Self Generation Incentive Program: Renewable Fuel Use Report No. 24

Submitted to PG&E and the SGIP Working Group

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GLOSSARY

Abbreviations and Acronyms

Term	Definition
ADG	Anaerobic Digester Gas
CEC	California Energy Commission
CHP	Combined Heat and Power
CSE	Center for Sustainable Energy
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
CPUC	California Public Utilities Commission
DBG	Directed Biogas
DG	Digester Gas
FC	Fuel Cell
GT	Gas Turbine
ICE	Internal Combustion (IC) Engine
IOU	Investor Owned Utility
MT	Microturbine
PA	Program Administrator
PBI	Performance Based Incentive
PG&E	Pacific Gas and Electric Company
PY	Program Year
RFU	Renewable Fuel Use
RFUR	Renewable Fuel Use Requirement
SCE	Southern California Edison Company
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company

SGIP	Self-Generation Incentive Program
WWTP	Wastewater Treatment Plant

Key Terms

Term	Definition
Applicant	The entity, either the Host Customer, System Owner, or third party designated by the Host Customer, that is responsible for the development and submission of the SGIP application materials and is the main contact for the SGIP Program Administrator for a specific SGIP application.
Biogas	A gas composed primarily of methane and carbon dioxide produced by the anaerobic digestion of organic matter. This is a renewable fuel. Biogas is typically produced in landfills, and in digesters at wastewater treatment plants, food processing facilities, and dairies.
Biogas Baseline	The assumed treatment of biogas fuel in the absence of the SGIP generator. See *Flaring* and *Venting*.
Combined Heat and Power (CHP)	A system that produces both electricity and useful heat simultaneously; sometimes referred to as "cogeneration."
CO_2 Equivalent (CO_2eq)	When reporting emission impacts from different types of greenhouse gases, total GHG emissions are reported in terms of tons of CO_2 equivalent so that direct comparisons can be made. To calculate CO_2eq, the global warming potential of a gas as compared to that of CO_2 is used as the conversion factor (e.g., the global warming potential (GWP) of methane is 21 times that of CO_2). Thus, the CO_2eq of a given amount of methane is calculated as the product of the GWP factor (21) and the amount of methane.
Completed	Projects that have been installed and begun operating, have passed their SGIP eligibility inspection, and were issued an incentive payment.
Confidence Interval	A particular kind of interval estimate of a population parameter (such as the mean value) used to indicate the reliability of the estimate. It is an observed interval (i.e., calculated from observations) that frequently includes the parameter of interest. How frequently the observed interval contains the parameter is determined by the confidence level or confidence coefficient. A confidence interval with a particular confidence level is intended to give the assurance that, if the statistical model is correct, then taken over all the data that might have been obtained, the procedure for constructing the interval would deliver a confidence interval that included the true value of the parameter the proportion of the time set by the confidence level.
Confidence Level (also Confidence Coefficient)	The degree of accuracy resulting from the use of a statistical sample. For example, if a sample is designed at the 90/10 confidence (or precision) level, resultant sample estimates will be within ±10 percent of the true value, 90 percent of the time.
Directed Biogas	Biogas delivered through a natural gas pipeline system and its nominal equivalent used at a distant customer's site. Within the SGIP, this is classified as a renewable fuel.
Electrical Conversion Efficiency	The ratio of electrical energy produced to the fuel energy used (lower heating value).

Term	Definition
Flaring (of Biogas)	A flaring baseline means that there is ***prior*** legal code, law or regulation requiring capture and flaring of the biogas. In this event an SGIP project ***cannot*** be credited with GHG emission reductions due to capture of **methane** in the biogas. A project cannot take credit for a prior action required by legal code, law or regulation. See also: *Venting (of Biogas)*.
Greenhouse Gas (GHG) Emissions	For the purposes of this analysis GHG emissions refer specifically to those of CO_2 and methane, expressed as CO_2eq.
Lower Heating Value (LHV)	The amount of heat released from combustion of fuel assuming that the water produced during the combustion process remains in a vapor state at the end of combustion. Units of LHV are typically Btu/SCF of fuel.
Metric Ton	Common international measurement for the quantity of greenhouse gas emissions. A metric ton is equal to 2,205 pounds.
Onsite Biogas	Biogas projects where the biogas source is located directly at the host site where the SGIP system is located. See also: *Directed Biogas*.
Prime Mover	A device or system that imparts power or motion to another device such as an electrical generator. Examples of prime movers in the SGIP include gas turbines, IC engines, and wind turbines.
Rebated Capacity	The capacity rating associated with the rebate (incentive) provided to the program participant. The rebated capacity may be lower than the manufacturer's nominal "nameplate" system size rating.
Venting (of biogas)	A venting baseline means that there is no ***prior*** legal code, law or regulation requiring capture and flaring of the biogas. Only in this event can an SGIP project be credited with GHG emission reductions due to capture of **methane** in the biogas. A project cannot take credit for a prior action required by legal code, law or regulation. *See also: Flaring (of Biogas)*.

1 EXECUTIVE SUMMARY

This report fulfills Decision 02-09-051 (September 19, 2002) of the California Public Utilities Commission (CPUC). That decision requires Self-Generation Incentive Program (SGIP) Program Administrators to provide updated information every six months on completed SGIP projects using renewable fuel. CPUC Rulemaking 12-11-005 (November 8, 2012) reduced the frequency of the filing requirement for the SGIP Renewable Fuel Use (RFU) reports from a semi-annual to an annual filing requirement. RFU Report No. 24 is the first report impacted by Rulemaking 12-11-005.

The primary purpose of these RFU reports is to provide the Energy Division of the CPUC with the required updated renewable fuel use information. The report specifically contains compliance determinations of Renewable Fuel Use facilities with renewable fuel use requirements (RFUR). 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.

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

RFU Report No. 24 covers projects completed during the twelve month period ending December 31, 2014, as well as all renewable fuel use projects installed previously under the SGIP since the Program's inception in 2001. Results of analysis of renewable fuel use compliance presented in this RFU Report are based on the 12 months of operation from January 1, 2014, to December 31, 2014.

1.1 RFU Report Methodology and Data Overview

SGIP RFU Report No. 24 presents the renewable fuel usage and cost information from the 136 renewable projects rebated by the SGIP as of December 31, 2014. The report leverages information found in the SGIP Statewide Project Database, the Inspection Reports prepared by 3rd party consultants, and metered data (electrical generation, fuel consumption, and other biogas usage documentation) provided to Itron through data requests or the Performance Based Incentive (PBI) data transfer process.

SGIP RFU projects are fueled by a variety of sources. These biogas sources can be either located onsite (onsite biogas) or at a location other than the SGIP generator (directed biogas). Of the 136 RFU projects rebated by the SGIP as of December 31, 2014, 72 are fueled by on-site biogas. Sources of on-site biogas include landfills, wastewater treatment plants (WWTPs), dairies, and other sources of digester gas (DG) such as food processing facilities. The remaining 64 facilities are fueled by directed biogas which is procured off-site, cleaned up, and injected into the natural gas distribution system. Sources of directed biogas include landfills and wastewater treatment plants. The technologies that utilize these biogas resources include fuel cells (FCs), internal combustion engines (IC engines or ICEs), and microturbines (MTs). Fuel cells in the program operate either in combined heat and power (FC-CHP) mode, or in electric only mode (FC-Elec.).

Projects that receive incentives at renewable levels (formerly Level 3R projects, now called a biogas adder) are required to comply with minimum renewable fuel usage requirements. Namely, these projects are required to consume a minimum of 75% of their energy input from renewable sources. Of the 136 RFU projects discussed in this report, 128 received incentives at a renewable level and are therefore required to comply with the SGIP's minimum renewable fuel use requirements. The compliance period is defined by the project's warranty which can be three, five, or ten years depending on the technology type and the year the project applied to the SGIP.

The methodology used to assess compliance with SGIP minimum renewable fuel use requirements is different for on-site biogas projects and for directed biogas projects. On-site biogas projects that operate exclusively on renewable fuel (no natural gas supplementation) are automatically assumed to be in compliance. For projects equipped with two fuel supplies (biogas and natural gas, dual-fueled), we use metered electrical generation and natural gas consumption data to arrive at an estimate of renewable fuel usage. These data are provided by project hosts, applicants, manufacturers, or Performance Data Providers (PDPs) for projects 30 kW or larger subject to PBI rules. For directed biogas projects, compliance determinations are made following the audit protocols prepared by a 3rd party consultant (see Appendix B). A detailed overview of renewable fuel use compliance findings is presented in Section 3.

1.2 Summary of RFU Report No. 24 Findings

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

- As of December 31, 2014, there were 136 RFU facilities deployed under the SGIP, representing approximately 67.2 MW of rebated capacity. One hundred and twenty eight of these facilities received higher renewable incentives and represented approximately 63.5 MW of rebated capacity. The remaining eight other RFU projects which did not receive renewable incentives represented approximately 3.8 MW of rebated capacity. The 136 RFU projects represent 18 % of all 769 SGIP projects (excluding solar photovoltaics) rebated as of December 31, 2014.
- Of the 128 projects that received higher renewable incentives, 43 (about 34 percent by project count) operated solely from on-site renewable fuels and as such inherently comply with renewable fuel use requirements.[1] Of the remaining 85 dual-fuel facilities (having both renewable and non-renewable fuel supplies) receiving higher renewable incentives:
  - Fifty-one directed biogas projects were found to be in compliance with renewable fuel use requirements based on the audit methodology described in this report,
  - Thirteen directed biogas projects and five on-site biogas projects could not have their compliance determined until additional data are received,
  - Twelve blended on-site biogas projects were out of warranty and as such were no longer subject to reporting and compliance requirements,
  - One project was found to be not applicable with respect to the requirements as it has not yet been operational for a full year, and
  - Three on-site blended RFUR projects were found to be out of compliance.

[1] Installation verification reports prepared by 3rd party consultants are used to determine renewable fuel supply configuration.

- RFU facilities are powered by a variety of renewable fuel (i.e., biogas) resources. Approximately 47 percent of the rebated capacity (31.6 MW) of RFU facilities deployed through December 31, 2014 was powered by directed biogas. The remaining 53 percent were fueled by on-site biogas.
- Prime movers used at RFU facilities include fuel cells, microturbines, and internal combustion engines. Historically, IC engines had been the dominant prime mover technology of choice at RFU facilities. With the emergence of directed biogas as an eligible renewable fuel, IC engines have been surpassed by electric-only fuel cells as the dominant prime mover technology. Electric-only fuel cells provide approximately 24.7 MW (about 37 percent) of the approximately 67.2 MW of rebated RFU capacity. IC engines provided 17.8 MW (about 26 percent of all RFU capacity). CHP fuel cells and microturbines make up the remainder of the RFU capacity.
- Based on analysis of costs of RFU facilities, the average costs of renewable projects appeared to be higher than the average costs of non-renewable projects. However, a limited sample and highly variable cost data prevent the conclusion that there is a 90 percent certainty that the mean cost of renewable-powered combined heat and power (CHP) fuel cells is higher than the mean cost of CHP fuel cells powered by non-renewable resources. Other factors such as system size, installation cost, and fuel cell chemistry may confound the comparison.
- RFU facilities have considerable potential for reducing GHG emissions. The magnitude of the GHG emission reduction depends largely on the manner in which the biogas would have been treated in the absence of the program (i.e., the "baseline" condition). RFU facilities that would have been venting biogas directly to the atmosphere have a much higher GHG emission reduction potential than RFU facilities that would have been required to capture and flare biogas.
  - In general, the 2013 SGIP Impact Evaluation Report showed that RFU facilities for which biogas flaring was the baseline condition decreased GHG emissions by around 0.30-0.53 metric tons of carbon dioxide equivalent (CO_2eq) per MWh of generated electricity.
  - The GHG emission reduction potential of RFU facilities for which biogas venting was the baseline condition is around 4.73 metric tons of CO_2eq per MWh of generated electricity; an order of magnitude greater in GHG emission reduction potential.
- Potential for GHG emission reductions from RFU facilities may also be 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 if natural gas would otherwise have been used to generate process heat.

1.3 Conclusions and Recommendations

In accordance with the original CPUC Decision 02-09-051 in September 2002, the overall purpose of the renewable fuel use reports is to help ensure that projects receiving increased incentives for being renewably fueled are in fact meeting the renewable fuel use requirements. Renewable Fuel Use Report No. 24 marks the tenth consecutive occurrence of non-compliance with renewable fuel use requirements. While some of these instances of non-compliance are due to projects occasionally falling below the minimum renewable fuel limit, some projects are consistently out of compliance.

This is the third consecutive RFU Report where directed biogas audit protocols developed by the PAs and their consultant Alternative Energy Systems Consulting (AESC) were used by the evaluation contractor to make compliance determinations (see Appendix B). This report found that 51 directed biogas projects were in compliance with renewable fuel use requirements but it also includes 13 instances where the compliance status remains 'Inconclusive' because sufficient data and supporting documentation were not provided in a timely manner.

Finally, in accordance with CPUC Decision 02-09-051, this report includes information on project installed costs. Comparison of the installed costs between renewable- and non-renewable fueled generation systems reveals that average non-renewable generator costs have typically been lower than average renewable fueled generator costs. However, confidence intervals calculated for populations comprising both past and present SGIP participants are very large. In fact, these confidence intervals prevent drawing conclusions about cost differences in CHP fuel cell projects; only IC engine and microturbine projects exhibit cost differences at 90 percent confidence. This suggests that data for past projects should not be used as the sole basis for SGIP design elements affecting future participants.

In light of these conclusions, we make the following recommendations:

1. **Conduct Further Studies on Projects Repeatedly Out of Compliance**

   We continue to recommend that further studies be conducted into projects that are consistently out of compliance as this information could potentially contribute to attainment of higher levels of compliance in the future.

2. **Require More Complete Monitoring and Streamlined Data Delivery**

   As indicated earlier, three projects were found to be out of compliance with SGIP renewable fuel use requirements. An additional 18 projects could not have their compliance status determined because insufficient data were available.

   With the adoption of a PBI payment mechanism for systems 30 kW or larger, the PAs have greatly improved the availability of metered data in the SGIP. All SGIP technologies 30 kW or larger must install metering and monitoring that measures net electrical output from the system. Furthermore, CHP and electric-only fuel cell technologies operating on non-renewable fuel must also install metering and monitoring equipment that measures and reports fuel input.[2] We recommend that this natural gas monitoring requirement be extended to renewable-fueled projects that are also equipped with a natural gas fuel supply (blended on-site RFUR projects). Without these additional data it is not possible to make compliance determinations of blended on-site RFUR projects. Installing natural gas metering after project commissioning is disruptive, expensive, and potentially dangerous. Establishing the transfer of fuel input data at the onset of project development is more cost-effective, would enable verification of renewable fuel use compliance, and allow for assessment of the actual greenhouse gas impacts of these projects.

   With regards to directed biogas audit documentation, the PAs have made significant progress in resolving data availability issues by establishing clear protocols governing the process for

[2] 2015 Self-Generation Incentive Program Handbook. January 13, 2015. Page 60 (Metering & Data Collection): *"All SGIP technologies 30 kW or larger must install metering and monitoring equipment that measures net electrical output from the system(s). Combined heat and power technologies operating on non-renewable fuels will in addition install metering and monitoring equipment that measures and reports useful thermal energy delivered to the Site from the CHP system as well as fuel input to the generator(s)."*

auditing SGIP directed biogas procurement. Having said that, we find that the timely delivery of directed biogas documentation from the relevant parties to the evaluation contractor remains a weak link in the process. Further, the documentation that is delivered is often unclear or at times illegible. We recommend the development of a centralized process by which the appropriate parties submit directed biogas audit documentation to the PAs instead of relying on the evaluation contractor. The California Energy Commission (CEC) Renewable Portfolio Standard (RPS) verification protocols for pipeline biomethane (equivalent to SGIP directed biogas) should be leveraged as they include standardized forms and timelines for delivery of audit documentation. The SGIP directed biogas audit protocols provide the accounting rules for the audit process but lack the timelines, forms, and enforcement mechanisms found in the CEC's RPS verification protocols.

3. **Leverage Additional Data Sources for Cost Comparisons**

Traditionally, the cost analysis presented in the RFU reports has relied on SGIP total eligible costs reported by participants during the application process. Statistical tests are applied to determine whether significant differences existed between renewable and non-renewable total projects costs. This approach is simple and leverages data that are readily available but is subject to a high degree of uncertainty. Namely, a comparison of total renewable and non-renewable eligible project costs is confounded by variability in other costs such as interconnection costs, warranty costs, waste heat recovery costs, and construction / installation costs.

To avoid these sources of variability and uncertainty we recommend future RFU reports leverage the detailed on-site fuel cleanup cost information that participants are required to provide to the PAs during the application process. These data represent an extremely valuable, but as yet underutilized resource for all SGIP stakeholders. The results of this work could also contribute to enhancement of the current statewide project tracking database. The database is designed to track biogas cleanup costs but as of April 2015 contained biogas cleanup cost values for only three renewable projects.

2 REPORT PURPOSE AND FUEL USE SUMMARY

This report fulfills Decision 02-09-051 (September 19, 2002) of the California Public Utilities Commission (CPUC). That decision requires Self-Generation Incentive Program[3] (SGIP or Program) Program Administrators (PAs) to provide updated information every six months[4] on completed SGIP projects using renewable fuel.[5] CPUC Rulemaking 12-11-005 (November 8, 2012) reduced the frequency of the filing requirement for the SGIP Renewable Fuel Use (RFU) reports from a semi-annual to an annual filing requirement. RFU Report No. 24 is the first report impacted by Rulemaking 12-11-005.

The purpose of these RFU reports is to provide the Energy Division of the CPUC with the required updated renewable fuel use information. The report specifically contains compliance determinations of Renewable Fuel Use facilities with renewable fuel use requirements. 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.

Due to a growing interest in the potential for renewable fuel use projects to reduce greenhouse gas (GHG) emissions,[6] a section on GHG emission impacts from renewable fuel SGIP projects was added to the reports beginning with RFU Report No. 15. This information originates from the most recent SGIP Impact Evaluation Report.

RFU Report No. 24 covers projects completed during the twelve month period ending December 31, 2014, as well as all renewable fuel use projects installed previously under the SGIP since the Program's inception in 2001. Results of analysis of renewable fuel use compliance presented in this RFU Report are based on the 12 months of operation from January 1, 2014, to December 31, 2014.

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3 The SGIP provides incentives to eligible utility customers for the installation of new qualifying technologies that are installed to meet all or a portion of the energy needs of a facility. 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 Center for Sustainable Energy (CSE), formerly known as the California Center for Sustainable Energy (CCSE), in San Diego Gas and Electric (SDG&E) territory.

4 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."

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

6 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 California Air Resources Board (CARB), determines will achieve reduction of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006.

2.1 Renewable Fuel Use Project Classifications

The incentives and requirements for SGIP projects utilizing renewable fuel have varied throughout the life of the SGIP.[7] In this report, assessment of 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.[8] 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 2-1. Similarly, Table 2-2 reports only on RFUR projects whereas Table A-1 lists all RFU projects, including those not subject to the Program’s minimum renewable fuel use requirements (“Other RFU projects”). RFUR projects are, among other things, required to comply with SGIP renewable fuel use requirements. Other RFU projects are not.

Directed Biogas Projects

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for RFUR incentives was expanded to include “directed biogas” projects. Directed biogas projects purchase biogas fuel that is produced at another location than the project site. 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. Deemed to be renewable fuel use projects, directed biogas projects are eligible for higher incentives (relative to non-renewable projects) under the SGIP, and subject to the fuel use requirements of RFUR projects.

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.

7 http://www.pge.com/en/mybusiness/save/selfgen/handbook/index.page

8 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 qualifying small power production facilities from the original Public Utility Regulatory Policy Act (PURPA) of 1978; Subpart B; section 292.204 (Criteria for qualifying small power production facilities).

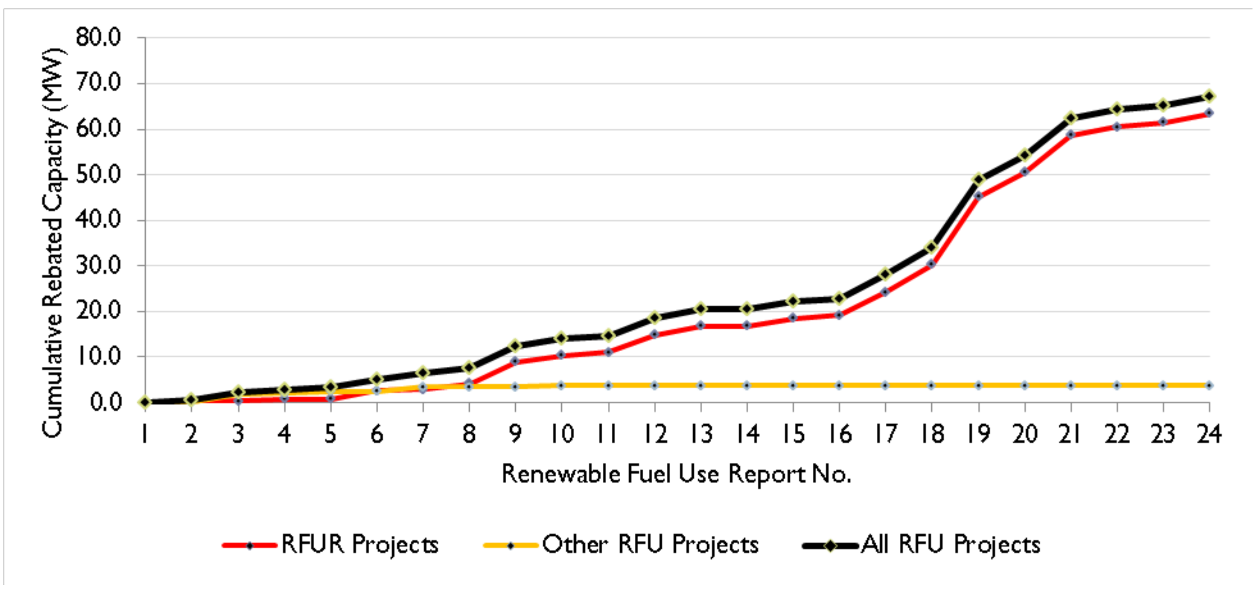
Table 2-1: Summary of RFU vs. RFUR Differences

Parameter	RFU	
	Other RFU	RFU Requirement
Allowed level of 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	128
Rebated capacity (MW)	3.8	63.5

2.2 Project Capacities, Fuel Types, and Prime Mover Technologies

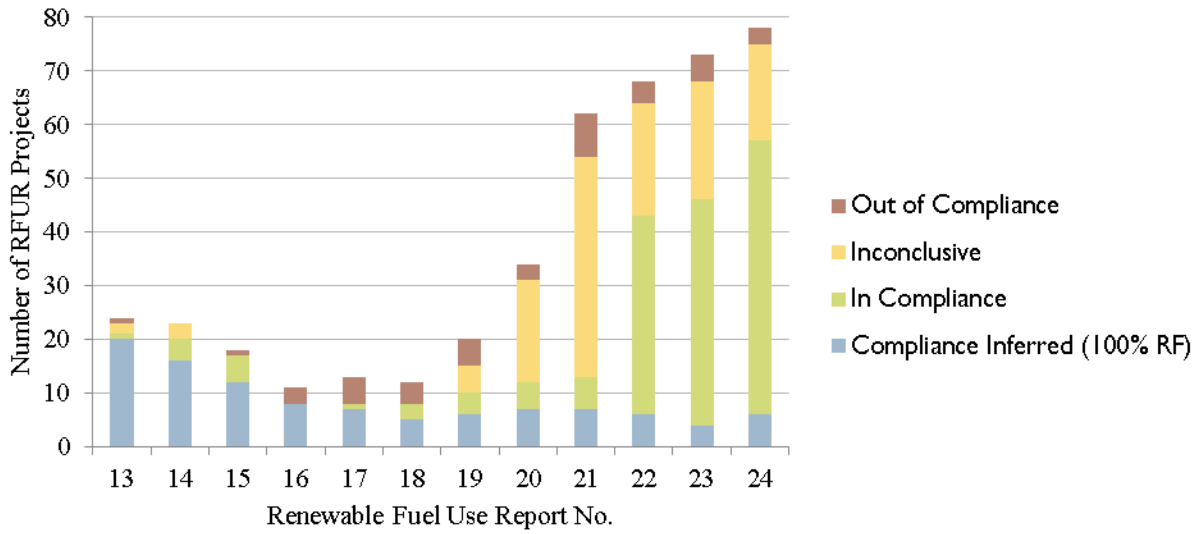
The capacity of RFUR and Other RFU projects, and the combined total (RFU projects) covered by each RFU report is depicted graphically in Figure 2-1.

Figure 2-1: Project Capacity Trend (RFU Reports 1-24)



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 projects. The current report contains three instances of non-compliance with these requirements. Figure 2-2 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 2-2: RFUR Project Compliance History



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 2-3 shows a breakout of all RFU projects as of December 31, 2014, by source of biogas (e.g., landfill gas, dairy digester gas, food processing digester gas) on a rebated capacity basis. The majority of biogas used in SGIP RFU projects is delivered as directed biogas.[9] Dairy digesters provide the smallest contribution at less than two percent of the total rebated RFU project capacity.

9 The biogas source of directed biogas projects is not always known. Historically, the primary source of SGIP directed biogas has been landfill gas.

Figure 2-3: Renewable Fuel Use Project Rebated Capacity by Fuel Type

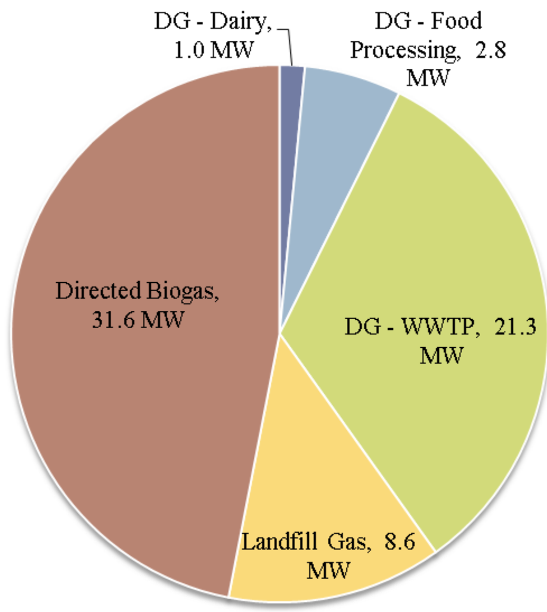
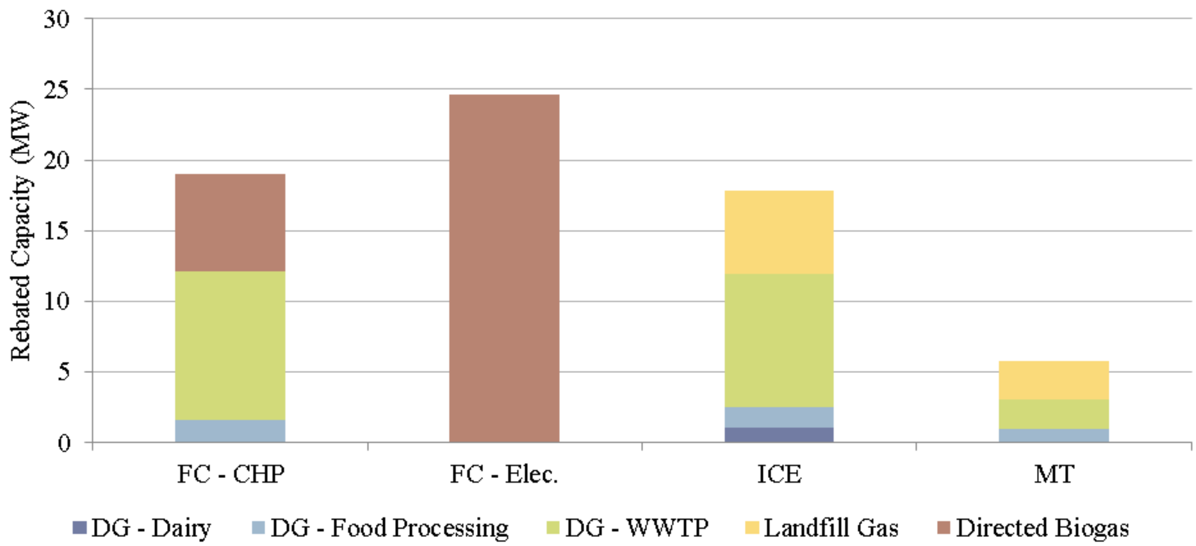


Figure 2-4 provides a breakdown of the relative contribution of the different biogas fuels by prime mover technology. All-electric fuel cells are the dominant technology with almost 37 percent of rebated RFU capacity.

Figure 2-4: Contribution of Biogas Fuel Type by Prime Mover Technology



2.3 Summary of Completed RFUR Projects

There were six new RFUR projects completed during the subject twelve-month reporting period. The six recently completed projects were three IC engines and three microturbines fueled by various on-site biogas sources. A total of 128 RFUR projects had been completed as of December 31, 2014. A list of all SGIP projects utilizing renewable fuel (RFUR and Other RFU) is included as Appendix A.

The 128 completed RFUR projects represent approximately 63.5 MW of rebated generating capacity. The prime mover technologies used by these projects are summarized in Table 2-2. Fuel cells alone accounted for over 67 percent of RFUR rebated capacity, with IC engines and microturbines making up the remaining 33 percent. The availability of out-of-state directed biogas between 2010 and 2013 led to significant growth in fuel cell projects. The average sizes of fuel cell and IC engine projects are two to four times those of microturbine projects.

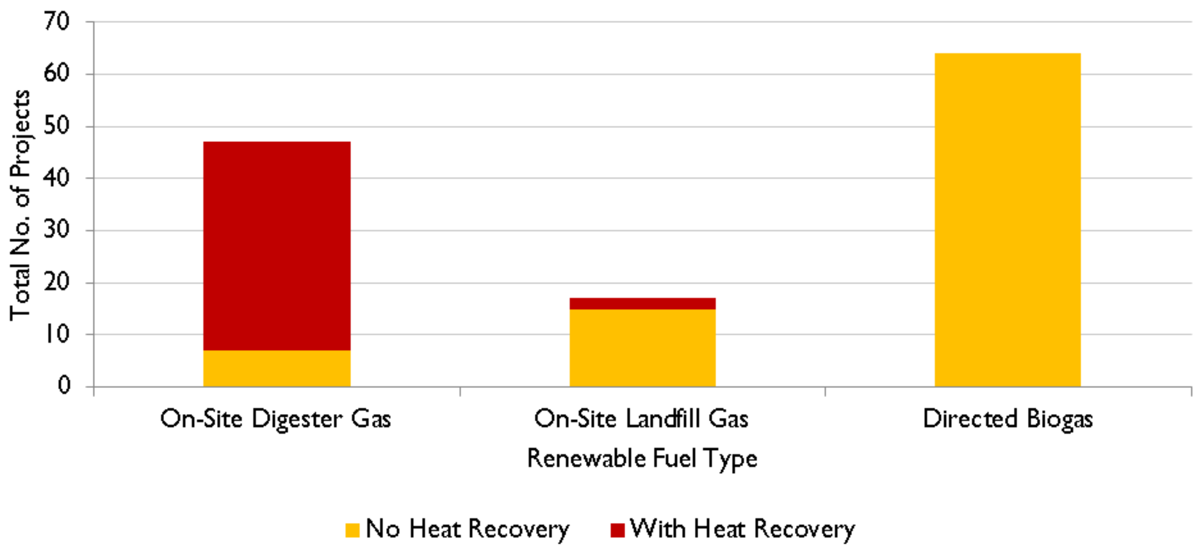
Table 2-2: Summary of Prime Movers for RFUR Projects

Prime Mover	Num. of Projects	Total Rebated Capacity (kW)	Arithmetic Average Rebated Capacity per Project (kW)
FC – CHP	20	18,010	901
FC – Elec.	58	24,660	425
ICE	28	15,941	569
MT	22	4,850	220
All	***128***	***63,461***	***496***

FC – CHP = CHP Fuel Cell, FC – Elec. = Electric-Only Fuel Cell, ICE = Internal combustion (IC) engine, MT = Microturbine

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 Figure 2-5 on the following page.

Figure 2-5: Summary of Waste Heat Recovery Incidence by Type of Renewable Fuel for RFUR Projects

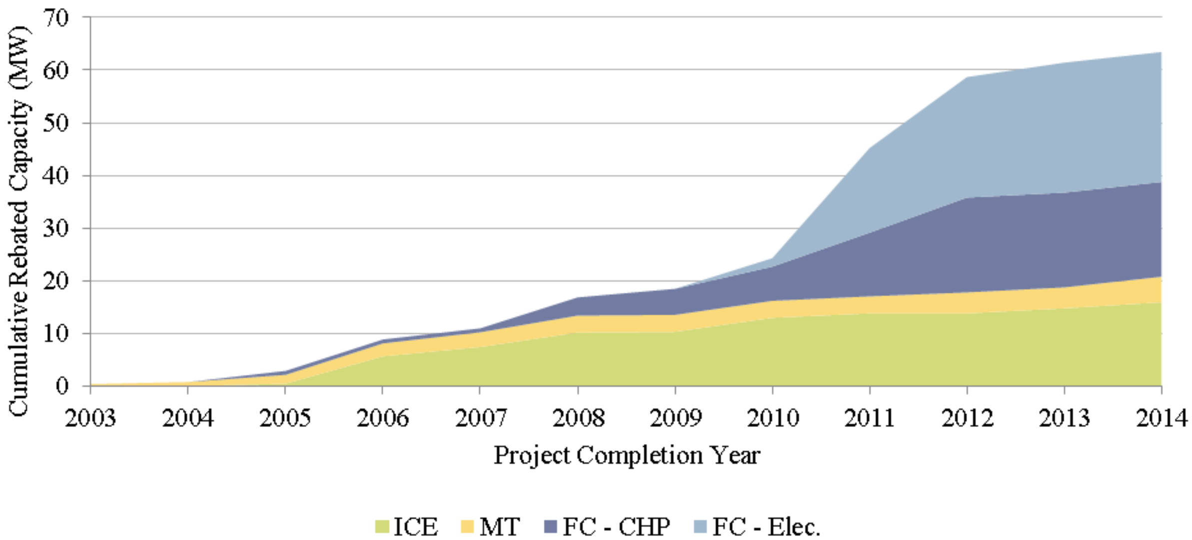


Verification inspection reports obtained from PAs and information from secondary sources such as direct contact with the participant, technical journals, industry periodicals, and news articles indicate that 41 of the 128 RFUR projects recover waste heat. The vast majority (all but seven) of the 47 on-site 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 being pumped to digester tanks. Conversely, 2 of 17 on-site 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.[10] 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. None of the 64 completed directed biogas projects include waste heat recovery.

Figure 2-6 on the following page shows the cumulative RFUR capacity for each year by technology. Calendar year 2006 saw the largest growth in IC engine RFUR capacity. Electric-only fuel cells were by far the most common RFUR projects introduced in 2011 and 2012 with over 21 MW of rebated capacity completed in both years. This period is also aligned with the eligibility of out-of-state biogas projects for SGIP incentives.

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

Figure 2-6: Cumulative Rebated RFUR Capacity by Technology and Project Completion Year



3 FUEL USE AT RFUR PROJECTS – COMPLIANCE DETERMINATION

RFUR projects are allowed to use a maximum of 25 percent non-renewable fuel; the remaining 75-100 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. For PY01-PY10 applications, 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. For PY11 - PY14 projects, all generation systems must have a minimum ten year warranty. Therefore, the fuel use requirement period is three, five, or ten years, depending on the technology type and program year. 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” RFUR facilities located where biogas is produced (e.g., wastewater treatment facilities, landfill gas recovery operations) and the biogas is the only source for the prime mover;
- “Blended” on-site RFUR facilities located where biogas is produced that use a blend of biogas and non-renewable fuel (e.g., natural gas); and
- “Directed” RFUR facilities, located somewhere other than where biogas is produced and not necessarily directly receiving any of the biogas.

Fuel supply and contract status for RFUR projects are summarized in Table 3-1. Seventy-nine of the total 128 RFUR projects had active warranty status. Forty-nine RFUR projects (over one-third of all RFUR projects) had an expired warranty status. Of the 79 RFUR projects with active warranties, six operated solely on renewable fuel (as verified by site inspection reports prepared by the PAs’ consultants). By definition, all six of those RFUR projects are in compliance with SGIP renewable fuel use requirements.

Table 3-1: Summary of Fuel Supplies and Warranty Status for RFUR Projects

	Warranty/Renewable Fuel Use Requirement Status					
	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	6	2,125	37	14,478	43	16,603
Non-Renewable & On-site Renewable	9	7,750	12	7,538	21	15,288
Non-Renewable & Off-Site, Directed Renewable	64	31,570	0	0	64	31,570
Total	79	41,445	49	22,016	128	63,461

* Only active projects that have been operational for one full year are required to comply with SGIP renewable fuel use requirements

Information on fuel use for the remaining 73 blended renewable and directed biogas projects with active warranties is presented below.

3.1 Fuel Use at Blended On-site RFUR Projects

For blended RFUR facilities using both on-site renewable and non-renewable fuel, assessing compliance requires information on the amount of biogas consumed relative to the amount of non-renewable fuel consumed on-site. Most blended RFUR projects are equipped with a dedicated natural gas meter that measures the amount of non-renewable fuel being consumed by the project. Meters indicating the amount of renewable fuel being consumed by the SGIP project are owned and maintained by other program participants like system owners or host customers. Historically, metered data obtained from these renewable fuel meters have proven unreliable due to uncertainty regarding the energy content of the fuel and general difficulties that arise when relying on third parties to develop, operate, and maintain data collection systems satisfying the accuracy and reliability requirements of program impacts evaluation.

In order to make a renewable fuel use compliance determination without metered on-site biogas data, it is necessary to estimate the total energy input (renewable + non-renewable fuel) of SGIP projects. The total energy input of SGIP projects is estimated by dividing the electrical generation of the project by assumed electrical conversion efficiency.[11] The estimate of renewable fuel consumption is then calculated as the difference between the estimate of total energy input and the metered non-renewable fuel consumption.

Blended On-Site RFUR Projects in Compliance

During this reporting period no blended RFUR projects were found to be in compliance with SGIP renewable fuel use requirements.

Blended On-Site RFUR Projects Not in Compliance

Three projects were found to be out of compliance with SGIP renewable fuel use requirements. These projects were using more non-renewable fuel than allowed during this reporting period:

- **SCE-SGIP-2009-0013.** This 600 kW fuel cell system came online in March 2012 and consists of two 300 kW fuel cells. The system is located at a water reclamation facility. ADG is produced by on-site anaerobic digesters. Supplemental natural gas is available when there is insufficient ADG to operate the fuel cells at full capacity. At the time of the SCE installation verification inspection, the system was operating on 100% anaerobic digester gas (ADG). Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period did not exceed 71 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

[11] In these calculations an electrical conversion efficiency of 26 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 26 percent (which is likely), then the actual non-renewable fuel use is higher than the estimated percent. The basis of this efficiency estimate is the lowest annual electrical conversion efficiency observed among CHP fuel cells in 2013.

- **PGE-SGIP-2010-1867.** This 1,400 kW fuel cell utilizes a blend of digester gas from a waste water treatment plant and natural gas. The system became operational in November 2012 and is therefore required to comply with SGIP renewable fuel use requirements. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period did not exceed 62 percent of the total annual fuel input. The system was found to be out of compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCG-SGIP-2010-0026.** This 2,800 kW fuel cell system came online in December 2012. The system is fueled by digester gas produced on-site at a waste water treatment plant. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period did not exceed 48 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

Blended On-Site RFUR Project Compliance Status Inconclusive

Five projects could not have their compliance status determined during this reporting period because they did not provide sufficient information to make a compliance determination:

- **SCE-SGIP-2010-0003 / SCE-SGIP-2010-0334.** This project is a 250 kW system that came online October, 2010 as an RFU project (not required to comply with renewable fuel use requirements). In November, 2012 the project was upgraded to RFUR and is required to comply with SGIP renewable fuel use requirements. Data required to make a compliance determination were not available in time for this report.
- **SCE-SGIP-2010-0002.** This project is a 750 kW fuel cell system consisting of three 250 kW stacks, of which only two are rebated as dual fueled systems under this application number. The system is located at a waste water treatment plant and at the time of the SCE installation verification inspection was capable of producing sufficient anaerobic digester gas to run two of the units using 100% ADG. Data required to make a compliance determination were not available in time for this report.
- **SCE-SGIP-2009-0003.** This 300 kW fuel cell is one of four systems installed at a water pollution control facility. The system utilizes a combination of waste water digester gas and natural gas. The system became operational in August 2011 and is therefore required to comply with SGIP renewable fuel use requirements. Data required to make a compliance determination were not available in time for this report.
- **SD-SGIP-2009-0362.** This 300 kW fuel cell utilizes a blend of digester gas from a waste water treatment plant and natural gas. The system became operational in December 2011 and is therefore required to comply with SGIP renewable fuel use requirements. When sufficient digester gas is not available to run this system at full load, natural gas is mixed in. In December, 2012 the system suffered a catastrophic failure that resulted in an extended outage. The system is believed to have re-started on October, 2014. Data required to make a compliance determination were not available in time for this report.
- **PGE-SGIP-2012-2061.** This 3,800 kW IC engine system came online in October, 2013. The system is fueled by digester gas generated onsite. At the time of the PG&E installation verification inspection, the system was operating on 90% digester gas and the output of the IC engine

modulated based on the diurnal cycle of the biogas production. Data required to make a compliance determination were not available in time for this report.

Blended On-Site RFUR Project Compliance Status Not Yet Applicable

A blended RFUR project is assigned compliance status “Not Yet Applicable” if it has not yet been operational for a complete calendar year. There is one IC engine project in this category. Historically, a summary of projects and a compliance assessment was attempted for projects not yet operational for a complete calendar year. In this report, information about projects not yet subject to compliance determination requirements is presented exclusively in Table 3-2. Furthermore, as the number of projects no longer under warranty has grown over time, summary information about these projects is no longer presented in this section.

A summary of the nine blended RFUR projects with active warranties during this reporting period, including those lacking a full year’s operational experience, is presented in Table 3-2.

Table 3-2: Fuel Use Compliance of Blended On-Site RFUR Projects

PA	SGIP Reservation No.	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	Annual Natural Gas Energy Flow (MMBtu)†	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
SCE	SCE-SGIP-2010-0334	FC – CHP	DG – WWTP	250	10/31/2010	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2010-0002	FC – CHP	DG – WWTP	500	10/31/2010	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2009-0003	FC – CHP	DG – WWTP	300	8/30/2011	Unknown	Unknown	Inconclusive; Data Not Reported
CSE	SD-SGIP-2009-0362	FC – CHP	DG – WWTP	300	12/21/2011	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2009-0013	FC – CHP	DG – WWTP	600	3/28/2012	14,958	71%	No
PG&E	PGE-SGIP-2010-1867	FC – CHP	DG – WWTP	1,400	11/29/2012	49,056	62%	No
SCG	SCG-SGIP-2010-0026	FC – CHP	DG – WWTP	2,800	12/21/2012	86,951	48%	No
PG&E	PGE-SGIP-2012-2061	ICE	DG – WWTP	950	10/31/2013	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2011-0348	ICE	DG – WWTP	650	6/18/2014	TBD	TBD	Not Yet Required

* 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, 2014. The basis is the lower heating value (LHV) of the fuel.

3.2 Fuel Use at Directed RFUR Projects

It is not possible to use the same method in assessing compliance of directed biogas projects as that used for assessing compliance of blended on-site RFUR projects. In blended RFUR 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 percent of the total annual energy input to the RFUR project. However, in directed biogas RFUR 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, transportation, and subsequent allocation to customers that may or may not be SGIP participants. Specification of the approach used to assess the balance of injections and extractions is dictated by the properties of transactions at the two points. These properties are summarized in Table 3-3. The properties at the extraction point represent a significant departure from conditions encountered to date for dedicated and blended on-site RFUR projects. Specifically, at the extraction point the transaction type is notional rather than physical, and information is obtained from invoices rather than metering. To assess the system's balance and thereby enable accurate assessment of the role of SGIP specifically in increasing overall biogas production and consumption, complete information for injections and extractions is required.

Table 3-3: Properties of Directed Biogas Injection and Extraction

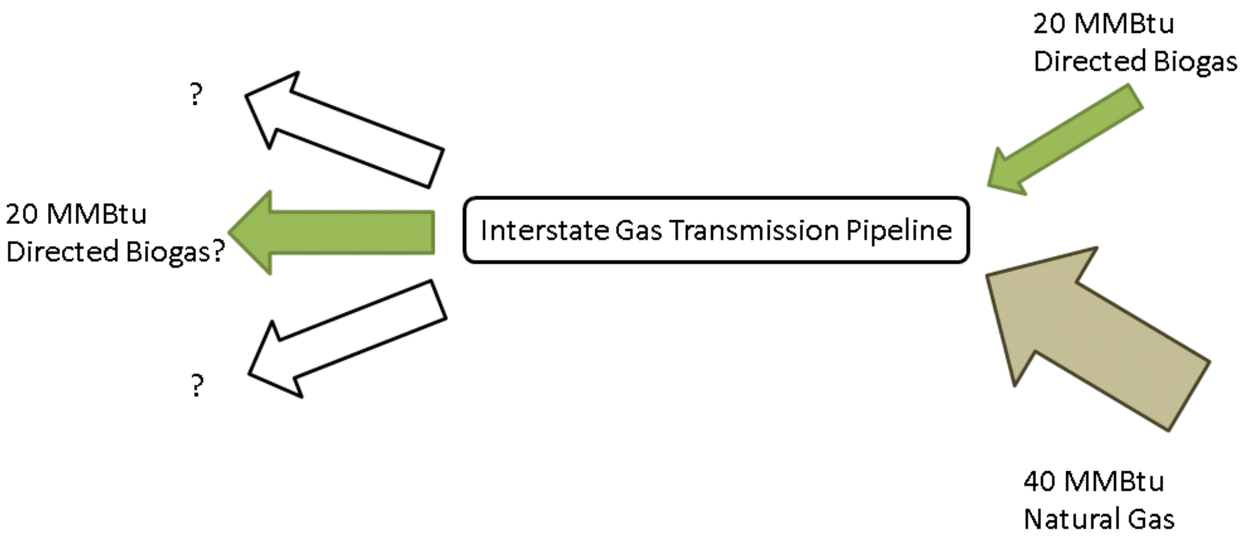
Property	At Injection	At Extraction
Carrier for renewable fuel	Biogas	Natural Gas
Transaction type	Physical	Notional
Information source	Metering	Invoices

The properties of directed biogas injection and extraction have a direct bearing on information needed to assess renewable fuel use compliance of directed biogas projects. On April 14, 2011, the SGIP PAs and their consultant AESC developed protocols for the audit of directed biogas usage. The audit protocol establishes data and verification requirements and is separated into three elements:

1. Transfer of Ownership
2. Transportation Path and Energy Accounting
3. Gas Fuel Consumption

The transportation path and energy accounting is notional rather than physical. Figure 3-1 is a representative example of the types of issues encountered during verification of the transportation path.

Figure 3-1: Representative Example of Gas Transportation Accounting Issue



In Figure 3-1, a gas marketer enters into contract with an interstate gas transmission pipeline for the transport of 20 MMBtu of directed biogas and 40 MMBtu of non-renewable natural gas. Assuming no fuel losses or imbalances, the same amount of gas exits the pipeline. Most interstate pipelines or gas hubs have various points at which gas can be delivered. In some cases, the only information regarding directed biogas allocations is guidance from the gas marketer. In this sense, compliance determinations rely on accurate information provided by program participants.

A similar situation occurs with out of state physical storage. If a storage vessel contains both directed biogas and non-renewable natural gas, the green attributes of any withdrawal are completely up to the discretion of the gas marketer. In this sense, the verification process is not truly independent. A hypothetical scenario where a gas marketer sells the same green gas attributed to SGIP projects to another entity outside of California is possible. Compliance determinations made in this report rely on the good faith of documentation provided by gas marketers and renewable fuel supply affidavits submitted to the SGIP PAs. The complete directed biogas audit protocol is included as Appendix B.

When gas marketers procure directed biogas for SGIP projects, they do not purchase renewable fuel for each project and transport it to California under separate contracts. Instead they pool SGIP projects into fleets and procure the amount of biogas required to meet the fleet's monthly biogas requirements. The nature of these transactions requires that compliance determinations be made at the fleet level and not at the individual project level.[12]

Fuel Use of Directed Biogas Fleet #1

As of December 31, 2014, directed biogas fleet #1 consists of 41 electric-only fuel cell projects completed between 2010 and 2013. All 41 of these systems have been operational for at least one

[12] A fleet of directed biogas projects is simply a group of projects whose compliance is determined together. The composition of a directed biogas fleet is determined by how the gas marketer procures biogas for a group of projects.

calendar year and are required to comply with the SGIP's renewable fuel use requirements. Directed biogas deliveries and consumptions for fleet #1 are summarized in Table 3-4.

Table 3-4: Directed Biogas Transactions for Fleet #1

Pool Balances and Transactions	Directed Biogas (MMBtu)
Pool starting balance on 1/1/2014	253,579
Added during 12-month period ending 12/31/2014	480,588
Consumed during 12-month period ending 12/31/2014	(621,974)
Pool ending balance on 12/31/2014	112,193

While consumption exceeds additions during the reporting period, the pool balance remained positive during the 12-month period. Based on the compliance protocols described in this report, the SGIP projects in directed biogas fleet #1 were found to be in compliance with renewable fuel use requirements during this reporting period. A list of the 41 projects included in directed biogas fleet #1 is shown in Table 3-6.

Fuel Use of Directed Biogas Fleet #2

As of December 31, 2014, directed biogas fleet #2 consists of ten fuel cell projects completed between November 2010 and February 2012. All ten of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewable fuel use requirements. Directed biogas deliveries and consumptions for fleet #2 are summarized in Table 3-5.

Table 3-5: Directed Biogas Transactions for Fleet #2

Pool Balances and Transactions	Directed Biogas (MMBtu)
Pool starting balance on 1/1/2014	0
Added during 12-month period ending 12/31/2014	177,995
Consumed during 12-month period ending 12/31/2014	(177,995)
Pool ending balance on 12/31/2014	0

Consumption equaled additions during the reporting period, and the pool balance remained positive during the 12-month period. Based on the compliance protocols described in this report, the SGIP projects in directed biogas fleet #2 were found to be in compliance with renewable fuel use requirements during this reporting period. A list of the ten projects included in directed biogas fleet #2 is shown in Table 3-6.

Fuel Use of Directed Biogas Fleet #3

As of December 31, 2014, directed biogas fleet #3 consists of seven fuel cell projects completed between March 2011 and December 2012. All seven of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewable fuel use requirements. The data and documentation required to evaluate the renewable fuel use compliance of fleet #3 according to the protocols described in this report were not made available in time for this report. Consequently, compliance status for this fleet of projects cannot be determined until the required data and documentation are available. A list of the seven projects included in directed biogas fleet #3 is shown in Table 3-6.

Fuel Use of Directed Biogas Fleet #4

As of December 31, 2014, directed biogas fleet #4 consists of two fuel cell projects completed on December 2011. Due to issues commissioning the in-state directed biogas source for these projects, the PA delayed the start of the directed biogas audit period to July 2012. Shortly after, on December 2012, the in-state directed biogas source suffered a catastrophic failure that resulted in a total shut down of the waste water treatment plant that supplied biogas to these two projects. The plant resumed normal directed biogas supplies on October 2014.

The compliance status of these two fuel cell projects remains 'Inconclusive' until the required data and documentation are available to make a compliance determination. A list of these two projects is shown in Table 3-6.

Fuel Use of Other Directed Biogas Projects

As of December 31, 2014, the renewable fuel use compliance of four fuel cell projects cannot be determined. These four projects are not part of large fleets like those discussed previously. Instead, their biogas procurements and usages are managed by smaller gas schedulers. All four of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewable fuel use requirements. The data and documentation required to evaluate the renewable fuel use compliance of these projects according to the protocols described in this report were not made available in time for this report. Consequently, the compliance status of these projects cannot be determined until the required data and documentation are available.

A list of the 64 directed biogas RFUR projects with active warranties during this reporting period is presented in Table 3-6.

Table 3-6: Fuel Use Compliance of Directed Biogas RFUR Projects

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu)†	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
PG&E	PGE-SGIP-2009-1810	Fleet #2	FC	400	11/10/2010	09/01/2010	20,603	75%	Yes
PG&E	PGE-SGIP-2009-1811	Fleet #2	FC	400	11/10/2010	09/01/2010	20,603	75%	Yes
PG&E	PGE-SGIP-2009-1812	Fleet #2	FC	400	11/10/2010	09/01/2010	20,603	75%	Yes
PG&E	PGE-SGIP-2009-1802	Fleet #2	FC	400	12/22/2010	10/01/2010	19,345	75%	Yes
CSE	SD-SGIP-2010-0369	Fleet #2	FC	400	12/31/2010	10/01/2010	23,724	75%	Yes
CSE	SD-SGIP-2010-0370	Fleet #2	FC	400	12/31/2010	10/01/2010	23,724	75%	Yes
PG&E	PGE-SGIP-2009-1805	Other	FC	200	01/18/2011	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
SCG	SCG-SGIP-2010-0012	Fleet #1	FC	1,000	01/24/2011	10/01/2010	53,369	75%	Yes
PG&E	PGE-SGIP-2010-1859	Fleet #2	FC	500	03/11/2011	12/01/2010	15,872	75%	Yes
PG&E	PGE-SGIP-2010-1871	Fleet #3	FC	300	03/14/2011	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2010-0004	Fleet #2	FC	800	03/23/2011	10/01/2010	47,449	75%	Yes
PG&E	PGE-SGIP-2010-1849	Fleet #1	FC	500	05/09/2011	02/01/2011	25,768	75%	Yes
PG&E	PGE-SGIP-2010-1856	Fleet #1	FC	300	05/09/2011	02/01/2011	15,434	75%	Yes
PG&E	PGE-SGIP-2010-1853	Fleet #1	FC	600	05/24/2011	12/01/2010	34,093	75%	Yes
PG&E	PGE-SGIP-2010-1882	Fleet #1	FC	400	05/24/2011	02/01/2011	2,732	75%	Yes

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu)†	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
PG&E	PGE-SGIP-2010-1886	Fleet #1	FC	300	05/24/2011	02/01/2011	16,389	75%	Yes
PG&E	PGE-SGIP-2010-1885	Fleet #1	FC	300	05/31/2011	01/01/2011	15,030	75%	Yes
PG&E	PGE-SGIP-2010-1851	Fleet #1	FC	300	06/29/2011	04/01/2011	16,817	75%	Yes
PG&E	PGE-SGIP-2010-1878	Fleet #3	FC	500	06/29/2011	06/01/2011	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2010-0009	Fleet #1	FC	300	08/08/2011	03/01/2011	16,463	75%	Yes
SCE	SCE-SGIP-2010-0012	Fleet #1	FC	300	08/08/2011	12/01/2010	16,595	75%	Yes
SCE	SCE-SGIP-2010-0022	Fleet #3	FC	400	08/08/2011	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2010-0023	Fleet #3	FC	400	08/08/2011	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
PG&E	PGE-SGIP-2010-1850	Fleet #1	FC	420	09/07/2011	06/01/2011	20,184	75%	Yes
PG&E	PGE-SGIP-2010-1874	Fleet #2	FC	500	09/07/2011	03/01/2011	27,405	75%	Yes
PG&E	PGE-SGIP-2010-1892	Fleet #1	FC	210	09/07/2011	06/01/2011	10,396	75%	Yes
PG&E	PGE-SGIP-2010-1893	Fleet #1	FC	210	09/07/2011	06/01/2011	10,461	75%	Yes
SCG	SCG-SGIP-2010-0005	Fleet #1	FC	100	09/20/2011	03/01/2011	5,613	75%	Yes
SCG	SCG-SGIP=2010-0011	Fleet #1	FC	900	09/21/2011	05/01/2011	47,859	75%	Yes
PG&E	PGE-SGIP-2010-1855	Fleet #1	FC	300	09/29/2011	07/01/2011	16,134	75%	Yes

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu)†	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
SCE	SCE-SGIP-2010-0014	Fleet #1	FC	420	11/15/2011	06/01/2011	18,649	75%	Yes
SCG	SCG-SGIP-2010-0018	Fleet #1	FC	420	12/15/2011	08/01/2011	20,899	75%	Yes
SCG	SCG-SGIP-2010-0019	Fleet #1	FC	420	12/15/2011	07/01/2011	19,967	75%	Yes
SCG	SCG-SGIP-2010-0020	Fleet #1	FC	420	12/15/2011	09/01/2011	16,538	75%	Yes
SCG	SCG-SGIP-2010-0015	Fleet #1	FC	420	12/16/2011	09/01/2011	15,149	75%	Yes
CSE	SD-SGIP-2009-0361	Fleet #4	FC	1,400	12/21/2011	07/01/2012	Unknown	Unknown	Inconclusive; Data Not Reported
CSE	SD-SGIP-2009-0363	Fleet #4	FC	2,800	12/21/2011	07/01/2012	Unknown	Unknown	Inconclusive; Data Not Reported
CSE	SD-SGIP-2009-0375	Fleet #1	FC	300	12/21/2011	10/01/2011	14,984	75%	Yes
PG&E	PGE-SGIP-2010-1852	Fleet #1	FC	400	12/29/2011	10/01/2011	19,590	75%	Yes
PG&E	PGE-SGIP-2010-1857	Fleet #1	FC	300	12/29/2011	10/01/2011	14,810	75%	Yes
PG&E	PGE-SGIP-2010-1858	Fleet #1	FC	300	12/29/2011	10/01/2011	9,254	75%	Yes
PG&E	PGE-SGIP-2010-1868	Fleet #1	FC	400	12/29/2011	10/01/2011	19,212	75%	Yes
PG&E	PGE-SGIP-2010-1869	Fleet #1	FC	600	12/29/2011	10/01/2011	28,817	75%	Yes
PG&E	PGE-SGIP-2010-1876	Fleet #1	FC	200	12/29/2011	10/01/2011	9,546	75%	Yes
PG&E	PGE-SGIP-2010-1877	Fleet #1	FC	200	12/29/2011	10/01/2011	9,546	75%	Yes

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu)†	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
PG&E	PGE-SGIP-2010-1929	Fleet #3	FC	420	12/29/2011	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
CSE	SD-SGIP-2010-0374	Fleet #1	FC	210	02/27/2012	12/01/2011	9,754	75%	Yes
CSE	SD-SGIP-2010-0376	Fleet #1	FC	210	02/27/2012	12/01/2011	10,676	75%	Yes
PG&E	PGE-SGIP-2010-1860	Fleet #1	FC	800	02/28/2012	12/01/2011	37,030	75%	Yes
PG&E	PGE-SGIP-2010-1926	Fleet #2	FC	400	02/28/2012	12/01/2011	17,997	75%	Yes
SCE	SCE-SGIP-2010-0011	Fleet #1	FC	210	03/28/2012	12/01/2011	11,109	75%	Yes
SCE	SCE-SGIP-2010-0028	Fleet #1	FC	600	03/28/2012	12/01/2011	28,678	75%	Yes
PG&E	PGE-SGIP-2011-1950	Fleet #3	FC	500	04/11/2012	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
CSE	SD-SGIP-2010-0398	Other	FC	420	05/01/2012	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
CSE	SD-SGIP-2010-0399	Other	FC	630	05/01/2012	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2010-0039	Fleet #1	FC	315	08/08/2012	04/01/2012	14,667	75%	Yes
SCE	SCE-SGIP-2010-0038	Fleet #1	FC	630	10/04/2012	05/01/2012	27,380	75%	Yes
SCE	SCE-SGIP-2010-0035	Fleet #3	FC	1,110	12/17/2012	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
SCE	SCE-SGIP-2010-0037	Fleet #1	FC	1,050	12/24/2012	06/01/2012	42,335	75%	Yes

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu)†	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
SCE	SCE-SGIP-2010-0041	Fleet #1	FC	840	12/24/2012	07/01/2012	35,853	75%	Yes
SCE	SCE-SGIP-2010-0024	Fleet #1	FC	1,050	03/29/2013	10/01/2012	51,114	75%	Yes
PG&E	PGE-SGIP-2010-1914	Other	FC	420	05/29/2013	Unknown	Unknown	Unknown	Inconclusive; Data Not Reported
SCG	SCG-SGIP-2010-0033	Fleet #1	FC	105	06/19/2013	03/01/2013	5,149	75%	Yes
SCG	SCG-SGIP-2010-0034	Fleet #1	FC	210	06/20/2013	03/01/2013	10,299	75%	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.

** This field represents the date the project began consuming directed biogas.

† This field represents the natural gas consumption during the 12-month period ending December 31, 2014. The basis is the higher heating value (HHV) of the fuel.

4 GREENHOUSE GAS EMISSION IMPACT

Due to increased interest in the GHG emission aspects of biogas projects, information regarding GHG emission impacts is presented in this section. The GHG emission information presented here is derived from data used to prepare the SGIP Thirteenth-Year (2013) Impact Evaluation Final Report.[13] Additionally, key factors that could influence GHG emission impacts from renewable fuel projects in the future are discussed.

Table 4-1 presents capacity-weighted average GHG emission results developed for the most recent (2013) SGIP Impact Evaluation Report. Results in Table 4-1 suggest one important observation: The baseline assumed for the biogas (i.e., whether the biogas would have been vented to the atmosphere or flared) is the most influential determinant of GHG emission impacts.[14] 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 4-1: Summary of GHG Emission Impacts from SGIP Biogas Projects in 2013

Baseline Biogas Assumption	Prime Mover Technology	Average GHG Impact Rate (Metric Tons CO_2eq / MWh)
Flare	CHP fuel cell	-0.30
	Electric-only fuel cell	-0.37
	Internal combustion engine	-0.53
	Microturbine	-0.47
Vent	Internal combustion engine	-4.73

Simplifying assumptions underlying the above results include:

- Heat recovered from RFUR projects was used to satisfy a heating load that otherwise would have been satisfied using biogas (e.g., in a boiler)[15]
- A single representative electrical conversion efficiency was assumed for each technology based on metered data:
  - CHP fuel cell: 39%
  - Electric-only fuel cell: 53%
  - Internal combustion engine: 30%
  - Microturbine: 23%

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13 http://www.cpuc.ca.gov/NR/rdonlyres/AC8308C0-7905-4ED8-933E-387991841F87/0/2013_SelfGen_Impact_Rpt_201504.pdf

14 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).

15 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 Section 218.5 (now Section 216.6).

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.[16] At the state level, the California Air Resources Board (CARB) provides guidelines for control of methane and other volatile organic compounds from biogas facilities.[17] At the federal level, New Source Performance Standards and Emission Guidelines regulate methane capture and use.[18]

Biogas baseline assumptions used to calculate GHG impact estimates for 2007-2009 were based on previous studies.[19,20] 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 through 2013 Impact Evaluations the biogas baseline was modified for WWTP and food processing SGIP projects smaller than 150 kW.

The evolution of biogas baseline assumptions is summarized in Table 4-2.

Table 4-2: Biogas Baseline Assumptions

Renewable Fuel Source	Facility Type	Size of Rebated System (kW)	Impact Report	
			PY07-08	PY09-13
Digester Gas	WWTP	< 150	Vent	Flare
		≥ 150	Flare	Flare
Digester Gas	Food Processing	< 150	Vent	Flare
		≥ 150	Flare	Flare
Landfill Gas	Landfill	All Sizes	Flare	Flare
Digester Gas	Dairy	All Sizes	Vent	Vent

The equivalent tons of CO_2 emissions associated with SGIP systems for which flaring and venting baselines were assumed for 2013 are presented in Figure 4-1. GHG emission impacts are depicted graphically as the difference between SGIP emissions and the total baseline emissions. Total baseline emissions exceed SGIP emissions in all cases; hence a reduction in GHG emissions is attributed to participation in the SGIP. During 2013, SGIP biogas projects reduced GHG emissions by over 126 thousand metric tons of CO_2.

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

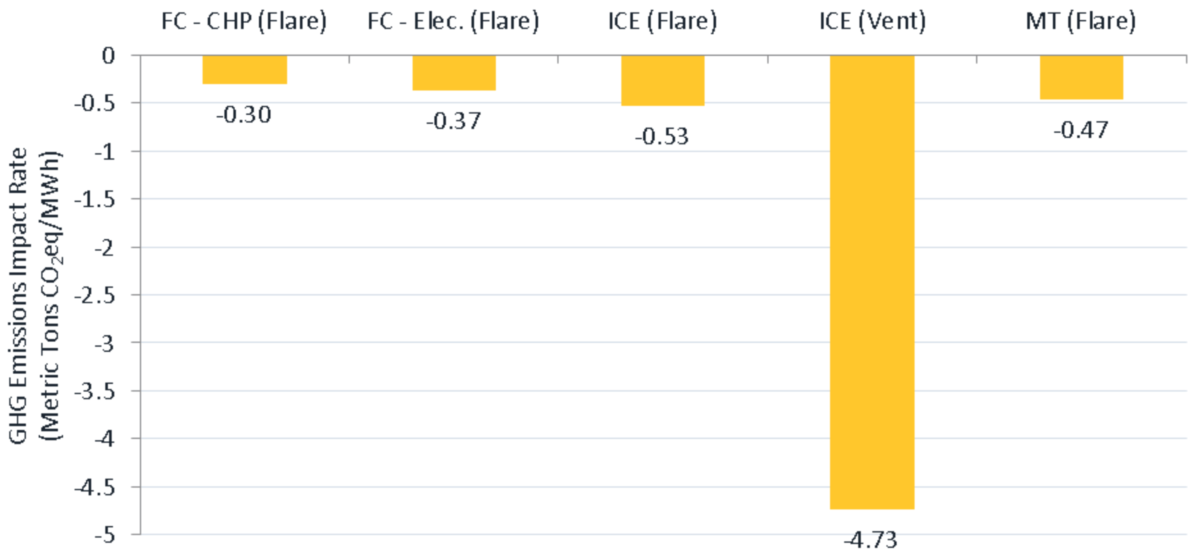
17 In June of 2007, CARB approved the Landfill Methane Capture Strategy.
See http://www.arb.ca.gov/cc/landfills/landfills.htm for additional information.

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

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

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

Figure 4-1: Summary of GHG Emission Impact Rates from SGIP Biogas Projects in 2013



The baseline assumption (i.e., flaring versus venting) made for biogas used in SGIP systems is the factor exerting the greatest influence over estimates of GHG impacts. Biogas projects for which a venting baseline is assumed achieve significantly greater GHG reductions per unit of electricity generated than those for which a flaring baseline is assumed. For impact evaluation purposes, we make the following simplifying assumptions:

- Blended on-site RFUR projects are assumed to operate on 100% renewable fuel
- “Other RFU” projects are assumed to operate on 100% non-renewable fuel
- Directed biogas projects are assumed to operate on 75% renewable fuel

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.[21] 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 RFUR project costs could fall below non-renewable project costs as RFUR projects are exempt from waste heat recovery requirements. As a result, RFUR projects could potentially be receiving a greater-than-necessary incentive, which could lead to fuel switching. To address this concern, the CPUC directed the SGIP PAs to monitor non-renewable project and RFUR project costs.

Eligible project cost data from all completed SGIP projects are used 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 costs differences due to renewable fuel use and heat recovery.

Eligible installed costs for all fuel cell, microturbine, and IC engine projects operational as of December 31, 2014, are summarized in Table 5-1, along with simple summary statistics. 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

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

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 5-1: Summary of Project Costs by Technology, Heat Recovery Provision, and Fuel Type

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	2014 $/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes	14	4.41 – 15.34	9.69	9.52	3.16	8.33
	Yes	No	1	7.50 – 7.50	7.50	7.50	-	7.50
	Yes	Yes or No	15	4.41 – 15.34	8.96	9.38	3.09	8.31
	No	Yes	24	6.13 – 24.06	8.18	9.84	4.16	9.04
FC – Elec.	No	No	83	3.88 – 16.35	11.54	11.82	1.63	11.90
	DBG	No	58	7.33 – 19.77	12.09	11.92	1.91	11.79
ICE	Yes	Yes	24	0.72 – 10.78	3.50	3.94	2.23	4.07
	Yes	No	6	1.47 – 4.98	3.25	3.08	1.20	3.11
	Yes	Yes or No	30	0.72 – 10.78	3.36	3.77	2.08	3.87
	No	Yes	231	1.14 – 12.98	2.95	3.29	1.56	2.94
MT	Yes	Yes	11	2.65 – 14.57	4.29	6.16	3.59	5.39
	Yes	No	15	1.62 – 8.78	4.89	5.31	2.18	4.25
	Yes	Yes or No	26	1.62 – 14.57	4.79	5.67	2.83	4.68
	No	Yes	119	0.92 – 9.59	4.04	4.23	1.61	4.05

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. Heat recovery equipment and fuel clean-up equipment cost comparisons are described below.

5.1 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 because those are the projects of most interest in this report. Additionally, analysis is performed separately for each technology type, using average (mean) eligible installed costs (see Table 5-1 above). For example, the cost difference due to heat recovery equipment for microturbine projects is calculated as $6.16 minus $5.31, or $0.86.

$$\Delta HeatRecovery = (RFU\ w/\ HR) - (RFU\ w/o\ HR)$$

Where:

RFU w/ HR = renewable fuel use with heat recovery

RFU w/o HR = renewable fuel use without heat recovery

Table 5-2: Cost Effect of Heat Recovery

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	2014 $/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes	14	4.41 – 15.34	9.69	9.52	3.16	8.33
	Yes	No	1	7.50 – 7.50	7.50	7.50	-	7.50
	Increase due to Heat Recovery				-	-	-	-
ICE	Yes	Yes	24	0.72 – 10.78	3.50	3.94	2.23	4.07
	Yes	No	6	1.47 – 4.98	3.25	3.08	1.20	3.11
	Increase due to Heat Recovery				0.25	0.86	1.03	0.95
MT	Yes	Yes	11	2.65 – 14.57	4.29	6.16	3.59	5.39
	Yes	No	15	1.62 – 8.78	4.89	5.31	2.18	4.25
	Increase due to Heat Recovery				-0.60	0.86	1.41	1.14

The mean costs for heat recovery are higher than non-heat recovery systems. The statistical significance of these differences is examined later in this report with uncertainty analysis. Note there was only one renewable fueled CHP fuel cell that did not include heat recovery, so it is not possible to perform this analysis for fuel cells.

5.2 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 confounding 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 average (mean) cost difference for fuel treatment equipment in IC engine projects is calculated as \$3.94 minus \$3.29, or \$0.65 (from Table 5-1, above).

$$\Delta FuelTreatment = (RFU\ w/\ HR)\ - (NG\ w/\ HR)$$

Where:

NG = natural gas

Table 5-3: Cost Effect of Renewable Fuel Treatment Equipment

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	2014 \$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes	14	4.41 – 15.34	9.69	9.52	3.16	8.33
	No	Yes	24	6.13 – 24.06	8.18	9.84	4.16	9.04
	Increase due to RF Equipment				1.51	-0.33	-0.99	-0.71
ICE	Yes	Yes	24	0.72 – 10.78	3.50	3.94	2.23	4.07
	No	Yes	231	1.14 – 12.98	2.95	3.29	1.56	2.94
	Increase due to RF Equipment				0.55	0.65	0.68	1.13
MT	Yes	Yes	11	2.65 – 14.57	4.29	6.16	3.59	5.39
	No	Yes	119	0.92 – 9.59	4.04	4.23	1.61	4.05
	Increase due to RF Equipment				0.25	1.93	1.97	1.34

The mean costs of renewable fueled projects except CHP fuel cells are higher than non-renewable fueled projects. 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.

5.3 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 CHP fuel cell projects, and many of the renewable fuel projects include heat recovery even though many were not required to do so.[22] By looking at the observed difference in costs of these two groups, it is

[22] Electric-only fuel cells are excluded from this analysis.

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 \$3.77 minus \$3.29, or \$0.48.

$$\Delta RFU = (RFU\ w/\ or\ w/o\ HR) - (NG\ w/\ HR)$$

Table 5-4: Cost Effect of Renewable Fuel Use

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	2014 \$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes or No	15	4.41 – 15.34	8.96	9.38	3.09	8.31
	No	Yes	24	6.13 – 24.06	8.18	9.84	4.16	9.04
	Increase due to RFU				0.78	-0.46	-1.07	-0.73
ICE	Yes	Yes or No	30	0.72 – 10.78	3.36	3.77	2.08	3.87
	No	Yes	231	1.14 – 12.98	2.95	3.29	1.56	2.94
	Increase due to RFU				0.41	0.48	0.52	0.93
MT	Yes	Yes or No	26	1.62 – 14.57	4.79	5.67	2.83	4.68
	No	Yes	119	0.92 – 9.59	4.04	4.23	1.61	4.05
	Increase due to RFU				0.75	1.44	1.21	0.64

The mean costs of renewable fueled IC Engine and microturbine projects are higher than non-renewable fueled projects. Again, for non-renewable fueled CHP fuel cells, the mean costs are higher than renewable systems.

5.4 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 5-1. 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 5-5. These data show, for instance, that the average incremental cost associated with presence of heat recovery was $0.86 per watt for SGIP participants with completed projects. When this value is used to estimate the incremental cost of heat recovery not only for completed projects but also for projects that will be completed in the future, it is necessary to summarize the uncertainty of the estimate.[23]

Table 5-5: Microturbine Project Cost Comparison Summary

Physical Difference	Difference of Means (2014 $ / Watt)	90% Confidence Interval (2014 $ / Watt)
Heat Recovery	0.86	-1.08 to 2.79
Fuel Treatment	1.93	0.97 to 2.90
RFU	1.44	0.77 to 2.11

The 90 percent confidence intervals presented in Table 5-5 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 -1.08 dollars (2014) per Watt. This counterintuitive result implies that systems with heat recovery might cost less than those without 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.

IC Engine Project Cost Comparisons

Cost comparison results for IC engine projects are summarized in Table 5-6. 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.

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

Table 5-6: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means (2014 $ / Watt)	90% Confidence Interval (2014 $ / Watt)
Heat Recovery	0.86	-0.76 to 2.48
Fuel Treatment	0.65	0.07 to 1.23
RFU	0.48	-0.04 to 0.99

CHP 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 5-7. Results for the incremental difference due to heat recovery are not presented because all but one of the renewable fuel cell projects completed to date 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. The confidence intervals span across zero and there is not 90% confidence that cost differences exist for the analyzed factors.

Table 5-7: CHP Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means (2014 $ / Watt)	90% Confidence Interval (2014 $ / Watt)
Heat Recovery	---	---
Fuel Treatment	-0.33	-2.50 to 1.85
RFU	-0.46	-2.56 to 1.64

5.5 Cost Comparison Summary

Comparison of the installed costs between renewable- and non-renewable fueled generation systems operational as of December 31, 2014, reveals that average non-renewable generator costs have typically been lower than average renewable-fueled generator costs (with CHP fuel cells being the only exception). However, these averages pertain to past Program participants. The fundamental question motivating examination of RFU 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. In fact, these confidence intervals prevent drawing conclusions about cost differences in CHP fuel cell projects; only microturbine and IC engine 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 PROJECTS UTILIZING RENEWABLE FUEL

All SGIP projects supplied with renewable fuel are listed in Table A-1. 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 (about 66 percent by count) are also equipped with a non-renewable fuel supply. These projects are identified in the “Any Non-Renewable Fuel Supply” column.

Table A–1: SGIP Projects Utilizing Renewable Fuel

SGIP Reservation No.	PA	Tech	Renewable Fuel Type	Size (kW)	Operational Date*	RFUR Project	Non-Renewable Fuel Supply
SD-SGIP-2001-0007	CSE	MT	DG - WWTP	84	08/30/2002	No	No
SCE-SGIP-2002-0055	SCE	MT	Landfill Gas	420	05/19/2003	Yes	No
SCE-SGIP-2001-0031	SCE	ICE	Landfill Gas	991	09/29/2003	No	No
PGE-SGIP-2002-0110	PG&E	ICE	DG - WWTP	900	10/23/2003	No	Yes
SCE-SGIP-2002-0074	SCE	MT	Landfill Gas	300	02/11/2004	Yes	No
SD-SGIP-2001-0026	CSE	MT	DG - WWTP	120	04/23/2004	No	No
PGE-SGIP-2003-0514	PG&E	MT	DG - WWTP	90	05/19/2004	Yes	No
SD-SGIP-2001-0023	CSE	MT	DG - WWTP	360	09/03/2004	No	No
PGE-SGIP-2003-0379	PG&E	MT	Landfill Gas	280	01/14/2005	Yes	No
SCE-SGIP-2003-0092	SCE	FC - CHP	DG - WWTP	500	03/11/2005	Yes	Yes
PGE-SGIP-2004-0640	PG&E	MT	Landfill Gas	70	04/14/2005	Yes	No
PGE-SGIP-2004-0641	PG&E	MT	Landfill Gas	70	04/14/2005	Yes	No
SCE-SGIP-2003-0045	SCE	FC - CHP	DG - WWTP	250	04/19/2005	Yes	No
SCE-SGIP-2003-0008	SCE	MT	Landfill Gas	70	05/11/2005	Yes	No
SCE-SGIP-2003-0017	SCE	ICE	DG - WWTP	500	05/11/2005	Yes	Yes
PGE-SGIP-2004-0842A	PG&E	MT	DG - WWTP	60	05/27/2005	Yes	No
SCE-SGIP-2003-0038	SCE	MT	DG - WWTP	250	07/12/2005	Yes	No
PGE-SGIP-2004-0747	PG&E	MT	DG - WWTP	60	07/18/2005	Yes	No
PGE-SGIP-2004-0653	PG&E	FC - CHP	DG - Food Processing	1,000	08/09/2005	No	Yes
PGE-SGIP-2004-0833	PG&E	MT	DG - Food Processing	70	11/07/2005	No	Yes
PGE-SGIP-2003-0483	PG&E	ICE	DG - Dairy	300	01/13/2006	Yes	No

SGIP Reservation No.	PA	Tech	Renewable Fuel Type	Size (kW)	Operational Date*	RFUR Project	Non-Renewable Fuel Supply
PGE-SGIP-2003-0313	PG&E	MT	DG - WWTP	300	03/16/2006	Yes	No
PGE-SGIP-2005-1297	PG&E	MT	DG - WWTP	280	04/07/2006	Yes	No
PGE-SGIP-2004-0856	PG&E	MT	Landfill Gas	210	05/05/2006	Yes	No
PGE-SGIP-2004-0658	PG&E	ICE	DG - Dairy	160	05/22/2006	Yes	No
PGE-SGIP-2005-1222	PG&E	ICE	Landfill Gas	970	07/05/2006	Yes	No
PGE-SGIP-2005-1316	PG&E	ICE	Landfill Gas	970	10/02/2006	Yes	No
SCE-SGIP-2004-0158	SCE	ICE	DG - WWTP	704	10/25/2006	Yes	Yes
SCE-SGIP-2004-0159	SCE	ICE	DG - WWTP	704	10/26/2006	Yes	Yes
PGE-SGIP-2005-1308	PG&E	ICE	DG - Dairy	400	11/17/2006	Yes	No
PGE-SGIP-2006-1505	PG&E	ICE	Landfill Gas	970	11/24/2006	Yes	No
PGE-SGIP-2003-0298	PG&E	MT	DG - WWTP	30	01/31/2007	Yes	No
PGE-SGIP-2005-1313	PG&E	MT	DG - WWTP	240	03/06/2007	Yes	Yes
SCE-SGIP-2005-0093	SCE	ICE	Landfill Gas	1,030	03/16/2007	Yes	No
PGE-SGIP-2006-1559	PG&E	ICE	DG - WWTP	160	05/16/2007	Yes	No
PGE-SGIP-2005-1298	PG&E	MT	DG - WWTP	250	06/11/2007	No	Yes
PGE-SGIP-2006-1528	PG&E	MT	DG - Food Processing	70	06/15/2007	Yes	No
SCE-SGIP-2006-0094	SCE	ICE	DG - WWTP	500	11/08/2007	Yes	No
PGE-SGIP-2006-1577	PG&E	ICE	DG - Dairy	80	12/31/2007	Yes	No
SCG-SGIP-2005-0082	SCG	ICE	DG - Food Processing	1,080	01/15/2008	Yes	No
SCG-SGIP-2006-0014	SCG	ICE	Landfill Gas	1,030	02/21/2008	Yes	No
SCE-SGIP-2006-0062	SCE	FC - CHP	DG - WWTP	900	03/04/2008	Yes	Yes
SD-SGIP-2005-0270	CSE	MT	Landfill Gas	210	04/04/2008	Yes	No
PGE-SGIP-2006-1490	PG&E	FC - CHP	DG - WWTP	600	04/24/2008	Yes	Yes
PGE-SGIP-2006-1640	PG&E	ICE	DG - WWTP	643	07/29/2008	Yes	No
PGE-SGIP-2006-1498	PG&E	MT	Landfill Gas	210	08/05/2008	Yes	No
SCG-SGIP-2006-0036	SCG	FC - CHP	DG - WWTP	1,200	10/27/2008	Yes	Yes
PGE-SGIP-2007-1749	PG&E	ICE	DG - WWTP	130	11/09/2009	Yes	Yes
SCG-SGIP-2008-0003	SCG	FC - CHP	DG - Food Processing	600	12/14/2009	Yes	Yes
SCG-SGIP-2006-0012	SCG	FC - CHP	DG - WWTP	900	12/18/2009	Yes	Yes
PGE-SGIP-2007-1775	PG&E	ICE	DG - Dairy	75	02/03/2010	Yes	No

SGIP Reservation No.	PA	Tech	Renewable Fuel Type	Size (kW)	Operational Date*	RFUR Project	Non-Renewable Fuel Supply
SD-SGIP-2007-0351	CSE	ICE	DG - WWTP	560	04/16/2010	Yes	Yes
SCE-SGIP-2010-0002	SCE	FC - CHP	DG - WWTP	500	10/31/2010	Yes	Yes
SCE-SGIP-2010-0334	SCE	FC - CHP	DG - WWTP	250	10/31/2010	Yes	Yes
PGE-SGIP-2009-1812	PG&E	FC - Elec.	Directed Biogas	400	11/10/2010	Yes	Yes
PGE-SGIP-2009-1811	PG&E	FC - Elec.	Directed Biogas	400	11/10/2010	Yes	Yes
PGE-SGIP-2009-1810	PG&E	FC - Elec.	Directed Biogas	400	11/10/2010	Yes	Yes
PGE-SGIP-2009-1802	PG&E	FC - Elec.	Directed Biogas	400	12/22/2010	Yes	Yes
PGE-SGIP-2007-1761	PG&E	ICE	DG - WWTP	330	12/23/2010	Yes	No
PGE-SGIP-2007-1759	PG&E	ICE	DG - WWTP	1,696	12/24/2010	Yes	No
SD-SGIP-2010-0369	CSE	FC - CHP	Directed Biogas	400	12/31/2010	Yes	Yes
SD-SGIP-2010-0370	CSE	FC - CHP	Directed Biogas	400	12/31/2010	Yes	Yes
PGE-SGIP-2009-1805	PG&E	FC - Elec.	Directed Biogas	200	01/18/2011	Yes	Yes
SCG-SGIP-2010-0012	SCG	FC - Elec.	Directed Biogas	1,000	01/24/2011	Yes	Yes
PGE-SGIP-2010-1859	PG&E	FC - Elec.	Directed Biogas	500	03/11/2011	Yes	Yes
PGE-SGIP-2010-1871	PG&E	FC - Elec.	Directed Biogas	300	03/14/2011	Yes	Yes
SCE-SGIP-2010-0004	SCE	FC - CHP	Directed Biogas	800	03/23/2011	Yes	Yes
PGE-SGIP-2010-1856	PG&E	FC - Elec.	Directed Biogas	300	05/09/2011	Yes	Yes
PGE-SGIP-2010-1849	PG&E	FC - Elec.	Directed Biogas	500	05/09/2011	Yes	Yes
PGE-SGIP-2010-1886	PG&E	FC - Elec.	Directed Biogas	300	05/24/2011	Yes	Yes
PGE-SGIP-2010-1853	PG&E	FC - Elec.	Directed Biogas	600	05/24/2011	Yes	Yes
PGE-SGIP-2010-1882	PG&E	FC - Elec.	Directed Biogas	400	05/24/2011	Yes	Yes
PGE-SGIP-2010-1885	PG&E	FC - Elec.	Directed Biogas	300	05/31/2011	Yes	Yes
PGE-SGIP-2010-1878	PG&E	FC - Elec.	Directed Biogas	500	06/29/2011	Yes	Yes
PGE-SGIP-2010-1851	PG&E	FC - Elec.	Directed Biogas	300	06/29/2011	Yes	Yes

SGIP Reservation No.	PA	Tech	Renewable Fuel Type	Size (kW)	Operational Date*	RFUR Project	Non-Renewable Fuel Supply
SCG-SGIP-2007-0013	SCG	ICE	DG - WWTP	150	07/13/2011	Yes	No
SCE-SGIP-2010-0023	SCE	FC - Elec.	Directed Biogas	400	08/08/2011	Yes	Yes
SCE-SGIP-2010-0022	SCE	FC - Elec.	Directed Biogas	400	08/08/2011	Yes	Yes
SCE-SGIP-2010-0012	SCE	FC - Elec.	Directed Biogas	300	08/08/2011	Yes	Yes
SCE-SGIP-2010-0009	SCE	FC - Elec.	Directed Biogas	300	08/08/2011	Yes	Yes
SCE-SGIP-2009-0003	SCE	FC - CHP	DG - WWTP	300	08/30/2011	Yes	Yes
PGE-SGIP-2010-1893	PG&E	FC - Elec.	Directed Biogas	210	09/07/2011	Yes	Yes
PGE-SGIP-2010-1892	PG&E	FC - Elec.	Directed Biogas	210	09/07/2011	Yes	Yes
PGE-SGIP-2010-1874	PG&E	FC - Elec.	Directed Biogas	500	09/07/2011	Yes	Yes
PGE-SGIP-2010-1850	PG&E	FC - Elec.	Directed Biogas	420	09/07/2011	Yes	Yes
SCG-SGIP-2010-0005	SCG	FC - Elec.	Directed Biogas	100	09/20/2011	Yes	Yes
SCG-SGIP-2010-0011	SCG	FC - Elec.	Directed Biogas	900	09/21/2011	Yes	Yes
SCE-SGIP-2007-0017	SCE	ICE	DG - WWTP	364	09/27/2011	Yes	No
PGE-SGIP-2010-1855	PG&E	FC - Elec.	Directed Biogas	300	09/29/2011	Yes	Yes
SCG-SGIP-2007-0036	SCG	ICE	DG - WWTP	340	11/01/2011	Yes	No
SCE-SGIP-2010-0014	SCE	FC - Elec.	Directed Biogas	420	11/15/2011	Yes	Yes
SCG-SGIP-2010-0020	SCG	FC - Elec.	Directed Biogas	420	12/15/2011	Yes	Yes
SCG-SGIP-2010-0019	SCG	FC - Elec.	Directed Biogas	420	12/15/2011	Yes	Yes
SCG-SGIP-2010-0018	SCG	FC - Elec.	Directed Biogas	420	12/15/2011	Yes	Yes
SCG-SGIP-2010-0015	SCG	FC - Elec.	Directed Biogas	420	12/16/2011	Yes	Yes
SD-SGIP-2009-0362	CSE	FC - CHP	DG - WWTP	300	12/21/2011	Yes	Yes
SD-SGIP-2009-0361	CSE	FC - CHP	Directed Biogas	1,400	12/21/2011	Yes	Yes
SD-SGIP-2009-0363	CSE	FC - CHP	Directed Biogas	2,800	12/21/2011	Yes	Yes
SD-SGIP-2010-0375	CSE	FC - Elec.	Directed Biogas	300	12/21/2011	Yes	Yes

SGIP Reservation No.	PA	Tech	Renewable Fuel Type	Size (kW)	Operational Date*	RFUR Project	Non-Renewable Fuel Supply
PGE-SGIP-2010-1929	PG&E	FC - Elec.	Directed Biogas	420	12/29/2011	Yes	Yes
PGE-SGIP-2010-1877	PG&E	FC - Elec.	Directed Biogas	200	12/29/2011	Yes	Yes
PGE-SGIP-2010-1876	PG&E	FC - Elec.	Directed Biogas	200	12/29/2011	Yes	Yes
PGE-SGIP-2010-1869	PG&E	FC - Elec.	Directed Biogas	600	12/29/2011	Yes	Yes
PGE-SGIP-2010-1868	PG&E	FC - Elec.	Directed Biogas	400	12/29/2011	Yes	Yes
PGE-SGIP-2010-1858	PG&E	FC - Elec.	Directed Biogas	300	12/29/2011	Yes	Yes
PGE-SGIP-2010-1857	PG&E	FC - Elec.	Directed Biogas	300	12/29/2011	Yes	Yes
PGE-SGIP-2010-1852	PG&E	FC - Elec.	Directed Biogas	400	12/29/2011	Yes	Yes
SD-SGIP-2010-0374	CSE	FC - Elec.	Directed Biogas	210	02/27/2012	Yes	Yes
SD-SGIP-2010-0376	CSE	FC - Elec.	Directed Biogas	210	02/27/2012	Yes	Yes
PGE-SGIP-2010-1926	PG&E	FC - Elec.	Directed Biogas	400	02/28/2012	Yes	Yes
PGE-SGIP-2010-1860	PG&E	FC - Elec.	Directed Biogas	800	02/28/2012	Yes	Yes
SCE-SGIP-2010-0028	SCE	FC - Elec.	Directed Biogas	600	03/28/2012	Yes	Yes
SCE-SGIP-2010-0011	SCE	FC - Elec.	Directed Biogas	210	03/28/2012	Yes	Yes
SCE-SGIP-2009-0013	SCE	FC - CHP	DG - WWTP	600	03/28/2012	Yes	Yes
PGE-SGIP-2011-1950	PG&E	FC - Elec.	Directed Biogas	500	04/11/2012	Yes	Yes
SD-SGIP-2010-0399	CSE	FC - Elec.	Directed Biogas	630	05/01/2012	Yes	Yes
SD-SGIP-2010-0398	CSE	FC - Elec.	Directed Biogas	420	05/01/2012	Yes	Yes
SCE-SGIP-2007-0006	SCE	MT	Landfill Gas	750	06/12/2012	Yes	No
SCE-SGIP-2010-0039	SCE	FC - Elec.	Directed Biogas	315	08/08/2012	Yes	Yes
SCE-SGIP-2010-0038	SCE	FC - Elec.	Directed Biogas	630	10/04/2012	Yes	Yes
PGE-SGIP-2010-1867	PG&E	FC - CHP	DG - WWTP	1,400	11/29/2012	Yes	Yes
SCE-SGIP-2010-0035	SCE	FC - CHP	Directed Biogas	1,110	12/17/2012	Yes	Yes
SCG-SGIP-2010-0026	SCG	FC - CHP	DG - WWTP	2,800	12/21/2012	Yes	Yes

SGIP Reservation No.	PA	Tech	Renewable Fuel Type	Size (kW)	Operational Date*	RFUR Project	Non-Renewable Fuel Supply
SCE-SGIP-2010-0041	SCE	FC - Elec.	Directed Biogas	840	12/24/2012	Yes	Yes
SCE-SGIP-2010-0037	SCE	FC - Elec.	Directed Biogas	1,050	12/24/2012	Yes	Yes
SCE-SGIP-2010-0024	SCE	FC - Elec.	Directed Biogas	1,050	03/29/2013	Yes	Yes
PGE-SGIP-2010-1914	PG&E	FC - Elec.	Directed Biogas	420	05/29/2013	Yes	Yes
SCG-SGIP-2010-0033	SCG	FC - Elec.	Directed Biogas	105	06/19/2013	Yes	Yes
SCG-SGIP-2010-0034	SCG	FC - Elec.	Directed Biogas	210	06/20/2013	Yes	Yes
PGE-SGIP-2012-2061	PG&E	ICE	DG - WWTP	950	10/31/2013	Yes	Yes
SCE-SGIP-2012-0413	SCE	MT	DG – Food Processing	750	02/26/2014	Yes	No
SCE-SGIP-2011-0348	SCE	ICE	DG - WWTP	650	06/18/2014	Yes	Yes
PGE-SGIP-2012-2110	PG&E	ICE	DG - Food Processing	350	07/25/2014	Yes	No
PGE-SGIP-2012-2415	PG&E	MT	Landfill Gas	65	07/31/2014	Yes	No
PGE-SGIP-2012-2432	PG&E	MT	Landfill Gas	65	09/12/2014	Yes	No
SD-SGIP-2012-0486	CSE	ICE	DG - WWTP	145	11/26/2014	Yes	No

* 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.

APPENDIX B
DIRECTED BIOGAS AUDIT PROTOCOL

The properties of directed biogas injection and extraction have a direct bearing on information needed to assess renewable fuel use compliance of directed biogas projects. On April 14, 2011, the SGIP PAs and their consultant AESC developed protocols for the audit of directed biogas usage. The audit protocol establishes data and verification requirements and is separated into three elements:

1. **Transfer of Ownership** – documentation and “linkage” demonstrating transfer of ownership of the directed biogas from source to one or more serial entities and then to the system owner.
2. **Transportation Path and Energy Accounting** – documentation reporting the amount (energy) of directed biogas from the eligible source to one or more serial pipelines and then to the System Owner. The documentation must report verifiable inputs and outputs of each pipeline segment. Imbalances, losses, and fees (paid in gas energy) must be included in the documented reports. Note that because directed biogas “accounting” is lost once it enters a gas distribution system, directed biogas can be notionally accounted for up to the gas utility receipt points (city gates). Note that “pooling” or carryover from unconsumed directed biogas is allowed.
3. **Gas Fuel Consumption** – documentation from the gas utility matching directed biogas receipts and reporting the metered total energy input to a SGIP eligible generator or fleet of SGIP eligible generators.

The data and documentation requirements for each element of the verification process are described in more detail below.

B.1 Transfer of Ownership

Acceptable documentation includes invoices or other statements showing transfer of ownership of biogas between the source and the SGIP system owner. If a broker, marketer, or scheduler takes ownership of the gas between the source and the system owner then intermediate documentation showing transfer of ownership is also required.

B.2 Transportation Path and Energy Accounting

Documentation from each entity in the transportation path must include:

- Documentation from the source showing the amount of directed biogas being moved onto the pipeline. Any non-renewable gas added at the source must be identified.
- Documentation from the gas transmission system showing:
  - Receipt of directed biogas (from source, storage, or other pipelines)
  - Pipeline losses or fees paid in gas (not carried over)
  - Positive or negative imbalances (carried over)

  - Delivery of directed biogas to either another pipeline, storage facility, or California utility receipt point
- Utility documentation showing the amount of biogas received at all California entry points
- Utility documentation showing the amount of fuel consumed by each SGIP project being supplied the directed biogas

The gas transportation accounting ends at the California entry point (city gate) and does not continue inside the gas company's distribution system.

B.3 Gas Fuel Consumption

Utility documentation showing the amount of fuel consumed by each SGIP project must be provided.

B.4 Usage Determination

SGIP projects are assumed to procure no more than 75% of their fuel input as directed biogas. The directed biogas delivered is compared to 75% of the project's fuel consumption. If the amount of directed biogas procured is less than 75% of the project's fuel consumption, then the project is out of compliance with the SGIP's renewable fuel use requirements. If the amount of directed biogas procured is equal to 75% of the project's fuel consumption, then the project is in compliance with the SGIP's renewable fuel use requirements. If the amount of directed biogas procured is greater than 75% of the project's fuel consumption, then the project is in compliance with the SGIP's renewable fuel use requirements and the remaining directed biogas over 75% of the project's fuel input will be considered pooled for future use. Once the pool is depleted, it cannot be borrowed against.

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