Self-Generation Incentive Program
Semi-Annual Renewable Fuel Use Report No. 18
for the Six-Month Period Ending June, 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 SGIP Handbook defines renewable fuels as wind, solar, and gas derived from biomass, landfills, and dairies. 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. 18 covers projects completed during the last six months (i.e., January 1, 2011, to June 30, 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 July 1, 2010 to June 30, 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

Table 1: Summary of RFU vs. RFUR Parameters

	RFU	
Parameter	**"Other" RFU**	**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	8	64

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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.

projects, including those not subject to the Program's minimum renewable fuel use requirements ("Other RFU projects").

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. Directed biogas projects are not subject to renewable fuel use requirements during this reporting period. Compliance protocols are expected to be implemented in the near-term.

Summary of RFU Report No. 18 Findings

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

- As of June 30, 2011, there were 72 RFU facilities deployed under the SGIP, representing approximately 33.0 megawatts (MW) of rebated capacity. Sixty-four of these facilities were RFUR projects and represented approximately 29.3 MW of rebated capacity. The remaining eight "Other" RFU projects represented approximately 3.8 MW of rebated capacity.
- RFU Report No. 18 marks the second appearance of completed SGIP projects utilizing directed biogas. All thirteen projects added during the first half of 2011 were natural gas fuel cells that fulfill renewable fuel use requirements via purchase of landfill gas that is produced off-site. Four of the seven projects completed during the second half of 2010 were directed biogas fuel cells.
- Of the 64 RFUR projects, thirty-four (53 percent) operated solely from renewable fuels and as such inherently comply with renewable fuel use requirements. Of the remaining 30 dual-fuel RFUR facilities:
  - Three were found to be in compliance with renewable fuel use requirements,

  - 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),
  - Eighteen were found not to be applicable with respect to the requirements as they have not yet been operational for a full year, and
  - Four were found to be out of compliance.
- Of the eighteen facilities not yet applicable with respect to the renewable fuel use requirements, seventeen are directed biogas systems where:
  - Nine facilities appear to be on track to be in compliance in a future reporting period based on limited information available and
  - Eight facilities could not have renewable fuel use evaluated at any level of rigor due to a lack of information.
- RFU facilities are powered by a variety of renewable fuel (i.e., biogas) resources. However, approximately 88 percent of the rebated capacity of RFU facilities deployed through June 30, 2011, was powered by biogas derived from landfills or wastewater treatment facilities.
- 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, constituting approximately 14.9 MW (about 45 percent) of the overall 33.0 MW of rebated RFU capacity. With the addition of 17 directed biogas fuel cell projects over the last year, fuel cells have nearly matched IC engines in terms of rebated capacity with 14.1 MW installed (about 43 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 was treated prior to receiving incentives (i.e., the “baseline” condition). RFU facilities that were allowed to vent biogas directly to the atmosphere have a much higher GHG emission reduction potential than RFU facilities that were required to capture and flare biogas.
  - In general, RFU facilities for which flaring biogas was the baseline condition increased GHG emissions by around 0.2 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

- 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 proposed 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."[6] 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.

[6] California Public Utilities Commission, "Proposed Decision Modifying the Self Generation Incentive Program and Implementing SB 412," July 19, 2011, page 19.

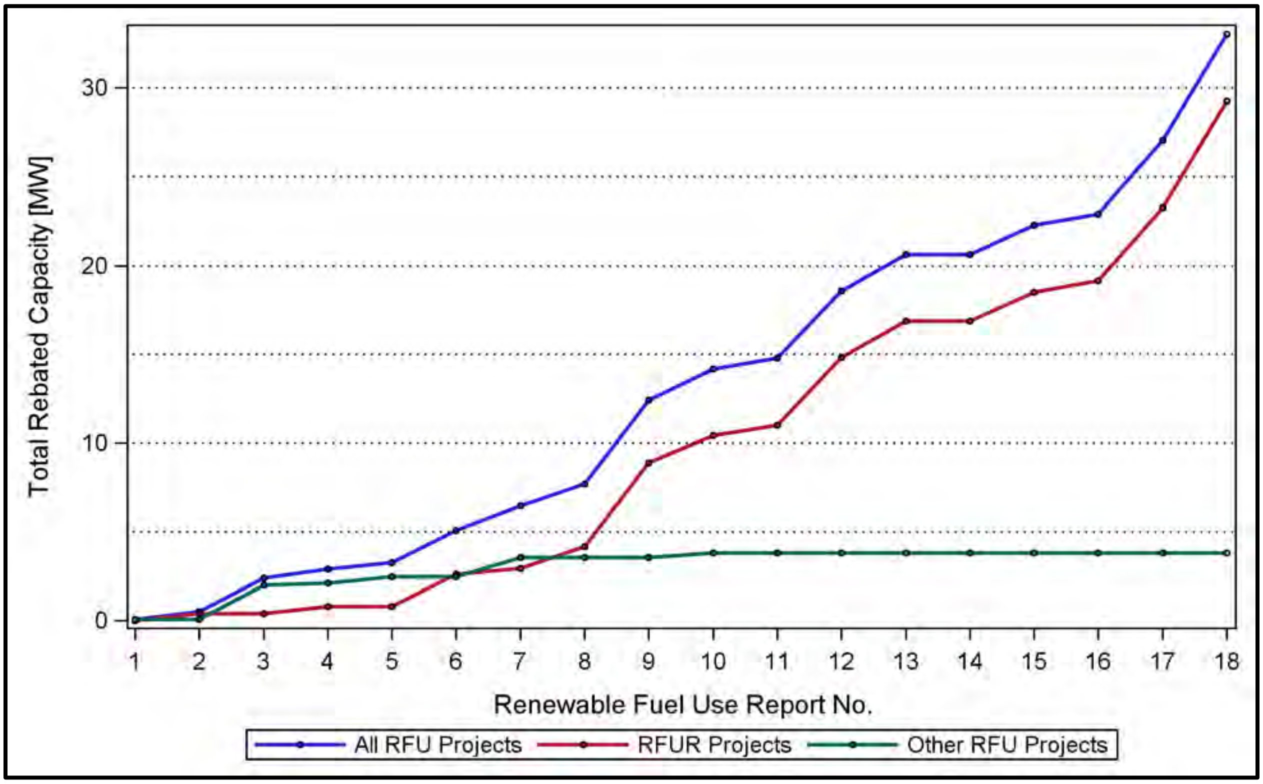
- The cost breakdown conducted to date on RFU projects does not provide definitive information on the costs of gas clean-up equipment. However, such information is important in determining if there should be differences in incentive levels for RFU projects using biogas fuels. In addition, gas clean-up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

- This RFU Report includes an evaluation of compliance of directed biogas projects that is preliminary in nature. These projects have not yet been operational for one full calendar year and therefore are not yet required to be in compliance with renewable fuel use requirements. Furthermore, development of compliance evaluation protocols for directed biogas projects is ongoing. Based on the fuel use information collected thus far, it is evident that additional information will be required to assess compliance 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 that identifies the source, quality magnitude (i.e., Btu/scf), quality basis (i.e., HHV or LHV), and amount of biogas associated with all purchases covered by renewable fuel invoices.
  - Clear connections between line items in renewable fuel invoices and the meter(s) associated with the sale of directed biogas.

Project Capacity, Fuel Types, and Prime Mover Technology

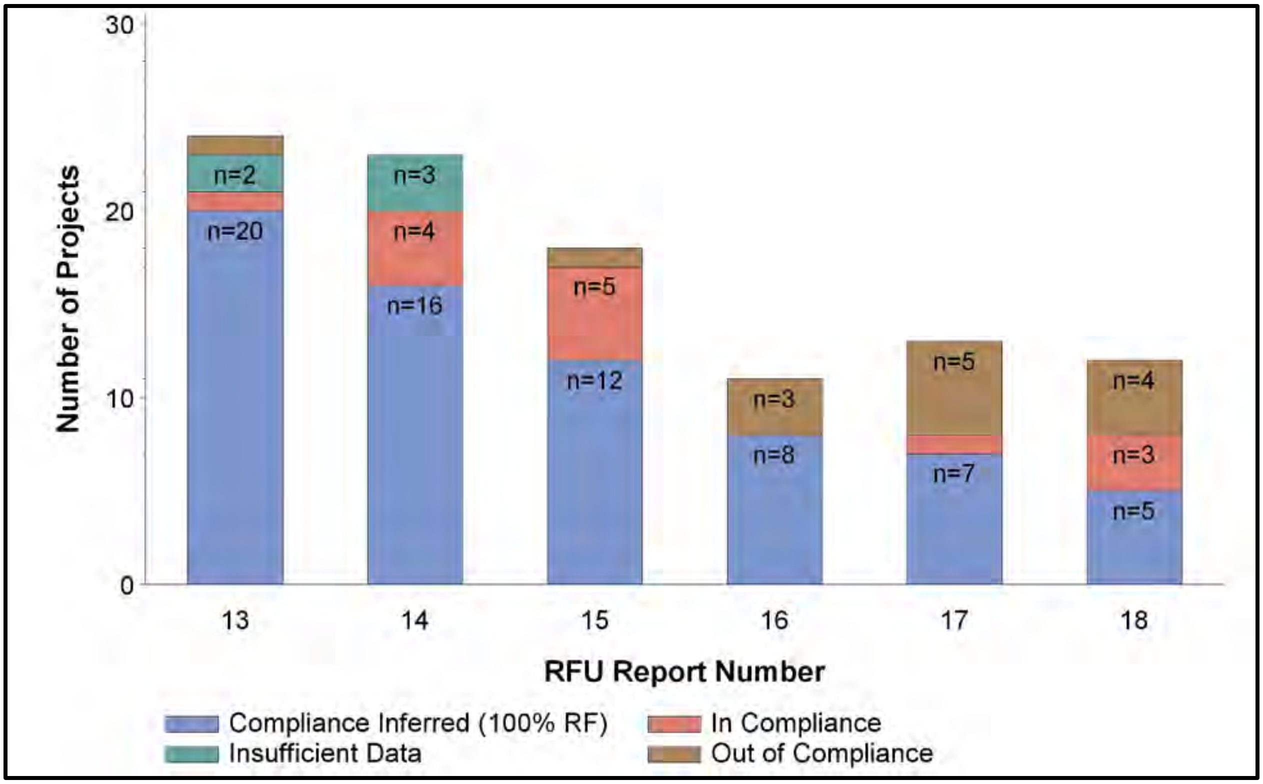
The capacity of RFUR and Other RFU projects, and the combined total (RFU projects) covered by each RFU report is depicted graphically in Figure 1.

Figure 1: Project Capacity Trend (RFU Reports 1–18)



While all RFUR projects are allowed to use as much as 25 percent non-renewable fuel, 53 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 four 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

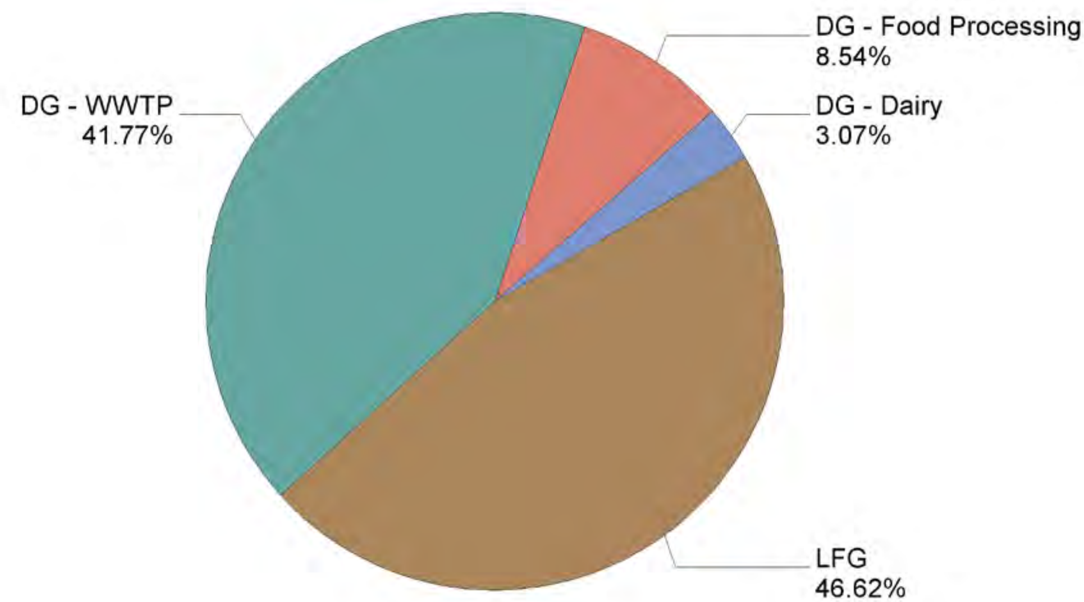


* This table contains information limited to systems that are subject to the renewable fuel use requirement – systems under warranty and operational for at least one calendar year during each RFU Report's specific reporting period. Other systems are excluded from this figure.

** 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 June 30, 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 47 and 42 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 three percent of the total rebated RFU project capacity.

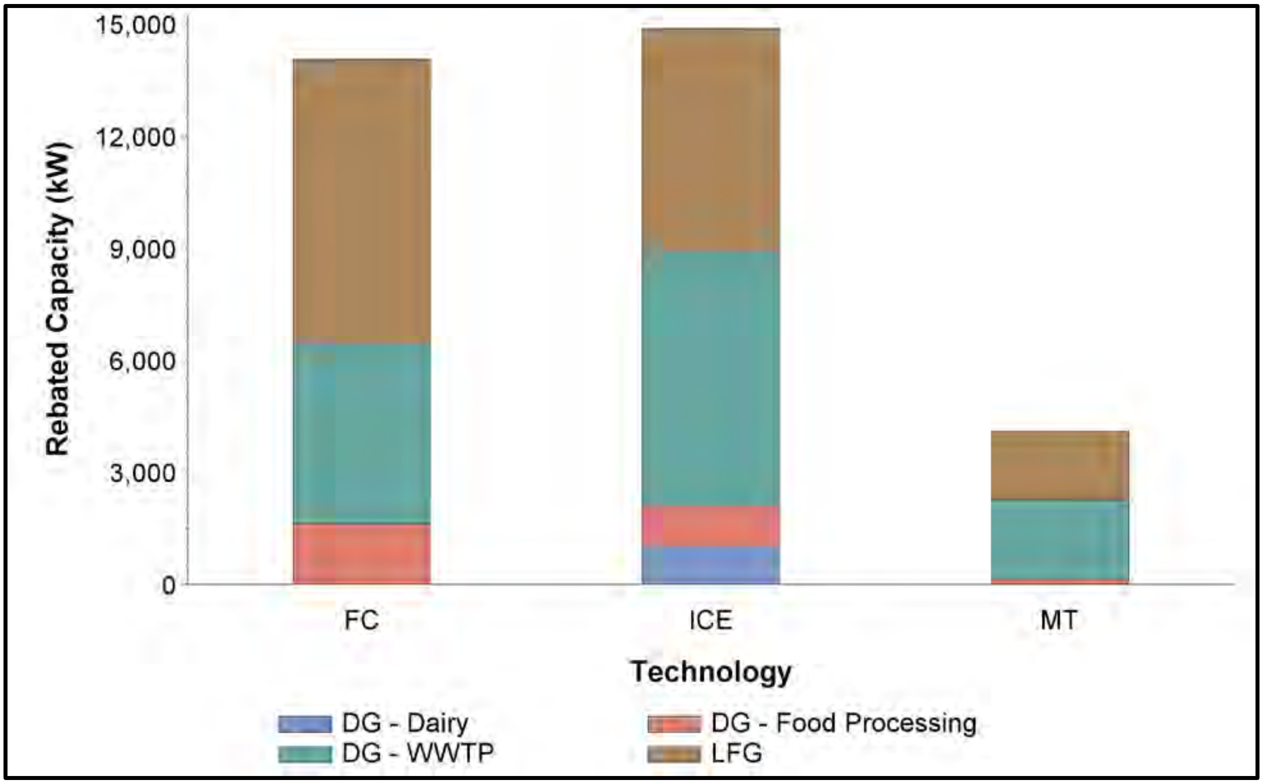
Figure 3: Renewable Fuel Use Project Rebated Capacity by Fuel Type



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 45 and 43 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. 18 marks the second 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 population 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, budget cost data, and rules-of-thumb likely continue to be more suitable for this purpose at this time.

2. Summary of Completed RFUR Projects

There were thirteen new RFUR SGIP projects completed during the subject six-month reporting period. All thirteen projects were fuel cells ranging in size from 200 kW to 1 MW and fueled by directed biogas. A total of 64 RFUR projects had been completed as of June 30, 2011. A list of all SGIP projects utilizing renewable fuel (RFUR and Other RFU) is included as Appendix A.

The 64 completed RFUR projects represent approximately 29.3 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 45 percent of RFUR rebated capacity, with microturbines making up the remaining 11 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	No. Projects	Total Rebated Capacity (kW)	Average Rebated Capacity Per Project (kW)*
FC	25	13,050	522
MT	18	3,220	179
ICE	21	12,992	619
Total	**64**	**29,262**	**457**

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 35 of the 64 RFUR projects recover waste heat. All but two of the 32 digester gas systems include waste heat recovery.[7] Waste heat recovered from digester gas systems is generally used to pre-heat waste water sludge prior to being pumped to digester tanks. Conversely, only 4 of 31 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

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

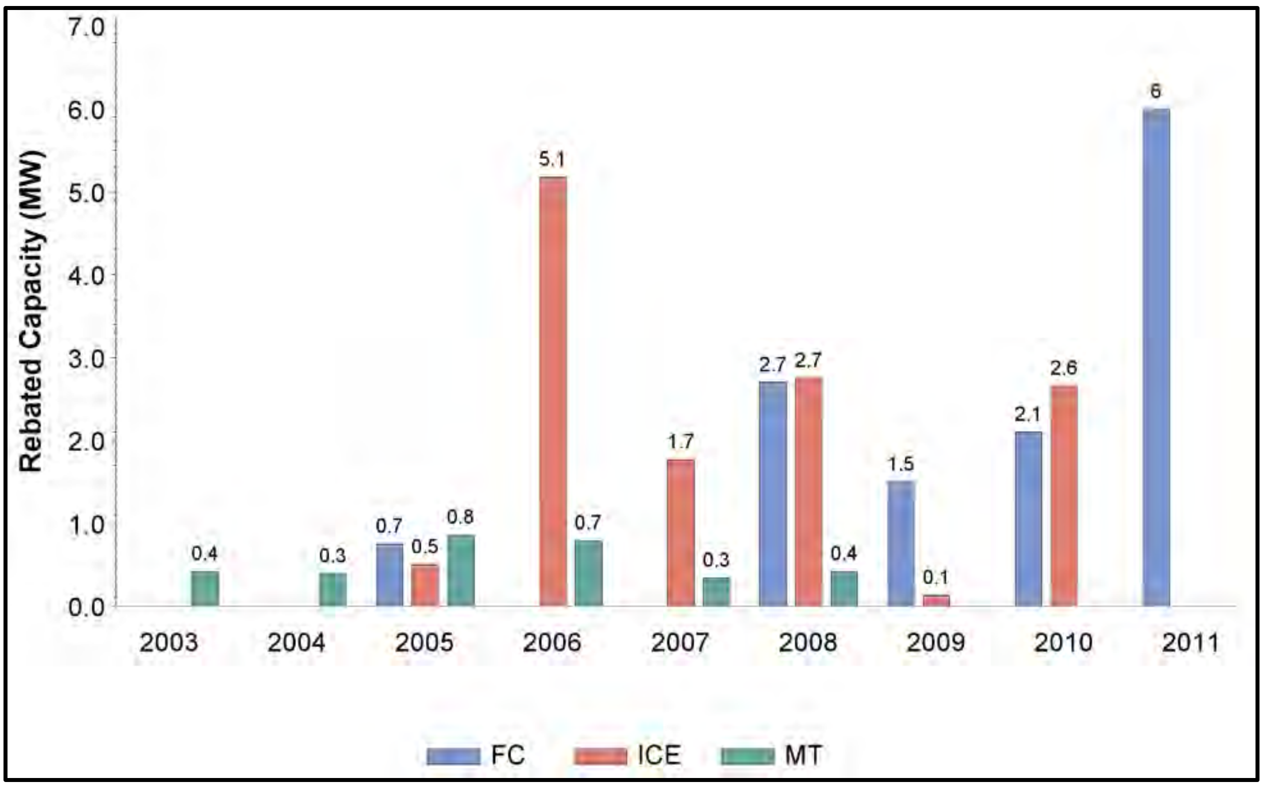
used in a prime mover at that site. None of the 17 completed directed biogas projects, which use landfill gas, include waste heat recovery.[8]

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	33	31	2
Landfill Gas	31	4	27
Total	**64**	**35**	**29**

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.

Figure 5: Rebated RFUR Capacity by Technology and Project Year



8 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.

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 34 RFU facilities where biogas was produced and acted as the only fuel source for the RFU system, the facility was automatically in compliance. For RFU facilities using a blend of fuels, 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. 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 30 of the total 64 RFUR projects had active warranty status. Thirty-four RFUR projects (over half of all RFUR projects) had an expired warranty status. Of the 30 RFUR projects with active warranties, five operated solely on renewable fuel. By definition, all five 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	5	2,954	29	10,670	34	13,624
Nonrenewable & Onsite Renewable	8	5,390	5	2,648	13	8,038
Nonrenewable & Offsite, Directed Renewable	17	7,600	-	-	17	7,600
Total	**30**	**15,944**	**34**	**13,318**	**64**	**29,262**

In addition, Table 4 shows that 34 of the total 64 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 30 dual-fueled and directed biogas projects (both active and expired) is as presented below.

Dual-fueled RFUR Projects In Compliance

During this reporting period, three of the dual-fueled projects were found to be in compliance with SGIP renewable fuel use requirements based on analysis of metered data.[9]

[9] In prior RFU Reports, Itron had proposed installing natural gas metering at this project to verify that the non-renewable fuel consumption remained below 25 percent of annual fuel use. However, after researching natural gas meters and installation practices, Itron found that installing a natural gas meter would require the facility to temporarily shut down their natural gas line, purge the line and install a T-valve before installing a gas meter. For safety and cost reasons, this was not found to be feasible.

- **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. The host customer provided natural gas and biogas usage for the entire reporting period. The contribution of non-renewable fuel was no more than 8 percent and is therefore determined to be in compliance with SGIP renewable fuel use requirements.

- **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 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 was no more than 25 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 for the period from July 1, 2010 to June 30, 2011. Based on the data provided, the natural gas usage during the reporting period did not exceed 6 percent of the total energy consumed. The system was in compliance with SGIP renewable fuel use provisions for this reporting period.

Dual-fueled RFUR Projects Not In Compliance

Four projects were found to be using more non-renewable fuel than allowed on an annual fuel input basis. For all of these projects it was necessary to estimate electrical conversion efficiency because metered biogas consumption data were not available.[10]

- **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

[10] 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.

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 36 percent of the total annual fuel input and the system was not in compliance with SGIP renewable fuel use provisions.

- **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 93 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 61 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 28 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

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 seventeen directed-biogas fuel cells and one dual-fueled fuel cell in this category.

Of the seventeen directed-biogas systems, only nine projects have sufficient information that makes them appear to be on track to be in compliance once they have been operational for a complete calendar year. For these projects, metered fuel consumption data were received from the equipment manufacturer and monthly directed biogas invoices were collected from various parties (applicants and hosts). The amount of directed biogas shown in the invoices was compared to the metered consumption of the SGIP system and was at least 75 percent on a fuel energy input basis during the period of operation. As directed biogas projects become applicable with respect to renewable fuel use requirements the data sources and analytic methods used to assess compliance are expected to evolve in several areas, including:

- In some instances directed biogas invoices included multiple facilities, but a facility-level breakdown of directed biogas allocation was not available. For determination of facility-level compliance, the amount of biogas allocated to each facility must be specified in directed biogas invoices.

- The SGIP Handbook requires metering of injection of renewable fuel into the natural gas pipeline system. Information from this metering was not available for this preliminary compliance assessment. Consequently, there was no way to validate information in the directed biogas invoices. A more rigorous assessment of compliance would require information including but not limited to:

  - Invoices indicating the sale of directed biogas, specifically identifying the source of biogas and the meter connected to the natural gas pipeline that supplied the biogas purchased. Enough information should be made available to enable the evaluator to match line items from renewable fuel invoices to metered renewable fuel flow into the natural gas pipeline system.

  - Metered data indicating the source, quality, and quantity of biogas associated with all purchases of directed biogas.

- The metered fuel data used in this evaluation was based on control grade metering from the prime movers, not revenue grade utility metering. In the future, data from dedicated utility meters will be sought.

For the remaining eight directed biogas systems, there was insufficient data to determine preliminary compliance for the following reasons:

- Natural gas consumption data and/or directed biogas invoices were not available due to data availability constraints.
- Directed biogas purchases were scheduled to be performed retroactively in bulk after this report was finalized.

In summary, the scope of the preliminary evaluation of compliance of directed biogas projects was limited due to a lack of information. For nine projects it would appear based on the information available that compliance will be achieved if operations do not change substantially. For the other eight directed biogas systems and for one on-site biogas system, little to no information was available. The following is a summary of projects that are not yet applicable with respect to renewable fuel use requirements.

<u>Not Yet Operational for a Complete Calendar Year</u>

- **SCE PY10-002.** This project is a 750 kW fuel cell system consisting of three 250 kW stacks, of which only two are rebated through the SGIP. The system is located on 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. The system became operational in October of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1812.** This 400 kW fuel cell project utilizes directed biogas from a landfill in Pennsylvania and natural gas. The system became operational in November of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1810.** This 400 kW fuel cell project utilizes directed biogas from a landfill in Pennsylvania and natural gas. The system became operational in November of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1811.** This 400 kW fuel cell project utilizes directed biogas from a landfill in Pennsylvania and natural gas. The system became operational in November of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1802.** This 400 kW fuel cell project utilizes directed biogas from a landfill in Pennsylvania and natural gas. The system became operational in December of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.

- **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.
- **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.

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 two reporting periods.

Overall (renewable-only and dual-fuel), eight (67 percent) of the 12 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 30 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	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	1749	3R	ICE	DG - WWTP	11/9/2009	566	92%	Active	Yes
SCE	PY06-062	2	FC	DG - WWTP	3/4/2008	8,582	76%	Active	Yes
CCSE	SDREO-0351-07	2	ICE	DG - WWTP	4/16/2010	12,096	94%	Active	Yes
PGE	1490	2	FC	DG - WWTP	4/24/2008	16,416	64%	Active	No
SCG	2006-012	2	FC	DG - WWTP	12/18/2009	21,441	7%	Active	No
SCG	2006-036	2	FC	DG - WWTP	10/27/2008	24,668	39%	Active	No
SCG	2008-003	2	FC	DG - Food Processing	12/14/2009	10,236	72%	Active	No
SCE	PY10-002	2	FC	DG - WWTP	10/31/2010	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1812	2	FC	Landfill Gas (DBG)	11/10/2010	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1810	2	FC	Landfill Gas (DBG)	11/10/2010	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1811	2	FC	Landfill Gas (DBG)	11/10/2010	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1802	2	FC	Landfill Gas (DBG)	12/22/2010	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1805	2	FC	Landfill Gas (DBG)	1/18/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCG	2010-012	2	FC	Landfill Gas (DBG)	1/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡

PA	Res No.	Incentive Level	Technology	Fuel Type	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	1859	2	FC	Landfill Gas (DBG)	3/11/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1871	2	FC	Landfill Gas (DBG)	3/14/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY10-004	2	FC	Landfill Gas (DBG)	3/23/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1849	2	FC	Landfill Gas (DBG)	5/9/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1856	2	FC	Landfill Gas (DBG)	5/9/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1853	2	FC	Landfill Gas (DBG)	5/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1886	2	FC	Landfill Gas (DBG)	5/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1882	2	FC	Landfill Gas (DBG)	5/24/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1885	2	FC	Landfill Gas (DBG)	5/31/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1851	2	FC	Landfill Gas (DBG)	6/29/2011	Not Available	Not Available	Active	Not Applicable ‡‡
PGE	1878	2	FC	Landfill Gas (DBG)	6/29/2011	Not Available	Not Available	Active	Not Applicable ‡‡
SCE	PY03-092	1	FC	DG - WWTP	3/11/2005	Decommissioned	Decommissioned	Expired	Not Applicable ‡
SCE	PY03-017	3R	ICE	DG - WWTP	5/11/2005	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡
SCE	PY04-158	3R	ICE	DG - WWTP	10/25/2006	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡

PA	Res No.	Incentive Level	Technology	Fuel Type	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	PY04-159	3R	ICE	DG - WWTP	10/26/2006	Not Applicable ‡	Not Applicable ‡	Expired	Not Applicable ‡
PGE	1313	3R	MT	DG - WWTP	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.

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 was previously presented in the SGIP Tenth-Year Impact Evaluation Final Report.[11] Additionally, key factors that could influence GHG emission impacts from renewable fuel projects in the future are discussed.

Table 6 presents the capacity-weighted average GHG emission results developed for the SGIP Tenth-Year Impact Evaluation Final Report. Results in Table 6 suggest one important observation: The assumed baseline for the biogas (i.e., whether the biogas was vented to the atmosphere or flared) is the most influential determinant of GHG emission impacts.[12] 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/MWh)
Flare	FC	0.06
	MT	0.42
	IC Engine	0.10
Vent	IC Engine	-4.46

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

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)[13]

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[11] GHG Information from the SGIP Tenth-Year Impact Evaluation Final Report was used here because this evaluation contains the most recent GHG estimates of the SGIP. The SGIP annual Impact Evaluation reports have included information about GHG emissions impacts starting with the 2005 report. All SGIP measurement and evaluation reports, including the Impact Evaluation reports, are available for download from the CPUC website (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm)

[12] 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).

[13] 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).

- 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

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.[14] At the state level, the California Air Resources Board (CARB) provides guidelines for control of methane and other volatile organic compounds from biogas facilities.[15] At the federal level, New Source Performance Standards and Emission Guidelines regulate methane capture and use.[16]

Biogas baseline assumptions used to calculate GHG impact estimates for 2007-2009 were based on previous studies.[17] [18] 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 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.

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

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

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

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

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

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 of renewable fueled flared and vented systems in 2010 are presented in Figure 6 and Figure 7.

Figure 6: Equivalent Tons of CO2 for Flared Biogas Systems

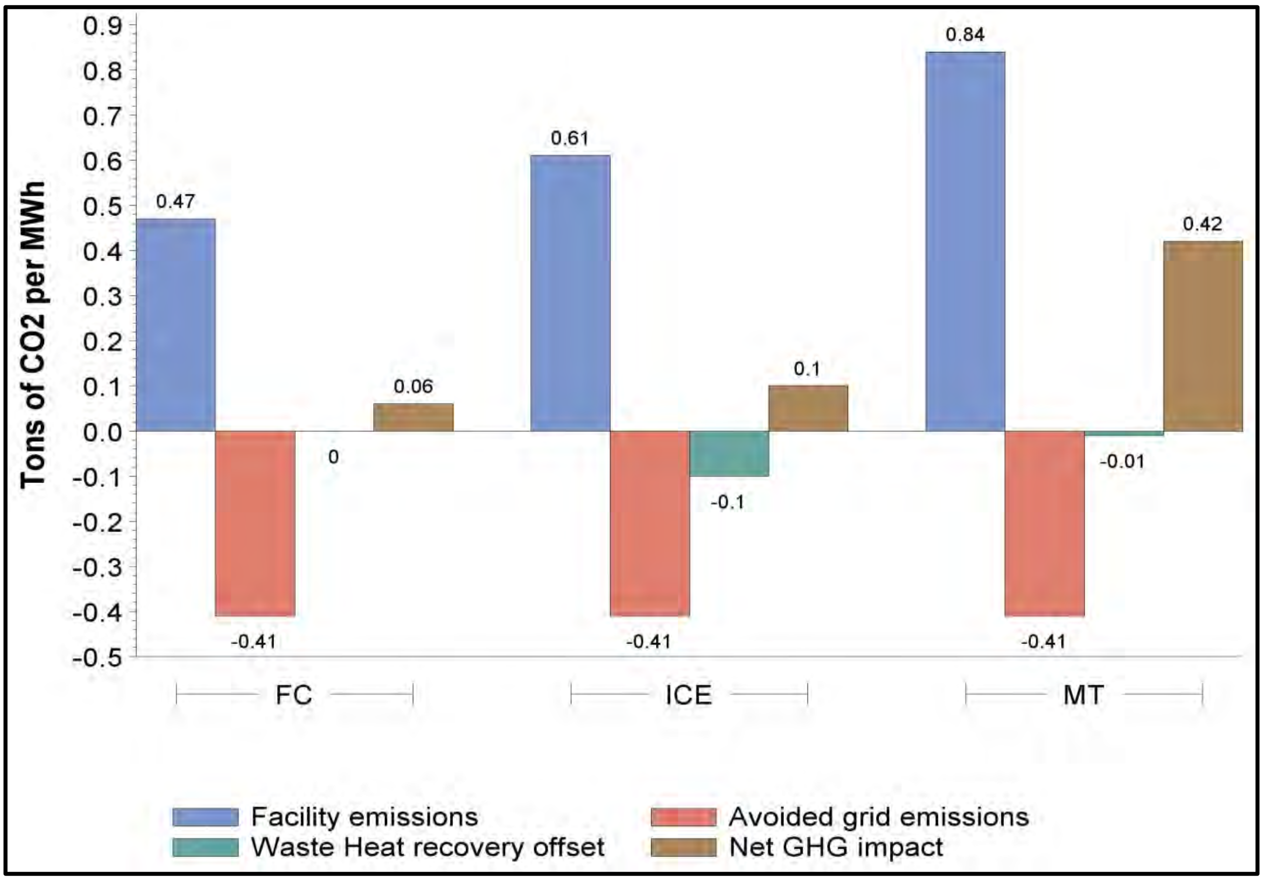
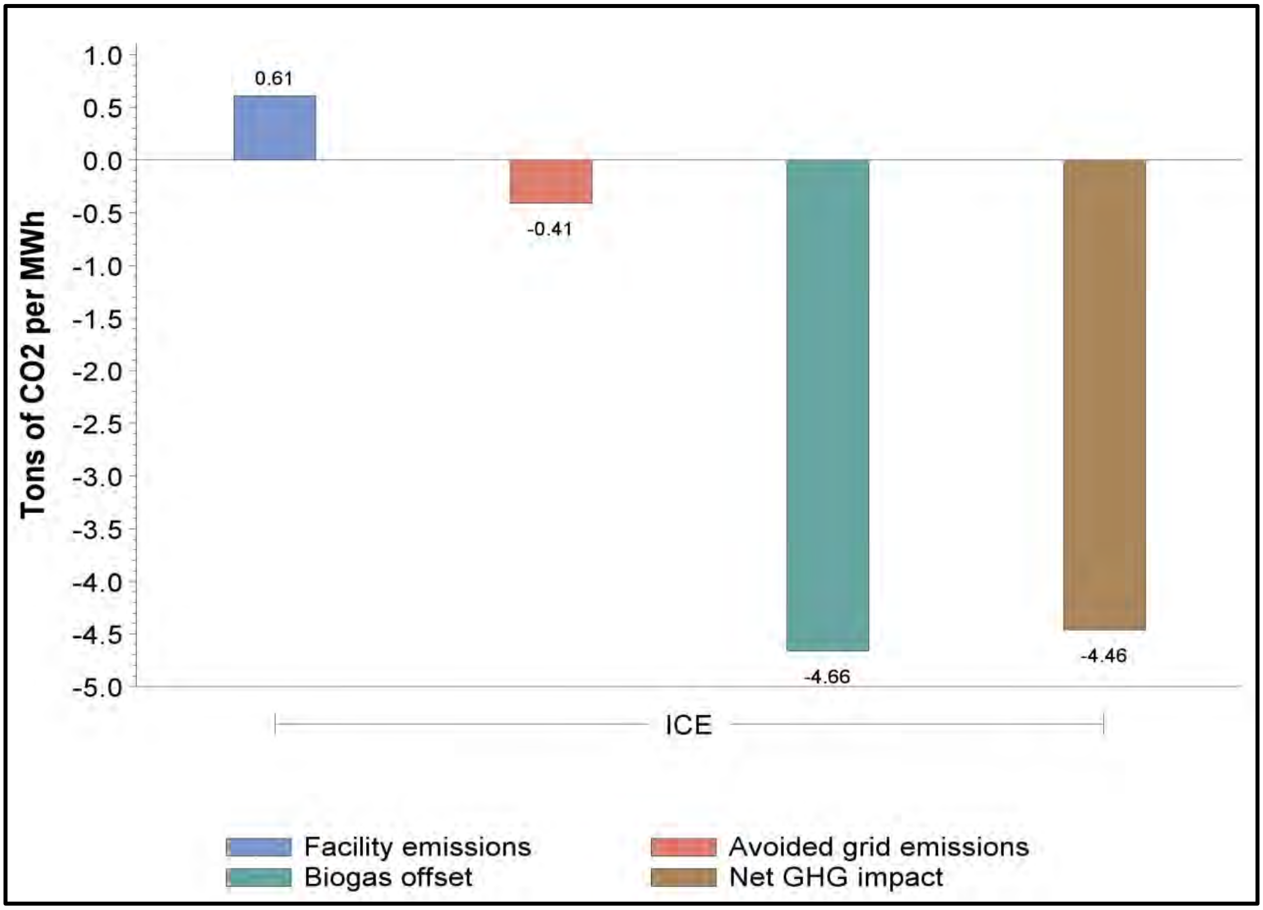


Figure 7: Equivalent Tons of CO2 for Vented Biogas Systems



It is clear that the biogas offset factor is the principal reason that biogas projects with a venting baseline are net GHG reducers, and those with a flaring baseline are not.

5. Cost Comparison between RFU and Other Projects

Incentive levels for renewable fuel projects have changed over time and are roughly defined as follows for the purposes of this report:[19]

- Incentive Level 1: Originally an incentive level for PV, wind, and fuel cells powered by renewable fuels
- Incentive Level 2: Fuel cells powered by renewable fuels

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[19] Itron has moved away from using incentive levels in the annual Impact Evaluation reports because of the confusion caused by changes in the incentive levels. Incentive levels are reported here only because of the manner in which incentive levels were used to designate RFUR classification.

- Incentive Level 3: Used for a short time following the Program's inception to designate microturbines, IC engines, and small gas turbines using renewable fuels
- Incentive Level 3-R: Microturbines, IC engines, and small gas turbines using renewable fuels
- Incentive Level 3-N: Microturbines, IC engines, and small gas turbines using non-renewable fuels

Beginning in September 2002, RFUR projects were eligible for a higher incentive level than non-renewable projects. 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

Concerns were expressed in CPUC Decision 02-09-051 that Level 3-R project costs could fall below Level 3 costs as Level 3-R projects are exempt from waste heat recovery requirements. As a result, Level 3-R 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 Level 3 and Level 3-R 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 June 30, 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?	No. Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC	Yes	Yes	9	4.51 - 10.98	9.41	8.04	2.34	7.45
	Yes	No	0	-	-	-	-	-
	Yes	Yes or No	9	4.51 - 10.98	9.41	8.04	2.34	7.45
	No	Yes	19	5.06 - 18	7.42	8.39	3.32	7.56
	No	No	4	8.71 - 10	9.61	9.48	0.55	9.29
	No	Yes or No	23	5.06 - 18	8.25	8.58	3.04	7.75
	DBG	No	17	6.08 - 18.21	11.22	11.51	2.35	10.93
ICE	Yes	Yes	21	1.08 - 7.58	2.79	3.03	1.57	2.95
	Yes	No	2	1.71 - 2.87	2.29	2.29	0.82	2.71
	Yes	Yes or No	23	1.08 - 7.58	2.79	2.97	1.52	2.93
	No	Yes	229	0.85 - 10.71	2.30	2.60	1.32	2.30
MT	Yes	Yes	13	2.26 - 11.32	3.99	5.13	2.69	4.55
	Yes	No	10	1.23 - 5.39	3.61	3.47	1.27	2.89
	Yes	Yes or No	23	1.23 - 11.32	3.75	4.40	2.30	3.78
	No	Yes	115	0.7 - 8.4	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.

$$\Delta Heat\,\mathrm{Re}\,\mathrm{cov}\,ery = \left(\frac{RFU}{w/\,HR}\right) - \left(\frac{RFU}{w/\,o\,HR}\right) \qquad \text{Equation 1}$$

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?	No. Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC	Yes	Yes	9	4.51 - 10.98	9.41	8.04	2.34	7.45
ICE	Yes	Yes	21	1.08 - 7.58	2.79	3.03	1.57	2.95
	Yes	No	2	1.71 - 2.87	2.29	2.29	0.82	2.71
	Increase due to Heat Recovery		-	-	0.50	0.74	0.75	0.24
MT	Yes	Yes	13	2.26 - 11.32	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 \$3.03 minus \$2.60, or \$0.43.

$$\Delta Fuel\,Treatment = \begin{pmatrix} RFU \\ w/HR \end{pmatrix} - \begin{pmatrix} NG \\ w/HR \end{pmatrix}$$ **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	9	4.51 - 10.98	9.41	8.04	2.34	7.45
	No	Yes	19	5.06 - 18	7.42	8.39	3.32	7.56
	Increase due to RF Equipment		-	-	1.99	(0.35)	(0.98)	(0.11)
ICE	Yes	Yes	21	1.08 - 7.58	2.79	3.03	1.57	2.95
	No	Yes	229	0.85 - 10.71	2.30	2.60	1.32	2.30
	Increase due to RF Equipment		-	-	0.49	0.43	0.25	0.65
MT	Yes	Yes	13	2.26 - 11.32	3.99	5.13	2.69	4.55
	No	Yes	115	0.7 - 8.4	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 \$2.97 minus \$2.60, or \$0.37.

$$\Delta RFU = \begin{pmatrix} RFU \\ w/\,or\,w/o\;\;HR \end{pmatrix} - \begin{pmatrix} NG \\ w/\,HR \end{pmatrix} \qquad \textbf{Equation 3}$$

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	9	4.51 - 10.98	9.41	8.04	2.34	7.45
	No	Yes or No	23	5.06 - 18	8.25	8.58	3.04	7.75
	Increase due to RFU		-	-	1.16	(0.54)	(0.70)	(0.30)
ICE	Yes	Yes or No	23	1.08 - 7.58	2.79	2.97	1.52	2.93
	No	Yes	229	0.85 - 10.71	2.30	2.60	1.32	2.30
	Increase due to RFU		-	-	0.49	0.37	0.20	0.63
MT	Yes	Yes or No	23	1.23 - 11.32	3.75	4.40	2.30	3.78
	No	Yes	115	0.7 - 8.4	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 11. 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.[20]

Table 11: 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 11 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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[20] 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 12. 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 12: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	0.74	-1.20 to 2.70
Fuel Treatment	0.43	-0.08 to 0.94
RFU	0.37	-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 13. 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 13: Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	---	---
Fuel Treatment	-0.35	-2.46 to 1.76
RFU	-0.54	-2.46 to 1.38

Cost Comparison Summary

Comparison of the installed costs between renewable- and non-renewable-fueled generation systems operational as of June 30, 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, budget cost data, and rules-of-thumb likely continue to be more suitable for this purpose at this time.

Appendix A

List of All SGIP Pro   jects 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 (37 percent) is also equipped with a non-renewable fuel supply. These projects are identified in the “Any Non-Renewable Fuel Supply?” column.

Table 14: SGIP Projects Utilizing Renewable Fuel

Res. No.	PA	Incentive Level	Technology	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
110	PGE	Level 3	ICE	DG - WWTP	900	10/23/2003	No	Yes
98	PGE	Level 3R	MT	DG - WWTP	30	1/31/2007	Yes	No
313	PGE	Level 3R	MT	DG - WWTP	300	3/16/2006	Yes	No
379	PGE	Level 3R	MT	Landfill Gas	280	1/14/2005	Yes	No
483	PGE	Level 3R	ICE	DG - Dairy	300	1/13/2006	Yes	No
514	PGE	Level 3R	MT	DG - WWTP	90	5/19/2004	Yes	No
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
653	PGE	Level 2	FC	DG - Food Processing	1000	8/9/2005	No	Yes
658	PGE	Level 3R	ICE	DG - Dairy	160	5/22/2006	Yes	No
747	PGE	Level 3R	MT	DG - WWTP	60	7/18/2005	Yes	No
833	PGE	Level 3N	MT	DG - Food Processing	70	11/7/2005	No	Yes
842A	PGE	Level 3R	MT	DG - WWTP	60	5/27/2005	Yes	No
856	PGE	Level 3R	MT	Landfill Gas	210	5/5/2006	Yes	No
1222	PGE	Level 3R	ICE	Landfill Gas	970	7/5/2006	Yes	No
1297	PGE	Level 3R	MT	DG - WWTP	280	4/7/2006	Yes	No
1298	PGE	Level 3N	MT	DG - WWTP	250	6/11/2007	No	Yes
1308	PGE	Level 3R	ICE	DG - Dairy	400	11/17/2006	Yes	No
1313	PGE	Level 3R	MT	DG - WWTP	240	3/6/2007	Yes	Yes
1316	PGE	Level 3R	ICE	Landfill Gas	970	10/2/2006	Yes	No

Res. No.	PA	Incentive Level	Technology	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
1490	PGE	Level 2	FC	DG - WWTP	600	4/24/2008	Yes	Yes
1498	PGE	Level 3R	MT	Landfill Gas	210	8/5/2008	Yes	No
1505	PGE	Level 2	ICE	Landfill Gas	970	11/24/2006	Yes	No
1528	PGE	Level 2	MT	DG - Food Processing	70	6/15/2007	Yes	No
1559	PGE	Level 2	ICE	DG - WWTP	160	5/16/2007	Yes	No
1577	PGE	Level 2	ICE	DG - Dairy	80	12/31/2007	Yes	No
1640	PGE	Level 3R	ICE	DG - WWTP	643	7/29/2008	Yes	No
1749	PGE	Level 3R	ICE	DG - WWTP	130	11/9/2009	Yes	Yes
1759	PGE	Level 2	ICE	DG - WWTP	1696	12/24/2010	Yes	No
1761	PGE	Level 2	ICE	DG - WWTP	330	12/23/2010	Yes	No
1775	PGE	Level 2	ICE	DG - Dairy	75	2/3/2010	Yes	No
1802	PGE	Level 2	FC	Landfill Gas (Directed)	400	12/22/2010	Yes	No
1805	PGE	Level 2	FC	Landfill Gas (Directed)	200	1/18/2011	Yes	No
1810	PGE	Level 2	FC	Landfill Gas (Directed)	400	11/10/2010	Yes	No
1811	PGE	Level 2	FC	Landfill Gas (Directed)	400	11/10/2010	Yes	No
1812	PGE	Level 2	FC	Landfill Gas (Directed)	400	11/10/2010	Yes	No
1849	PGE	Level 2	FC	Landfill Gas (Directed)	500	5/9/2011	Yes	No
1851	PGE	Level 2	FC	Landfill Gas (Directed)	300	6/29/2011	Yes	No
1853	PGE	Level 2	FC	Landfill Gas (Directed)	600	5/24/2011	Yes	No
1856	PGE	Level 2	FC	Landfill Gas (Directed)	300	5/9/2011	Yes	No
1859	PGE	Level 2	FC	Landfill Gas (Directed)	500	3/11/2011	Yes	No
1871	PGE	Level 2	FC	Landfill Gas (Directed)	300	3/14/2011	Yes	No
1878	PGE	Level 2	FC	Landfill Gas (Directed)	500	6/29/2011	Yes	No
1882	PGE	Level 2	FC	Landfill Gas (Directed)	400	5/24/2011	Yes	No
1885	PGE	Level 2	FC	Landfill Gas (Directed)	300	5/31/2011	Yes	No
1886	PGE	Level 2	FC	Landfill Gas (Directed)	300	5/24/2011	Yes	No
PY01-031	SCE	Level 3	ICE	Landfill Gas	991	9/29/2003	No	No
PY02-055	SCE	Level 3R	MT	Landfill Gas	420	5/19/2003	Yes	No
PY02-074	SCE	Level 3R	MT	Landfill Gas	300	2/11/2004	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

Res. No.	PA	Incentive Level	Technology	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
PY03-038	SCE	Level 3R	MT	DG - WWTP	250	7/12/2005	Yes	No
PY03-045	SCE	Level 1	FC	DG - WWTP	250	4/19/2005	Yes	No
PY03-092	SCE	Level 1	FC	DG - WWTP	500	3/11/2005	Yes	Yes
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
PY05-093	SCE	Level 3R	ICE	Landfill Gas	1030	3/16/2007	Yes	No
PY06-062	SCE	Level 2	FC	DG - WWTP	900	3/4/2008	Yes	Yes
PY06-094	SCE	Level 2	ICE	DG - WWTP	500	11/8/2007	Yes	No
PY10-002	SCE	Level 2	FC	DG - WWTP	500	10/31/2010	Yes	Yes
PY10-004	SCE	Level 2	FC	Landfill Gas (Directed)	800	3/23/2011	Yes	No
2005-082	SCG	Level 3R	ICE	DG - Food Processing	1080	1/15/2008	Yes	No
2006-012	SCG	Level 2	FC	DG - WWTP	900	12/18/2009	Yes	Yes
2006-014	SCG	Level 2	ICE	Landfill Gas	1030	2/21/2008	Yes	No
2006-036	SCG	Level 2	FC	DG - WWTP	1200	10/27/2008	Yes	Yes
2008-003	SCG	Level 2	FC	DG - Food Processing	600	12/14/2009	Yes	Yes
2010-012	SCG	Level 2	FC	Landfill Gas (Directed)	1000	1/24/2011	Yes	No
0007-01	CCSE	Level 3	MT	DG - WWTP	84	8/30/2002	No	No
0023-01	CCSE	Level 3	MT	DG - WWTP	360	9/3/2004	No	No
0026-01	CCSE	Level 3	MT	DG - WWTP	120	4/23/2004	No	No
0270-05	CCSE	Level 3R	MT	Landfill Gas	210	4/4/2008	Yes	No
0351-07	CCSE	Level 2	ICE	DG - WWTP	560	4/16/2010	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.