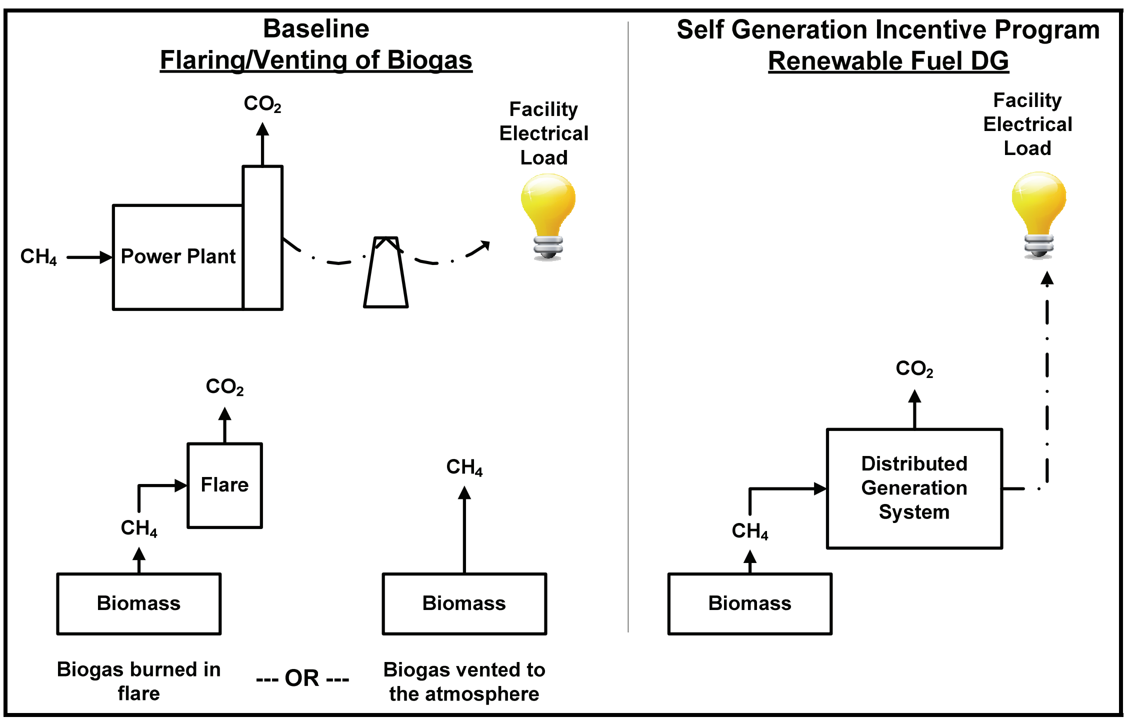
Self-Generation Incentive Program
Semi-Annual Renewable Fuel Use Report No. 14
for the Six-Month Period Ending June 30, 2009

1. Summary

The purpose of this report is to provide the Energy Division of the California Public Utilities Commission (CPUC) with updated information on fuel use and installed costs of Self-Generation Incentive Program[1] (SGIP) projects utilizing renewable fuel.[2] These SGIP distributed generation (DG) projects are characterized by their use of biogas that would otherwise have been either burned in a flare or released directly to the atmosphere. This general arrangement is summarized at a very high level in Figure 1, where the SGIP renewable fuel DG scenario is presented alongside the baseline scenario that would have occurred in the absence of the program.

Figure 1: Renewable Fuel DG Overview



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.

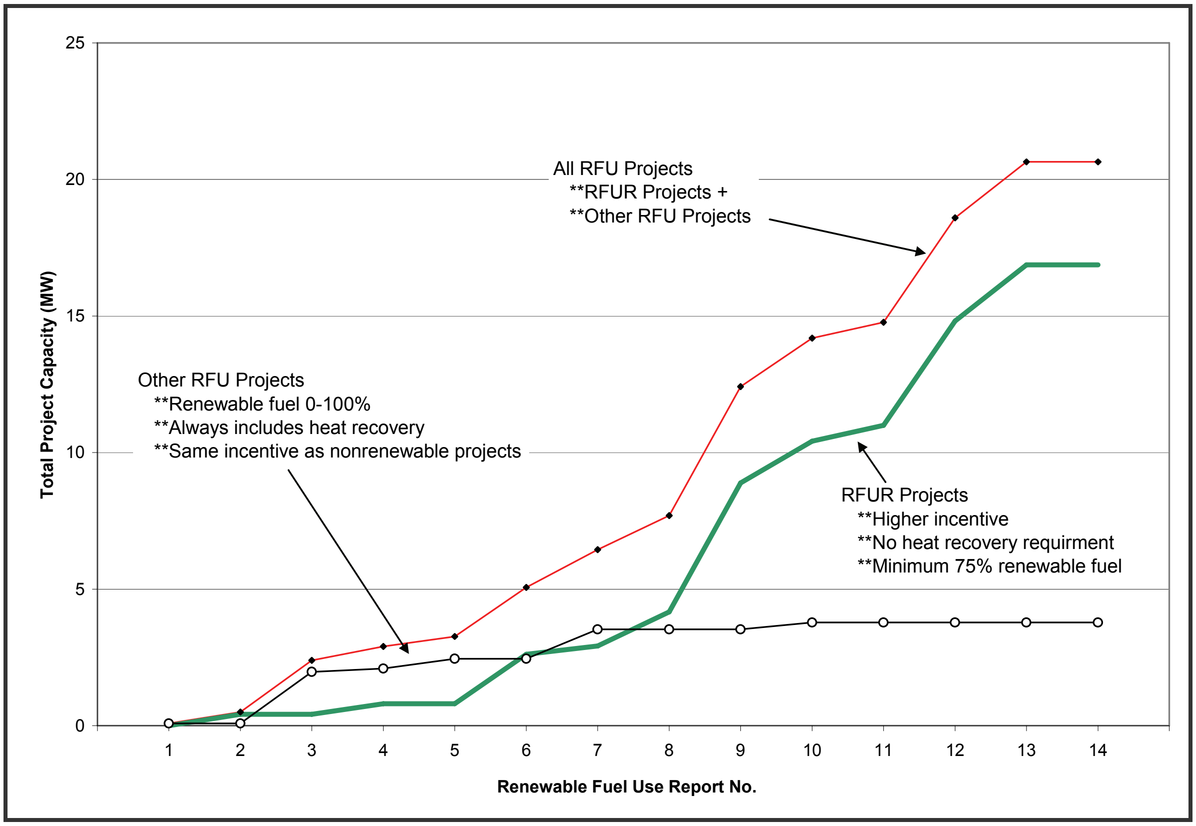
2 The SGIP Handbook defines renewable fuels as wind, solar, and gas derived from biomass, landfills, and dairies. Renewable fuel use in the context of this report effectively refers to biogas fuels obtained from landfills, wastewater treatment plants, food processing facilities, and dairy anaerobic digesters.

The principal difference between the two scenarios (i.e., the SGIP's impact) is that SGIP renewable fuel DG systems use biogas as fuel instead of releasing it directly into the atmosphere or burning it in a flare. This decreases power plant natural gas consumption and carbon dioxide (CO_2) emissions, as well as need for distribution of electricity to customer facilities.

Use of biogas in SGIP DG systems reduces overall greenhouse gas (GHG) emissions relative to the baseline. The magnitude of the reduction depends on whether the biogas (or more specifically the methane contained in the biogas) would otherwise have been flared or vented directly to the atmosphere. Methane (CH_4) is 21 times as potent a GHG as CO_2. The SGIP's GHG emissions impacts, therefore, are largest in cases where biogas would otherwise have been vented directly to the atmosphere. In those situations, the SGIP facilities gain GHG credit for essentially all of the CH_4 that would have been emitted into the atmosphere. In cases where biogas would otherwise have been converted to CO_2 in a flare the SGIP DG systems reduce GHG emissions to a lesser extent. In those situations, the SGIP facilities gain GHG credit only for the avoided CO_2 from the grid combustion processes that otherwise have supplied electricity to the SGIP facility. Note that the net differences between the levels of CO_2 emitted from the flare versus the SGIP combustion process are essentially zero.

The six-month reporting period for this report extends from January 1, 2009 to June 30, 2009 and includes analysis of all such projects installed since the SGIP's inception in 2001. This is the fourteenth report in the series. The project capacity covered by each report is depicted graphically in Figure 2.

Figure 2: Project Capacity Trend (RFU Reports 1–14)

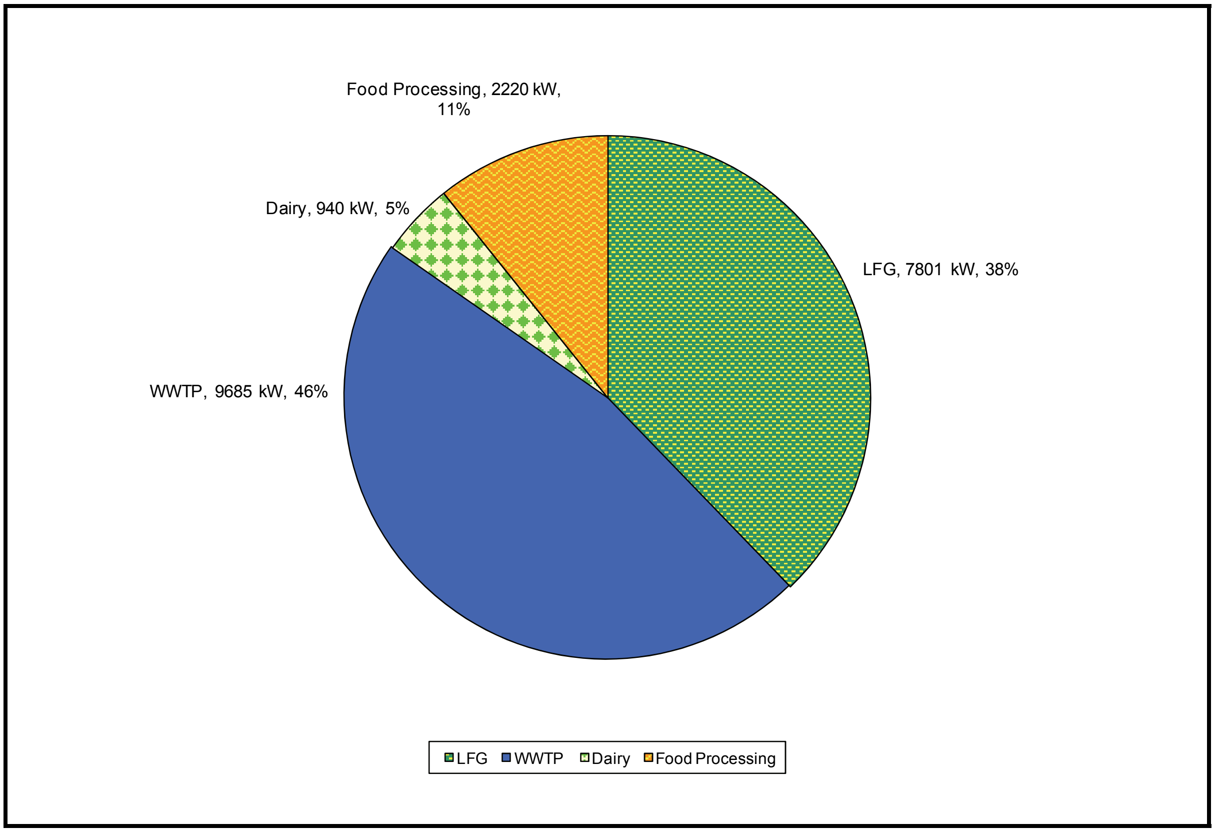


The incentives and requirements for SGIP projects utilizing renewable fuel have varied through the years. In this report, assessment of compliance with the program's minimum renewable fuel use requirements is restricted to the subset of projects (i.e., Renewable Fuel Use Requirement (RFUR) projects) actually subject to those requirements by virtue of their participation year, project type designation, and warranty status. 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. For example, Table 1 reports on RFUR projects whereas Table 9 lists all RFUR projects as well as those RFU projects not subject to the program's minimum renewable fuel use requirements.

While all RFUR projects could use as much as 25 percent non-renewable fuel, most operate completely from renewable fuel resources. To date, 79 percent of the RFUR projects have operated solely on renewable fuel. The SGIP requires the remaining projects to limit their use of non-renewable fuel to 25 percent on an annual fuel energy input basis. Data were not available for all dual-fuel projects. However, up to and including RFU Report #12, there had been no instances where available data indicated non-compliance with the program's renewable fuel use requirements. RFU Report #13 was the first and only instance of non-compliance with these requirements, as the current report also shows all projects with metered data as compliant.

RFUR projects typically use biogas derived from landfills or anaerobic digesters as the renewable fuel source. Figure 3 shows a breakout of RFUR projects as of June 30, 2009 by source of biogas (e.g., landfill gas or digester gas) on a rebated capacity basis. It illustrates that nearly half of the biogas used in SGIP RFUR projects is derived from wastewater treatment plants and over a third is derived from landfill gas projects. Dairy digesters provide the smallest contribution at approximately five percent of the total rebated RFUR project capacity.

Figure 3: Breakout of Renewable Fuel Use Requirement Projects by Fuel Type



LFG = landfill gas; WWTP = wastewater treatment plants

Project cost data available for the *samples* comprising renewable and non-renewable SGIP projects completed to date were analyzed. Average costs of those renewable projects are higher than the average costs of those non-renewable projects. However, the combined influence of small sample sizes and substantial variability preclude drawing general conclusions about incremental costs likely to be faced by participants in the future.

Confidence intervals calculated for *populations* comprising both past and future SGIP participants are very large. There was a limited quantity of cost data for fuel cells and internal combustion (IC) engines. This limited amount of data increases the uncertainty associated with the mean costs of fuel cells and IC engines. As a result, it is impossible to say with 90 percent confidence that the mean value of the costs of renewable IC engines and fuel cells is any higher than the mean value of the costs of non-renewable IC engines and fuel cells. This counter-intuitive result suggests that data for past projects should not be used as the sole basis for SGIP program 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. Purpose of this Report

The purpose of this report is to provide the Energy Division of the CPUC with updated information on fuel use and installed costs of SGIP projects utilizing renewable fuel.

The report identifies the compliance of renewable fuel use projects in the SGIP with specified renewable fuel use requirements. In particular, no more than 25 percent of the annual fuel consumption (determined on an energy input basis) of a renewable fuel use project can be derived from non-renewable resources. These projects, which are *exempt* from waste heat recovery requirements, are referred to as Renewable Fuel Use Requirements (RFUR) projects in this report.

In addition, the report includes comparisons between costs of RFUR projects and other projects typically fueled by natural gas that receive smaller incentives and are subject to heat recovery requirements. The reason for this comparison is a concern that RFUR projects might have lower net project costs than other projects, which could result in fuel switching. The analysis of project costs includes examination of waste heat recovery and fuel treatment equipment costs.

This information is provided to the Energy Division to assist staff in making recommendations to the CPUC concerning modifications to the renewable project aspects of the SGIP. This report complies with Decision 02-09-051 (September 19, 2002) that requires SGIP Program Administrators (PAs) to provide updated information on completed renewable fuel use projects on a six-month basis.[3] The six-month reporting period for this report extends from January 1, 2009 to June 30, 2009 and includes analysis of all such projects installed since the SGIP's inception in 2001.

3. Summary of Completed RFUR Projects

There were no new RFUR SGIP projects completed during the six-month reporting period. A total of 39 RFUR projects had been completed as of June 30, 2009. A list of all SGIP projects utilizing renewable fuel is included as Appendix A.

The 39 completed RFUR projects represent nearly 17 MW of installed generating capacity. The prime mover technologies used by these projects are summarized in Table 1. Sixty percent of the total rebated RFUR capacity use IC engines. Fuel cells, an emerging technology, account for 20 percent of RFUR project capacity. The average size of microturbine projects is approximately 180 kW, whereas that of renewable-powered fuel cells is 690 kW and that of renewable-fueled IC engines is approximately 640 kW.

Table 1: Summary of Prime Movers for RFUR Projects

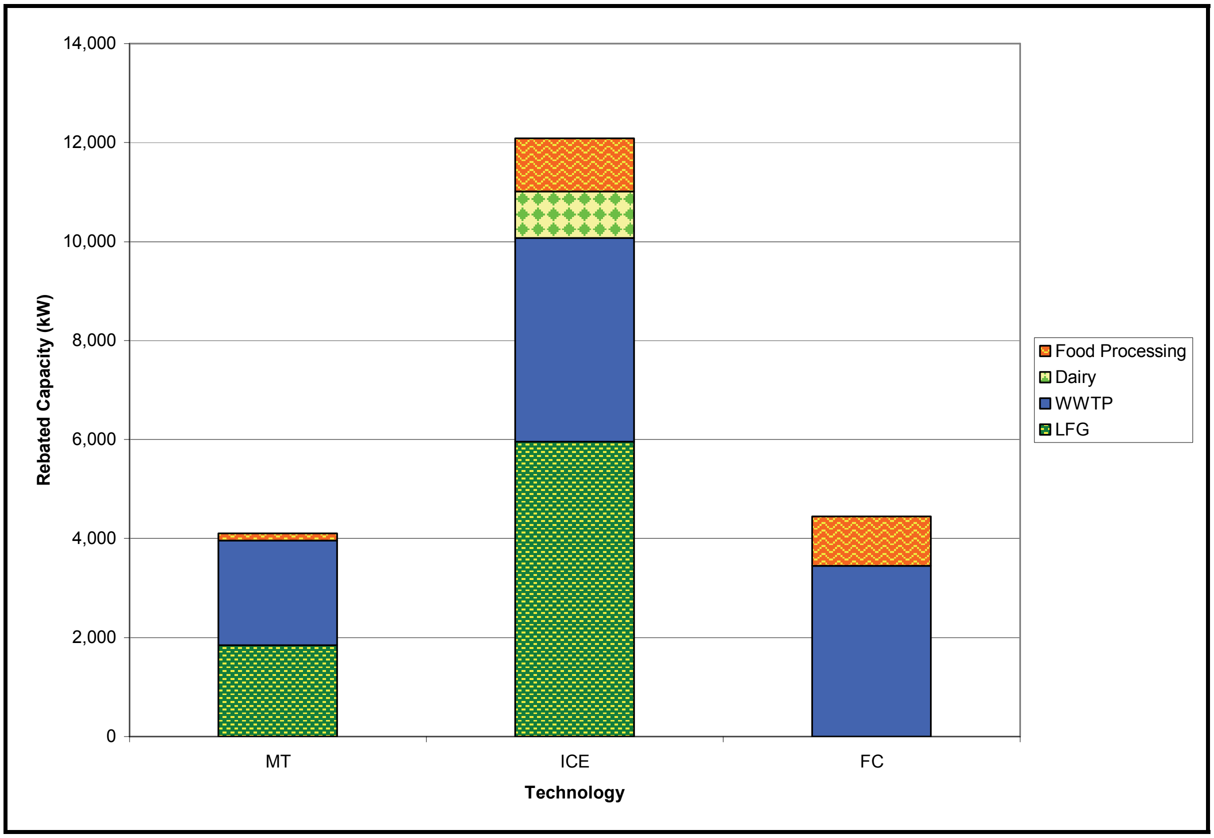
Prime Mover	No. Projects	Total Rebated Capacity (kW)	Average Rebated Capacity (kW)*
FC	5	3,450	690
MT	18	3,220	179
IC Engine	16	10,201	638
Total	**39**	**16,871**	**433**

FC = fuel cell; MT = microturbine; IC engine = internal combustion engine
* Represents an arithmetic average

3 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."

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. Biogas-powered IC engines, which represent the largest rebated capacity of SGIP RFUR facilities, are fueled primarily with biogas derived from landfills and wastewater treatment plants. From a different perspective, Figure 4 shows that dairy digesters use IC engines almost exclusively for power generation and that biogas-powered fuel cells installed under the SGIP to date have been associated only with wastewater treatment facilities or food processing facilities.

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



LFG = landfill gas; WWTP = wastewater treatment plan

While all RFUR projects could use as much as 25 percent non-renewable fuel, most operate completely from renewable fuel resources. Nearly 70 percent of the total RFUR project capacity represents such projects. The period during which RFUR projects are subject to the non-renewable fuel use cap is specified in SGIP contracts between customers and PAs. The length of the renewable fuel use requirement 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. The Applicant must provide warranty (and/or maintenance contract) start and end dates in the

Reservation Confirmation and Incentive Claim Form. Fuel supply and contract status for RFUR projects are summarized in Table 2.

Table 2: Summary of Fuel Supplies and Warranty Status for RFUR Projects

	Warranty/Renewable Fuel Use Requirement Status[4]					
	Active		Expired		Total	
Fuel Supply	**No. Projects (n)**	**Rebated Capacity (kW)**	**No. Projects (n)**	**Rebated Capacity (kW)**	**No. Projects (n)**	**Rebated Capacity (kW)**
Renewable only	16	8,603	15	2,920	31	11,523
Renewable & non-renewable	7	4,848	1	500	8	5,348
Total	**23**	**13,451**	**16**	**3,420**	**39**	**16,871**

Many of the renewable fuel use 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 indicate that 26 of the 39 RFUR projects recover waste heat. All but three of the 25 digester gas systems include waste heat recovery. Waste heat recovered from digester gas systems is generally used to pre-heat waste water sludge prior to its being pumped to digester tanks. Less than one-third of the landfill gas systems include waste heat recovery. Those 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 mover at that site.

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

Renewable Fuel Type	No. of Sites	Sites With Heat Recovery	Sites Without Heat Recovery
Digester Gas	25	22	3
Landfill Gas	14	4	10
Total	**39**	**26**	**13**

4 Since project-specific warranty start dates and lengths are not readily available, for reporting purposes all warranties are assumed to be the minimum required length and start on the incentive payment date.

4. Fuel Use at RFUR Projects

As shown in Table 2, 16 of the 23 RFUR projects remaining under warranty obtain 100 percent of their fuel from renewable resources. By definition, all 16 of those projects are in compliance with the SGIP's renewable fuel use requirements. Information on fuel use of the dual-fuel projects follows.

- **PG&E A-1313**. Metered daily electric generation, biogas consumption, and natural gas consumption data were obtained from the SGIP participant for this microturbine system. These data indicate that the system was off for the entire reporting period, thus both renewable and nonrenewable fuel usage for this period were zero.
- **PG&E A-1490**. This 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. 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 was at most 15 percent of the total annual fuel input and the system was in compliance with the SGIP's renewable fuel use provisions.[5]
- **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 PY06-062.** This 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. 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 was at most 15 percent of the total annual fuel input. The annual natural gas usage for the entire span of metered data,

[5] In these calculations an electrical conversion efficiency of 47 percent was assumed similarly to RFU Report #12. The intent was to develop an efficiency likely to be higher than the actual efficiency. If the actual efficiency is lower than 47 percent (which is likely), then the actual non-renewable fuel use is lower than the estimated percent. It is for this reason that in Table 4 the Renewable Fuel Use is reported as being *greater than* the given percentage.

from November 15, 2007 to June 30, 2009, was at most 16 percent. The system was in compliance with the SGIP's renewable fuel use provisions for all reporting periods. [5]

- **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. No metered data were available for this reporting period to assess the actual fuel mix. 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.[6]
- **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.

  Itron received natural gas usage data from SCG and metered electric output data from the applicant for the 12-month period ending June 30, 2009. An assumed electrical conversion efficiency was used to estimate total fuel use during periods of electricity generation. During this reporting period there were many hours when, instead of being generated, electricity was being consumed to maintain a "hot standby" condition. As noted above, biogas use is not metered. For the purposes of assessing compliance with the SGIP's renewable fuel use requirements Itron assumed that no biogas was used while the system was in a "hot standby" condition. The resulting estimate of non-renewable fuel contribution was at most 12 percent. In conclusion, during this reporting period the renewable fuel use was at least 88 percent and the system was in compliance with the SGIP's renewable fuel use provisions.[5]
- **SCG 2006-036.** This fuel cell system 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. No metered data were available to assess the actual fuel mix during this reporting period.

Fuel use compliance for the eight dual-fuel systems is presented in Table 4. Overall, between 20 (90 percent) and 23 (100 percent) of the RFUR projects remaining under warranty comply with the SGIP's 25 percent non-renewable cap. Currently there are insufficient data to draw definitive conclusions about three RFUR projects remaining under warranty.

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6 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 and this is not practical.

Table 4: Fuel Use Compliance of RFUR Projects Utilizing Non-Renewable Fuel

PA Project ID No.	PA/ Incentive Level	Technology/ Fuel Type	Capacity (kW)	Operational Date[7]	Annual Natural Gas Energy Flow (MM Btu)[8]	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements?
PY03-092	SCE / Level 1	FC / Digester gas	500	3/11/2005	655	>88	Active	Yes
PY03-017	SCE / Level 3-R	IC Engine / Digester gas	500	5/11/2005	NA	NA	Expired	Not Applicable
PY04-158	SCE / Level 3-R	IC Engine / Digester Gas	704[9]	10/25/2006[10]	NA	NA	Active	NA
PY04-159	SCE / Level 3-R	IC Engine / Digester Gas	704	10/26/2006[10]	NA	NA	Active	NA
1313	PG&E / Level 3-R	MT / Digester Gas	240	3/6/2007	0	Not Applicable[11]	Active	Yes
PY06-062	SCE/ Level 2	FC/ Digester gas & Natural gas	900	3/4/2008	4551	≥85	Active	Yes
1490	PG&E/ Level 2	FC/ Digester Gas & Natural gas	600	4/24/2008	3003	≥85	Active	Yes
2006-036	SCG/ Level 2	FC/ Digester gas & Natural gas	1200	10/27/2008	NA	NA	Active	NA

FC = fuel cell; MT = microturbine; IC engine = internal combustion engine
"NA" ≡ "Not Available". Metered data necessary to calculate estimates of natural gas energy use were not available for this reporting period. Projects with active warranties are not required to meter system performance, but those that do are required to share their data for program evaluation purposes. Once a project's warranty has expired, the site is no longer required to share data.

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7 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.

8 This field represents the natural gas consumption during the 12-month period ending June 30, 2009. The basis is the LHV of the fuel.

9 In RFU Reports #9 and #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.

10 In RFU Reports #9 through #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 7.

11 The percent of renewable fuel used is not applicable during this reporting period because the denominator (i.e., Total Energy Input) is zero.

Incentive levels for renewable fuel projects have changed over time and are roughly defined as below for the purposes of this report:[12]

- 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
- Incentive Level 3: Used for a short time 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

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. 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.

[12] 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.

It is possible to use historical SGIP project cost data to examine fuel treatment and heat recovery costs faced by SGIP participants. Eligible installed costs for all fuel cell, microturbine, and IC engine projects operational as of June 30, 2009 are summarized in Table 5. 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 for which summary statistics are presented in Table 5 comprise only a few projects. In these instances the sample sizes play a very important role in determining ability to draw general 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 5: Summary of Project Costs by Technology, Heat Recovery Provisions & Fuel Type*

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	Project Cost Range ($/W)	Project Cost Median ($/W)	Project Cost Mean ($/W)	Project Cost Std. Dev. ($/W)	Project Cost Size-Weighted Average ($/W)
FC	Yes	Yes	6	4.51 - 9.85	6.64	7.04	2.20	6.33
	Yes	No	0	-------	-------	-------	-------	-------
	Yes	Yes or No	6	4.51 - 9.85	6.64	7.04	2.20	6.33
	No	Yes	16	5.06 - 18.00	6.92	8.43	3.57	7.55
IC Engine	Yes	Yes	15	1.08 - 5.70	2.64	2.59	1.26	2.51
	Yes	No	3	1.71 - 2.87	2.66	2.41	0.62	2.69
	Yes	Yes or No	18	1.08 - 5.70	2.65	2.56	1.16	2.55
	No	Yes	213	0.85 - 10.70	2.29	2.50	1.20	2.27
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
	Yes	Yes or No	23	1.23 - 11.30	3.75	4.40	2.30	3.78
	No	Yes	111	0.70 - 6.39	3.15	3.23	1.14	3.09

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

* 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 5 by identifying those using any amount of renewable fuel as a "Yes" classification.

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

Heat Recovery Equipment Costs

All of the projects using renewable fuel include fuel-conditioning equipment. Most of the renewable fuel projects include heat recovery even though most of them were not required to. Differences observed between the average costs of these two groups could be due to the difference in provisions for heat recovery. This relationship is expressed symbolically in Equation 1. For example, the heat recovery difference for microturbines ($1.66) is calculated as $5.13 minus $3.47.

$$\Delta Heat\,\mathrm{Re}\,\mathrm{cov}\,ery = \begin{pmatrix} RFU \\ w/\,HR \end{pmatrix} - \begin{pmatrix} RFU \\ w/\,o\,HR \end{pmatrix}$$

Equation 1

Where

RFU = renewable fuel use
HR = heat rate
w/ = with
w/o = without

Fuel Treatment Equipment Costs

All of the non-renewable fuel projects include heat recovery equipment. Many of the renewable fuel projects include heat recovery even though most of them were not required to. Any difference observed between the costs of these two groups could be due to the difference in provisions for fuel treatment (which is usually, but not always, limited to gas clean-up such as removal of hydrogen sulfide). For example, the fuel treatment difference for IC engines ($0.09) is calculated as $2.59 minus $2.50.

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

Equation 2

Where

NG = natural gas

RFU Equipment Costs

All of the non-renewable fuel projects include heat recovery equipment. Many of the renewable fuel projects include heat recovery even though many were not required to employ heat recovery. By looking at the observed difference in costs of these two groups, it is possible to see the average overall influence of different SGIP requirements. For example, the RFU difference for IC engines ($0.06) is calculated as $2.56 minus $2.50.

$$\Delta RFU = \left(\begin{matrix} RFU \\ w/\,or\, w/\,o\;\; HR \end{matrix} \right) - \left(\begin{matrix} NG \\ w/\,HR \end{matrix} \right) \qquad \textbf{Equation 3}$$

Uncertainty Analysis

Project cost data are available for all completed projects. The sampling error included in difference of means results calculated for projects completed in the past is zero because project cost data are available for all of these projects. However, the key question faced by the CPUC and other program designers is:

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 more difficult to answer. 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.

Cost comparison discussions for microturbines, IC engines, and fuel cells are presented below. Difference of means results are augmented with 90 percent confidence intervals about these means. In each of these cases the confidence intervals are based on the sample statistics (e.g., n, mean, and std. dev.) presented in Table 5.

Microturbine Project Cost Comparisons

Cost comparison results for microturbines are summarized in Table 6. 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.[13]

Table 6: 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	1.90	0.54 to 3.26
RFU	1.17	0.36 to 1.98

The 90 percent confidence intervals presented in Table 6 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.

13 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 & $n_2 \geq 30$ then a z-Test is used to determine confidence intervals. When n_1 or $n_2 < 30$ then a t-Test is used.

IC Engine Project Cost Comparisons

Cost comparison results for IC engines are summarized in Table 7. Results for the incremental difference due to heat recovery are not presented because all but three of the renewable IC engine projects completed to date have included heat recovery even though it was not required by the SGIP. 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.

Table 7: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Fuel Treatment	0.09	-0.46 to 0.64
RFU	0.06	-0.41 to 0.53

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 8. 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.

Table 8: Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Fuel Treatment	-1.39	-3.47 to 0.69
RFU	-1.39	-3.47 to 0.69

Cost Comparison Summary

Comparison of the installed costs between renewable- and non-renewable-fueled generation systems operational as of June 30, 2009 reveals that average non-renewable generator costs have 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 future SGIP participants?

Confidence intervals calculated for populations comprising both past *and* future SGIP participants are very large. This suggests that data for past projects should not be used as the sole basis for SGIP program 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 Projects Utilizing Renewable Fuel

All SGIP projects supplied with renewable fuel are listed in Table 9. Renewable Fuel Use Requirements (RFUR) projects subject to renewable fuel use requirements and exempt from heat recovery requirements are identified in the column titled “RFUR Project?” Only a small portion of these projects is also equipped with a non-renewable fuel supply. These projects are identified in the “Any Non-Renewable Fuel Supply?” column.

Table 9: SGIP Projects Utilizing Renewable Fuel

PA Project ID No.	PA/ Incentive Level	Technology/ Fuel Type	Capacity (kW)	Operational Date[14]	RFUR Project?	Any Non-Renewable Fuel Supply?
0007-01	CCSE/ Level 3	MT/ Digester gas	88	8/30/2002	No	No
PY02-055	SCE/ Level 3-R	MT/ Landfill gas	420	4/18/2003	Yes	No
PY01-031	SCE/ Level 3	IC Engine/ Landfill gas	970	9/29/2003	No	No
110	PG&E/ Level 3	IC Engine/ Digester gas & Natural gas	900	10/23/2003	No	Yes
PY02-074	SCE/ Level 3-R	MT/ Landfill gas	300	2/12/2004	Yes	No
0026-01	CCSE/ Level 3	MT/ Digester gas	120	4/23/2004	No	No
514	PG&E/ Level 3-R	MT Digester gas	90	5/19/2004	Yes	No
298	PG&E Level 3-R	MT/ Digester gas	30	8/4/2004	Yes	No
0023-01	CCSE/ Level 3	MT/ Digester gas	360	9/3/2004	No	No

[14] 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.

Table 9: SGIP Projects Utilizing Renewable Fuel (Continued)

PA Project ID No.	PA/ Incentive Level	Technology/ Fuel Type	Capacity (kW)	Operational Date	RFUR Project?	Any Non-Renewable Fuel Supply?
379	PG&E/ Level 3-R	MT/ Landfill gas	280	1/14/2005	Yes	No
PY03-092	SCE/ Level 1	FC/ Digester gas & Natural gas	500	3/11/2005	Yes	Yes
640	PG&E/ Level 3-R	MT/ Landfill gas	70	4/14/2005	Yes	No
641	PG&E/ Level 3-R	MT/ Landfill gas	70	4/14/2005	Yes	No
PY03-045	SCE/ Level 1	FC/ Digester gas	250	4/19/2005	Yes	No
PY03-008	SCE/ Level 3-R	MT/ Landfill gas	70	5/11/2005	Yes	No
PY03-017	SCE/ Level 3-R	IC Engine/ Digester gas	500	5/11/2005	Yes	Yes
842A	PG&E/ Level 3-R	MT/ Digester gas	60	5/27/2005	Yes	No
PY03-038	SCE Level 3-R	MT/ Digester gas	250	7/12/2005	Yes	No
747	PG&E Level 3-R	MT/ Digester gas	60	7/18/2005	Yes	No
653	PG&E Level 2	FC/ Digester gas	1000	8/9/2005	No	Yes
833	PG&E/ Level 3-N	MT/ Digester gas	70	9/1/2005	No	Yes
483	PG&E/ Level 3-R	IC Engines/ Digester gas	300	1/13/2006	Yes	No
313	PG&E/ Level 3-R	MT/ Digester gas	300	3/16/2006	Yes	No
1222	PG&E Level 3-R	IC Engines/ Landfill gas	970	3/24/2006	Yes	No
1297	PG&E/ Level 3-R	MT/ Digester gas	280	4/7/2006	Yes	No
856	PG&E/ Level 3-R	MT/ Landfill gas	210	5/5/2006	Yes	No
658	PG&E/ Level 3-R	IC Engines/ Digester gas	160	5/22/2006	Yes	No

Table 9: SGIP Projects Utilizing Renewable Fuel (Continued)

Project ID No.	Program Administrator/ Funding Level	Technology/ Fuel Type	Capacity (kW)	Operational Date	RFUR Project?	Any Non-Renewable Fuel Supply?
1313	PG&E Level 3-R	MT/ Digester gas & Natural gas	240	7/17/2006	Yes	Yes
PY05-093	SCE Level 3-R	IC Engines/ Landfill gas	1030	9/1/2006	Yes	No
1316	PG&E Level 3-R	IC Engines/ Landfill gas	970	10/2/2006	Yes	No
PY04-158	SCE Level 3-R	IC Engines/ Digester gas	704[15]	10/25/2006[16]	Yes	Yes
PY04-159	SCE Level 3-R	IC Engines/ Digester gas	704	10/26/2006[16]	Yes	Yes
1559	PG&E Level 2	IC Engines/ Digester gas	160	11/16/2006	Yes	No
1308	PG&E Level 3-R	IC Engines/ Digester gas	400	11/17/2006	Yes	No
1505	PG&E Level 2	IC Engines/ Landfill gas	970	11/24/2006	Yes	No
1298	PG&E Level 3N	MT/ Digester gas & Natural gas	250	1/19/2007	No	Yes
1528	PG&E Level 2	MT/ Digester gas	70	3/16/2007	Yes	No
PY06-094	SCE Level 2	IC Engines/ Digester gas	500	5/27/2007	Yes	No
1577	PG&E Level 2	IC Engines/ Digester gas	80	10/1/2007	Yes	No
2005-082	SCG/ Level 3R	IC Engines/ Digester gas	1080	1/15/2008	Yes	No
2006-014	SCG/ Level 2	IC Engines/ Landfill gas	1030	2/21/2008	Yes	No
PY06-062	SCE/ Level 2	FC/ Digester gas & Natural gas	900	3/4/2008	Yes	Yes

[15] In Renewable Fuel Use Reports #9 and #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.

[16] In Renewable Fuel Use Reports #9 through #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 in footnote 7.

Table 9: SGIP Projects Utilizing Renewable Fuel (Continued)

Project ID No.	Program Administrator/ Funding Level	Technology/ Fuel Type	Capacity (kW)	Operational Date	RFUR Project?	Any Non-Renewable Fuel Supply?
0270-05	CCSE/ Level 3R	MT/ Landfill gas	210	4/4/2008	Yes	No
1490	PG&E/ Level 2	FC/ Digester gas & Natural gas	600	4/24/2008	Yes	Yes
1640	PG&E Level 3-R	IC Engines/ Digester gas	643	7/29/2008	Yes	No
1498	PG&E Level 3-R	MT/ Landfill gas	210	8/5/2008	Yes	No
2006-036	SCG/ Level 2	FC/ Digester gas & Natural gas	1200	10/27/2008	Yes	Yes