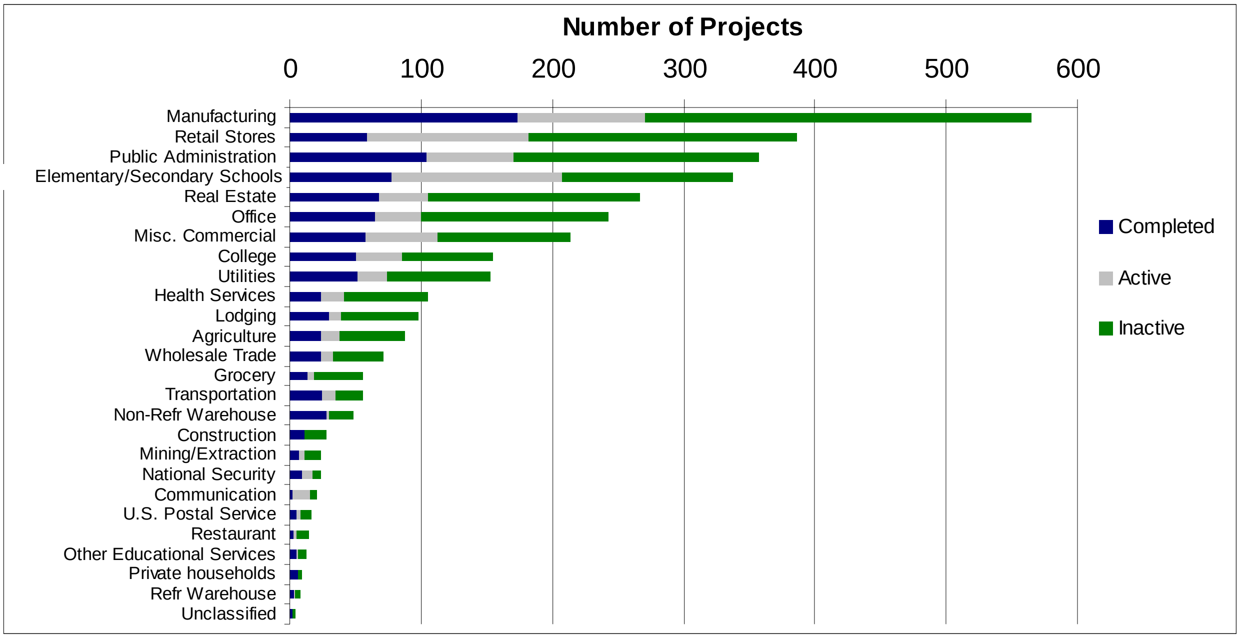
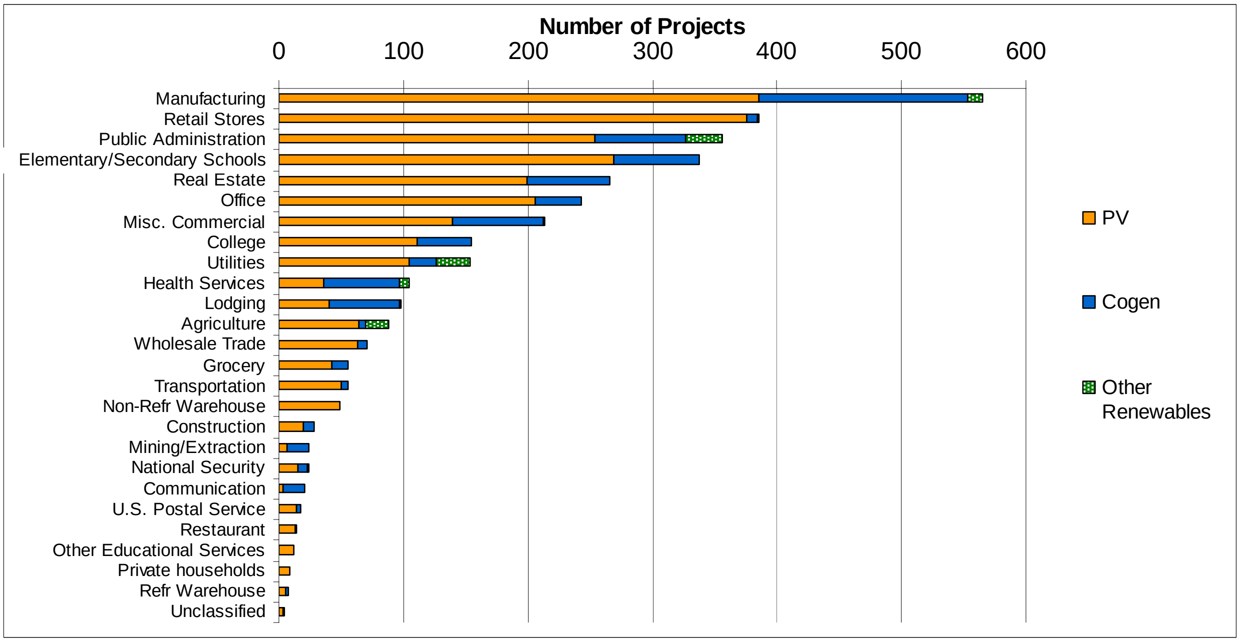


Figure 3-4b. Applications by Sector



Additional context for this information can be provided by observing the application rates to the SGIP over time by market segment and technology. Figure 3-5 shows that the number of applications for cogeneration systems is declining for each market segment shown. Each point on the charts represents the total number of applications by year of application. From this data it is apparent that PV applications increase sharply over time in the schools sector, but decrease in the retail stores and public administration

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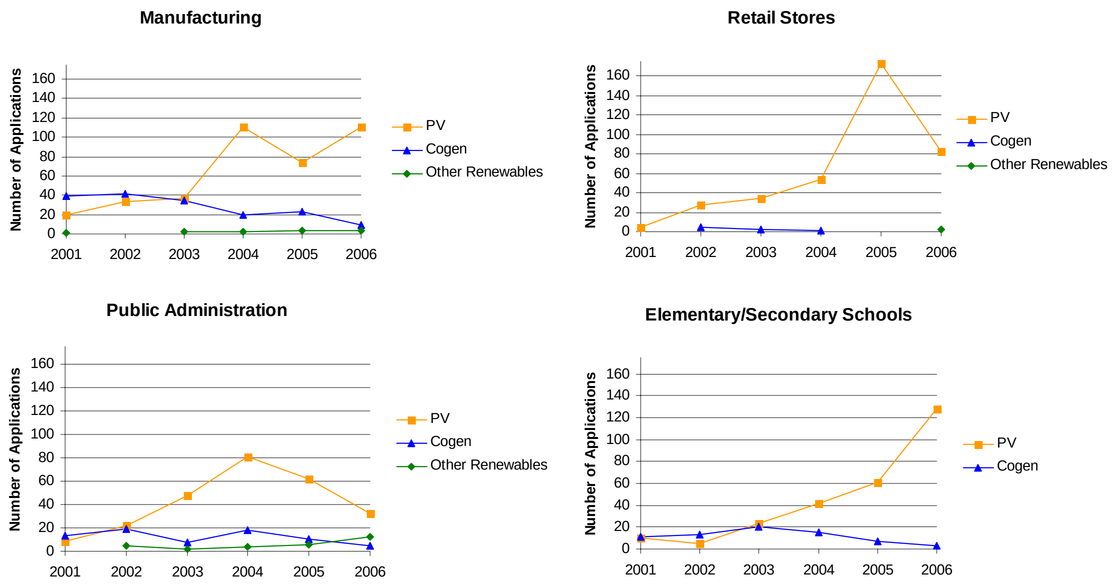
[17] The real estate sector is comprised of operators of non-residential and apartment buildings, operators of other dwellings, lessors of real property, real estate agents and managers, and land sub-dividers and developers.

sectors.[18] The increase in retail store application in 2005 is almost entirely the result of one chain retailer that submitted approximately 60 applications in that year, most of which were subsequently withdrawn. On the other hand the increase in PV applications by schools would exist even without the large number of school applications received by SDREO to the program.

Figure 3-5. Yearly Applications to SGIP by Technology and Market Segment[19]



Completion of project applications to the SGIP varies significantly by market segment and is discussed further in Section 3.7.1.

3.4 Host Customer Experience with the Program

Host customers experienced the program both directly and indirectly through project developers. Their views on their experiences are presented in this section, including interaction with developers, the program's various administrative processes, the program's marketing and outreach efforts, eligibility and, for those who had projects withdrawn, what were reasons for the withdrawals.

3.4.1 Overall Experiences in the Program for Host Customers and DG Contractors

The Connection between Host Customers and Developers

Overall, program host customers rely heavily on the energy services industry to aid them in the application process. Seventy-six percent of developers interviewed felt that the host customer essentially takes a hands-off approach to the application process, leaving their company to make most of the decisions. This number compares favorably with the results reported by host customers in survey data that

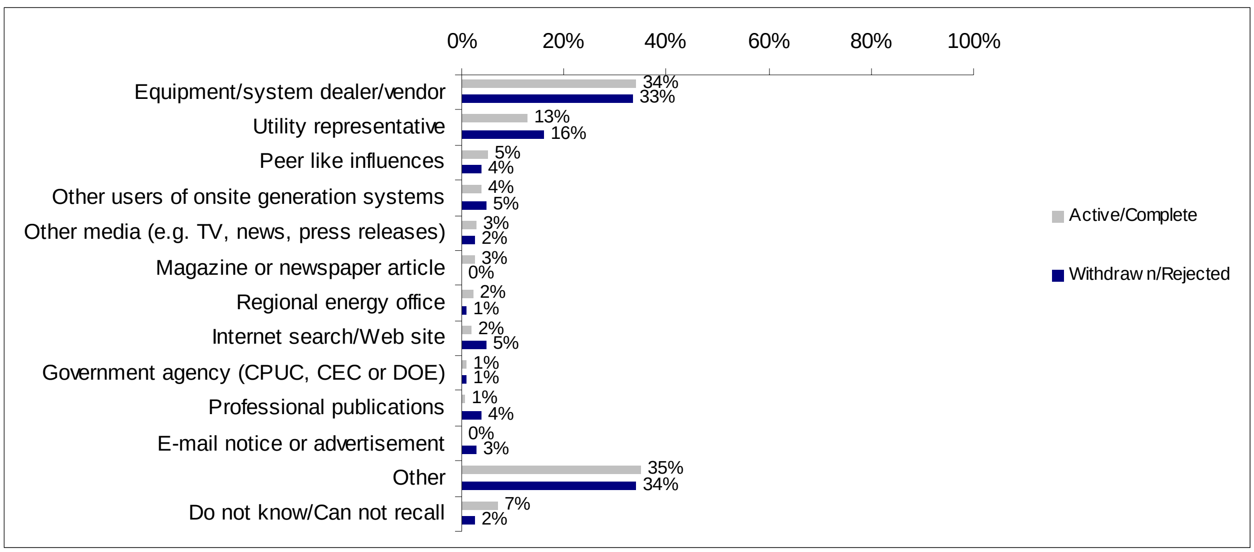
[18] Public Administration includes city and county entities but does not include other types of public sector entities such as schools, public utilities and colleges.

[19] Manufacturing, retail stores, public administration, and elementary/secondary schools represent the top four segments by applications.

shows that about 40% of host customers in the SGIP were not very involved in the SGIP process.[20] For these host customers, an energy services company, contractor or some other party completed and submitted the application forms. An additional 40% of host customers also had an energy services company, contractor or some other party complete and submit the application forms, but they were closely involved in the application process. Therefore, indications are that the energy services industry was involved in a significant fashion in about 80% of host customer applications to SGIP. Similar results are also shown in the program data. About 82% of projects in the database have a developer or installer listed and most of those records (about 80%) show different entities for applicant and host customer. Notably of those customers interviewed in depth, those that report no significant difficulties with the SGIP process were very likely to have outsourced a significant percentage of the project. Those that encountered difficulty were more likely to have applied on their own to the program.

Working closely with a third-party supplier, or services company, is consistent with the ways program host customers learned about the program. For all host customers, the major channel through which they learn about the program is the equipment vendor or third-party supplier. Also high on the list is the utility representative (Figure 3-6).

Figure 3-6. How Program Host customers Learned about the Program



Note: Other includes general knowledge, consultants and previous experience with DG

Program Application Materials

When asked about the clarity of the program application materials, the developers had a range of feelings. Most felt that the applications materials were clear and had improved over time, while other developers felt that the application materials were too complex. For those host customers that were actively involved in application efforts (about 40% of host customers interviewed did not review the materials), they also had mixed reviews. Like the developers, some felt that they were clear and others felt that they were confusing. Those who felt the forms were difficult mentioned that they were complicated, contained

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[20] Public entities are almost twice as likely to process the application paperwork themselves, compared to private firms. See Section 3.5.

technical language that was not easy to understand, and they had no direct information about a point of contact. In the in-depth interviews, the dominant reason for having a negative experience stemmed from the sheer volume and perceived bureaucracy that the paperwork, including the application, represented. However, this complaint should be taken in context, in that, very large incentives are being offered under the SGIP. While it shouldn't be unnecessarily difficult to apply to the SGIP, a threshold level of business and electrical sophistication could rightfully be expected from applicants. Moreover some improvement has occurred, in that paperwork burdens have been reduced by eliminating the maximum percentage payment limits.

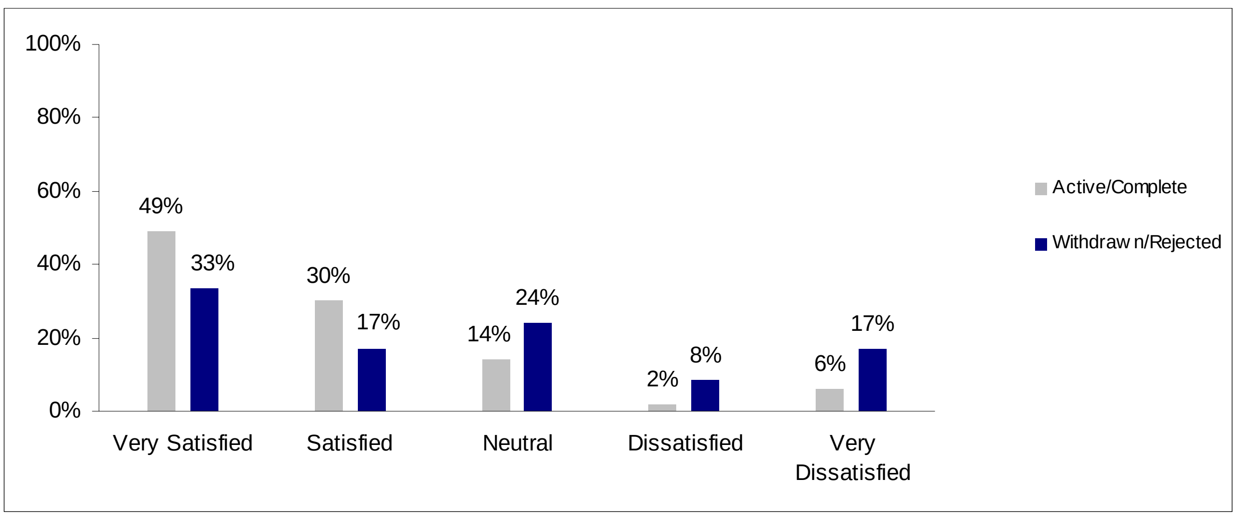
"I've got two feet of paperwork from this project in my files." Withdrawn applicant to SGIP[21]

Program Satisfaction

The host customers overall satisfaction with the program is shown in Figure 3-7. Not surprisingly, a higher percentage of host customers with active or completed projects were very satisfied or satisfied with the program than those host customers with withdrawn or rejected projects. About 80% of host customers with active or completed projects were very satisfied or satisfied with the program, and about 50% of the host customers with withdrawn or rejected projects were very satisfied or satisfied with the program. More noteworthy is that so high a percentage of customers with withdrawn or rejected applications were nonetheless very satisfied or satisfied with the program.[22]

Satisfaction with the SGIP was initially low for host customers that applied in 2001 with active or completed projects-48% of host customers were satisfied or very satisfied with the program. During 2002-2005, satisfaction was relatively high and constant, ranging from 81% to 90%. However, for those host customers that applied in 2006, only 58% were satisfied or very satisfied with the program.

Figure 3-7. Host customers Overall Satisfaction with the SGIP



[21] This participant applied before the elimination of the maximum percentage payment limits which reduced some paperwork.

[22] Only about 8% of the host customers surveyed with withdrawn or rejected projects also had a project that was completed or active.

Program Processes Satisfaction

During the in-depth interviews, the developers and host customers were asked about the ease of different process stages. Some developers reported that the 60-day deadline to reach the Proof of Project Advancement (PPA) was especially difficult for public entity projects. Others had varying views on the difficulty of reaching the deadline: some felt it was obtainable, while others felt the deadline was difficult to reach. Typical reasons given for this in the in-depth interviews included: obtaining air pollution permits (where applicable) and other miscellaneous building permitting issues such as obtaining an occupancy permit. Interconnection was also a difficult hurdle for many in obtaining PPA. Other environmental issues included water permitting and environmental impact analyses. Some public entity participants admitted that their own internal bureaucracy contributed to the difficulty in achieving the PPA stage gate. Many of the host customers noted that the deadline to meet the PPA was sufficient, though some did mention receiving extensions. A few felt that the 240-day deadline for public entities was still insufficient. The developers said that the 1-year overall deadline was hard to meet for some projects, but that extensions were given for good cause. The majority of host customers also felt the 1-year deadline was tight and many mentioned receiving extensions.

The results from the host customer survey regarding the application process are shown in Figure 3-8, Figure 3-9, and Figure 3-10. The processes listed in Figure 3-8 were asked of all host customers, whereas the processes listed in Figure 3-9 were asked *only* of host customers with non-solar projects. From the survey of host customers with withdrawn or rejected projects (Figure 3-9), only the first set of questions provided useful information. Overall, host customers found the application process to be not too difficult. For all surveys processes, the majority reported them to be “Easy” or “Very Easy.”

All host customers with active or completed projects found that obtaining the necessary insurance was relatively the easiest stage gate. The data also show that there was a small population that found obtaining the necessary insurance “very difficult” (5% over all host customers) with more host customers with non-solar (other) renewable projects finding this process “very difficult” (27%) than host customers with cogeneration or PV projects (4-5%). Also, those host customers that did not use a developer were more likely to find this “difficult” or “very difficult” (14%) compared to those that used a developer’s aid in some fashion (only 2-4% found it “difficult” or “very difficult”). Obtaining any necessary air quality permits and financing the project were cited as most difficult.

For non-solar host customers, working with the electric utility to connect the unit to the grid was perceived to be relatively difficult compared to the other program processes. The host customers with withdrawn or rejected projects found that choosing the technology was the easiest, while financing the project was most difficult. One significant difference between active and completed projects is the perception of the ease in obtaining an air permit. Note that those who have not yet completed an SGIP project are much more likely to perceive air permitting as relatively easy. Many of these active applicants have not yet completed the air permitting stage gate. Nonetheless, this significant departure between the perceived ease of those that have completed air permits and those that are in process is important in managing the expectations of SGIP participants. Another difference in active and completed project applicant perception is the perceived ability to obtain equipment from the manufacturer. Active (and more recent) projects appear to be somewhat less confident in the ease of obtaining equipment. Finally, meeting waste heat requirements was not cited by host customers to be as difficult as was expected. Those that did find it “difficult” were more likely to be host customers with fuel cell projects (29%) compared to host customers with microturbine (15%) or reciprocating engine/turbine (4%) projects. Overall, the process appears to have become easier over time. Of those that applied in 2001, 33% cited meeting waste heat requirements as difficult compared to 0% of those that applied in 2006, with a slight bump in 2005 (11% cited this process as difficult).

Figure 3-8. Ease of Application Process- Host Customer Survey [Active(A)/Completed(C)]

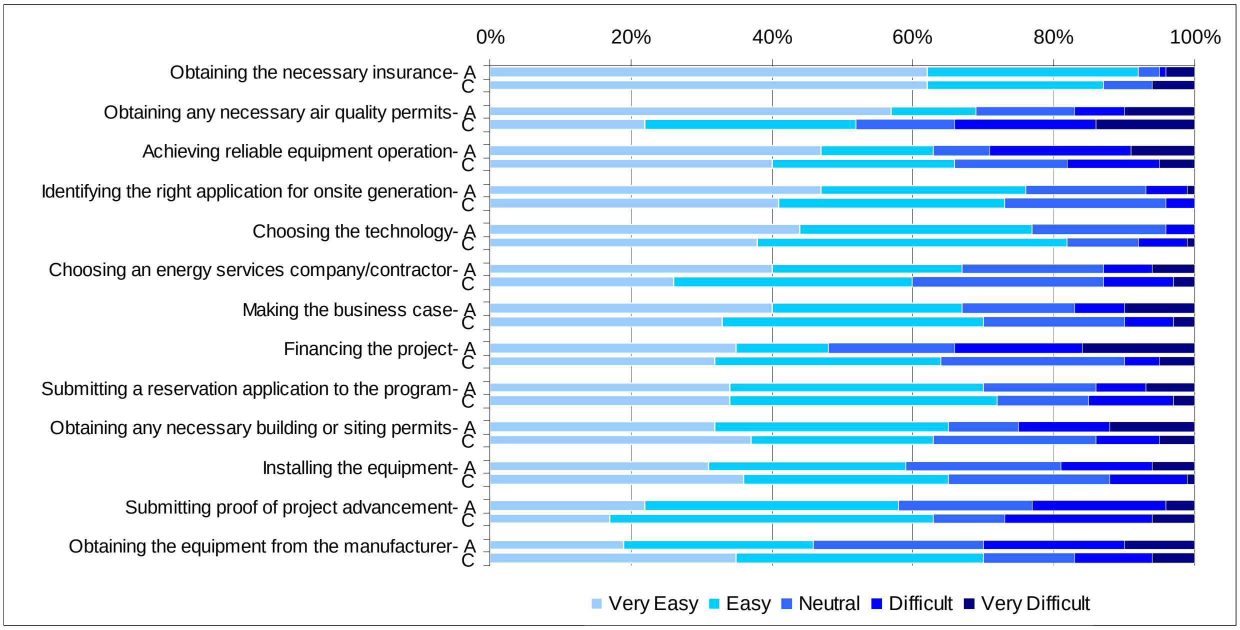
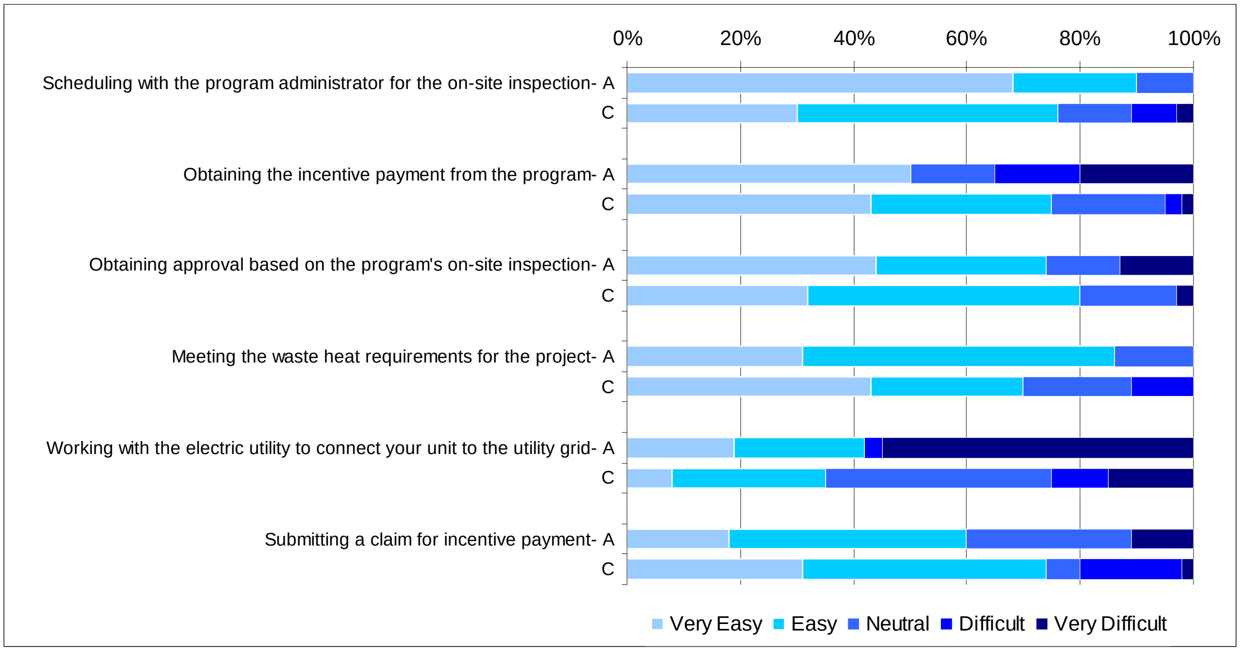
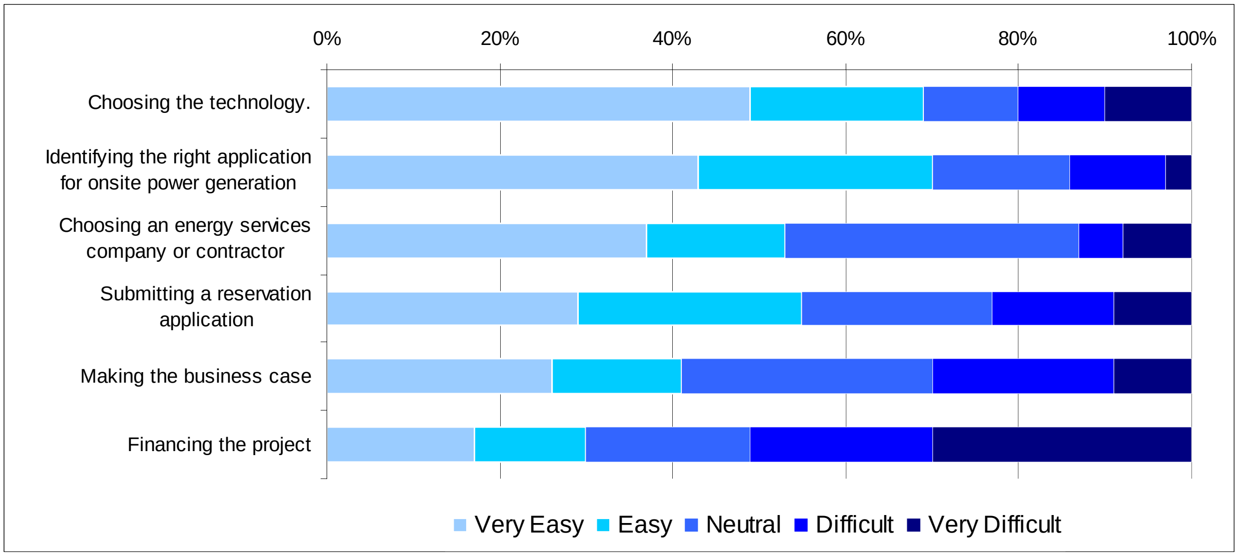


Figure 3-9. Ease Associated with Application Process- Non Solar Host Customer Survey [Active(A)/Completed(C)][23]



[23] These questions were asked of only non-solar host customers.

Figure 3-10. Ease Associated with Application Process - Withdrawn/Rejected Host Customer Survey



Project Delays

Most developers felt that host customers do not cause project delays, although some said they can change their minds about the installation or can be difficult to contact. However, some developers commented that public entities (city governments, water districts, etc.) have more laborious approval and board processes that can make them difficult to work with. Only one host customer interviewed mentioned the developer as causing program delays.

Host customers also mentioned other delays in the project process including obtaining PV panels, submitting additional program requirements, obtaining city and air permits, and waiting for the utility to install a meter or other utility equipment supply issues such as transfer switch issues. On a positive note, one customer indicated that a utility representative had visited their site to help with interconnection on his day off.

Overall Success

Owners of PV systems and fuel cells are the most optimistic that the on-site generation project will be "successful". Eighty-eight percent of the three owners of fuel cells and 90% of owners of PV systems feel confident or very confident of project success. By comparison, 60%-70% of owners of microturbines, reciprocating engines, and other ICEs feel confident of success.

Program Changes

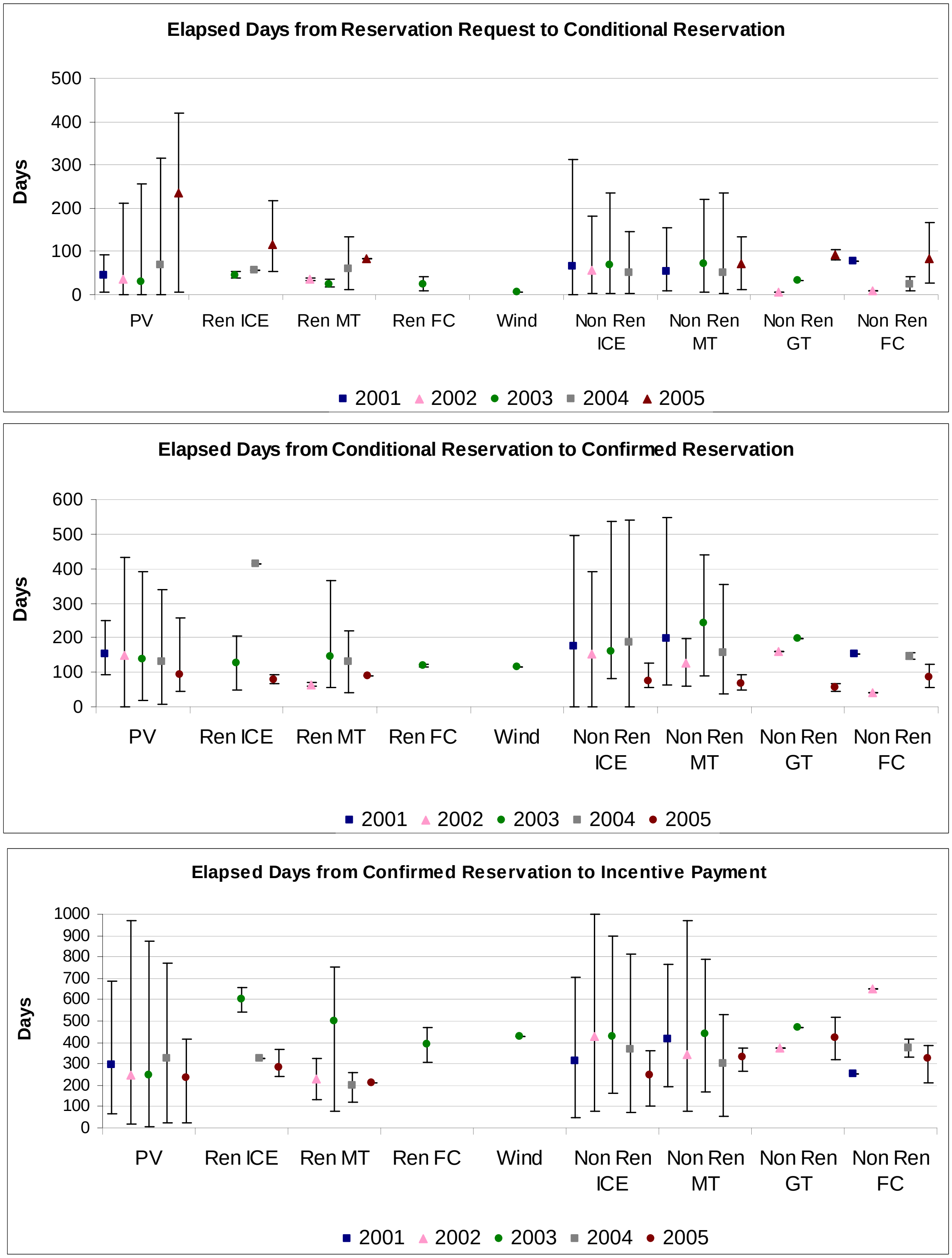
When asked about the program changes to the SGIP, developers complained generally about the frequent changes to the program. (See Figure 1-1 above for an overview of the ten significant changes in the SGIP processes over six years.) In particular, changes that affect their role in the program were typically named, such as the application fee, wait list, stricter emissions standards, and decreasing incentives. One host customer interviewed felt that the application process was not fluid and that the changes do not appear to be improving the project. A few others felt that the frequent modifications and bureaucracy made it difficult to understand eligibility, leading to a perception that the utility did not seem to "want to pay for the project." These are significant, but apparently minority, views on the SGIP, and it should be noted that generally past program changes have increased eligible technologies, while admittedly decreasing incentives.

Reviewing the survey data by the date the host customer applied also provides insights into the program experiences. Overtime, fewer host customers are completing forms themselves, from 76% of those that applied in 2001 saying they did complete the forms themselves to 13% of those that applied in 2006. This decrease has been a steady decline from 2001 to 2006. Most program processes have stayed consistently easy or difficult for host customers over time. One process of note is the ease of submitting proof of project advancement to the program. Forty percent of host customers felt this was easy or very easy in 2001, rising to 79% of host customers that applied in 2004 feeling this way, then decreasing to 54% of host customers that applied in 2006.

3.4.2 Time to Process Applications

The following charts in Figure 3-11 show elapsed days to reach project milestones. Single data points represent the mean, and the range is shown with minimum and maximum bars. For the rest of this section, the minimum, maximum, and mean (or average) days are discussed for each process stage.

Figure 3-11. Days to Reach Process Milestones



Application Date to Conditional Reservation

The average days an applicant waited to receive a conditional reservation after submitting a reservation request varied, depending on year the application was received and technology type. Between 2001 and

2006, projects took between six and 235 days to complete this process, with most systems taking between 40 to 50 days, as shown in Figure 3-10. Based on conversations with PAs about wait list processing, this result may be an artifact of wait list and wait list rollovers, particularly for PV applications. However, the time on the wait list was not tracked in program data and thus can not be shown.

Conditional Reservation to Confirmed Reservation

Once an applicant has received a conditional reservation, they must provide proof of project advancement (PPA) materials by a specified time period to remain in the program and receive their confirmed reservation. The SGIP Program Handbook outlines the time periods in Table 3-4 for confirmed reservation to conditional reservation.

Table 3-4. Conditional Reservation to Confirmed Reservation Time Periods

Program Year	Conditional Reservation to Confirmed Reservation Time Period Allotment
2001-2004	90 days
2005	60 days
2006	60 days (private firms) 240 days (public entities, effective 7/1/06)

The program data shows that, despite the limitations to receive a confirmed reservation, on average the projects were exceeding this time frame.

- In 2001-2004, projects took between 41 to 546 days to complete this portion of the SGIP process. Most projects took about 150 days to reach confirmed reservation, far exceeding the 90-day limit.

- In 2005, the time period reduction did result in a reduction in days to reach confirmed reservation stage. Projects took between 43 to 259 days to complete this portion of the SGIP process, and the average time to complete this process was 77 days.

Therefore, while most projects in 2005 still exceeded the time limit to provide the PPA materials, the time to navigate this stage gate is down. Given that the overall drop out rate in the SGIP is somewhat constant (see below) it does not appear that projects are better vetted, but rather that developers and ESCOs are improving in their ability to navigate the system. Moreover this is also to some extent an artifact of the large number of PV projects in the system, which have on average lower completion dates for this stage gate. Because only six projects that applied in 2006 have completed the process, there is not sufficient data to show the effect of the time limit change. But the data for these six projects show that they took between 70 and 80 days to submit their PPA materials.

For PV projects, primarily for projects administered by PG&E and SCE, there was a spike in the number of applications in 2005, which carried through to a lesser extent in 2006 (due to the advent of the CSI). Concern about incentive reductions appears to have driven this, based on developer and participant interviews. There may also be an effect from pre-2005 projects being placed on the wait list, which also could contribute to the spike in PV applications in 2005 and 2006.

From 2001 through 2004, PPA extensions could be granted at the PA's discretion. These extensions could be given for up to 90 days. In 2005 and 2006, the SGIP Program Handbook states that extensions may be granted for 60 days and only for public entities. However, the data show that additional extensions were given during this stage, because some projects exceeded even the time allotted for this stage plus the extension limit.

Confirmed Reservation to Incentive Payment

The number of days from the confirmed reservation to the incentive payment varied slightly, depending on application year and technology, though on the whole this average time period stayed fairly consistent. Across technologies, the time to receive the incentive payment varied from 89 to 652 days. Overall, the average time to complete this stage of the process was 315 days (see Figure 3-11). Per the SGIP Program Handbook, the confirmed reservation expiration date may be extended for up to 180 days. Therefore, the days to receive the incentive payment from the confirmed reservation in Figure 3-11 may include any extensions given to projects.

Most of the in-depth interviews and surveys reflect these extensions, as discussed above in the discussion on conditional reservations to confirmed reservations. The regular grant of extensions for "cause," while a fair and appropriate use of PA authority, is not universally understood in the applicant pool. Developers who have been working with the SGIP over the years do understand the means to ask for extensions, but individual applicants that do not work with developers do not understand this as well, as evidenced by in-depth interviews and questions received by the Summit Blue team after the focus groups. There is therefore an issue of parity with regard to the knowledge about the availability of extensions.

3.4.3 Drop Out Rates

Over the lifetime of the SGIP, project withdrawal rates have been over 50% (Figure 3-12). For the projects that were submitted during the first year of the SGIP, the drop out rate was higher than for other years of the program (73% of projects that applied in 2001 ultimately dropped out). For 2002-2004, the drop out rate remained relatively constant at about 50%. The drop out rate for projects that applied in 2005 is already higher than the previous years' averages, and the final rate may be higher because some currently "active" projects may have simply not yet informed a PA of program withdrawal. This is also true for projects that applied in 2006, as 69% of the total projects that applied in 2006 are still active as of December 2006. The higher 2005 drop out rate may also be a reflection of the surge of applications in 2005 that occurred most likely in an effort to avoid the application fee (which was instituted in July of 2005), as well as concern over declining solar rebates.

Figure 3-12. Withdrawal Rates over SGIP Project Year

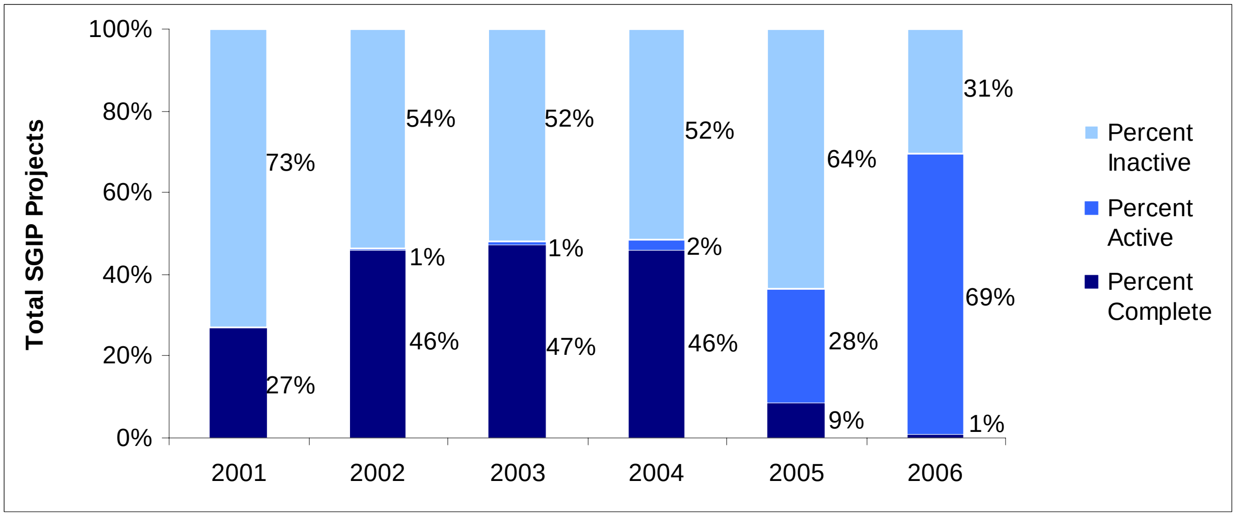
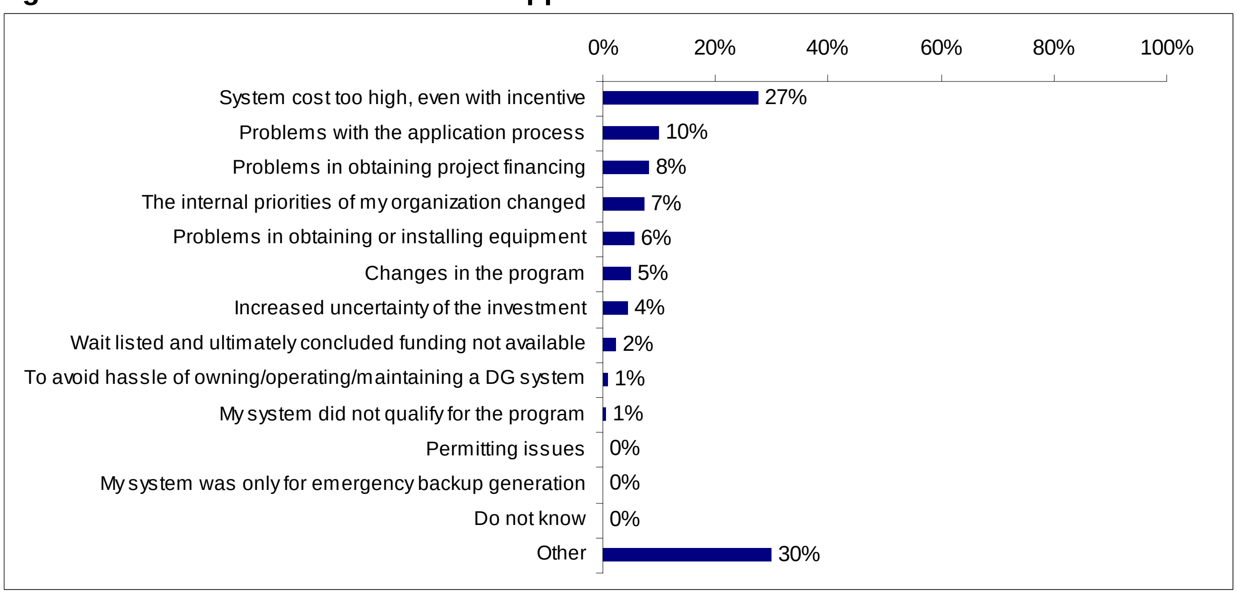


Figure 3-13 presents the reasons host customers withdrew applications. The main reason cited by host customers for drop out was that the system costs were too high even with the incentive. Problems with the application process and problems in obtaining project financing were other top reasons given for withdrawing the project. Because of the low number of projects surveyed that were actually rejected (as opposed to merely letting the applications lapse as untimely), the information on reasons for suspension and rejection is much less robust. However, the two top reasons cited by host customers were missing deadlines or "did not know." It is important to note that host customers may not know precisely why they were rejected, because the majority of program host customers rely heavily on a service provider or DG vendor to assist them with the program application process. It is possible that customer can be left with the impression that the "application process" was the reason for withdrawal, when in fact an incomplete application or an untimely application or progression through a stage gate could be at fault.

Figure 3-13. Reasons for Withdrawn Applications



Other includes problems with the contractor/consultant, lack of guaranteed SGIP rebate, lack of response from the utility, delays, metering, tax reasons, time constraints, issues with the ownership of the system, better rebates in 2007, too many requirements, and initially unknown additional fees.

Despite withdrawing from the program, some projects were completed anyway. Of the surveyed host customers that withdrew, were suspended, or were rejected from the program, almost half (43%) indicated that they had either installed (14%) the system anyway or planned to do so (29%).[24] It should be noted that many of these projects would not have been initiated without the potential of receiving funding through SGIP. About 90% of host customers with active/completed and withdrawn/rejected projects ranked the availability of rebates from the program in their initial decision to go forward with this project as very important.[25] Therefore, the availability of funding is crucial for many of the on-site generation projects to begin. Also, the surveys show that the perception and reality of the ease of different program processes can be different; thus the 29% that plan to continue with project installations may encounter logistical or economic roadblocks that stop them from installing the generation equipment.

3.4.4 Eligibility Issues

For the most part, the PAs, developers, and host customers did not cite eligibility issues as a reason that projects do not complete the SGIP. SCG did mention that a few host customers did acquire gas meters to be eligible to apply through SCG, but this is not thought to be a dominant response. The PAs also noted that the increase in system size to 5 MW was a positive change for the SGIP and allowed more projects to be eligible for rebates. The majority of developers interviewed had no projects that they could not get through the SGIP because they were not eligible. Of the few who did have eligibility issues, the main concerns were around sizing limits and waste heat requirements. When developers were asked if host customers understood eligibility, all but one of them said that they did not and that the developer had to explain it to them. The majority of the host customers interviewed had no eligibility issues, though during the in-depth interviews a few cited difficulty understanding these issues. Due to the frequent program changes there seemed to be a general concern on the part of customers that they could be ineligible or become ineligible without knowing it.

There are also projects that would seem to meet the overall intent of the SGIP that do not technically qualify because of lack of on-site demand for electricity. Landfill gas or biogas projects were cited by two PAs as examples of the types of projects that failed at the concept stage because the on-site loads were sometimes not high enough for project economics to work out, as long as SGIP restrictions did not permit them to send power to nearby facilities. A few of the withdrawn projects also reported similar experiences where projects appear to meet the intent of the SGIP but fail for what are perceived to be "technicalities."

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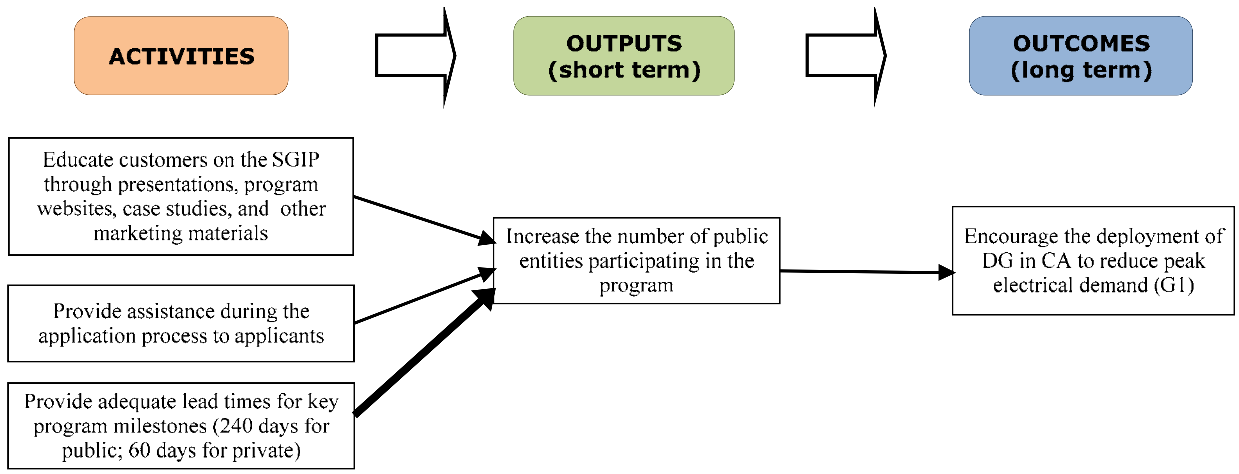
[24] Source: participant survey, weighted.

[25] On a scale of 1 to 5, with 5 meaning "Very important," 1 meaning "Not at all important," and 3 meaning "Neutral."

3.5 The SGIP Process for Public versus Private Entities

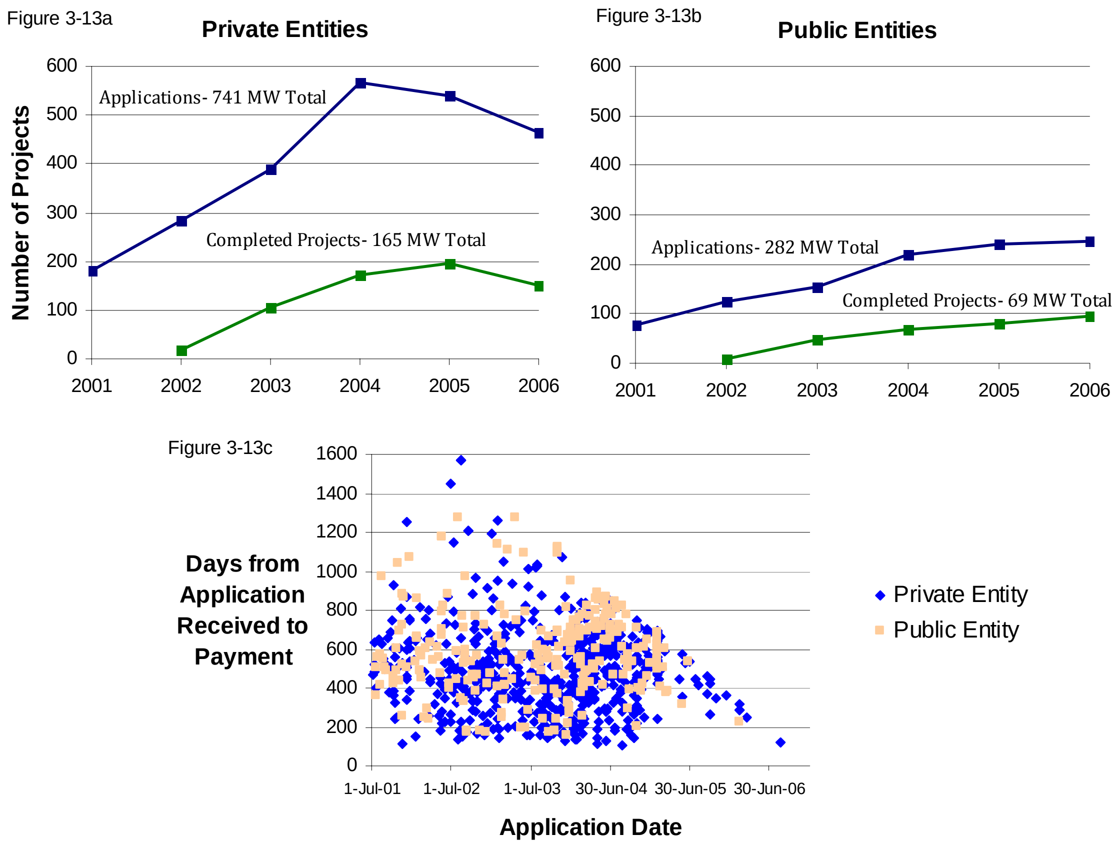
As part of the long-term outcome the program seeks to encourage DG deployment in the State to reduce peak electricity demand (as denoted in the program sub-logic diagram below), the program has targeted its processes to increase the number of public entities participating in the program. Elements of particular interest in achieving this increased number of public entities include educating customers, application assistance and, critically, adequate lead times for key program milestones. This section examines whether there have been notable differences between public and private entities participating in the program along these and related lines of interest.



3.5.1 Public and Private Entities in the SGIP

In terms of gross numbers, private firms were more active in the SGIP than public entities in both number and size (kW) of applications and number and size (kW) of completed projects (Figure 3-14).

Figure 3-14. Yearly Private and Public Entity Project Counts and Days to Complete the SGIP Process



Throughout the lifetime of the SGIP, private firms applied for over 741 MW of clean energy capacity (2,422 projects) and completed 165 MW in total (646 projects). Public entities applied for 282 MW of clean energy capacity (1,065 projects) and completed 69 MW in total (302 projects). (see Figure 3-14a and Figure 3-14b). Overall, public and private entities applied to the program in similar waves (Figure 3-15).

Figure 3-14c also shows that private and public entity projects take a varying number of days to complete the entire SGIP process; however, public entities surprisingly do not take much longer, as might be expected, to navigate the SGIP than do private entities. Private entities are permitted 12 months (365 days) to complete the SGIP process, where public entities have 18 months (about 548 days) to complete the process. On average, private entity projects take 495 days to complete the process, which is over their reservation period, and public entity projects take 597 days to complete the process, which is within their reservation period, considering that the time on the wait list increases this value. Though public entities do take, on average, 100 days longer than private firms to complete the process, they are allowed 180 days more than private firms. Therefore, public entities are able to navigate through the process well within their extended time frame, where private firms are taking much longer than their allotted time and are completing project closer to the time allotted for public entities.

One pattern that is notable is the relative decline in private-entity applications since 2004, compared to public-entity applications. We conclude, based on developer and participant interviews and recent renewable energy program evaluation work in New Jersey,[26] that the difference is due to declining incentive levels and, based on PA staff interviews, some saturation of the best opportunities, particularly for cogeneration. For example, the decline in incentive levels as noted below, with the results of a regression analysis on reasons for cogeneration project declines, also appears to explain the general decline in private-entity applications. This conclusion is bolstered by host customer reports on reasons for program participation. Private entities are more focused on energy cost reduction and somewhat less on green public image. Conversely, public entities are more concerned about green image and somewhat less focused on energy cost (Table 3-5). Public entities are also willing to accept longer payback periods for their project than private firms. Over 50% of public entities stated that they were willing to accept a payback period of greater than 10 years, but about 20% of private firms were willing to accept a payback period of greater than 10 years (Table 3-9). Further reductions in incentive levels would more severely test this view of the declines in private-entity projects.

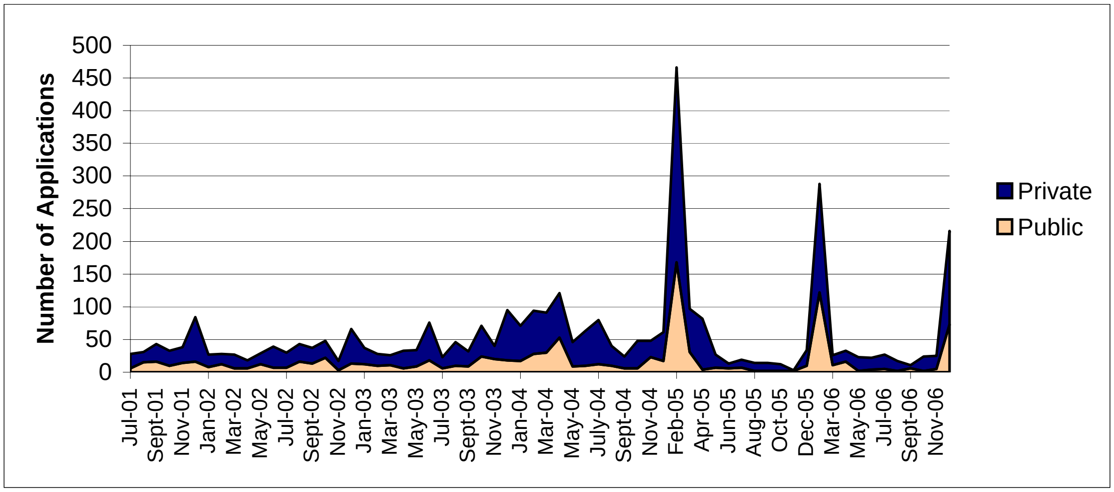
Table 3-5. Reasons for Purchasing and Using On-Site Generation Technology by Private and Public Entities

Reasons for Purchasing and Using On-Site Generation Technology that were "Very influential"*	Private Firms	Public Entities
Wanted to reduce utility bills	74%	52%
Concern for the environment	56%	55%
Wanted to reduce peak demand	43%	34%
Improve our business image-green marketing	40%	55%
Provide technical demonstration	19%	43%
Energy supply independence	18%	29%

**Asked on a scale from "very uninfluential" to "very influential". The responses reported here are only the "very influential" responses.*

[26] Summit Blue Consulting is concluding evaluation of the New Jersey Renewable Energy program and has conducted survey research for that evaluation which touches on this issue; project report is forthcoming.

Figure 3-15. SGIP Applications over Time (by Public and Private Entities)



Source: SGIP December 2006 Monthly Reports

Public entities accounted for about one-third of all completed projects, one-third of all PV projects, almost half of completed microturbine projects, and one quarter of the internal combustion engine projects by number. Private firms developed seven of the 10 non-renewable fuel cells and all four non-renewable gas turbines. Public entities developed the two renewable fuel cell projects and the one wind energy project (Table 3-6).

Table 3-6. Projects by Technology and Public-Private

System Type	Private	% of Total	Public	% of Total	Total
PV	434	68%	204	32%	638
Ren ICE	6	86%	1	14%	7
Ren MT	3	23%	10	77%	13
Ren Fuel Cell	0	0%	2	100%	2
Non Ren ICE	139	79%	37	21%	176
Non Ren MT	53	55%	44	45%	97
Non Ren Gas Turbine	4	100%	0	0%	4
Non Ren Fuel Cell	7	70%	3	30%	10
Wind Turbine	0	0%	1	100%	1
Grand Total	**646**	**68%**	**302**	**32%**	**948**

The proportion of private firms to public entities that had clean energy projects funded by SGIP overall (69:31) is fairly consistent across different PA's. SCG has a slightly higher proportion of private firms (75

%), while almost half of SDREO applications came from public entities in part because one school district alone submitted close to 80 applications.

Private firms (27%) and public entities (28%) are equally likely to process an application all the way to project completion.

Process Differences

Public and private entities are treated similarly in the SGIP application process in terms of what technologies are eligible, size requirements for eligible projects, the incentive levels that get paid per technology type, application fees, and waste heat and system efficiencies required. They are treated differently, however, in terms of the amount of time provided to meet application milestones and complete projects and in terms of certain paperwork requirements. A number of project developers commented that the project cycle process is much more difficult with public entities than private firms because of significant additional bureaucracy related to approvals, boards and multiple stakeholders involved. Because of the additional administrative burdens inherent in public management, public entities – many of which had to ask for extensions due to longer administrative processes — were provided with extended time periods for meeting various requirements. The current process differences between public and private entities are presented in Table 3-7, below. However in the final analysis, it should be observed that the completion rate for public entities is not significantly different, nor are the actual days to complete. Also, public entities are completing the process within their reservation period, where private firms are well exceeding their reservation period, on average, and are operating closer to the public entity time frame.

Table 3-7. Process Timelines for Public Entities and Private Firms as of 7/1/2006

Milestone in Process	Private Firms	Public Entities
Reservation Period	12 Months	18 months
Proof of Project Advancement	Required within 60 days after Conditional Reservation Notice is issued	Required within 240 days after Conditional Reservation Notice is issued
Request for Proposal for Purchase or Installation of Generating System	Not required	Required within 60 days after Conditional Reservation Notice

Though proof of project advancement was extended to 240 days for public entities, many still feel this is a short window of time to complete the extensive, internal process for securing financing and getting approval, often from multiple agencies, as is the case with schools who need approval from the State Architect's office.[27]

[27] Cooney, K., P. Thompson, Summit Blue Consulting, Energy Insights, RLW Analytics. "Self-Generation Incentive Program: Program Administrator Comparative Assessment." Report to the SGIP Working Group. April 25, 2007.

Differences in Program Experiences

Almost 43% of private firms that completed projects learned about the incentives from an equipment dealer or vendor, compared to only 17% of public entities. Public entities were somewhat more likely to learn about incentives through their utility account representatives than private firms (Table 3-8).

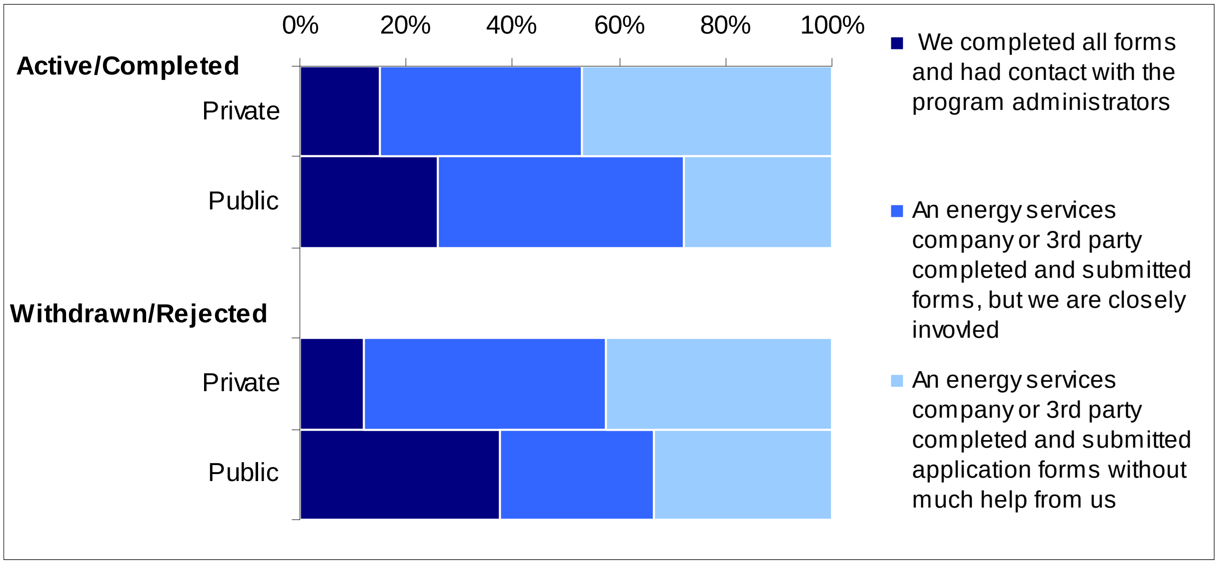
Table 3-8. Learning about SGIP, by Public-Private

Active/Complete Survey	Private	Public
Equipment/system dealer/vendor	43%	17%
Utility Representative	11%	19%
Onsite generation systems' users	4%	3%
Magazine/newspaper article	4%	1%
Other media (TV, news, press release)	3%	4%
Regional Energy Office	-	7%
Internet search/website	2%	2%
Professional publications	-	2%
Email notice/advertisement	-	1%
Withdrawn/Rejected Survey	**Private**	**Public**
Equipment/system dealer/vendor	36%	25%
Utility Representative	11%	38%
Onsite generation systems' users	7%	-
Internet search/website	7%	-
Professional publications	5%	-
Other media (TV, news, press release)	3%	-
Regional Energy Office	-	4%
Email notice/advertisement	-	4%
Magazine/newspaper article	-	-

Overall, the rebates played a similarly important role for both private and public entities when deciding about the project. About 90% of both public and private entities claimed that the availability of the rebate was important or very important in their decision to install onsite generation.

With regards to involvement in the process, public entities were about twice as likely as private entities to complete all the forms themselves, while private entities were about twice as likely to hire ESCOs to manage the application and program paperwork. The difference is due to a greater percentage of private-entity projects being of a turnkey nature. This was true for both active/complete projects as well as withdrawn/rejected projects. (See Figure 3-16.)

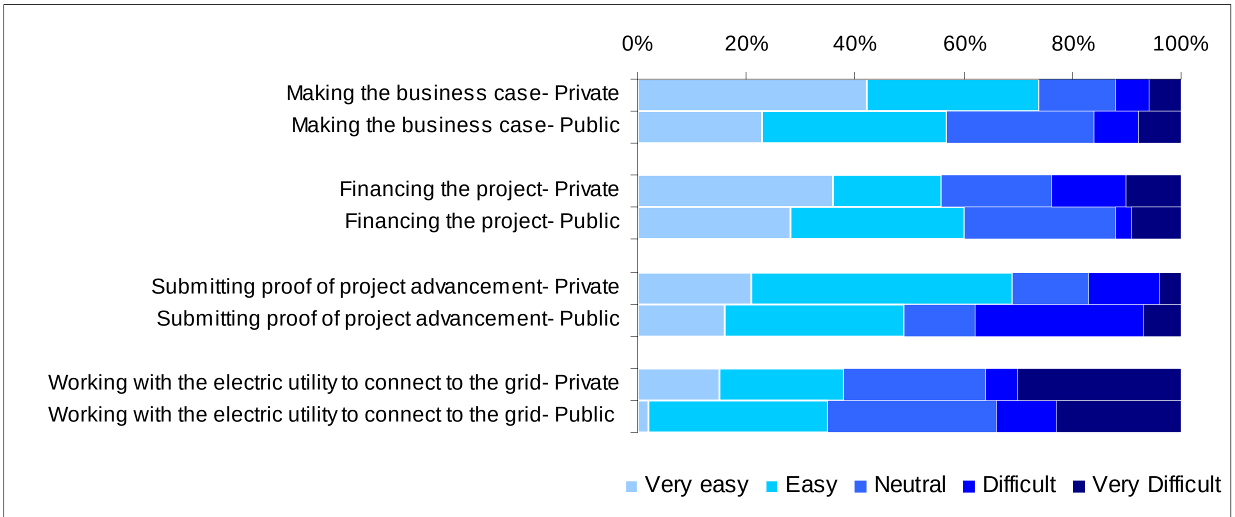
Figure 3-16. Completing Application Forms by Public-Private and Active-Withdrawn



Private firms and public entities experienced some program processes similarly and some differently (Figure 3-17). Public entities found it slightly more difficult to make the business case for on-site generation than private entities, but more than 55% of both host customer classes found it easy or very easy. Private entities had more difficulty in obtaining project financing. Public entities found it difficult or very difficult 12% of the time, versus 24% of the time for private entities. Proof of project advancement was harder to achieve for public entities (38% found it difficult or very difficult, compared to 17% of private entities).

Notwithstanding the greater challenges faced by public entities regarding achieving proof of project advancement and gaining interconnections with utilities, very few public entities were dissatisfied with the SGIP. Public and private entities were basically satisfied with SGIP, but more than 10% of private companies were either dissatisfied or very dissatisfied, whereas just one percent of public entities felt that way. It is possible that public entity applicants recognize that detailed paperwork and administrative processes are part of the necessary checks and balances on a program that disburses incentives as large as the SGIP.

Figure 3-17. Differences in Program Experiences- Private vs. Public Entities



Eighty-seven percent of private and 80% of pubic entities own the equipment. Yet, public entities are more likely to keep maintenance and repair duties in-house rather than outsource them (33% of public entities handle maintenance and repair of equipment in-house, compared to 23% of private firms).

Private firms clearly require shorter payback periods from onsite generation projects than public entities. More than half of active/complete public entities can tolerate payback periods greater than 10 years, compared to 26% of active/complete private firms. Similarly, applicants who withdrew from the program require shorter payback periods from onsite generation projects than active/complete host customers (which contributed to their decision to withdraw their applications). (See Table 3-9.)

Table 3-9. Acceptable Payback Periods by Public-Private

	Private Firms		**Public Entities**	
Longest payback period willing to accept	**Active/ Completed**	**Withdrawn/ Rejected**	**Active/ Completed**	**Withdrawn/ Rejected**
6 months or less	-	5%	-	-
1 year	-	-	-	-
2 years	4%	2%	-	-
3 years	7%	5%	1%	-
4 years	2%	-	-	-
5 years	15%	23%	6%	7%
6-10 years	46%	51%	36%	40%
More than 10 years	**26%**	14%	**57%**	53%

The essential success factors for onsite generation projects are about the same for public and private entities. At the top of the list for both private firms and public entities was that the system achieves payback or a positive return on investment (33% of private firms felt that this was the most important criteria to their business; in comparison, 30% of public entities felt this way). The second most important essential success factor was that the system produced the amount of power that was anticipated (21% of private firms, 32% of public entities felt this was important). The third most important essential success factor was that the system meets all of their operational specifications (16% of private firms, 17% of public entities felt this was important).

Barriers to Additional Onsite Generation

Overall, most program host customers are not likely to install additional onsite power generation at their facilities in the following five years. However, public entities are twice as likely to do so: almost 25% claimed they are very likely to install additional generation in the next five years, compared to 12% of private firms.

Table 3-10 lists the barrier to installing additional on-site power generation grouped by private and public host customers and by host customers with active or completed projects and withdrawn or rejected projects.

Table 3-10. Significant Barriers to Installing Additional On-Site Power Generation[28]

	Private		Public	
Barrier	**Active/ Completed**	**Withdrawn / Rejected**	**Active/ Completed**	**Withdrawn/ Rejected**
No more space/room for generation	47%	26%	41%	42%
Equipment prices	37%	55%	46%	50%
No additional loads to be served	28%	12%	39%	13%
Experience with the prior project/application	26%	30%	15%	29%
Difficulty in working with the utility	19%	25%	21%	21%
Natural gas prices	16%	16%	18%	25%
Environmental concerns	8%	7%	18%	25%
Other	39%	48%	30%	29%
For entities with active/completed projects, other included payback, changes in technology, electricity price, generating funding, jurisdiction issues, lack of adequate incentives, and the 2007 AQMD CARB standards are difficult to meet. For entities with withdrawn/rejected projects, other included economics, the CSI program, and the rebate amount.				

More than one barrier response was permitted, with an option for most significant barrier. The most significant three barriers for *public entities* with active and completed projects are: no additional loads to be served (19%), no more space for generation (18 %), and equipment prices (17%). For public entities that had withdrawn or rejected projects, the most significant three barriers are: equipment prices (26 %), no more space for generation (22%), and experience with the prior project (17%).

The most significant three barriers to installing additional on-site power generation for *private firms* with active and completed projects are: no more space for generation (28%), no additional loads to be served (17%), and equipment prices and experience with the current system (both at 10%). For private firms that had withdrawn or rejected projects, the most significant three barriers are: equipment prices (26%), no more space for generation (11%), and difficulty in working with the utility (8%).

[28] Respondents listed all barriers that applied.

Reasons for Withdrawing Applications

Private firms and public entities cited similar reasons for withdrawing project applications, as shown in Table 3-11.

Table 3-11. Top Reasons for Withdrawn Applications by Public-Private

Top 3 Reasons for Withdrawn Applications	
Private	**Public**
System cost too high even with incentive (28%)	System cost too high even with incentive (25%)
Problems in obtaining project financing (10%)	Problems with the application process (13%)
Problems with the application process (10%)	The internal priorities of my organization have changed (8%)

3.5.2 Tax and Other Incentive-Availability Issues

During the host customer focus groups in all four program administrator territories, participants mentioned that tax credits are critical to project economics. Issues discussed at the focus groups included the necessity of tax credits for project economics, the unavailability of tax credits for public entities, the option for public entities to work with a third-party to take advantage of the tax benefit, and the uncertainty of the true benefit from the tax credits (one respondent initially expected a $40,000 tax credit, but only received $6,000 because of other tax issues). Many respondents felt that the incentives plus the tax credit made the project viable financially. One respondent commented that, "*The tax advantages, besides the rebates, were advantageous enough to where I felt I was actually going to come out ahead.*" Another respondent mentioned that their project initially was not economical, but with a project redesign and additional tax benefits, they decided to build the project. On the other hand, several interview subjects expressed surprise over taxability of incentives. Therefore, tax issues, though important, remain a point of confusion to the host customers in the SGIP, and for many, the tax benefits were a significant reason for their participation in the program.

A variety of federal, state, and utility-based financial incentives continue to be available to improve the economic viability of SGIP-funded projects. These incentives come in the form of tax benefits or credits, direct payments for clean power generation, grant monies, and options for low-interest financing. Since the majority of federal financial incentives are offered in the form of tax benefits, private projects generally stand to benefit more substantially than do public projects, but opportunities do exist for both classes.

The inability of public projects to directly take advantage of federal tax incentives does not appear to have seriously limited the development of public projects under the SGIP. Over 300 public projects were funded under the Program from 2001 through 2006. This represents 32% of all funded projects during that period. Considering the numerous bureaucratic limitations associated with capital expenditures by public entities, one might expect fewer projects to be developed by public entities even in the absence of a disparity in incentive benefits between public and private projects. This may in part be due to the desire of many public entities to demonstrate leadership in energy alternatives and action on climate change.[29]

While several of the federal incentives have existed in some form for a number of years, the Energy Policy Act of 2005 resulted in the extension and/or modification of most of the incentives. Many of the incentives affected by the Energy Policy Act of 2005 are currently set to expire on December 31, 2008.[30] Some of the incentives may be renewed beyond this sunset date. However, consistent with the broader history of renewable energy policy, the short-term nature of most federal incentives places a burden on the project development cycle and makes it difficult for DG market actors to plan for the future. And both private and public entities are concerned about programmatic stability in relation to their planning and budgeting processes.

Federal Tax Incentives

The Business Energy Tax Credit (BETC) is the simplest federal tax incentive in that it results in a direct lump sum tax credit in the year that an eligible system is installed. The tax credit offsets 30% of project capital costs for PV and fuel cell projects (for non-residential entities), and 10% of capital costs for all microturbine projects.

While wind is not an eligible technology under the Business Energy Tax Credit, it is eligible under the Renewable Energy Production Tax Credit (PTC). The only other SGIP-eligible technology eligible for the PTC is microturbines operating on renewable fuels.[31] Since the PTC incentive (1.9 cents per kilowatt-hour for the first ten years of operation) can be so valuable to large-scale projects, wind energy development cycles have closely tracked the expiration and renewal periods of this incentive since it was first enacted in 1992.

Another tax incentive that can substantially enhance project economics is an accelerated depreciation provision called the “Modified Accelerated Cost Recovery System” (MACRS). The Internal Revenue Service defines depreciation as “an annual income tax deduction that allows you to recover the cost or other basis of certain property. It is an allowance for the wear and tear, deterioration, or obsolescence of the property.”[32] While most DG technologies have operating lives on the order of twenty years, under MACRS, all SGIP-eligible technologies (other than internal combustion engines or turbines running on waste gas fuel) can depreciate the value of their system over a five-year period. Since depreciation is a tax *deduction* and not a tax *credit* it does not hold the same amount of value for project owners as do the BETC and the PTC, and the value is dependent on the tax bracket of the entity that owns the DG system.

The BETC, PTC, and MACRS must all be claimed by private entities. And in general, the larger the tax burden of the entity, the larger the value of these tax incentives. However, a project located on public property can also benefit from these incentives, if it is owned by a private entity. Entities with little or no tax burdens can enter into a variety of ownership, leasing, or service contract arrangements which enable the entity with the largest “tax appetite” to own the facility and maximize the potential to take advantage

[29] Kousky, C., S.H. Schneider. “Global climate policy: will cities lead the way?” Climate Policy 3 (2003), 359–372. August 2003.

[30] The Energy Policy Act of 2005 specified December 31, 2007 as the sunset date for many of the tax incentives. However, these sunset dates were extended to December 31, 2008 under the Tax Relief and Health Care Act of 2006.

[31] IRS Form 8835 provides a complete description of qualifying resources and facilities.

[32] Internal Revenue Service Publication 946, “How to Depreciate Property.”

of tax incentives. Under certain arrangements, after this entity fully exhausts all tax benefits, ownership will revert to a different structure more suitable for the remaining term of the project's operational life.

The Renewable Energy Production Incentive (REPI) has been widely used by *public entities* in California and throughout the country since its inception in 1992. Qualifying entities include state and local governments, municipal utilities, rural electric cooperatives, and tribal governments. Project owners receive incentive payments of 1.5 cents per kilowatt-hour[33] for the first ten years that a system is in operation. REPI program funding depends on congressional appropriations. Therefore, unlike tax-related incentives, the program faces budget limitations that vary each year. In any given year, if insufficient funds exist to provide full payment to all applicants, 60 % of appropriated funds will be paid to solar, wind, ocean thermal, tidal energy, wave energy, geothermal and closed-loop biomass projects. The remaining 40 % of funds will be paid to fuel cell projects using renewable fuels, livestock methane and other eligible projects. See the following text box for an illustration on how tax benefits can affect project economics in public versus private entity applicants.

[33] The 1.5 cent per kilowatt-hour incentive level was set based on 1993 dollars. The incentive level is indexed each year to account for inflation.

Tax benefits a private firm can leverage under current state and federal tax policy

The table below compares the overall economic advantage private entities enjoy relative to public entities regarding federal tax benefits when installing new PV systems. Though both private firms and public entities are eligible for the same state incentives per kW (estimated to be $2.80/watt in this example, the current incentive level), public entities cannot take advantage of tax incentives available to private firms. The value of the Investment Tax Credit in this 50 kW example ($127,500) and the value of Modified Accelerated Cost Recovery ("MACRS," or accelerated depreciation, valued at $144,500) together reduce project costs by $216,000 (or over half of initial total costs). Public entities arguably have an advantage in that they can often access low-cost project financing, and do not have to pay taxes at all. However, this example illustrates the extent to which PV project costs decrease if the project is owned by a private entity. A number of public entities have entered into lease agreements with private firms in order to leverage the substantial value of federal tax incentives.

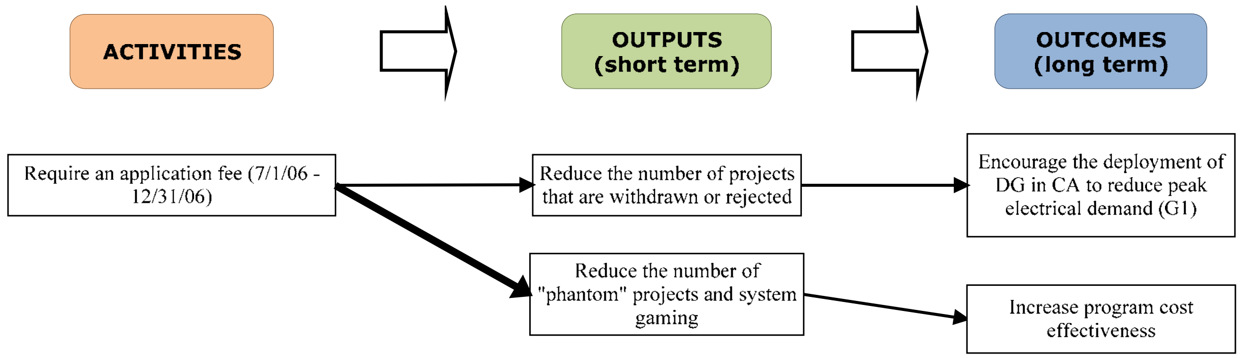
Type of Entity	Private Commercial Entity	Public Entity
Type of Project	Solar PV	Solar PV
Project size (kWac)	50	50
Cost per kWac	$8,500	$8,500
Total Pre-Tax Project Cost	$425,000	$425,000
Rebate ($/Wac)	$2.80	$2.80
Rebate Amount	$140,000	$140,000
Value of Federal Investment Tax Credit[1]	$127,500	N/A
Assumed Tax Rate	40%	N/A
Tax Paid on Rebate Received	$56,000	N/A
Value of Modified Accelerated Cost Recovery System (MACRS)[2]	$144,500	N/A
Total Cost After Financial Incentives	$69,000	$285,000
Total value of Tax / Federal Incentives Only	$216,000	$0
Tax / Federal Incentives as % of Project Costs	51%	0%

[1] Assumes rebate is taxable and, therefore, the full system installation cost is used for purpose of determining tax basis. Treatment of rebates as taxable for commercial entities has been confirmed with Keith Martin, a tax attorney and author of the Solar Energy Industries Association 2006 *Guide to Federal Tax Incentives for Solar Energy*.

[2] Total project cost, minus 1/2 of ITC value used as depreciation basis.

3.6 The Application Fee

A high-quality program will maximize its cost-effectiveness. Toward that end, and with the indirect outcome of encouraging deployment of viable capacity from DG, the program looks to minimize the number of projects withdrawn or rejected, and to reduce the cost and time spent dealing with program "gaming" by participants. Specifically, the effects of the application fee instituted in SGIP are addressed in this section, to ascertain whether the fee has had the intended result of reducing project withdrawals and so-called "phantom" projects.



CPUC Decision 04-12-045 directed the SGIP Working Group to "develop appropriate procedural and financial mechanisms to deter inappropriate reservation requests." In response to this delegation, the Working Group implemented an application fee for all SGIP reservations on July 1, 2005.

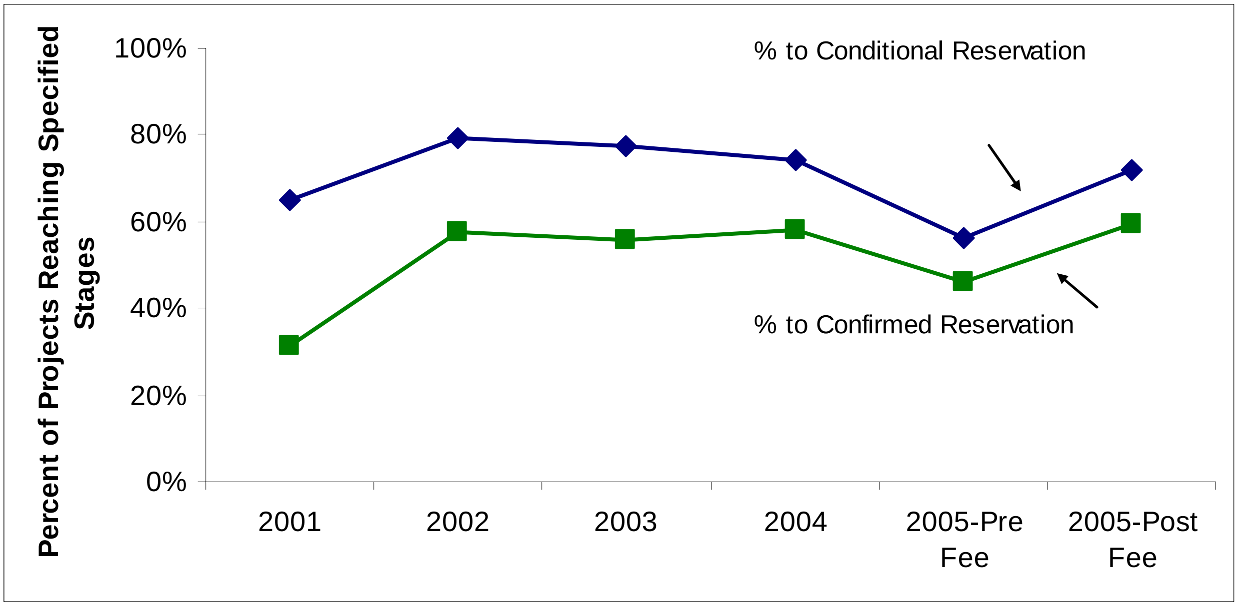
The application fee was instituted to help assure that projects being submitted for program incentive funding would be committed to completion. Prior to establishing the application fee, a number of project applications had been submitted and program funds were reserved for projects that were later withdrawn for various reasons. The PAs believe that at least some were "phantom" projects, submitted to ensure program incentive funding reservation, but without a bona fide project in hand. The intent of the application fee was to encourage developers and host customers to have a project sufficiently planned so that a financial commitment, in the form of the fee, could be made (the fees reimbursed as part of the project incentive payment). Based on the trend in project withdrawals and comments from those involved with the program (PAs, regulatory staffs, developers, and participating host customers), the fee has helped accomplish this goal of ensuring that project incentive funds reservations are being made to actual, committed projects. In 2007, the fee has been discontinued except for projects employing new technologies not yet certified eligible (but in certification testing) for incentives.

This section presents information regarding the experience with the application fee as gained from interviews with PA and regulatory staffs; surveys, in-depth interviews, and focus groups with host customers; and in-depth interviews of developers.

Program Data

Various program data were examined to look for patterns of interest in relation to the central issue of the fees reducing the number of phantom projects. Instituting the application fee appears to have had some association with a higher completion rate for projects. The recent timing of the fee being instituted means that actual project completions are still too few to analyze, but using conditional and confirmed reservations as a proxy, there was an up-tick in the percentage of projects moving to completion after the fee was instituted. (See Figure 3-18.)

Figure 3-18. Percentage of Projects Receiving Reservations, Before and After Instituting the Application Fee



On the other hand, the fees may not have been substantial enough to deter some parties from applying for incentive reservations and paying the application fee without a firm project in hand, as evidenced by forfeited fees. Overall, about one-third of the total amount of application fees to date has been forfeited. In 2006, SDREO has had the lowest percentage of fees forfeited (12%), PG&E saw 29% of projects they administered forfeit their application fees, and SCE and SCG had 36% and 39% forfeiture rates, respectively. This finding shows a significant number of developers and host customers were willing to pay the fee despite some uncertainty about the project being completed. However, the application fee is nonetheless considered a qualified success from the totality of the experiences of the PAs, developers and host customers, as described below.

There has been little difference in the fee amounts paid by developers who applied for projects versus host customers who applied for projects: fees paid in 2006 by developers averaged just over $3,700 and host-customer application fees averaged about $4,100. Thus, the fees appear not to have disproportionately burdened either type of entity.

PA and Regulatory Staff Perspective

The application fee had mixed reviews from PA and regulatory staffs. In general, PA staffs liked the fees but were unsure of their effect toward simplifying the administrative process by reducing phantom projects. SCE staff expressed some frustration in having to deal with a lot of small checks, and the application fee translated into a wide range of check amounts being received – further complicating the administrative process.[34] PAs reported that many applicants applied but neglected to send in their application fee checks. Other applicants applied and sent in their application fee checks to assure funds reservation and to expedite projects. However, they sometimes forfeited these fees because the project was initiated, but subsequently was not completed. Some PAs questioned whether the fee was high

[34] Apparently one half of a percent is a number that engenders some innumeracy. A number of stakeholders suspect that a simple one percent would lead to more accurate checks.

enough to influence professional project developers, as developers appeared to readily take on the financial risk of the fee if projects do not progress. Despite these concerns, regulatory staff and other stakeholders generally perceived that the application fee has been successful in its purpose.

Developer Perspective

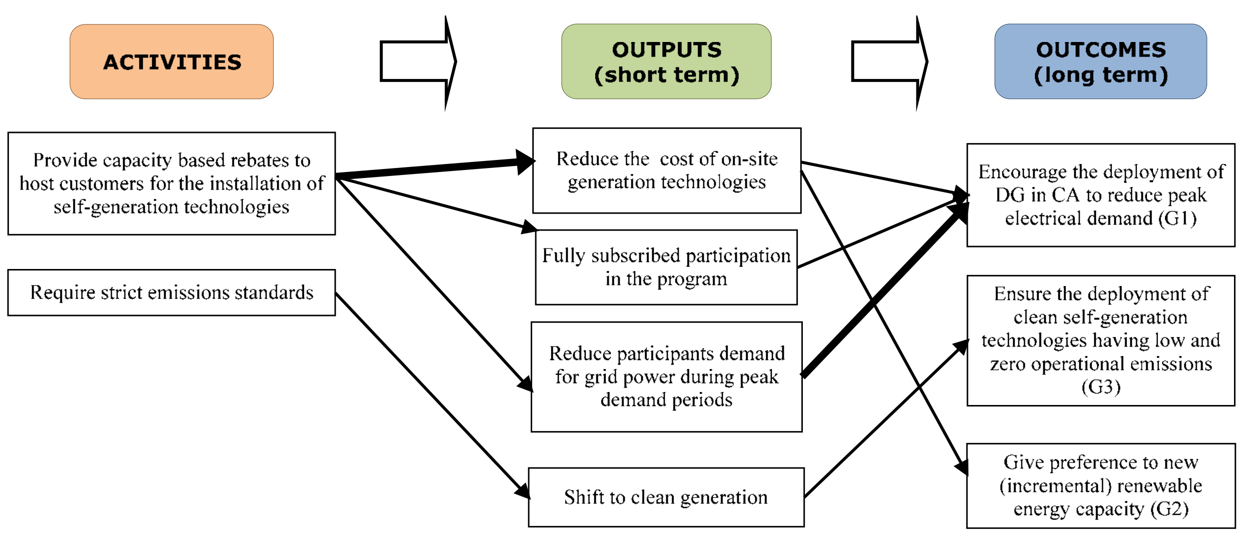
Overall, most developers did not object strongly to the application fee. Those with unfavorable comments were concerned with a minor dampening effect on the number of applications, or making developers more cautious, and concerned that the fee might disproportionately affect public entities due to financial uncertainties in projects they are planning. Of those with positive reactions, some found it beneficial because it forced their sales force to do a better job of qualifying prospective projects. One developer was even sorry to see the fee discontinued, as he felt it really weeded out the projects that weren't serious – he even felt the fee should have been higher than it was.

Participating Host Customer Perspective

The focus groups conducted with host customers found that these customers believe the fee is significant and got their attention. The groups understood the reason for the fee, and seemed to think of it as a necessary aspect of the program. Of those host customers who participated in in-depth interviews, only one complained of the fee being too steep, and that same person expressed a preference for a policy of refunding the fee to "earnest" projects. Otherwise, host customers generally understood the purpose of the fee, and they had no particular issues.

3.7 Cogeneration Projects

Cogeneration combines thermal and electricity production to achieve good overall thermodynamic efficiency. There are, however, constraints to deploying cogeneration systems in light of environmental emissions requirements, such that the program logic dictates a progression toward zero-emissions cogeneration systems. A number of other factors affect cogen project economics: increasing natural gas retail prices, electricity demand charges, and decreasing incentives in the face of increasingly stringent air permitting issues. This section addresses cogeneration in light of the program logic as it concerns encouraging or discouraging cogeneration from the perspective of these issues, and the resulting outcome of encouraging this type of DG deployment while reducing emissions.



Cogeneration has played an important role in SGIP since its inception. Overall, 22% of program applications and 30% of completed projects were for cogeneration systems, accounting for 61% of total kW installed under SGIP. Qualifying cogeneration systems under SGIP include internal combustion engines (ICE), reciprocating engines, microturbines, and fuel cells. In 2003, waste gas projects also became eligible. Applications for cogeneration were received by all PAs, and accounted for 52% of completed projects for SCG by number.

Cogeneration project applications began to wane considerably in recent years as incentives dropped, the price of natural gas increased, electricity prices leveled off, and local air quality requirements became more stringent. A number of cogeneration projects experienced long delays in obtaining emission permits from Air Quality Management Districts (AQMDs) and interconnection switches from the utilities. Figure 1-1 at the beginning of this report highlights the key milestones and events that affected cogeneration program activity.

Funding for cogeneration is scheduled to sunset from the SGIP at the end of 2007. Bill AB 1064, introduced into the Assembly in 2007, last amended on June 25, 2007, and currently in Committee, would order the CPUC to continue funding cogeneration projects through the end of 2012, but in its current form, AB 1064 would only cover cogeneration projects that utilize waste gas.[35]

3.7.1 Cogeneration Trends in the SGIP

Table 3-12 shows cogeneration applications by year and technology. Whereas the volume of applications for microtubines and fuel cell projects remained fairly steady throughout the program lifetime, applications for ICEs were concentrated in the early years of the program.

Table 3-12. Cogen Applications by Year and Technology

Year Application Received	Non Ren ICE	Non Ren MT	Non Ren Fuel Cell	Non Ren Gas Turbine	Total
2001	118	45	6		169
2002	136	34	1	1	172
2003	101	54	3	2	160
2004	75	41	7	1	124
2005	59	20	7	8	94
2006	34	17	5	3	59
Total	523	211	29	15	778

Of 778 applications for cogeneration systems, 287 projects were brought to completion and received funding through SGIP. Almost 60% of completed projects are ICEs and about 30% are microturbines. Ten fuel cell projects received incentives through SGIP, seven of which became operational and received funding in 2006 (see Table 3-13).

[35] Waste gas is defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system. Thus, biogas and landfill gas resources would not be eligible in the program post-2007.

Table 3-13. Completed Cogeneration Projects by Year and Technology

Year Incentive Paid	Non Ren ICE	Non Ren MT	Non Ren Fuel Cell	Non Ren Gas Turbine	Grand Total
2002	6	3	1		10
2003	35	20			55
2004	51	23	1	1	76
2005	30	26	1	1	58
2006	54	25	7	2	88
Grand Total	176	97	10	4	287

Table 3-14. Cogeneration Applications and Projects by Program Administrator

Program Administrator	Cogeneration Applications	Total Applications	% of Total Applications by PA	Total Cogeneration Completed Projects	% of Total Cogeneration Completed Projects
PG&E	319	1737	18%	113	39%
SCE	176	867	20%	63	22%
SCG	216	540	40%	76	26%
SDREO	67	346	19%	35	12%
Grand Total	778	3490	22%	287	100%

PG&E received the most applications for cogeneration systems, and that PA's projects account for almost 40% of the total incentives paid to cogeneration projects, though SCG's installed cogeneration capacity dominates the completed cogeneration projects – accounting for 52% of completed projects and 82% of capacity. Out of a total of 778 cogeneration projects, PG&E administered 319 (Table 3-14).

Applications for new cogeneration projects started dropping off in mid-2003, while program activity for PV systems and for other renewables continued to increase. Early in the program, cogeneration accounted for more than 50% of project applications (Figure 3-19).

Figure 3-19. Yearly Applications to SGIP by Technology

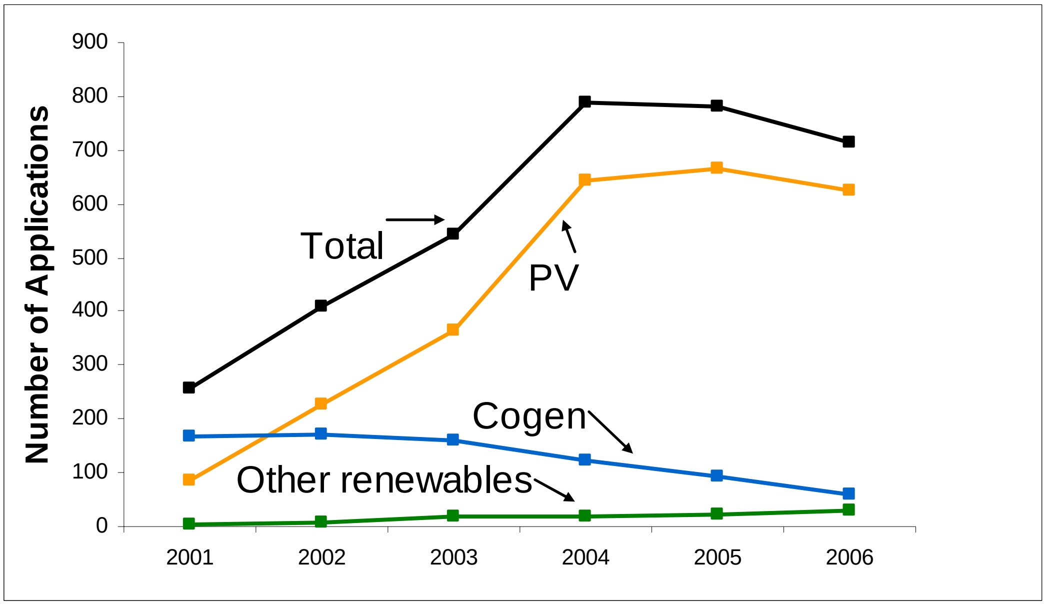
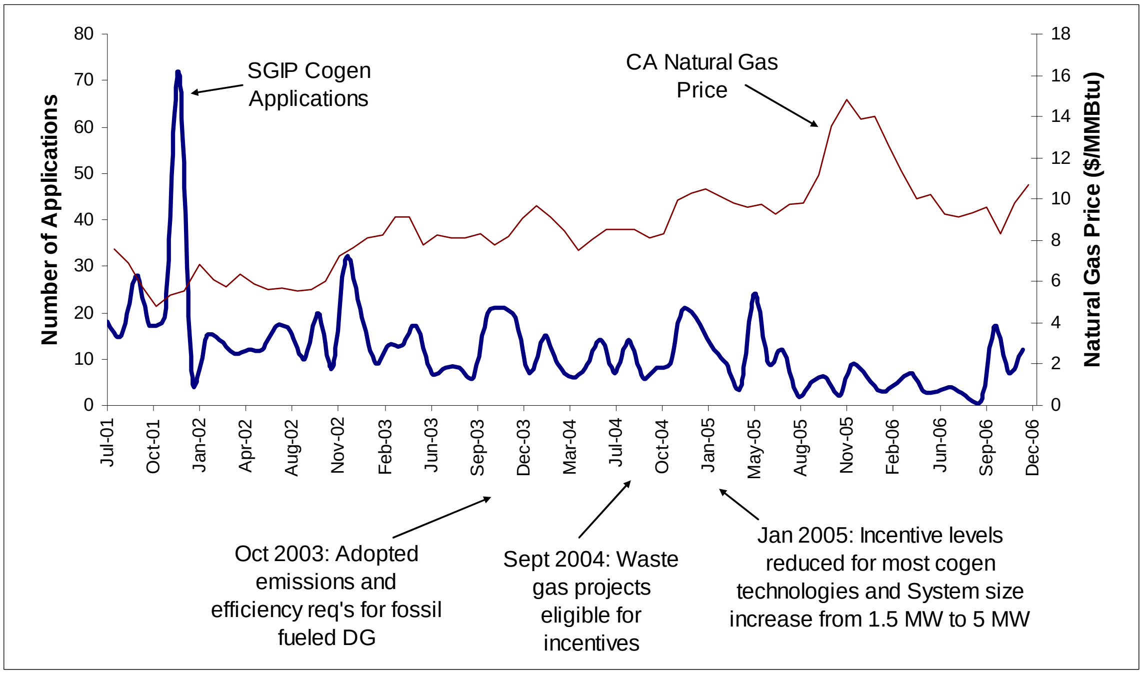


Figure 3-20 shows the number of applications to the SGIP by month. The largest surge in cogeneration applications was in late 2001, when electricity prices soared and gas prices were relatively low. As natural gas prices started to increase in late 2002, applications for cogeneration projects began to decrease, with the decline continuing over the subsequent four years of the program. There was a small increase in applications in 2004 when waste gas projects were made eligible to participate in the program. When gas prices jumped up in 2005, the same year the incentive level for cogeneration projects decreased, new applications dwindled nearly to a halt. A more detailed discussion of the decline in cogeneration system applications is discussed later in this section.

Figure 3-20. Cogeneration Applications over Time[36]



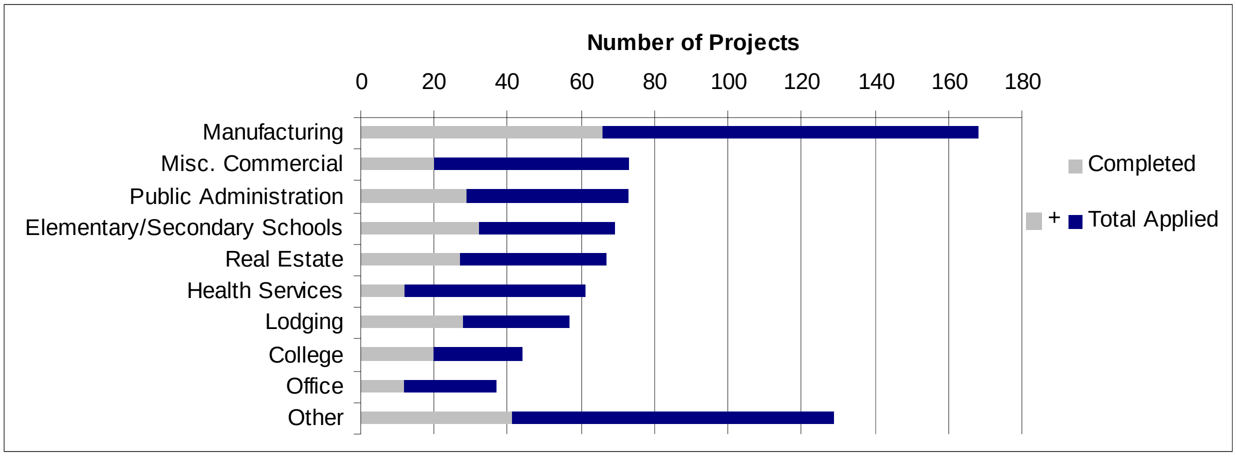
Source: SGIP December 2006 Monthly Reports; Energy Information Administration

Figure 3-21 shows that manufacturing was the top sector to apply for cogeneration projects under SGIP, with 22% of the total applications. This makes sense because of the SGIP waste heat requirements for this technology. The top five sectors (manufacturing, commercial, public administration, schools, and real estate) account for almost 58% of all completed cogen projects.

The lodging, schools, and college sectors had the highest chance of bringing their projects to completion once they had applied for funding through the program. A few ESCOs focused on these sectors. For example, California Power Partners was the developer for 22% of the schools projects, and Powerhouse Energy developed 19% of the lodging projects. Conversely, communications, retail stores, and health services have the lowest success rate of getting cogeneration projects approved after applying.

[36] The natural gas price is the price of natural gas sold to commercial consumers in California. This price shown is consistent with the data in the SGIP Program Administrator Comparative Assessment (2007). The average of commercial and industrial prices will be lower on an absolute scale, but do have the same trend over time. Incentive level changes to non-renewable and waste gas microturbines (from $1/W to $0.80/W) and non-renewable and waste gas internal combustion engines and gas turbine (from $1/W to $0.60/W). Note that the incentives began at $1/W in D.01-03-073.

Figure 3-21. Percent of Cogeneration Projects Completed Compared to Applications, by Sector



Note: Only those sectors with 10 completed projects or more are broken out on the graph. "Other" includes Utilities, Mining/Extraction, Wholesale Trade, Transportation, Construction, Communication, National Security, Refr Warehouse, Restaurant, U.S. Postal Service, Grocery, Retail Stores, Agriculture, and Unclassified.

Sixty-nine percent of the applications for cogeneration projects were from private companies, and 31 % were from public entities. This is proportionate with the spread between public and private entities participating in the SGIP program as a whole.

About the same proportions of private and public entities were awarded incentives for cogeneration projects as those that applied. Public entities accounted for 84 projects out of a total of 287 cogeneration projects, or close to 30 %.

Over 64% of applications for cogeneration projects were rejected, suspended, or withdrawn. The top reason cited for withdrawing applications was that the system cost was too high, even with incentives (27%). This is greater than the average for SGIP. In a distant second place came problems with application process (10%), followed by a variety of other reasons (problems in obtaining project financing, system did not qualify for program, internal priorities of organization have changed, to avoid the hassle of owning, operating and maintaining a DG system, and increased uncertainty of the investment). The top three barriers to installing additional cogeneration equipment cited by those that ultimately were not successful were: experience with prior project (30%), difficulty in working with the utility (24%), and high natural gas prices (18%).

3.7.2 Cogeneration Host Customer and Developer Experience

Program host customers pursued cogeneration projects for a number of reasons, both economic and environmental. The top three factors that influenced the decision to purchase and use on-site generation technology in general include: reducing utility bills, reducing peak demand, and concern for the environment.

The availability of the rebate was highly influential in the decision to pursue on-site power generation across all technology types consistent with applicants to other technology types. As mentioned earlier, only 47% of host customers with cogeneration projects cited concern for the environment as a major factor in their participation in the SGIP. However, concern for the environment was markedly more influential in the decision to pursue on-site generation for owners of fuel cells, than for owners of microturbines, reciprocating engines and other internal combustion engines (Table 3-15).

Table 3-15. Concern for the Environment in Decision to Pursue Onsite Generation

Concern for the Environment	Recips/ Turbines	Fuel Cells	Microturbines
Very Influential	16%	70%	56%
Influential	20%	18%	20%
Neutral	33%	12%	17%
Uninfluential	7%	-	-
Very uninfluential	24%	-	7%

Active- project program host customers investing in PV systems expected long payback periods (greater than 10 years) from their investment in on-site generation, while almost 50% of active host customers that invested in cogeneration systems expected payback periods of 1-5 years. Almost 50% of the active host customers that invested in PV expected a payback period of greater than 10 years.

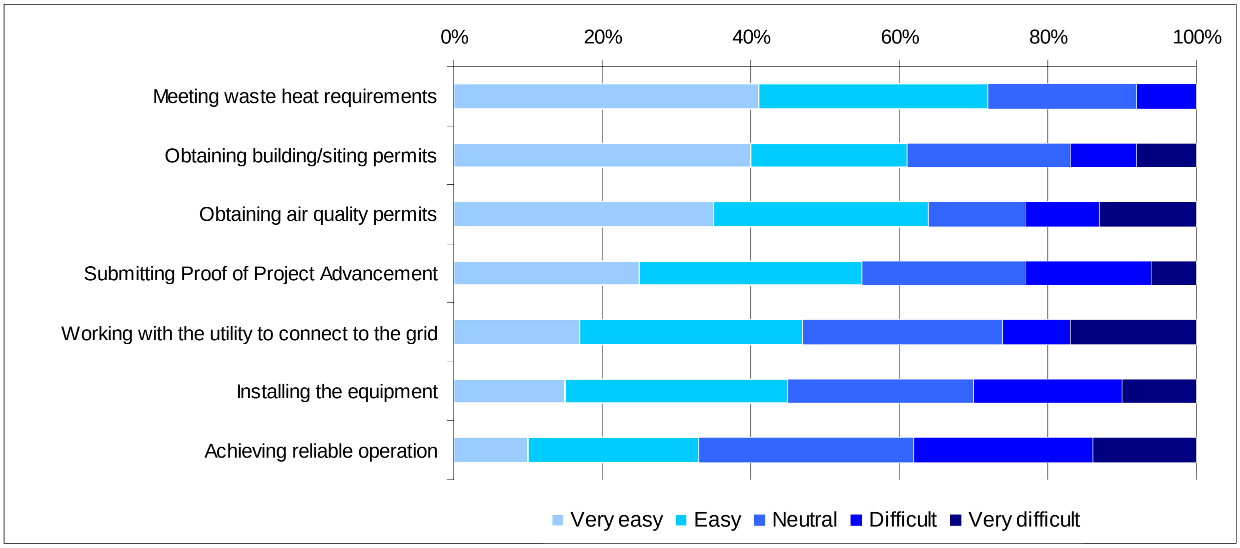
Even shorter payback periods for PV and cogeneration investments were originally expected by program host customers that either withdrew their applications or were rejected from the program. Almost 75% of withdrawn or rejected applicants for cogeneration systems originally expected payback periods of only 1-5 years, and more than 60% of withdrawn or rejected applicants for PV systems originally expected payback periods of less than 10 years.

Host customers seeking to develop cogeneration systems under SGIP have a number of administrative and technical hurdles to pass through related to air quality, siting, waste heat requirements, and proof of project advancement paperwork before they could begin installation of the equipment. Once the project is approved, host customers face additional hurdles in the forms of installing the equipment, gaining utility interconnection to the grid, and achieving reliable equipment operation.

Meeting Program Requirements

Meeting waste heat requirements was generally not challenging for most host customers pursuing cogeneration projects, but almost 10% did find it difficult (mostly microturbines and fuel cells). Almost 20% found obtaining building and siting permits to be difficult or very difficult, and almost 25% found obtaining air quality permits to be difficult or very difficult. Obtaining proof of project advancement was also found to be difficult or very difficult for over 20% of host customers with cogeneration projects (Figure 3-22).

Figure 3-22. Ease of Addressing Various Aspects of SGIP Cogeneration Projects



Once the cogeneration project was approved, 26% of host customers found obtaining interconnection with the utility to be difficulty or very difficult. A number of host customers mentioned in focus groups and interviews that they were surprised by how long it took to navigate the interconnection process. Examples ranged from those that did not appreciate access issues, i.e., “I had to get a new lock and key before I could get approval” to those that stated that site inspection criteria varied and were not always consistent. These concerns were typically voiced against a backdrop of timing issues where applicants perceived delays and were worried about their ability to meet project completion deadlines. Finally, installing the cogeneration equipment and achieving reliable equipment operation both were difficult or very difficult for 30-40% of the host customers.

Among the different cogeneration technologies, fuel cell developers had the most difficult time meeting waste heat requirements. Even then, almost 70% found this easy or very easy. Meeting waste heat requirements generally was easy for owners of microturbines, ICEs and reciprocating engines.

In terms of choosing an ESCO, owners of microturbines, reciprocating engines and other ICEs had a more difficult time, when compared to owners of fuel cells and PV systems. Roughly 25% found it difficult or very difficult, whereas neither of the fuel cell owners and fewer than 10% of the owners of PV systems found it difficult or very difficult. Several focus group host customers and in-depth interview subjects mentioned that they would look for a different ESCO or review proposals more carefully next time or if they could “do it over again.”

Similarly, equipment installation was difficult or very difficult for 25-30% of the owners of microturbines, reciprocating engines and ICEs, and very easy for only 10%-25% of the host customers. Conversely, nearly 75% of the PV system installations were found to be easy.

Across all technologies, most felt there were unnecessary delays. Though applicants for PV projects did not face air quality or waste heat efficiency requirements, a *slightly greater* percentage of PV-project participants surveyed indicated that obtaining proof of project advancement was slightly more difficult for them than was reported by participants installing other technologies. This somewhat surprising finding may be due to some difficulty in obtaining project financing and constraints on PV panel supply.

Barriers

The most significant barrier to installing additional onsite cogen power raised by active host customers was high natural gas prices. Overall, 50% of owners of ICEs and microturbines and one-third of fuel cell owners cited this as a significant barrier. Nearly 40% of active host customers within SCG's program territory cited this as a top barrier as well.

Equipment prices are seen to be an important barrier to installing additional onsite power for owners of fuel cells and microturbines. ICE owners see equipment costs as a less serious barrier, as those are more common technologies.

Environmental factors are naturally more significant barriers to installing additional onsite power for owners of ICEs and microturbines (roughly 20% cited these factors) than owners of fuel cells (zero) or PV systems (less than 10 %). Not having additional loads to be served is also mentioned as an important barrier to installing additional on-site power.

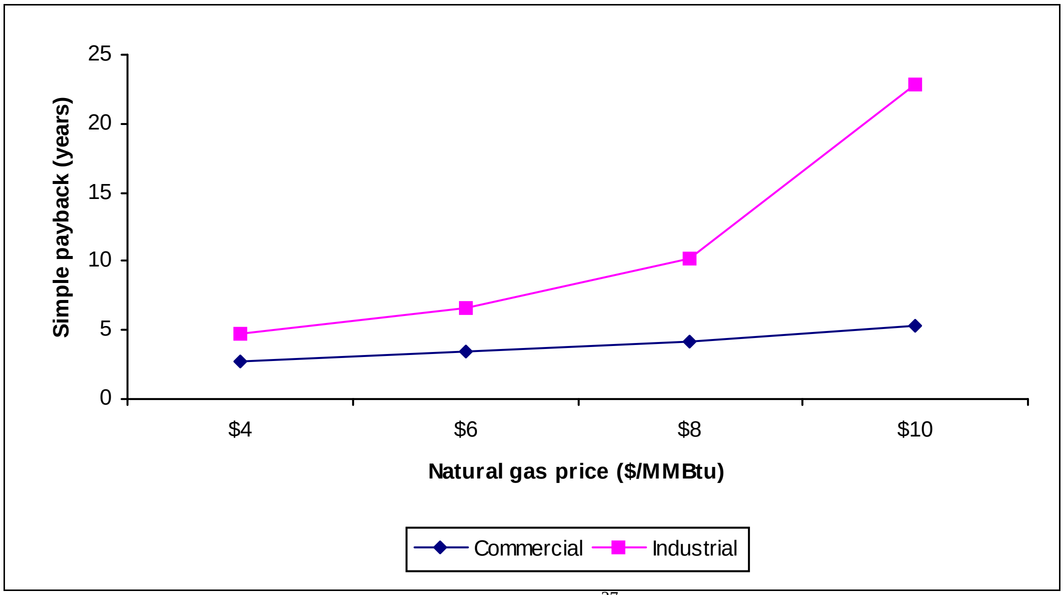
Why Applications for New Cogeneration Systems Have Been Declining

A review of reported reasons for cogeneration decline follows, however, a more detailed regression analysis is presented in Section 3.8 on Incentive Levels and Equipment Costs. In that section, regression analysis shows that declining incentives are more closely correlated with application drop off than are natural gas price increases. Applications for additional cogeneration projects have been declining due to a confluence of forces: increasing natural gas prices, decreasing retail electricity prices, increasing air quality requirements, challenges in installing and operating cogeneration equipment, the flight of manufacturing facilities from California and decreasing SGIP incentive levels (see Figure 3-23). While the price of natural gas dramatically increased since the beginning of the program, average commercial retail electricity rates in California have decreased somewhat from their historic highs in 2002.

According to host customers in focus groups and in-depth interviews, payback periods for cogeneration systems that had once been two to three years in 2001-2003 increased to seven to ten years after 2003 because of this change in spark spread. Data from the participant and non-participant surveys indicates that most SGIP participants are willing to accept paybacks of this length, but most non-participants are not. The respondents for 80% of the active/completed projects said that they would be willing to accept a simple payback of 6+ years for any future on-site generation projects they might undertake. The percentage of respondents for withdrawn/rejected projects that would accept paybacks of this length in the future was slightly lower, but still high (71%). We have no way of knowing if the percentage is lower in this group because of their experiences with the SGIP program to date, or if those host customers whose projects were ultimately withdrawn or rejected had more stringent payback requirements from the beginning.

When we look at the data for non-participants, however, the picture is much different. Only 24% said they would be willing to accept a payback of 6+ years for an on-site generation project. Thirty-one percent of non-participants required a payback of no more than five years, and 45% required a payback of four years or less. Based on Energy Insights prior research with business customers, we believe that non-participants have shorter payback requirements for two reasons. First, they are less familiar with the actual economics of on-site generation systems, and thus have somewhat unrealistic expectations that would likely change with education. Second, they simply do have stricter payback requirements, which is one reason why they are not already participating in the program.

Figure 3-23. Simple Payback on a 1 MW Gas Turbine CHP Application as a Function of Natural Gas Prices



Source: Energy Insights' DE Analyzer economic model.[37]

Meeting emissions requirements also became more difficult after higher thresholds for NOx emissions became effective in January 2005. All combustion-operated distributed generation projects had to meet a standard of 0.14 lbs/MWh, and commencing January 1, 2007, all these distributed generation projects must meet a standard of 0.07 lbs/MWh. This level is required of all combustion-related technologies that must obtain a permit, irrespective of fuel type and other operating characteristics (e.g., annual hours).

The emissions compliance test, which is typically conducted within a reasonable time frame after construction and installation, is the determining factor whether emission limits are being met. The SGIP's previous year's level of 0.14 lb/MWh has been achievable, particularly with the installation of add-on control technologies and improvements in combustion technologies. For the SGIP host customers going forward through 2007, emissions testing must be conducted to confirm the NO_x exhaust emission level is no greater than 0.07 lb/MWh, which is significantly less than the previous years' requirements. To do so, at a minimum, the load, heat rate, and mass emissions must be determined.

The air quality permit process proceeds at a pace that is independent of the SGIP deadlines and milestones, even though the SGIP process requires AQMD approval for projects with emissions.

Besides the spark spread and air quality permit hurdles, the SGIP incentive levels for most cogeneration decreased in 2004 (see Table 3-16 below). Only the incentive level for fuel cells remained constant throughout the program. Taken together, these three impediments have had a significant influence on the decline in the number of SGIP applications for cogeneration projects.

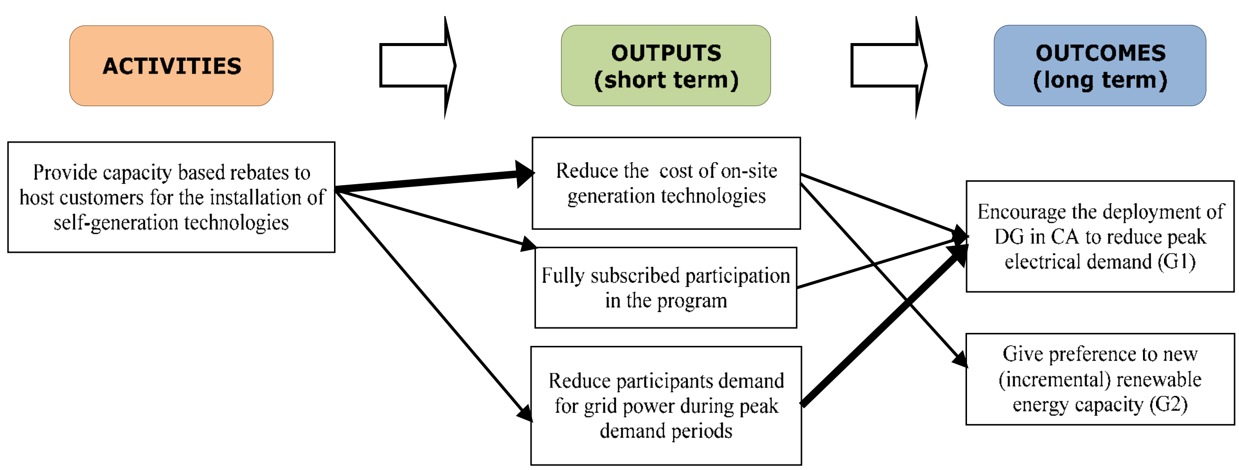
[37] This model assumes a host customer that is able to use the full electrical and thermal output of the turbine. Commercial customers are assumed to be paying $0.121/kWh for electricity, while industrial customers are assumed to be paying $0.086/kWh.

Table 3-16. Incentive Levels for Cogeneration Technologies

Technologies Included		System Size (kW)		Rebate 2001 - 12/15/2004 Lesser of:		Rebate Post 12/16/2004	Rebate Post 12/15/2005	
	Level	Min	Max	$/W	% of Project Cost	$/W	Level	Rebate $/W
Fuel Cells using natural gas	2	None	5,000	$2.50	40%	$2.50	3	$2.50
Microturbines, Small Gas Turbines (under 1 MW)	3R	None	5,000	$1.50	40%	$1.30	2	$1.30
Internal Combustion (I/C) Engines, Large Gas Turbines (over 1 MW)		None	5,000	$1.50	40%	$1.00		$1.00
Microturbines, Small Gas Turbines (under 1 MW)	3N	None	5,000	$1.00	30%	$0.80	3	$0.80
Internal Combustion (I/C) Engines, Large Gas Turbines (over 1 MW)		None	5,000	$1.00	30%	$0.60		$0.60

3.8 Incentive Levels and Equipment Costs

The program sub-logic diagram below shows that financial incentives are seen as a key factor in reducing self-generation project costs, with the associated effect of fully subscribing the program and actually reducing peak electrical demand. To the extent these outputs continue, the long-term outcome of the program in deploying DG is much likelier.



An important question for the evaluation, therefore, is whether the incentive amounts for the various technologies are appropriate in relation to project equipment costs and the financial risks developers and host customers bear in constructing self-generation projects. This section presents information from the various evaluation research sources to address this question.

3.8.1 Program Data

Except for PV, incentive levels have not varied much. There was a single significant change that occurred in one year between 2004 and 2005 for wind and PV, but a single variation does not lend itself well to quantitative analysis. Nonetheless, regression models were developed to assess the relationship between the decline in incentive levels and the volume of cogeneration and PV projects. The cogeneration analysis found that there is a statistically significant relationship between the decline in the number of cogeneration projects and the reduction in the incentive level provided to such projects. This relationship has a greater dampening effect than that of increasing natural gas prices. The summary statistics for the model are shown in Table 3-17. The independent variables included: the change in emissions requirements, the change in the eligibility of waste heat projects, a seasonal factor, the year of the project, the price of natural gas, and the reduction in the incentive level. There appears to be no collinearity, incidentally, between gas price trends and incentive level reductions (a second model without natural gas prices also found the incentive level reduction to be significant).

Table 3-17. Cogeneration Project Volume Regression Analysis Results

Regression Statistics		
R Square		0.408
	Coefficients	**t Statistics**
Intercept	36.100	5.133
Emissions Requirements Change	6.091	0.917
Waste Heat Eligibility	3.772	0.663
Incentive Reduction	-26.288	-2.544
Winter	4.060	1.732
2002	-14.187	-3.364
2003	-12.830	-2.581
2004	-21.217	-2.524
2005	4.190	1.087
Natural Gas Price	-1.603	-1.456

A similar analysis was done for PV project volume, with the results shown in Table 3-18. The results of that analysis showed that the incentive effects on PV project volume have not yet been significant, but note that this does not take into account recent changes in 2006.

Table 3-18. PV Project Volume Regression Analysis Results

Regression Statistics		
R Square	0.27	
	Coefficients	**t Statistic**
Intercept	-68.96	-0.54
Incentive Reduction	0.34	0.02
Winter	31.23	1.80
2002	-2.93	-0.09
2003	-17.36	-0.48
2004	34.39	0.90
2005	-53.89	-1.55
Natural Gas Price	12.28	1.50

The issue of global costs of PV equipment was raised by various developers, customers, and program staff. Of particular relevance to this issue is an analysis conducted by R. Wiser et al. in 2006 for the U.S. Department of Energy.[38] This analysis compared cost-related factors and results of both the SGIP and the California Energy Commission (CEC) PV programs. In relation to this SGIP process study, the chief issue from the Wiser et al. analysis is whether the incentive level for either the CEC or SGIP programs invited gaming, whereby pre-incentive project costs were inflated to some extent because of the program incentives. The analysis found some evidence that this was the case, though the authors concluded that PV costs are affected by a number of variables not included in their analysis, or – as was found in analyzing PV project volume against reduction in PV incentives – that there is a considerable amount of "noise" in PV costs over time that is unexplained by the factors that were included in the analysis. The authors suggest that the PV market does not have enough participants to have true price competition.

With that caveat, the authors of the DOE report found that PV system costs have gone down, more for the smaller sized installations under the CEC's emerging renewables program than the SGIP. They found cost declines in both module and non-module costs, and that there was a statistically significant association between the level and design of the program rebates, particularly for the CEC program. The authors conclude that the system cost reductions occur because of the decline in program incentives. Developers appear to have retained a portion of the higher pre-rebate system cost, and conversely have absorbed incentive level decreases by reducing pre-rebate system prices. It should be noted that the authors of the report were using the applicants' self-reported PV system costs, *at the time of project application to the SGIP*. Thus the data (largely from 2004 and earlier) were potentially out of date and do not reflect the recent trend of PV panel shortage and price increases described in developer and participant interviews as well as focus groups.

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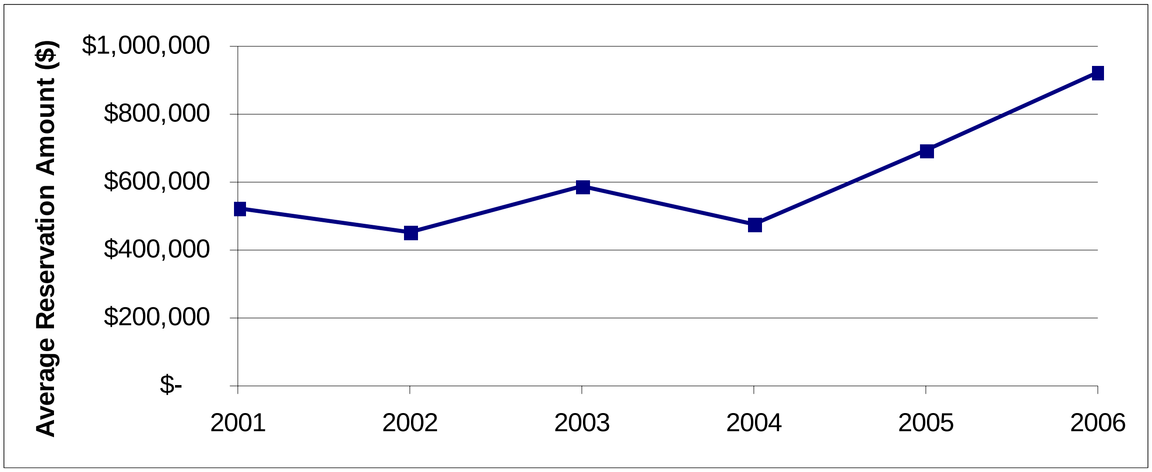
[38] Wiser, R., M. Bolinger, P. Cappers, R. Margolis. "Analyzing Historical Cost Trends in California's Market for Customer-Site Photovoltaics." Report Prog. Photovolt. Res. Appl. 15. 69-85. June 2005.

These questions indicate that further research is needed on the effects of incentive level changes on PV developer business capabilities and the relative size and volume of projects under differing incentive programs.

There has been a recent increase in the average incentive amount for projects dropped or withdrawn, as Figure 3-24 shows. This increase is likely due to the fact that some renewable and PV project reservation amounts in 2005 and 2006 were very high, and these projects withdrew, were rejected, or were suspended.

Figure 3-24. Approved Average Incentive Amount for Projects Withdrawn, Rejected, or Suspended (Inactive Projects Only)



3.8.2 PA and Regulatory Staff Perspective

From the PAs' perspective, past incentives were high enough to attract marginal projects, but now most are not high enough to do that. Thus, there may be a continuing need to track overall project costs to determine whether future incentives are set correctly.

To the PA staff, solar and non-solar technologies really present two different situations with respect to incentive structure. The CPUC goals for solar energy are stated clearly, and the incentive levels for solar technologies are pre-defined, including how they will change over time. On the other hand, the goals and future incentive levels for non-solar technologies are much more nebulous and need refinement.

Incentives have been paid on a system capacity rating, which appear to have led to some sub-optimal PV installations. Performance-based incentives (PBIs) would appropriately penalize sub-optimal installations. SCE staff thought there would be pent-up demand for performance-based incentives, based on what some market actors had been saying, but that demand only materialized in some markets. The SGIP rebate structure may be preferred by organizations because of its simplicity and that it addresses up-front capital costs better than a potentially uncertain performance incentive.

Equipment cost caps had caused problems such as not buying needed warranty coverage, and they have led to much customer frustration. PAs, therefore, were glad to see the caps removed.

Beyond the program incentives, utility rates affect projects. SDREO and SCG cited PG&E's favorable rate as helping solar projects, but SDG&E's continuing use of high demand charges with ratchets for solar projects is seen as dampening the market for that technology. Indeed, SDREO believes electric tariffs (with demand charges) affect PV system economics more than reduction in incentive levels.

No incentive restructuring appears to be currently planned, but the broad concept of SGIP expanding to include new technologies has been suggested by many stakeholders. This may require revisiting the incentive structure as other technologies get included. The question of the current incentive levels not capturing marginally economic projects needs to be included in this consideration.

Regulatory staff indicated that moving toward a PBI structure is appropriate, although it was noted that it may not be appropriate to handicap newer technologies with such incentive structures where performance is less certain. Rather, a PBI design seems better suited to mature technologies with predictable performance. In-depth interviews indicate that the *theoretical* openness of existing customers in moving to PBI has been undercut somewhat by experience with equipment performance over time. Interviews show that experienced participants are more inclined to be keenly aware of the real possibility of equipment failure or malfunction with specific technologies, and the resultant bill increases, particularly with PV systems in areas with solar unfriendly tariffs. This appeared to have dampened the acceptance of PBI; however several interview subjects promoted the idea of a hybrid PBI where some upfront incentive was retained in the program to defray first costs. Even though the lump sum design of the current incentive has been criticized by some, regulatory staff felt it has precipitated a good outcome in spurring the market.

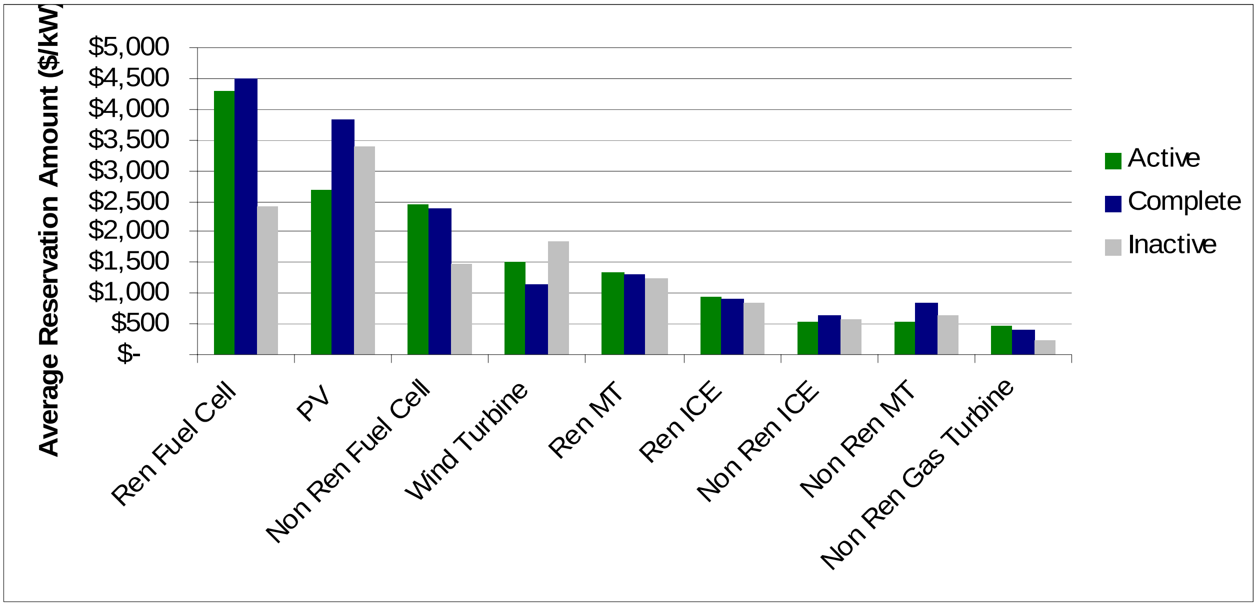
3.8.3 Developer Perspective

Perhaps not surprisingly, developers did not like the reductions in the incentive levels, though more than one allowed that the change did not have a major impact on either project volume or timelines. One PV developer explicitly cited a 30% drop in the number of projects developed. Another PV developer cited a "definite" reduction in project volume and said that some of his wait-listed customers dropped out as a result. It should be said, however, that other changes in the program were cited at least as often as being of consequence. This suggests that the reductions were not of a fatal magnitude, though it does not suggest how additional reductions might affect project volume. Developers were concerned about the decreased cogeneration incentives and predicted a precipitous drop if incentives were cut further.

3.8.4 Participating Host Customer Perspective

In focus groups, telephone surveys and in-depth interviews, host customers were asked about their experience with the form and level of incentives provided by the program. Many PV projects barely make strict economic sense from a project view, even with incentives. Given the view shown in Figure 3-25, where solar project costs per kW are substantially greater than for most non-solar technologies, this view reflects the relatively more difficult economics seen for solar technologies.

Figure 3-25. $/kW Incentive by Technology and Project Status



The current form of incentive as a payment upon completion is preferred by many market actors because systems are typically front-loaded capital projects and first-cost sensitive. Incentive checks generally get signed over to developers, and even though many customers do not directly see the checks, they do realize that the developers are carrying the capital costs until the payment is made. Pay-for-performance incentives are understood to help ensure performance, and they are believed to be acceptable for 3rd party financing, but they are problematic for capital projects and may not be understood by many small contractors. The current up-front rebate for PV systems is based on a system's DC rating, but a pay-for-performance would be based on lower, AC-inverted output. Focus group host customers expressed a concern that customers and developers would receive less revenue from a performance-based incentive based on AC-inverter output.

Incentives are now at a "tipping point," according to focus group host customers. Further reductions would be "radical" and run counter to current PV costs that resist decline because of the shortage of panels. Incentive reductions will not reduce pending resolution of panel shortages and associated cost run-ups, plus rising costs of labor and non-panel materials. Host customers said that incentives need to be sufficient to bring system costs to within a three- to five-year simple payback. However, about half of the host customers participating in the telephone survey indicated that, if they were to install more on-site generation in the next five years, they would tolerate paybacks over five years.

In a telephone survey of host customers, about nine of ten host customers with active projects felt the incentive was "very important" to their decision to go forward with the project. The same was true for those with projects that dropped out of the program. Yet, over 40% of "dropout-project" respondents indicated they still intended to install the project. This suggests that, although the incentives are important to nearly all host customers, for many projects that dropped out, the lack of program incentives is not necessarily a "show-stopper." It is unlikely that all those projects will go forward, nonetheless nearly a quarter of those who indicated they planned going forward even without the program incentives actually have already installed their projects.

Additionally, most host customer in depth interviews revealed a preference for an up-front incentive. Interviewees represented institutions such as cities and non-profit organizations where budgets tend to favor up-front incentives as well as private sector entities. Still, a number of respondents in the interviews indicated an interest in performance-based incentives, particularly if the incentives address performance risks outside the control of the host customer (e.g., addressed through a performance guarantee from developers).

Simplicity as well as certainty were valued in an upfront incentive payment, including the ability to compare capital costs without having to use sophisticated financial analyses. Three interviewees (out of 45) preferred a PBI in theory, but given how equipment performance has been problematic, they ultimately prefer the rebate design. One person who favors a PBI felt it would attract long-term capital investors better than the rebate structure, while another person felt a PBI would put all systems on a more level playing field. One host customer thought a hybrid approach would work best, providing at least some of the benefits of each design. Another host customer commented that his company would use power purchase agreements in the CSI program, because they felt that approach would be better than the CSI's PBI design.

Interviewees had a variety of opinions about whether the incentives were able to make projects yield an adequate payback. Some were unsure. Others thought it depended on the technology, seeing payback periods on PV systems as less favorable when compared to payback periods for microturbines or fuel cells. Others mentioned that tax credits, other available incentives and higher electricity rates are important factors that determine payback periods, in addition to the program incentive. Those with natural-gas fired generators noted the adverse effect of gas prices on their project's payback, and that the reduced incentives could not overcome this problem. Some interview subjects noted that they discovered that the incentives they actually would earn were less than the incentive they thought they would receive. The effect of this was that project were judged not to provide an acceptable return on investment, and therefore did not proceed to completion. This suggests that the current incentive levels may not sufficient.

In general, interviewees expressed a lot of uncertainty about what the actual payback of their systems would be in relation to the incentives provided, because of future operating uncertainties and overarching economic conditions such as fuel and electricity prices. Partly, this uncertainty is due to many interviewees being uncertain about general cost trends, with most opining that equipment costs are increasing. The ability of the incentive to be meaningful in light of those trends was highlighted by a number of customers who commented that they would be less likely to install self-generation in the future. Despite our analysis on the strong impact of declining incentives in cogeneration, customers looking at cogeneration projects are more likely to be sensitive to natural gas prices as the primary factor, compared to program incentives. Finally, several interviewees said they would accelerate their project efforts if they knew incentives would be declining in the future.

3.9 Transition to the California Solar Initiative

The transition from the SGIP to the California Solar Initiative (CSI) was and continues to be challenging for PAs, developers and customers, though this is not abnormal when rolling out large, new programs. Early in the transition there were no forms for applicants to use, outreach was lagging behind the program, and the PAs were working both the SGIP and the CSI simultaneously. Some solar developers mentioned that the CSI had been two months behind (at the time of the interview) in releasing a Guidebook for program participation and many expressed the fear that moving to performance-based incentives (rather than a one-time upfront payment) will stunt the market for PV in California. Yet other developers commented that, notwithstanding the birth pains of this new program and the greater difficulty in selling performance-based incentives over time to customers, the CSI will become more effective at spawning and stabilizing solar PV markets in California.

3.9.1 The Landscape under CSI

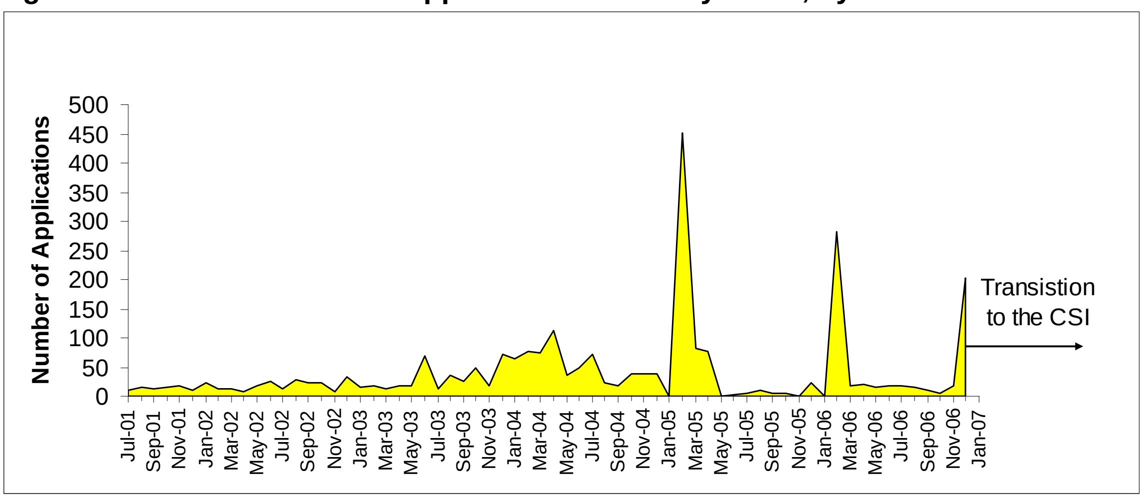
The overarching goal of the California Solar Initiative (CSI) is to help fund 3,000 MW of solar energy within 10 years (i.e., by 2016). The CSI inherits the entire over-30 kW solar energy portfolio from the SGIP and the under-30 kW solar energy portfolio (for existing residential homes) from the CEC's Emerging Renewables Program. Starting January 1, 2007, solar energy systems greater than 100 kW were to be paid monthly incentives based on actual energy produced (a performance-based incentive – PBI). Solar energy systems less than 100 kW will be paid an up-front incentive based on expected system performance. In 2010, all systems greater than 30 kW will be paid based on actual energy produced (PBI).

Incentive payment levels are anticipated to gradually decrease on a ten-step schedule, with each step triggered at an installed capacity threshold. Incentives are projected to decline at a rate of 7% per year. In August 2006, Senate Bill 1 expanded eligibility so that host customers could be customers of investor-owned utilities or municipal utilities. Municipal utilities are required to start offering incentives starting in 2008.

3.9.2 The CSI's Effect on the SGIP

Though a number of solar market actors had been looking forward to the transition from SGIP to the CSI, there was a significant surge of applications to SGIP in December 2006, the final month of the program in its current form (Figure 3-26). Over 200 applications were received by the SGIP in December 2006 alone. Two sectors, elementary and secondary schools (47 applications) and retail stores (49 applications), accounted for almost half of these applications

Figure 3-26. Number of SGIP Applications for PV Systems, by Month



Source: SGIP December 2006 Monthly Reports

Program host customers and project developers both expressed some concern about the transition from SGIP to CSI, which may account for some of this last-month surge in applications. Uncertainty about the incentive level reference point under CSI created confusion in the market; therefore, several developers recommended that their customers apply under SGIP while they still could. Also, the CSI process imposes a higher application fee, which may have driven some customers to apply under SGIP in the program's final month.[39]

The uncertainty about CSI in the market is reflected in the data collected in surveys of project host customers. Nearly 45% of respondents commented that the shift to CSI has affected them in some way. Roughly 13% stated that they believe the transition to CSI will "be an improvement on the prior program for PV." Just over 20% stated that they think it will *not* be an improvement, and perhaps most telling, almost 66% were simply not sure. Respondents with projects in SDREO's territory were most likely to be apprehensive about the transition to CSI. Almost 45% of respondents in SDREO's territory stated that they think it will *not* be an improvement. Note that the survey was fielded while customers were still expecting mandatory TOU under the CSI.[40]

Public entities were almost twice as likely as private firms to state that they think the transition to CSI *will* be an improvement over the prior program. A similar amount of private entities and public entities felt that the transition to the CSI will *not* be an improvement (about 20%) or are *not sure* (56-70%). Also, 40% of the public entities and almost 50% of the private entities feel that they will be affected by the transition. (See Table 3-19.)

Table 3-19. The Transition to the California Solar Initiative

	Private	Public
Transition to CSI *will* be an improvement	**9%**	**20%**
Transition to CSI *will not* be an improvement	20%	23%
Not sure if the transition to CSI will be an improvement	70%	56%
Will be affected by the transition	48%	39%

3.9.3 Impact on PA Budgets, Operations and Staffing

Because the CSI combines both the over-30 kW solar PV project base from SGIP with the existing residential home (under 30 kW) project base from the CEC, the volume of applications is expected to greatly increase under the CSI for the PAs administering it. The PAs are revising their administrative processes to accommodate the different program needs. One obvious difference is that the PAs must now manage residential-scale PV systems, which are smaller in size and more numerous.

Three of the four PAs reported having added some additional staff to administer the CSI, and they are receiving much higher volume of applications since the CSI began. This leads to some difficulty in

[39] Application fees apply to certain sectors (commercial, government, non-profit entities with systems greater than or equal to 10 kW). Application fees under SGIP were 0.5% of requested incentive, and under CSI they are 1.0%, or twice as much.

[40] California Assembly Bill 1714, chaptered on June 7, 2007, stated that "The commission may delay implementation of time-variant pricing pursuant to subparagraph (A), until the effective date of the rates subject to the next general rate case of the state's three largest electrical corporations, scheduled to be completed after January 1, 2009."

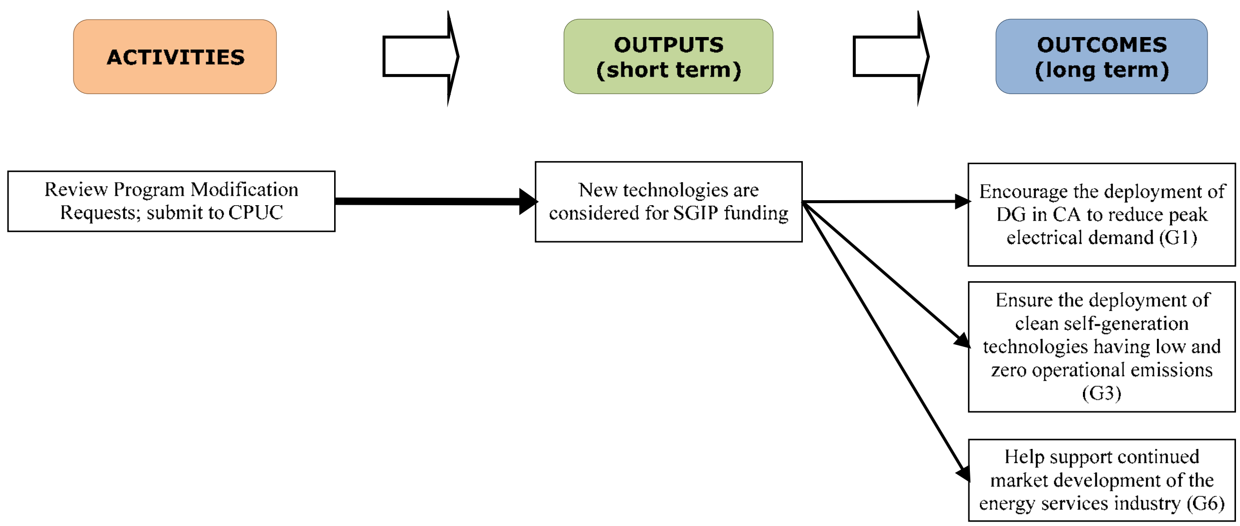
projecting how many people are needed and retaining competent staff. This is a particular concern of SCG, in that they will experience a reduction in project flow because they will no longer administer new PV projects after 2006 and will no longer administer cogeneration projects (Level 3) after January 1, 2008. In this regard, SCG is a unique case, as the other PAs are receiving much higher volumes of applications, especially for smaller (under 10 kW) projects.[41]

Surges in applications can also be difficult to process. For example, several PAs reported being surprised by how many solar applications were received in December of 2006 before solar transitioned to the CSI. Moreover, a small number of projects (even some that were close to receiving their incentive monies) dropped out of the SGIP and have re-applied under the CSI. About 900 new applications have been received for new PV projects under CSI during the first five months of its existence.

The budgeting process for the CSI has also been a point of concern for PAs, particularly in regards to how to allocate leftover monies from the SGIP into the CSI. The general method is that monies remaining from SGIP in 2006 were to be reallocated out of SGIP and into the CSI, based on the PA's percentage of electric vs. gas ratepayers.[42] There has been a need for clarification from the CPUC on budget items surrounding this issue.

3.10 Program Modification Guidelines for New Technologies

One influence on the long-term outcome of the SGIP is whether new, low/zero-emissions technologies will be available and economical. As new technologies are developed, therefore, the program has an obligation to consider their worth in contributing to the eventual outcome of deploying substantial amounts of clean DG capacity. The program has a process for considering modifications, which includes a venue for considering new technologies. As the sub-logic diagram below shows, the evaluation has included research on this matter.



[41] For example, SCE has added two more staff-people and are planning to add three more. PG&E added five more project managers, mostly focusing on applications for systems less than 30 kW.

[42] For example, for SCE, 100 percent of leftover monies were reallocated to the CSI.

Earlier in the SGIP history, a number of petitions for modification were received requesting consideration of additional technologies or other changes to the SGIP.[43] Findings of fact concluded that, "[p]etitions to modify do not facilitate a careful consideration of new technologies..." As an alternative, it was decided that a Commission process to provide for careful consideration for new technologies would be more effective than the petition process.[44] As a result, the Energy Division proposed a process for consideration of eligible technologies that was adopted with minor modification.[45] A seven-step process was outlined, describing how the application should be presented at the Working Group and submitted to the assigned commissioner. It was also envisioned that the Working Group could submit and propose changes to the program. However, despite creating a process for considering modifications and new technologies, the CPUC has not officially acted on any of the petitions received in this manner. Over time, some of the petitions have become moot. Discussions with PAs and CPUC staff indicate there is some concern about this process.

The investigation of other approval mechanisms for program modifications may be appropriate at this point. For example, the SGIP could conceivably be structured such that the Working Group could make recommendations to the Commission. Whenever there is unanimous support for a modification, the recommendations could become part of the program unless the CPUC objected to it within a specific time frame. Recommendations that are not unanimous would require specific approval by the CPUC in order to modify the program. In this manner, the Energy Division could tacitly approve a modification. There would need to be bounds to the level of authority delegated (for example, the Working Group would not be allowed to unilaterally modify incentive levels), but it may be appropriate to allow the Working Group to add additional technologies.

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[43] About 16 Program Modification Requests have been submitted to the SGIP Working Group since December 2003. SGIP Working Group Meeting Minutes, Dec 11, 2003 through June 22, 2007.

[44] D.03-01-006.

[45] D.03-08-013.

3.11 Comparison to Previous SGIP Process Reports

Table 3-20 shows the comparison of this study's finding to the two previous SGIP process reports- the SGIP Second Year Process Evaluation completed in 2003 by Regional Economic Research and the SGIP 2004 Targeted Process Assessment completed in 2005 by Itron.

Table 3-20. Previous Process Report Comparison

Themes	2003 Results (2nd Year Process Evaluation)	2007 Results
Customer Awareness	Awareness among non-participants was 15%.[46] Marketing was not effectively reaching the host customers. The dominant source of information about the program was from third-party suppliers, followed by utility representatives.	Awareness increase to 26% of non-participants. The dominant source of information about the program continued to be from third-party suppliers, followed by their utility representative.
Utility Representatives	PAs have increased efforts to educate customers through utility account representatives, though some comments revealed that they are not always helpful (lack of program knowledge).	Thirteen percent of host customers with active or completed projects and 16% of host customers with withdrawn or rejected projects heard about the incentives through a utility representative.
Uncertainty Over Exit Fees	Uncertainty over exit fees causes eligible candidates to not participate in the program.	Program authorization through 2012 has mitigated this concern.
Application Process	Suppliers and customers commented on the complexity of the handbook. Insurance requirements are burdensome.	Supplier and host customers continued to have mixed reviews about the application materials. Some PAs mentioned the burdensome insurance requirements, though 62% of host customers with active or completed projects felt that obtaining the necessary insurance was very easy, and 27% felt that is was easy. Of host customers with withdrawn or rejected projects, about 50% said it was very easy; about 30% said it was very difficult. Difficulties with the application process included submitting the PPA and working with the electric utility to connect to the grid.

[46] Itron, Inc. for Southern California Edison. "Self-Generation Incentive Program: Second Year Process Evaluation." April 2003.

Themes	2003 Results (2nd Year Process Evaluation)	2007 Results
Program Deadlines	On average, applications exceed the 90-day PPA though PAs report that most applicants do not have difficulty in meeting this deadline. One year completion deadline also not a strong issue.	Applications on average exceeded the 90-day or 60-day PPA. Suppliers and host customers felt the overall one year completion deadline was tight but reachable due to available extensions.
Interconnection and Net Metering Problems	Suppliers and customers report that interconnection is an issue. Net metering an issue because of misunderstanding about credits to the grid.	Interconnection continues to be an issue for some: 27% of host customers with active or completed projects felt that interconnection was very difficult.
Participant Satisfaction	Overall 4.3 (5-point scale) satisfaction level. Concerns: complex/confusing application materials, delays (cited by 40% of hosts with completed projects), project financing, emissions permitting, PPA requirements, grid interconnection.	Overall satisfaction continued to be high, though areas of concern also continued: nearly 80% of active-project host customers are either Satisfied or Very Satisfied (30% are Very Satisfied) overall. Project financing, obtaining equipment, PPA requirements, emissions permitting, equipment installation and operational reliability and grid interconnection were aspects seen as being the least easy to address. Unnecessary delays cited by about 60%.
Third-Party Development	Program has a significant effect on the development of third-party market.	Third-party market continues to be affected, though not all positively: CSI transition is naturally affecting how PV developers worked with SGIP, and cogeneration developers have seen a significant drop in the number of projects due to saturation of best opportunities and natural gas price increases.
Markets Involved	**By number of applications:** 1. Manufacturing 2. Office 3. Misc. commercial (in 2001) and Unclassified (in 2002) **By number of completed projects:** 1. Office 2. Misc. Commercial 3. Lodging (in 2001) and Transport./communication/ utilities (TCU), Manuf., and Non-refrig. warehouse (in 2002)	**By number of applications:** 1. Manufacturing 2. Real estate 3. Elementary/secondary schools **By number of completed projects:** 1. Manufacturing 2. Public administration 3. Elementary/secondary schools Note: Real estate and Public administration were not building types in the 2nd Year Process Evaluation

Key Findings	2004 Result (Targeted Process Assessment)	2007 Results
Program Incentive Structure and Exit Strategy	Administrators supported declining capacity-based incentives and performance-based incentives. No suggestions for exit strategy. Host customers unenthusiastic about declining incentive levels.	Mixed views across market actor groups on PBI, though among customers and many developers, an up-front lump sum design continues to be favored. The advent of CSI and the declining number of cogeneration projects have trumped all exit strategies; cogeneration may return in limited form via legislative initiative. Declining incentives affected cogeneration project volumes but affected PV project volumes less.
Interconnection Issues	Delays and requirements uncertainties were key concerns, including metering aspects and Rule 21 compliance.	Interconnection continues to be problematic for some developers and host customers.
M&E Data Collection	Concerns over metering installation and data transfer logistics, communication lines, PA and meter data provider responsibilities.	PA Impact and Verification contractors were not interviewed.
Participant Satisfaction	Overall 3.9 (5-point scale) satisfaction level – may be less than the 2002 Process Evaluation. Interconnection process shows least satisfaction; developer services show greatest satisfaction.	See above.

4. CONCLUSIONS AND RECOMMENDATIONS

This section summarizes a brief summary of conclusions, followed by a set of general recommendations. These are followed by topic specific recommendations. The chapter concludes with a summary of potential future work, including both the work planned for the upcoming SGIP Market Study, and initial thoughts on potential research that is outside the current scope of this evaluation.

4.1 Summary of Conclusions

SGIP Participation and Market Context

- The SGIP has disbursed over $403 M in incentives for 234 MW of capacity since its inception through December 2006. This represents 948 on-site generation projects (638 solar photovoltaic, 7 renewable internal combustion engine, 13 renewable microturbine, 2 renewable fuel cell, 1 wind turbine, 176 non-renewable internal combustion engine, 97 non-renewable microturbine, 4 non-renewable gas turbine and 10 non-renewable fuel cell projects).

- Average total incentives per completed projects have increased due in part to the changing mix of technologies applying to the SGIP over time.

- Host customers in the SGIP find three factors more compelling in the decision to participate than their non-participant counterparts: utility bill reduction, concern for the environment, and peak demand reduction. Non-participants thought that the desire for back up power would be an important factor, but few SGIP participants agreed.

- Ten market sectors applying to the SGIP account for most applications (78%). Manufacturing dominates with 16% of the total number of program applications. Other sectors, while not dominant in terms of total applications can represent a number significant proportion of applications of specific technologies, e.g., lodging applications for cogeneration or the utilities segment in "other renewables" technology types (e.g., renewable fuel cell, renewable internal combustion engine, renewable microturbine, wind turbine).

Participant Experiences

- Overall program satisfaction is high (80% of survey respondents with active/completed projects were satisfied or very satisfied and 50% of withdrawn or rejected projects).

- Over time, fewer host customers are completing forms themselves, from 76% of those that applied in 2001 saying they did complete the forms themselves to 13% of those that applied in 2006. This decrease has been a steady decline from 2001 to 2006.

- Satisfaction with the SGIP was initially low for host customers that applied in 2001: 48% of host customers were satisfied or very satisfied with the program. During 2002-2005, satisfaction was relatively high and constant, ranging from 81% to 90%. However, for those host customers that applied in 2006, only 58% were satisfied or very satisfied with the program.

- Most program processes have stayed consistently easy or difficult for host customers over time. One process of note is the ease of submitting proof of project advancement to the program. Forty percent of host customers felt this was easy or very easy in 2001, rising to 79% of host customers that applied in 2004 feeling this way, then decreasing to 54% of host customers that applied in 2006 feeling that submitting the proof of project advancement was easy or very easy.

- Consistent with the SGIP's stated approach, most applicants rely on project developers in some fashion (about 80%) to participate in the SGIP. A significant fraction of applicants take a "hands off" approach to the application process (40%) and a similar percentage are involved, but rely on developers to handle forms. Public entities are almost twice as likely to apply without assistance of a third party on paperwork.

- Of those having a negative experience, paperwork and bureaucracy were typical complaints.

- In terms of navigating the stage gates, both withdrawn and completed projects had difficulty with financing the project, but withdrawn or rejected projects also had more difficulty with appropriate technology selection. Though business case and contracting type issues were cited more often. Air permitting was a significant burden to projects for which these permits must be obtained.

- Participants and developers complained about frequent changes to the programs, making it harder to plan for projects in their budget cycles.

- Extensions during the process are granted relatively often but there seems to be some confusion amongst participants as to when extensions can be expected.

- Drop out rates in the program are relatively constant over time with some increase in 2005.

- The dominant reason reported for withdrawing from the SGIP by far is that system costs relative to rebates are too high (27%). Application process issues were cited by some (10%) and other business reasons such as project financing, internal business priorities changing or problems obtaining or installing equipment, and investment uncertainty represented a significant fraction in sum as well (25% in total).

Public versus Private Entity

- Public entity participation is robust and has grown steadily over the SGIP while private entity participation is beginning to decline from the high in 2004. Public entity satisfaction is comparable to private entity satisfaction with the SGIP.

- Public entities do have different decision making and contracting needs which make the SGIP timeframes somewhat difficult to navigate (e.g. 50% of public entities find proof of project advancement difficult or very difficult while only about 20% of private firms find it that difficult). However, aggregate analysis does not show a very large differential on average in project completion times as between public an private.

- Public entity participants are more focused on green image than private counterparts and energy costs, while important to both, are somewhat less important for public entities. However, completion rates for both types are roughly the same. Public entities also see it as their responsibility to provide sites for technical demonstration of projects.

- Public entities are more likely to complete all application forms by themselves and are less likely to outsource in a turn key manner. This may account for some of their relatively greater difficulty in the interconnection process. Additional consideration of tax consequences of outsourcing by public entities could help them obtain some of the tax benefits otherwise unavailable to them.

Application Fees

- The institution of the application fee is generally seen by most participants, developers, and PAs as a success in deterring phantom or premature project application. However, the forfeited fees are significant and some developers appear to be taking the risk for some premature projects.

Transition Issues – Cogeneration, Incentives and CSI

- PAs, participants, and developers indicate that cogeneration applications to the program have been declining due to a number of reasons: decreasing incentives, increasing natural gas prices, more stringent air regulations, difficulty meeting waste heat requirements, and softening of retail electricity rates from historic 2002 highs. Regression analysis of participation data indicates that incentive reductions have had a greater dampening effect than increasing natural gas prices.

- With regard to PBI and the CSI transition, many are concerned that the transition to PBI will not be an improvement though more are not sure. Concerns voiced reflected worries about TOU requirements (survey fielded before change) and difficulty obtaining financing or making the business case in the absence of an upfront incentive. Experienced participants also have some concerns about equipment reliability and malfunction.

- There is a general concern about how to bring new technologies into the SGIP. Some think that the PMG guidelines could be used. However, because no applications using the PMG process have resulted directly in a program modification, stakeholders are not confident in this approach.

General Recommendations

- Maintain the current project milestone framework that allows more time for public-entity projects and continue to allow extensions to both public and private entities where good cause is shown. In the program handbook, define (or at least provide examples of) what constitutes “good cause” to ensure that extensions are granted on a consistent basis.

- Host customers that completed projects were significantly more focused on environmental benefits than non-host customers surveyed with regard to the “value proposition” of the SGIP. It follows that additional case studies emphasizing environmental leadership could assist those entities with similar mission statements or value constructs. As the market value of RECs becomes clear, there may be even more information desired on this topic. The Working Group could direct the M&E Committee to develop those case studies that highlight this value.

- Retention to the project could be improved by continuing to provide *accessible* information about technology performance.

- Continue to provide support to applicants and coordinate with the interconnection group at utilities, so as to improve the number of applicants that get interconnection right the first time and reduce frustration with “bureaucracy.”

- As the program continues to mature, make changes judiciously as the market participants are frustrated by a steady diet of changes.

Recommendations Specific to Public Entities

- Because public entities are more likely to file their paperwork (including interconnection agreements) without benefit of an energy services company, they may need more frequent follow up or specialized outreach efforts.

- Consider developing a compilation of known tax and other incentives as a program resource to various entities, to maximize the program's value and minimize the cost to both public and private entities searching for such information. This could include a set of case studies and/or description of alternative ownership strategies for public entities.

Cogeneration-Related Recommendations

- Do not further reduce the incentive levels for cogeneration projects, as in-depth analysis shows that this is the dominant reason cogeneration applications have dropped off, more so than declining natural gas prices.

- If cogeneration is reinstated, the program should continue to consider biogas and landfill gas resources as eligible for incentives. Reduction of landfill gas emissions (methane) are one of the early responses actions advocated under AB 32.

Incentive Levels

- The market prefers and is used to rebate-style incentives as being more certain and simple, though a performance-based incentive is not alien and some market actors (particularly those PV applicants that switched from SGIP to CSI) do prefer such a program design. To ease transition effects, the Working Group should consider recommending a hybrid approach that retains some rebate aspects but conditions full payout on quality assurance and performance standards.

- Do not further reduce incentive levels at this time. Undertake a continuing review of equipment cost trends, payback implications, and market adoption rates to determine at what point incentive levels should be changed (up or down).

Application Fee

- In retrospect, the application fee appears to have been a qualified success. It appears to be an appropriate mechanism to reduce phantom projects, though it is problematic for public entities. Where relatively small amounts of incentive dollars are available in a technology category, application fees could still serve to reduce immature project sign up.

Program Modification Process

- The program modification process could be improved by creating a delegation mechanism to the Working Group on a limited basis, or by creating a required response time on the part of the CPUC.

4.2 Recommendations for Future Research

It appears to be worth looking at how business models are evolving in the state to serve on-site generating markets. The extent to which PV project developers have used incentives, which they may have captured through higher pre-rebate system prices as an investment in their business capabilities, may be driving new partnerships helping them create new delivery methods for marketing, selling and installing systems. The upcoming market study will make an initial review of the evolving market to deliver SGIP services.

Some additional topics that may warrant investigation:

- Review data on regional variations in market appetite for on-site generation, i.e., are there climate differences, and/or social circumstances that may explain participation differences across various regions and locales in California? The PA study identified potentially significant regional variations in customers' expectation about PV costs that warrant further investigation.

- Review regulatory mechanisms required to delegate more authority to the Working Group for program modifications.

- Review how tariff issues affect market participation and projects that decide NOT to produce power in some instances.

- Conduct further research on total installation cost. For example, does geography determine the "street price"[47] of an installed system? GIS mapping of projects may help determine whether social effects in neighborhoods or communities where installations may be clustered are influencing customer decisions. There were some indications from focus group participants that the visual impact of other local PV systems, and/or communications with peers in their market sector may have influenced their decision to participate. This research would explore whether the data indicate if early adopters of self generation technologies influence others to participate because of proximity

- Conduct further research on how program marketing expenditures and other internal support or outreach activities, particularly PA account representative efforts, may have affected participation rates.

[47] Wiser, R., M. Bolinger, P. Cappers, R. Margolis. "Analyzing Historical Cost Trends in California's Market for Customer-Site Photovoltaics." Report Prog. Photovolt. Res. Appl. 15. 69-85. June 2005.. Some variation in costs between Northern and Southern California are shown in this work.

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