Self-Generation Incentive Program Semi-Annual Renewable Fuel Use Report No. 19 for the Six-Month Period Ending December, 2011

1. Overview

Report Purpose

This report complies with Decision 02-09-051 (September 19, 2002) of the California Public Utilities Commission (CPUC). That decision requires Self-Generation Incentive Program[1] (SGIP or Program) Program Administrators (PAs) to provide updated information every six months[2] on completed SGIP projects using renewable fuel.[3] The purpose of these Renewable Fuel Use (RFU) reports is to provide the Energy Division of the CPUC with the required updated renewable fuel use information. In addition, the reports help assist the Energy Division in making recommendations concerning modifications to the renewable project aspects of the SGIP. Traditionally, these reports have included updated information on project fuel use and installed costs.

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[1] The SGIP provides incentives to eligible utility customers for the installation of new self-generation equipment. The program is implemented by the CPUC and administered by Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and Southern California Gas Company (SCG) in their respective territories, and the California Center for Sustainable Energy (CCSE), formerly the San Diego Regional Energy Office (SDREO), in San Diego Gas and Electric (SDG&E) territory.

[2] Ordering Paragraph 7 of Decision 02-09-051 states:

"Program administrators for the self-generation program or their consultants shall conduct on-site inspections of projects that utilize renewable fuels to monitor compliance with the renewable fuel provisions once the projects are operational. They shall file fuel-use monitoring information every six months in the form of a report to the Commission, until further order by the Commission or Assigned Commissioner. The reports shall include a cost comparison between Level 3 and 3-R projects…."

Ordering Paragraph 9 of Decision 02-09-051 states:

"Program administrators shall file the first on-site monitoring report on fuel-use within six months of the effective date of this decision [September 19, 2002], and every six months thereafter until further notice by the Commission or Assigned Commissioner."

[3] The Decision defines renewable fuels as wind, solar, biomass, digester gas, and landfill gas. Renewable fuel use in the context of this report effectively refers to biogas fuels obtained from landfills, wastewater treatment plants, food processing facilities, and dairy anaerobic digesters.

Due to a growing interest in the potential for renewable fuel use projects to reduce greenhouse gas (GHG) emissions,[4] a section on GHG emission impacts from renewable fuel SGIP projects has been added to the reports beginning with RFU Report No. 15.

RFU Report No. 19 covers projects completed during the last six months (i.e., July 1, 2011, to December 31, 2011) as well as all renewable fuel use projects installed previously under the SGIP since the Program's inception in 2001. Results of analysis of renewable fuel use compliance presented in this RFU Report are based on the 12 months of operation from January 1, 2011, to December 31, 2011.

RFU and RFUR Projects

The incentives and requirements for SGIP projects utilizing renewable fuel have varied throughout the life of the SGIP. In this report, assessing compliance with the Program's minimum renewable fuel use requirements is restricted to the subset of projects actually subject to those requirements (i.e., Renewable Fuel Use Requirement (RFUR) projects) by virtue of their participation year, project type designation, and warranty status.[5] However, the analysis of project costs included in this report covers all projects using some renewable fuel (i.e., Renewable Fuel Use (RFU) projects). All RFUR projects are also RFU projects; however, not all RFU projects are RFUR projects. This distinction is responsible for differences in project counts in this report's tables. Differences between RFU and RFUR projects are summarized in Table 1. Similarly, Table 2 reports only on RFUR projects whereas Table 15 lists all RFU projects, including those not subject to the Program's minimum renewable fuel use requirements ("Other RFU projects").

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[4] While the SGIP was initially implemented in response to AB 970 (Ducheny, chaptered 09/07/00) primarily to reduce demand for electricity, SB 412 (Kehoe, chaptered 10/11/09) limits the eligibility for incentives pursuant to the SGIP to distributed energy resources that the CPUC, in consultation with the state board, determines will achieve reduction of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006.

[5] The SGIP requires such projects to limit use of non-renewable fuel to 25 percent on an annual fuel energy input basis. This requirement is based on FERC definitions of renewable energy qualifying facilities from the original Public Utility Regulatory Policy Act (PURPA) of 1978.

Table 1: Summary of RFU vs. RFUR Parameters

Parameter	RFU	
	"Other" RFU[6]	RFUR
Annual Renewable Fuel Use	0 – 100%	75% - 100%
Heat Recovery	Required	Not Required
Incentive Level	Same as non-renewable projects	Higher than non-renewable projects
No. of Projects	9	86

Directed Biogas Projects

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for RFUR incentives was expanded to include "directed biogas" projects. Deemed to be renewable fuel use projects, directed biogas projects are eligible for higher incentives under the SGIP, and subject to the fuel use requirements of renewable fuel use projects. Directed biogas projects purchase biogas fuel that is produced at another location. The procured biogas is processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased biogas is not likely to be delivered and used at the SGIP renewable fuel project, the SGIP is credited with the overall use of biogas resources.

RFU Report No. 17 marked the first appearance of completed directed biogas projects under the SGIP. Each project is equipped with an on-site supply of utility-delivered natural gas. As such, the directed biogas is not literally delivered, but notionally delivered, as the biogas may actually be utilized at any other location along the pipeline route. Six directed biogas projects have been operational for one full calendar year and therefore are required to be in compliance with renewable fuel use requirements. Based on the fuel use information collected thus far, it is evident that additional information will be required to make a final compliance determination of directed biogas projects. In the meantime, preliminary compliance assessments have been developed using available data.

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6 The number of "Other" RFU projects increased from eight to nine in RFU report #19 due to the completion of SCE project PY10-003. This project was completed in December of 2010 but was not included in RFU reports No. 17 and 18. The project was initially listed as non-renewable only but examination of metered data revealed the presence of renewable fuel.

Summary of RFU Report No. 19 Findings

The following bullets represent a summary of key findings from this report:

- As of December 31, 2011, there were 95 RFU facilities deployed under the SGIP, representing approximately 41.3 megawatts (MW) of rebated capacity. Eighty-six of these facilities were RFUR projects and represented approximately 37.2 MW of rebated capacity. The remaining nine "Other" RFU projects represented approximately 4.0 MW of rebated capacity.
- RFU Report No. 19 marks the third appearance of completed SGIP projects utilizing directed biogas. Twenty nine projects added during 2011 were natural gas fuel cells that fulfill renewable fuel use requirements via purchase of landfill gas that is produced off-site.
- Of the 86 RFUR projects, thirty-seven (43 percent) operated solely from on-site renewable fuels and as such inherently comply with renewable fuel use requirements. Of the remaining 49 dual-fuel RFUR facilities:
  - Four were found to be in compliance with renewable fuel use requirements,
  - Three were found to have their compliance status indeterminable based on the information available,
  - Two could not have their compliance determined due to a lack of information,
  - Five were found not to be applicable with respect to the requirements as they were no longer required to report compliance status (due to being out of contract and so no longer subject to the renewable fuel use requirements),
  - Thirty were found not to be applicable with respect to the requirements as they have not yet been operational for a full year, and
  - Five were found to be out of compliance.
- Of the thirty facilities not yet applicable with respect to the renewable fuel use requirements, 29 are directed biogas systems where:
  - Eight facilities appear to be on track to use no more than 25% non-renewable fuel once they reach a full year of operation based on the information available, and
  - Twenty one facilities did not have compliance evaluated.[7]
- RFU facilities are powered by a variety of renewable fuel (i.e., biogas) resources. However, approximately 91 percent of the rebated capacity of RFU facilities deployed through December 31, 2011, was powered by biogas derived from landfills or wastewater treatment facilities.

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[7] Reasons why compliance was not evaluated are delineated in Section 3: Fuel Use at RFUR Projects

- Prime movers used at RFU facilities include fuel cells, microturbines, and internal combustion (IC) engines. Historically, IC engines have been the dominant prime mover technology of choice but have as of this reporting period been surpassed by fuel cells. Fuel cells provide approximately 20.1 MW (about 49 percent) of the overall 41.3 MW of rebated RFU capacity. IC engines provided 13.8 MW (about 37 percent of all RFU capacity).
- Based on samples of costs of RFU facilities, the average costs of renewable projects appeared to be higher than the average costs of non-renewable projects. However, limited and highly variable cost data prevent the conclusion that there is a 90 percent certainty that the mean cost of renewable-powered fuel cells and IC engines is higher than the mean cost of fuel cells and IC engines powered by non-renewable resources.
- RFU facilities have significant potential for reducing GHG emissions. The magnitude of the GHG emission reduction depends significantly on the manner in which the biogas would have been treated in the absence of the program (i.e., the "baseline" condition). RFU facilities that would have been venting directly to the atmosphere have a much higher GHG emission reduction potential than RFU facilities that would have been required to capture and flare biogas.
  - In general, RFU facilities for which flaring biogas was the baseline condition decreased GHG emissions by around 0.4 tons of carbon dioxide equivalent (CO_2eq) per megawatt-hour (MWh) of generated electricity.
  - Conversely, the GHG emission reduction potential for RFU facilities for which venting biogas was the baseline condition is around five tons of CO_2(eq) per MWh of generated electricity; an order of magnitude greater in GHG emission reduction potential.
- Potential for GHG emission reductions from RFU facilities is also affected by the use of waste heat recovery at the RFU facility. In general, RFU facilities that use waste heat recovery increase the potential for GHG emission reduction by displacing natural gas otherwise used to generate process heat.

Conclusions and Recommendations

On-Site Biogas

California has significant biogas resources that could potentially be used to generate renewable power and reduce GHG emissions. For example, there are over 1,000 landfills, 200 wastewater treatment facilities and thousands of dairies in the state that do not capture and use biogas generated by their operations. Locating RFU systems at these facilities could provide significant GHG emission reductions; help address regional ground water quality issues; serve as new renewable energy generating capacity; and create local jobs and employment. In the final decision on implementing the SGIP in accordance with SB 412 requirements, the CPUC noted that "using renewable biogas and developing California's biogas industry remain important objectives as California transitions to a low carbon future."[8] Consistent with this decision, the CPUC should consider ways to significantly increase deployment of RFU facilities under the SGIP to help capture these potential benefits. Among the ways in which the CPUC could help facilitate increased deployment of RFU facilities is addressing the following issues:

- Updating the technical and economic potential for RFU projects in California, identified by source of the biogas (e.g., landfills, wastewater treatment plants, dairies, etc.), prime mover technology (e.g., IC engines, fuel cells, microturbines, etc.) and location.
- Identifying the primary barriers preventing further application and deployment of biogas-to-energy projects in California; and by extension to the SGIP.
- Identifying and implementing actions that could be reasonably be taken by the PAs or the CPUC to help mitigate the barriers and help increase RFU application and deployment under the SGIP.
- Updating the estimated GHG emission reductions associated with successfully deploying increased levels of RFU facilities and achieving the economic potential.

Project Cost Breakdown

The cost breakdown conducted to date on RFU projects does not provide definitive information on the costs of gas clean-up equipment. However, such information is important in determining if there should be differences in incentive levels for RFU projects using biogas fuels. In addition, gas clean-up requirements (and therefore costs) are likely to differ significantly between prime mover technologies (e.g., fuel cells versus microturbines).

- The CPUC / Working Group (WG) should pursue steps to obtain specific and accurate information from project applicants on gas clean up costs and their relationship to the overall reported project costs
- The CPUC / Working Group should also consider funding an expanded study on the costs (capital and operating/maintenance costs) of different gas clean-up systems required on different prime movers fueled by biogas. The study should include biogas projects operating outside of the SGIP and California.

[8] California Public Utilities Commission, "Decision Modifying the Self-Generation Incentive Program and Implementing Senate Bill 412," September 8, 2011, page 22.

Directed Biogas Compliance Protocols

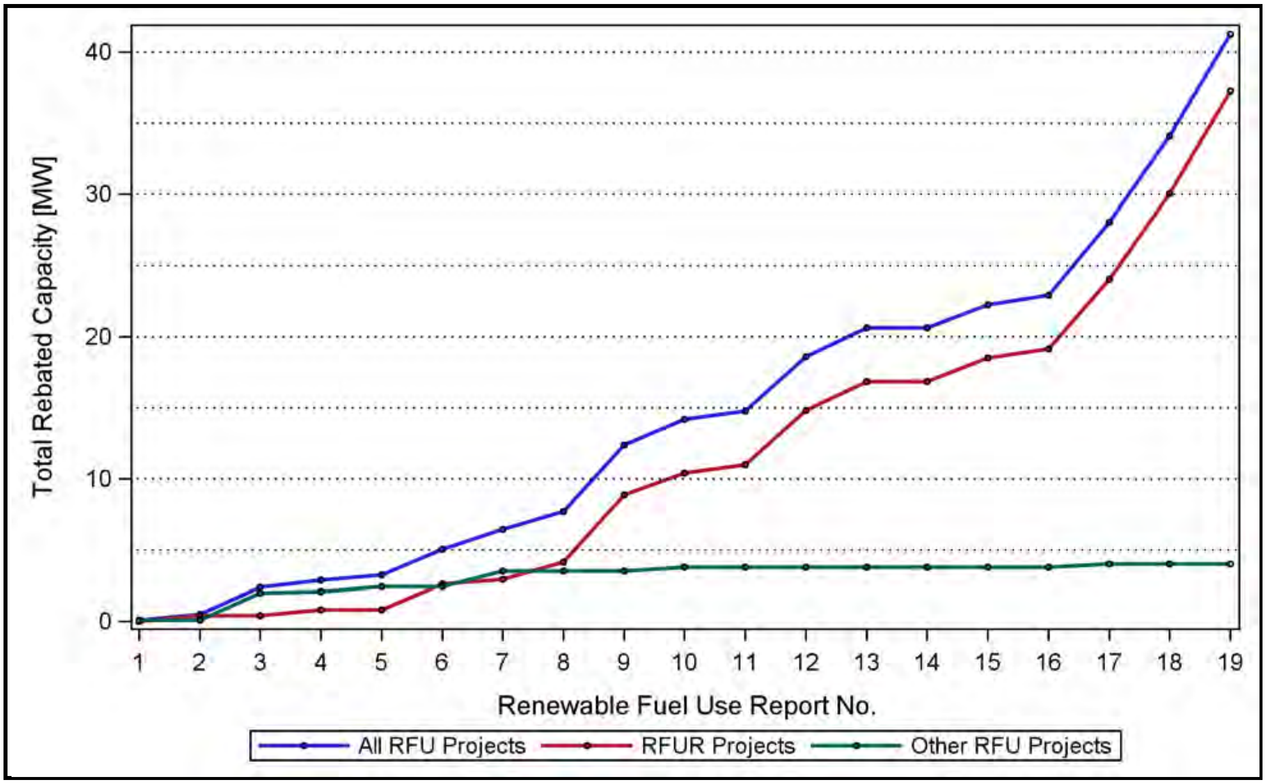
This RFU Report includes an evaluation of compliance of directed biogas projects that is preliminary in nature. Six directed biogas projects have been operational for one full calendar year and therefore are required to be in compliance with renewable fuel use requirements. Based on the fuel use information collected thus far, it is evident that additional information will be required to make a final compliance determination of directed biogas projects. In particular, we recommend the protocols governing compliance include the following information:

- Renewable fuel invoices for each individual SGIP directed biogas project; rather than for aggregated facilities. If an invoice covers more than one SGIP RFU project then the total quantity of directed biogas purchased must be allocated to individual SGIP projects.
- Renewable fuel invoice information for directed biogas sales outside of the SGIP (if applicable).
  - Applicable only if a SGIP directed biogas project and a project outside of the SGIP are serviced by the same biogas meter.
  - Identification by name of customers outside of the SGIP is not requested.
- Renewable fuel metering information associated with injection of directed biogas into the pipeline at the source.

Project Capacity, Fuel Types, and Prime Mover Technology

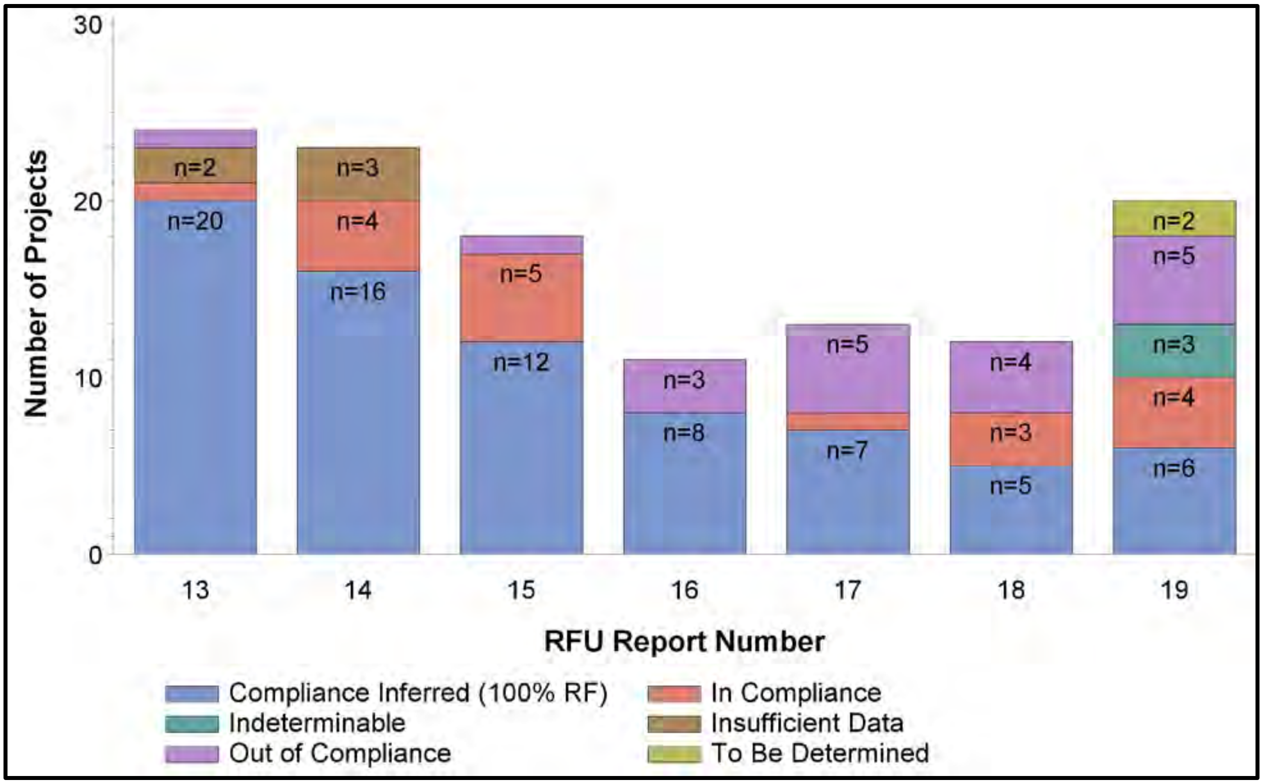
The capacity of RFUR and Other RFU projects, and the combined total (RFU projects) covered by each RFU report is depicted graphically in Figure 1.

Figure 1: Project Capacity Trend (RFU Reports 1–19)



While all RFUR projects are allowed to use as much as 25 percent non-renewable fuel, 43 percent of RFUR projects operate completely from on-site renewable fuel resources. Up to and including RFU Report No. 12, there had been no instances where available data indicated non-compliance with the Program's renewable fuel use requirements. However, note that prior to RFU Report No. 13 some data were not available to evaluate compliance of all dual-fuel projects. The current report contains five instances of non-compliance with these requirements. Figure 2 shows the history of compliance back to RFU Report No. 13 for all projects that were subject to the renewable fuel use requirement when the respective report was written.

Figure 2: History of Compliance with RFU Requirement

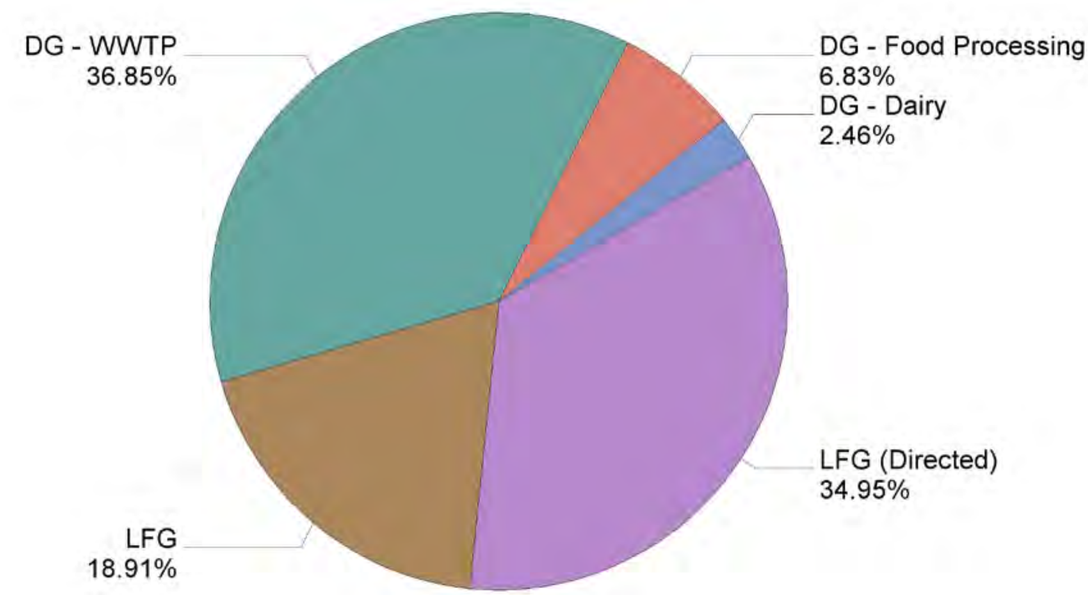


* This table contains information limited to systems that are subject to the renewable fuel use requirement – systems under warranty and operational for at least one calendar year during each RFU Report's specific reporting period. Other systems are excluded from this figure.

** No data label is shown when n=1

RFU projects typically use biogas derived from landfills or anaerobic digestion processes that convert biological matter to a renewable fuel source. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert wastes from these facilities to biogas. Figure 3 shows a breakout of RFU projects as of December 31, 2011, by source of biogas (e.g., landfill gas, dairy digester gas, food processing digester gas, etc.) on a rebated capacity basis. It illustrates that the majority of biogas used in SGIP RFU projects is derived from landfills and wastewater treatment plants, with 54 and 37 percent, respectively. The recently completed directed biogas projects have noticeably increased the proportion of projects using landfill gas. Dairy digesters provide the smallest contribution at two percent of the total rebated RFU project capacity.

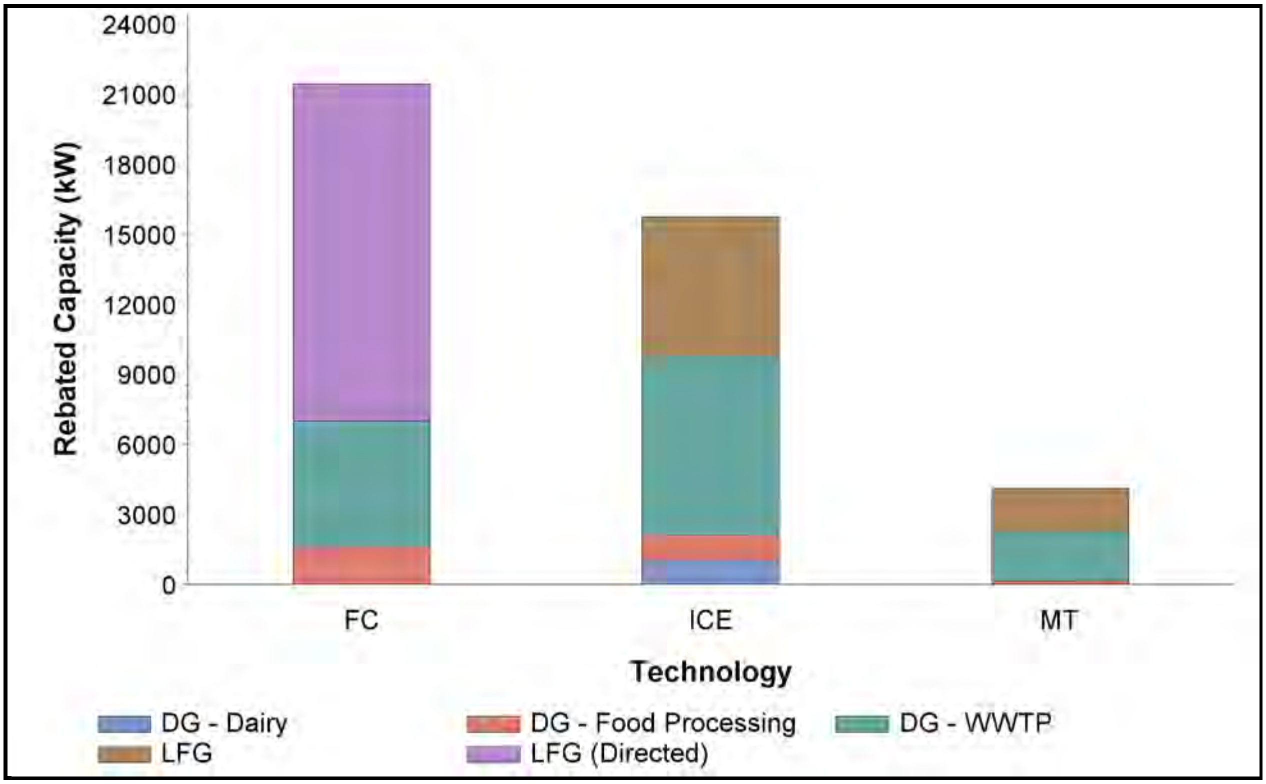
Figure 3: Renewable Fuel Use Project Rebated Capacity by Fuel Type



LFG = landfill gas; WWTP = wastewater treatment plants; DG=digester gas

Figure 4 provides a breakdown of the relative contribution of the different biogas fuels by prime mover technology. Several observations can be made from examining Figure 4. IC engines and fuel cells are the dominant technologies with 37 and 54 percent of rebated capacity, respectively. Each technology uses a similar proportion of the various fuel sources, with the exception that IC engines are used exclusively with dairy digester sourced fuel. RFU Report No. 19 marks the third appearance of directed biogas projects installed under the SGIP; all of these projects are fuel cells utilizing directed biogas sourced from landfills. These directed biogas projects have increased the prominence of fuel cells as a prime mover technology.

Figure 4: Contribution of Biogas Fuel Type by Prime Mover Technology



LFG = landfill gas; WWTP = wastewater treatment plants; MT = micro-turbines; ICE = internal combustion engine; FC = fuel cells; DG = digester gas

Cost Data

Itron also analyzed project cost data available for the renewable and non-renewable SGIP projects completed to date. Average costs of renewable projects were higher than the average costs of non-renewable projects – however the combined influence of relatively small sample sizes and substantial variability preclude us from estimating incremental costs for future SGIP participants that are accurate enough to be used directly for program incentive design purposes.

Confidence intervals estimated for the entire population of SGIP participants (both past and future) are very large. There was a limited quantity of cost data for fuel cells and IC engines. This limited amount of data increases the uncertainty associated with estimates of population mean costs of fuel cells and IC engines. As a result, it is impossible to say with 90 percent confidence that the populations mean costs of renewable IC engines and fuel cells are any higher than the population mean costs of non-renewable IC engines and fuel cells. This lack of confidence suggests that data for past projects should not be used as the sole basis for SGIP design elements affecting future participants. Engineering estimates and budget cost data continue to be more suitable for this purpose at this time.

2. Summary of Completed RFUR Projects

There were twenty new RFUR SGIP projects completed during the subject six-month reporting period. Thirteen projects were fuel cells ranging in size from 100 kW to 900 kW and fueled by directed biogas. Three projects were IC engines ranging in size from 150 kW to 364 kW. A total of 86 RFUR projects had been completed as of December 31, 2011. A list of all SGIP projects utilizing renewable fuel (RFUR and Other RFU) is included as Appendix A.

The 86 completed RFUR projects represent approximately 37.2 MW of installed generating capacity. The prime mover technologies used by these projects are summarized in Table 2. Fuel cells and IC engines each account for almost 91 percent of RFUR rebated capacity, with microturbines making up the remaining 9 percent. The average sizes of fuel cell and IC engine projects are more than three times as large as the average microturbine project size.

Table 2: Summary of Prime Movers for RFUR Projects

Prime Mover	Num. of Projects	Total Rebated Capacity (kW)	Average Rebated Capacity Per Project (kW)*
FC	44	20,170	458
MT	18	3,220	179
ICE	24	13,846	577
Total	**86**	**37,236**	**433**

FC = fuel cell; MT = micro-turbine; ICE = internal combustion engine
* Represents an arithmetic average

Many of the RFUR projects recover waste heat even though they are exempt from heat recovery requirements. Waste heat recovery incidence by renewable fuel type is summarized in Table 3. Verification inspection reports obtained from PAs and information from secondary sources such as direct contact with the participant, technical journals, industry periodicals, and news articles indicate that 39 of the 86 RFUR projects recover waste heat. All but two of the 35 digester gas systems include waste heat recovery.[9] Waste heat recovered from digester gas systems is generally used to pre-heat waste water sludge prior to being pumped to digester tanks. Conversely, 17 of 49 landfill gas systems include waste heat recovery. In addition, those landfill gas systems that do recover heat do not use it directly at the landfill site. Instead, the landfill gas is piped to an adjacent site that has both electric and thermal loads, and the gas is used in a prime

[9] In several RFU reports up to and including RFU Report No. 15 three (3) projects were incorrectly reported as <u>not</u> including heat recovery. This error resulted from misinterpretation of contents of Installation Verification Inspection Reports.

mover at that site. None of the 35 completed directed biogas projects include waste heat recovery.[10]

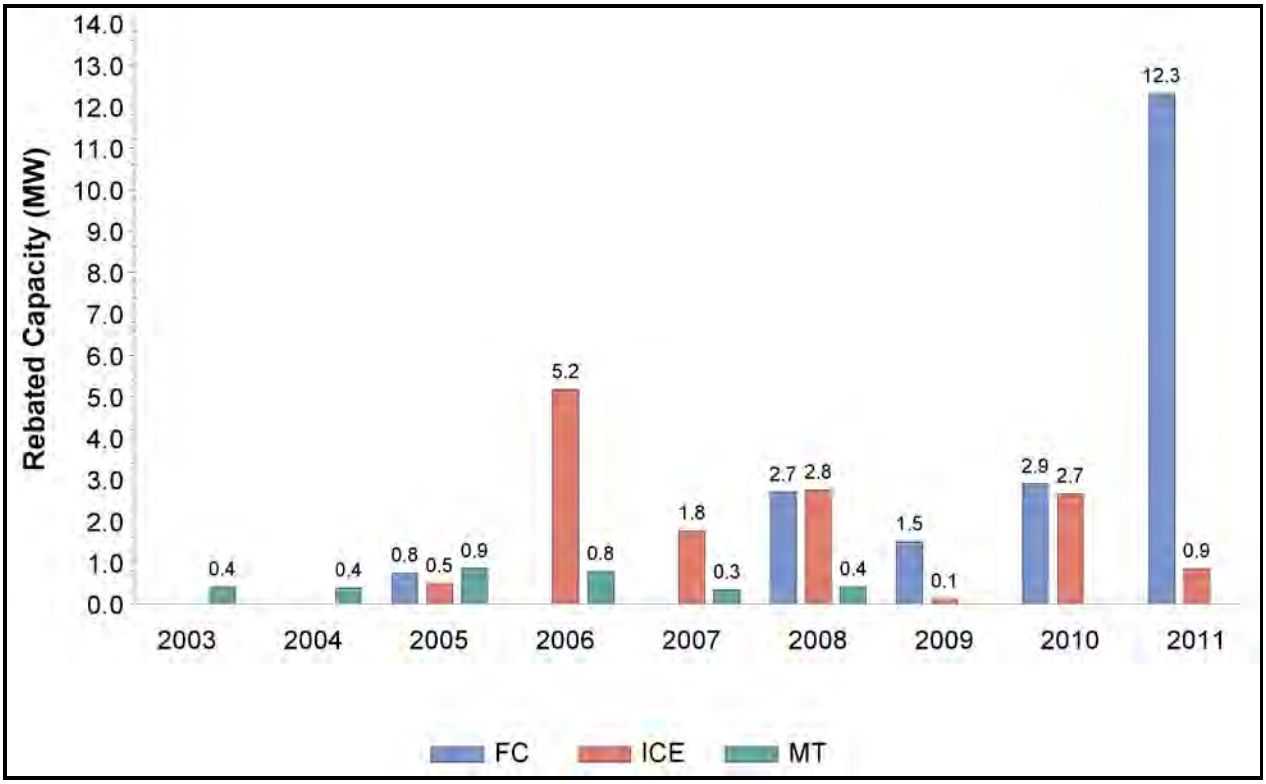
Table 3: Summary of Waste Heat Recovery Incidence by Type of Renewable Fuel for RFUR Projects

Renewable Fuel Type	Total No. of Sites	Sites With Heat Recovery	Sites Without Heat Recovery
Digester Gas	37	35	2
Landfill Gas	14	4	10
Landfill Gas (Directed)	35	0	35
Total	**86**	**39**	**47**

Figure 5 shows the total renewable fuel capacity for each year by technology. The peak project year for internal combustion engines was 2006 for a total capacity of 5.1 MW. The 2010 and 2011 fuel cell capacity represents the directed biogas projects that came on-line with a peak capacity of 12.0 MW in 2011.

[10] In general, above-ground digesters have a built-in thermal load as they operate better if heated. Landfill gas and covered lagoon operations do not typically use recovered waste heat to increase the rate of the anaerobic digestion process.

Figure 5: Rebated RFUR Capacity by Technology and Project Year



3. Fuel Use at RFUR Projects

RFUR projects are allowed to use a maximum of 25 percent non-renewable fuel; the remaining 75 percent must be renewable fuel. The period during which RFUR projects are obliged to comply with this requirement is specified in the SGIP contracts between the host customer, the system owner, and the PAs. Specifically, this compliance period is the same as the equipment warranty requirement. Microturbine and IC engine systems must be covered by a warranty of not less than three years. Fuel cell systems must be covered by a minimum five-year warranty. Therefore, the fuel use requirement period is three or five years, depending on the technology type. The SGIP applicant must provide warranty (and/or maintenance contract) start and end dates in the Reservation Confirmation and Incentive Claim Form.

Facilities are grouped into three categories in assessing renewable fuel use compliance:

- "Dedicated" RFU facilities located where biogas is produced (e.g., wastewater treatment facilities, landfill gas recovery operations, etc.) and the biogas is the only fuel source used for powering the RFU system;

- "Blended" RFU facilities located where biogas is produced that use a blend of biogas and non-renewable fuel (e.g., natural gas); and
- "Directed" RFU facilities, located somewhere other than where biogas is produced and not necessarily directly receiving any of the biogas.

For the 37 RFU facilities where biogas was produced and acted as the only fuel source for the RFU system, the facility was automatically in compliance. For dual-fueled RFU facilities using both renewable and non-renewable fuel, assessing compliance requires information on the amount of biogas consumed relative to the amount of non-renewable fuel consumed on-site. It is not possible to use the same method in assessing compliance of directed biogas projects as that used for assessing compliance of "blended" RFU projects. In "blended" RFU projects using biogas produced on-site, the metered amount of non-renewable fuel is used to determine if it is less than or equal to 25% of the total annual energy input to the RFU facility. However, in directed biogas RFU projects, metering of SGIP systems captures total fuel use only; it provides no information on how much biogas was actually produced and allocated to the project.

Assessing compliance of directed biogas projects requires information about off-site biogas production and subsequent allocation to customers that may or may not be SGIP participants. In this report, compliance of these projects was assessed by comparing a project's total metered natural gas consumption data to the biogas amount purchased as shown by invoices. Compliance of directed biogas projects was found to fall into one of three categories:

- In Compliance (Conditional): Analysis of metered natural gas consumption data and renewable fuel invoices for the reporting period indicate that renewable fuel was purchased to account for at least 75% of the project's total fuel consumption. A final compliance finding would require collection of substantially more information to validate contents of renewable fuel invoices. Collection of this information was outside the scope of this report.
- Compliance Indeterminable: Compliance could not be determined at the site-specific level based on currently available information. This was found to be the case when the renewable fuel invoices provided to Itron applied to a fleet of projects rather than a specific project.
- Compliance to be Determined: Metered fuel consumption data required to make a compliance assessment are not yet available from the gas utility company. These data are expected to become available in the future.

A detailed discussion of the transactions and complications that arise when evaluating compliance of directed biogas projects was presented in RFU Report No. 17.

Fuel supply and contract status for RFUR projects are summarized in Table 4. Only 50 of the total 86 RFUR projects had active warranty status. Thirty-six RFUR projects (almost half of all RFUR projects) had an expired warranty status. Of the 50 RFUR projects with active warranties, six operated solely on renewable fuel. By definition, all six of those RFUR projects are in compliance with SGIP renewable fuel use requirements.

Table 4: Summary of Fuel Supplies and Warranty Status for RFUR Projects

Fuel Supply	Warranty/Renewable Fuel Use Requirement Status					
	Active		Expired		Total	
	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)
Renewable only	6	2,955	31	11.523	37	14,478
Nonrenewable & Onsite Renewable	9	5,690	5	2,648	14	8,338
Nonrenewable & Offsite, Directed Renewable	35	14,420	-	-	35	14,420
Total	**50**	**23,065**	**36**	**14,171**	**86**	**37,236**

In addition, Table 4 shows that 37 of the total 86 RFUR sites (both those with expired or active warranties) obtain 100 percent of their fuel from renewable resources. Information on fuel use for the remaining 49 blended renewable and directed biogas projects (both active and expired) is presented below.

Dual-fueled RFUR Projects In Compliance

During this reporting period, four of the dual-fueled projects were found to be in compliance with SGIP renewable fuel use requirements based on analysis of metered data.[11]

- **PG&E A-1490**. This 600 kW fuel cell project came on-line in April 2008. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. Biogas use is metered by the participant. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation. Based on these estimates, Itron believes natural gas usage during the current reporting period did not exceed 12 percent of the total annual fuel input and the system was in compliance with SGIP renewable fuel use provisions.

[11] For directed biogas projects the reported findings are conditional. A final compliance finding would require collection of substantially more information to validate contents of renewable fuel invoices. Collection of this information was outside the scope of this report.

- **PG&E A-1749.** This 130 kW IC engine system came on-line in November 2009. The system uses renewable fuel from a wastewater treatment plant digester and recovers waste heat from the engine to preheat the digester sludge. Itron assumed an electrical conversion efficiency of 31 percent to estimate total fuel use during periods of electricity generation. Based on these estimates and an estimated biogas energy content of 650 Btu/SCF, Itron believes natural gas usage during the current reporting period did not exceed 18 percent of the total annual fuel input. The system was in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SDREO-0351-07.** This 560 kW IC engine system came on-line in April 2010. The system is located at a waste water treatment facility and utilizes the anaerobic digester gas from five digesters on-site to provide base load electric power to the treatment facility. When sufficient digester gas is not available to run this system at full load, natural gas is mixed in. Electrical output, natural gas consumption, and digester gas consumption data are being collected by the host customer and were provided to Itron. Based on the data provided, the natural gas usage during the reporting period did not exceed 22 percent of the total energy consumed. The project was in compliance with SGIP renewable fuel use provisions for this reporting period.
- **PG&E 1802.** This 400 kW fuel cell project utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2010 and therefore is required to comply with SGIP renewable fuel use requirements. Itron has obtained directed biogas invoices from January 2011 through December 2011. Itron has also obtained natural gas consumption data from the manufacturer for the entire reporting period. A comparison of the natural gas consumption data and the renewable fuel invoices shows that renewable fuel purchases amounted to 80% of total fuel consumption.

Dual-fueled RFUR Projects Not In Compliance

Five projects were found to be using more non-renewable fuel than allowed on an annual fuel input basis. For some of these projects it was necessary to estimate electrical conversion efficiency because metered biogas consumption data were not available.[12]

- **SCE PY06-062.** This 900 kW fuel cell system came on-line in March 2008. The system is located at a wastewater treatment facility and utilizes renewable fuel produced by a digester system. Metered electric generation and natural gas consumption data were

[12] In these calculations an electrical conversion efficiency of 33 percent was assumed. The intent was to develop an efficiency likely to be lower than the actual efficiency. If the actual efficiency is higher than 33 percent (which is likely), then the actual non-renewable fuel use is higher than the estimated percent.

obtained from the SGIP participant. Itron assumed an electrical conversion efficiency of 33 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, Itron believes natural gas usage during the current reporting period exceeded 25 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

- **SCE PY10-002.** This project is a 750 kW fuel cell system consisting of three 250 kW stacks, of which only two are rebated as dual fueled systems. The system is located at a waste water treatment plant and at the time of the SCE installation verification inspection was capable of producing sufficient anaerobic digester gas (ADG) to run two of the units using 100% ADG. Itron assumed an electrical conversion efficiency of 33 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, Itron believes natural gas usage during the current reporting period exceeded 33 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCG 2006-012.** This 900 kW fuel cell project came on-line in December 2009 and consists of three 300 kW fuel cells. The system is located at a wastewater treatment facility and utilizes renewable fuel produced from two digesters and natural gas from SCG. These digesters are provided sewage sludge and fat, oil, and grease as feedstock. The fat, oil, and grease feedstock comes from local restaurants and is supplied by a vendor under a contractual agreement. No description of how or when natural gas is used by this system was included in SCG's installation verification inspection report. Itron received metered electric generation and natural gas consumption data from the SGIP participant. In addition the participant is monitoring biogas usage. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation. Based on these estimates, the natural gas usage during the current reporting period exceeded 73 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCG 2006-036.** This 1200 kW fuel cell system came on-line in October 2008 and is located at a wastewater treatment facility and utilizes renewable fuel produced by a digester system. A fuel blending system controls the mix of renewable and non-renewable fuel. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. In addition the participant is monitoring biogas usage. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation. Based on these estimates, Itron believes natural gas usage during the current reporting period exceeded 48 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

- **SCG 2008-003.** This 600 kW fuel cell project came on-line in December 2009 and consists of two 300 kW fuel cells. The system utilizes renewable fuel produced from onion feedstock and natural gas from SCG. At the time of the SCG installation verification inspection, the fuel cells were using a 21 percent natural gas and 79 percent renewable fuel mix. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. In addition, the participant is monitoring biogas usage. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation. Based on these estimates, the natural gas usage during the current reporting period exceeded 27 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

Dual-Fueled RFUR Project Site-Specific Compliance Status Indeterminable

A dual-fueled RFUR project is assigned compliance status "Indeterminable" if its compliance verification is required but information necessary to draw conclusions about site-specific compliance was not available. The available information was sufficient to enable calculating renewable fuel use at the fleet level only.

- **PG&E 1810, PG&E 1811, and PG&E 1812.** These three 400 kW fuel cell projects (1,200 kW total) utilize directed biogas from a landfill and natural gas. The projects became operational in November of 2010 and therefore are required to comply with SGIP renewable fuel use requirements. Itron has obtained directed biogas invoices from January 2011 through December 2011. Itron has also obtained natural gas consumption data from the manufacturer for the entire reporting period. While the metered data are available for each individual project, the directed biogas purchases are made for all three projects combined and do not provide a project-specific differentiation. Based on the information available this fleet of projects appears to be using 87% renewable fuel, but its compliance at the project level is indeterminable.

Dual-Fueled RFUR Project Compliance Status To Be Determined

A dual-fueled RFUR project is assigned compliance status "To Be Determined" if its compliance verification is required but Itron did not have sufficient information. There are two directed biogas projects in this category.

- **SDREO-0369-10.** This 400 kW fuel cell project utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2010 and therefore is required to comply with SGIP renewable fuel use requirements. Itron has obtained directed biogas invoices from January 2011 through December 2011. Natural gas consumption data are expected to be available from utility metering but have not yet been received. The information available at the time this report was prepared is not sufficient to determine compliance with renewable fuel use requirements.

- **SDREO-0370-10.** This 400 kW fuel cell project utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2010 and therefore is required to comply with SGIP renewable fuel use requirements. Itron has obtained directed biogas invoices from January 2011 through December 2011. Natural gas consumption data are expected to be available from utility metering but have not yet been received. The information available at the time this report was prepared is not sufficient to determine compliance with renewable fuel use requirements.[13]

Dual-Fueled RFUR Project Compliance Status Not Applicable

A dual-fueled RFUR project is assigned compliance status "Not Applicable" if it has not yet been operational for a complete calendar year, or if its warranty has expired. There are 29 directed-biogas fuel cells and six blended renewable fuel cells in this category.

Of the 29 directed-biogas systems, eight appear to be on track to use no more than 25% non-renewable fuel once they have been operational for a complete calendar year. For the remaining systems, a preliminary compliance assessment was not attempted.

The following is a summary of projects that are not yet applicable with respect to renewable fuel use requirements.

Not Yet Operational for a Complete Calendar Year

- **PG&E 1805.** This 200 kW fuel cell project utilizes directed biogas from a landfill and natural gas. The system became operational in January of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCG 2010-012.** This 1 MW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in January of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1859.** This 500 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in March of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.

[13] SDREO projects 0369-10 and 0370-11 became operational in December of 2010 but were not included in RFUR reports # 17 and # 18. Due to ongoing improvements to the statewide project tracking system, Itron was not aware of these completions until after report # 18 was submitted.

- **PG&E 1871.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in March of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCE PY10-004.** This 800 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in March of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1849.** This 500 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in March of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1856.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in May of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1853.** This 600 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in May of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1886.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in May of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1882.** This 400 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in May of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1885.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in May of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1851.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in June of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1878.** This 500 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in June of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCE PY09-003.** This 300 kW fuel cell is one of four systems installed at the City of Tulare water pollution control facility. The system utilizes a combination of waste water digester gas and natural gas. The system became operational in August of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCE PY10-009.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in August of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.

- **SCE PY10-012.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in August of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCE PY10-022.** This 400 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in August of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCE PY10-023.** This 400 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in August of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1850.** This 420 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1874.** This 500 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1892.** This 210 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1893.** This 210 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCG 2010-005.** This 100 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCG 2010-011.** This 900 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1855.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in September of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCG 2010-018.** This 420 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCG 2010-019.** This 420 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.

- **SCG 2010-020.** This 420 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCG 2010-015.** This 420 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1858.** This 300 kW fuel cell utilizes directed biogas from a landfill and natural gas. The system became operational in December of 2011 and therefore is not required to comply with SGIP renewable fuel use requirements yet.

Warranty Expired

- **SCE PY03-092.** This 500 kW fuel cell project uses natural gas for backup fuel supply and piloting purposes. The fuel cell system is composed of two molten carbonate fuel cells, each of which is rated for 250 kW of electrical output. Renewable fuel used by this system is produced as a by-product of a municipal wastewater treatment process. A natural gas metering system has been installed by SCG to monitor natural gas usage. Biogas use is not metered. In December of 2010 the fuel cells were removed and decommissioned after the warranty period had lapsed. During the period when data were provided and the system was under contract the actual contribution of non-renewable fuel never exceeded 25 percent on an annual fuel input basis.
- **SCE PY03-017.** This IC engine system was designed to use natural gas for back-up and piloting purposes. The SGIP participant provided metered electric generation, biogas consumption, and natural gas consumption data for previous reporting periods. However, in Q2 2008 the participant's SGIP contract reached the end of its term and data were no longer available from this participant. During the period when data were provided and the system was under contract the actual contribution of non-renewable fuel never exceeded 25 percent on an annual fuel input basis.
- **SCE PY04-158 and SCE PY04-159.** These two systems are located at the same wastewater treatment facility and utilize renewable fuel produced by the same digester system. The two projects are grouped together here because they share a common fuel blending system. The fuel blending system controls the mix of renewable and non-renewable fuel. In the second quarter of 2008 the participant's SGIP contract reached the end of its term and no metered data have been available to assess the actual fuel mix since this time. In SCE's September 2006 installation verification inspection reports, the participant reported that the systems were using 80 percent digester gas and 20 percent natural gas.
- **PG&E A-1313**. This 240 kW system consists of eight 30 kW microturbines installed at a wastewater treatment facility and uses heat recovered from the system to warm the

digesters. Metered daily electric generation, biogas consumption, and natural gas consumption data were obtained from the SGIP participant for this microturbine system. The system has been off during the last three reporting periods.

Overall (renewable-only and dual-fuel), nine (64 percent) of the 14 RFUR projects remaining under warranty for which renewable fuel use compliance is applicable during this reporting period comply with the SGIP 25 percent non-renewable requirement. A summary of renewable fuel use compliance for the 49 dual-fuel systems is presented in Table 5.

Table 5: Fuel-Use Compliance of Dual-Fueled RFUR Projects (Projects Utilizing Non-Renewable Fuel)

PA	Res No.	Incentive Level	Technology	Fuel Type	Size (kW)	Date Operational	Annual Natural Gas Energy Flow (MM Btu) †	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements?
PGE	1490	2	FC	DG - WWTP	600	4/24/2008	4,347	87%	Active	Yes
PGE	1749	3R	ICE	DG - WWTP	130	11/9/2009	717	82%	Active	Yes
CCSE	SDREO-0351-07	2	ICE	DG - WWTP	560	4/16/2010	10,687	78%	Active	Yes
PGE	1802	2	FC	Landfill Gas (DBG)	400	12/22/2010	24,667	80%	Active	Yes (Conditionally)[¥]
PGE	1810	2	FC	Landfill Gas (DBG)	400	11/10/2010	24,793	Not Available	Active	Indeterminable
PGE	1811	2	FC	Landfill Gas (DBG)	400	11/10/2010	24,513	Not Available	Active	Indeterminable
PGE	1812	2	FC	Landfill Gas (DBG)	400	11/10/2010	25,137	Not Available	Active	Indeterminable
CCSE	CCSE-0369-10	2	FC	Landfill Gas (DBG)	400	12/31/2010	Not Available	Not Available	Active	TBD
CCSE	CCSE-0370-10	2	FC	Landfill Gas (DBG)	400	12/31/2010	Not Available	Not Available	Active	TBD
SCG	2006-036	2	FC	DG - WWTP	1200	10/27/2008	10,100	51%	Active	No
SCE	PY06-062	2	FC	DG - WWTP	900	3/4/2008	7,664	74%	Active	No
SCG	2008-003	2	FC	DG - Food Processing	600	12/14/2009	5,579	72%	Active	No
SCG	2006-012	2	FC	DG - WWTP	900	12/18/2009	20,638	27%	Active	No
SCE	PY10-002	2	FC	DG - WWTP	500	10/31/2010	1,439	66%	Active	No
PGE	1805	2	FC	Landfill Gas (DBG)	200	1/18/2011	Not Available	Not Available	Active	Not Applicable ‡‡

PA	Res No.	Incentive Level	Technology	Fuel Type	Size (kW)	Date Operational	Annual Natural Gas Energy Flow (MM Btu) †	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements?
SCG	2010-012	2	FC	Landfill Gas (DBG)	1000	1/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1859	2	FC	Landfill Gas (DBG)	500	3/11/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1871	2	FC	Landfill Gas (DBG)	300	3/14/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY10-004	2	FC	Landfill Gas (DBG)	800	3/23/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1849	2	FC	Landfill Gas (DBG)	500	5/9/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1856	2	FC	Landfill Gas (DBG)	300	5/9/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1853	2	FC	Landfill Gas (DBG)	600	5/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1882	2	FC	Landfill Gas (DBG)	400	5/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1886	2	FC	Landfill Gas (DBG)	300	5/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1885	2	FC	Landfill Gas (DBG)	300	5/31/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1851	2	FC	Landfill Gas (DBG)	300	6/29/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1878	2	FC	Landfill Gas (DBG)	500	6/29/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY10-009	2	FC	Landfill Gas (DBG)	300	8/8/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY10-012	2	FC	Landfill Gas (DBG)	300	8/8/2011	Not Available	Not Available	Active	Not Applicable ‡‡

PA	Res No.	Incentive Level	Technology	Fuel Type	Size (kW)	Date Operational	Annual Natural Gas Energy Flow (MM Btu) †	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements?
SCE	PY10-022	2	FC	Landfill Gas (DBG)	400	8/8/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY10-023	2	FC	Landfill Gas (DBG)	400	8/8/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY09-003	2	FC	DG - WWTP	300	8/30/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1850	2	FC	Landfill Gas (DBG)	420	9/7/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1874	2	FC	Landfill Gas (DBG)	500	9/7/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1892	2	FC	Landfill Gas (DBG)	210	9/7/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1893	2	FC	Landfill Gas (DBG)	210	9/7/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-005	2	FC	Landfill Gas (DBG)	100	9/20/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-011	2	FC	Landfill Gas (DBG)	900	9/21/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1855	2	FC	Landfill Gas (DBG)	300	9/29/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-018	2	FC	Landfill Gas (DBG)	420	12/15/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-019	2	FC	Landfill Gas (DBG)	420	12/15/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-020	2	FC	Landfill Gas (DBG)	420	12/15/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-015	2	FC	Landfill Gas (DBG)	420	12/16/2011	Not Available	Not Available	Active	Not Applicable ‡‡

PA	Res No.	Incentive Level	Technology	Fuel Type	Size (kW)	Date Operational	Annual Natural Gas Energy Flow (MM Btu) †	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements?
PGE	1858	2	FC	Landfill Gas (DBG)	300	12/29/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY03-092	1	FC	DG - WWTP	500	3/11/2005	Decommissioned	Decommissioned	Expired	Not Applicable ‡
SCE	PY03-017	3R	ICE	DG - WWTP	500	5/11/2005	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡
SCE	PY04-158	3R	ICE	DG - WWTP	704	10/25/2006	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡
SCE	PY04-159	3R	ICE	DG - WWTP	704	10/26/2006	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡
PGE	1313	3R	MT	DG - WWTP	240	3/6/2007	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡

* Since assignment of a project's operational date is subject to individual judgment, the incentive payment date as reported by the PAs is used as a proxy for the operational date for reporting purposes.

† This field represents the natural gas consumption during the 12-month period ending December 31, 2010. The basis is the lower heating value (LHV) of the fuel.

‡ SGIP renewable fuel use requirements are not applicable to projects no longer under warranty

** In RFU Reports No. 9 and No. 10 this project's size was reported as 296 kW. That was the capacity used in incentive calculations. The actual physical size of the system is 704 kW. In this particular circumstance, there were two separate applications, both 704 kW of physical capacity, for a total combined capacity of 1,408 kW. The maximum total incentive is one MW. As a result, one application was rebated in full (rebated capacity of 704 kW) while the second application was rebated up to the remainder of the eligible kW (296 kW). The result was a much lower value for rebated capacity than physical capacity.

†† In RFU Reports No. 9 through No. 13 this project's Operational Date was incorrectly reported as 11/15/2005. That date is an estimate of when the system began operating. For this report the basis of Operational Date values is incentive payment date as described above in footnote 13.

‡‡ This site has not been operational for a year, thus the issue of compliance is not yet applicable.

¥ A final compliance finding would require collection of substantially more information to validate contents of renewable fuel invoices. Collection of this information was outside the scope of this report.

4. Greenhouse Gas Emissions Impacts

Due to increased interest in the GHG emission aspects of biogas projects, information regarding GHG emission impacts is presented in this section. The GHG emission information presented here is derived from data used to prepare the SGIP Tenth-Year Impact Evaluation Final Report. Additionally, key factors that could influence GHG emission impacts from renewable fuel projects in the future are discussed.

Table 6 presents capacity-weighted average GHG emission results developed for 2010.[14] Results in Table 6 suggest one important observation: The assumed baseline for the biogas (i.e., whether the biogas would have been vented to the atmosphere or flared) is the most influential determinant of GHG emission impacts.[15] This is due to the global warming potential of methane (CH_4) vented directly into the atmosphere, which is much higher than the global warming potential of CO_2 resulting from the flaring of CH_4.

Table 6: Summary of CO_2 Emission Impacts from SGIP Biogas Projects in 2010

Baseline Biogas Assumption	Prime Mover Technology	Capacity-Weighted Average (Tons CO_2 /MWh)
Flare	FC	-0.41
	IC Engine	-0.51
	MT	-0.42
Vent	IC Engine	-4.46

FC = fuel cell; IC Engine = internal combustion engine; MT = microturbine

[14] The GHG emission results discussed in this report differ from those presented in the SGIP Tenth Year Evaluation Final Report (July 7, 2011). The differences reflect an updated analytic methodology for the GHG emissions baseline for biogas. The prior methodology underestimated GHG emission reductions by not accounting for CO_2 not emitted through avoided flaring.

[15] The baseline treatment of biogas is an influential determinant of GHG emission impacts for renewable-fueled SGIP systems. Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared).

Simplifying assumptions underlying the above results include:

- Heat recovered from RFUR projects was used to satisfy heating load that otherwise would have been satisfied using biogas (e.g., in a boiler)[16]
- Estimates for GHG reductions from biogas projects were based solely on estimates of the methane content in the used biogas and did not take into account natural gas used by the biogas facilities
- A single representative electrical conversion efficiency was assumed for each technology.
  - Fuel Cell: 40%
  - IC Engine: 31%
  - Microturbine: 23%

All SGIP annual impact evaluations (Impact Evaluations) prior to the Ninth-Year (2009) Impact Evaluation assumed biogas baselines by type of biomass input and rebated capacity of system. Requirements regarding venting and flaring of biogas projects are governed by a variety of regulations in California. At the local level, venting and flaring at the different types of biogas facilities is regulated by California's 35 air quality agencies.[17] At the state level, the California Air Resources Board (CARB) provides guidelines for control of methane and other volatile organic compounds from biogas facilities.[18] At the federal level, New Source Performance Standards and Emission Guidelines regulate methane capture and use.[19]

Biogas baseline assumptions used to calculate GHG impact estimates for 2007-2009 were based on previous studies.[20] [21] Because of the importance of the baseline treatment of biogas in the GHG analysis, SGIP biogas facilities were contacted in 2009 to gather baseline-related information. This research suggested a venting baseline for dairy digesters and a flaring baseline

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16 Heat recovered from non-RFUR projects utilizing renewable fuel was assumed to displace natural gas. There are very few such projects. The first Program Year of the SGIP (2001) was the only one in which renewable-fueled systems were required to recover heat and meet system efficiency requirements of Public Utilities Code 218.5 (now 216.6).

17 An overview of California's air quality districts is available at: http://www.capcoa.org

18 In June of 2007, CARB approved the Landfill Methane Capture Strategy. See http://www.arb.ca.gov/cc/landfills/landfills.htm for additional information.

19 EPA's Landfill Methane Outreach Program provides background information on control of methane at the federal level. See: http://www.epa.gov/lmop/

20 California Energy Commission, *Landfill Gas-to-Energy Potential in California*, CEC Report 500-02-041V1, September 2002.

21 Simons, G., and Zhang, Z., "Distributed Generation From Biogas in California," presented at Interconnecting Distributed Generation Conference, March 2001.

for all other project types. For the 2009 and 2010 Impact Evaluations the biogas baseline was modified for WWTP and food processing SGIP projects smaller than 150 kW.

The evolution of biogas baseline assumptions is summarized in Table 7.

Table 7: Biogas Baseline Assumptions

Renewable Fuel Source	Facility Type*	Size of Rebated System (kW)	Impact Report	
			PY07-08	PY09-10
Digester Gas	WWTP	<150	Vent	Flare
		≥150	Flare	Flare
Digester Gas	Food Processing	<150	Vent	Flare
		≥150	Flare	Flare
Landfill Gas	LFG	All Sizes	Flare	Flare
Digester Gas	Dairy	All Sizes	Vent	Vent

* WWTP = Waste Water Treatment Plant; LFG = Landfill Gas

The equivalent tons of CO_2 emissions associated with SGIP systems for which flaring and venting baselines were assumed for 2010 are presented in Figure 6 and Figure 7. GHG emission impacts are depicted graphically as the difference between SGIP emissions and the total baseline emissions. Total baseline emissions exceed SGIP emissions in these two cases, hence a reduction in GHG emissions is attributed to participation in the SGIP.

Figure 6: Equivalent Tons of CO2 Emissions - Flaring Baseline

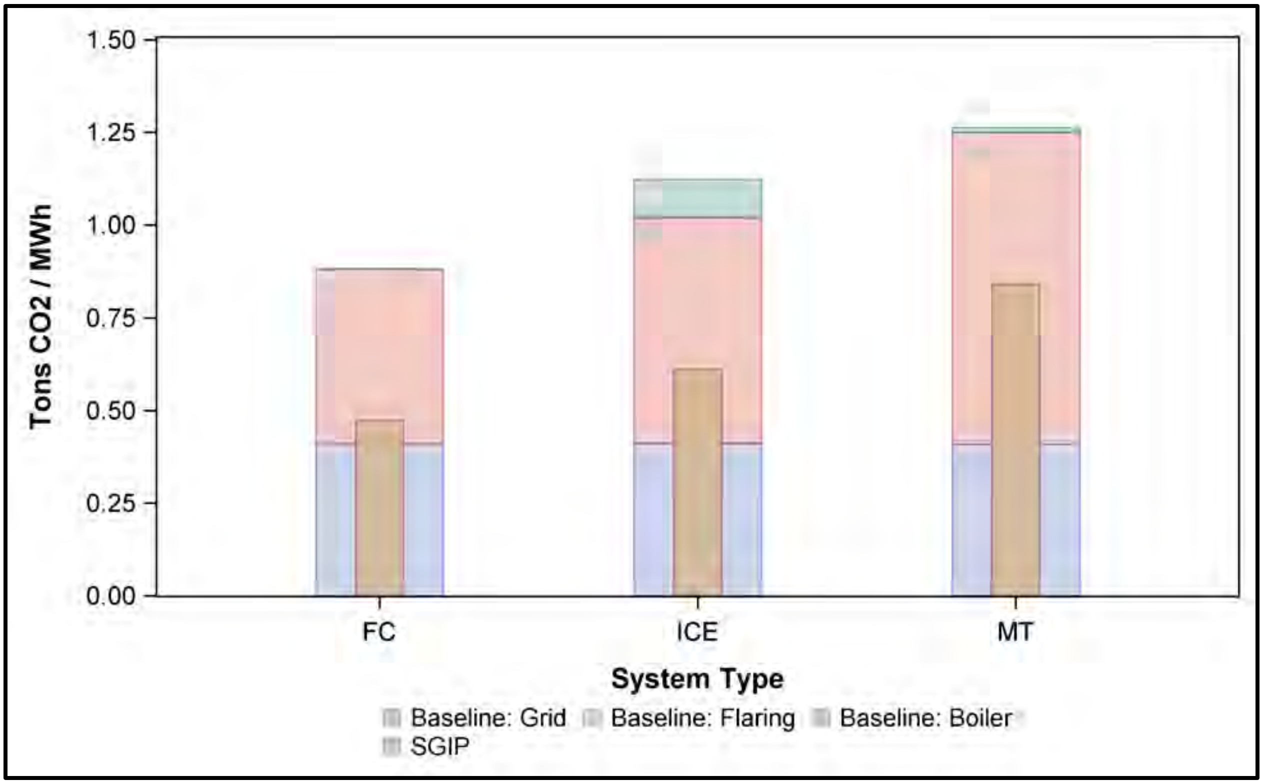
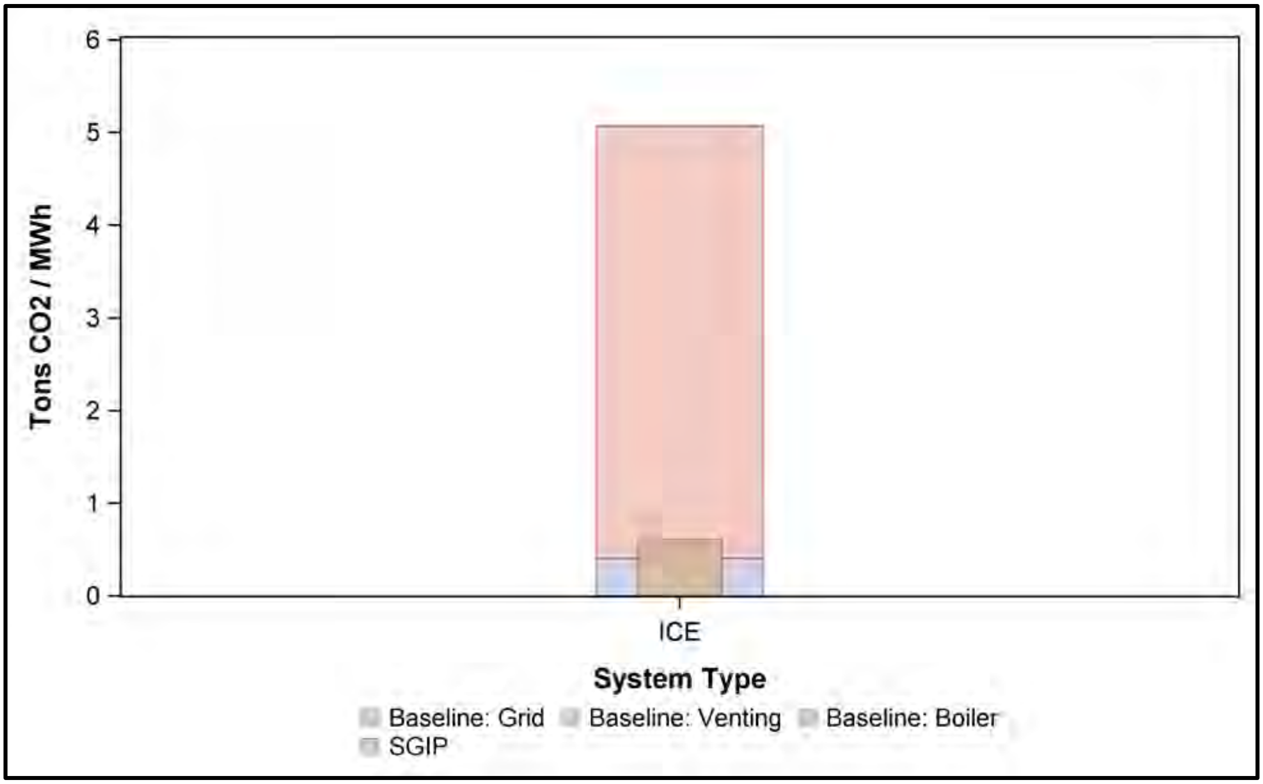


Figure 7: Equivalent Tons of CO2 Emissions – Venting Baseline



The baseline assumption (i.e., flaring versus venting) made for biogas used in SGIP systems is the factor exerting the greatest influence over estimates of GHG impacts. Biogas projects for which a venting baseline is assumed achieve significantly greater GHG reductions than those for which a flaring baseline is assumed.

5. Cost Comparison between RFU and Other Projects

Beginning in September 2002, RFUR projects were eligible for a higher incentive level than non-renewable projects.[22] The size of this incentive premium was designed to account for numerous factors, including:

- RFUR projects face higher fuel pre-treatment costs
- RFUR projects might not face heat recovery equipment costs
- RFUR projects do not face fuel purchase expenses

[22] In September 2002 RFUR projects were classified as “Level 3-R” projects. Since that time the definitions of Levels have changed numerous times. Itron has moved away from using incentive levels in the annual Impact Evaluation and Renewable Fuel Use reports because of the confusion caused by these changes

Concerns were expressed in CPUC Decision 02-09-051 that RFUR project costs could fall below non-renewable project costs as RFUR projects are exempt from waste heat recovery requirements. As a result, RFUR projects could potentially be receiving a greater-than-necessary incentive, which could lead to fuel switching. To address this concern, the CPUC directed SGIP PAs to monitor non-renewable project and RFUR project costs.

Eligible project costs from all completed SGIP projects provide the data for monitoring and analyzing differences in project costs. However, these are historical costs, raising a key question faced by the CPUC and other Program designers:

How accurately do the cost differences calculated for projects completed in the past represent the cost differences that are likely to be faced by Program participants in the future?

This question is difficult to answer and the answer depends on many factors, including:

1. The number of projects completed in the past.
2. The variability exhibited by cost data for the projects completed in the past.
3. The possible changes in system costs through time yielded by experience, economies of scale and/or technology innovation.

The following analysis provides insight into mean costs and cost differences due to renewable fuel use and heat recovery.

Eligible installed costs for all fuel cell, microturbine, and IC engine projects operational as of December 31, 2011, are summarized in Table 8, along with simple statistics of the data. The summary distinguishes between fuel type and heat recovery incidence to facilitate independent examination of the principal factors influencing costs of projects utilizing renewable fuel. Several of the groups comprise only a few projects and others have extreme variability in project costs, greater than an order of magnitude. Sample sizes and overall cost variability play a very important role in the ability to draw conclusions from the data. The combined influence of sample size and sample variability on the inferential statistics is discussed below in the section titled *Uncertainty Analysis*.

Table 8: Summary of Project Costs by Technology, Heat Recovery Provisions & Fuel Type

Tech	Includes Renewable Fuel?*	Includes Heat Recovery?	Num. of Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size - Wtd. Avg.
FC	Yes	Yes	11	4.51 – 11.00	9.41	8.13	2.37	7.52
FC	Yes	No	0	-	-	-	-	-
FC	Yes	Yes or No	11	4.51 – 11.00	9.41	8.13	2.37	7.52
FC	No	Yes	22	5.06 – 18.00	7.30	8.46	3.23	7.47
FC	No	No	5	8.71 - 11.30	9.63	9.84	0.93	9.92
FC	No	Yes or No	27	5.06 – 18.00	8.25	8.72	2.97	7.84
FC	DBG	No	35	6.08 - 18.20	11.20	10.70	2.24	10.46
ICE	Yes	Yes	24	1.08 - 7.58	2.76	3.00	1.51	2.92
ICE	Yes	No	2	1.71 - 2.87	2.29	2.29	0.82	2.71
ICE	Yes	Yes or No	26	1.08 - 7.58	2.76	2.94	1.47	2.90
ICE	No	Yes	229	0.85 - 10.70	2.30	2.60	1.32	2.30
MT	Yes	Yes	13	2.26 - 11.32	3.99	5.13	2.69	4.55
MT	Yes	No	10	1.23 - 5.39	3.61	3.47	1.27	2.89
MT	Yes	Yes or No	23	1.23 - 11.32	3.75	4.40	2.30	3.78
MT	No	Yes	115	0.70 - 8.40	3.23	3.35	1.32	3.26

FC = fuel cell; MT = microturbine; ICE = internal combustion engine; DBG = directed biogas.

* To assess the difference in costs between those technologies using renewable fuel resources versus those using only non-renewable fuels, fuel types are differentiated in Table 8 by identifying those using any amount of renewable fuel with a "Yes" classification.

The cost of waste heat recovery equipment and fuel clean-up may account for much of the difference between renewable and non-renewable project costs. The basis for heat recovery equipment and fuel clean-up equipment cost comparisons are described below.

Heat Recovery Equipment Costs

The cost difference due to heat recovery equipment can be evaluated by comparing costs of projects with heat recovery to the costs of otherwise similar projects without heat recovery. The analysis is limited to projects that use renewable fuel to keep that variable constant and since those are the projects of most interest in this report. Additionally, analysis is performed separately for each technology type. For example, the cost difference due to heat recovery equipment for microturbine projects is calculated as $5.13 minus $3.47, or $1.66.

$$\Delta Heat\,\mathrm{Re}\,\mathrm{cov}\,ery = \left(\begin{matrix} RFU \\ w/\,HR \end{matrix}\right) - \left(\begin{matrix} RFU \\ w/\,o\,HR \end{matrix}\right)$$

Equation 1

Where

RFU = renewable fuel use

HR = heat rate

w/ = with

w/o = without

Table 9: Cost Effect of Heat Recovery

Tech	Includes Renewable Fuel?*	Includes Heat Recovery?	Num. of Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size - Wtd. Avg.
FC	Yes	Yes	11	4.51 – 11.00	9.41	8.13	2.37	7.52
ICE	Yes	Yes	24	1.08 - 7.58	2.76	3.00	1.51	2.92
	Yes	No	2	1.71 - 2.87	2.29	2.29	0.82	2.71
	Increase due to Heat Recovery		-	-	0.47	0.71	0.69	0.21
MT	Yes	Yes	13	2.26 - 11.30	3.99	5.13	2.69	4.55
	Yes	No	10	1.23 - 5.39	3.61	3.47	1.27	2.89
	Increase due to Heat Recovery		-	-	0.38	1.66	1.42	1.66

The mean costs for heat recovery is higher than non-heat recovery systems. The statistical significance of these differences is examined later in this report with uncertainty analysis. Note there are no renewable fueled fuel cells that do not include heat recovery, so it is not possible to perform this analysis for fuel cells.

Fuel Treatment Equipment Costs

Renewable fueled projects utilize fuel treatment equipment, which is usually used for gas clean-up, such as removal of hydrogen sulfide. To examine whether this fuel treatment equipment significantly increases project costs, the differences in costs between renewable and non-renewable fueled projects are analyzed. However, we must take into account whether the project also includes heat recovery equipment to avoid influencing the results. The analysis is limited to projects with heat recovery for this reason and to maximize the sample size of non-renewable fueled projects. Any difference observed between the costs of these two groups could be due to the difference in provisions for fuel treatment. For example, the cost difference for fuel treatment equipment in IC engine projects is calculated as $3.00 minus $2.60, or $0.40.

$$\Delta Fuel\,Treatment = \begin{pmatrix} RFU \\ w/HR \end{pmatrix} - \begin{pmatrix} NG \\ w/HR \end{pmatrix} \qquad \textbf{Equation 2}$$

Where

NG = natural gas

Table 10: Cost Effect of Renewable Fuel Treatment Equipment

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	$/Watt Eligible Installed Costs: Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC	Yes	Yes	11	4.51 - 11.00	9.41	8.13	2.37	7.52
	No	Yes	22	5.06 - 18.00	7.30	8.46	3.23	7.47
	Increase due to RF Equipment		-	-	2.11	(0.33)	(0.86)	0.05
ICE	Yes	Yes	24	1.08 - 7.58	2.76	3.00	1.51	2.92
	No	Yes	229	0.85 - 10.70	2.30	2.60	1.32	2.30
	Increase due to RF Equipment		-	-	0.46	0.40	0.19	0.62
MT	Yes	Yes	13	2.26 - 11.30	3.99	5.13	2.69	4.55
	No	Yes	115	0.70 - 8.40	3.23	3.35	1.32	3.26
	Increase due to RF Equipment		-	-	0.76	1.78	1.37	1.29

The mean and median costs of renewable fueled ICE and MT projects are higher than non-renewable fueled projects. Interestingly, for renewable fueled fuel cells, the mean cost is lower while the median cost is higher than non-renewable systems. This is due to a skewed distribution of fuel cell project costs. Costs for all technology and fuel types display great variability, making it difficult to draw significant conclusions about cost differences for renewable fueled systems. Statistical significance of the results is further explored via uncertainty analysis later in this report.

Overall RFU Costs

An alternative and more general analysis of cost differences between renewable and non-renewable fueled projects is to compare costs of the two groups without regard to heat recovery provision. Note that all of the non-renewable fuel projects include heat recovery equipment, with the exception of a few fuel cell projects, and many of the renewable fuel projects include heat recovery even though many were not required to do so. By looking at the observed difference in costs of these two groups, it is possible to see the average overall influence of the different SGIP requirements for renewable and non-renewable projects. For example, the cost difference between renewable and non-renewable fueled IC engine projects is calculated as \$2.94 minus \$2.60, or \$0.34.

$$\Delta RFU = \left(\frac{RFU}{w/ or\; w/o\;\; HR}\right) - \left(\frac{NG}{w/HR}\right)$$

Equation 3

Table 11: Cost Effect of Renewable Fuel Use

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	\$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC	Yes	Yes or No	11	4.51 - 11.00	9.41	8.13	2.37	7.52
	No	Yes or No	27	5.06 - 18.00	8.25	8.72	2.97	7.84
	Increase due to RFU		-	-	1.16	(0.59)	(0.60)	(0.32)
ICE	Yes	Yes or No	26	1.08 - 7.58	2.76	2.94	1.47	2.90
	No	Yes	229	0.85 - 10.70	2.30	2.60	1.32	2.30
	Increase due to RFU		-	-	0.46	0.34	0.15	0.60
MT	Yes	Yes or No	23	1.23 - 11.30	3.75	4.40	2.30	3.78
	No	Yes	115	0.70 - 8.40	3.23	3.35	1.32	3.26
	Increase due to RFU		-	-	0.52	1.05	0.98	0.52

Uncertainty Analysis

This section augments the difference of means analysis with an uncertainty analysis that provides a confidence interval for the mean differences. The confidence intervals are calculated with the sample statistics (e.g., n, mean, and std. dev.) presented in Table 8. The presented confidence intervals are based on a 90 percent confidence level, meaning there is 90 percent confidence that the true mean difference falls within the stated range. Note that if the range spans across zero, it is possible that there is no difference in cost between the two groups being analyzed.

Microturbine Project Cost Comparisons

Cost comparison results for microturbines are summarized in Table 12. These data show, for instance, that the average incremental cost associated with presence of heat recovery was $1.66 per watt for SGIP participants with completed projects. When this value is used to estimate the incremental cost of heat recovery not only for completed projects but also for projects that will be completed in the future, it is necessary to summarize the uncertainty of the estimate.[23]

Table 12: Microturbine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	1.66	0.07 to 3.25
Fuel Treatment	1.78	1.05 to 2.51
RFU	1.05	0.47 to 1.63

The 90 percent confidence intervals presented in Table 12 summarize uncertainty in estimates of the incremental costs associated with several key physical differences for the population comprising projects already completed as well as those that will be completed in the future. For heat recovery, the lower bound of the confidence interval is just seven cents per watt. This counterintuitive result implies that systems without heat recovery might be nearly the same cost as those with it. The possibility of this unlikely result, along with the very large confidence interval, are likely simply due to the small quantity of, and considerable variability exhibited by cost data available for SGIP projects completed in the past. This is a representative example of the general rule that caution must be exercised when interpreting summary statistics when sample sizes are small.

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[23] Uncertainty is assessed by calculating confidence intervals around the point estimates. Standard statistical tests are used to describe the likelihood that the two samples underlying the two means used to calculate each incremental difference came from the same population. When n_1 & $n_2 \geq 30$, a z-Test is used to determine confidence intervals. When n_1 or $n_2 < 30$, a t-Test is used.

IC Engine Project Cost Comparisons

Cost comparison results for IC engine projects are summarized in Table 13. The differences between means are small in comparison to the variability exhibited by past costs of renewable fuel projects. This variability, combined with relatively small numbers of renewable fuel projects, results in very large confidence intervals. Each of the confidence intervals span across zero, meaning there is not 90% confidence that there is a difference in cost for the factors analyzed.

Table 13: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	0.71	-1.20 to 2.70
Fuel Treatment	0.40	-0.08 to 0.94
RFU	0.34	-0.11 to 0.85

Fuel Cell Project Cost Comparisons

Due to the sensitivity of fuel cells to contaminants in the gas stream, gas clean-up costs for fuel cells powered by renewable fuels—which contain sulfur, halide, and other contaminants—should be higher than gas clean-up costs for fuel cells operating with cleaner fuels, such as natural gas. Cost comparison results for fuel cells are summarized in Table 14. Results for the incremental difference due to heat recovery are not presented because all renewable fuel cell projects completed to date have included heat recovery even though they were not required to by the SGIP. The 90 percent confidence interval for fuel cells is very large, which is not surprising given the emerging status of this technology and the small number of facilities. Again, the confidence intervals span across zero and there is not 90% confidence that cost differences exist for the analyzed factors.

Table 14: Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	---	---
Fuel Treatment	-0.33	-2.46 to 1.76
RFU	-0.59	-2.46 to 1.38

Cost Comparison Summary

Comparison of the installed costs between renewable- and non-renewable-fueled generation systems operational as of December 31, 2011, reveals that average non-renewable generator costs have typically been lower than average renewable-fueled generator costs. However, these averages pertain to past Program participants. The fundamental question motivating examination of RFUR project costs is stated explicitly below:

Do SGIP project cost data for past participants suggest that project costs are changing in ways that could necessitate modification of incentive levels received by <u>future</u> *SGIP participants?*

Confidence intervals calculated for populations comprising both past *and* future SGIP participants are very large. In fact, these confidence intervals prevent drawing conclusions about cost differences in IC Engine and Fuel Cell projects; only Microturbine projects exhibit cost differences at 90% confidence. This suggests that data for past projects should not be used as the sole basis for SGIP design elements affecting future participants. Engineering estimates and budget cost data continue to be more suitable for this purpose at this time.

Appendix A

List of All SGIP Projects Utilizing Renewable Fuel

All SGIP projects supplied with renewable fuel are listed in Table 15. Renewable Fuel Use Requirement (RFUR) projects subject to renewable fuel use requirements and exempt from heat recovery requirements are identified in the column titled "RFUR Project?" Only a portion of these projects (57 percent) are also equipped with a non-renewable fuel supply. These projects are identified in the "Any Non-Renewable Fuel Supply?" column.

Table 15: SGIP Projects Utilizing Renewable Fuel

Res. No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
0007-01	SDREO	Level 3	MT	DG - WWTP	84	8/30/2002	No	No
PY02-055	SCE	Level 3R	MT	Landfill Gas	420	5/19/2003	Yes	No
PY01-031	SCE	Level 3	ICE	Landfill Gas	991	9/29/2003	No	No
110	PGE	Level 3	ICE	DG - WWTP	900	10/23/2003	No	Yes
PY02-074	SCE	Level 3R	MT	Landfill Gas	300	2/11/2004	Yes	No
0026-01	SDREO	Level 3	MT	DG - WWTP	120	4/23/2004	No	No
514	PGE	Level 3R	MT	DG - WWTP	90	5/19/2004	Yes	No
0023-01	SDREO	Level 3	MT	DG - WWTP	360	9/3/2004	No	No
379	PGE	Level 3R	MT	Landfill Gas	280	1/14/2005	Yes	No
PY03-092	SCE	Level 1	FC	DG - WWTP	500	3/11/2005	Yes	Yes
640	PGE	Level 3R	MT	Landfill Gas	70	4/14/2005	Yes	No
641	PGE	Level 3R	MT	Landfill Gas	70	4/14/2005	Yes	No
PY03-045	SCE	Level 1	FC	DG - WWTP	250	4/19/2005	Yes	No
PY03-008	SCE	Level 3R	MT	Landfill Gas	70	5/11/2005	Yes	No
PY03-017	SCE	Level 3R	ICE	DG - WWTP	500	5/11/2005	Yes	Yes
842A	PGE	Level 3R	MT	DG - WWTP	60	5/27/2005	Yes	No
PY03-038	SCE	Level 3R	MT	DG - WWTP	250	7/12/2005	Yes	No
747	PGE	Level 3R	MT	DG - WWTP	60	7/18/2005	Yes	No
653	PGE	Level 2	FC	DG - Other	1000	8/9/2005	No	Yes
833	PGE	Level 3N	MT	DG - Other	70	11/7/2005	No	Yes
483	PGE	Level 3R	ICE	DG - Dairy	300	1/13/2006	Yes	No

Res. No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
313	PGE	Level 3R	MT	DG - WWTP	300	3/16/2006	Yes	No
1297	PGE	Level 3R	MT	DG - WWTP	280	4/7/2006	Yes	No
856	PGE	Level 3R	MT	Landfill Gas	210	5/5/2006	Yes	No
658	PGE	Level 3R	ICE	DG - Dairy	160	5/22/2006	Yes	No
1222	PGE	Level 3R	ICE	Landfill Gas	970	7/5/2006	Yes	No
1316	PGE	Level 3R	ICE	Landfill Gas	970	10/2/2006	Yes	No
PY04-158	SCE	Level 3R	ICE	DG - WWTP	704	10/25/2006	Yes	Yes
PY04-159	SCE	Level 3R	ICE	DG - WWTP	704	10/26/2006	Yes	Yes
1308	PGE	Level 3R	ICE	DG - Dairy	400	11/17/2006	Yes	No
1505	PGE	Level 2	ICE	Landfill Gas	970	11/24/2006	Yes	No
298	PGE	Level 3R	MT	DG - WWTP	30	1/31/2007	Yes	No
1313	PGE	Level 3R	MT	DG - WWTP	240	3/6/2007	Yes	Yes
PY05-093	SCE	Level 3R	ICE	Landfill Gas	1030	3/16/2007	Yes	No
1559	PGE	Level 2	ICE	DG - WWTP	160	5/16/2007	Yes	No
1298	PGE	Level 3N	MT	DG - WWTP	250	6/11/2007	No	Yes
1528	PGE	Level 2	MT	DG - Other	70	6/15/2007	Yes	No
PY06-094	SCE	Level 2	ICE	DG - WWTP	500	11/8/2007	Yes	No
1577	PGE	Level 2	ICE	DG - Dairy	80	12/31/2007	Yes	No
2005-082	SCG	Level 3R	ICE	DG - Other	1080	1/15/2008	Yes	No
2006-014	SCG	Level 2	ICE	Landfill Gas	1030	2/21/2008	Yes	No
PY06-062	SCE	Level 2	FC	DG - WWTP	900	3/4/2008	Yes	Yes
0270-05	SDREO	Level 3R	MT	Landfill Gas	210	4/4/2008	Yes	No
1490	PGE	Level 2	FC	DG - WWTP	600	4/24/2008	Yes	Yes
1640	PGE	Level 3R	ICE	DG - WWTP	643	7/29/2008	Yes	No
1498	PGE	Level 3R	MT	Landfill Gas	210	8/5/2008	Yes	No
2006-036	SCG	Level 2	FC	DG - WWTP	1200	10/27/2008	Yes	Yes
1749	PGE	Level 3R	ICE	DG - WWTP	130	11/9/2009	Yes	Yes
2008-003	SCG	Level 2	FC	DG - Other	600	12/14/2009	Yes	Yes
2006-012	SCG	Level 2	FC	DG - WWTP	900	12/18/2009	Yes	Yes
1775	PGE	Level 2	ICE	DG - Dairy	75	2/3/2010	Yes	No
0351-07	SDREO	Level 2	ICE	DG - WWTP	560	4/16/2010	Yes	Yes
PY10-002	SCE	Level 2	FC	DG - WWTP	500	10/31/2010	Yes	Yes
PY10-003	SCE	Level 3	FC	DG - WWTP	250	10/31/2010	No	Yes
1810	PGE	Level 2	FC	Landfill Gas (Directed)	400	11/10/2010	Yes	Yes
1811	PGE	Level 2	FC	Landfill Gas (Directed)	400	11/10/2010	Yes	Yes
1812	PGE	Level 2	FC	Landfill Gas (Directed)	400	11/10/2010	Yes	Yes
1802	PGE	Level 2	FC	Landfill Gas	400	12/22/2010	Yes	Yes

Res. No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
				(Directed)				
1761	PGE	Level 2	ICE	DG - WWTP	330	12/23/2010	Yes	No
1759	PGE	Level 2	ICE	DG - WWTP	1696	12/24/2010	Yes	No
0369-10	SDREO	Level 2	FC	Landfill Gas (Directed)	400	12/31/2010	Yes	Yes
0370-10	SDREO	Level 2	FC	Landfill Gas (Directed)	400	12/31/2010	Yes	Yes
1805	PGE	Level 2	FC	Landfill Gas (Directed)	200	1/18/2011	Yes	Yes
2010-012	SCG	Level 2	FC	Landfill Gas (Directed)	1000	1/24/2011	Yes	Yes
1859	PGE	Level 2	FC	Landfill Gas (Directed)	500	3/11/2011	Yes	Yes
1871	PGE	Level 2	FC	Landfill Gas (Directed)	300	3/14/2011	Yes	Yes
PY10-004	SCE	Level 2	FC	Landfill Gas (Directed)	800	3/23/2011	Yes	Yes
1849	PGE	Level 2	FC	Landfill Gas (Directed)	500	5/9/2011	Yes	Yes
1856	PGE	Level 2	FC	Landfill Gas (Directed)	300	5/9/2011	Yes	Yes
1853	PGE	Level 2	FC	Landfill Gas (Directed)	600	5/24/2011	Yes	Yes
1882	PGE	Level 2	FC	Landfill Gas (Directed)	400	5/24/2011	Yes	Yes
1886	PGE	Level 2	FC	Landfill Gas (Directed)	300	5/24/2011	Yes	Yes
1885	PGE	Level 2	FC	Landfill Gas (Directed)	300	5/31/2011	Yes	Yes
1851	PGE	Level 2	FC	Landfill Gas (Directed)	300	6/29/2011	Yes	Yes
1878	PGE	Level 2	FC	Landfill Gas (Directed)	500	6/29/2011	Yes	Yes
2007-013	SCG	Level 2	ICE	DG - WWTP	150	7/13/2011	Yes	No
PY10-009	SCE	Level 2	FC	Landfill Gas (Directed)	300	8/8/2011	Yes	Yes
PY10-012	SCE	Level 2	FC	Landfill Gas (Directed)	300	8/8/2011	Yes	Yes
PY10-022	SCE	Level 2	FC	Landfill Gas (Directed)	400	8/8/2011	Yes	Yes
PY10-023	SCE	Level 2	FC	Landfill Gas (Directed)	400	8/8/2011	Yes	Yes
PY09-003	SCE	Level 2	FC	DG - WWTP	300	8/30/2011	Yes	Yes
1850	PGE	Level 2	FC	Landfill Gas (Directed)	420	9/7/2011	Yes	Yes
1874	PGE	Level 2	FC	Landfill Gas (Directed)	500	9/7/2011	Yes	Yes
1892	PGE	Level 2	FC	Landfill Gas (Directed)	210	9/7/2011	Yes	Yes
1893	PGE	Level 2	FC	Landfill Gas (Directed)	210	9/7/2011	Yes	Yes
2010-005	SCG	Level 2	FC	Landfill Gas (Directed)	100	9/20/2011	Yes	Yes

Res. No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
2010-011	SCG	Level 2	FC	Landfill Gas (Directed)	900	9/21/2011	Yes	Yes
PY07-017	SCE	Level 2	ICE	DG - WWTP	364	9/27/2011	Yes	No
1855	PGE	Level 2	FC	Landfill Gas (Directed)	300	9/29/2011	Yes	Yes
2007-036	SCG	Level 2	ICE	DG - WWTP	340	11/1/2011	Yes	No
2010-018	SCG	Level 2	FC	Landfill Gas (Directed)	420	12/15/2011	Yes	Yes
2010-019	SCG	Level 2	FC	Landfill Gas (Directed)	420	12/15/2011	Yes	Yes
2010-020	SCG	Level 2	FC	Landfill Gas (Directed)	420	12/15/2011	Yes	Yes
2010-015	SCG	Level 2	FC	Landfill Gas (Directed)	420	12/16/2011	Yes	Yes
1858	PGE	Level 2	FC	Landfill Gas (Directed)	300	12/29/2011	Yes	Yes

* Since assignment of a project's operational date is subject to individual judgment, the incentive payment date as reported by the PAs is used as a proxy for the operational date for reporting purposes.

† In Renewable Fuel Use Reports No. 9 through No. 13 this project's Operational Date was incorrectly reported as 11/15/2005. That date is an estimate of when the system began operating. For this report the basis of Operational Date values is incentive payment date. In Renewable Fuel Use Reports No. 9 and No. 10 this project's size was reported as 296 kW, the capacity used in incentive calculations. The actual physical size of the system is 704 kW.