2013 SGIP

Impact Evaluation

Submitted to:

PG&E and
The SGIP
Working Group

Prepared by:

Itron
330 Madson Pl
Davis, CA 95618

Apr 2015

ACKNOWLEDGEMENTS

Itron would like to acknowledge the following for their contributions to the 2013 Self-Generation Incentive Program (SGIP) Impact Evaluation Report:

» Rachel Sackman at PG&E for her role as Project Manager and for providing guidance on the report approach and content as well as feedback on earlier drafts;

» The Program Administrators (Rebecca Feuerlicht at CSE, Brian Bishop at PG&E, James Stevenson at SCE, and Rosie Magana at SoCal Gas) for their review of earlier presentations of results and draft versions of the report, as well as their assistance in obtaining required and critical information for this report;

» The members of the Measurement & Evaluation oversight team (Ria Langheim at CSE and Emrah Ozkaya at SCE) for providing detailed review of our estimation methodology and for providing feedback on earlier drafts;

» James Loewen and Shannon O'Rourke at the CPUC for their guidance and feedback on earlier versions of the report;

» Energy + Environmental Economics for providing the avoided marginal heat rates used to quantify avoided greenhouse gas emissions;

» Our subcontractors, Trimark Associates and Independent Energy Solutions, for providing electrical metering support; and,

» The large number of third-party data providers who supplied performance data important to this impact evaluation.

Lead Author:

William Marin

Contributors:

Myles O'Kelly	Kurt Scheuermann
George Simons	Stephan Barsun
Smita Gupta	Jonathan Wanjiru
Susan Harris	Luke Scheidler
Vanessa Arent	Ryan Matsumori
Xinyan Xu	

We also wish to acknowledge the following for the report cover images:

NREL Image Gallery — Wind Turbine

fuelcell.org — Fuel Cells

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GLOSSARY

Abbreviations & Acronyms

Term	Definition
AES	Advanced Energy Storage
CAISO	California Independent System Operator
CEC	California Energy Commission
CSE	Center for Sustainable Energy
CO_2	Carbon dioxide
CO_2eq	CO_2 equivalent
CPUC	California Public Utilities Commission
DER	Distributed energy resource
FC	Fuel cell
GT	Gas turbine
ICE	Internal combustion engine
IOU	Investor-owned utility
MCS	Monte Carlo Simulation
MT	Microturbine
NEM	Net energy metering
NO_X	Nitric oxide (NO) and nitrogen dioxide (NO_2)
PA	Program Administrator
PBI	Performance based incentive
PG&E	Pacific Gas and Electric Company
PM_{10}	Particulate matter (PM) with diameter of 10 micrometers or less
PPA	Power Purchase Agreement
PRT	Pressure reduction turbine
PY	Program Year
SCE	Southern California Edison Company
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company
SO_2	Sulfur Dioxide
SGIP	Self-Generation Incentive Program
WD	Wind turbine

Key Terms

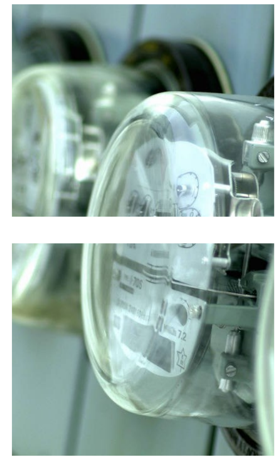
Term	Definition
Applicant	The entity, either the Host Customer, System Owner, or third party designated by the Host Customer, that is responsible for the development and submission of the SGIP application materials and is the main contact for the SGIP Program Administrator for a specific SGIP application.
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*.
California Independent System Operator (CAISO)	A non-profit public benefit corporation charged with operating the majority of California's high-voltage wholesale power grid.
Capacity Factor	A measure of system utilization that is calculated as the ratio of electrical energy generated to the electrical energy that would be produced by the generating system at rebated capacity during the same period (e.g., hourly, annually)
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 CH_4 is 21 times that of CO_2). Thus, the CO_2eq of a given amount of CH_4 is calculated as the product of the GWP factor (21) and the amount of CH_4.
Commercial	Non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and for-profit health, social, and educational institutions.
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.

Term	**Definition**
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.
Decommissioned	Projects that have been retired from service and the equipment removed.
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).
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 CH_4, expressed as CO_2eq.
Heat Rate	The amount of input energy used by an electrical generator to generate one kilowatt-hour (kWh) of electricity. Heat rate is commonly defined using units such as Btu/kWh.
Higher Heating Value (HHV)	The amount of heat released from combustion of fuel when all the products of combustion are brought back to the original pre-combustion temperature, and in particular condensing any vapor produced. Units of HHV are typically Btu/SCF of fuel.
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.
Load	Either the device or appliance which consumes electric power, or the amount of electric power drawn at a specific time from an electrical system, or the total power drawn from the system. Peak load is the amount of power drawn at the time of highest system demand.
Marginal Heat Rate	The marginal heat rate is the amount of source energy that is saved as a result of a change in generation.
Metric Ton	Common international measurement for the quantity of greenhouse gas emissions. A metric ton is equal to 2,205 pounds.
Offline	Projects with an annual capacity factor less than 0.05.
Online	Projects with an annual capacity factor of at least 0.05. Online projects are considered connected to the grid and providing power to the grid.
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*.
Performance	A general reference to the operational effectiveness of an SGIP system. *See also: electrical conversion efficiency and utilization.*

Term	Definition
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. *See also: system size.*
Recoverable Heat	The amount of heat available for recovery from a CHP system after generation of electricity. If heat load at the host site is lower than the amount of recoverable heat, the useful heat will be less than the recoverable heat.
System Efficiency	The unit-less ratio of useful energy produced to the fuel energy used (lower heating value).
System Owner	The owner of the SGIP system at the time the incentive is paid. For example, in the case when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner.
System Size	The manufacturer rated nominal size that approximates the generator's highest capacity to generate electricity under specified conditions.
Useful Heat	Recovered heat actually delivered and used to satisfy the on-site heating demand for a specific process or application at the host site. Useful heat may differ significantly from recoverable heat rates included in CHP manufacturer specifications.
Utilization	A general reference to how much an SGIP system is used. *See also: capacity factor, decommissioned, online, and offline.*
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



1 EXECUTIVE SUMMARY

The 2013 Impact Evaluation Report represents the thirteenth annual impact evaluation conducted for the Self-Generation Incentive Program (SGIP). The primary purpose of this report is to quantify the energy, demand, and environmental impacts of the SGIP during calendar year 2013. Impacts are reported for the SGIP as a whole and by other categories such as technology type, fuel type, Program Administrator (PA), and electric utility. Some reported 2013 impacts are further categorized by program year to recognize the different program goals and rules in effect at the time of project development. Figure 1-1 shows a timeline of key events.

Specific objectives for the 2013 evaluation include:

» Energy impacts including electricity generated, fuel consumed, and useful heat recovered. Efficiency and utilization metrics include: annual capacity factor, electrical conversion efficiency, useful heat recovery rate, and system efficiency.

» Demand impacts (average reduction and capacity factor) during top demand hour and top 200 hours of the California Independent System Operator (CAISO) and California's three investor owned utilities (IOUs).

» Case studies of impacts on IOU distribution feeders.

» Environmental impacts including those on greenhouse gas (GHG) emissions and criteria air pollutants.

The scope of this impact evaluation is limited to the performance metrics discussed above. The SGIP's goals also include market transformation and improved electric system reliability. While the findings in this impact evaluation are useful when discussing metrics for these goals, the report does not attempt to fully quantify the SGIP's impact on market transformation, electric system reliability, or improved transmission and distribution system utilization. A comprehensive analysis of the cost effectiveness of SGIP projects and the impact of the SGIP on market transformation will be included in subsequent reports to be released over the course of the next year. Beginning in 2007, solar photovoltaic (PV) projects were no longer eligible for incentives under the SGIP. Consequently, SGIP PV impacts are not reported in this evaluation report.[1]

The impacts evaluated in this report are based directly on metered performance data collected from a sample of SGIP systems. Where appropriate, efficiency and utilization trends are shown. In these cases, metered data from multiple years (not just 2013) are included in the analysis. Advanced Energy Storage

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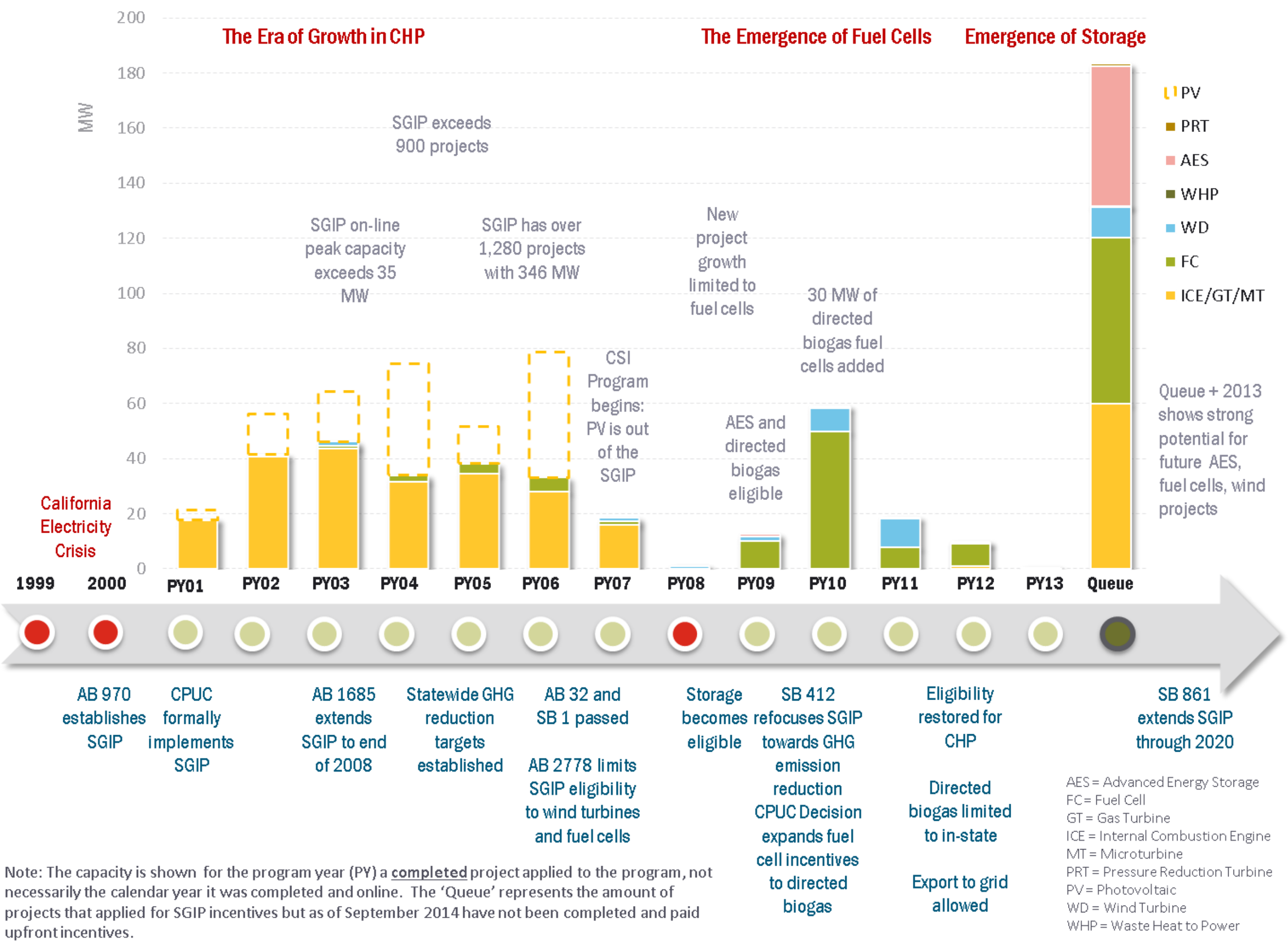
1 SGIP PV impacts are discussed in the California Solar Initiative (CSI) impacts evaluation report.

(AES) technologies are emerging in the SGIP and limited performance data were available for this evaluation. Consequently, AES performance in this report is not considered an impact but merely a preliminary performance assessment.

FIGURE 1-1: KEY EVENTS IN THE HISTORY OF THE SGIP

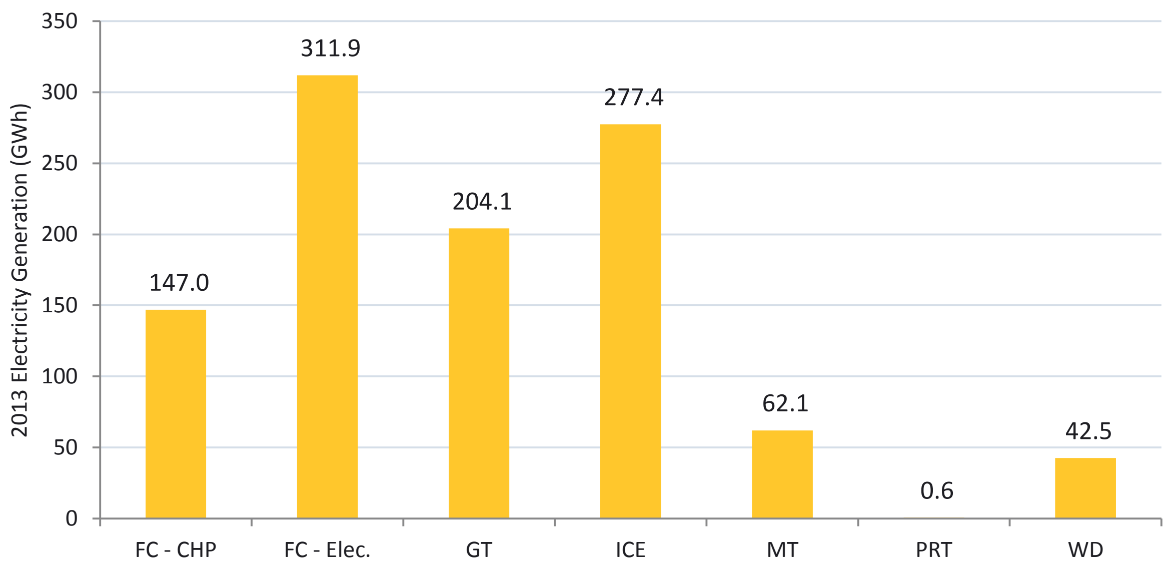


Note: The capacity is shown for the program year (PY) a completed project applied to the program, not necessarily the calendar year it was completed and online. The 'Queue' represents the amount of projects that applied for SGIP incentives but as of September 2014 have not been completed and paid upfront incentives.

1.1 Program Impacts in 2013

By the end of 2013, the SGIP had provided incentives to 672 projects representing almost 330 MW of rebated capacity (excluding PV projects rebated prior to 2007). Since the program's inception in 2001, total incentives paid or reserved exceeded 480 million dollars.[2] Total eligible project costs reported by applicants surpassed 1.5 billion dollars. During 2013, projects rebated by the SGIP generated 1,046 GWh of electricity. Electrical impacts by technology type are shown in Figure 1-2.

FIGURE 1-2: 2013 ELECTRICAL IMPACTS BY TECHNOLOGY TYPE



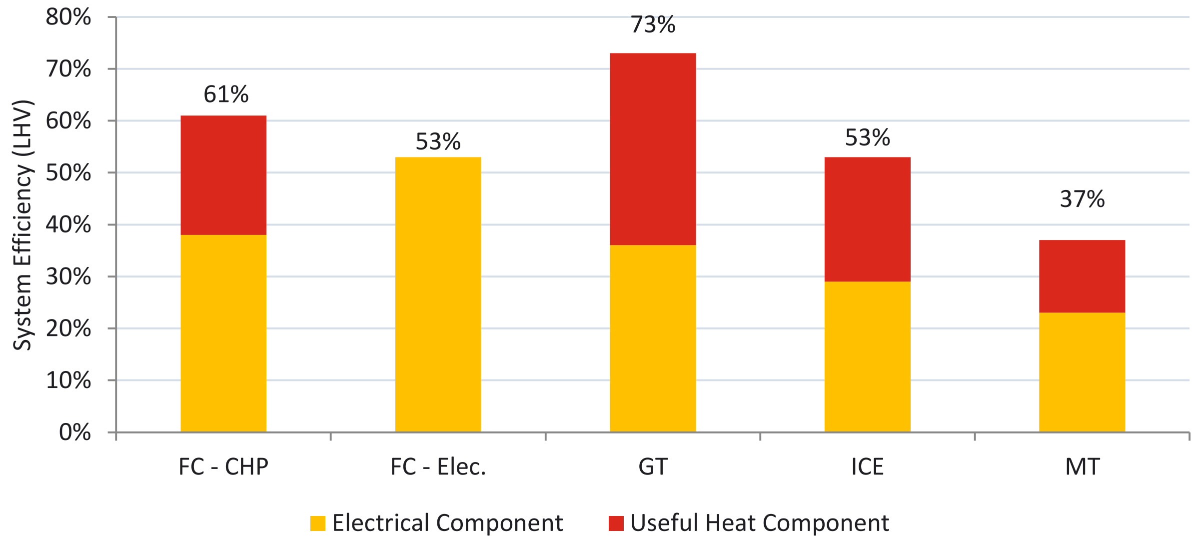
* FC = Fuel Cell, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

Electric-only fuel cells and internal combustion engines had the largest contributions to electrical impacts during 2013, followed by gas turbines and combined heat and power (CHP) fuel cells. There was only one pressure reduction turbine (PRT) in the program during 2013, which helps explain its minor electrical impact.

Gas turbines achieved the highest system efficiency in the program at 73 percent followed by CHP fuel cells at 61 percent. Electric-only fuel cells had the largest electrical component of system efficiency at 53 percent, meaning they were the most efficient at converting natural gas into electricity. Microturbines had the lowest electrical and useful heat components and achieved a combined 37 percent system efficiency. System efficiencies by technology type are shown in Figure 1-3.

2 Excluding incentives paid to PV projects before 2007.

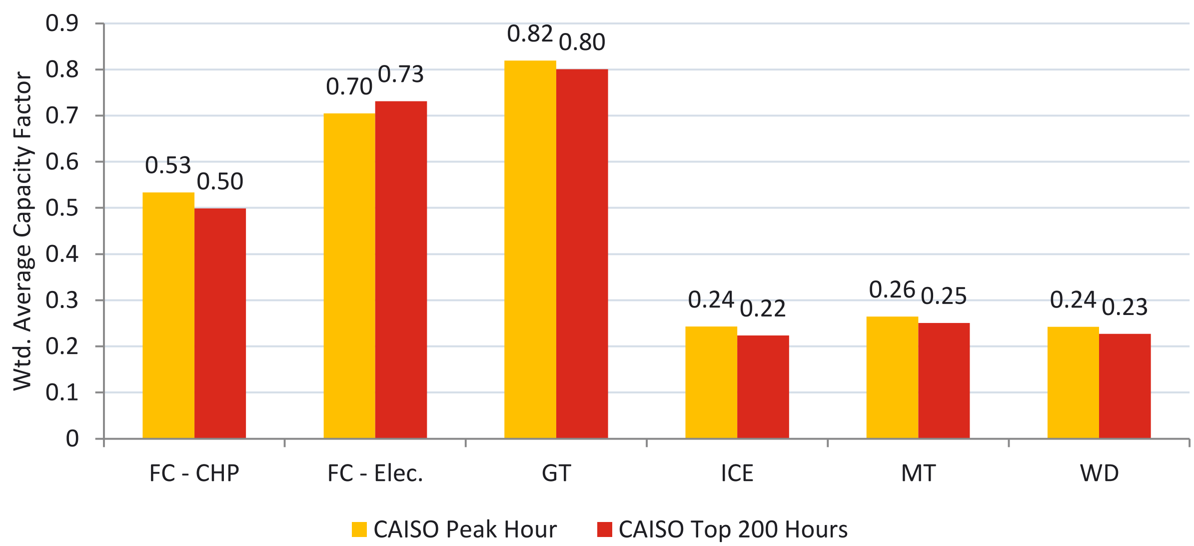
FIGURE 1-3: SYSTEM EFFICIENCY BY FUELED TECHNOLOGY TYPE



* FC = Fuel Cell, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine

The CAISO recorded its highest 2013 hourly system load of 44,924 MW on June 28 from 4-5 p.m. PDT. During that time, the combined impact from all SGIP systems was 127 MW. Peak hour capacity factors by technology type are shown in Figure 1-4.

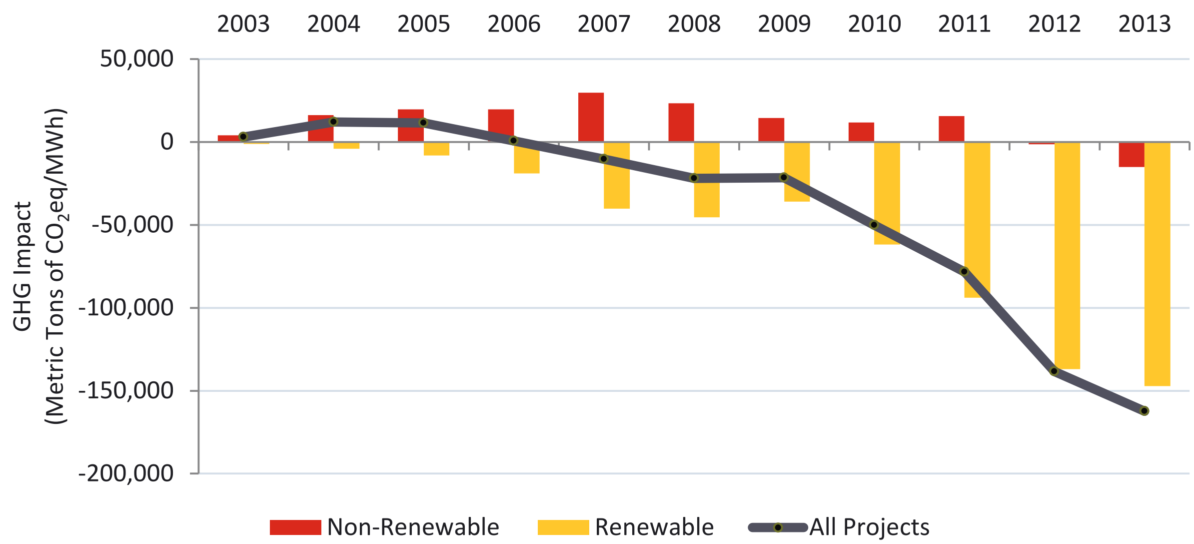
FIGURE 1-4: CAISO PEAK HOUR AND TOP 200 HOUR CAPACITY FACTORS BY TECHNOLOGY TYPE



* FC = Fuel Cell, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, WD = Wind Turbine

Passage of Senate Bill (SB) 412[3] (Kehoe, October 11, 2009) refocused the SGIP toward GHG emission reductions as the SGIP's primary goal. During 2013, the GHG impact of the SGIP was a reduction of more than 162 thousand metric tons of CO_2. As Figure 1-5 indicates, the SGIP continues its trend of GHG impact reductions year over year.

FIGURE 1-5: GREENHOUSE GAS IMPACTS OVER TIME

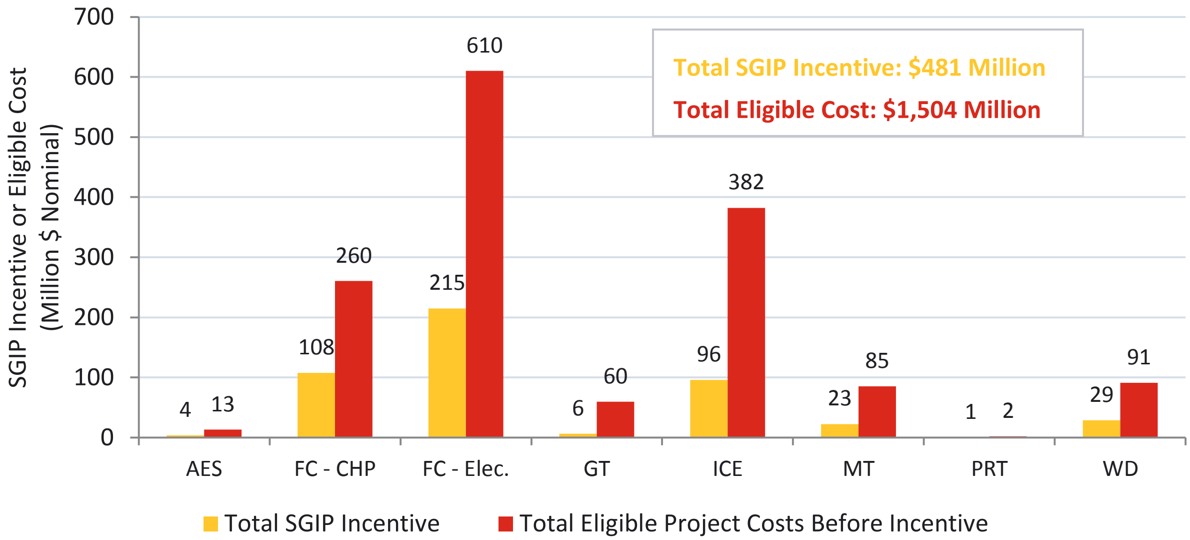


* Years indicate calendar years during which SGIP projects operated, not program years during which SGIP applications were received

Figure 1-6 shows the breakdown of incentives paid by the SGIP and costs reported by applicants for each technology type.

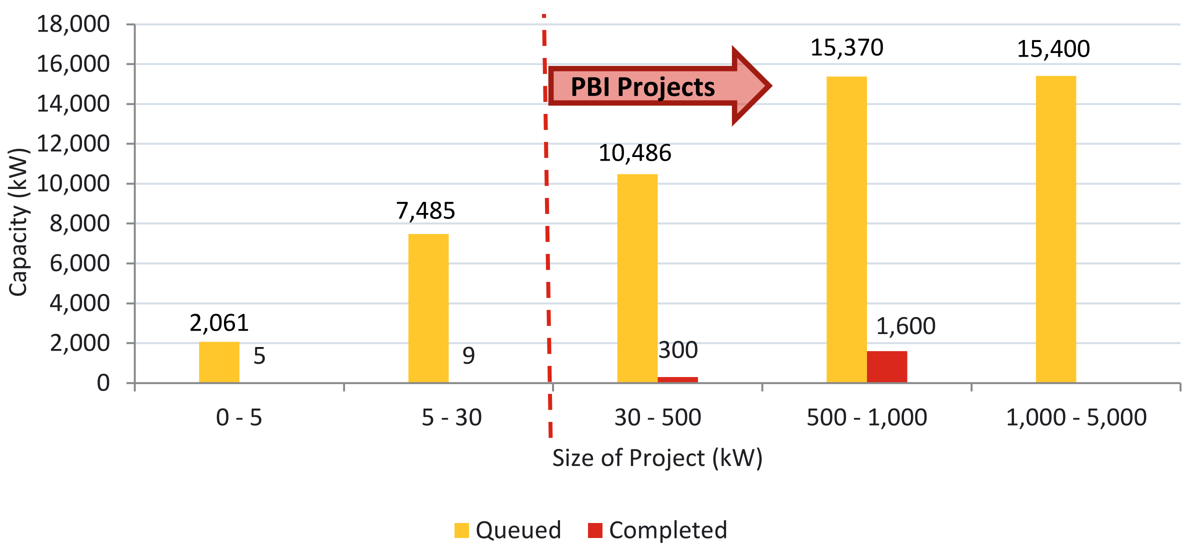
[3] http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

FIGURE 1-6: CUMULATIVE INCENTIVES PAID AND REPORTED ELIGIBLE COSTS BY TECHNOLOGY TYPE



The importance of AES in the SGIP will change dramatically in the coming years. As of September 2014, there were over 800 advanced energy storage projects that had applied for SGIP incentives. Most of these are smaller than 30 kW but seven are sized larger than one MW. Figure 1-7 shows the queued and completed AES capacity. As seen in Figure 1-7, despite the large number of projects in the queue under the performance-based incentive (PBI) threshold, a large portion of the queued capacity would be PBI projects.

FIGURE 1-7: QUEUED AND COMPLETED ADVANCED ENERGY STORAGE CAPACITY



1.2 Conclusions and Recommendations

Based on the information presented throughout this study, the following conclusions are provided:

1. **The SGIP continues to decrease GHG emissions.** During 2013, the SGIP decreased more than 162 thousand metric tons of GHG emissions (CO_2eq); an amount equivalent to the GHG emissions of more than 33 thousand passenger vehicles.[4] This also represents a fifteen-fold improvement in GHG emission reductions from 2007.

2. **The SGIP continues to provide peak demand and energy reductions.** During 2013, the SGIP decreased CAISO system peak demand by almost 127 MW and reduced customer electricity consumption by 1,046 GWh.

3. **The SGIP reduced criteria pollutant emissions impacts.** During 2013, the SGIP decreased NO_X and PM_{10} emissions by 234 thousand pounds and 69 thousand pounds respectively. The SGIP also decreased SO_2 emissions by 12 thousand pounds.

4. **The SGIP may provide peak demand relief to distribution feeders.** Based on case studies, we found that even small numbers of SGIP projects represent a significant amount of distribution feeder loading. In one particular case study, SGIP generation kept the feeder load from exceeding its rated capacity. For the case studies included in this report, SGIP projects reduced feeder load by more than 10 percent.

5. **There is not enough information to quantify the impacts of advanced energy storage projects.** While there are large numbers of storage projects in the SGIP queue, very few storage projects reached complete status in 2013 and, most importantly, there were very little metered data available from those storage projects. Case studies on storage projects point to the importance of obtaining metered data to enable accurate estimates of storage projects on peak demand reductions, energy arbitrage, and GHG emission reductions.

6. **The composition of SGIP projects has changed.** The composition of the SGIP fleet influences the impacts created by the program. Prior to the passage of SB 412, over 70 percent of the SGIP capacity consisted of internal combustion engines, gas turbines, and microturbines. Post-SB 412, these technologies represent less than four percent of the rebated capacity. The fleet of SGIP projects completed post-SB 412 consists primarily of fuel cells and wind turbines. Looking ahead, the SGIP queue is made up primarily of fuel cells, advanced energy storage, and wind turbines.

7. **Over 75 percent of SGIP rebated capacity was online during 2013.** Increased online capacity not only improves the overall performance of the program but provides important cost-effectiveness benefits. Forty percent of the internal combustion engine capacity and 37 percent of the microturbine capacity in SGIP was offline during 2013.

4 http://www.epa.gov/cleanenergy/energy-resources/refs.html

Based on these conclusions, we present the following recommendations:

1. **Ensure that sufficient data from advanced energy storage projects are available for future impacts evaluations.** PBI data from performance data providers (PDPs) is among the most effective and simplest ways to gather system performance data. Because they are early projects, of the five AES projects whose performance was discussed in this evaluation, only one had PBI data. The remaining AES projects were evaluated based on data provided by host customers, vendors, and applicants. Going forward, almost 90 percent of the projects (by project count) in the SGIP queue will fall under the PBI threshold. It is imperative that data from these AES projects be available in order for future impacts evaluations to yield meaningful results. Customer load data is essential in assessing impacts of storage in meaningful ways to utilities and the distributed energy marketplace. Additional data needs for evaluation purposes include interval AES charge/discharge, customer tariff information, and interval data from on-site generation paired with the AES system. These data will likely not be provided from PDPs in the future. Going forward, we recommend that data requests to electric utilities be placed for customer load data, or alternatively, that independent metering of host customer load be pursued for evaluation purposes. If possible, we recommend that host customer tariff information be tracked in the statewide project database.
2. **Continue investing in technologies that reduce GHG emissions.** Renewable technologies such as wind turbines, pressure reduction turbines, and distributed generation fueled by renewable biogas all inherently reduce greenhouse gas emissions. Similarly, non-renewable distributed generation (DG) technologies that achieve sufficiently high electrical conversion efficiencies or high system efficiencies can all contribute to greenhouse gas reductions while also reducing peak demand and energy consumption.
3. **Further refine the criteria air pollutant emissions impacts methodology.** The 2013 impacts evaluation marks the first attempt at quantifying the NO_X, PM_{10}, and SO_2 impacts of the SGIP. While the analysis methodology presented here is sound, there is room for improvement. Emissions data from the California Air Resources Board and local air quality municipal districts should be leveraged to obtain more accurate estimates of emissions rates from distributed energy resources and boilers. Host customer surveys may be appropriate to properly establish emissions baselines.

Additional information on program background, status, and impacts is provided in Sections 2 through 8. The report's five appendices describe in detail the sources of data and methodologies used to quantify impacts.

2 Introduction and Objectives

2 INTRODUCTION AND OBJECTIVES

The Self-Generation Incentive Program (SGIP) provides support to distributed energy resources (DERs) located behind the meter at utility customer facilities. The program was originally conceived in 2001 with a principal focus on reducing electric system peak demand to address the rolling blackouts that resulted from the California electricity crisis. The SGIP's goals have expanded since then in response to California Public Utilities Commission (CPUC) guidance to include reducing greenhouse gas (GHG) emissions, reducing customer electricity purchases, improving electric system reliability, and transforming the market for DERs.

Funded by California ratepayers, the SGIP is managed by Program Administrators (PAs) representing California's major investor owned utilities (IOUs).[1] The CPUC provides program oversight. The list of SGIP eligible technologies and their associated incentive rates have evolved over time as the program's goals have evolved. Eligible technologies during 2013 are shown in Table 2-1.[2]

TABLE 2-1: ELIGIBLE TECHNOLOGIES

Category	Technology Type
Renewable and Waste Energy Recovery	Wind Turbine
	Waste Heat to Power
	Pressure Reduction Turbine
Non-Renewable Conventional Combined Heat and Power (CHP)	Internal Combustion Engine – CHP
	Microturbine – CHP
	Gas Turbine – CHP
Emerging Technologies	Advanced Energy Storage
	Biogas Adder[3]
	Fuel Cell – CHP or Electric Only

1 The Program Administrators are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and the Center for Sustainable Energy (CSE) which implements the program for customers of San Diego Gas & Electric (SDG&E).

2 http://www.cpuc.ca.gov/NR/rdonlyres/D138BD29-2B31-4082-B963-2943114F5B68/0/2014_SGIPHandbook_V1.pdf

3 The biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technology.

2.1 Purpose and Scope of Report

The original CPUC Decision (D.) 01-03-073 establishing the SGIP required "program evaluations and load impact studies to verify energy production and system peak demand reductions" resulting from the SGIP.[4] That March 2001 decision also directed the assigned Administrative Law Judge (ALJ), in consultation with the CPUC Energy Division (ED) and the PAs, to establish a schedule for filing the required evaluation reports. Twelve annual SGIP impact evaluations have been conducted to date.[5] Annual impact evaluation reports have evolved to include the SGIP's evolving eligibility criteria and success metrics.

The 2013 Impact Evaluation Report represents the thirteenth annual impact evaluation conducted for the SGIP. The primary purpose of this report is to quantify the energy, demand, and environmental impacts of the SGIP during calendar year 2013. Impacts are reported for the SGIP as a whole and by other categories such as technology type, fuel type, PA, and electric utility. Some reported 2013 impacts are further categorized by program year to recognize the different program goals and rules in effect at the time of project development.

Specific objectives for the 2013 evaluation include:

» Energy impacts including electricity generated, fuel consumed, and useful heat recovered. Efficiency and utilization metrics include: annual capacity factor, electrical conversion efficiency, useful heat recovery rate, and system efficiency.

» Demand impacts (average reduction and capacity factor) during top demand hour and top 200 hours of the California Independent System Operator (CAISO) and California's three investor owned utilities.

» Case studies of impacts on IOU distribution feeders.

» Environmental impacts including those on GHG emissions and criteria pollutants.

» Preliminary performance assessment of advanced energy storage (AES).

The scope of this impact evaluation is limited to the performance metrics discussed above. As stated earlier, the SGIP's goals include market transformation and improved electric system reliability. While the findings in this impact evaluation are useful when discussing metrics for these goals, the report does not attempt to fully quantify the SGIP's impact on market transformation, electric system reliability, or improved transmission and distribution system utilization. A comprehensive analysis of the cost effectiveness of SGIP projects and the impact of the SGIP on market transformation will be included in

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4 CPUC Decision 01-03-073, March 27, 2001, page 37.

5 A listing of past SGIP impact reports can be found on the CPUC's website: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

subsequent reports. Solar photovoltaic (PV) projects are no longer eligible for incentives under the SGIP. Consequently, SGIP PV impacts are not reported in this evaluation report.[6]

The impacts evaluated in this report are based directly on metered performance data collected from a sample of SGIP systems. Where appropriate, efficiency and utilization trends are shown. In these cases, metered data from multiple years (not just 2013) are included in the analysis. Advanced Energy Storage technologies are emerging in the SGIP and limited performance data were available for this evaluation. Consequently, AES performance in this report is not considered an impact but merely a preliminary performance assessment.

2.2 Report Organization

This report is organized into eight sections and five appendices as described below:

» **Section 1** provides an executive summary of the key findings and recommendations from this evaluation.

» **Section 2** lays out the purpose, scope, and organization of the report.

» **Section 3** provides background and program status including project counts, rebated capacities, and incentive payment totals by technology type, energy source, and PA.

» **Section 4** summarizes the sources of data and statistical methods used to quantify impacts.

» **Section 5** presents energy impacts including electricity generated, waste heat recovered, and fuel consumed. Trends in utilization and efficiency are also shown.

» **Section 6** presents demand impacts during CAISO peak hours and IOU peak hours. It also includes distribution feeder peak demand impacts case studies.

» **Section 7** quantifies the GHG and criteria pollutant impacts of SGIP projects.

» **Section 8** summarizes the performance of AES projects in 2013.

» **Appendix A** provides supplementary program statistics not shown in Section 3.

» **Appendix B** provides a detailed and comprehensive review of the sources of data used in this evaluation, describes in detail the methodology used to quantify impacts, and provides additional impact results not shown in Section 5 and Section 6.

» **Appendix C** describes in detail the methodology used to quantify greenhouse gas impacts and provides additional impacts not shown in Section 7.

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6 SGIP PV impacts are discussed in the California Solar Initiative (CSI) impact evaluation report. The latest CSI impact evaluation was completed in 2010. http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf

- **Appendix D** describes in detail the methodology and assumptions used to quantify criteria pollutant impacts and presents additional impacts not shown in Section 7.
- **Appendix E** describes the sources of uncertainty in impact estimates, the methodology used to quantify the uncertainty, and the results of the uncertainty analysis.

Background and Status

3

3 PROGRAM BACKGROUND AND CURRENT STATUS

This section provides background on program policy and information on the status of the Self-Generation Incentive Program (SGIP) as of December 31, 2013. The status information is based on project data obtained from the Statewide Database provided by the Program Administrators (PAs). This section also summarizes active projects in the SGIP queue, which contains projects that may receive payments and become operational in future years. This report does not include impacts from photovoltaic (PV) systems that, prior to 2007, had been eligible to receive incentives under the SGIP.[1]

3.1 Program Background

In response to the electricity crisis of 2001, the California Legislature passed several bills to help reduce the state's electricity demand. In September 2000, Assembly Bill (AB) 970[2] (Ducheney, September 6, 2000) established the SGIP as a peak-load reduction program. In March 2001, the California Public Utilities Commission (CPUC) formally created the SGIP and the first SGIP application was received in July 2001.

The SGIP was originally designed to reduce energy use and demand at host customer sites. The program included provisions to help ensure that projects met certain performance specifications. Minimum efficiencies were established, and manufacturer warranties were required. Originally, the SGIP did not establish targets for a total rebated capacity to be installed, reductions in energy use and demand, or contributions to greenhouse gas emissions reductions.

By 2007, growing concerns with potential air quality impacts prompted changes to the eligibility of technologies under the SGIP. In particular, approval of AB 2778[3] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Beginning January 1, 2007, only fuel cells and wind turbines were eligible under the SGIP. Passage of Senate Bill (SB) 412[4] (Kehoe, October 11, 2009) refocused the SGIP toward greenhouse gas (GHG) emission reductions and led to a re-examination of technology eligibility by the CPUC. As a result of that re-examination, the list of technologies eligible for the SGIP expanded to again include combined heat and power (CHP), pressure reduction turbines, and waste heat-to-power technologies. In addition, SB 412 required fossil

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1 Effective January 1, 2007, PV technologies installed on the customer side of the meter were eligible to receive incentives under the California Solar Initiative (CSI). Impacts from PV installed under the SGIP are reported in the CSI impacts evaluation studies. Electronic versions of the CSI impacts studies are located at: http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm

2 http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

3 http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

4 http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

fueled combustion technologies to be adequately maintained so that during operation they continue to meet or exceed the established efficiency and emissions standards. The passage of SB 412 marked a significant change in the composition of SGIP applications toward fuel cells and advanced energy storage projects.

In SB 412 a sunset date of January 1, 2016, was set for the SGIP. Most recently, SB 861[5] authorized collections for the SGIP through 2019 and administration through 2020. The SGIP continues to be one of the largest and longest lived distributed energy resource (DER) incentive programs in the nation. The projects rebated by the SGIP since its inception reflect program objectives that have evolved over time.

The following section describes the composition of the SGIP fleet at the end of 2013.

3.2 Program Status at the End of 2013

Each SGIP project advances through a series of stages during its development. The scope of this impact evaluation is limited to 'completed' projects. Completed projects have been installed and begun operating, have passed their eligibility inspection, and were issued an incentive payment on or before December 31, 2013.[6,7,8] The SGIP has provided incentives to 672 completed projects representing almost 330 MW of rebated capacity. Counts and rebated capacities of completed projects are shown in Table 3-1 for each Program Administrator. Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and Southern California Gas Company (SCG) administer the SGIP within their electric and/or gas distribution service territories. The Center for Sustainable Energy (CSE) administers the program within San Diego Gas & Electric's (SDG&E's) service territory.

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5 Public resources trailer bill, June 20, 2014.
http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB861

6 Some SGIP projects have been withdrawn/cancelled and are no longer under development. Others remain active and under development but are not yet complete. These active projects may be completed in the future.

7 Installation and final SGIP and local utility approval of SGIP systems occur over periods ranging from months to years. Limited operations (and thus small impacts) occur during this period, prior to incentive payment. However, operations (e.g., testing, commissioning) prior to incentive payment do not reflect long-run average performance. For purposes of this impacts evaluation, only completed SGIP projects are assumed to be accruing impacts.

8 Some projects receive a single incentive payment at the time of projection completion. Others receive a portion of their total incentive at the time of project completion, and the remainder in annual payments following the first five years of operation. A detailed discussion of this distinction appears later in this section.

TABLE 3-1: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR

Program Administrator	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
CSE	66	35.7	10.8 %
PG&E	313	128.6	39.0 %
SCE	141	71.5	21.7 %
SCG	152	94.2	28.5 %
Total	***672***	***329.9***	***100 %***

Project counts and rebated capacities by technology type are shown in Table 3-2. Internal combustion engines have been the predominant technology type in SGIP with 257 projects representing 157 MW of rebated capacity. The aggregate capacity of electric only and combined heat and power fuel cells ranks second in the program at 91 MW. Only five advanced energy storage (AES) projects representing 1.9 MW of capacity have received incentives by the SGIP but their participation in the program is expected to increase in coming years.[9] Other technology types rebated by the SGIP include gas turbines, microturbines, pressure reduction turbines, and wind turbines.

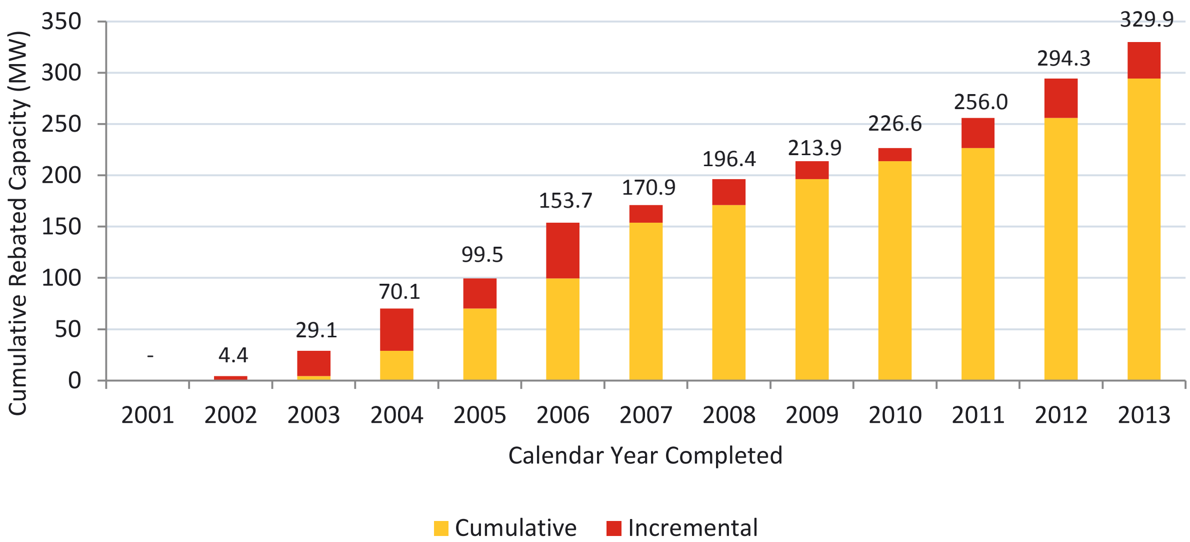
TABLE 3-2: PROJECT COUNT AND REBATED CAPACITY BY TECHNOLOGY TYPE

Technology Type	Project Count	Average Rebated Capacity (kW)	Cumulative Rebated Capacity (MW)	Percent of Rebated Capacity
Advanced Energy Storage	5	383	1.9	0.6%
Fuel Cell - CHP	114	300	34.2	10.4%
Fuel Cell - Electric Only	124	455	56.4	17.1%
Gas Turbine	9	3,349	30.1	9.1%
Internal Combustion Engine	257	613	157.4	47.7%
Microturbine	142	181	25.6	7.8%
Pressure Reduction Turbine	1	500	0.5	0.2%
Wind Turbine	20	1,186	23.7	7.2%
Total	***672***	***491***	***329.9***	***100%***

The cumulative growth in SGIP capacity since its inception in 2001 is shown in Figure 3-1. Fifty-five projects representing 35.6 MW of rebated capacity were completed during 2013. Of those projects, 17.1 MW (48 percent of capacity) were electric-only fuel cells and 13.4 MW (38 percent of capacity) were wind turbines.

9 There are over 850 AES projects in the SGIP queue. Per CPUC Decision 13-10-040 (October 17, 2013), PG&E, SCE, and SDG&E are required to procure a combined 200 MW of behind-the-meter storage by 2020.

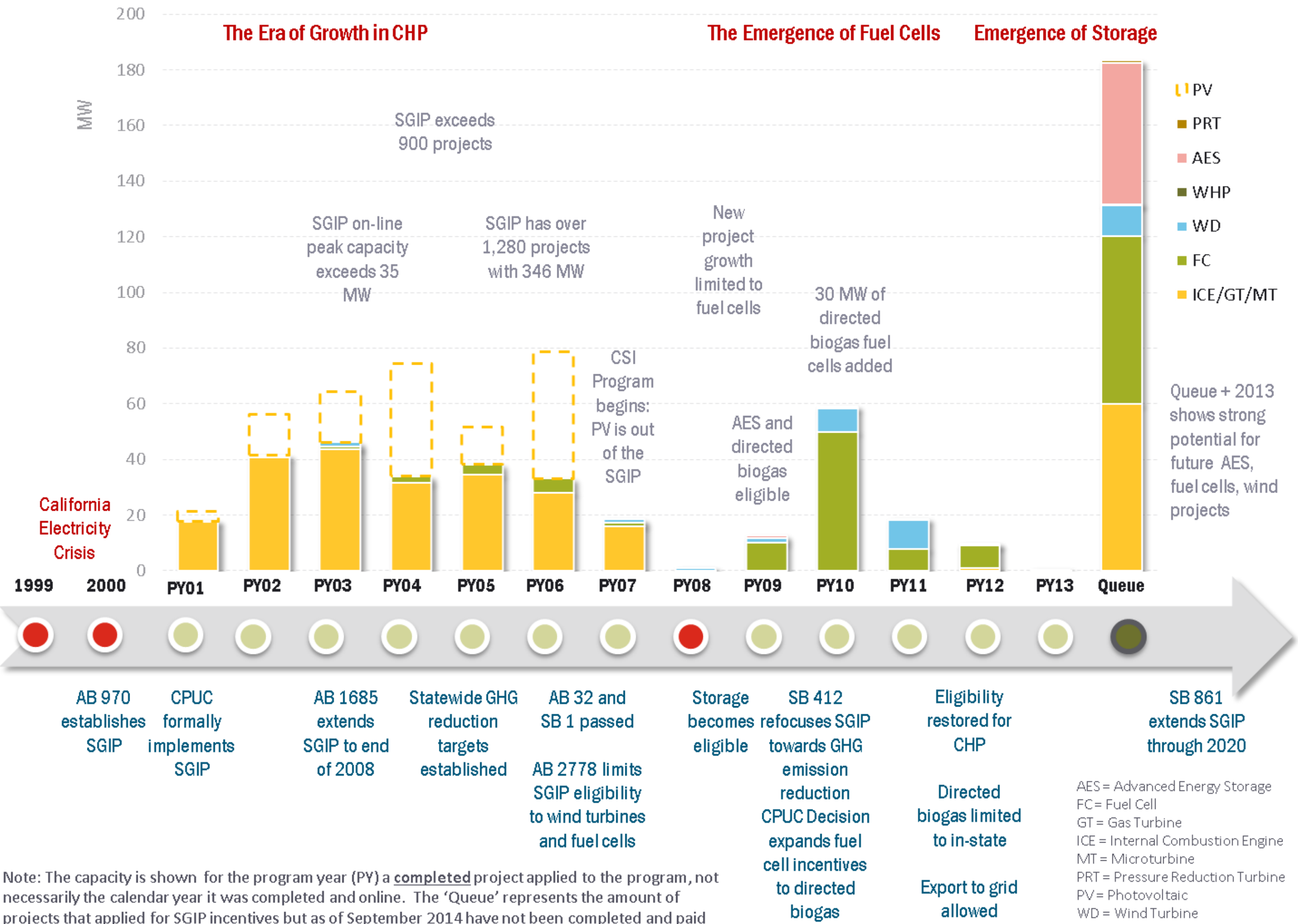
FIGURE 3-1: CUMULATIVE REBATED CAPACITY BY CALENDAR YEAR



The date a project is completed is used to calculate its age, whereas the program year (PY) is the year in which the application for the project was received. Because program rules have evolved over time, a project's program year is used to determine what program rules and policies are applicable to it. For instance, PY12 projects are required to meet GHG emissions requirements, whereas PY02 projects are not.

Figure 3-2 lists project counts and rebated capacities by program year for projects completed on or before December 31, 2013 along with major program policy influences. The year a project applies to the SGIP is almost always earlier than the year in which it is completed due to the time required to construct and commission DER systems and confirm that applicants have met all of the SGIP's requirements. PY13 projects do not necessarily accrue impacts during calendar year 2013 as those projects may be completed in 2014 or beyond.

FIGURE 3-2: REBATED CAPACITY BY PROGRAM YEAR AND KEY EVENTS IN THE SGIP'S HISTORY



Note: The capacity is shown for the program year (PY) a completed project applied to the program, not necessarily the calendar year it was completed and online. The 'Queue' represents the amount of projects that applied for SGIP incentives but as of September 2014 have not been completed and paid upfront incentives.

AES = Advanced Energy Storage
FC = Fuel Cell
GT = Gas Turbine
ICE = Internal Combustion Engine
MT = Microturbine
PRT = Pressure Reduction Turbine
PV = Photovoltaic
WD = Wind Turbine
WHP = Waste Heat to Power

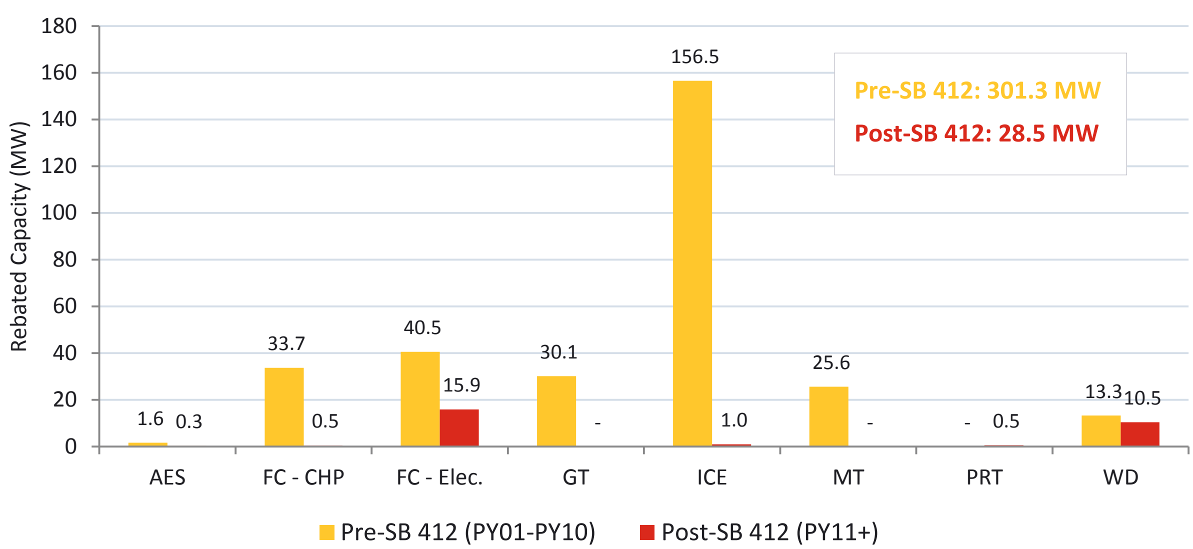
One of the most important changes in the SGIP's design targeted its incentive structure. Completed projects from PY10 or earlier received their entire SGIP incentive at the time of project completion. This incentive structure is referred to as a 'capacity based" incentive. However, beginning in PY11 as a result of SB 412, new projects 30 kW and larger will receive half of their SGIP incentive at the time of completion and the remainder in annual payments following each of the first five years of operation. This incentive structure is known as a performance-based incentive (PBI).

All completed PBI projects remained in their first five years of operation at the end of 2013. Each of these projects is required to submit performance data to the PA to enable calculation of its annual PBI payments. Annual PBI payments are based on achieved system efficiency and utilization.

To support assessment of possible differences in average performance of projects receiving capacity based incentives versus those receiving performance based incentives, each project was classified as either Pre-SB 412 or Post-SB 412 based on its program year. Completed projects that applied to the SGIP during PY01-PY10 are classified as Pre-SB 412. Completed projects that applied during or after PY11 (regardless of their incentive payment mechanism) are classified as Post-SB 412.

Figure 3-3 shows the rebated capacities of each technology type grouped by Pre/Post-SB 412 status. Fifty projects representing 28.5 MW of rebated capacity have been completed Post-SB 412. The majority of the Post-SB 412 projects are electric-only fuel cell (36) and wind turbine (5) projects. Very few Post-SB 412 advanced energy storage (3), pressure reduction turbine (1), and CHP (5) projects have been paid incentives as of December 31, 2013. The small population of Post-SB 412 projects limits the significance of performance comparisons Pre/Post-SB 412.

FIGURE 3-3: REBATED CAPACITY BY TECHNOLOGY TYPE[10] PRE/POST-SB 412



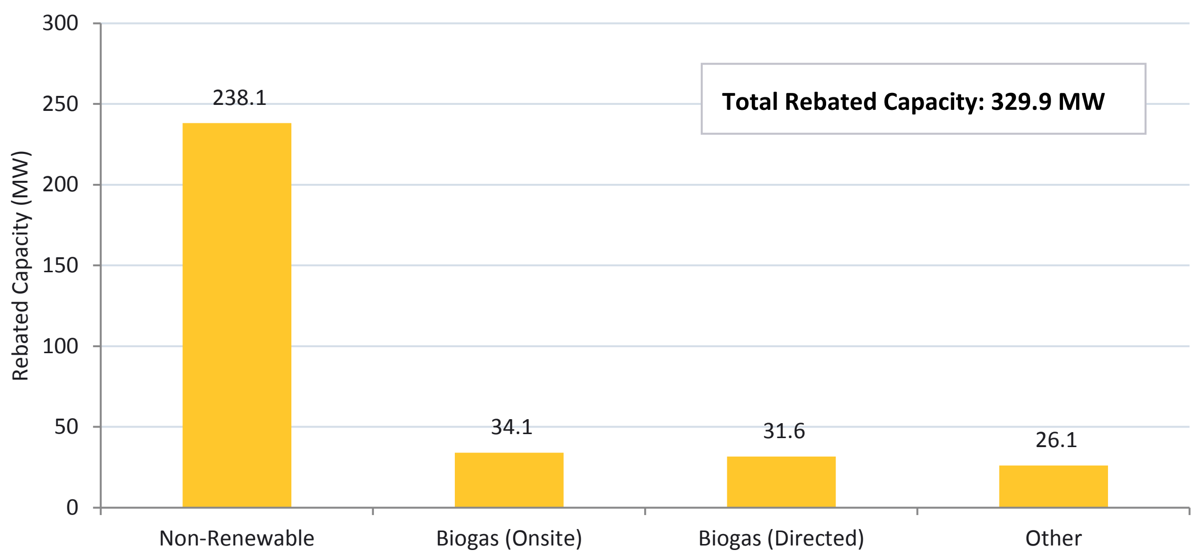
10 AES = Advanced Energy Storage, FC – CHP = CHP Fuel Cell, FC – Elec. = Electric-only Fuel Cell, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

SGIP projects are powered by a variety of renewable and non-renewable energy sources as shown in Figure 3-4. The majority of SGIP projects are powered by non-renewable fuels such as natural gas. Onsite biogas projects typically use biogas derived from landfills or anaerobic digestion processes that convert biological matter to renewable fuel. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert wastes from these facilities to biogas.

In CPUC Decision 09-09-048 (September 24, 2009), SGIP eligibility was expanded to include "directed biogas" projects. Directed biogas projects use biogas fuel that is produced at a location other 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 by the SGIP renewable fuel project, the directed biogas is notionally delivered and the SGIP is credited with the overall use of biogas resources. Beginning in PY11 the SGIP limited eligibility for directed biogas projects to in-state biogas sources only.[11] No directed biogas projects have been completed Post-SB 412.

In Figure 3-4 the 'Other' energy source group includes advanced energy storage, wind turbine, and pressure reduction turbine projects. One pressure reduction turbine project has been completed to date in the SGIP.

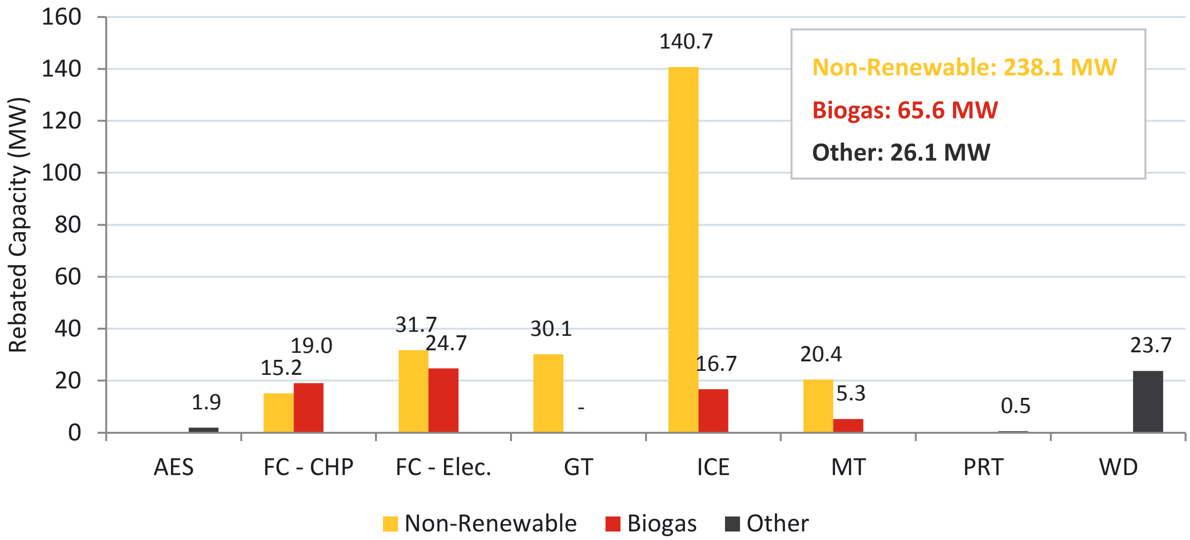
FIGURE 3-4: REBATED CAPACITY BY ENERGY SOURCE



Energy sources for each SGIP technology type are shown in Figure 3-5. The SGIP fleet is diverse and contains almost all combinations of technology and energy source. With the exception of gas turbines, all fuel-consuming technology types have projects powered by non-renewable natural gas and renewable biogas. All of the biogas used for electric-only fuel cells is directed biogas. Some CHP fuel cells are also fueled by directed biogas, but most are fueled by onsite biogas.

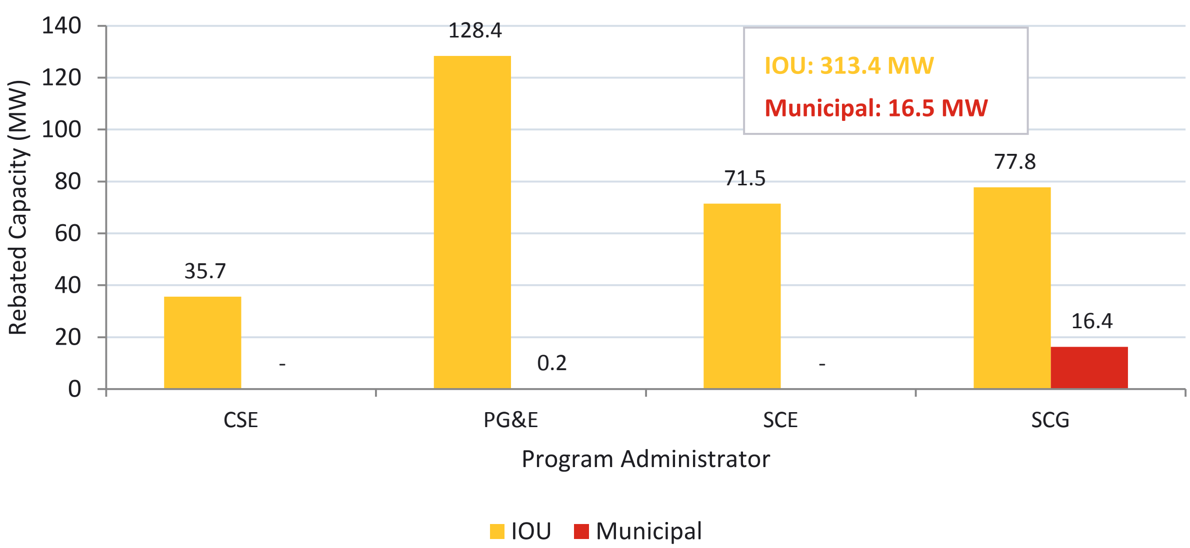
11 CPUC Decision 11-09-015 (September 8, 2011)

FIGURE 3-5: REBATED CAPACITY BY SGIP TECHNOLOGY TYPE AND FUEL TYPE



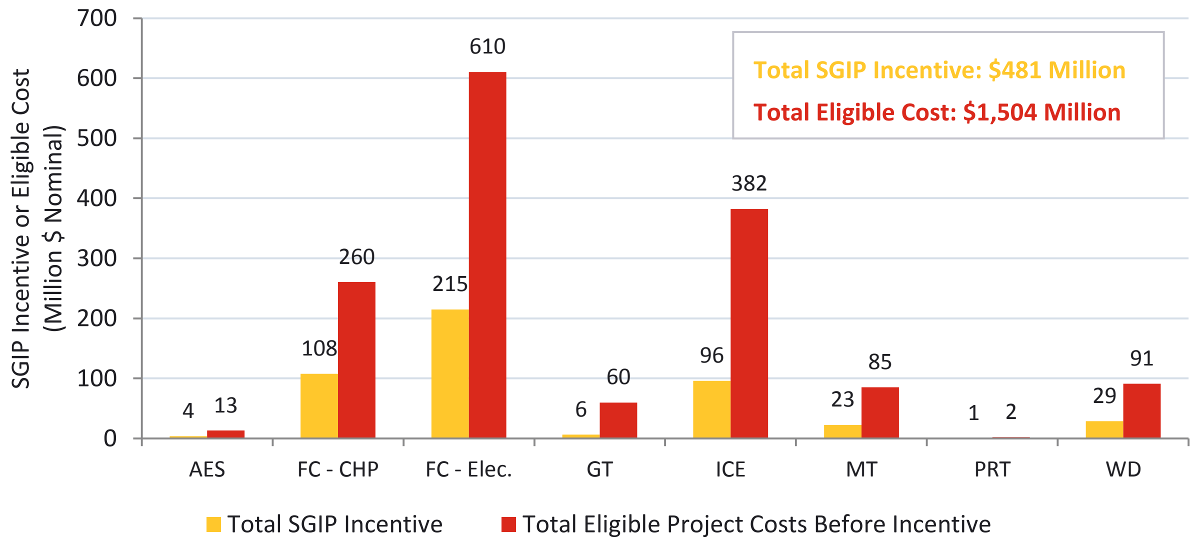
SGIP projects are electrically interconnected to load serving entities that are either investor owned (IOU) or municipal utilities. Figure 3-6 shows each PA's rebated capacity by electric utility type. Five percent of the SGIP rebated capacity is interconnected to municipal utilities; the remaining capacity offsets IOU electricity purchases. Any project interconnected to a municipal electric utility must be served by a gas IOU. Almost all of the capacity interconnected with municipal utilities is administered by SCG. Of the 77.8 MW administered by SCG interconnected to IOUs, 72.3 MW are served by SCE. The remaining IOU capacity is served by PG&E and SDG&E. All projects administered by CSE and SCE are interconnected to IOUs.

FIGURE 3-6: REBATED CAPACITY BY PROGRAM ADMINISTRATOR AND ELECTRIC UTILITY TYPE



By the end of 2013 the SGIP had allocated over 480 million dollars in incentives for completed projects. Eligible costs[12] reported by applicants surpassed 1.5 billion dollars. Figure 3-7 shows the breakdown of incentives paid by the SGIP and costs reported by applicants for each technology type.

FIGURE 3-7: CUMULATIVE INCENTIVES PAID AND REPORTED ELIGIBLE COSTS BY TECHNOLOGY TYPE



A detailed examination of SGIP incentive rates and the costs/benefits of each technology type is outside the scope of this report.[13]

3.3 Status of Queue

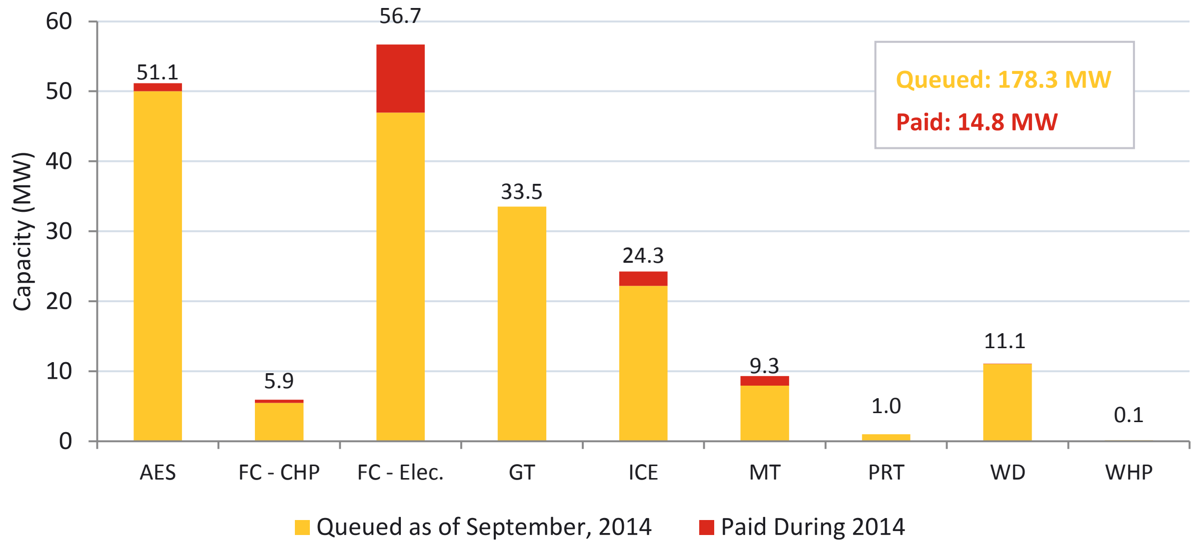
Projects that were not paid on or before December 31, 2013, and have not had their applications cancelled, rejected, or withdrawn remain in the SGIP queue. As of September 2014, there were 1,050 projects representing 193 MW of capacity in the SGIP queue. Figure 3-8 summarizes the SGIP queue by technology type.

---

12 Eligible costs are specified in the SGIP handbook.

13 The cost effectiveness of SGIP technologies will be treated in a forthcoming SGIP cost-effectiveness study.

FIGURE 3-8: SGIP QUEUE BY TECHNOLOGY TYPE[14]



Of the 1,050 projects in the queue, 39 were completed in 2014[15] and, therefore, are not included in the analysis of energy, demand, and environmental impacts occurring during 2013. The remaining 1,011 projects are making their way through the queue, and may either receive incentive payments or exit the queue.[16] The SGIP queue is composed primarily of advanced energy storage and electric-only fuel cell projects. Of the 14.8 MW of projects paid in 2014, 9.7 MW are electric-only fuel cell projects.

During its thirteenth year, the SGIP provided incentives to 672 projects representing almost 330 MW of rebated capacity. The SGIP now boasts eight different technology types that are powered by a variety of energy sources. These projects entered the SGIP program in different program years and are, therefore, subject to different program rules as described in the SGIP handbooks. The following section describes the sources of data and the analytic methodology used to evaluate the impacts of the SGIP during 2013. More detailed program statistics are included in Appendix A.

14 WHP = Waste heat to power

15 As of September 2014

16 A project may exit the queue if it does not submit all SGIP requirements on time or if it fails to meet minimum SGIP requirements

Sources of Data and Estimation Methodology

4

4 SOURCES OF DATA AND ESTIMATION METHODOLOGY

This section provides an overview of the primary sources of data and the ratio estimation methodology used to quantify the energy and peak demand impacts of the Self-Generation Incentive Program (SGIP). The primary sources of data include:

- The statewide project list managed by the Program Administrators (PAs)
- Site inspection and verification reports completed by the PAs' consultants
- Metered electricity, fuel, and useful heat recovery data provided by the utilities, applicants, performance data providers (PDPs), and meters installed by Itron and its subcontractors
- Responses from the operations status surveys conducted by Itron

This section is not meant to be a comprehensive overview of the analysis but instead provides a high level review of the methodology. A more detailed discussion of sources of data and analytic methodology is provided in Appendix B. An overview of the environmental impacts methodology is provided in Appendix C and Appendix D. The treatment of measurement and sampling uncertainty is discussed in Appendix E.

4.1 Statewide Project List and Site Inspection Verification Reports

The statewide project list forms the "backbone" of the impacts evaluation as it contains information on all projects that have applied to the SGIP. Critical fields from the statewide project list include:

- Project tracking information such as the reservation number, facility address, program year, payment status/date, and incentive/eligible cost information
- Project characteristics including technology/fuel type, rebated capacity, and equipment manufacturer/model

Data obtained from the statewide project list are verified and supplemented by information from site inspection verification reports. Site inspections are performed by consultants on behalf of the PAs to verify that SGIP projects installed match the application data and to ensure they meet minimum requirements for program eligibility. The inspection verification reports are reviewed by Itron to verify and supplement the information in the statewide project list. Additional information in verification reports includes descriptions of useful heat recovery end uses for combined heat and power (CHP) projects and identification of existing metering equipment that can be used for impact evaluation purposes.

4.2 Metered Data

Metered electricity, fuel consumption, and useful heat recovery data form the basis of this impacts evaluation. Metered data are requested and collected from electricity/gas distribution companies, system manufacturers, host customers, and applicants. Meters were installed by Itron and its subcontractors based on a sampling approach designed to achieve statistically significant impacts estimates. In total, 18 distinct data providers provided metered data for 370 projects whose 2013 impacts were evaluated. The data are processed, validated, and converted into standard format datasets. The processing and validation steps include:

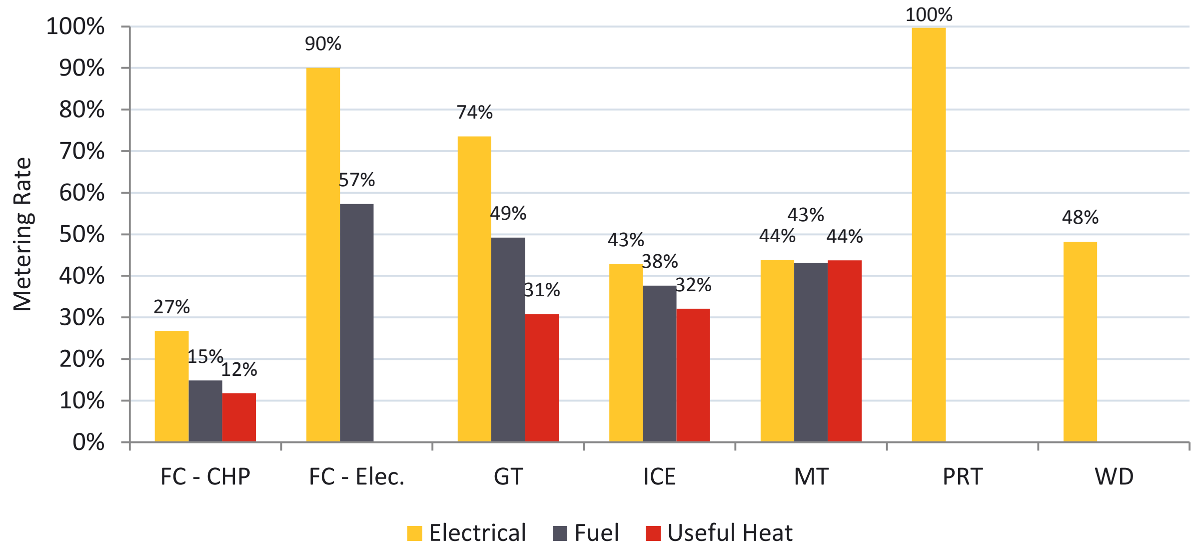
- Conversion of timestamps to Pacific Standard Time, including adjustments for Daylight Savings Time
- Standardization of interval length and units of measure:
  - All electrical generation data are converted to 15-minute net generator output kWh
  - All fuel consumption data are converted to 15-minute MBtu[1]$_{LHV}$ assuming 935 Btu/SCF[2]
  - All useful heat recovery data are converted to 15-minute MBtu
- Suspect observations are flagged, investigated, and removed if necessary

All valid metered data are cataloged in a library and added to the backbone of projects built from the statewide project list. The result is a backbone that is partially fleshed out with metered data but has gaps that result from metering equipment issues or projects outside the metered sample. Metering rates for calendar year 2013, defined as the number of hours for all projects during 2013 with metered data over the number of hours for all projects during 2013, are shown in Figure 4-1. These metering rates are unweighted and, therefore, do not reflect the relative importance of metering large projects.

[1] During the combustion of hydrocarbon fuels, some of the oxygen is combined with hydrogen, forming water vapor that may leave the combustion device either in vapor or condensed to liquid state. When the latent heat of vaporization is extracted from the flue products, causing the water to become liquid, the fuel's energy density is identified as higher heating value (HHV). When the equipment used allows the water to remain in the vapor state, the energy density is identified as lower heating value (LHV). (Petchers, 2003.)

[2] Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.

FIGURE 4-1: METERING RATES BY TECHNOLOGY TYPE



Unmetered hours cannot be ignored and their values must be estimated. These observations are estimated using the operations status survey and ratio estimation.

4.3 Operations Status Survey

Operations status surveys represent the first attempt at filling metered data gaps. The surveys target SGIP hosts whose 2013 backbone is lacking large amounts of metered data. A total of 126 systems were targeted for the 2013 operations status survey, which had a success rate of 71 percent. The survey seeks to determine if periods without metered data fit into one of three categories:

» **Normal,** the system was online and operating normally during the period in question.

» **Off,** the system did not generate electricity during the period in question but is still installed at the host site.

» **Decommissioned,** the system has been physically removed from the host site and will never operate again.

Hosts that respond with an “Off” operational status have zero energy generation assigned to the backbone during the time period in question. Similarly, hosts who respond with a decommissioned operational status have zeros added to the backbone starting from the date the system was decommissioned through the remainder of the evaluation period. Projects whose operational status is “Normal” and projects with data gaps but no operational status information must have missing observations estimated.

4.4 Ratio Estimation

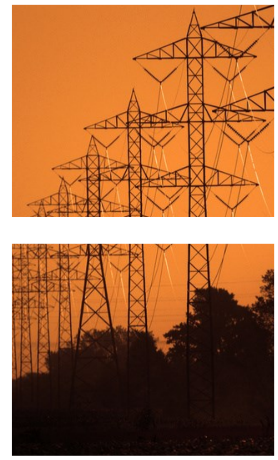
At this point in the estimation process, the project backbone has been built with the contents of the statewide project list, validated by information from installation verification reports, and fleshed out with metered data and information from operational status surveys. The remaining observations contain missing values and must be estimated.

Ratio estimation is used to generate hourly estimates of performance for periods where observations would otherwise contain missing values. The premise of ratio estimation is that the performance of unmetered projects can be estimated from projects with metered data using a “ratio estimator” and an “auxiliary variable”. The ratio estimator is calculated from the metered sample and the auxiliary variable is used to apply the estimator to the unmetered portion of the backbone. The characteristics of the ratio estimation are summarized in Table 4-1.

TABLE 4-1: RATIO ESTIMATION PARAMETERS

Variable Estimated	Ratio Estimator	Auxiliary Variable	Stratification
Electricity Generation (kWh)	Capacity Factor (kWh/kW·hr)	Rebated Capacity (kW)	Hourly, by technology type, fuel type, PA, operations status, incentive structure, capacity category, and warranty status
Fuel Consumption (MBtu)	Electrical Conversion Efficiency (unitless)	Electricity Generated (kWh)	Annual, by technology type
Useful Heat Recovered (MBtu)	Useful Heat Recovery Rate (MBtu/kWh)	Electricity Generated (kWh)	Annual, by technology type

The outcome of the ratio estimation process is fully fleshed out backbones with all metered data gaps filled with estimated electricity, fuel, and useful heat recovery values. These datasets form the basis of the energy, demand, and environmental impacts evaluation findings that are presented in Section 5 through Section 7. A discussion of the treatment of measurement and sampling uncertainty is included in Appendix E.



Energy Impacts

5

5 ENERGY IMPACTS

This section discusses the energy impacts attributable to the Self-Generation Incentive Program (SGIP) projects during 2013. Where appropriate, performance data from previous years are used to highlight important trends over time and as a function of system age. The sources of data and estimation methodology used to develop impacts estimates are described in Appendix B. The accuracy of these estimates is summarized in Appendix E.

This section is organized into the following subsections:

» **Summary of Electrical Energy Impacts:** provides an overview of electricity generated by SGIP projects in 2013

» **Utilization and Capacity Factor:** includes an investigation of utilization (measured as annual capacity factor) and decommissioning

» **System Efficiency and Natural Gas Impact:** quantifies the impact of SGIP projects on the natural gas distribution system

» **Assessment of Performance Based Incentive (PBI) Impact:** attempts to quantify differences in utilization that result from the new payment mechanism

This section intentionally excludes any energy impacts from Advanced Energy Storage (AES) projects. The performance of AES projects is described separately in Section 8.

5.1 Summary of Electrical Energy Impacts

In 2013 SGIP projects generated 1,046 GWh of electricity net of parasitic loads.[1] This is equivalent to 0.5 percent of California's total in-state generation.[2] The electric generation for each Program Administrator (PA) is listed in Table 5-1.

1 Excludes any secondary electricity impacts of useful heat recovery chillers

2 199,772 GWh generated in state according to California Energy Commission report at http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

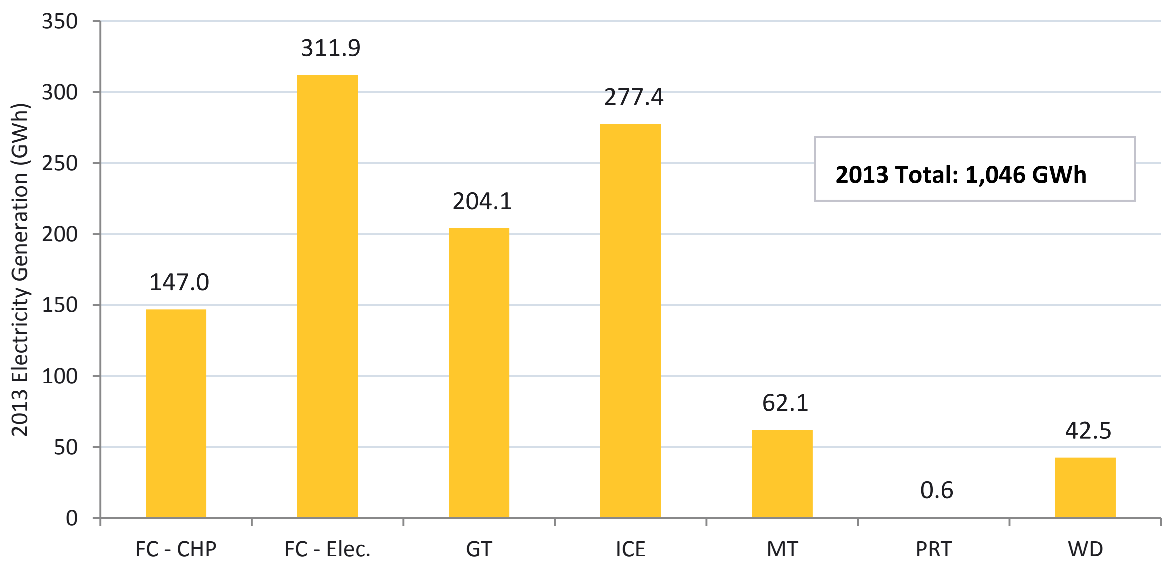
TABLE 5-1: 2013 SGIP ELECTRIC GENERATION, BY PROGRAM ADMINISTRATOR

Program Administrator	SGIP Electric Generation (MWh)	Percent Share of SGIP Electric Generation
CSE	151,748	14.5 %
PG&E	390,567	37.4 %
SCE	193,215	18.5 %
SCG	310,084	29.7 %
Total	**1,045,614**	**100 %**

* CSE = Center for Sustainable Energy, PG&E = Pacific Gas & Electric, SCE = Southern California Edison, SCG = Southern California Gas Company

Electrical impacts by technology type are shown in Figure 5-1.

FIGURE 5-1: 2013 SGIP ELECTRIC GENERATION, BY TECHNOLOGY TYPE[3]



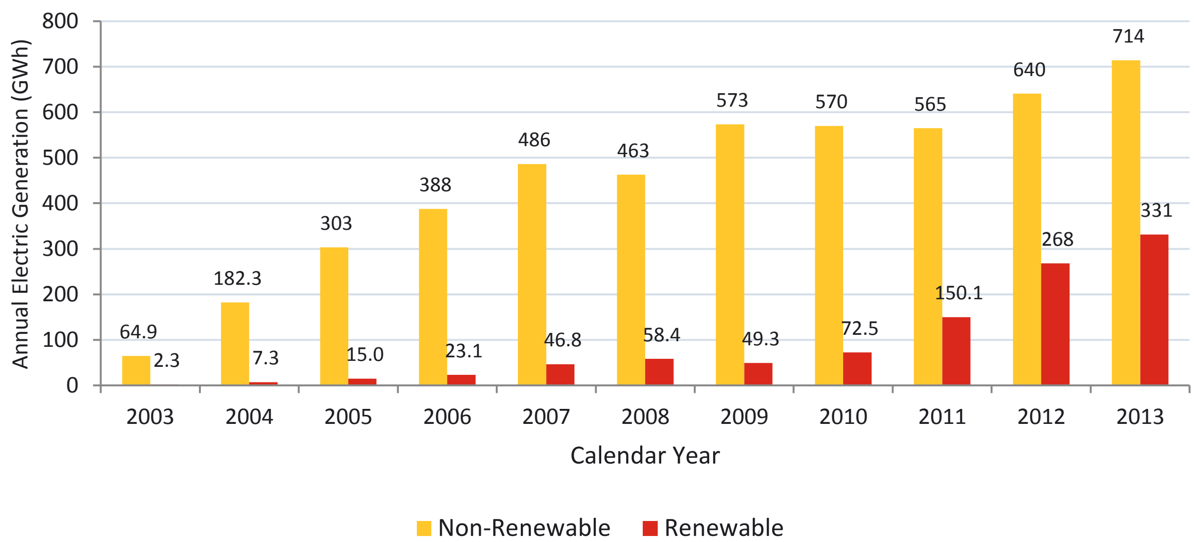
All-electric fuel cells and internal combustion engines made the largest contribution to annual electrical impacts. Pressure reduction turbine impacts were small due to the size of the population (one project) and a payment date late in 2013.[4]

SGIP projects are fueled by a variety of energy sources including natural gas, on-site biogas, directed biogas, and other renewable energy sources like wind and hydro. Electrical impacts by calendar year and energy source are shown in Figure 5-2.

3 FC – CHP = CHP Fuel Cell, FC – Elec. = Electric-only Fuel Cell, GT = Gas Turbine, ICE = Internal Combustion (IC) Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

4 For this evaluation, impacts begin to accrue the day the upfront payment is issued.

FIGURE 5-2: ELECTRIC GENERATION, BY CALENDAR YEAR AND ENERGY SOURCE



Electric energy generated by SGIP projects has increased over time as more projects are rebated by the SGIP. From 2003 through 2009 the SGIP saw significant growth in impacts from non-renewable gas projects. Beginning in 2010 the SGIP experienced significant growth from renewable projects, largely due to the inclusion of out-of-state directed biogas as an eligible renewable fuel.

The SGIP's electrical generation impacts by calendar year under the different eligibility rules are shown in Figure 5-3.

FIGURE 5-3: ELECTRICAL GENERATION IMPACTS PRE/POST-SB 412 BY CALENDAR YEAR

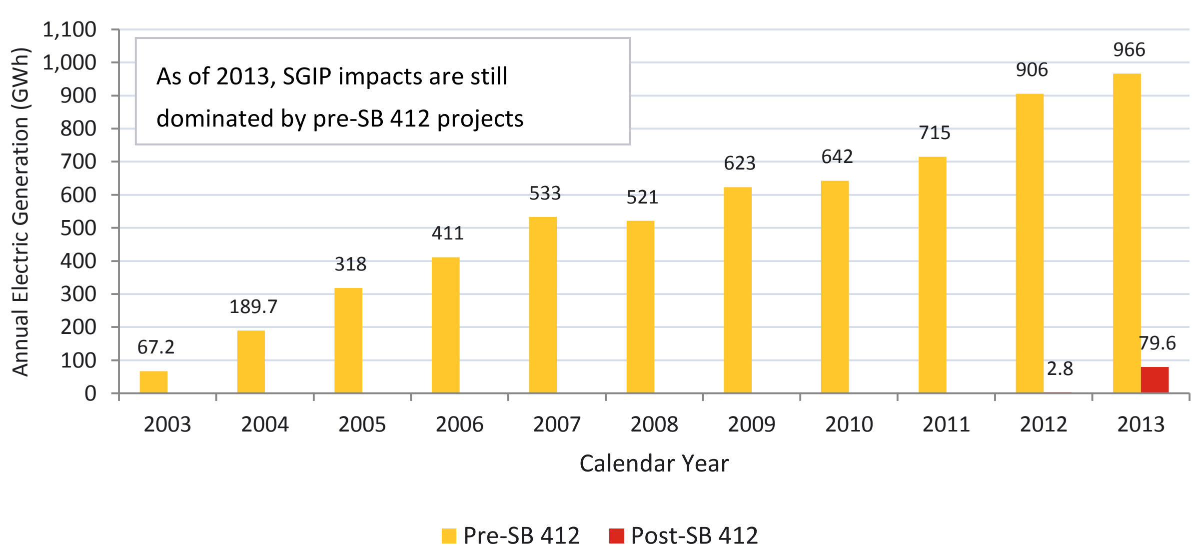


Figure 5-3 highlights the difference between program year and calendar year impacts. Pre-SB 412 impacts continued to increase through calendar year 2013 despite being limited to projects that applied during or before 2010. This is due to the delay that exists between a project's application submittal and the incentive payment date. Sixty-seven pre-SB 412 projects were paid incentives in 2012, and an additional nine pre-SB 412 projects were paid incentives in 2013. The same effect is visible in post-SB 412 impacts beginning to accrue in 2012 and to a larger extent in 2013. The contribution of post-SB 412 generation to SGIP electrical generation impacts increased from less than three percent in 2012 to nearly eight percent of annual electricity generation in 2013. When evaluating the success or failure of program modifications, it is important to consider the time lag between policy implementation and the measurement of impacts.

5.2 Utilization and Capacity Factor

Energy impacts are a function of generating capacity and utilization. Capacity factor is defined as the amount of energy generated during a given time period divided by the maximum possible amount of energy that could have been generated during that time period. Capacity factor is a metric of system utilization. A high capacity factor (near one) indicates that the system is being utilized to its maximum potential. SGIP rebated capacities for individual projects range from tens of kilowatts to several megawatts. Host customers operate their projects according to their individual needs. Some only need full capacity during weekday afternoons; others need full capacity 24/7.

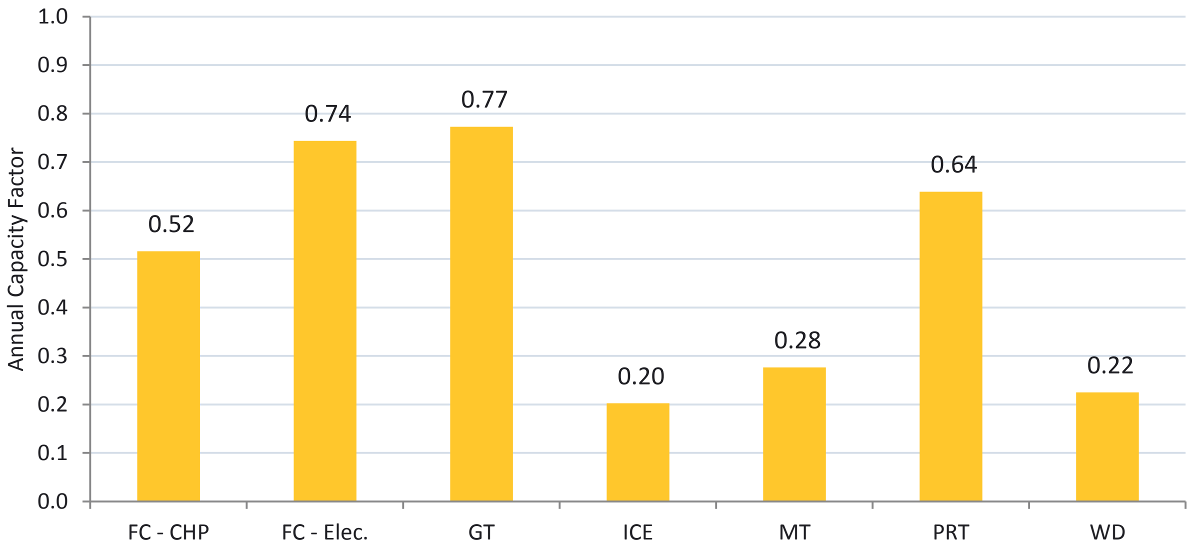
Capacity factors are useful when comparing utilizations between or across wide varieties of project sizes and technologies. To the extent that SGIP projects are cleaner (with respect to greenhouse gases and criteria air pollutants) than the grid energy they displace, high capacity factors are desirable. A capacity factor of 1.0 is full utilization regardless of a project's generating capacity. The annual capacity factor of a project, CF_a, is defined in Equation 5-1 as the sum of hourly electric net generation output, $ENGO_h$, during all 8,760 hours of the year divided by the product of the project's capacity and number of hours in the year. If a project was completed mid-2013, then the annual capacity factor is evaluated from the completion date through December 31, 2013.

$$CF_a = \frac{\sum_{h=1}^{8,760} ENGO_h\,(kWh)}{Capacity\,(kw) \cdot 8,760\,(hr)}$$

EQUATION 5-1

When reporting average performance from a group of projects, individual annual capacity factors are weighted by project rebated capacity so that larger projects have a greater impact in the reported average capacity factor. Annual average capacity factors by technology type during calendar year 2013 are shown in Figure 5-4.

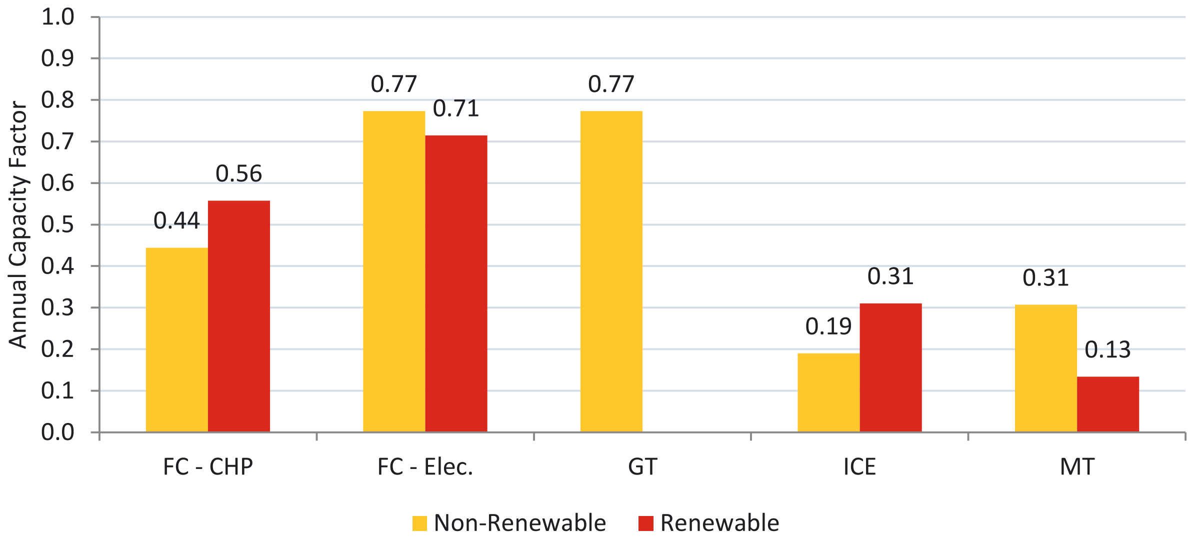
FIGURE 5-4: ANNUAL WEIGHTED AVERAGE CAPACITY FACTOR BY TECHNOLOGY TYPE



Capacity factors are impacted by operational status (online vs. offline/decommissioned) and host customer operating schedules (baseload vs. load following). Gas turbines and electric-only fuel cells achieved the highest annual capacity factors in the program. These capacity factors are typical of technologies that are deployed in "baseload" 24/7 operations. Internal combustion engines and microturbines achieved lower capacity factors often associated with "load following" or daytime-only operations. The influence of offline/decommissioned projects on annual average capacity factors is discussed later in this section.

Capacity factors are also correlated with fuel type. Projects with a biogas energy source may have lower capacity factors as they are more susceptible to interruptions in biogas supply. On the other hand, non-renewable projects may face stricter local air quality district rules that lead to earlier retirement. Capacity factors by technology type and energy source are shown in Figure 5-5.

FIGURE 5-5: ANNUAL CAPACITY FACTOR BY TECHNOLOGY TYPE AND ENERGY SOURCE



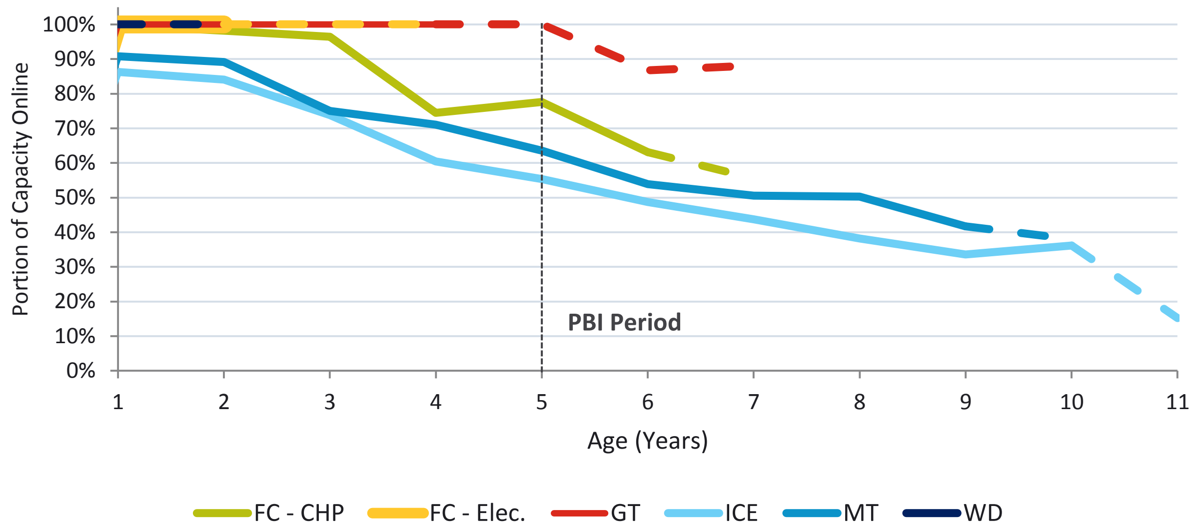
CHP fuel cells and internal combustion engines fueled by renewable biogas had higher capacity factors than their non-renewable versions. In contrast, non-renewable microturbines and electric-only fuel cells had higher capacity factors than their renewable versions. Some renewable CHP fuel cells and all renewable electric-only fuel cell projects are supplied directed biogas.

Performance Over Time

Average annual capacity factors tend to decrease as systems grow older. As time goes on, maintenance costs increase, warranty periods lapse, power purchase agreements end, and host customer economics change. As some systems become temporarily offline or decommissioned, they reduce the SGIP's average annual capacity factor. Figure 5-6 shows the portion of the rebated capacity that remains online[5] as projects age.

[5] In Figure 5-6 projects are classified as offline if their annual capacity factor is below 0.05. Dashed lines are drawn where less than 10 projects are used to calculate portion of capacity online.

FIGURE 5-6: PORTION OF CAPACITY ONLINE AS A FUNCTION OF AGE



* Dashed lines indicate that metered data from less than ten projects were available to calculate portion of capacity online

Figure 5-6 makes it clear that as projects age they are more likely to be offline or decommissioned. After ten years of operation, only 36 percent of the internal combustion engine capacity and 38 percent of the microturbine capacity was online. Both technology types exhibit a decrease in online capacity of six to seven percent per year. All CHP fuel cells have remained online for two years but starting in year three they began to exhibit an attrition rate similar to internal combustion engines and microturbines. Also shown in Figure 5-6 is a vertical line at year 5 representing the length of the PBI reporting period. Going forward, all new projects that fall under the PBI program rules are expected to remain online for at least five years.

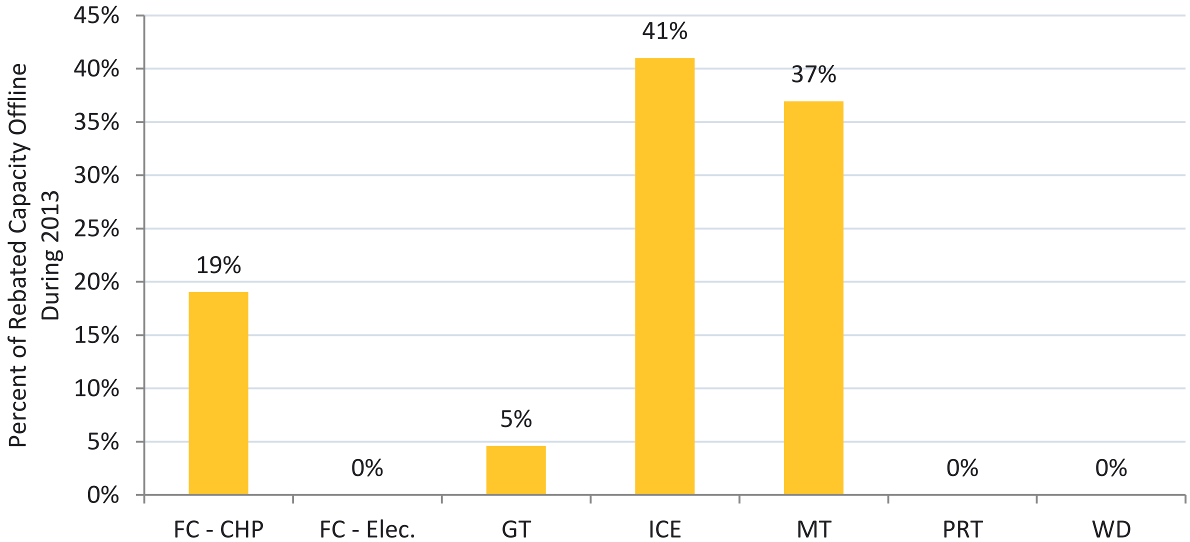
Electric-only fuel cells and wind turbines are newer technologies that thus far have remained online during their entire life in the program. All gas turbines remained online until after their fifth year of operation, when attrition begins to take place. In 2013, 270 projects representing 82 MW of rebated capacity were offline or decommissioned. A summary of project counts and capacities offline by PA is shown in Table 5-2.

TABLE 5-2: PROJECT COUNTS AND CAPACITIES OFFLINE BY PROGRAM ADMINISTRATOR

Program Administrator	Count Off	Capacity Off (MW)	Percent of Capacity Off	Mean Weighted Age (Years)
CSE	38	11.5	32%	8
PG&E	117	29.7	23%	8
SCE	40	14.4	20%	9
SCG	75	26.2	28%	8
Total	**270**	**81.9**	**25%**	**8**

Almost 25 percent of the SGIP's rebated capacity was offline during 2013. Offline projects tend to be older and beyond minimum warranty periods. The mean age of projects that were offline during 2013 is eight years. The percent of rebated capacity offline during 2013 by technology type is shown in Figure 5-7.

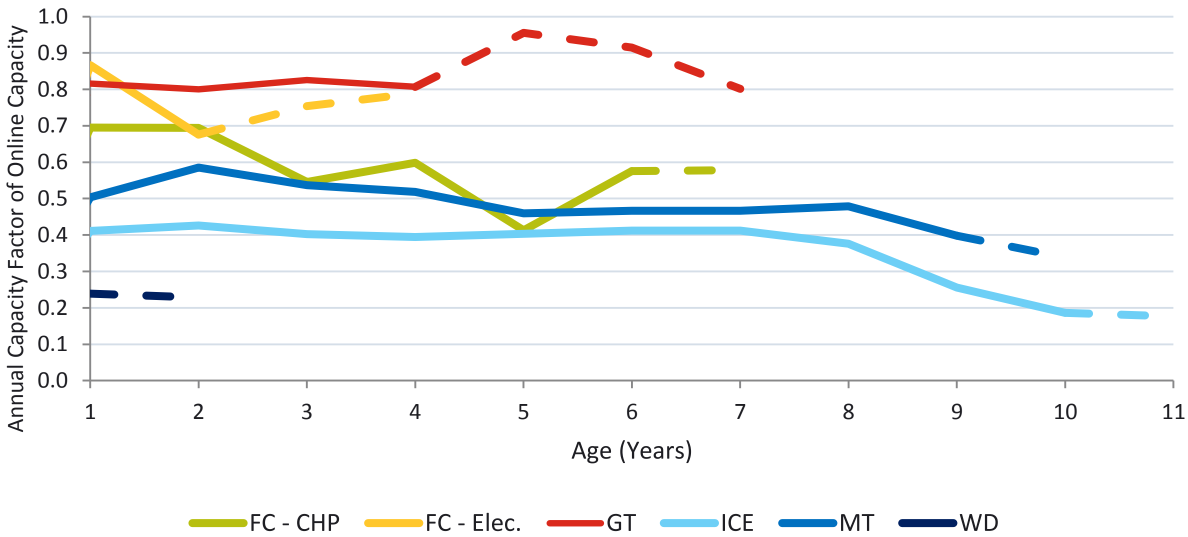
FIGURE 5-7: PERCENT OF REBATED CAPACITY OFFLINE DURING 2013 BY TECHNOLOGY TYPE



Forty-one percent of internal combustion engine capacity was offline during 2013. Internal combustion engines are among the oldest projects in the SGIP; so, it is not unreasonable for them to have the largest percent of capacity offline. Combustion-based technologies are also subject to stringent local air quality district requirements that may have led to increased offline capacity.

Offline projects decrease average capacity factors which complicates assessment of technology performance. Figure 5-8 examines the utilization of the portion of projects that have remained online as a function of age. This analysis eliminates offline or decommissioned systems and examines the behavior of operational projects only.

FIGURE 5-8: CAPACITY FACTOR OF ONLINE CAPACITY AS A FUNCTION OF AGE



* Dashed lines indicate that metered data from less than ten projects were available to calculate annual capacity factor of online capacity

Capacity factors for online projects have remained relatively constant as a function of age. Electric-only fuel cells and gas turbines started their lives with high capacity factors and maintained them as they age. Internal combustion engines and microturbines began their lives at or below 50 percent capacity factor and remained there for most of their operating history. This suggests that most of the internal combustion engine and microturbine capacity in the SGIP was originally intended to operate in load following or partial power mode, not as baseload capacity. Low capacity factors among online projects are not necessarily indicators of poor performance. For example, a project that only operates from 9 a.m. – 5 p.m. during weekdays would have an annual capacity factor of 0.24. This may be sufficient to meet a host customer's needs.

5.3 System Efficiency and Natural Gas Impact

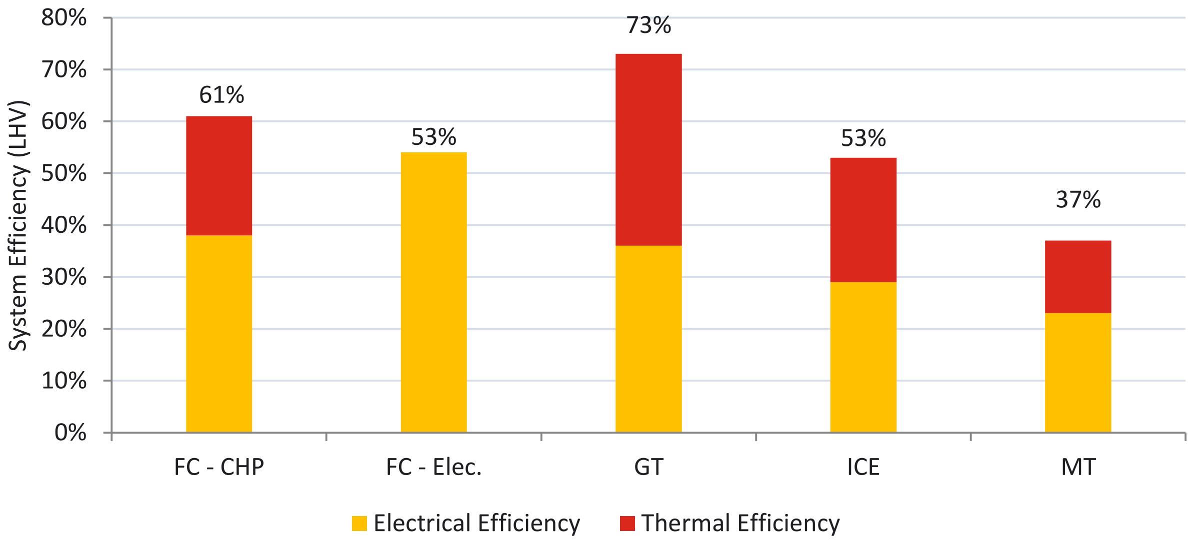
The ability to convert fuel into useful electrical and thermal energy is measured by the system's efficiency. The system efficiency is defined in Equation 5-2 as the ratio of total useful energy output over total energy input.

$$\eta_{system} = \frac{ENGO_{kWh} \cdot 3.412 + HEAT_{MBtu}}{FUEL_{MBtu,\ LHV}}$$

EQUATION 5-2

The higher the system's efficiency the less fuel input is required to generate electricity and useful heat. Certain technologies like electric-only fuel cells do not have external useful heat recovery capabilities; therefore, the system efficiency has only an electrical component. Other technologies that recover useful heat can achieve system efficiencies greater than just the electrical component. In the context of this report, useful heat is defined as heat that is recovered from CHP projects and used to serve on-site thermal loads. Waste heat that is lost to the atmosphere or dumped via radiators is not considered useful heat. System efficiencies observed in 2013 for non-renewable projects are shown in Figure 5-9. All efficiencies are reported on a lower heating value (LHV) basis.[6]

FIGURE 5-9: SYSTEM EFFICIENCY BY TECHNOLOGY TYPE



Gas turbines achieved the highest system efficiency in the program at 73 percent followed by CHP fuel cells at 61 percent. Electric-only fuel cells had the largest electrical component of system efficiency at 53 percent, meaning they were the most efficient at converting natural gas into electricity. Microturbines had the lowest electrical and useful heat components and achieved a combined 37 percent system efficiency.

Recovered useful heat can be used to serve heating loads such as process hot water or cooling loads by use of an absorption chiller. The useful heat end use has important implications for natural gas distribution impacts and consequently greenhouse gas emissions impacts. Over 70 percent of the total SGIP rebated capacity employs some form of useful heat recovery. The useful heat end uses observed in the SGIP are summarized in Table 5-3.

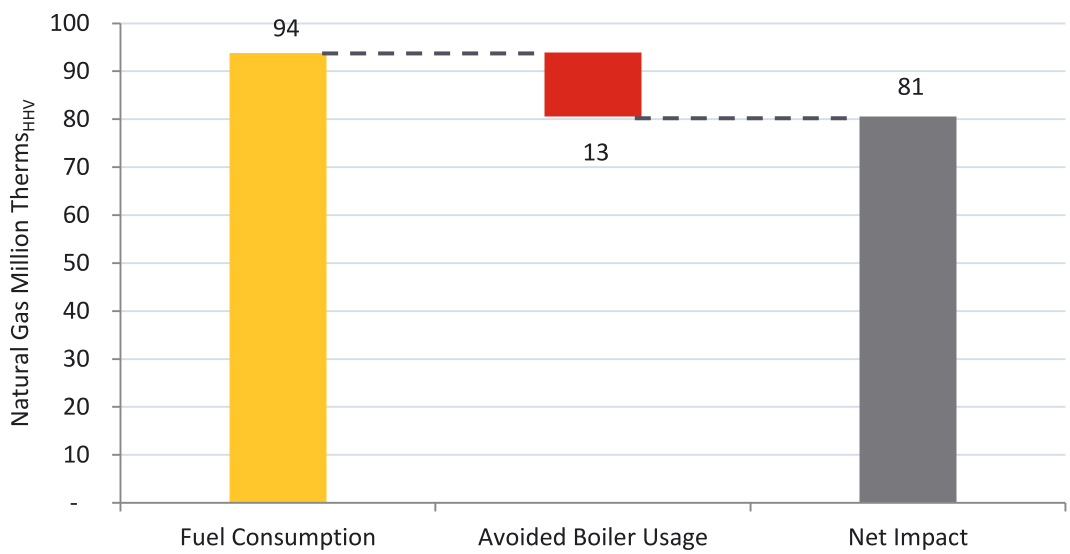
[6] This evaluation report assumes a natural gas lower heating value energy content of 935 Btu/SCF (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.)

TABLE 5-3: USEFUL HEAT END USES

Useful Heat End Use	Rebated Capacity with Useful Heat Recovery (MW)	Percent of Rebated Capacity with Useful Heat Recovery
Cooling Only	34.7	14.9%
Heating Only	128.8	55.2%
Cooling + Heating	70.0	30.0%
Total	***233.6***	***100%***

Over 85 percent of all SGIP project capacity with useful heat recovery used the recovered thermal energy to supplant the use of a conventional boiler. A project's useful heat end use and its system efficiency have an impact on the natural gas distribution system. Non-renewable SGIP projects produce electricity by consuming natural gas. Higher electrical components of the system efficiency imply reduced consumption of natural gas from the distribution system. When used for heating, useful heat recovery displaces natural gas consumption from boilers. Figure 5-10 summarizes the SGIP's impact on the natural gas distribution system.

FIGURE 5-10: NATURAL GAS DISTRIBUTION SYSTEM IMPACT



During 2013, the SGIP increased the consumption of natural gas from the distribution system by 81 million therms$_{HHV}$.[7] This increase in natural gas usage has implications for environmental impacts that are explored in more detail in Section 7.

[7] Natural gas impacts are shown in higher heating value (HHV) assuming 1,032 Btu/SCF (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003).

5.4 Assessment of Performance Based Incentive Impact

All projects 30 kW and larger that apply to the SGIP on or after PY11 will receive their payment through a Performance Based Incentive. Under the PBI rules, eligible projects will receive 50 percent of their incentive payment upon project completion and up to the remainder of the incentive over five years. The PBI payment rate is based on actual performance. Projects are required to meet minimum GHG emissions and annual capacity factor requirements.[8] The required minimum capacity factors upon which PBI payment rates are based are presented in Table 5-4.

TABLE 5-4: MINIMUM REQUIRED PBI CAPACITY FACTORS

Technology Type	Capacity Factor
Advanced Energy Storage[9]	0.10
Wind Turbine	0.25
All Other Technologies	0.80

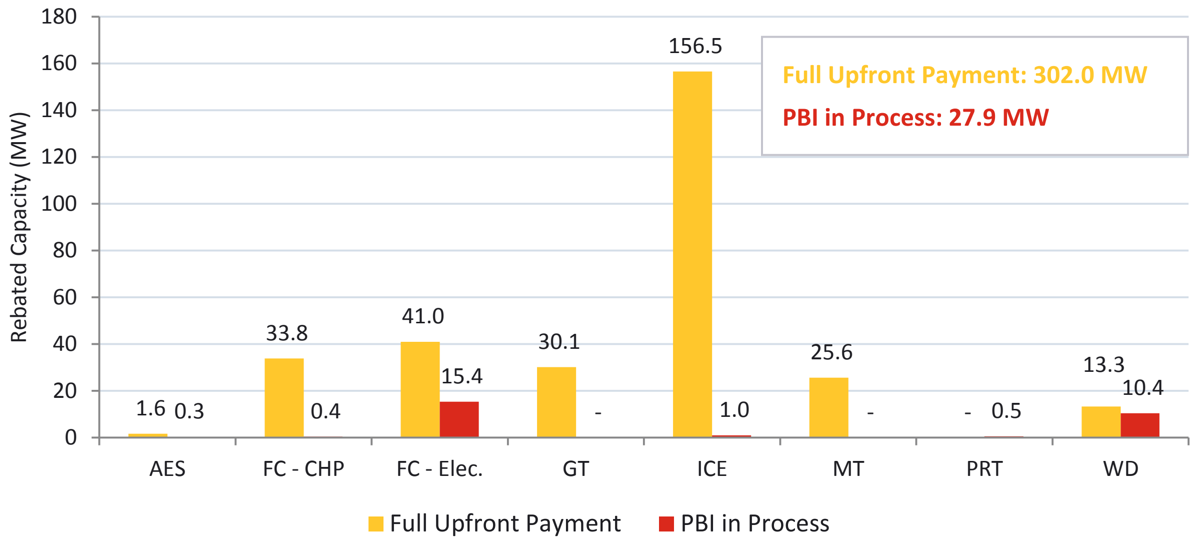
One reason for instituting PBI rules is to create a larger incentive for projects to meet minimum performance targets for at least five years. Ideally, the PBI rules result in increased performance relative to pre-SB 412 projects with 100 percent upfront incentive payments. This premise can be tested by comparing capacity factors of PBI projects to capacity factors of pre-SB 412 projects with capacity payments. In order for the comparison to be fair, the comparison should be made between similar technology types.

As of December 31, 2013, 27.9 MW of capacity had been rebated under new PBI rules. Of those 27.9 MW, 15.4 MW are electric-only fuel cells and 10.4 MW are wind turbines. The remaining eight percent of the capacity are CHP fuel cells, advanced energy storage, pressure reduction turbines, and internal combustion engine projects. This distribution is summarized in Figure 5-11.

[8] PBI payments are reduced by half in years when a project average emission rate is equal to or greater than 398 kg CO_2/MWh but less than 417 kg CO_2/MWh. Projects that exceed an average emission rate of 417 kg CO_2/MWh in any given year will receive no PBI payment for that year.

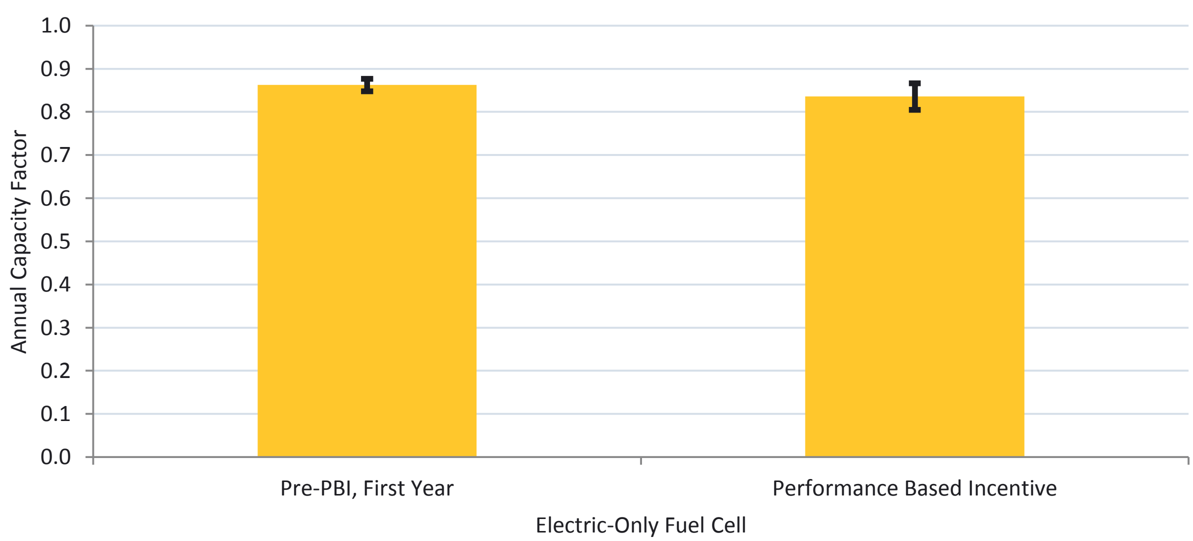
[9] Based on 5,200 hours of operation.

FIGURE 5-11: REBATED CAPACITY BY INCENTIVE MECHANISM



The only technology type for which sufficient data are available to make a comparison of capacity factors by incentive mechanism are electric-only fuel cells. The first 50 percent upfront incentive payment for an electric-only fuel cell was made on March 20, 2013, so PBI electric-only fuel cells in 2013 were all in their first year of operation. Capacity factors of 2013 PBI electric-only fuel cells were compared to capacity factors for pre-PBI electric-only fuel cells during their first year of operation (this is not necessarily calendar year 2013). The result of this weighted means comparison is summarized in Figure 5-12.

FIGURE 5-12: ELECTRIC-ONLY FUEL CELL CAPACITY FACTOR COMPARISON BY INCENTIVE MECHANISM



During the first year of operation no significant difference was observed between capacity factors for electric-only fuel cells with pre-PBI incentives relative to electric-only fuel cells that received performance based incentives.[10] This result is not surprising for two reasons:

- » All electric-only fuel cells typically operate as baseload projects and are, therefore, more likely to achieve high capacity factors
- » The population of electric-only fuel cells with PBI incentives is less than one year old. Any differences in utilization would more likely be observed toward the end of the PBI period (years four and five).

Going forward, as more data become available, and the PBI population becomes larger and more diverse, performance differences between projects with capacity incentives and PBI projects should be tested to evaluate the effectiveness of the PBI.

The following section summarizes SGIP impacts during critical hours of peak electric system demand.

[10] Statistical significance tested at 90 percent confidence level. Bars indicated upper and lower confidence intervals.

6

Peak Demand Impacts

6 ELECTRIC SYSTEM PEAK DEMAND IMPACTS

This section discusses the peak demand impacts attributable to Self-Generation Incentive Program (SGIP) projects during 2013. Peak demand impacts are the facility electricity demands that SGIP hosts meet with their on-site generation during hours with the highest California Independent System Operator (CAISO) or Investor Owned Utility (IOU) system demands. These peak system demand hours are not necessarily coincident with the hours of the SGIP host's highest demand.

During peak hours, SGIP generation supplants host customer purchases of peak energy as well as their utility's purchase of peak wholesale energy. SGIP generation also avoids transmission and distribution losses during what are typically hours of very high system congestion.

The peak demand hours during which SGIP impacts are evaluated include:

» The peak hour and top 200 hours of the CAISO system demand

» The peak hour and top 200 hours of IOU system demand

In addition to impacts during the CAISO and IOU peak hours, this section also includes brief case studies of SGIP project impacts on their local utility distribution feeders during the top 100 hours of feeder demand. These SGIP impact case studies provide insights into the magnitude of SGIP impacts relative to feeder loads and maximum ratings. The case studies should not be considered representative of all California utility operations. A detailed study of transmission and distribution impacts of the SGIP is outside the scope of this evaluation report.

The electric system peak demand impacts from advanced energy storage (AES) projects are treated separately in Section 8.

6.1 CAISO Peak Demand Impacts

The CAISO recorded its highest 2013 hourly system load of 44,924 MW on Friday, June 28, from 4-5 p.m. PDT. During that hour, the total impact of all SGIP systems was 127 MW. On this day, the high temperature in Sacramento was 102°F; the high temperatures in Los Angeles and San Diego were 87°F and 78°F, respectively. Table 6-1 lists the 2013 CAISO peak hour demand impacts for each Program Administrator (PA).

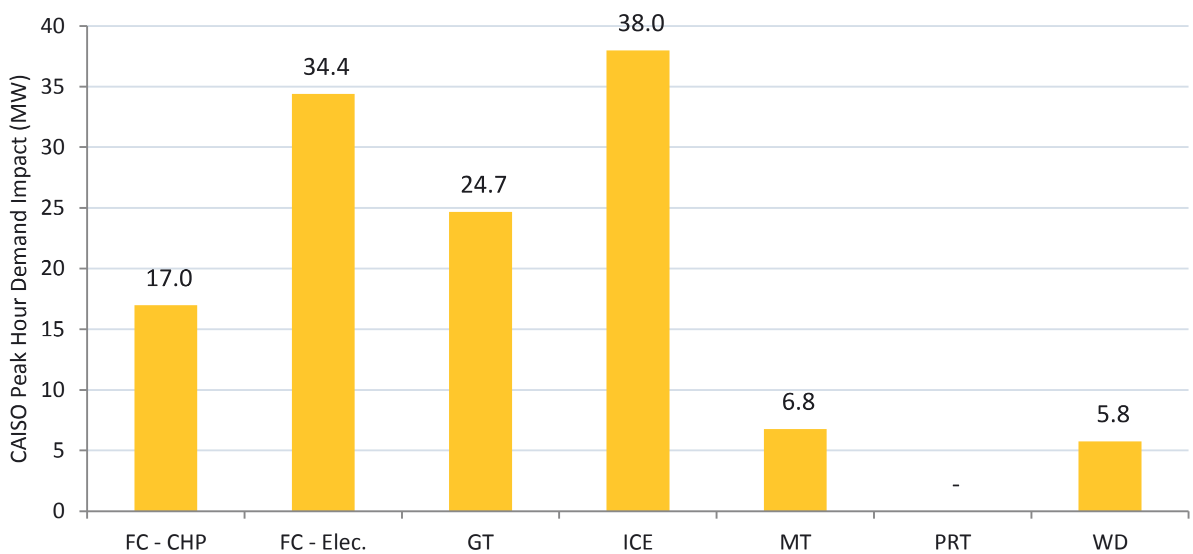
TABLE 6-1: CAISO PEAK HOUR IMPACT BY PROGRAM ADMINISTRATOR

Program Administrator	Peak Hour SGIP Project Impact (MW)	Peak Hour SGIP Project Capacity Factor
CSE	19.7	0.56
PG&E	44.9	0.37
SCE	25.4	0.37
SCG	36.6	0.37
Total	**126.6**	**0.40**

* CSE = Center for Sustainable Energy, PG&E = Pacific Gas & Electric, SCE = Southern California Edison, SCG = Southern California Gas Company

The SGIP peak hour demand impact represents less than 0.3 percent of the CAISO peak hour system demand. This is not unexpected given the SGIP's total capacity of 330 MW is less than 0.5 percent of the combined capacity of in-state power plants.[1] CAISO peak hour impacts by technology type are shown in Figure 6-1.

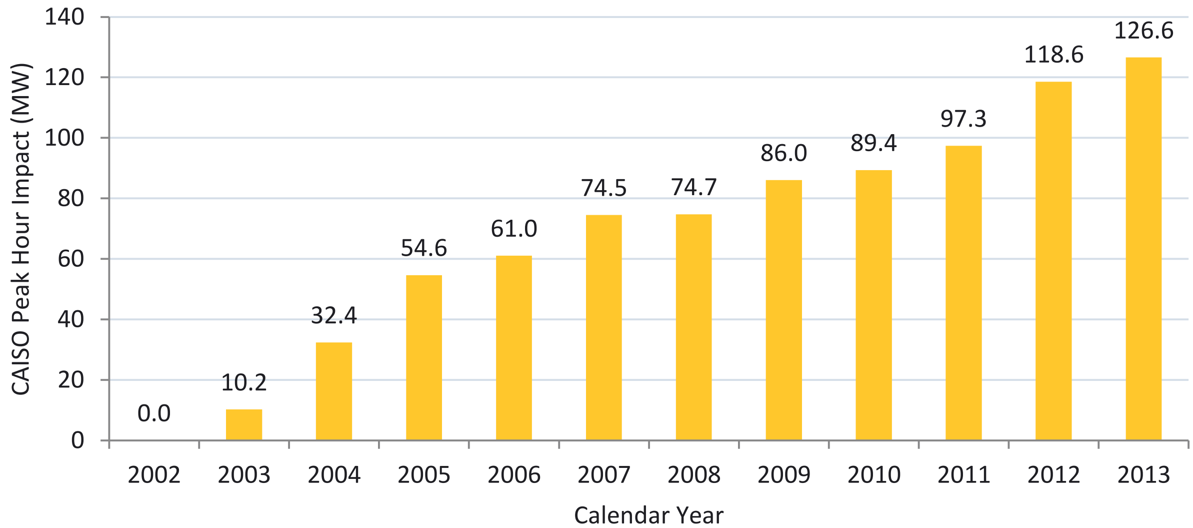
FIGURE 6-1: CAISO PEAK HOUR IMPACTS BY TECHNOLOGY TYPE



CAISO peak hour impacts have increased over time as the total SGIP capacity has grown. Figure 6-2 shows the SGIP impact during the CAISO peak hour by calendar year.

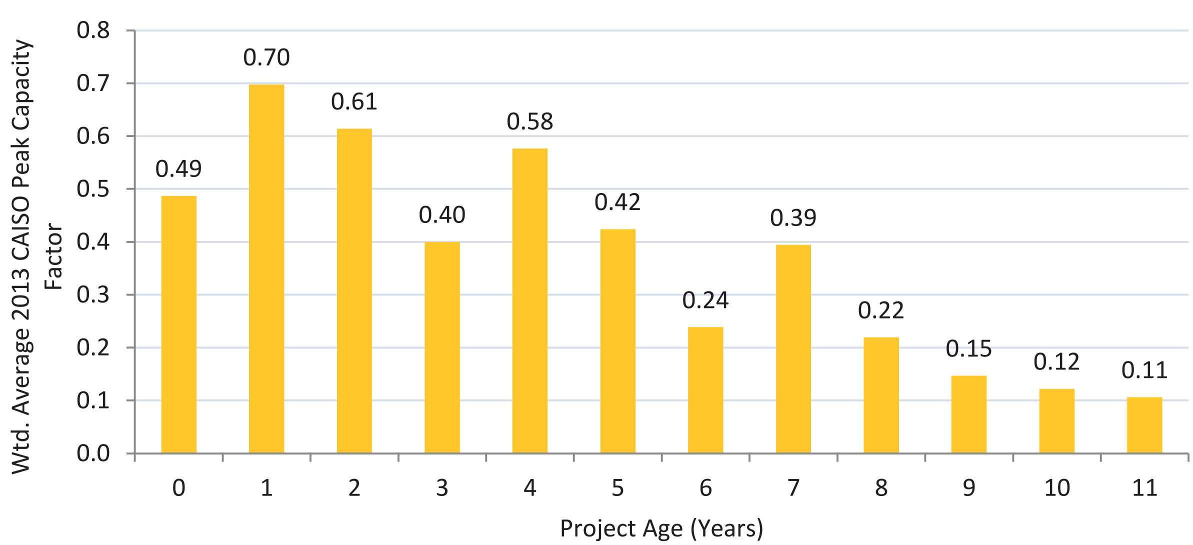
1 http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

FIGURE 6-2: CAISO PEAK HOUR IMPACTS BY CALENDAR YEAR



CAISO peak hour impacts have increased every year but less so between 2007 and 2008. During those years, SGIP eligibility rules were in transition and a limited number of new projects entered the program. As the SGIP continues to grow and rebated capacity increases, peak demand impacts are expected to increase. However, much of the capacity from earlier program years is now beyond its warranty period, reaching the end of its economic life, and being retired. As projects are decommissioned, they decrease the SGIP's overall peak demand impact. Peak demand impacts in future years will be affected by these two opposing influences. Figure 6-3 shows capacity factors for all technology types during the 2013 CAISO peak hour by SGIP system age. As expected, older projects attained lower capacity factors during the CAISO peak hour.

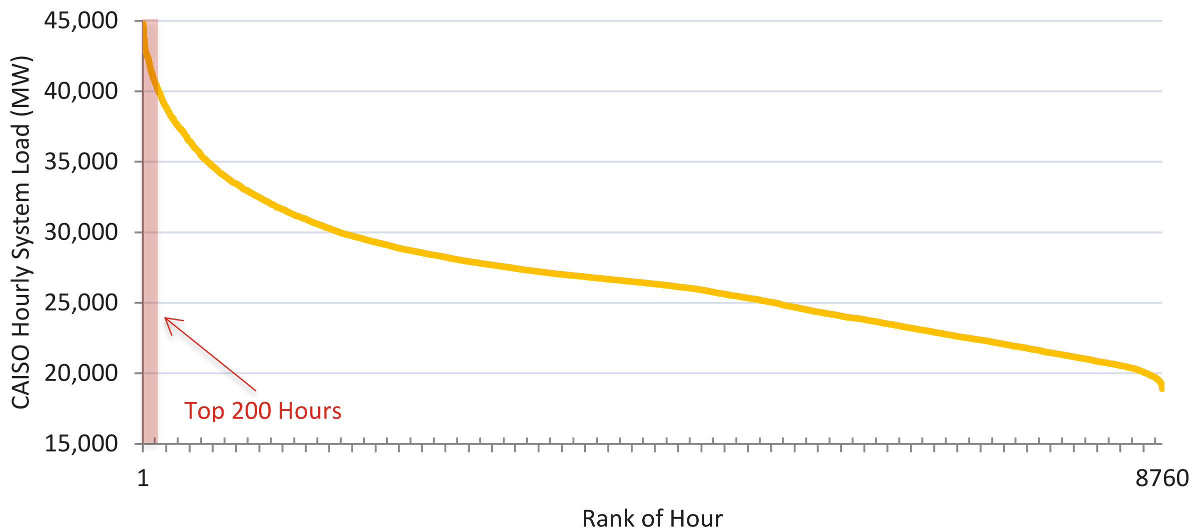
FIGURE 6-3: CAISO PEAK HOUR IMPACTS CAPACITY FACTORS BY PROJECT AGE



Peak demand periods represent a small portion of the year but account for a large portion of the required generation capacity and transmission & distribution (T&D) infrastructure. A more robust measure of SGIP peak demand impacts are the top 200 hours of demand. The top 200 hours of system demand represent only 2.3 percent of the year but account for over 13 percent of the generating capacity and T&D infrastructure required to serve load.

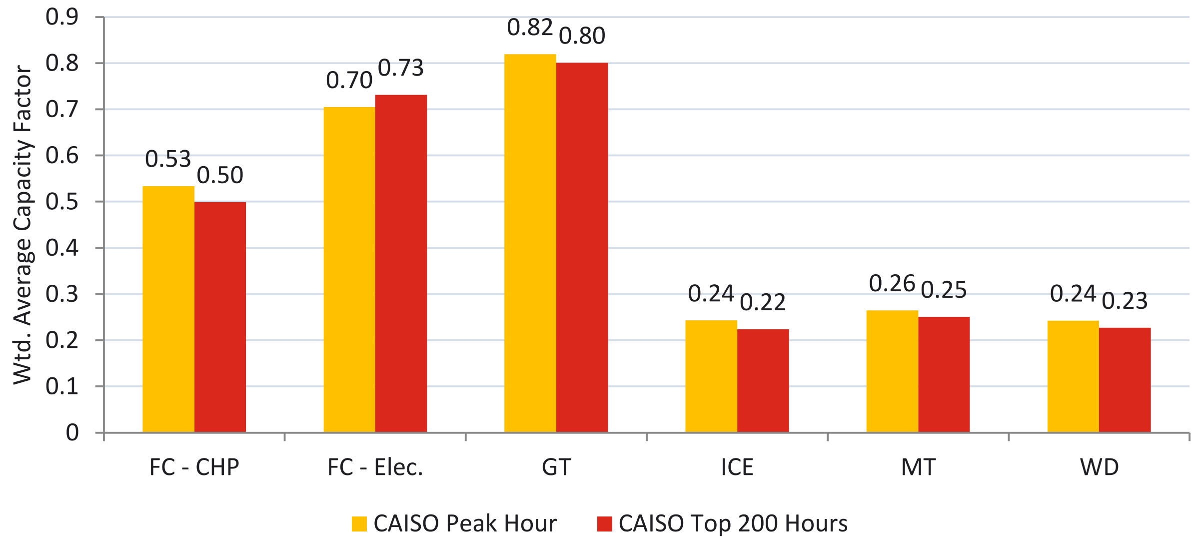
Of those 200 hours, 174 occurred in weekdays and the remaining 26 hours occurred on weekends (Saturday or Sunday). The vast majority of the top 200 hours (197) occurred during the months of June – September, the remaining three hours occurred during May. All 2013 top 200 CAISO hours occurred between 11 a.m. and 9 p.m. PDT. The CAISO's 2013 load duration curve is shown in Figure 6-4.

FIGURE 6-4: CAISO 2013 LOAD DURATION CURVE



The capacity factor of each technology type during the CAISO top hour and the mean weighted capacity factor during the CAISO top 200 hours of demand are shown in Figure 6-5.

FIGURE 6-5: CAISO PEAK HOUR AND TOP 200 HOUR CAPACITY FACTORS BY TECHNOLOGY TYPE



Differences in peak hour capacity factors across technology types are similar to those observed for annual capacity factors. Baseload technologies like electric-only fuel cells and gas turbines tend to have higher peak hour capacity factors. Technology types that are older often have higher decommissioning rates and, therefore, tend to have lower peak hour capacity factors. Internal combustion engines and microturbines have lower CAISO peak capacity factors due to their non-baseload operation and the impact of offline or decommissioned projects. Very minor differences are observed between CAISO peak hour capacity factors and average capacity factors across the top 200 hours.

6.2 IOU Peak Demand Impacts

Like the CAISO, the three California IOUs have specific top demand hours and associated demand impacts. The top demand hours for each IOU are summarized in Table 6-2. The fact that IOU-specific peak demand hours occurred on different days helps explain why their sum (48,018 MW) is larger than the CAISO peak hour demand impact (44,924 MW).

TABLE 6-2: ELECTRIC IOU PEAK DEMAND HOURS

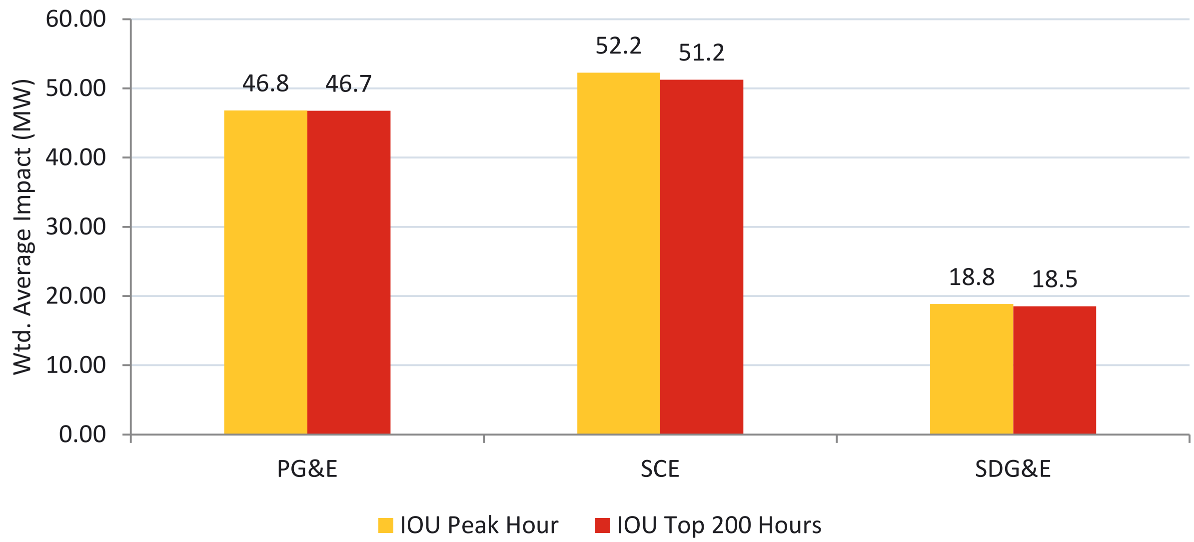
Electric IOU	Peak Demand (MW)	Peak Date/Time (PDT)
PG&E	20,916	Wednesday 7/3/2013 4-5 p.m.
SCE	22,498	Thursday 9/5/2013 3-4 p.m.
SDG&E*	4,604	Friday 8/30/2013 4-5 p.m.

* SDG&E = San Diego Gas & Electric

Ninety-five percent of SGIP projects are electrically interconnected to a California IOU; the remaining five percent are served by non-IOUs such as the Los Angeles Department of Water and Power (LADWP).

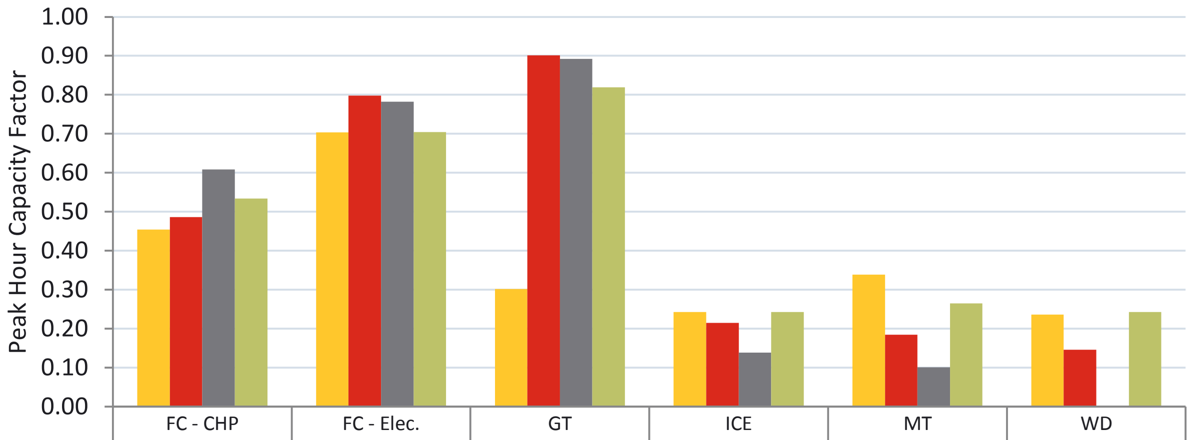
Demand data from non-IOUs are not available; therefore, the SGIP impacts on non-IOU systems are not evaluated. SGIP impacts during IOU top hour and top 200 demand hours are shown in Figure 6-6.

FIGURE 6-6: IOU PEAK HOUR AND TOP 200 HOUR IMPACTS



The SGIP provided peak demand reductions of 47 MW and 52 MW for PG&E's and SCE's systems respectively. Demand reductions on SDG&E's system were smaller due to the relatively lower rebated capacity on SDG&E's system. These reductions do not account for any T&D losses avoided due to the local generation. Very minor differences exist between peak hour and top 200 hour impacts for each IOU. On average, SGIP impacts represent less than one percent of IOU peak system demand. The capacity factors for each technology during the IOU and CAISO top peak hours are shown in Figure 6-7.

FIGURE 6-7: CAISO AND IOU PEAK HOUR CAPACITY FACTORS BY TECHNOLOGY TYPE



	FC - CHP	FC - Elec.	GT	ICE	MT	WD
PG&E	0.45	0.70	0.30	0.24	0.34	0.24
SCE	0.49	0.80	0.90	0.21	0.18	0.15
SDG&E	0.61	0.78	0.89	0.14	0.10	0.00
CAISO	0.53	0.70	0.82	0.24	0.26	0.24

6.3 Distribution Feeder Case Studies

One of the goals of the SGIP is grid support. When compared to the CAISO and the IOU system peak demand levels, the magnitude of SGIP impacts is small, in both cases less than one percent. However, it is possible that more significant impacts are observed on the individual distribution feeder branches that serve SGIP hosts.

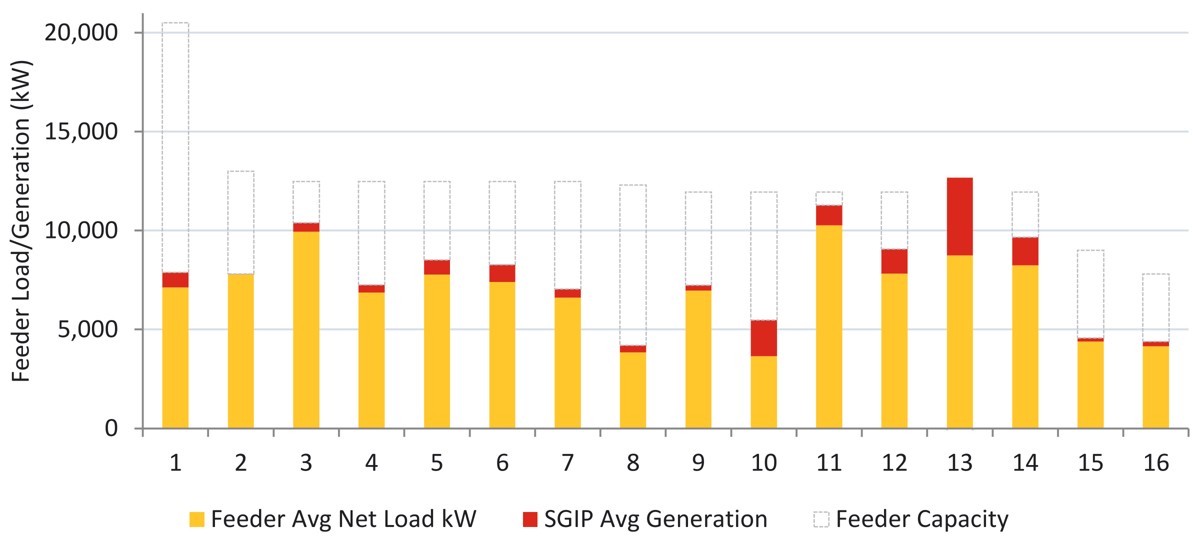
SGIP projects may have various positive or adverse impacts on the distribution system. Potential impacts include:[2]

- Avoided distribution system line losses
- Peak demand reduction
- Deferred distribution system upgrades
- Frequency control
- Voltage regulation
- Reverse power flow
- Operational flexibility

[2] Biennial Report on Impacts of Distributed Generation (http://www.cpuc.ca.gov/NR/rdonlyres/29DCF6CC-45BC-4875-9C7D-F8FD93B94213/0/CPUCDGImpactReportFinal2013_05_23.pdf)

To begin understanding the relative magnitude of SGIP peak demand reduction impacts on distribution feeders, load data from electric IOUs were requested for specific feeders with SGIP generation installed and operational. Feeder selection was based on availability of metered data from SGIP projects. The top 100 hours of feeder branch load were requested for sixteen representative feeders with SGIP metered data available. The impacts of SGIP generation on feeder peak demand reduction are shown in Figure 6-8. The average feeder net load during the top 100 hours of demand as measured by the utility is shown in yellow. SGIP generation is superimposed on each bar in red to indicate what the average peak feeder demand would have been in the absence of the SGIP. The remaining feeder capacity as reported by the utility is shown above the bar to give a sense of the "head room" available on each feeder.

FIGURE 6-8: DISTRIBUTION FEEDER PEAK DEMAND IMPACT CASE STUDY



Average feeder peak demand reductions across the top 100 hours ranged from 17 kW to 3,935 kW. These reductions represent between 0.2 and 33.5 percent of the average feeder load during the top 100 hours. SGIP feeder penetration levels, defined as the ratio of SGIP capacity to feeder peak load, ranged from 0.7 to 57.7 percent. SGIP distribution feeder peak reduction metrics are summarized in Table 6-3.

TABLE 6-3: FEEDER PEAK REDUCTION PERFORMANCE METRICS

Feeder ID	Feeder Capacity (kW)	Number of SGIP Projects on Feeder	SGIP Rebated Capacity on Feeder (kW)	SGIP Average 100-Hour Capacity Factor	Feeder Peak Load (kW)	Average 100-Hour Load Reduction of Load	SGIP Penetration
1	20,500	2	1,050	0.72	7,674	9.6 %	13.7 %
2	13,000	1	60	0.28	8,531	0.2 %	0.7 %
3	12,480	1	4,527	0.10	11,088	4.4 %	40.8 %
4	12,480	1	1,400	0.27	7,920	5.2 %	17.7 %
5	12,480	1	1,500	0.50	9,120	8.7 %	16.4 %
6	12,480	1	1,050	0.84	9,232	10.7 %	11.4 %
7	12,480	1	630	0.71	7,644	6.3 %	8.2 %
8	12,300	2	610	0.59	4,131	8.5 %	14.8 %
9	11,950	1	4,500	0.06	7,804	3.8 %	57.7 %
10	11,950	1	3,200	0.57	7,466	33.5 %	42.9 %
11	11,950	1	1,400	0.72	11,696	9.0 %	12.0 %
12	11,950	1	2,800	0.44	10,022	13.6 %	27.9 %
13	11,950	1	4,600	0.86	10,500	31.0 %	43.8 %
14	11,950	1	3,501	0.41	10,182	14.8 %	34.4 %
15	9,000	1	210	0.89	4,828	4.1 %	4.3 %
16	7,800	1	400	0.63	4,579	5.7 %	8.7 %

The relative magnitude of SGIP distribution feeder impacts can be greater than the impacts on the CAISO or IOU systems depending on the feeder peak load, feeder capacity, and SGIP penetration level. The majority of feeders in the sample had relatively low SGIP penetration levels, and, they were not loaded close to their feeder ratings. Consequently, the feeder peak demand and congestion relief benefits observed were minor. Feeders nine and ten had high SGIP penetration levels but were not loaded near the feeder ratings. Feeders 12, 13, and 14 had high SGIP penetrations and were loaded near the feeder ratings. Feeder 13 appears to be an extreme case where, in the absence of the SGIP generation serving on-site load, the feeder would have exceeded its rated capacity during the top 100 hours of load. Although it is only one of the 16 feeders studied, Feeder 13 shows that SGIP is affecting, in this case positively, the functioning of the grid, by preventing overloading on the distribution system. As distributed energy resources reach higher penetration levels, they will have ever greater impacts on the grid, especially at the distribution level.

These case studies should be considered a first step toward understanding SGIP distribution system impacts and not an assessment of distribution system impacts. A comprehensive investigation of SGIP impacts on distribution feeders is outside the scope of this evaluation.

Environmental Impacts

7

7 ENVIRONMENTAL IMPACTS

The Self-Generation Incentive Program (SGIP) was originally established in 2001 to help address California's peak electricity supply shortcomings. Projects rebated by the SGIP were designed to maximize electricity generation during utility system peak periods and not necessarily to reduce greenhouse gas (GHG) or criteria pollutant emissions. Passage of Senate Bill (SB) 412 (Kehoe) required the California Public Utilities Commission (CPUC) to establish GHG goals for the SGIP.

This section discusses the GHG and criteria air pollutant impacts of the SGIP during calendar year 2013. The fleet of projects whose impacts are evaluated in this section includes projects completed before the passage of SB 412. The GHG impact analysis is limited to carbon dioxide (CO_2) and CO_2 equivalent (CO_2eq) methane (CH_4) emissions impacts associated with SGIP projects. The criteria air pollutant impact analysis is limited to NO_X, PM_{10}, and SO_2 emissions impacts associated with SGIP projects. The discussion is organized into the following subsections:

» Methodology Overview and Summary of Environmental Impacts

» Non-renewable Project Impacts

» Renewable Biogas Project Impacts

» Wind and Pressure Reduction Turbine (PRT) Project Impacts

» Greenhouse Gas Impact Trend

The scope of this analysis is further limited to operational impacts of SGIP projects and does not discuss any lifecycle emissions impacts that occur during the manufacturing, transportation, and construction of SGIP projects. A more detailed discussion of the environmental impacts methodology is included in Appendix C and Appendix D. The environmental impacts of advanced energy storage (AES) projects are discussed in Section 8.

7.1 Methodology Overview and Summary of Environmental Impacts

Emission impacts are calculated as the difference between the emissions generated by SGIP systems and baseline emissions that would have occurred in the absence of the program. The sources of these emissions (generated and avoided) vary by technology and fuel type. For example, all distributed generation technologies avoid emissions associated with displacing central station grid electricity, but only those that recover useful heat avoid emissions associated with displacing boiler use.

Greenhouse Gas Impact Summary

In 2013, the GHG impact of the SGIP was a reduction of more than 162 thousand metric tons of CO_2eq. The GHG impacts for each Program Administrator (PA) are shown in Table 7-1.

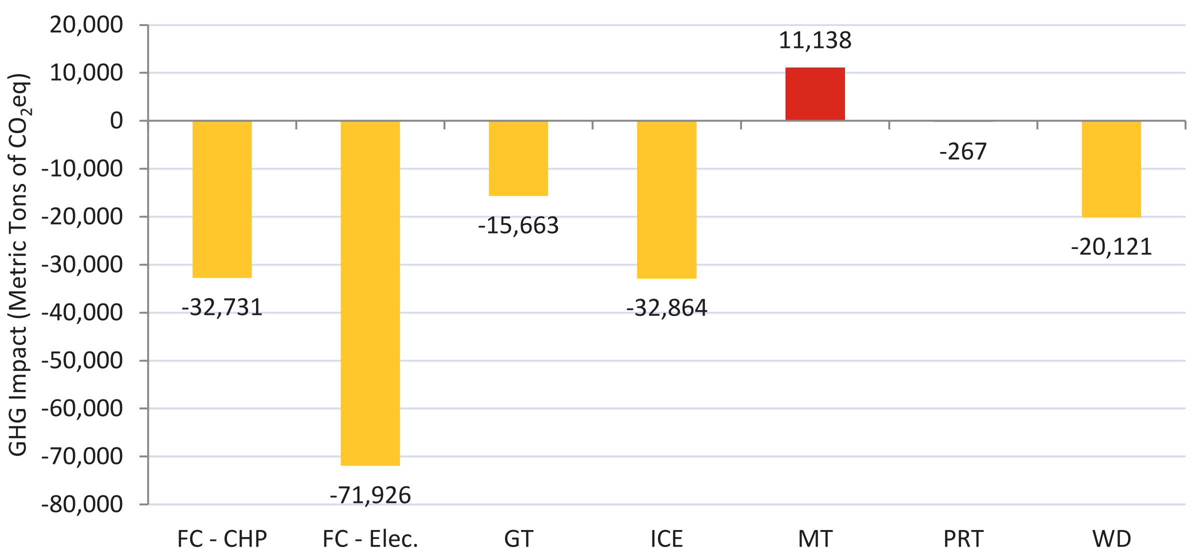
TABLE 7-1: GREENHOUSE GAS IMPACTS BY PROGRAM ADMINISTRATOR

Program Administrator	Greenhouse Gas Impact (Metric Tons CO_2eq)	Total Rebated Capacity (MW)	Greenhouse Gas Metric Tons CO_2eq per Rebated MW	Percent of Greenhouse Gas Impact
CSE	- 13,077	35.6	-367	8.1 %
PG&E	- 66,209	127.3	-520	40.8 %
SCE	- 48,764	71.5	-682	30.0 %
SCG	- 34,384	93.6	-367	21.2 %
Total	***-162,434***	***328.0***	***-495***	***100 %***

* CSE = Center for Sustainable Energy, PG&E = Pacific Gas & Electric, SCE = Southern California Edison, SCG = Southern California Gas Company

Figure 7-1 shows the GHG impacts of seven major technology types rebated by the SGIP. Advanced energy storage (AES) performance is treated separately in Section 8.

FIGURE 7-1: GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE



* FC – CHP = CHP Fuel Cell, FC – Elec = Electric-Only Fuel Cell, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

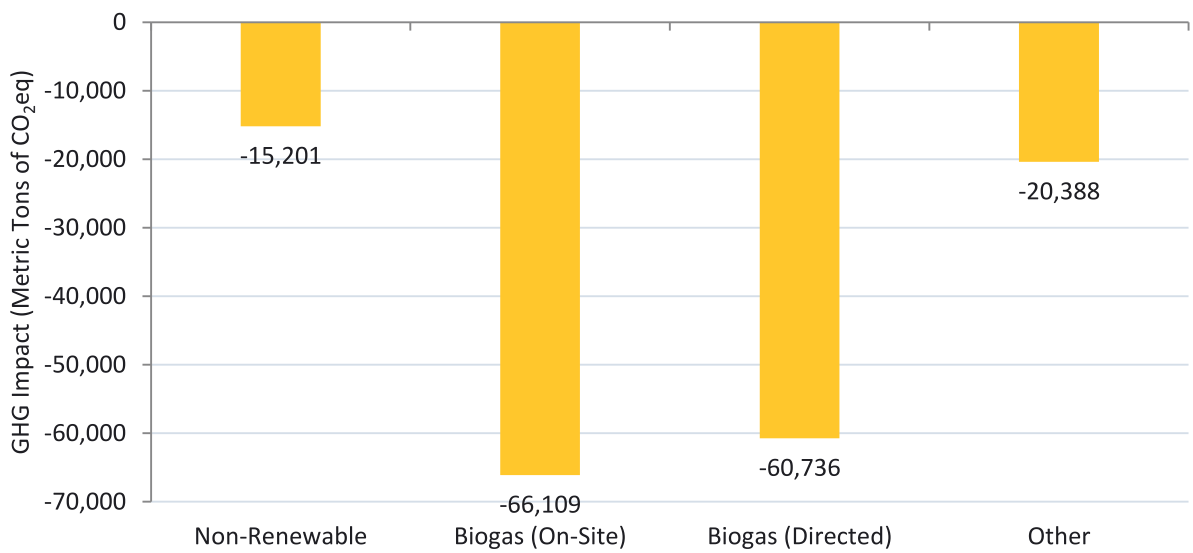
Electric-only fuel cells achieved the largest reductions in GHG emissions followed by CHP fuel cells and internal combustion engines. Microturbines were the only technology type that increased greenhouse gas emissions relative to a conventional energy services baseline. Table 7-2 compares the GHG impacts from each technology type to the total capacity rebated by the SGIP.

TABLE 7-2: GREENHOUSE GAS IMPACTS AND REBATED CAPACITY BY TECHNOLOGY TYPE

Technology Type	Greenhouse Gas Impact (Metric Tons CO_2eq)	Total Rebated Capacity (MW)	Greenhouse Gas Metric Tons CO_2eq per Rebated MW
FC – CHP	-32,731	34.2	-957
FC – Elec.	-71,926	56.4	-1,275
GT	-15,663	30.1	-520
ICE	-32,864	157.4	-209
MT	11,138	25.6	435
PRT	-267	0.5	-534
WD	-20,121	23.7	-849
Total	***-162,434***	***328.0***	***-482***

GHG impacts in Figure 7-1 include both non-renewable and renewable projects. Figure 7-2 summarizes GHG impacts by energy source.

FIGURE 7-2: GREENHOUSE GAS IMPACTS BY ENERGY SOURCE



On average, all SGIP energy sources achieved GHG emissions reductions. The majority of SGIP emissions reductions arise from on-site and directed biogas projects. Non-renewable projects also reduced GHG emissions during 2013. The energy source 'Other' includes wind turbines and pressure reduction turbines.

Criteria Air Pollutant Impact Summary

While California's air quality has significantly improved over the past two decades, many areas in the state still suffer from poor air quality. A recent report issued by the American Lung Association points out that “almost eighty percent of Californians –30 million residents – live in areas plagued with unhealthy air during certain parts of the year.”[1]

To help control air pollution and improve air quality, the California Air Resources Board (CARB) and the United States Environmental Protection Agency (EPA) established ambient air quality standards. Criteria pollutants are air pollutants with national air quality standards that define allowable concentrations of these substances in ambient air. Criteria air pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and sulfur dioxide.[2]

Studies conducted in the early 2000’s indicated that growth in distributed generation (DG) technologies in California could possibly lead to increased air pollution due to the cleanliness of central station power plants and differences in efficiencies between DG and central station systems.[3,4] However, to date no study has used metered performance data in determining the net emissions of criteria air pollutants between SGIP projects and grid sources. This 2013 impact evaluation represents a preliminary assessment of the emissions impacts due to SGIP projects operating as of December 31, 2013. In estimating criteria air pollution impacts, assumptions have been made regarding representative efficiencies and emission rates of combined cycle gas turbine (CCGT) and combustion turbines (CT) used to provide grid power as well as representative emission rates for DG technologies deployed under the SGIP. Appendix D contains the methodology, assumptions and references used in estimating 2013 impacts from criteria air pollutant emissions.

During 2013, SGIP projects decreased NO_X and PM_{10} emissions by 233,852 pounds and 69,077 pounds respectively. During the same period SO_2 emissions decreased by 11,991 pounds relative to the absence of the program. The criteria pollutant impacts attributed to each PA are shown in Table 7-3.

TABLE 7-3: CRITERIA POLLUTANT IMPACTS BY PROGRAM ADMINISTRATOR

Program Administrator	NO_X Impact (lb)	PM_{10} Impact (lb)	SO_2 Impact (lb)	Total Rebated Capacity (MW)
CSE	-14,981	-8,612	-1,031	35.6
PG&E	-95,054	-24,909	-2,236	127.3
SCE	-57,765	-17,671	-4,855	71.5
SCG	-66,052	-17,885	-3,869	93.6
Total	***-233,852***	***-69,077***	***-11,991***	***328.0***

[1] American Lung Association, “State of the Air 2014,”2014

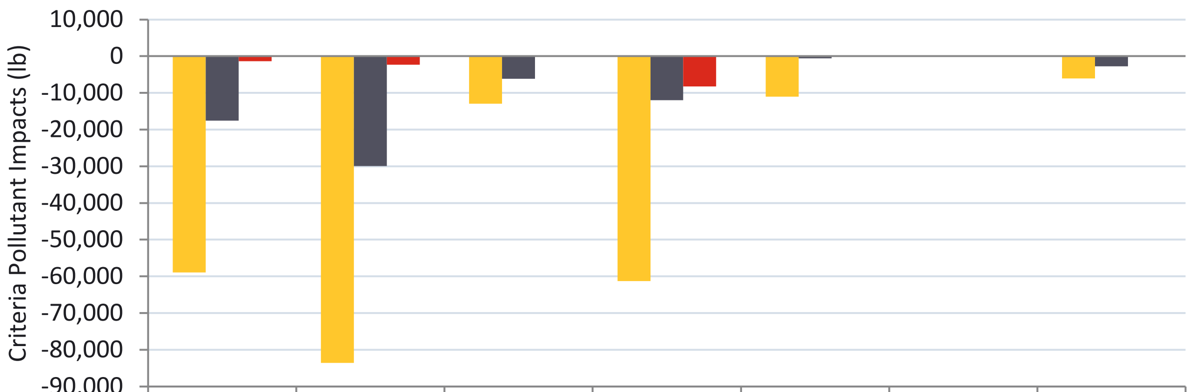
[2] Environmental Protection Agency, from http://www.epa.gov/air/criteria.html

[3] Ianucci, J., Horgan, S., Eyer, J., Cibulka, L., 2000. “Air pollution emissions impacts associated with the economic market potential of distributed generation in California,” Distributed Utility Associates, prepared for The California Air Resources Board, Contract #97-326.

[4] California Institute for Energy and Environment, “Impacts of Distributed Generation on Air Quality: A Roadmap,” prepared for the California Energy Commission, CEC-500-2008-022, June 2008

Figure 7-3 shows the criteria pollutant impacts by technology type.

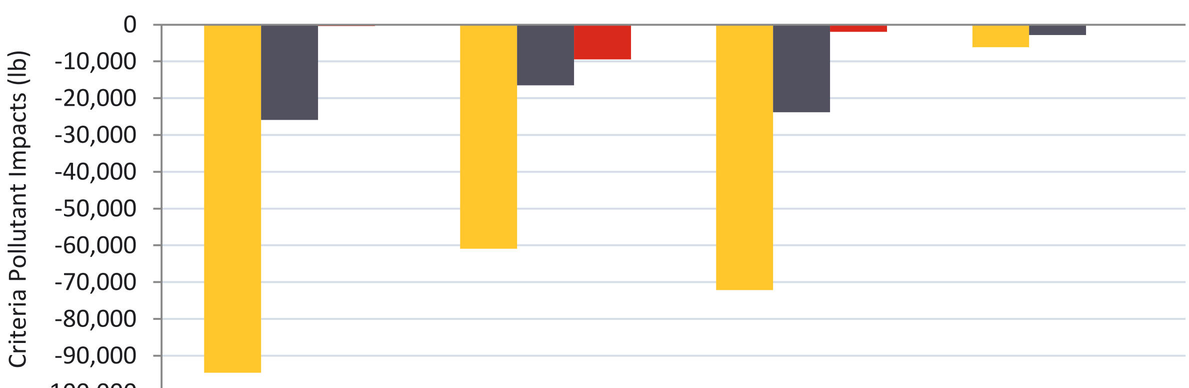
FIGURE 7-3: CRITERIA POLLUTANT IMPACTS BY TECHNOLOGY TYPE



	FC - CHP	FC - Elec.	GT	ICE	MT	PRT	WD
NOx	-58,940	-83,570	-12,909	-61,284	-11,004	-79	-6,066
PM10	-17,593	-29,922	-6,155	-12,028	-583	-36	-2,760
SO2	-1,347	-2,354	11	-8,271	161	-2	-188

All SGIP technologies achieved NO_X and PM_{10} emissions reductions but the largest contributions came from fuel cells and internal combustion engines. SO_2 emissions impacts were minor except for internal combustion engines, which contributed to large decreases in SO_2 emissions. Additional information on criteria pollutant impacts by technology type and energy source are provided in subsequent sections. Figure 7-4 summarizes criteria pollutant impacts by energy source.

FIGURE 7-4: CRITERIA POLLUTANT IMPACTS BY ENERGY SOURCE



	Non-Renewable	Biogas (On-Site)	Biogas (Directed)	Other
NOx	-94,628	-60,941	-72,138	-6,145
PM10	-25,923	-16,514	-23,844	-2,796
SO2	-414	-9,418	-1,969	-190

All energy sources decreased NO_X, PM_{10}, and SO_2 emissions. The following subsections describe in more detail the environmental impacts of SGIP projects by energy source.

7.2 Non-renewable Project Impacts

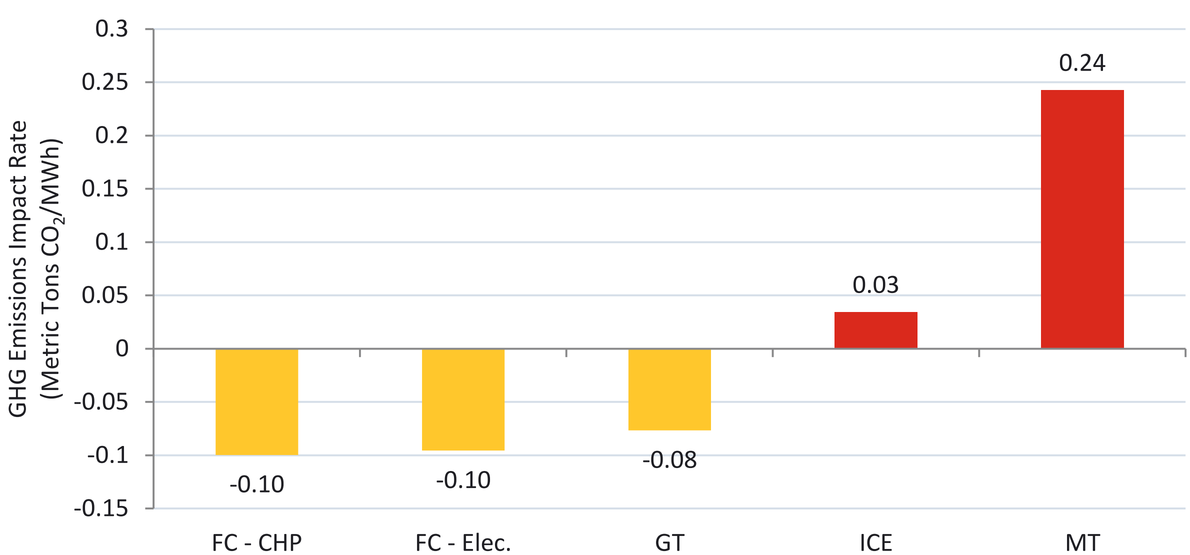
Non-renewable SGIP projects include CHP fuel cells, electric-only fuel cells, gas turbines, internal combustion engines, and microturbines. These projects consume natural gas and generate electricity to serve a customer's load. Non-renewable SGIP projects produce emissions that are proportional to the amount of fuel they consume. In the absence of the program, the customer's electrical load would have been served by the electricity distribution company. Consequently, if SGIP systems only served electrical loads, they would need to generate electricity more cleanly than the avoided marginal grid generator to achieve GHG emission reductions.

SGIP CHP projects are able to recover waste heat and use it to serve on-site thermal loads. The recovered waste heat may be used to serve a customer's heating or cooling needs. In the absence of the SGIP, a heating end use is assumed to be met by a natural gas boiler, and a cooling end use is assumed to be met by an electric chiller. Natural gas boilers generate emissions associated with the combustion of the gas to heat water. The emissions associated with electric chillers are due to the central station plant that would have generated the electricity to run the chiller. Emissions impacts are the difference between SGIP emissions and avoided emissions.

Non-Renewable Greenhouse Gas Impacts

The GHG performance of non-renewable SGIP projects is summarized in Figure 7-5.

FIGURE 7-5: GREENHOUSE GAS IMPACT RATE BY TECHNOLOGY TYPE (NON-RENEWABLE FUEL)



Non-renewable CHP fuel cells, electric-only fuel cells, and gas turbines decreased GHG emissions in 2013. Internal combustion engines and microturbines increased GHG emissions. It should be noted that Figure 7-5 shows GHG emissions impact rates in metric tons of CO_2 per MWh. To arrive at 2013 GHG impacts these rates must be multiplied by the non-renewable electrical generation impact. This is important because while non-renewable microturbines had the largest emissions impact rate (0.24 metric tons of CO_2 per MWh), they had the second lowest electrical generation impact (56,552 MWh).

GHG impacts are the net difference between SGIP emissions and total avoided emissions. The individual components contributing to non-renewable emissions impacts for each technology type are listed in Table 7-4.

TABLE 7-4: NON-RENEWABLE GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE

Technology Type	Metric Tons of CO_2 per MWh						
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Cooling Services (D)	Total Avoided Emissions (E=B+C+D)	Emissions Impact (F=A-E)	Annual Energy Impact (MWh)
FC – CHP	0.49	0.46	0.13	0.00	0.59	- 0.10	58,881
FC – Elec.	0.37	0.46	0.00	0.00	0.46	- 0.10	161,084
GT	0.54	0.48	0.11	0.03	0.62	- 0.08	204,114
ICE	0.65	0.47	0.12	0.01	0.61	0.03	233,700
MT	0.82	0.46	0.11	0.01	0.58	0.24	56,552

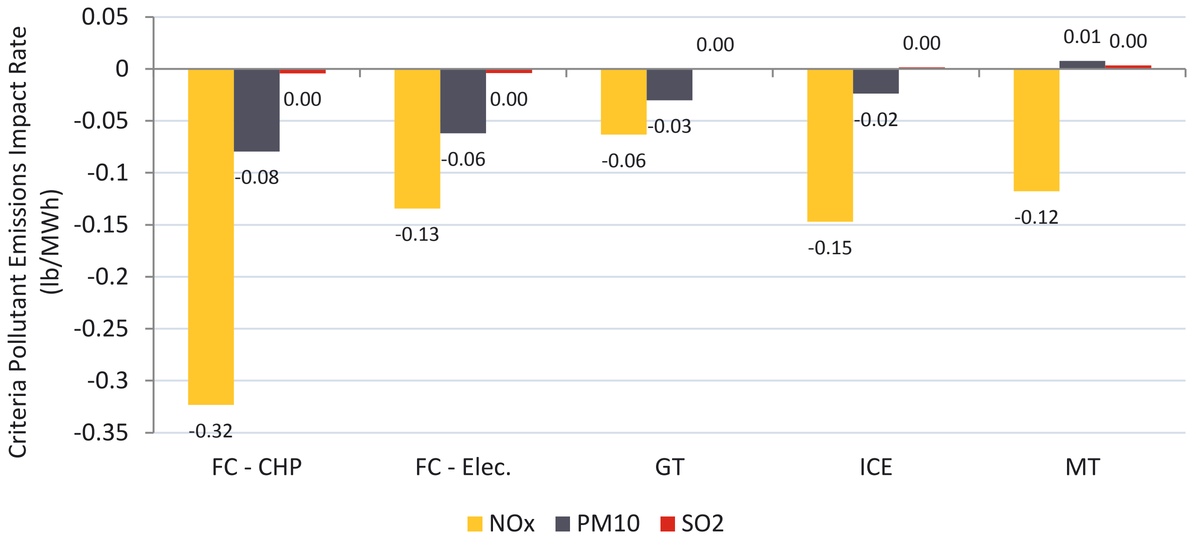
CHP fuel cells and gas turbines have a higher emissions rate than the electrical power plants that they avoid (A > B) but are able to overcome this deficit by recovering useful heat for heating (C) and cooling (D) services. The result is a negative emissions impact (F) relative to the conventional energy services baseline. Electric-only fuel cells do not recover useful heat but have a lower emissions rate than the electric power plants they avoid (A < B). Internal combustion engines and microturbines had high emissions rates and did not recover sufficient useful heat to achieve negative GHG impacts.

When reviewing SGIP GHG impacts results, it is important to keep in mind that results for technologies are reported in aggregate and are not necessarily indicative of individual project performance or technology potential. Non-renewable internal combustion engines and microturbines are capable of achieving GHG emissions reductions, and some do. However, when viewed as a group, their combined performance resulted in increased GHG emissions. When all non-renewable projects are grouped together, their combined emissions impact rate (calculated as the total GHG impact divided by total MWh) is -0.02 metric tons of CO_2 per MWh.

Non-Renewable Criteria Air Pollutant Impacts

Like GHG emissions, the net impact of criteria air pollutant emissions are proportional to the amount of fuel consumed by the SGIP technology to generate electricity relative to grid sources and the amount of avoided boiler fuel. The criteria pollutant emission performance of non-renewable SGIP projects is summarized in Figure 7-6.

FIGURE 7-6: CRITERIA POLLUTANT IMPACT RATE BY TECHNOLOGY TYPE (NON-RENEWABLE FUEL)



All technologies supplied with non-renewable fuel decreased NO_X and PM_{10} emissions. SO_2 emissions from technologies supplies with non-renewable fuel were marginal. These results indicate that non-renewable SGIP technologies with high electrical efficiencies and low air pollutant emissions (e.g., fuel cells) generate fewer emissions than the conventional energy services baseline. In addition, SGIP technologies with lower electrical efficiencies but which recovered useful waste heat reduce criteria air pollutants overall.

7.3 Renewable Biogas Project Impacts

SGIP renewable biogas projects include CHP fuel cells, electric-only fuel cells, microturbines, and internal combustion engines. Almost 20 percent of the total SGIP rebated capacity is fueled by renewable biogas. Sources of biogas include landfills, wastewater treatment plants (WWTP), dairies, and food processing facilities. Analysis of the emission impacts associated with renewable biogas SGIP projects is more complex than for non-renewable projects. This complexity is due in part to the additional baseline component associated with biogas collection and treatment in the absence of the SGIP project installation. In addition, some projects generate only electricity while others are CHP projects that use waste heat to meet site heating and cooling loads. Consequently, renewable biogas projects can directly impact emissions the same way that non-renewable projects can, but they also include emission impacts caused by the treatment of the biogas in the absence of the program.

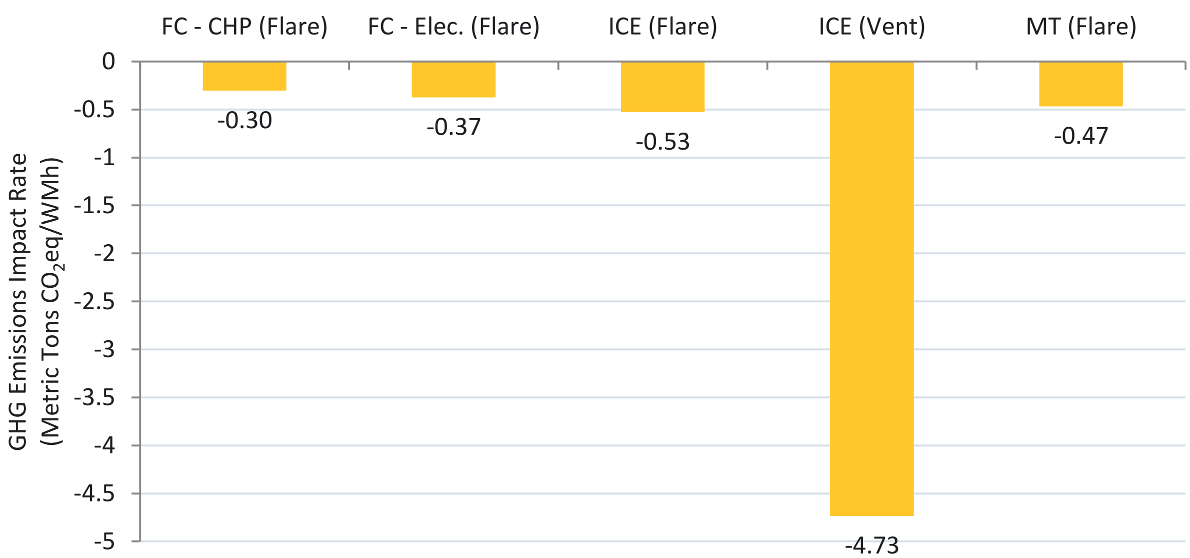
Renewable biogas SGIP projects capture and use biogas that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained in Appendix C.

Renewable Biogas Greenhouse Gas Impacts

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of metric tons of CO_2 equivalent so that direct comparisons can be made across technologies and energy sources. On a per mass unit basis, the global warming potential of CH_4 is 21 times that of CO_2. The biogas baseline estimates of vented emissions (CH_4 emissions from renewable SGIP facilities) are converted to CO_2eq by multiplying the metric tons of CH_4 by 21. In this section, CO_2eq emissions are reported if projects with a biogas venting baseline are included, otherwise; CO_2 emissions are reported.

The GHG performance of renewable biogas SGIP projects is summarized in Figure 7-7 by technology type and biogas baseline. CHP fuel cells, electric-only fuel cells, internal combustion engines, and microturbines were deployed in locations that would otherwise have flared biogas. Internal combustion engines were the only technology deployed at locations such as dairies that would otherwise have vented biogas.

FIGURE 7-7: RENEWABLE GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY AND BIOGAS BASELINE TYPE



All renewable biogas technologies reduced GHG emissions regardless of the biogas baseline. Technologies with flaring biogas baselines achieved reductions between 0.30 and 0.53 metric tons of CO_2 per MWh. Internal combustion engines with venting biogas baselines achieved GHG reductions that were an order of magnitude greater at 4.73 metric tons of CO_2eq per MWh. The individual components contributing to renewable emissions impacts for each technology and biogas baseline are listed in Table 7-5.

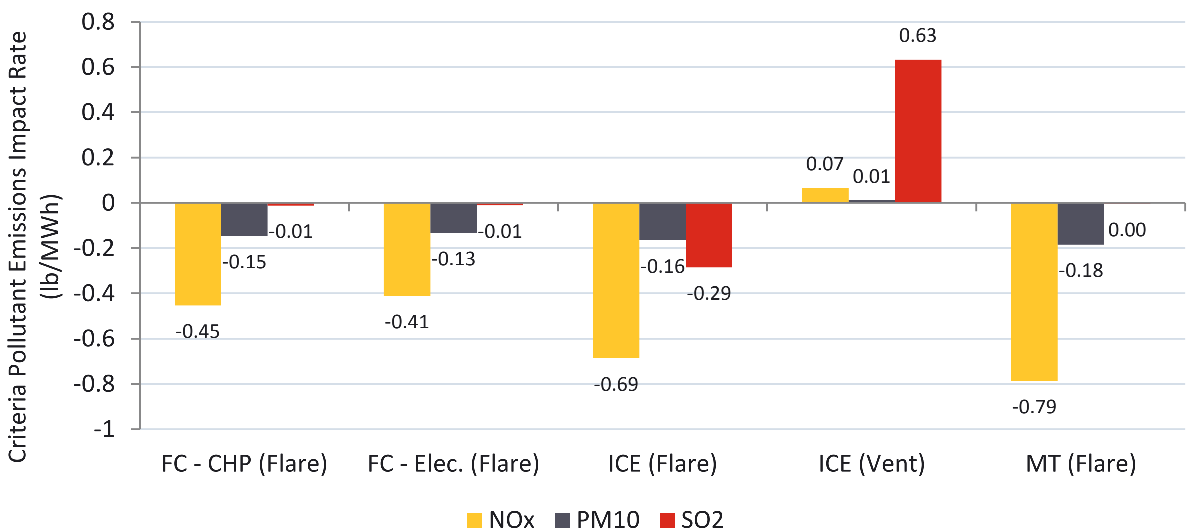
TABLE 7-5: RENEWABLE BIOGAS GREENHOUSE GAS IMPACTS BY TECHNOLOGY AND BIOGAS BASELINE TYPE

Technology and Biogas Baseline Type	Metric Tons of CO_2eq per MWh						
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Biogas Treatment (D)	Total Avoided Emissions (E=B+C+D)	Emissions Impact (F=A-E)	Annual Energy Impact (MWh)
FC – CHP (Flare)	0.49	0.48	0.00	0.32	0.80	- 0.30	88,001
FC – Elec (Flare)	0.37	0.47	0.00	0.28	0.74	- 0.37	150,868
ICE (Flare)	0.65	0.47	0.06	0.65	1.17	- 0.53	36,884
ICE (Vent)	0.65	0.45	0.00	4.93	5.38	- 4.73	3,922
MT (Flare)	0.82	0.47	0.00	0.82	1.29	- 0.47	5,320

Renewable Biogas Criteria Pollutant Impacts

The criteria pollutant emission performance of renewable biogas SGIP projects is summarized in Figure 7-8.

FIGURE 7-8: CRITERIA POLLUTANT IMPACT RATES BY TECHNOLOGY TYPE AND BIOGAS BASELINE



All technology types with flaring baselines decreased. Internal combustion engines with venting biogas baselines have positive NO_2 and PM_{10} emissions impact rates since there is no combustion in the biogas baseline to create NO_2, PM_{10}, or SO_2.

7.4 Wind and Pressure Reduction Turbine Project Impacts

Wind turbine and pressure reduction turbine (PRT) projects do not consume any type of fuel and do not recover waste heat. Their emissions reduction rates are equal to the emissions rate of the grid as described in Appendix D and Appendix E. The individual components contributing to wind and PRT GHG emissions impacts are listed in Table 7-6.

TABLE 7-6: WIND AND PRT GREENHOUSE GAS IMPACTS

Technology Type	Metric Tons of CO_2 per MWh				
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Total Avoided Emissions (C=B)	Emissions Impact (D=A-C)	Annual Energy Impact (MWh)
PRT	0.00	0.46	0.46	- 0.46	576
WD	0.00	0.48	0.48	- 0.48	42,529

Criteria pollutant impacts from wind turbine and PRT projects are summarized in Table 7-7.

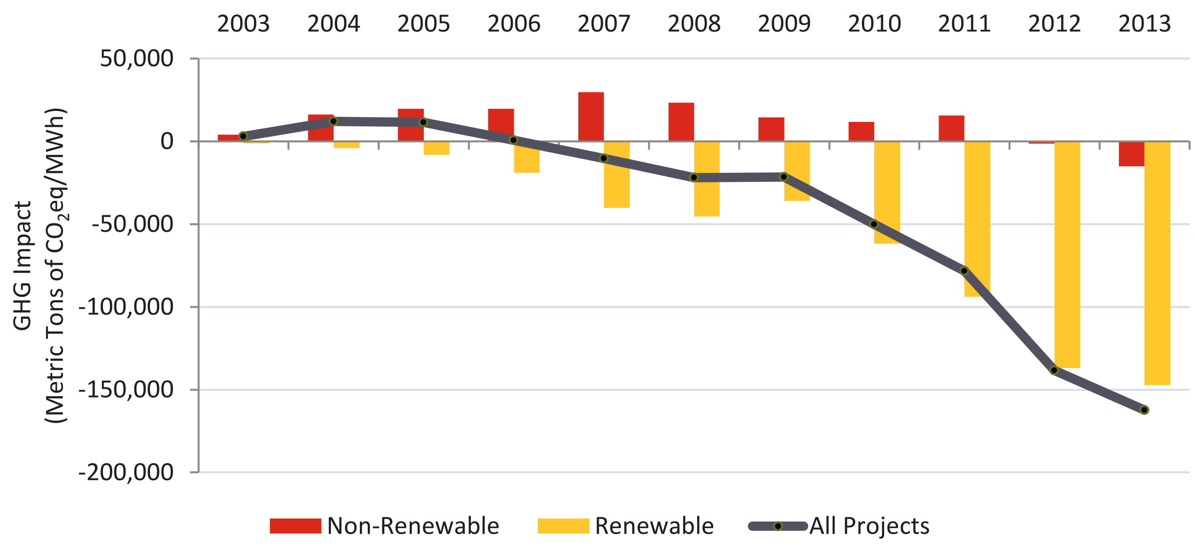
TABLE 7-7: WIND AND PRT CRITERIA POLLUTANT IMPACTS

Technology Type	NO_X Impact (lb)	PM_{10} Impact (lb)	SO_2 Impact (lb)	Annual Energy Impact (MWh)
PRT	-79	-36	-2	576
WD	-6,066	-2,760	-188	42,529

7.5 Greenhouse Gas Impact Trend

GHG impacts during 2013 are calculated using hourly performance data and implied marginal heat rates specific to 2013. In order to simplify the estimation of historical trends in GHG impacts, the 2013 hourly marginal heat rates are applied to all previous years. This simplifying assumption reduces the accuracy of historical greenhouse gas impacts estimates but allows for a straightforward comparison of trends. Figure 7-9 shows the SGIP's greenhouse gas impacts since 2003.

FIGURE 7-9: GREENHOUSE GAS IMPACTS OVER TIME



The SGIP program continues to improve its ability to reduce GHG emissions. Based on this preliminary assessment, the SGIP appears to be reducing criteria pollutant impacts as well. There has been a sharp decline in SGIP greenhouse gas impacts beginning in 2010. The steady decline in GHG impacts between 2010 and 2013 coincides with a significant increase in generation from renewable sources like wind turbines and biogas projects.

Advanced Energy Storage Performance

8

8 ADVANCED ENERGY STORAGE PERFORMANCE

Advanced energy storage (AES) is one of the fastest growing and most anticipated distributed energy resources (DERs) on California's electricity grid. Since the first AES application was paid in March 2012, the Self-Generation Incentive Program (SGIP) has seen a remarkable increase in the number of AES applications received. AES project applications are being located at residential, commercial, and industrial host customer sites in size ranges from 5 kW to several megawatts. SGIP AES projects promise to deliver benefits through numerous value streams including increased customer reliability, reduced customer demand, reduced peak energy consumption (arbitrage), and balancing of intermittent renewable resources such as solar photovoltaics and wind.

As of December 31, 2013, the SGIP had paid incentives to five AES projects representing 1.9 MW of rebated capacity. Limited data from those projects were available to support a rigorous impacts evaluation. Furthermore, the performance of projects completed and paid by the SGIP may not be representative of those projects pending payment in the SGIP queue. As of September 2014, there were over 800 AES projects representing approximately 50 MW of capacity in the SGIP queue. Recognizing the limitations of the existing SGIP AES population and metered sample, this section provides a preliminary assessment of AES performance in 2013 and discusses the metered data requirements for fully quantifying the impacts of AES. This section is divided into the following subsections:

- **Policy Background:** summarizes the current policy landscape for AES
- **Storage Technologies:** provides an overview of AES technologies
- **Potential Benefits:** describes the potential value streams for AES to customers, utilities, and society
- **Overview of Current Data Availability and Constraints**: summarizes status of current data availability and limitations
- **SGIP Performance Case Studies:** based on current data from SGIP AES projects
- **Advanced Energy Storage in the Queue**: reviews the composition of AES projects to be completed in the future

The discussion of SGIP AES should not be considered an impacts assessment but rather a preliminary assessment of AES performance in the SGIP during 2013.

8.1 Policy Background

On September 29, 2010, former Governor Schwarzenegger signed AB 2514 (Skinner, 2010) into law, requiring the California Public Utilities Commission (CPUC) to open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems. The CPUC was to consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems.[1]

In October 2013, the CPUC adopted an energy storage procurement framework and established an energy storage target for Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). A total of 1,325 MW are to be procured by 2020, with installations to be completed no later than 2024. The decision further establishes a target for community choice aggregators and electric service providers to procure energy storage equal to one percent of their annual 2020 peak load by 2020 with installations completed no later than 2024. An important component of the targets was the specific allocation to customer sited behind-the-meter storage with the intent to affect areas such as bill management, permanent load shifting, maintaining power quality, and electric vehicle charging. In total, 200 MW of behind-the-meter storage must be collectively procured by the electric investor owned utilities (IOUs) by 2020. The targets for each IOU are listed in Table 8-1.

TABLE 8-1: BEHIND-THE-METER ENERGY STORAGE TARGETS BY UTILITY (MW)[2]

Utility	2014	2016	2018	2020	Total
Pacific Gas and Electric	10	15	25	35	85
Southern California Edison	10	15	25	35	85
San Diego Gas and Electric	3	5	8	14	30
Total	**23**	**35**	**58**	**84**	**200**

The California Independent System Operator (CAISO), along with the California Energy Commission (CEC) and the CPUC, have also initiated development of an Energy Storage Roadmap to facilitate the advancement of energy storage. The roadmap supports California's energy and environmental policy goals by identifying actions to address the challenges and barriers that have been identified by industry participants and other stakeholders.[3]

Interconnection, Rule 21, and Net Energy Metering (NEM)

Interconnection is one of the key issues at the heart of the financial feasibility of energy storage. Electric distribution companies are wary of the potential impacts of behind-the-meter storage on the distribution system and the financial implications of energy arbitrage. Consequently, the interconnection of AES projects behind-the-meter can be slowed down by detailed studies and safety requirements. These hurdles are partly responsible for a large number of SGIP projects being in the queue pending but not yet issued their incentive payments.

1 Bill 2514 (Skinner, 2010)

2 CPUC Decision 13-10-040 October 17, 2013

3 http://www.caiso.com/informed/Pages/CleanGrid/EnergyStorageRoadmap.aspx

In 2013, the Federal Energy Regulatory Commission (FERC) issued Order No. 792 which, among other things, directed transmission providers to define electric storage devices as generating facilities that can take advantage of generator interconnection procedures. A recent staff proposal by the CPUC begins to explore what changes will be required to accommodate storage interconnection within Rule 21.[4] The standardization of AES interconnection practices is expected to accelerate the adoption rate of behind-the-meter AES.

The export of energy from behind-the-meter AES projects is governed by Net Energy Metering (NEM) tariffs. Behind-the-meter storage devices that are not paired with NEM-eligible generators[5] currently are not eligible for NEM.

A more detailed treatment of the policy influences on AES adoption will be presented in a forthcoming SGIP market transformation report.

8.2 Storage Technologies

Energy storage technologies can be categorized into six primary categories:[6]

» Solid state batteries

» Flow batteries

» Flywheels

» Compressed air energy storage

» Thermal (not eligible for SGIP incentives in 2013)

» Pumped hydro-power

Of these energy storage technologies, solid state batteries and flow batteries are most commonly employed at customer sited locations and are, therefore, expected to have the largest impact in the SGIP. Solid state batteries are electrical storage devices that are made of solid electrochemical materials. These batteries are often referred to as “dry” and can be further described by their underlying chemistry (lithium ion, nickel-cadmium, sodium sulfur, etc.). Flow batteries contain liquid electrolytes that are enclosed in storage tanks but pumped as needed to store or generate electricity.

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4 Issues, Priorities and Recommendations for Energy Storage Interconnection, CPUC Staff Proposal, July 18, 2014 (http://www.cpuc.ca.gov/NR/rdonlyres/529F4161-620E-4DFA-98E2-F434462824F6/0/Rule21storageandinterconnectionFINAL724.pdf)

5 Grid-tied distributed renewable energy generation, including customer-sited solar PV systems

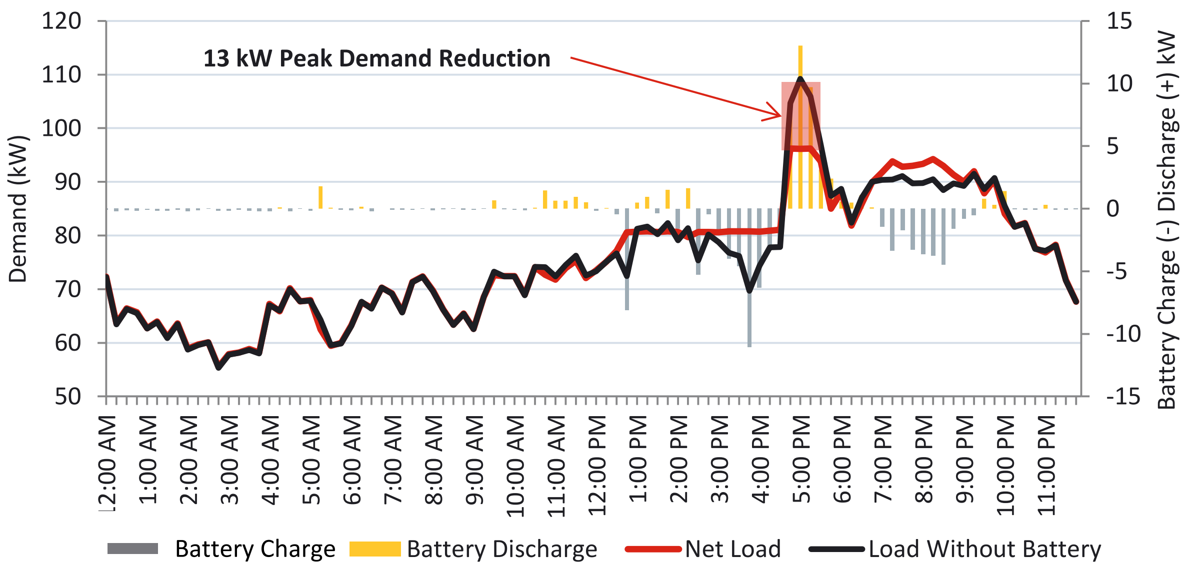
6 Energy Storage Association

8.3 Potential Benefits

Advanced energy storage may provide benefits to balancing authorities, distribution companies, aggregators, rate payers, host customers, and society. While there are more than 20 discrete value streams for storage, depending on the point at which it is interconnected, the greatest potential opportunity for the layering of these value streams tends to be for systems interconnected closest to customer load.[7] The potential for demand charge reduction and peak load management are the primary driving factors for siting storage at commercial customer sites. The primary benefit to host customers for installations at residential sites, however, is often backup power.[8] The increasing policy focus and drive to zero net energy at a building or community level may also lead to the increased value of siting storage in conjunction with on-site renewable generation.

The use of intelligent controllers that run the charge and discharge cycles of storage based on several operating and cost parameters to create desired load profiles is finding increasing use in the field. Figure 8-1 illustrates the use of storage at a hotel to reduce peak demand. In doing so, the customer reduces the peak demand for that day by 13kW and potentially reduces the magnitude of the billed demand charge.

FIGURE 8-1: BATTERY USE CASE FOR PEAK DEMAND REDUCTION



Some developers are working to aggregate behind-the-meter storage to provide demand response in order to generate additional value streams from their projects. If successful, this aggregation will

7 GTM Research: Distributed Energy Storage 2014: Applications and Opportunities for Commercial Energy. Feb 2014

8 Final SolarCity CSI RD&D report, section 4.1 'Advanced Energy Storage Market' Survey http://calsolarresearch.ca.gov/images/stories/documents/sol2_funded_projects/solarcity/201404_SolarCity_FinalRpt.pdf

provide developers and host customers another value stream to make storage more cost effective. Furthermore, the ancillary services market is one of the biggest opportunities for the employment of distributed energy storage to help maintain stable grid operations on a short-term basis.[9] However, behind-the-meter storage cannot currently bid into the ancillary services market in California.

AES projects may indirectly reduce greenhouse gas (GHG) emissions by allowing greater penetrations of renewables to interconnect into the grid.[10] However, this indirect reduction in GHG emissions is difficult to quantify and attribute to the SGIP, and therefore, is not quantified in this study. On the other hand, AES projects may reduce GHG emissions directly, depending on the battery's round trip efficiency and its time of use. Batteries inherently consume more electricity than they discharge due to electrochemical losses; therefore, to provide GHG reductions, batteries must charge from the grid during relatively "clean" hours of grid generation and discharge during "dirty" hours of grid generation to overcome their net increase in energy consumption.

8.4 Overview of Data Availability and Constraints

AES projects are a relatively new technology in the SGIP, and therefore, limited data are available upon which to base an estimate of program impacts. This section describes the types and amounts of data available to Itron at the time of this evaluation, and the relationship between potential data types and evaluation metrics.

As of December 31, 2013, five AES projects were paid incentives by the SGIP. Two projects applied to the program before program year (PY) 2011 and, consequently, are not subject to Performance Based Incentive (PBI) data delivery requirements. Of the remaining three projects, two are less than 30 kW and, therefore, not subject to the PBI data delivery requirements. As a result, only one AES project had PBI data available.

The 2013 SGIP Handbook[11] specifies that for PBI projects "a meter must be installed to measure the charge and discharge of the AES" no less frequently than every 15 minutes. Interval charge and discharge data are sufficient for quantifying PBI payments and can be used to calculate certain system-level energy, demand, and environmental impacts of storage but do not provide enough information to fully quantify the multiple value streams of behind-the-meter AES.

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9 Grid Scale Energy Storage Conference. June 12, 2014. San Diego, CA. Presentation by Stephen Kelley of Green Charge Network.

10 Press Release. "Hawaiian Electric announces plans for approval of pending solar applications". November 3, 2014. http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/20141103_HE_announces_plans_for_approval_solar_apps.pdf

11 http://www.cpuc.ca.gov/NR/rdonlyres/0DDABA86-9DF1-41C7-AD08-FF5B255155FA/0/2013_SGIP_Handbook_v1.pdf

When evaluating AES projects, the addition of host customer tariff information to the PBI data allows for analysis of arbitrage and quantification of load shifting across utility time-of-use (TOU) tariff periods. The addition of 15-minute interval host customer load data would allow for a more detailed financial analysis of host customer economics including quantification of bill savings from energy and demand charges and an evaluation of storage operational strategies. Finally, for projects co-located with distributed generation, the addition of 15-minute interval generation (kWh) data would provide a complete picture into storage operational strategies, and would allow quantification of storage impacts related to firming of intermittent renewable generation.

Metered data were available from four out of the five SGIP AES projects completed on or before December 31, 2013. All metered data sets included some observations with missing values. SGIP AES data availability is summarized in Table 8-2. Metered data were collected from PBI performance data providers (PDPs), vendors, and system owners.

TABLE 8-2: SUMMARY OF 2013 SGIP AES DATA AVAILABILITY

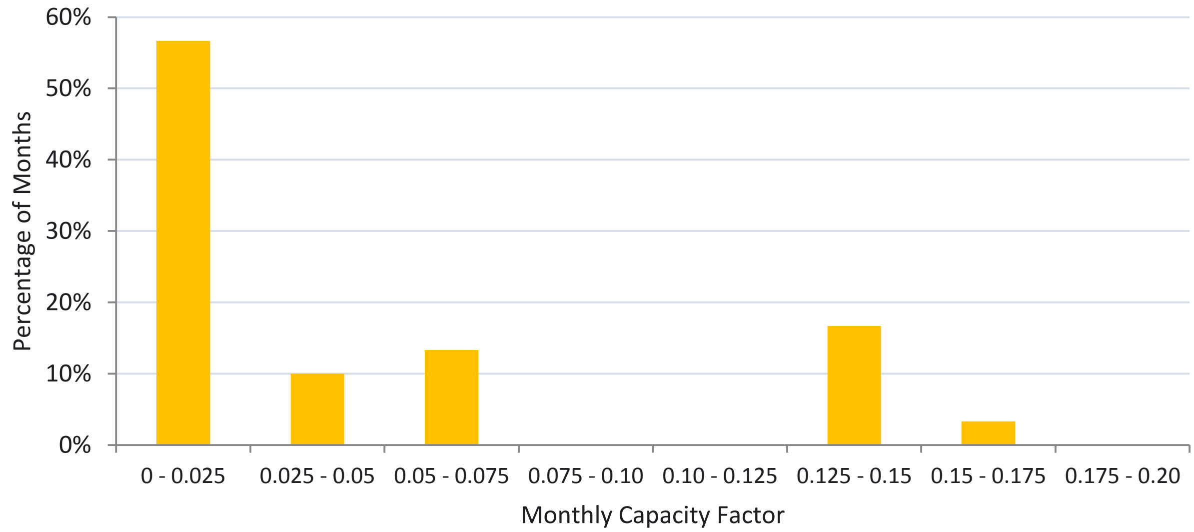
SGIP AES Project	AES Interval Charge / Discharge	Host Customer Tariff Information	Host Customer Load Data	DG Interval Generation Data	Complete Metered Dataset	PBI? (Yes/No)
1	Yes	Yes	Yes	Yes	No	No
2	Yes	No	No	Yes	No	No
3	Yes	No	No	N/A	No	Yes
4	Yes	No	Yes	N/A	No	No
5	No	No	No	No	No	No

Due to the emerging nature of AES projects and the limited data available, no efforts were made to estimate program level impacts of AES. Instead, the following subsection summarizes the AES performance data available to date.

8.5 SGIP Performance Case Studies

Figure 8-2 shows the distribution of AES monthly capacity factors using data from all available projects based on 8,760 hours of potential operation. Note that the SGIP uses an expected capacity factor of 10 percent based on 5,200 hours of operation. Here, 8,760 hours are used to facilitate comparisons of utilization with other technologies described in this report.

FIGURE 8-2: HISTOGRAM OF OBSERVED AES MONTHLY CAPACITY FACTORS



The information in Figure 8-2 is useful in understanding what typical levels of utilization have been in 2013. Of the 30 monthly data points included in this analysis, 24 (80 percent) had capacity factors below 10 percent.

Including tariff information allows quantification of energy load shifting from one TOU period to another. AES Project #1 is known to be on a TOU tariff with three distinct summer periods and two winter periods. As a simplifying assumption, this same tariff was applied to all projects regardless of their electric utility to approximate the load shifting impacts of SGIP AES. The results of the load shifting analysis are summarized in Figure 8-3.

FIGURE 8-3: CASE STUDY OF TOU LOAD SHIFTING

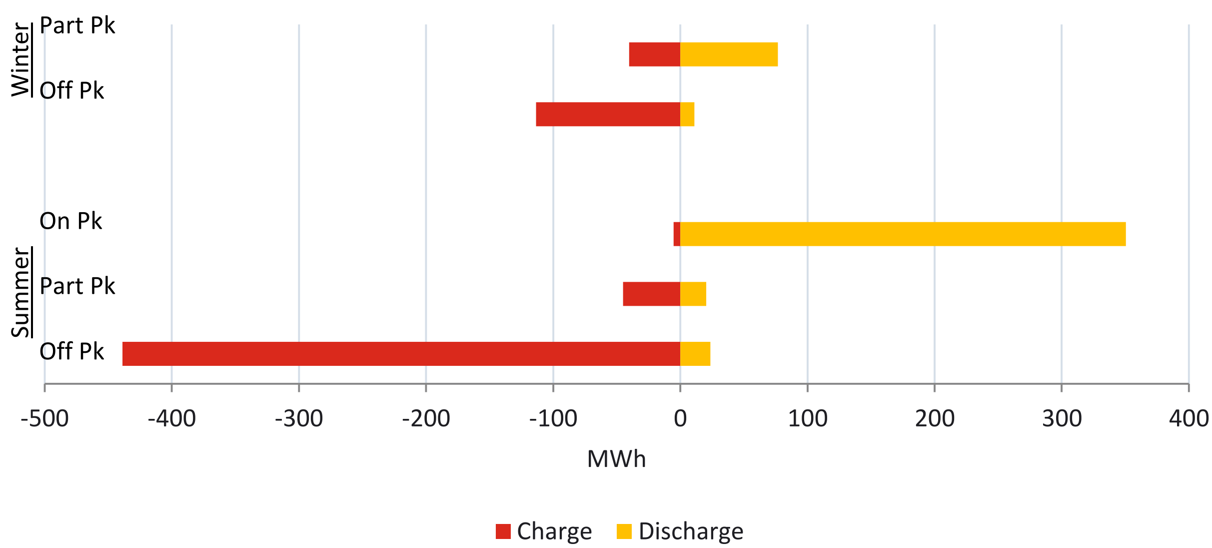
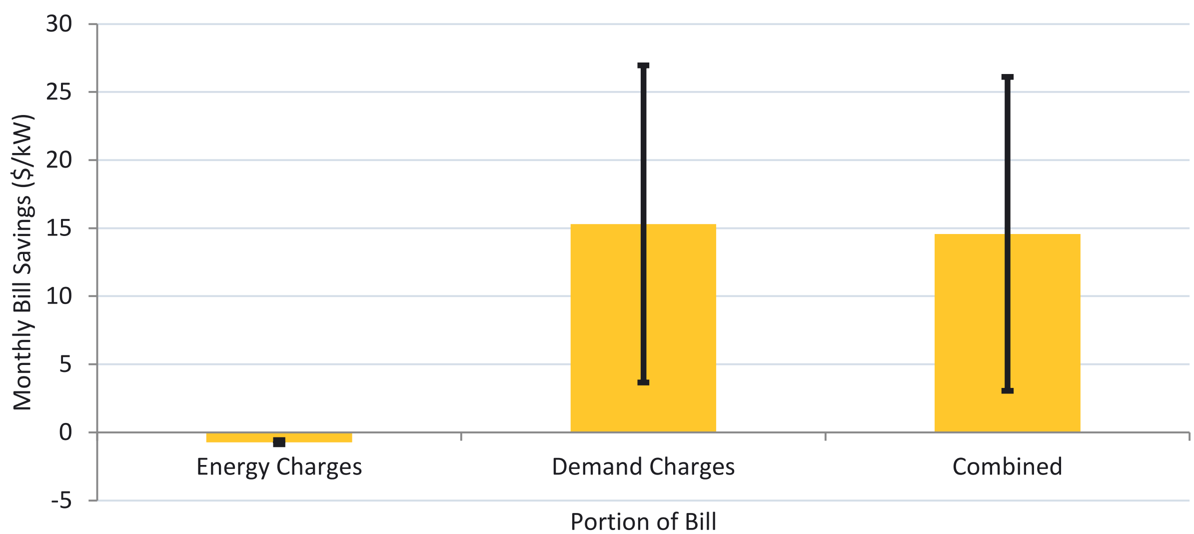


Figure 8-3 reveals that SGIP AES projects are used to shift energy consumption from on-peak time of use periods to off-peak periods. During the summer months, SGIP AES projects increased energy consumption by 439 MWh during the off-peak period and decreased energy consumption by 350 MWh during the on-peak period. A similar but less pronounced pattern is observed in the winter. More accurate impacts can be quantified if actual host customer tariffs are known.

Aside from increasing reliability during temporary grid outages, most commercial host customers may install AES to reduce demand charges on bills. Demand charges are incurred based on a customer's maximum load during a given time period (typically monthly). SGIP AES can be used to discharge during anticipated periods of high demand, thereby reducing billed demand charges. AES Project #4 was identified as a project implemented to reduce demand charges. Charge, discharge, and load data were available for AES Project #4 but the tariff information was approximated from AES Project #1's tariff.[12] Using this information, the AES project's impacts on the host customer's bill were calculated. The results are summarized in Figure 8-4.

FIGURE 8-4: CASE STUDY OF AES BILL IMPACTS



Bill impacts can be separated into energy charges and demand charges. Figure 8-4 shows that for AES Project #4, operation of the storage system increased the energy portion of the bill (negative savings). Because of inefficiencies, AES projects increase overall energy consumption. The energy bill savings are dependent on the AES round trip efficiency and its hours of operation. In contrast, the demand portion of the bill saw significant savings due to the AES and, as a result, there were combined bill savings of almost $15 per kW of rebated AES capacity. The error bars in Figure 8-4 are drawn at +/- one standard deviation.

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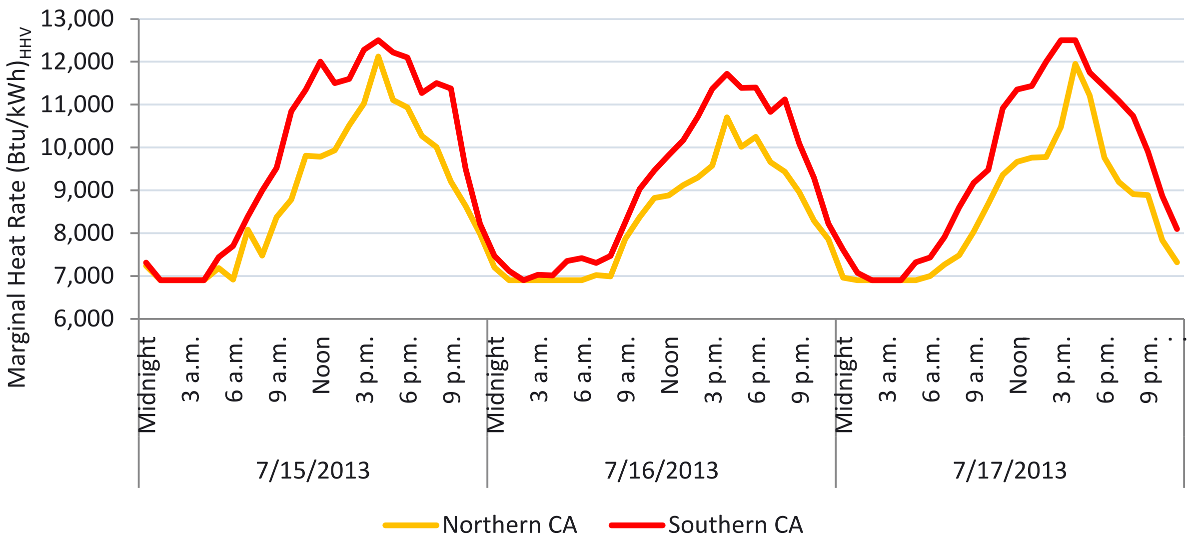
[12] The host customer's electricity tariff is not a field currently tracked by the SGIP Program Administrators.

AES projects may provide societal benefits in the form of GHG emissions reductions. Direct GHG impacts from AES projects are due to the shift in energy consumption from "dirty" hours of grid generation to "cleaner" hours. The GHG impacts methodology used to quantify SGIP impacts in Section 7 assumes that SGIP generation displaces a natural gas generator on the margin.[13] The average heat rate of natural gas generators operating at the margin determines the emissions associated with grid generation during any given hour. Figure 8-5 shows the implied marginal heat rates used to quantify GHG impacts for three representative days in 2013. Gas generation plants with higher heat rates consume more fuel, and therefore, emit more greenhouse gases. Marginal heat rates are up to 80 percent higher during afternoon hours (when plants with higher heat rates are dispatched to meet load requirements) than those in the middle of the night.

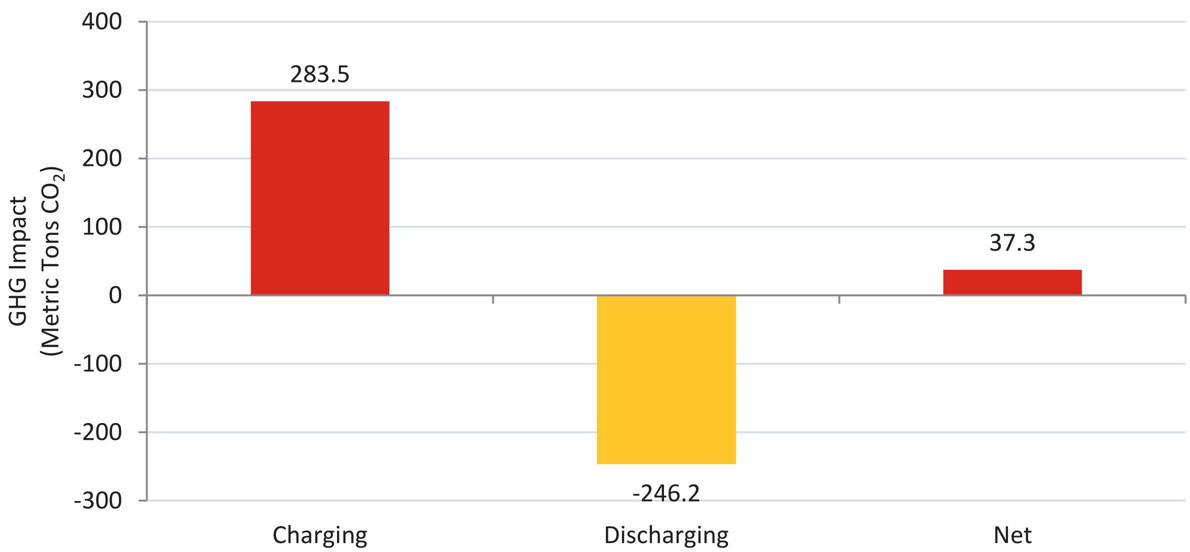
FIGURE 8-5: REPRESENTATIVE MARGINAL HEAT RATES USED TO QUANTIFY GHG EMISSIONS



SGIP AES projects can achieve GHG emissions reductions if they charge during times when the grid is very efficient (for example between 12 a.m. and 6 a.m.) and discharge during the grid's less efficient hours (for example between 2 p.m. and 6 p.m.). This TOU behavior is required for achieving GHG emissions reductions since the inherent inefficiencies in SGIP AES projects mean that energy consumption will always be greater than in the absence of the AES project. Figure 8-6 summarizes the GHG impacts estimated for all AES projects in 2013.

13 A more detailed discussion of GHG emissions calculations is included in Appendix C.

FIGURE 8-6: ESTIMATED GREENHOUSE GAS EMISSIONS RESULTING FROM SGIP AES OPERATION



The metered data available for 2013 indicate that operation of SGIP AES projects increased GHG emissions by 37 metric tons of carbon dioxide (CO_2). Put differently, SGIP AES projects in 2013 did not use charge/discharge in ways that would have realized AES' potential to yield GHG emissions reductions via load shifting. Greenhouse gas impacts from AES projects are driven by two key metrics: round trip efficiency and time-of-use. AES projects inherently consume more energy than they are able to discharge due to inefficiencies and losses. Minimizing these losses leads to higher round trip efficiencies and increased potential for GHG emission reductions. AES project time-of-use also affects GHG impacts. In order to maximize GHG reduction potential, AES projects must charge during relatively "cleaner" hours of marginal grid operation and discharge during "dirtier" hours. Relatively low round trip efficiencies and sub-optimal time-of-use (from an environmental impacts perspective) contributed to the increased GHG emissions of AES projects in the SGIP.

8.6 Advanced Energy Storage in the Queue

The importance of AES in the SGIP will change dramatically in the coming years. There were only five AES projects completed by the end of 2013. As of September 2014, there were over 800 advanced energy storage projects that had applied for SGIP incentives. Most of these are smaller than 30 kW but seven are sized larger than one MW. Figure 8-7 shows the queued and completed AES projects. The queued advanced energy storage projects are much more likely to be relatively small, mostly under the 30 kW PBI limit. Additionally, many of the queued projects will likely be coupled to photovoltaic solar systems. These new solar-coupled storage projects are likely to behave quite differently from the four completed AES systems for which 2013 metered performance data were available.

FIGURE 8-7: QUEUED AND COMPLETED ADVANCED ENERGY STORAGE PROJECTS

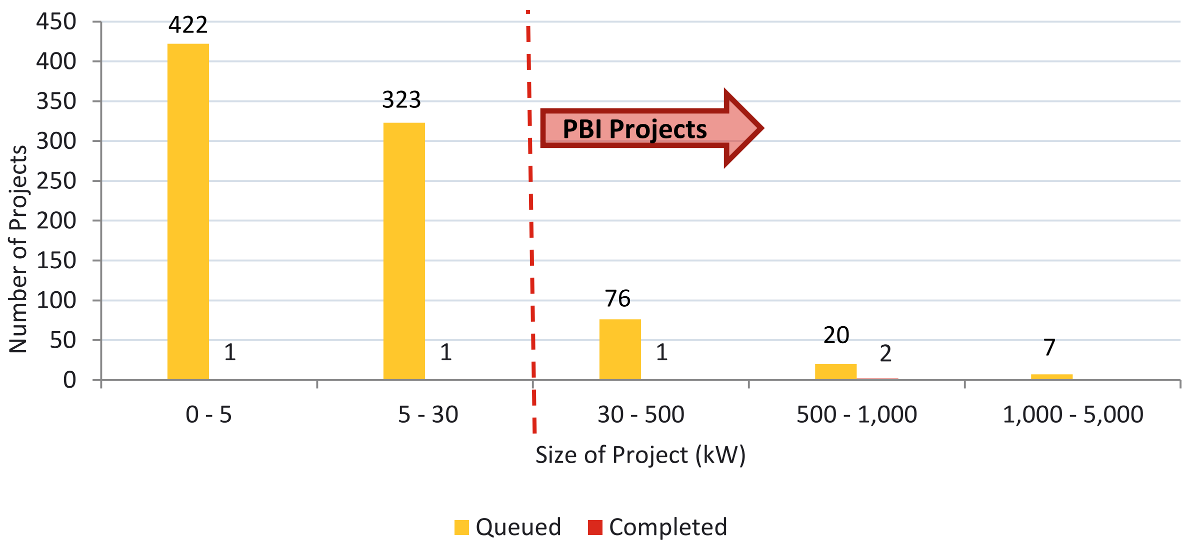
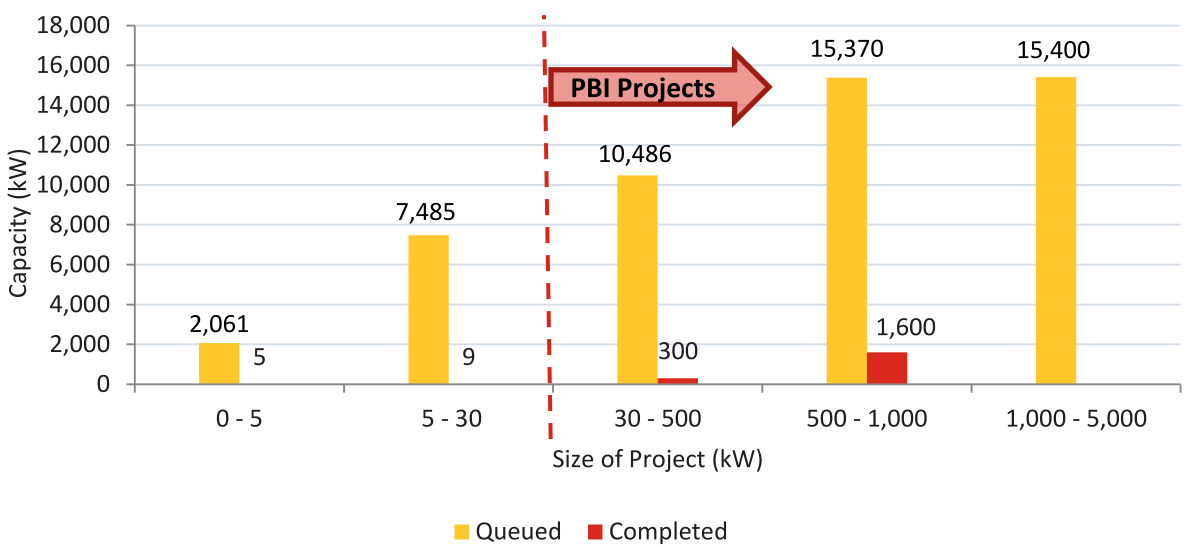


Figure 8-8 shows the queued and completed AES capacity. As seen in Figure 8-8, despite the large number of projects in the queue under the PBI threshold, a large portion of the queued capacity would be PBI projects.

FIGURE 8-8: QUEUED AND COMPLETED ADVANCED ENERGY STORAGE CAPACITY



SGIP AES projects may provide benefits through myriad different value streams including energy arbitrage to reduce consumption during peak periods, demand charge mitigation for bill savings, and societal benefits such as GHG emissions reductions. AES projects are an emerging technology and very little information on operational characteristics has been published to date. While it is important that data from these projects be disseminated rapidly, it is imperative that premature conclusions are not drawn from small, non-random, unrepresentative samples. As SGIP AES capacity increases, deep data sets that go beyond interval charge/discharge behavior will be required to fully quantify all the potential benefits that are possible through AES operation.

Appendix A

A PROGRAM STATISTICS

This appendix provides detailed Self-Generation Incentive Program (SGIP) statistics beyond the tables and figures included in Section 3.

A.1 Program Statistics end of 2013

By the end of 2013, the SGIP had paid incentives to 672 projects representing almost 330 MW of rebated capacity. Table A-1 shows counts and rebated capacities of completed projects for each Program Administrator (PA).

TABLE A-1: PROJECT COUNTS AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR

Program Administrator	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
CSE	66	35.7	10.8%
PG&E	313	128.6	39.0%
SCE	141	71.5	21.7%
SCG	152	94.2	28.5%
Total	***672***	***329.9***	***100%***

* CSE = Center for Sustainable Energy, PG&E = Pacific Gas & Electric, SCE = Southern California Edison, SCG = Southern California Gas Company

The SGIP provides incentives for a variety of different technologies. Table A-2 shows project counts and rebated capacities of completed projects by technology type.

TABLE A-2: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE

Technology Type	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
Advanced Energy Storage	5	1.9	0.6%
Fuel Cell – CHP	114	34.2	10.4%
Fuel Cell - Electric Only	124	56.4	17.1%
Gas Turbine	9	30.1	9.1%
Internal Combustion Engine	257	157.4	47.7%
Microturbine	142	25.6	7.8%
Pressure Reduction Turbine	1	0.5	0.2%
Wind Turbine	20	23.7	7.2%
Total	***672***	***329.9***	***100%***

Beginning in program year (PY) 11, the SGIP implemented an incentive structure where projects 30 kW and larger will receive half of their incentive payment upfront and the remainder of the incentive during the first five years of operation. This mechanism is known as a Performance Based Incentive (PBI). Paid projects are classified as having a capacity incentive or a PBI incentive. Table A-3 shows project counts and rebated capacities of completed projects by technology type and incentive payment mechanism.

TABLE A-3: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND PAYMENT MECHANISM

System Type	Capacity Incentive		PBI Incentive	
	MW	Count	MW	Count
Advanced Energy Storage	1.6	4	0.3	1
Fuel Cell – CHP	33.8	113	0.4	1
Fuel Cell – Electric Only	41.0	89	15.4	35
Gas Turbine	30.1	9	-	-
Internal Combustion Engine	156.5	256	1.0	1
Microturbine	25.6	142	-	-
Pressure Reduction Turbine	-	-	0.5	1
Wind Turbine	13.3	16	10.4	4
Total	***302.0***	***629***	***27.9***	***43***

In an effort to recognize significant changes in program policy, this report further classifies projects as Pre-SB412 and Post-SB412 based on their program year. Paid projects that applied to the SGIP during PY01-PY10 are classified as Pre-SB412. Paid projects that applied during or after PY11 (regardless of their incentive payment mechanism) are classified as Post-SB412. This classification scheme is intended to allow comparisons between the two groups to identify changes in project performance. Table A-4 shows project counts and rebated capacities of paid projects by technology type and Pre/Post-SB412 status.

TABLE A-4: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND PRE/POST-SB412 STATUS

System Type	Pre-SB412		Post-SB412	
	MW	Count	MW	Count
Advanced Energy Storage	1.6	2	0.3	3
Fuel Cell - CHP	33.7	110	0.5	4
Fuel Cell - Electric Only	40.5	88	15.9	36
Gas Turbine	30.1	9	-	-
Internal Combustion Engine	156.5	256	1.0	1
Microturbine	25.6	142	-	-
Pressure Reduction Turbine	-	-	0.5	1
Wind	13.3	15	10.5	5
Total	***301.3***	***622***	***28.5***	***50***

Table A-5 shows that SGIP projects are powered by a variety of renewable and non-renewable energy sources. The majority of SGIP projects are powered by non-renewable fuels such as natural gas. On-site biogas 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. Directed biogas projects purchase biogas fuel that is produced at a location other than the project site. The

'Other' energy source group includes advanced energy storage, wind turbine, and pressure reduction turbine projects. There is one pressure reduction turbine project completed in the SGIP. This project is installed at a water treatment plant and is powered by water from a nearby lake.

TABLE A-5: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND ENERGY SOURCE

System Type	Energy Source	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
Advanced Energy Storage	Other	5	1.9	0.6%
Fuel Cell - CHP	Non-Renewable	93	15.2	4.6%
	Biogas (Onsite Blended)	14	11.9	3.6%
	Biogas (Onsite Only)	1	0.3	0.1%
	Biogas (Directed)	6	6.9	2.1%
Fuel Cell - Electric Only	Non-Renewable	66	31.7	9.6%
	Biogas (Directed)	58	24.7	7.5%
Gas Turbine	Non-Renewable	9	30.1	9.1%
Internal Combustion Engine	Non-Renewable	230	140.7	42.7%
	Biogas (Onsite Blended)	7	4.4	1.3%
	Biogas (Onsite Only)	20	12.2	3.7%
Microturbine	Non-Renewable	117	20.4	6.2%
	Biogas (Onsite Blended)	4	1.0	0.3%
	Biogas (Onsite Only)	21	4.3	1.3%
Pressure Reduction Turbine	Other	1	0.5	0.2%
Wind Turbine	Other	20	23.7	7.2%
Total		***672***	***329.9***	***100%***

Combined heat and power (CHP) projects can recover useful heat to serve heating loads such as process hot water or cooling loads by use of an absorption chiller. The useful heat end use has important implications for natural gas distribution impacts and consequently greenhouse gas emissions impacts. Table A-6 summarizes the useful heat end uses observed in the SGIP.

TABLE A-6: PROJECT COUNTS AND CAPACITIES BY USEFUL HEAT END USE

Useful Heat End Use	**Project Count with Useful Heat Recovery**	**Rebated Capacity with Useful Heat Recovery (MW)**	**Percent of Rebated Capacity with Useful Heat Recovery***
Cooling Only	40	34.7	10.5%
Heating Only	368	128.8	39.1%
Cooling + Heating	88	70.0	21.2%
Total	***496***	***233.6***	***92%***

* Total project count and rebated capacity in this table excludes advanced energy storage, electric-only fuel cell, pressure reduction turbine, and wind projects.

By the end of 2013 the SGIP paid or reserved over $480 million in incentives. Eligible costs reported by applicants surpassed $1.5 billion. Table A-7 shows the breakdown of incentives paid by the SGIP and costs reported by applicants for each technology type. The leverage ratio, calculated as the ratio of SGIP participant investment to SGIP incentives, is one financial measure of the SGIP's effectiveness in accelerating development of markets for distributed energy resources.

TABLE A-7: INCENTIVES PAID, REPORTED COSTS, AND LEVERAGE RATIO BY TECHNOLOGY TYPE

System Type	Rebated Capacity (MW)	SGIP Incentive (Nominal $MM)	Eligible Costs (Nominal $ MM)	Leverage Ratio
Advanced Energy Storage	1.9	3.9	13.1	2.33
Fuel Cell - CHP	34.2	107.7	260.4	1.42
Fuel Cell - Electric Only	56.4	214.9	610.4	1.84
Gas Turbine	30.1	6.3	59.9	8.56
Internal Combustion Engine	157.4	96.2	382.3	2.97
Microturbine	25.6	22.5	85.0	2.77
Pressure Reduction Turbine	0.5	0.6	2.2	2.58
Wind Turbine	23.7	28.7	91.0	2.17
Total	***329.9***	***480.8***	***1,504.4***	***2.13***

SGIP projects are electrically interconnected to load serving entities that are either investor owned (IOU) or municipal utilities. Table A-8 shows each PA's rebated capacity by electric utility type and technology type. Almost 95 percent of rebated capacity was interconnected to investor owned electric utilities.

TABLE A-8: ELECTRIC UTILITY TYPE BY PROGRAM ADMINISTRATOR AND TECHNOLOGY TYPE

Program Administrator / Electric Utility Type		Rebated Capacity (MW)								
		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
CSE	IOU	0.0	8.0	4.9	9.1	11.2	1.9	0.5	-	***35.7***
	Municipal	-	-	-	-	-	-	-	-	**-**
PG&E	IOU	1.3	10.0	30.5	4.0	62.8	11.2	-	8.6	***128.4***
	Municipal	-	-	-	-	0.2	-	-	-	***0.2***
SCE	IOU	-	6.2	13.2	-	30.9	6.1	-	15.1	***71.5***
	Municipal	-	-	-	-	-	-	-	-	**-**
SCG	IOU	0.6	4.9	0.8	17.0	49.6	4.9	-	-	***77.8***
	Municipal	-	5.0	7.0	-	2.9	1.5	-	-	***16.4***
Total		***1.9***	***34.2***	***56.4***	***30.1***	***157.4***	***25.6***	***0.5***	***23.7***	***329.9***

A.2 Trends in Program Statistics

The date a project is issued its upfront incentive payment is used as a proxy for the date it enters normal operations and begins to accrue impacts. Table A-9 and Table A-10 show project counts and capacities by technology type and upfront payment year. Table A-9 shows annual counts and capacities while Table A-10 shows cumulative counts and capacities.

TABLE A-9: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND UPFRONT PAYMENT YEAR

Upfront Payment Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
2001	Count	-	-	-	-	-	-	-	-	**-**
	Capacity (MW)	-	-	-	-	-	-	-	-	**-**

Upfront Payment Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
2002	Count	-	1	-	-	6	3	-	-	***10***
	Capacity (MW)	-	0.2	-	-	4.0	0.3	-	-	***4.4***
2003	Count	-	-	-	-	35	21	-	-	***56***
	Capacity (MW)	-	-	-	-	22.2	2.5	-	-	***24.7***
2004	Count	-	1	-	1	51	25	-	-	***78***
	Capacity (MW)	-	0.6	-	1.4	35.2	3.9	-	-	***41.1***
2005	Count	-	3	-	1	31	33	-	2	***70***
	Capacity (MW)	-	1.8	-	1.2	19.4	5.3	-	1.6	***29.4***
2006	Count	-	7	-	2	62	27	-	-	***98***
	Capacity (MW)	-	4.0	-	9.0	36.3	5.0	-	-	***54.2***
2007	Count	-	2	-	1	23	14	-	-	***40***
	Capacity (MW)	-	1.5	-	1.4	12.7	1.7	-	-	***17.3***
2008	Count	-	6	-	1	20	11	-	-	***38***
	Capacity (MW)	-	3.9	-	4.6	13.5	3.5	-	-	***25.4***
2009	Count	-	3	2	2	9	3	-	2	***21***
	Capacity (MW)	-	2.1	0.7	8.1	4.7	1.7	-	0.3	***17.5***
2010	Count	-	6	6	-	12	3	-	4	***31***
	Capacity (MW)	-	2.0	2.2	-	5.3	0.4	-	2.8	***12.7***
2011	Count	-	56	39	-	6	1	-	2	***104***
	Capacity (MW)	-	8.1	15.6	-	3.0	0.8	-	2.1	***29.5***
2012	Count	2	24	38	1	1	1	-	4	***71***
	Capacity (MW)	1.6	6.9	20.8	4.4	0.3	0.8	-	3.6	***38.3***
2013	Count	3	5	39	-	1	-	1	6	***55***
	Capacity (MW)	0.3	3.3	17.1	-	1.0	-	0.5	13.4	***35.6***
Total	***Count***	***5***	***114***	***124***	***9***	***257***	***142***	***1***	***20***	***672***
	Capacity (MW)	***1.9***	***34.2***	***56.4***	***30.1***	***157.4***	***25.6***	***0.5***	***23.7***	***329.9***

TABLE A-10: CUMULATIVE PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND UPFRONT PAYMENT YEAR

Upfront Payment Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
2001	Count	0	0	0	0	0	0	0	0	***0***
	Capacity (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	***0.0***
2002	Count	0	1	0	0	6	3	0	0	***10***
	Capacity (MW)	0.0	0.2	0.0	0.0	4.0	0.3	0.0	0.0	***4.4***
2003	Count	0	1	0	0	41	24	0	0	***66***
	Capacity (MW)	0.0	0.2	0.0	0.0	26.1	2.7	0.0	0.0	***29.1***
2004	Count	0	2	0	1	92	49	0	0	***144***
	Capacity (MW)	0.0	0.8	0.0	1.4	61.3	6.6	0.0	0.0	***70.1***
2005	Count	0	5	0	2	123	82	0	2	***214***
	Capacity (MW)	0.0	2.6	0.0	2.6	80.7	11.9	0.0	1.6	***99.5***
2006	Count	0	12	0	4	185	109	0	2	***312***
	Capacity (MW)	0.0	6.5	0.0	11.6	117.0	16.9	0.0	1.6	***153.7***
2007	Count	0	14	0	5	208	123	0	2	***352***
	Capacity (MW)	0.0	8.0	0.0	13.0	129.7	18.6	0.0	1.6	***170.9***
2008	Count	0	20	0	6	228	134	0	2	***390***
	Capacity (MW)	0.0	11.9	0.0	17.6	143.1	22.0	0.0	1.6	***196.4***
2009	Count	0	23	2	8	237	137	0	4	***411***
	Capacity (MW)	0.0	14.0	0.7	25.7	147.8	23.7	0.0	1.9	***213.9***
2010	Count	0	29	8	8	249	140	0	8	***442***
	Capacity (MW)	0.0	16.0	2.9	25.7	153.1	24.1	0.0	4.7	***226.6***
2011	Count	0	85	47	8	255	141	0	10	***546***
	Capacity (MW)	0.0	24.0	18.5	25.7	156.1	24.9	0.0	6.8	***256.0***
2012	Count	2	109	85	9	256	142	0	14	***617***
	Capacity (MW)	1.6	30.9	39.2	30.1	156.5	25.6	0.0	10.3	***294.3***
2013	Count	5	114	124	9	257	142	1	20	***672***
	Capacity (MW)	1.9	34.2	56.4	30.1	157.4	25.6	0.5	23.7	***329.9***

A project's program year is used to determine what program rules and policies are applicable to it. Table A-11 and Table A-12 list project counts and rebated capacities by program year and technology type for projects paid on or before December 31, 2013. Table A-11 shows annual counts and capacities. Table A-12 shows cumulative counts and capacities.

TABLE A-11: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND PROGRAM YEAR

Program Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY01	Count	0	1	0	0	27	21	0	0	***49***
	Capacity (MW)	0.0	0.2	0.0	0.0	14.7	2.8	0.0	0.0	***17.7***
PY02	Count	0	1	0	1	54	17	0	0	***73***
	Capacity (MW)	0.0	0.6	0.0	1.4	36.5	2.9	0.0	0.0	***41.4***
PY03	Count	0	2	0	1	54	40	0	2	***99***
	Capacity (MW)	0.0	0.8	0.0	1.2	37.5	5.0	0.0	1.6	***46.1***
PY04	Count	0	3	0	1	49	30	0	0	***83***
	Capacity (MW)	0.0	2.3	0.0	1.4	24.6	5.7	0.0	0.0	***33.9***
PY05	Count	0	6	0	2	31	14	0	0	***53***
	Capacity (MW)	0.0	3.7	0.0	9.0	22.4	3.1	0.0	0.0	***38.2***
PY06	Count	0	7	0	3	17	13	0	0	***40***
	Capacity (MW)	0.0	5.1	0.0	12.7	11.2	4.1	0.0	0.0	***33.1***
PY07	Count	0	2	1	1	24	7	0	2	***37***
	Capacity (MW)	0.0	0.8	0.4	4.4	9.6	2.1	0.0	1.2	***18.4***
PY08	Count	0	6	0	0	0	0	0	1	***7***
	Capacity (MW)	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.2	***0.9***
PY09	Count	1	18	8	0	0	0	0	3	***30***
	Capacity (MW)	1.0	7.3	2.7	0.0	0.0	0.0	0.0	1.6	***12.6***
PY10	Count	1	64	79	0	0	0	0	7	***151***
	Capacity (MW)	0.6	12.4	37.4	0.0	0.0	0.0	0.0	8.6	***59.0***

Program Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY11	Count	1	2	13	0	0	0	0	5	***21***
	Capacity (MW)	0.0	0.4	7.3	0.0	0.0	0.0	0.0	10.5	***18.2***
PY12	Count	2	2	22	0	1	0	1	0	***28***
	Capacity (MW)	0.3	0.1	7.9	0.0	1.0	0.0	0.5	0.0	***9.7***
PY13	Count	0	0	1	0	0	0	0	0	***1***
	Capacity (MW)	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	***0.6***
Total	***Count***	***5***	***114***	***124***	***9***	***257***	***142***	***1***	***20***	***672***
	Capacity (MW)	***1.9***	***34.2***	***56.4***	***30.1***	***157.4***	***25.6***	***0.5***	***23.7***	***329.9***

TABLE A-12: CUMULATIVE PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND PROGRAM YEAR

Program Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY01	Count	0	1	0	0	27	21	0	0	**49**
	Capacity (MW)	0.0	0.2	0.0	0.0	14.7	2.8	0.0	0.0	**17.7**
PY02	Count	0	2	0	1	81	38	0	0	**122**
	Capacity (MW)	0.0	0.8	0.0	1.4	51.3	5.7	0.0	0.0	**59.1**
PY03	Count	0	4	0	2	135	78	0	2	**221**
	Capacity (MW)	0.0	1.6	0.0	2.6	88.8	10.7	0.0	1.6	**105.2**
PY04	Count	0	7	0	3	184	108	0	2	**304**
	Capacity (MW)	0.0	3.8	0.0	4.0	113.3	16.3	0.0	1.6	**139.1**
PY05	Count	0	13	0	5	215	122	0	2	**357**
	Capacity (MW)	0.0	7.5	0.0	13.0	135.7	19.5	0.0	1.6	**177.3**
PY06	Count	0	20	0	8	232	135	0	2	**397**
	Capacity (MW)	0.0	12.6	0.0	25.7	146.9	23.6	0.0	1.6	**210.5**

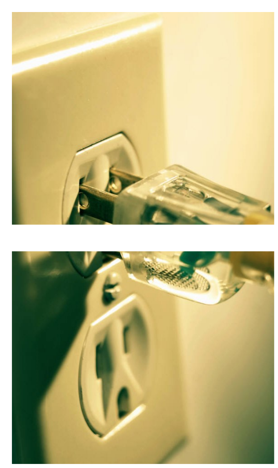
Program Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY07	Count	0	22	1	9	256	142	0	4	**434**
	Capacity (MW)	0.0	13.4	0.4	30.1	156.5	25.6	0.0	2.9	**228.9**
PY08	Count	0	28	1	9	256	142	0	5	**441**
	Capacity (MW)	0.0	14.0	0.4	30.1	156.5	25.6	0.0	3.1	**229.8**
PY09	Count	1	46	9	9	256	142	0	8	**471**
	Capacity (MW)	1.0	21.3	3.1	30.1	156.5	25.6	0.0	4.7	**242.3**
PY10	Count	2	110	88	9	256	142	0	15	**622**
	Capacity (MW)	1.6	33.7	40.5	30.1	156.5	25.6	0.0	13.3	**301.3**
PY11	Count	3	112	101	9	256	142	0	20	**643**
	Capacity (MW)	1.6	34.1	47.8	30.1	156.5	25.6	0.0	23.7	**319.5**
PY12	Count	5	114	123	9	257	142	1	20	**671**
	Capacity (MW)	1.9	34.2	55.7	30.1	157.4	25.6	0.5	23.7	**329.2**
PY13	Count	5	114	124	9	257	142	1	20	**672**
	Capacity (MW)	1.9	34.2	56.4	30.1	157.4	25.6	0.5	23.7	**329.9**

Table A 13 lists incentives, total eligible costs, and leverage ratios by program year and technology type.

TABLE A-13: INCENTIVES, COSTS, AND LEVERAGE RATIO BY PROGRAM YEAR AND TECHNOLOGY TYPE

Program Year / Incentive, Cost, and Leverage (MM Nominal $)		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY01	Incentive	0.00	0.50	0.00	0.00	9.04	2.22	0.00	0.00	11.76
	Cost	0.00	3.60	0.00	0.00	30.71	8.14	0.00	0.00	42.45
	Leverage	N/A	6.20	N/A	N/A	2.40	2.67	N/A	N/A	2.61
PY02	Incentive	0.00	1.50	0.00	0.81	20.67	2.33	0.00	0.00	25.31
	Cost	0.00	4.26	0.00	3.73	81.12	8.41	0.00	0.00	97.53
	Leverage	N/A	1.84	N/A	3.61	2.92	2.61	N/A	N/A	2.85
PY03	Incentive	0.00	3.38	0.00	1.00	21.54	4.78	0.00	2.63	33.33
	Cost	0.00	7.28	0.00	4.69	81.33	17.41	0.00	5.38	116.09
	Leverage	N/A	1.16	N/A	3.69	2.78	2.64	N/A	1.04	2.48
PY04	Incentive	0.00	5.58	0.00	1.00	16.86	5.07	0.00	0.00	28.51
	Cost	0.00	16.97	0.00	7.18	61.53	17.50	0.00	0.00	103.19
	Leverage	N/A	2.04	N/A	6.18	2.65	2.45	N/A	N/A	2.62
PY05	Incentive	0.00	7.89	0.00	1.05	12.13	2.85	0.00	0.00	23.92
	Cost	0.00	22.46	0.00	13.30	53.58	11.62	0.00	0.00	100.96
	Leverage	N/A	1.85	N/A	11.64	3.42	3.08	N/A	N/A	3.22
PY06	Incentive	0.00	19.46	0.00	1.80	6.96	3.28	0.00	0.00	31.50
	Cost	0.00	37.43	0.00	29.57	29.78	14.08	0.00	0.00	110.86
	Leverage	N/A	0.92	N/A	15.43	3.28	3.29	N/A	N/A	2.52
PY07	Incentive	0.00	2.00	1.00	0.60	6.61	2.02	0.00	1.84	14.07
	Cost	0.00	4.47	3.85	1.38	34.30	7.88	0.00	6.35	58.24
	Leverage	N/A	1.24	2.85	1.30	4.19	2.90	N/A	2.46	3.14

Program Year / Incentive, Cost, and Leverage (MM Nominal $)		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY08	Incentive	0.00	2.78	0.00	0.00	0.00	0.00	0.00	0.26	3.03
	Cost	0.00	5.98	0.00	0.00	0.00	0.00	0.00	0.35	6.33
	Leverage	N/A	1.16	N/A	N/A	N/A	N/A	N/A	0.34	1.09
PY09	Incentive	2.00	23.54	11.50	0.00	0.00	0.00	0.00	2.41	39.45
	Cost	6.49	62.49	30.51	0.00	0.00	0.00	0.00	5.14	104.62
	Leverage	2.25	1.65	1.65	N/A	N/A	N/A	N/A	1.14	1.65
PY10	Incentive	1.20	40.02	159.16	0.00	0.00	0.00	0.00	12.08	212.47
	Cost	5.17	90.73	387.27	0.00	0.00	0.00	0.00	33.46	516.62
	Leverage	3.30	1.27	1.43	N/A	N/A	N/A	N/A	1.77	1.43
PY11	Incentive	0.01	0.91	20.66	0.00	0.00	0.00	0.00	9.47	31.05
	Cost	0.03	3.98	89.02	0.00	0.00	0.00	0.00	40.36	133.38
	Leverage	1.85	3.36	3.31	N/A	N/A	N/A	N/A	3.26	3.30
PY12	Incentive	0.73	0.11	21.13	0.00	2.38	0.00	0.63	0.00	24.97
	Cost	1.44	0.76	91.63	0.00	9.93	0.00	2.24	0.00	106.00
	Leverage	0.97	5.78	3.34	N/A	3.18	N/A	2.58	N/A	3.25
PY13	Incentive	0.00	0.00	1.47	0.00	0.00	0.00	0.00	0.00	1.47
	Cost	0.00	0.00	8.12	0.00	0.00	0.00	0.00	0.00	8.12
	Leverage	N/A	N/A	4.51	N/A	N/A	N/A	N/A	N/A	4.51
Total	***Incentive***	***3.94***	***107.67***	***214.93***	***6.26***	***96.18***	***22.55***	***0.63***	***28.69***	***480.85***
	Cost	***13.13***	***260.41***	***610.39***	***59.86***	***382.30***	***85.04***	***2.24***	***91.03***	***1,504.38***
	Leverage	***2.33***	***1.42***	***1.84***	***8.56***	***2.97***	***2.77***	***2.58***	***2.17***	***2.13***



Appendix B

B ENERGY IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix provides additional detail about the metered data and the ratio estimation methodology used to quantify the energy impacts of the Self-Generation Incentive Program (SGIP) in this evaluation report. This appendix also includes energy and peak demand impacts detail not shown in Section 5 and Section 6.

B.1 Metered Data

Additional descriptions of the metered electricity generation, fuel consumption, and useful heat recovery data that form the basis of this impacts evaluation is presented below

Electric Net Generator Output (NGO) Data

Metered electric NGO data provide information on the amount of electricity generated by SGIP projects net of ancillary loads such as pumps and compressors. These data (typically recorded at 15-minute intervals, but sometimes at hourly or longer intervals) determine energy and demand impacts from SGIP projects.

Electric NGO data are collected from a variety of sources, including meters installed by Itron and its subcontractors under the direction of the PAs, and meters installed by project hosts, applicants, electric utilities, and third parties. Because many different meters are in use among the many different providers, these electric NGO data arrive in a wide variety of data formats. Some formats require processing to be associated with the correct project and put into a format common to all projects. During processing to the common format all electric NGO data pass through a rigorous quality control review. Only data that pass the review are accepted for use in this evaluation.

Fuel Consumption Data

Fuel consumption data are used in this impacts evaluation to determine system efficiencies and to estimate greenhouse gas (GHG) emission impacts. To date, fuel consumption data collection activities have focused exclusively on consumption of natural gas by SGIP projects. In the future it may also be necessary to monitor consumption of gaseous renewable fuel (i.e., biogas) to more accurately asses the impacts of SGIP projects using blends of renewable and non-renewable fuels.

Fuel consumption data used in this impacts evaluation are obtained mostly from natural gas metering systems installed on SGIP projects by natural gas distribution companies, SGIP participants, or by third parties. Itron reviews fuel consumption data and documents their bases prior to processing the data into a common data format. Quality control reviews of fuel consumption data include merging fuel consumption and electric NGO data to check for reasonableness of gross electrical conversion efficiency. In cases where validity checks fail, data providers are contacted to further refine the basis of data. In some cases it is determined that the data are for a host customer's entire facility rather than from metering dedicated to the SGIP projects. These facility-level data are excluded from impacts analysis.

Most fuel consumption data are reported in intervals much greater than one hour (e.g., in daily or monthly intervals). These fuel data enable calculation of monthly and annual efficiencies but are not used to estimate performance for shorter intervals.

Useful Heat Recovery Data

Useful heat recovery is the thermal energy captured by heat recovery equipment and used to satisfy heating and/or cooling loads at the SGIP project site. Useful heat recovery data are used to assess overall efficiencies of SGIP projects. In addition, useful heat recovery data for SGIP projects enable estimation of baseline electricity and natural gas use that would otherwise have been purchased from the utility companies. This baseline information is used in the calculation of GHG emission impact estimates. Heat recovery data are collected from metering systems installed by Itron as well as metering systems installed by applicants, hosts, and third parties.

Over the course of the SGIP, the approach for collecting useful heat recovery data has changed. Useful heat recovery data collection historically has involved installation of invasive monitoring equipment (i.e., insertion-type flow meters). Many third parties had this type of equipment installed at the time the SGIP project was commissioned, either as part of their contractual agreement with a third-party vendor or as part of an internal process/energy monitoring plan. In numerous cases, Itron obtains useful heat recovery data metered by others in an effort to minimize both the cost and disruption of installing useful heat recovery monitoring equipment. The majority of useful heat recovery data for years 2003 and 2004 were obtained in this manner.

Itron began installing useful heat recovery metering in the summer of 2003 for SGIP projects that were included in the sample design but for which data were not available. As the useful heat recovery data collection effort grew, it became clear that we could no longer rely on data from third-party or host customer metering. In numerous instances agreements and plans concerning these data did not yield valid data for analysis. Uninterrupted collection and validation of useful heat recovery data was labor-intensive and required examination of the data by more expert staff, thereby increasing costs. In addition, reliance on useful heat recovery data collected by SGIP host customers and third parties created evaluation schedule impacts and other risks that more than outweighed the benefits of not having to install new metering.

In mid-2006, Itron responded to the useful heat recovery data issues by changing the approach to collection of useful heat recovery data. We continued to collect useful heat recovery data from program participants in those instances where valid data could be obtained easily and reliably. For all other projects selected for metered data collection, we installed useful heat recovery metering systems ourselves. These systems utilized non-invasive components such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications to reduce the time and disruption of the installations and to increase data communication reliability. The increase in equipment costs was offset by the decrease in installation time and a decrease in maintenance problems.

B.2 Impacts Estimation Methodology

An overview of the ratio estimation methodology was included in Section 4.4. The strata included in the ratio analysis for electricity generation values were presented in Table 4-1, and are also listed below:

1. Technology type
2. Operational status
3. Program incentive structure (pre SB412 and post SB412)
4. Warranty status (under corresponding handbook)
5. Fuel type
6. Capacity size category
7. PA

The ratio estimation methodology works well when metered data are available in each stratum. In a limited number of cases, lack of metered data for certain strata necessitated use of more general strata. For these estimates the criteria of matching hours and/or project characteristics is relaxed. The relaxation begins with inclusion of other hours, daytime or night, from the same date. If fewer than five projects have metered data during those hours, the relaxation continues to any hours on the same date. If still fewer than five projects have metered data during that date, the hours are allowed to include the same hour in similar days, weekend or weekday, of the same week. The hours included continue to expand ultimately to include the entire month. If still fewer than five projects have metered data in that month, systems with a different PA are allowed and the hours then are contracted to the same hour on weekends or weekdays in that month. The cycle of expansion of allowed hours then repeats. All estimates include the same technology type and warranty status.

B.3 Energy Impacts

The following tables summarize program energy impacts for 2013. Some tables include earlier years with 2013 to demonstrate observed trends in impacts.

Table B-1 lists 2013 annual electrical energy impact by technology type as well as associated annual capacity factor.

TABLE B-1: 2013 ELECTRIC ENERGY IMPACT AND CAPACITY FACTOR BY TECHNOLOGY TYPE

Technology Type	Annual Electricity Generated (GWh)	Annual Capacity Factor
Fuel Cell – CHP	147.0	0.52
Fuel Cell - Electric Only	311.9	0.74
Gas Turbine	204.1	0.77
Internal Combustion Engine	277.4	0.20
Microturbine	62.1	0.28
Pressure Reduction Turbine	0.6	0.64
Wind Turbine	42.5	0.22
Total	***1,046***	***0.38***

Table B-2 lists 2013 annual electrical energy impact by technology and energy source as well as the associated annual capacity factor.

TABLE B-2: 2013 ELECTRIC ENERGY IMPACT AND CAPACITY FACTOR BY TECHNOLOGY AND ENERGY SOURCE

Technology Type	Energy Source	Annual Electricity Generated (MWh)	Annual Capacity Factor
Fuel Cell – CHP	Non-Renewable	58,874	0.46
	Renewable	88,122	0.56
Fuel Cell - Electric Only	Non-Renewable	161,061	0.77
	Renewable	150,849	0.71
Gas Turbine	Non-Renewable	204,092	0.77
Internal Combustion Engine	Non-Renewable	233,676	0.19
	Renewable	43,772	0.33
Microturbine	Non-Renewable	56,546	0.31
	Renewable	5,525	0.14
PRT	Other	575	0.64
Wind Turbine	Other	42,522	0.22
Total		***1,045,614***	***0.38***

Table B-3 lists 2013 annual electrical energy impact by Program Administrator, technology type, and energy source.

TABLE B-3: 2013 ELECTRIC ENERGY IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND PROGRAM ADMINISTRATOR

Technology Type / Energy Source		Electric Energy Impact (GWh)				
		Program Administrator				Total
		CSE	PG&E	SCE	SCG	
Fuel Cell – CHP	Non-Renewable	5.4	35.8	3.6	14.1	58.9
	Renewable	34.1	10.3	20.5	23.2	88.1
	All	***39.5***	***46.1***	***24.1***	***37.3***	***147.0***
Fuel Cell – Electric Only	Non-Renewable	18.7	91.8	33.4	17.2	161.1
	Renewable	10.6	74.4	42.7	23.2	150.8
	All	***29.2***	***166.2***	***76.1***	***40.4***	***311.9***
Gas Turbine	Non-Renewable	74.4	11.2	0.0	118.4	204.1
	All	***74.4***	***11.2***	***0.0***	***118.4***	***204.1***
Internal Combustion Engine	Non-Renewable	2.6	99.1	43.8	88.2	233.7
	Renewable	3.7	17.3	12.3	10.5	43.8
	All	***6.3***	***116.4***	***56.1***	***98.7***	***277.4***
Microturbine	Non-Renewable	1.2	34.4	5.8	15.2	56.5
	Renewable	0.6	2.3	2.7	0.0	5.5
	All	***1.7***	***36.7***	***8.5***	***15.2***	***62.1***
Pressure Reduction Turbine	Renewable	0.6	0.0	0.0	0.0	0.6
	All	***0.6***	***0.0***	***0.0***	***0.0***	***0.6***
Wind	Renewable	0.0	14.0	28.5	0.0	42.5
	All	***0.0***	***14.0***	***28.5***	***0.0***	***42.5***
Non-Renewable		102.2	272.2	86.6	253.2	***714.2***
Renewable		49.5	118.3	106.6	56.9	***331.4***
Grand Total		***151.7***	***390.6***	***193.2***	***310.0***	***1,045.6***

Table B-4 lists 2013 annual electrical energy impact by technology type and system age.

TABLE B-4: 2013 ELECTRIC ENERGY IMPACT BY TECHNOLOGY AND SYSTEM AGE

Technology Type/ Project Age	2013 Electric Energy Impact (MWh)												
	11	10	9	8	7	6	5	4	3	2	1	0	All
Fuel Cell – CHP	0.1	--	--	7.8	8.9	5.2	7.2	8.0	13.7	48.9	37.6	9.54	147
Fuel Cell - Electric Only	--	--	--	--	--	--	--	4.1	14.3	93.2	140	60.8	312
Gas Turbine	--	--	--	0.8	71.3	10.4	38.8	54.0	--	--	28.8	--	204
Internal Combustion Engine	3.6	19.4	38.2	31.7	93.9	14.8	38.9	13.4	11.2	11.3	0.8	0.4	274
Micro-turbine	--	2.6	4.7	12.4	13.0	3.8	9.9	6.2	1.8	5.1	2.6	--	62.1
Pressure Reduction Turbine	--	--	--	--	--	--	--	--	--	--	--	0.6	0.6
Wind	--	--	--	3.5	--	--	--	0.4	4.8	2.2	6.6	25.1	42.5
Total	***3.8***	***22.0***	***42.9***	***56.2***	***187***	***34.2***	***94.8***	***86.0***	***45.7***	***161***	***216***	***96.4***	***1,046***

Table B-5 lists annual electrical energy impact from 2003 through 2013 by energy source. Wind and pressure reduction turbine impacts are included as renewable.

TABLE B-5: 2003-2013 ANNUAL ELECTRIC ENERGY IMPACT BY ENERGY SOURCE (GWH)

Energy Source	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Non-Renewable	64.9	182	303	388	486	463	573	570	565	640	714
Renewable	2.3	7.3	15.0	23.1	46.8	58.4	49.3	72.5	150	268	331
Total	***67.2***	***190***	***318***	***411***	***533***	***521***	***623***	***642***	***715***	***908***	***1,046***

Table B-6 lists annual electrical energy impact from 2003 through 2013 by Pre-/Post-SB412 status.

TABLE B-6: 2003-2013 ANNUAL ELECTRIC ENERGY IMPACT BY PROGRAM CATEGORY (GWH)

Program Category	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Pre-SB412	67.2	190	318	411	533	521	623	642	715	906	966
Post-SB412										2.8	79.6
Total	***67.2***	***190***	***318***	***411***	***533***	***521***	***623***	***642***	***715***	***908***	***1,046***

Table B-7 lists 2013 annual LHV efficiencies by technology type. These efficiencies are derived from electricity generated, useful heat recovered, and fuel consumed.

TABLE B-7: 2013 EFFICIENCIES BY TECHNOLOGY TYPE

Technology Type	Electrical Efficiency (LHV)	Thermal Efficiency (LHV)	Overall Efficiency (LHV)
Fuel Cell – Combined Heat & Power	38%	23%	61%
Fuel Cell – Electric Only	53%	0%	53%
Gas Turbine	36%	37%	73%
Internal Combustion Engine	29%	24%	53%
Microturbine	23%	14%	37%

Table B-8 lists 2013 heat recovery and natural gas distribution system impact by Program Administrator and technology type.

TABLE B-8: 2013 HEAT RECOVERY AND NATURAL GAS DISTRIBUTION SYSTEM IMPACT

PA	Technology Type	Gross Gas Consumption (Million Therms HHV)	Heat Recovered (Million Therms)	Avoided Consumption through Heat Recovery (Million Therms HHV)	Net Consumptio n (Million Therms HHV)
CSE	Fuel Cell – Combined Heat & Power	3.67	0.11	0.11	3.56
	Fuel Cell - Electric Only	1.98	-	-	1.98
	Gas Turbine	7.96	2.65	0.79	7.17
	Internal Combustion Engine	0.32	0.05	0.05	0.27
	Microturbine	0.20	2.83	0.02	0.18
	Total	***14.14***	***2.83***	***0.96***	***13.17***
PG&E	Fuel Cell – Combined Heat & Power	3.43	0.83	1.00	2.44
	Fuel Cell - Electric Only	13.46	-	-	13.46
	Gas Turbine	1.18	0.40	0.27	0.92
	Internal Combustion Engine	12.80	3.07	3.14	9.65
	Microturbine	5.55	0.69	0.79	4.77
	Total	***36.44***	***4.98***	***5.20***	***31.24***
SCE	Fuel Cell – Combined Heat & Power	0.94	0.07	0.09	0.85
	Fuel Cell - Electric Only	5.25	-	-	5.25
	Gas Turbine	-	-	-	-
	Internal Combustion Engine	5.72	1.31	1.16	4.57
	Microturbine	0.94	0.11	0.12	0.82
	Total	***12.85***	***1.50***	***1.37***	***11.49***
SCG	Fuel Cell – Combined Heat & Power	1.33	0.29	0.25	1.08
	Fuel Cell - Electric Only	2.87	-	-	2.87
	Gas Turbine	12.32	4.23	3.41	8.90
	Internal Combustion Engine	11.35	2.66	1.79	9.56
	Microturbine	2.53	0.37	0.28	2.26
	Total	***30.40***	***7.55***	***5.73***	***24.67***

B.4 Peak Demand Impacts

The following tables summarize program demand impacts for 2013. Demand impacts include CAISO- and IOU-level impacts. CAISO impacts include all systems. IOU impacts include systems with electrical service from an IOU. Impacts are described for both the single peak load hour and the top 200 load hours. Some tables include earlier years with 2013 to demonstrate observed trends in impacts.

Table B-9 lists 2013 CAISO peak load hour demand impact and capacity factor as well as top 200 load hour mean demand impact and mean capacity factor.

TABLE B-9: 2013 CAISO PEAK DEMAND IMPACT AND CAPACITY FACTOR BY TECHNOLOGY TYPE

Technology Type	CAISO Peak Hour Demand Impact (MW)	CAISO Peak Hour Capacity Factor	CAISO Top 200 Hour Mean Demand Impact (MW)	CAISO Top 200 Mean Capacity Factor
Fuel Cell – Combined Heat & Power	17.0	0.53	16.4	0.49
Fuel Cell - Electric Only	34.4	0.70	36.9	0.73
Gas Turbine	24.7	0.82	24.1	0.80
Internal Combustion Engine	38.0	0.24	35.0	0.22
Microturbine	6.8	0.26	6.4	0.25
Wind Turbine	5.8	0.24	5.4	0.23
Total	***126.6***	***0.40***	***124.2***	***0.39***

Table B-10 lists 2003-2013 CAISO peak load hour demand impact and capacity factor as well as associated system counts and capacity in place at the peak load hour.

TABLE B-10: 2003-2013 CAISO PEAK HOUR SYSTEM COUNT, CAPACITY, DEMAND IMPACT, AND CAPACITY FACTOR

Metric	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
System Count	38	119	184	270	343	375	401	424	508	597	643
Capacity (MW)	15.4	55.9	87.8	131.7	166.0	187.3	206.9	218.4	243.8	276.3	316.5
Impact (MW)	10.2	32.4	54.6	61.0	74.5	74.7	86.0	89.4	97.3	118.6	126.6
Capacity Factor	0.66	0.58	0.62	0.46	0.45	0.40	0.42	0.41	0.40	0.43	0.40

Table B-11 lists 2013 IOU peak load hour demand impact by technology type.

TABLE B-11: 2013 IOU PEAK HOUR DEMAND IMPACT BY TECHNOLOGY TYPE (MW)

Technology Type	PG&E	SCE	SDG&E
Fuel Cell – Combined Heat & Power	4.6	5.4	4.9
Fuel Cell – Electric Only	19.2	11.2	3.8
Gas Turbine	1.2	15.3	8.1
Internal Combustion Engine	15.9	16.2	1.8
Microturbine	3.9	2.0	0.2
Wind Turbine	2.0	2.2	-
Total	***46.8***	***52.2***	***18.8***

Table B-12 lists 2013 IOU peak load hour capacity factor by technology type.

TABLE B-12: 2013 IOU PEAK HOUR CAPACITY FACTOR BY TECHNOLOGY TYPE

Technology Type	PG&E	SCE	SDG&E
Fuel Cell – Combined Heat & Power	0.45	0.49	0.61
Fuel Cell – Electric Only	0.70	0.80	0.78
Gas Turbine	0.30	0.90	0.89
Internal Combustion Engine	0.24	0.21	0.14
Microturbine	0.34	0.18	0.10
Wind Turbine	0.24	0.15	-

Appendix C

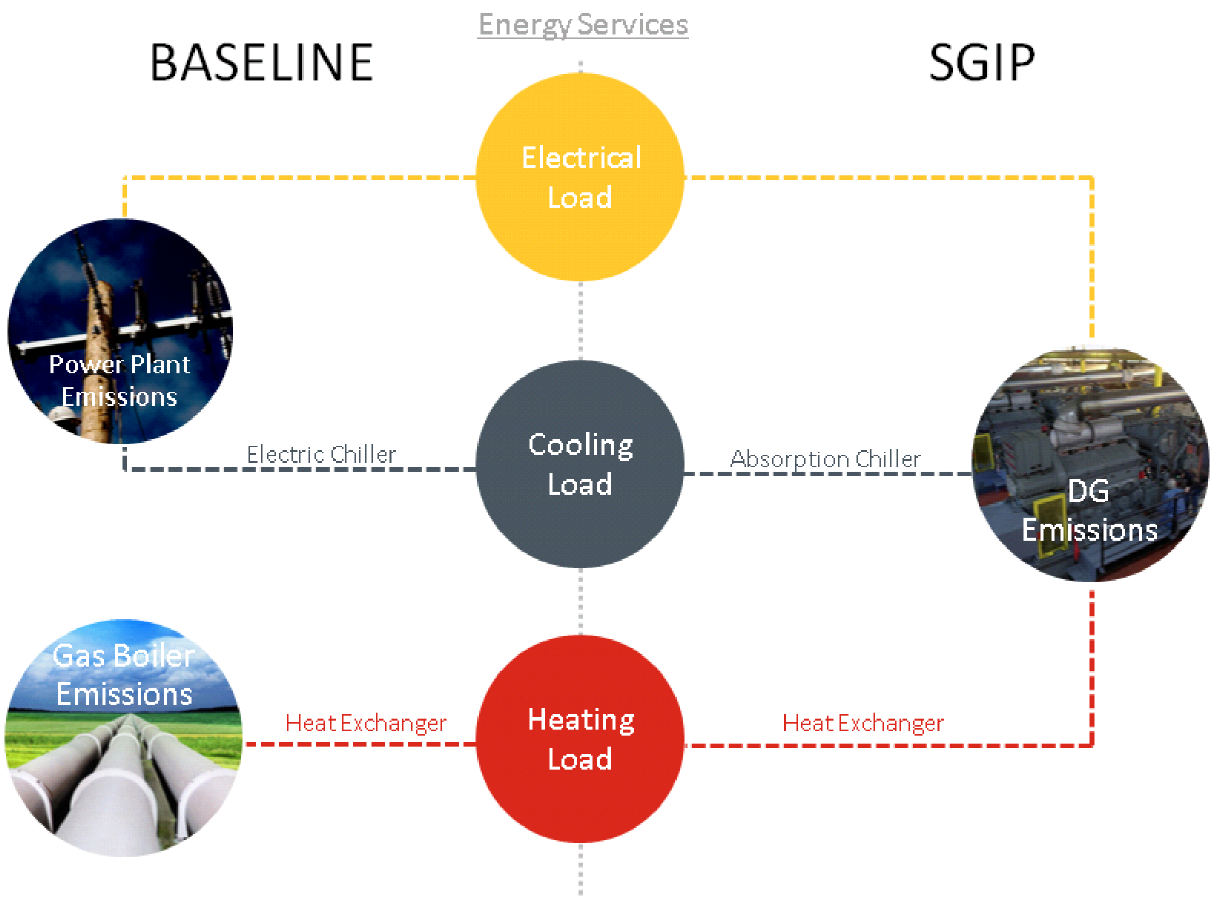
C GREENHOUSE GAS IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of Self-Generation Incentive Program (SGIP) projects. The GHGs considered in this analysis are limited to carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants that are potentially affected by the operation of SGIP projects.

C.1 Overview

Figure C-1 shows each component of the GHG impacts calculation and is described below along with the variable name used in equations presented later.

FIGURE C-1: GREENHOUSE GAS IMPACTS SUMMARY SCHEMATIC



Hourly GHG impacts are calculated for each SGIP project as the difference between the GHG emissions produced by the rebated distributed generation (DG) project and baseline GHG emissions. Baseline

GHG emissions are those that would have occurred in the absence of the SGIP project. SGIP projects displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases. SGIP projects powered by biogas may reduce emissions of CH_4 in cases where venting of the biogas directly to the atmosphere would have occurred in the absence of the SGIP project.

SGIP Project CO_2 Emissions (sgipGHG)

The operation of renewable and non-renewable fueled DG projects (excluding wind and PRT) emits CO_2 as a result of combustion/conversion of the fuel powering the project. Hour-by-hour emissions of CO_2 from SGIP projects are estimated based on their electricity generation and fuel consumption throughout the year.

Electric Power Plant CO_2 Emissions (basePpEngo)

When in operation, power generated by all SGIP projects directly displaces electricity that in the absence of the SGIP would have been generated by a central station power plant to satisfy the site's electrical loads.[1] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The avoided CO_2 emissions for these baseline conventional power plants are estimated on an hour-by-hour basis over all 8,760 hours of the year.[2] The estimates of electric power plant CO_2 emissions are based on a methodology developed by Energy + Environmental Economics, Inc. (E3) and made publicly available on its website as part of its avoided cost calculator.[3]

CO_2 Emissions Associated with Cooling Services (basePpChiller)

SGIP projects delivering recovered heat to absorption chillers are assumed to reduce the need to operate on-site electric chillers using electricity purchased from the utility company. Baseline CO_2 emissions associated with electric chiller operations are calculated based on estimates of hourly chiller operations and on the electric power plant CO_2 emissions methodology described previously.

1 In this analysis, GHG emissions from SGIP projects are compared only to GHG emissions from utility power generation that could be subject to economic dispatch (i.e., central station natural gas-fired combined cycle facilities and simple cycle gas turbine peaking plants). It is assumed that operation of SGIP projects has no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP projects to nuclear or hydroelectric facilities is not made as neither of these technologies is subject to dispatch.

2 Consequently, during those hours when an SGIP project is idle, displacement of CO_2 emissions from central station power plants is equal to zero.

3 Energy + Environmental Economics, Inc. Methodology and Forecasting of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs. For the California Public Utilities Commission. October 25, 2004. http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

CO_2 Emissions Associated with Heating Services (baseBlr)

Recovered useful heat may displace natural gas that would have been used in the absence of the SGIP to fuel boilers to satisfy site heating loads. This displaces accompanying CO_2 emissions from the boiler's combustion process.[4]

CO_2 Emissions from Biogas Treatment (baseBio)

Biogas-powered SGIP projects capture and use CH_4 that otherwise may have been emitted to the atmosphere (vented), or captured and burned, producing CO_2 (flared). A flaring baseline was assumed for all facilities except dairies. Flaring was assumed to have the same degree of combustion as SGIP prime movers.

GHG impacts expressed in terms of CO_2 equivalent (CO_2eq)[5] were calculated by date and time (hereafter referred to as "hour") as:

$$\Delta GHG_{i,h} = sgipGHG_{i,h} - (basePpEngo_{i,h} + basePpChiller_{i,h} + baseBlr_{i,h} + baseBio_{i,h})$$

Where:

$\Delta GHG_{i,h}$ is the GHG impact for SGIP project *I* for hour *h*

Units: Metric Tons CO_2eq / hr

Negative GHG impacts (*ΔGHG*) indicate reduction in GHG emissions. Not all SGIP projects include all of the above variables. Inclusion is determined by the SGIP DG technology and fuel types and is discussed further in Sections C.2 and C.3. Section C.2 describes GHG emissions from SGIP projects (*sgipGHG*), as well as heating and cooling services associated with combined heat and power (CHP) projects. In Section C.3, baseline GHG emissions are described in detail.

C.2 SGIP Project GHG Emissions (sgipGHG)

SGIP projects that consume natural gas or renewable biogas emit CO_2. CO_2 emission rates for the SGIP projects that use gaseous fuel were calculated as:

$$(CO_2)_T = \left(\frac{3412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{1\ ft^3 CH_4}{935\ Btu}\right)\left(\frac{1\ lbmole\ of\ CH_4}{379\ ft^3}\right)\left(\frac{1\ lbmole\ of\ CO_2}{1\ lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{1\ lbmole\ of\ CO_2}\right)$$

Where:

$(CO_2)_T$ is the CO_2 emission rate for technology T.

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4 Since virtually all carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in this baseline component.

5 Carbon dioxide equivalency describes, for a given mixture and amount of greenhouse gas, the amount of CO_2 that would have the same global warming potential (GWP), when measured over a specific time period (100 years). This approach must be used to accommodate cases where the assumed baseline is venting of CH_4 to the atmosphere directly.

Units: lbs CO_2 / kWh

EFF_T is the electrical efficiency of technology T.

Value: Measured value, dependent on technology type (see Table C-1)

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV) metered data collected from SGIP projects.

TABLE C-1: ELECTRICAL EFFICIENCY BY TECHNOLOGY TYPE USED FOR GHG EMISSIONS CALCULATION

Technology Type (T)	Electrical Efficiency (EFF_T)
Fuel Cell – Combined Heat and Power	0.39
Fuel Cell – Electric Only	0.53
Gas Turbine	0.35
Internal Combustion Engine	0.30
Microturbine	0.23

The technology-specific emissions rates were calculated to account for CO_2 emissions from SGIP projects. When multiplied by the electricity generated by these projects, the results represent hourly CO_2 emissions in pounds, which are then converted to metric tons, as shown in the equation below.

$$sgipGHG_{i,h} = \left((CO_2)_T \cdot engohr_{i,h}\right)\left(\frac{1\ metric\ ton\ of\ CO_2}{2{,}205\ lbs\ of\ CO_2}\right)$$

Where:

$sgipGHG_{i,h}$ is the CO_2 emitted by SGIP project *i* during hour *h*.

Units: Metric ton / hr

$engohr_{i,h}$ is the electrical output of SGIP project *i* during hour *h.*

Units: kWh

Basis: Metered data collected from SGIP projects net of any parasitic losses.

C.3 Baseline GHG Emissions

The following description of baseline operations covers three areas. The first is the GHG emissions from electric power plants that would have been required to operate more in the SGIP's absence. These emissions correspond to electricity that was generated by SGIP projects, as well as to electricity that would have been consumed by electric chillers to satisfy cooling loads discussed in the previous section. Second, the GHG emissions from natural gas boilers that would have operated more to satisfy heating load discussed in the previous section. Third, the GHG emissions corresponding to biogas that would otherwise have been flared (CO_2) or vented in to the atmosphere (CH_4).

Central Station Electric Power Plant GHG Emissions (basePpEngo & basePpChiller)

This section describes the methodology used to calculate CO_2 emissions from electric power plants that would have occurred to satisfy the electrical loads served by the SGIP project in the absence of the program. The methodology involves combining emission rates (in metric tons of CO_2 per kWh of electricity generated) that are service territory- and hour-specific with information about the quantity of electricity either generated by SGIP projects or displaced by absorption chillers operating on heat recovered from SGIP CHP projects.

The service territory of the SGIP project is considered in the development of emission rates by accounting for whether the site is located in Pacific Gas & Electric's (PG&E's) territory (northern California) or in Southern California Edison's (SCE's) or Center for Sustainable Energy's (CSE's) territory (southern California). Variations in climate and electricity market conditions have an effect on the demand for electricity. This in turn affects the emission rates used to estimate the avoided CO_2 release by central station power plants. Lastly, timing of electricity generation affects the emission rates because the mix of high and low efficiency plants differs throughout the day. The larger the proportion of low efficiency plants used to generate electricity, the greater the avoided CO_2 emission rate.

Electric Power Plant CO2 Emissions Rate

The approach used to formulate hourly CO_2 emission rates for this analysis is based on methodology developed by E3 and found in its avoided cost calculation workbook. The E3 avoided cost calculation workbook assumes:

» The emissions of CO_2 from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and

» The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

The premise for hourly CO_2 emission rates calculated in E3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the market demand conditions for electricity. As demand for electricity increases, all else being equal, the price of electricity will rise. To meet the higher demand for electricity, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission rate for CO_2. In other words, one can expect an emission rate representing the release of CO_2 associated with electricity purchased from the utility company to be higher during peak hours than during off-peak hours.

$baseCO_2EF_{r,h}$ is the CO_2 emission rate for region r (northern or southern California) for hour *h.*

Source: Energy + Environmental Economics

Units: Metric tons / kWh

Electric Power Plant Operations Corresponding to Electric Chiller Operation

An absorption chiller may be used to convert heat recovered from SGIP CHP projects into chilled water to serve buildings or process cooling loads. Since absorption chillers replace the use of electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions associated with these cogeneration facilities.

$$COOLING_{i,h} = CHILLER_i \cdot heathr_{i,h} \cdot COP$$

Where:

$COOLING_{i,h}$ is the cooling services provided by SGIP CHP project *i* for hour *h*.

Units: MBtu

$CHILLER_i$ is an allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating & cooling, or cooling only)

Value: 1, 0.5, or 0. See Table C-2.

TABLE C-2: ASSIGNMENT OF CHILLER ALLOCATION FACTOR

Project Design	$CHILLER_i$
Heating & Cooling	0.5
Cooling Only	1
Heating Only	0

Units: Dimensionless

Basis: Project design as represented in installation verification inspection report

$heathr_{i,h}$ is the quantity of useful heat recovered for SGIP CHP project *i* for hour *h*.

Units: MBtu

Basis: Metering or ratio analysis depending on availability of useful heat recovery data

COP is the efficiency of the absorption chiller using heat from the SGIP CHP project.

Value: 0.6

Units: $MBtu_{out}$ / $MBtu_{in}$

Basis: Assumed

The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$chlrElec_{i,h} = COOLING_{i,h} \cdot effElecChlr \cdot \left(\frac{1\ ton \cdot hr\ cooling}{12\ MBtu}\right)$$

Where:

$chlrElec_{i,h}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for SGIP CHP project *i* for hour *h*.

Units: kWh

effElecChlr is the efficiency of the baseline new standard efficiency electric chiller

Value: 0.634

Units: kWh / ton·hr cooling

Basis: assumed

Baseline GHG Emissions from Power Plant Operations

The location- and hour-specific CO_2 emission rate, when multiplied by the quantity of electricity generated for each baseline scenario, estimates the hourly emissions avoided.

$basePpChiller_{i,h} = baseCO_2EF_{i,h} \cdot chlrElec_{i,h}$

$basePpEngo_{i,h} = baseCO_2EF_{i,h} \cdot engohr_{i,h}$

Where:

$basePpChiller_{i,h}$ is the baseline power plant GHG emissions avoided due to SGIP CHP project *i* delivery of cooling services for hour *h*.

Units: Metric Ton CO_2 / hr

$basePpEngo_{i,h}$ is the baseline power plant GHG emissions avoided due to SGIP CHP project *i* electricity generation for hour *h*.

Units: Metric Ton CO_2 / hr

Boiler GHG Emissions (baseBlr)

A heat exchanger is typically used to transfer useful heat recovered from SGIP CHP projects to building heating loads. The equation below represents the process by which heating services provided by SGIP CHP projects are calculated.

$HEATING_{i,h} = BOILER_i \cdot heathr_{i,h} \cdot effHx$

Where:

HEATING$_{i,h}$ is the heating services provided by SGIP project *i* for hour *h.*

Units: MBtu

BOILER$_{i}$ is an allocation factor whose value depends on SGIP CHP project design (i.e., heating only, heating & cooling, or cooling only)

Value: 1, 0.5, or 0. See Table C-3.

TABLE C-3: ASSIGNMENT OF BOILER ALLOCATION FACTOR

Project Design	CHILLER$_i$
Heating & Cooling	0.5
Cooling Only	0
Heating Only	1

Units: Dimensionless

Basis: Project design as represented in installation verification inspection report

heathr$_{i,h}$ is the quantity of useful heat recovered for SGIP CHP project *i* for hour *h*.

Units: MBtu

Basis: Metering or ratio analysis depending on availability of useful heat recovery data

effHx is the efficiency of the SGIP CHP project's primary heat exchanger

Value: 0.9

Units: Dimensionless fractional efficiency

Basis: Assumed

Baseline natural gas boiler CO_2 emissions were calculated based upon hourly useful heat recovery values for the SGIP CHP project as follows:

$$baseBlr_{i,h} = HEATING_{i,h} \cdot \frac{1}{effBlr} \cdot \left(\frac{1\,ft^3\ of\ CH_4}{935\ Btu}\right)\left(\frac{1{,}000\ Btu}{1\ MBtu}\right)\left(\frac{1\ lbmole\ CO_2}{1\ lbmole\ CH_4}\right)\left(\frac{1\ lbmole\ of\ CH_4}{379\ ft^3\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{1\ lbmole\ of\ CO_2}\right)\left(\frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}\right)$$

Where:

baseBlr$_{i,h}$ is the CO_2 emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h*

Units: Metric Tons CO_2 / hr

effBlr is the efficiency of the baseline natural gas boiler

Value: 0.8

Units: $MBtu_{out}$ / $MBtu_{in}$

Basis: Previous program cost-effectiveness evaluations.

This equation reflects the ability to use recovered useful heat in lieu of natural gas and, therefore, help reduce CO_2 emissions.

Biogas GHG Emissions (baseBio)

DG projects powered by renewable biogas carry an additional GHG reduction benefit. The baseline treatment of biogas is an influential determinant of GHG impacts for renewable-fueled SGIP projects. 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).

There are two common sources of biogas found within the SGIP: landfills and digesters. Digesters in the SGIP to date have been associated with wastewater treatment plants (WWTP), food processing facilities, and dairies. Because of the importance of the baseline treatment of biogas in the GHG analysis, these facilities were contacted in 2009 to more accurately estimate baseline treatment. This resulted in the determination that venting is the customary baseline treatment of biogas for dairy digesters, and flaring is the customary baseline for all other renewable fuel sites. For dairy digesters, landfills, WWTPs, and food processing facilities larger than 150 kW, this is consistent with PY07 and PY08 SGIP impact evaluation reports. However, for WWTPs and food processing facilities smaller than 150 kW, PY07 and PY08 SGIP impact evaluations assumed a venting baseline, whereas in PY09-PY13 impact evaluations the baseline is more accurately assumed to be flaring. Additional information on baseline treatment of biogas per biogas source and facility type is provided below.

For dairy digesters the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2,000 dairies in California, conventional manure management practice for flush dairies[6] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO_2 and CH_4. These lagoons are typically uncovered, so all CH_4 generated in the lagoon escapes into the atmosphere. Currently, there are no statewide requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for volatile organic compounds. This information and the site contacts support a biogas venting baseline for dairies.

For other digesters, including WWTPs and food processing facilities, the baseline is not quite as straightforward. There are approximately 250 WWTPs in California, and the larger facilities (i.e., those

[6] Most dairies manage their waste via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in CH_4 being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas projects).

that could generate 1 MW or more of electricity) tend to install energy recovery systems; therefore, the baseline assumption for these facilities in past SGIP impact evaluations was flaring. However, in some previous SGIP impact evaluations, it was assumed that most of the remaining WWTPs do not recover energy and flare the gas on an infrequent basis. Consequently, for smaller facilities (i.e., those with capacity less than 150 kW), venting of the biogas (CH_4) was used in PY07 and PY08 SGIP impact evaluations as the baseline. However, all renewable-fueled distributed generation WWTPs and food processing facilities participating in the SGIP that were contacted in 2009 said that they flare biogas, and cited local air and water regulations as the reason. Therefore, flaring was used as the biogas baseline for the PY09-PY13 impact evaluation reports.

Defining the biogas baseline for landfill gas recovery operations presented a challenge in past SGIP impact evaluations. A study conducted by the California Energy Commission in 2002[7] showed that landfills with biogas capacities less than 500 kW would tend to vent rather than flare their landfill gas by a margin of more than three to one. In addition, landfills with over 2.5 million metric tons of waste are required to collect and either flare or use their gas. Installation verification inspection reports and renewable-fueled DG landfill site contacts verified that they would have flared their CH_4 in the absence of the SGIP. Therefore, the biogas baseline assumed for landfill facilities is flaring of the CH_4.

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

For directed biogas projects where the biogas is injected into the pipeline outside of California, information on the renewable fuel baseline was not available.[8] To establish a directed biogas baseline the following assumptions were made:

- The renewable fuel baseline for all directed biogas projects is flaring biogas[9], and
- Seventy-five percent of the energy consumed by directed biogas SGIP projects on an energy basis (the minimum amount of biogas required to be procured by a directed biogas project) is assumed to have been injected at the biogas source.

[7] California Energy Commission. Landfill Gas-to-Energy Potential in California. 500-02-041V1. September 2002. http://www.energy.ca.gov/reports/2002-09-09_500-02-041V1.PDF

[8] Information on consumption of directed biogas at SGIP projects is based on invoices instead of metered data.

[9] From a financial feasibility standpoint, directed biogas was assumed to be procured only from large biogas sources, such as large landfills. In accordance with Environmental Protection Agency (EPA) regulations for large landfills, these landfills would have been required to collect the landfill gas and flare it. As a result, the basis for directed biogas projects was assumed to be flaring.

If a directed biogas project is known to have not received any directed biogas during the reporting period, the biogas baseline is set to zero. The GHG emissions characteristics of biogas flaring and biogas venting are very different and, therefore, are discussed separately below.

GHG Emissions of Flared Biogas

CH_4 is naturally created in landfills, wastewater treatment plants, and dairies. If not captured, the methane escapes into the atmosphere contributing to GHG emissions. Capturing the CH_4 provides an opportunity to use it as a fuel. When captured CH_4 is not used to generate electricity or satisfy heating or cooling loads, it is burned in a flare.

In situations where flaring occurs, baseline GHG emissions comprise CO_2 only. The flaring baseline was assumed for the following types of biogas projects:

- Facilities using digester gas (with the exception of dairies),
- Landfill gas facilities, and
- Projects fueled by directed biogas.

The assumption is that the flaring of CH_4 would have resulted in the same amount of CO_2 emissions as occurred when the CH_4 was captured and used in the SGIP project to produce electricity.

$$baseBio_{i,h} = sgipGHG_{i,h}$$

GHG Emissions of Vented Biogas

CH_4 capture and use at renewable fuel use facilities where the biogas baseline is venting avoids release of CH_4 directly into the atmosphere. The venting baseline was assumed for all dairy digester SGIP projects. Biogas consumption is typically not metered at SGIP projects. Therefore, CH_4 emission rates were calculated by assuming an electrical efficiency.

$$CH_4EF_T = \left(\frac{3{,}412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{1\ ft^3\ of\ CH_4}{935\ Btu}\right)\left(\frac{1\ lbmole\ of\ CH_4}{379\ ft^3\ of\ CH_4}\right)\left(\frac{16\ lbs\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb}\right)$$

Where:

CH_4EF_T is the CH_4 capture rate for SGIP projects of technology T

Units: grams / kWh

EFF_T is the electrical efficiency of technology T.

Value: Dependent on technology type (see Table C-1)

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV). Metered data collected from natural gas CHP projects.

The derived CH_4 emission rates (CH_4EF_T) are multiplied by the total electricity generated from the SGIP renewable fuel use project to estimate baseline CH_4 emissions.

$$baseBioCH_{4i,h} = CH_4EF_T \cdot engohr_{i,h} \cdot \left(\frac{1\ lb}{454\ grams}\right)\left(\frac{1\ metric\ ton}{2{,}205\ lbs}\right)$$

The avoided metric tons of CH_4 emissions were then converted to metric tons of CO_2eq by multiplying the avoided CH_4 emissions by 21, which represents the global warming potential of CH_4 (relative to CO_2) over a 100-year time horizon.

$$baseBio_{i,h} = baseBioCH_{4i,h} \cdot \left(\frac{21\ metric\ tons\ CO_2}{1\ metric\ ton\ CH_4}\right)$$

C.4 Summary of GHG Impact Results

TABLE C-4: GHG IMPACTS BY TECHNOLOGY TYPE AND ENERGY SOURCE

Technology Type / Energy Source	GHG Impact (Metric Tons CO_2eq)	Electrical Energy Impact (MWh)	GHG Impact Rate (Metric Tons CO_2eq / MWh)
Fuel Cell – CHP	**-32,731**	**147,011**	**-0.22**
Non-Renewable	-5,870	58,881	-0.10
Renewable – Directed	-4,229	40,463	-0.10
Renewable – Flared	-22,632	47,668	-0.47
Fuel Cell – Electric Only	**-71,926**	**311,952**	**-0.23**
Non-Renewable	-15,419	161,084	-0.10
Renewable – Directed	-56,507	150,868	-0.37
Gas Turbine	**-15,663**	**204,114**	**-0.08**
Non-Renewable	-15,663	204,114	-0.08
Internal Combustion Engine	**-32,864**	**277,478**	**-0.12**
Non-Renewable	8,029	233,700	0.03
Renewable – Flared	-20,901	39,555	-0.53
Renewable – Vented	-19,992	4,223	-4.73
Microturbine	**11,138**	**62,078**	**0.18**
Non-Renewable	13,721	56,552	0.24
Renewable – Flared	-2,583	5,526	-0.47
Pressure Reduction Turbine	**-267**	**576**	**-0.46**
Wind	**-20,121**	**42,529**	**-0.47**

TABLE C-5: GHG IMPACTS BY PROGRAM ADMINISTRATOR AND TECHNOLOGY TYPE

Program Administrator / Technology Type	GHG Impact (Metric Tons CO_2eq)	Electrical Energy Impact (MWh)	GHG Impact Rate (Metric Tons CO_2eq / MWh)
Center for Sustainable Energy	**-13,077**	**151,766**	**-0.09**
Fuel Cell – CHP	-2,492	39,527	-0.06
Fuel Cell – Electric Only	-6,176	29,253	-0.21
Gas Turbine	-2,558	74,404	-0.03
Internal Combustion Engine	-1,594	6,272	-0.25
Microturbine	10	1,735	0.01
Pressure Reduction Turbine	-267	576	-0.46
Pacific Gas & Electric Company	**-66,209**	**390,614**	**-0.17**
Fuel Cell – CHP	-8,312	46,091	-0.18
Fuel Cell – Electric Only	-34,641	166,174	-0.21
Gas Turbine	-601	11,248	-0.05
Internal Combustion Engine	-23,775	116,382	-0.20
Microturbine	7,537	36,687	0.21
Wind	-6,417	14,033	-0.46
Southern California Edison	**-48,764**	**193,239**	**-0.25**
Fuel Cell – CHP	-9,528	24,075	-0.40
Fuel Cell – Electric Only	-20,263	76,082	-0.27
Internal Combustion Engine	-5,319	56,124	-0.09
Microturbine	49	8,462	0.01
Wind	-13,704	28,496	-0.48
Southern California Gas Company	**-34,384**	**310,119**	**-0.11**
Fuel Cell – CHP	-12,400	37,318	-0.33
Fuel Cell – Electric Only	-10,846	40,444	-0.27
Gas Turbine	-12,504	118,463	-0.11
Internal Combustion Engine	-2,177	98,700	-0.02
Microturbine	3,543	15,194	0.23

TABLE C-6: GHG IMPACTS BY PROGRAM ADMINISTRATOR AND ENERGY SOURCE

Program Administrator / Energy Source	GHG Impact (Metric Tons CO_2eq)	Electrical Energy Impact (MWh)	GHG Impact Rate (Metric Tons CO_2eq / MWh)
Center for Sustainable Energy	**-13,077**	**151,766**	**-0.09**
Non-Renewable	-4,755	102,236	-0.05
Renewable – Directed	-6,042	44,726	-0.14
Renewable – Flared	-2,013	4,229	-0.48
Other	-267	576	-0.46
Pacific Gas & Electric Company	**-66,209**	**390,614**	**-0.17**
Non-Renewable	-99	272,274	-0.00
Renewable – Directed	-26,808	74,377	-0.36
Renewable – Flared	-12,893	25,708	-0.50
Renewable – Vented	-19,992	4,223	-4.73
Other	-6,417	14,033	-0.46
Southern California Edison	**-48,764**	**193,239**	**-0.25**
Non-Renewable	-1,189	86,631	-0.01
Renewable – Directed	-18,895	48,990	-0.39
Renewable – Flared	-14,977	29,122	-0.51
Other	-13,704	28,496	-0.48
Southern California Gas Company	**-34,384**	**310,119**	**-0.11**
Non-Renewable	-9,159	253,191	-0.04
Renewable – Directed	-8,991	23,238	-0.39
Renewable - Flared	-16,234	33,690	-0.48

Appendix D

D CRITERIA AIR POLLUTANT IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix describes the methodology used to estimate the impacts of criteria air pollutant emissions from the operation of Self-Generation Incentive Program (SGIP) projects. Criteria air pollutants are those air pollutants having national air quality standards with defined allowable concentrations in ambient air. Criteria air pollutants are carbon monoxide (CO), lead (Pb), oxides of nitrogen (NO_X), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2).[1] Ozone is not directly generated by SGIP technologies and therefore ozone impacts are not reported.[2] In addition, there is insufficient information on lead emissions to include an assessment of lead emission impacts. Consequently, criteria air pollutants considered in this analysis are limited to NO_X, SO_2 and particulate matter in the 10 micron size range (PM_{10}).

This appendix is organized in six sections:

» **D.1** provides an overview of the analytic methodology

» **D.2** discusses in detail how NO_X emission rates were developed

» **D.3** discusses in detail how PM_{10} emission rates were developed

» **D.4** discusses in detail how SO_2 emission rates were developed

» **D.5** describes how the emissions rates are implemented into the impacts calculation

» **D.6** presents summary information on criteria air pollutant impacts

D.1 Overview

Criteria air pollutant impacts are estimated using an approach similar to the greenhouse gas (GHG) impacts estimation methodology described in Appendix C. Criteria air pollutant impacts are estimated as the difference between the emissions that occur from operation of SGIP projects and those that would occur from serving electrical, heating, and cooling loads via conventional energy services (i.e., the electricity grid, boilers, and electric chillers) in the absence of the SGIP. The principal difference between the GHG and criteria pollutant impacts methodologies is that the emissions from central station grid generation, boilers, and SGIP generators are not a simple function of the amount of gas consumed. For example, NO_X emissions rates are a function of combustion stoichiometry and temperature, which can vary from one internal combustion engine to the next. In addition, post-

[1] Environmental Protection Agency, from http://www.epa.gov/air/criteria.html

[2] Ozone or oxidant makes up photochemical smog and NO_X emissions are critical precursors to the formation of oxidant.

combustion emission control technologies such as catalysts can significantly impact emissions rates. Emission control requirements can vary by air quality management district (AQMD) and program year (PY). This variability in potential emissions rates necessitates the development of emissions rate estimates that are specific to a given technology, program year, and energy source.

The sections below describe the overall approach and assumptions made in estimating emissions rates for each of the criteria air pollutants treated.

D.2 Oxides of Nitrogen (NO_X) Emission Rates

The rate at which NO_X is created is a function of the energy source, the combustion process/chemical reaction, and the type of emissions control technology installed. All fuel-consuming SGIP technologies generate NO_X emissions. Sources of avoided NO_X emissions include central-station grid power plants, natural gas boilers, and biogas flares.

SGIP Project NO_X Emission Rates

NO_X emission rates from SGIP projects are based on literature research and personal communications with industry experts conducted by Itron. The amount of NO_X produced by each technology type can vary by program year, primary due to changes in air emission requirements imposed by the California Air Resources Board (CARB) and improvements in Best Available Control Technology (BACT). Studies conducted in the 2000 to 2005 timeframe indicated that widespread adoption of distributed generation (DG) technologies could potentially lead to a degradation of air quality due to increased emissions of NO_X from DG systems.[3,4] Leading into 2000, many of the DG systems operating in California were fueled by diesel and had relatively high NO_X emissions. A 2006 survey of air quality management district regulations on NO_X controls for natural gas-fired reciprocating engines found NO_X requirements ranged from 0.3 lb/MWh in the South Coast AQMD to over 4 lb/MWh.[5] Due to concerns over potential increases in NO_X emissions from DG resources, the Legislature passed Senate Bill 1298 (Bowen/Peace) in September 2000.[6] SB 1298 directed by CARB to develop an air pollution control certification program for DG technologies by January 2003. The CARB certification had a phase-in approach that required increasingly lower NO_X emissions between 2005 and 2007.

Table D-1 lists the NO_X emission rates used to estimate 2013 emissions from SGIP technologies.

[3] Ianucci, J., Horgan, S., Eyer, J., Cibulka, L., 2000. "Air pollution emissions impacts associated with the economic market potential of distributed generation in California," Distributed Utility Associates, prepared for The California Air Resources Board, Contract #97-326.

[4] California Institute for Energy and Environment, "Impacts of Distributed Generation on Air Quality: A Roadmap," prepared for the California Energy Commission, CEC-500-2008-022, June 2008

[5] SMUD, "Small Engine Emission Reduction for Dairy Digesters," prepared by Itron, November 2006

[6] http://leginfo.ca.gov/pub/99-00/bill/sen/sb_1251-1300/sb_1298_bill_20000927_chaptered.html

TABLE D-1: NO_X EMISSION RATES FOR SGIP TECHNOLOGIES

Technology Type	Program Year	Energy Source	NO_X Emission Rate (Pounds NO_X / MWh)
Fuel Cell – Combined Heat and Power	All	All	0.010
Fuel Cell – Electric Only	All	All	0.002
Gas Turbine	PY01-PY06	All	0.300
	PY07	All	0.070
Internal Combustion Engine / Microturbine	PY01-PY06	All	0.200
	PY07	All	0.135
	PY08-PY13	All	0.070

Due to their chemistry, fuel cells tend to have significantly lower NO_X emissions rates compared to combustion technologies. Prior to PY07, before stringent NO_X control rules went into effect, combustion technologies had the highest NO_X emission rates. All combustion technologies that applied after PY07 are assumed to meet CARB's 0.070 lb / MWh target. During PY07, combustion technologies were eligible for SGIP incentives if they met the CARB's NO_X target either through emission controls or by using a combined heat and power (CHP) offset due to avoided boiler use. Consequently, it cannot be assumed that all PY07 combustion technologies achieved CARB's emissions targets. Instead, PY07 is treated as a transition year for internal combustion engines and microturbines; their average emission rate is assumed to be half way between the PY01-PY06 rate and the CARB 0.070 lb / MWh target. This is a proxy for an assumption that half the projects achieved CARB's target through emissions controls and the other half achieved CARB's target via CHP credits. PY07 gas turbines are assumed to have met CARB's NO_X target using emission controls

Baseline NO_X Emission Rates

Central station power plants and on-site boilers all generate NO_X as a result of the combustion of natural gas. Biogas flares also generate NO_X as a result of the combustion of biogas.

Central Station Power Plant NO_X Emission Rates

NO_X emissions rates from central station power plants are based on literature research conducted by Itron. Two central station technologies are considered: a new baseload high efficiency combined cycle gas turbine (CCGT), and an old low efficiency simple cycle gas turbine peaker plant. These technologies are considered representative of the best and worst case scenario for marginal emissions. The best and worst case values are then mapped to the best and worst marginal emissions rates. Hourly NO_X emissions rates are interpolated between this maximum and minimum according to the marginal heat rate during any given hour. Table D-2 lists the maximum and minimum NO_X emission rates used to estimate 2013 emissions from baseline central station power plants.

TABLE D-2: NO_X EMISSION RATES FOR CENTRAL STATION POWER PLANTS

Central Station Marginal Generator	NO_X Emission Rate (Pounds NO_X / MWh)
New Baseload Combined Cycle Gas Turbine	0.070
Old Simple Cycle Gas Turbine Peaker	0.246

Boiler and Flare NO_X Emission Rates

NO_X emission rates from natural gas boilers and biogas flares are based on literature research conducted by Itron. In most urban areas in California, air pollution control districts passed regulations in the mid-1990's requiring some form of NO_X control on commercial sized boilers (i.e., boilers in the size range of less than 10 MMBtu heat input up to about 50 MMBtu heat input). In these urban areas (e.g., Bay Area, Southern California, San Diego), the regulations required control of NO_X to 30 parts per million by volume (ppmv) at 3% O2.[7] This corresponds to approximately 0.037 lb of NO_X/MMBtu heat input. In non-urban areas of California, boilers were left to meet new source performance standards (NSPS) requirements.

This analysis assumes that two thirds of SGIP projects are in urban areas with the remaining third in non-urban areas and that the average boiler NO_X emission rate can be approximated by the following equation:

$$NO_{X,boiler} = \frac{2}{3} \cdot \frac{0.037lb}{MMbtu} + \frac{1}{3} \cdot \frac{0.190lb}{MMBtu} = 0.088\frac{lb}{MMBtu}$$

Table D-3 lists the NO_X emission rates used to estimate 2013 emissions from baseline natural gas boilers and biogas flares.

TABLE D-3: NO_X EMISSION RATES FOR NATURAL GAS BOILERS AND BIOGAS FLARES

Baseline Component	NO_X Emission Rate (Pounds NO_X / MMBtu)
Natural Gas Boiler	0.088
Biogas Flare	0.056

Venting of biogas to the atmosphere does not produce NO_X, therefore, there is no avoided NO_X component for projects that would have otherwise vented biogas.

[7] Bay Area Air Quality Management District, "BAAQMD Regulation 9, Rule 7: Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional and Commercial Boilers, Steam Generators and Process Heaters, May 2007

D.3 Particulate Matter Emission Rates

Particulate matter is a complex mixture of extremely small particles and liquid droplets. The size of particles is directly linked to their potential for causing health problems. The Environmental Protection Agency (EPA) is concerned about particles that are 10 micrometers in diameter or smaller because those are the particles that generally pass through the throat and nose and enter the lungs.[8] Once inhaled, these particles can affect the heart and lungs and cause serious health effects.[9] As with NO_X, the rate at which PM_{10} is created is a function of the energy source, the combustion process/chemical reaction, and the types of emissions controls installed. All fuel-consuming SGIP technologies generate PM_{10} emissions. Sources of avoided PM_{10} emissions include central-station grid power plants, natural gas boilers, and biogas flares.

SGIP Project PM_{10} Emission Rates

PM_{10} emissions rates from SGIP projects are based on literature research and personal communications with industry experts conducted by Itron staff. Table D-4 lists the PM_{10} emission rates used to estimate 2013 emissions from SGIP projects.

TABLE D-4: PM_{10} EMISSION RATES FOR SGIP TECHNOLOGIES

Technology Type	Program Year	Energy Source	PM_{10} Emission Rate (Pounds PM_{10} / MWh)
Fuel Cell – CHP or Electric Only	All	All	0.00002
Gas Turbine	All	Natural Gas	0.05635
Internal Combustion Engine	All	Natural Gas	0.06006
	All	Biogas	0.06969
Microturbine	All	All	0.08575

As with NO_X, fuel cells have the lowest PM_{10} emissions rates when compared to combustion technologies.

Baseline PM_{10} Emission Rates

Central station power plants and on-site boilers all generate PM_{10} as a result of the combustion of natural gas. Biogas flares also generate PM_{10} as a result of the combustion of biogas.

8 This report only examines particulate matter between 2.5 and 10 micrometers in diameter.

9 http://www.epa.gov/pm/

Central Station Power Plant PM_{10} Emission Rates

PM_{10} emissions rates from central station power plants are based on literature research conducted by Itron. Table D-5 lists the PM_{10} emission rates used to estimate 2013 emissions from central station power plants.

TABLE D-5: PM_{10} EMISSION RATES FOR CENTRAL STATION POWER PLANTS

Central Station Marginal Generator	PM_{10} Emission Rate (Pounds PM_{10} / MWh)
New Baseload Combined Cycle Gas Turbine	0.03000
Old Simple Cycle Gas Turbine Peaker	0.11456

Hourly PM_{10} emission rates from central station power plants are interpolated using the same methodology described above for NO_X emissions.

Boiler and Flare PM_{10} Emission Rates

PM_{10} emission rates from natural gas boilers and biogas flares are based on literature research conducted by Itron. Table D-6 lists the PM_{10} emission rates used to estimate 2013 emissions from natural gas boilers and biogas flares.

TABLE D-6: PM_{10} EMISSION RATES FOR NATURAL GAS BOILERS AND BIOGAS FLARES

Baseline Component	PM_{10} Emission Rate (Pounds PM_{10} / MMBtu)
Natural Gas Boiler	0.00773
Biogas Flare	0.01418

Venting of biogas to the atmosphere does not produce PM_{10}, therefore, there is no avoided PM_{10} component for projects that would have otherwise vented biogas.

D.4 Sulfur Dioxide (SO_2) Emission Rates

Sulfur dioxide is one of a group of highly reactive gasses known as "oxides of sulfur." Existing literature on SO_2 emissions from natural gas generation are limited. In general, SO_2 emissions from combustion processes are due to the oxidation of sulfur compounds contained in the fuel. To estimate SO_2 emission rates, reported concentrations of sulfur in the fuel (natural gas or biogas) are used and it is assumed that all of the sulfur in the fuel is converted to SO_2. This provides a conservatively high estimate of SO_2 emissions as not all of the sulfur in the fuel may actually be converted to SO_2.

SGIP Project SO_2 Emission Rates

SGIP project energy sources are the primary driver of SO_2 emissions from SGIP projects. The amount of sulfur in biogas is significantly higher than the sulfur content of pipeline quality natural gas. The following sections describe the assumptions employed to arrive at SO_2 emission rates for non-renewable and renewable projects.

SGIP Project SO_2 Emission Rates from Natural Gas

Natural gas contains very low concentrations of sulfur compounds. Gas utilities may add sulfur compounds to odorize the gas for safety purposes. Sulfur compounds typically found in natural gas consist of Tetrahydrothiophene (THT), Tertiary Butyl Mercaptan (TBM), Dimethyl Sulfide (DMS), and Hydrogen Sulfide (H_2S).[10] Both Pacific Gas & Electric Company (PG&E) and Southern California Gas Company (SCG) restrict the amount of sulfur compounds that can be contained in natural gas transported in the natural gas pipelines through Gas Rule 21. Gas Rule 21 limits the amount of sulfur compounds in natural gas to the following levels:

- » Total Sulfur: The gas shall contain no more than one grain (17 ppm) of total sulfur per one hundred standard cubic feet.
- » Mercaptan Sulfur: The gas shall contain no more than 0.5 grain (8 ppm) of mercaptan sulfur per one hundred standard cubic feet.
- » Hydrogen Sulfide: The gas shall contain no more than 0.25 grain (4 ppm) of hydrogen sulfide per one hundred standard cubic feet.

The limits above represent maximum concentrations of sulfur contained in natural gas. PG&E also provides information on representative sulfur concentrations for natural gas during 2013 as shown in Table D-7. In practice, natural gas has lower concentrations of total sulfur. The 2013 average value from all sites of 0.173 grains per hundred standard cubic feet (2.91 ppmv) is used as a representative value of total sulfur contained in natural gas.

TABLE D-7: REPRESENTATIVE TOTAL SULFUR CONCENTRATIONS IN NATURAL GAS

	Total Sulfur			
	Maximum		Average all Sites	
Quarter in 2013	PPMv	gr/100 SCF	PPMv	gr/100 SCF
Fourth	4.99	0.296	2.62	0.156
Third	5.69	0.338	2.89	0.171
Second	7.33	0.435	3.17	0.188
First	6.71	0.398	2.97	0.176
Average	***6.18***	***0.367***	***2.91***	***0.173***

[10] From PG&E's Gas Transmission website: http://www.pge.com/pipeline/operations/sulfur/sulfur_info.shtml

During combustion, sulfur contained in the fuel is converted to SO_2 in accordance with the following chemical equation:

$$S + O_2 \rightarrow SO_2$$

Using the representative concentration of sulfur in natural gas and the above chemical equation, SO_2 emission rates in units of pounds of SO_2 per MWh of generated electricity are estimated as follows:[11]

$$SO_{2,T}\frac{lb}{MWh} = \left(\frac{0.00000025\ lb\ S}{scf\ natgas}\right)\cdot\left(\frac{3412\ Btu}{kWh}\right)\cdot\left(\frac{1}{EFF_T}\right)\left(\frac{1\ scf\ natgas}{935\ Btu}\right)\left(\frac{64\ lb\ SO_2}{lbmole\ SO_2}\right)\left(\frac{1\ lbmole\ SO_2}{1\ lbmole\ S}\right)\left(\frac{1\ lbmole\ S}{32\ lb\ S}\right)\left(\frac{1{,}000\ kWh}{1\ MWh}\right)$$

Where EFF_T refers to the electrical efficiency of the technology as defined in Table D-8.

TABLE D-8: ELECTRICAL EFFICIENCY BY TECHNOLOGY TYPE USED FOR SO_2 EMISSIONS CALCULATION

Technology Type (T)	Electrical Efficiency (EFF_T)
Gas Turbine	0.35
Internal Combustion Engine	0.30
Microturbine	0.23

Table D-9 lists the SO_2 emission rates used to estimate 2013 emissions from SGIP projects fueled by natural gas using the equation above. Note that fuel cells are assumed to have lower tolerances for sulfur and, therefore, the SO_2 emission rates are based on values in the literature.

TABLE D-9: SO_2 EMISSION RATES FOR SGIP PROJECTS FUELED BY NATURAL GAS

Technology Type	Program Year	Energy Source	SO_2 Emission Rate (Pounds SO_2 / MWh)
Fuel Cell – CHP	All	Natural Gas	0.0001
Fuel Cell – Electric Only	All	Natural Gas	0.0001
Gas Turbine	All	Natural Gas	0.0050
Internal Combustion Engine	All	Natural Gas	0.0062
Microturbine	All	Natural Gas	0.0078

SGIP Project SO_2 Emission Rates from Renewable Biogas

Biogas is a mixture of methane, carbon dioxide, water and a variety of other trace compounds. In general, the biogas contains approximately 60 to 70 percent by volume of methane.[12] For the purposes of this analysis, biogas is assumed to have an energy content of approximately 600 Btu per standard

[11] 0.173 grains of sulfur/100 scf is approximately equal to 0.00000025 lbs of sulfur/scf of natural gas

[12] http://www.biogas-renewable-energy.info/biogas_composition.html

cubic foot (Btu/scf). Sulfur compounds are among the different trace gas mixtures found in biogas. Typically, anaerobic processes produce hydrogen sulfide. Concentrations of H_2S can vary significantly from site to site and by resource type (e.g., landfill gas operations versus dairy digesters). For example, H_2S concentrations can range from 500 to over 2,500 ppmv at wastewater treatment plants. However, H_2S poses corrosion issues to most generation equipment and must be reduced through biogas cleaning processes. Based on operational considerations, biogas used in PY01-PY06 internal combustion engines is usually controlled to less than 200 ppmv.[13] For PY01-PY06 internal combustion engines, the sulfur concentration in the biogas is assumed to be a maximum of 200 ppmv. Internal combustion engines deployed after PY07 are required to meet CARB NO_X requirements, which necessitate the use of post-combustion control technologies such as selective catalytic reduction (SCR) systems. SCR systems can be poisoned by even small amounts of sulfur compounds. As a result, sulfur concentrations of 5 ppmv are assumed for PY08-PY13 internal combustion engines to protect post-combustion air pollution control equipment. As with NO_X emissions, PY07 is treated as a transition year for biogas internal combustion engines; the SO_2 emission rate is assumed to be halfway between the PY06 and PY08 emission rate.

The following chemical equation is used for the oxidation of H_2S to SO_2 during combustion of biogas:

$$2H_2S + 3O_2 \rightarrow 2H_2O + 2SO_2$$

Using the above chemical reaction equation, SO_2 emission rates in units of pounds of SO_2 per MWh of generated electricity from SGIP generators are estimated as follows:

$$SO_{2,T}\frac{lb}{MWh} = \left(\frac{X_T\ scf\ H_2S}{scf\ biogas}\right)\cdot\left(\frac{3412\ Btu}{kWh}\right)\cdot\left(\frac{1}{EFF_T}\right)\left(\frac{1\ scf\ biogas}{600\ Btu}\right)\left(\frac{64\ lb\ SO_2}{lbmole\ SO_2}\right)\left(\frac{1\ lbmole\ SO_2}{1\ lbmole\ H_2S}\right)\left(\frac{1\ lbmole\ H_2S}{379\ scf\ H_2S}\right)\left(\frac{1{,}000\ kWh}{1\ MWh}\right)$$

Where: X_T refers to the volumetric concentration of H_2S in the biogas.

Based on assumed concentrations of sulfur in the fuel and measured electrical efficiencies of SGIP generators, Table D-10 lists SO_2 emission rates for SGIP generators fueled by biogas.

TABLE D-10: ESTIMATED SO_2 EMISSION RATES FOR SGIP GENERATORS FUELED BY BIOGAS

Technology Type	Program Year	Sulfur Content (ppmv)	SO_2 Emission Rate (Pounds SO_2 / MWh)
Fuel Cell – CHP	All	--	0.0001
Internal Combustion Engine	PY01-PY06	200	0.6623
	PY07	--	0.3394
	PY08-PY13	5	0.0166
Microturbine	PY01-PY07	5	0.0209

13 Department of Ecology, State of Washington, "Technical Support Document for Dairy Manure Anaerobic Digester Systems with Digester Gas Fueled Engine Generators," March 2012

Fuel cell operations require very low biogas sulfur concentrations. Consequently, the SO_2 emission rate for fuel cells is obtained from the literature.

Baseline SO_2 Emissions Rates

Central Station Power Plant SO_2 Emission Rates

Central station power plant SO_2 emission rates are calculated in the same manner as SGIP generator emissions but assuming different electrical conversion efficiencies (EFF_T). The assumed efficiencies and resulting SO_2 emission rates are listed in Table D-11.

TABLE D-11: ESTIMATED SO_2 EMISSION RATES FOR CENTRAL STATION POWER PLANTS

Central Station Marginal Generator	Sulfur Content (gr/100 scf)	EFF_T (%)	SO_2 Emission Rate (Pounds SO_2 / MWh)
New Baseload Combined Cycle Gas Turbine	0.173	0.55	0.0033
Old Simple Cycle Gas Turbine Peaker	0.173	0.30	0.0060

Hourly SO_2 emission rates from central station power plants are interpolated using the same methodology described above for NO_X emissions.

Boiler and Flare SO_2 Emission Rates

Natural gas boilers are assumed to have burned gas with total sulfur concentrations of 0.173 grains per 100 scf. Any biogas flares associated with PY01-PY06 internal combustion engines are assumed to have burned biogas with sulfur concentrations of 200 ppmv while all other biogas flares are assumed to have burned biogas with sulfur concentrations of 5 ppmv.

Based on the above assumptions for H_2S concentrations in biogas, the following SO_2 emission rates (in units of pounds of SO_2 per million Btu of fuel input) are obtained for natural gas boilers and biogas flares at SGIP projects that consume biogas.

TABLE D-12: ESTIMATED SO_2 EMISSION RATES FOR NATURAL GAS BOILERS AND BIOGAS FLARES

Baseline Component	Underlying Technology Type	Underlying Technology Program Year	PM_{10} Emission Rate (Pounds PM_{10} / MMBtu)
Natural Gas Boiler	All	All	0.0005
Biogas Flare	Internal Combustion Engine	PY01-PY06	0.0855
		PY07	0.0435
		PY08-PY13	0.0014
Biogas Flare	Other Than Internal Combustion Engine	All	0.0014

D.5 Emissions Impact Calculations

Criteria pollutant impacts are calculated as the annual sum of hourly SGIP project emissions minus the annual sum of hourly electric power plant emissions, natural gas boiler emissions, and biogas flare emissions for all projects.

$$\Delta Pollut_{i,h} = sgipPollut_{i,h} - (basePpEngoPollut_{i,h} + basePpChillerPollut_{i,h} + baseBlrPollut_{i,h} + baseBioPollut_{i,h})$$

Where:

$\Delta Pollut_{i,h}$ is the criteria pollutant impact for SIGP project i during hour h

Each component of the criteria pollutant impacts calculation is further described below.

SGIP Project Emissions

The emissions from SGIP project operation are calculated as follows:

$$sgipPollut_{i,h} = engohr_{i,h} \cdot sgipPollutRate_i \cdot \frac{1\ MWh}{1{,}000\ kWh}$$

Where:

$sgipPollut_{i,h}$ is the specific criteria pollutant emitted by SGIP project *i* during hour *h*.

Units: pound / hr

$engohr_{i,h}$ is the electrical output of SGIP project *i* during hour *h.*

Units: kWh

Basis: Metered data collected from SGIP projects net of any parasitic losses.

$sgipPollutRate_i$ is the criteria pollutant emissions rate for SGIP project *i*

Units: pounds / MWh

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

Baseline Power Plant Emissions

The baseline power plant criteria pollutant emission rate, when multiplied by the quantity of electricity generated for each baseline scenario, estimates the hourly emissions avoided from central station power plants.

$$basePpChillerPollut_{i,h} = powerPlantPollutRate_h \cdot chlrElec_{i,h} \cdot (1\ MWh/1{,}000\ kWh)$$

$$basePpEngoPollut_{i,h} = powerPlantPollutRate_h \cdot engohr_{i,h} \cdot (1\ MWh/1{,}000\ kWh)$$

Where:

$basePpChillerPollut_{i,h}$ is the baseline power plant criteria pollutant emissions avoided due to SGIP CHP project *i* delivery of cooling services for hour *h*.

Units: pound / hr

basePpEngoPollut$_{i,h}$ is the baseline power plant criteria pollutant emissions avoided due to SGIP CHP project *i* electricity generation for hour *h*.

Units: pound / hr

powerPlantPollutRate$_h$ is the baseline power plant criteria pollutant emissions rate

Units: pound / MWh

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

chlrElec$_{i,h}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for SGIP CHP project *i* for hour *h*.

Units: kWh

Basis: Defined in Appendix C

Baseline Boiler Emissions

Baseline natural gas boiler criteria pollutant emissions are calculated based upon hourly useful heat recovery values for the SGIP CHP project as follows:

$$baseBlrPollut_{i,h} = HEATING_{i,h} \cdot \frac{1}{effBlr} \cdot blrPolutRate \cdot \left(\frac{1\ MMBtu}{1{,}000\ MBtu}\right)$$

Where:

baseBlrPollut$_{i,h}$ is the criteria pollutant emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h*

Units: pound / hr

HEATING$_{i,h}$ is the heating services provided by SGIP project *i* for hour *h.*

Units: MBtu

effBlr is the efficiency of the baseline natural gas boiler

Value: 0.8

Units: $MBtu_{out}$ / $MBtu_{in}$

Basis: Previous program cost-effectiveness evaluations.

baseBlrPollut$_{i,h}$ is the criteria pollutant emissions rate of baseline natural gas boilers

Units: pound / MWh

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

Biogas Flaring Emissions

The criteria pollutant emissions due to the flaring of biogas are calculated as follows:

$$baseBioPollut_{i,h} = engohr_{i,h} \cdot \frac{1}{EFF_T} \cdot flarePollutRate_i \cdot \left(\frac{1\ MMBtu}{1{,}000\ MBtu}\right)$$

Where:

$baseBioPollut_{i,h}$ is the criteria pollutant emissions of the baseline biogas flare for SGIP CHP project *i* for hour *h*

Units: pound / hr

$flarePollutRate_i$ is the criteria pollutant emissions rate of the baseline biogas flare for SGIP CHP project *i*

Units: pound / MMBtu

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

D.6 Summary of Criteria Air Pollutant Impacts Results

TABLE D-13: CRITERIA POLLUTANT IMPACTS BY TECHNOLOGY TYPE

Technology Type	NO_x Emission Impact (Pounds NO_x)	PM_{10} Emission Impact (Pounds PM_{10})	SO_2 Emission Impact (Pounds SO_2)
Fuel Cell – CHP	-58,940	-17,593	-1,347
Fuel Cell – Electric Only	-83,570	-29,922	-2,354
Gas Turbine	-12,909	-6,155	11
Internal Combustion Engine	-61,284	-12,028	-8,271
Microturbine	-11,004	-583	161
Wind Turbine	-79	-36	-2
Pressure Reduction Turbine	-6,066	-2,760	-188
Total	***-233,852***	***-69,077***	***-11,991***

TABLE D-14: CRITERIA POLLUTANT IMPACTS BY ENERGY SOURCE

Energy Source	NO_x Emission Impact (Pounds NO_x)	PM_{10} Emission Impact (Pounds PM_{10})	SO_2 Emission Impact (Pounds SO_2)
Non - Renewable	-94,628	-25,923	-414
Renewable - Onsite	-60,941	-16,514	-9,418
Renewable - Directed	-72,138	-23,844	-1,969
Other	-6,145	-2,796	-190
Total	***-233,852***	***-69,077***	***-11,991***

Appendix E

E SOURCES OF UNCERTAINTY AND RESULTS

This appendix provides an assessment of the uncertainty associated with Self-Generation Incentive Program (SGIP) impacts estimates. Program impacts discussed include those on energy (electricity, fuel, and heat), as well as those on greenhouse gas (GHG) emissions. The principal factors contributing to uncertainty in the results reported for these two types of program impacts are quite different. The treatment of those factors is described below for each of the two types of impacts.

Uncertainty estimates are provided for annual and peak electrical impacts.

E.1 Overview of Energy (Electricity, Fuel, and Heat) Impacts Uncertainty

Electricity, fuel, and useful heat recovery impacts estimates are affected by at least two sources of error that introduce uncertainty into the population-level estimates: measurement error and sampling error. Measurement error refers to the differences between actual values (e.g., actual electricity production) and measured values (i.e., electricity production values recorded by metering and data collection systems). Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

The actual performance of unmetered systems is not known, and will never be known. It is therefore not possible to directly assess the validity of the assumption regarding identical central tendencies. However, it is possible to examine this issue indirectly by incorporating information about the performance *variability* characteristics of the systems.

Theoretical and empirical approaches exist to assess uncertainty effects attributable to both measurement and sampling error. Propagation of error equations are a representative example of theoretical approaches. Empirical approaches to quantification of impact estimate uncertainty are not grounded on equations derived from theory. Instead, information about factors contributing to uncertainty is used to create large numbers of possible sets of actual values for unmetered systems. Characteristics of the sets of simulated actual values are analyzed. Inferences about the uncertainty in impacts estimates are based on results of this analysis.

For this impacts evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impacts estimates uncertainty. The term MCS refers to "the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[1]

A principle advantage of this approach is that it readily accommodates complex analytical questions. This is an important advantage for this evaluation because numerous factors contribute to variability in impacts estimates, and the availability of metered data upon which to base impact estimates is variable. For example, metered electricity production and heat recovery data are both available for some cogeneration systems, whereas other systems may also include metered fuel consumption, while still others might have combinations of data available.

E.2 Overview of Greenhouse Gas Impacts Uncertainty

Electricity and fuel impacts estimates represent the starting point for the analysis of GHG emission impacts; thus, uncertainty in those electricity and fuel impacts estimates flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impact analysis. GHG emissions impact estimates are, therefore, subject to greater levels of uncertainty than are electricity and fuel impact estimates. The two most important additional sources of uncertainty in GHG emissions impacts are summarized below.

Baseline Central Station Power Plant GHG Emissions

Estimation of GHG emission impacts for each SGIP project involves comparison of emissions of the SGIP project with emissions that would have occurred in the absence of the program. The latter quantity depends on the central station power plant generation technology (e.g., natural gas combined cycle, natural gas turbine) that would have met the participant's electric load if the SGIP project had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and, hence, GHG emissions factors) were obtained from Energy + Environmental Economics (E3). Quantitative assessment of uncertainty in E3's avoided GHG emissions rates is outside the scope of this SGIP impacts evaluation.

Baseline Biogas Project GHG Emissions

Biomass material (e.g., trash in landfills, manure in dairies) would typically have existed and decomposed (releasing methane (CH_4)), even in the absence of the program. While the program does not influence the existence or decomposition of the biomass material, it may impact whether or not the CH_4 is released directly into the atmosphere. This is critical because CH_4 is a much more active GHG than are the products of its combustion (e.g., CO_2).

The CH_4 disposition baseline assumptions used in this GHG impact evaluation are summarized in Table E-1. More detailed treatment of biogas baseline assumptions is included in Appendix C.

[1] Webster's Dictionary.

TABLE E-1: METHANE DISPOSITION BASELINE ASSUMPTIONS FOR BIOGAS PROJECTS

Renewable Fuel Facility Type	Methane Disposition Baseline Assumption
Dairy Digester	Venting
Waste Water Treatment	Flaring
Landfill Gas Recovery	
Directed Biogas	

Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, this evaluation continues to incorporate site-specific information about CH_4 disposition into impacts analyses.

E.3 Sources of Data for Uncertainty Analysis

The usefulness of MCS results rests on the degree to which the factors underlying the simulations of actual performance of unmetered systems resemble factors known to influence those SGIP projects for which impacts estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include PA, payment status, project location, technology type, fuel type, and project size. This information is obtained from the statewide database maintained by Energy Solutions on behalf of the Program Administrators (PAs). More detailed project information (e.g., heat exchanger configuration) is obtained from site inspection verification reports developed by the PAs' consultants just prior to issuance of incentive payments.

Metered Data for SGIP Projects

Collection and analysis of metered performance data for SGIP projects is a central focus of the overall program evaluation effort. In the MCS study, the metered performance data are used for two principal purposes:

1. Metered data are used to estimate the actual performance of metered systems. The metered data are not used directly for this purpose. Rather, information about measurement error is applied to metered values to estimate actual values.

2. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study. Values from the distributions are randomly picked to estimate the performance of unmetered systems in large numbers of simulation runs to explore the likelihood that actual total performance of groups of unmetered systems deviates by certain amounts from estimates of their performance.

Manufacturer's Technical Specifications

Metering systems are subject to measurement error. The values recorded by metering systems represent very close approximations to actual performance; they are not necessarily identical to actual performance. Technical specifications available for metering systems provide information necessary to characterize the difference between measured and actual performance.

E.4 Uncertainty Analysis Analytic Methodology

The analytic methodology used for the MCS study is described in this section. The discussion is broken down into five steps:

- Ask Question
- Design Study
- Generate Sample Data
- Calculate the Quantities of Interest for Each Sample
- Analyze Accumulated Quantities of Interest

Ask Question

The first step in the MCS study is to clearly describe the question(s) that the MCS study was designed to answer. In this instance, that question is: How confident can one be that *actual* program total impact deviates from *reported* program total impact by less than certain amounts? The scope of the MCS study includes the following program total impacts:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total System Efficiency

Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility, accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the projects came online during 2013 and, therefore, contributed to energy impacts for only a portion of the year. Some of the projects for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2013. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of the monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came online during 2013, and, therefore, contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the project is metered. However, for many of the SGIP projects, metered data are available for a portion – but not all – of 2013. This complicates any analysis that requires classification of projects as either "metered" or "not metered."

An effort was made to accommodate the project status and data availability details described above without consuming considerable time and resources. To this end, two important simplifying assumptions are included in the MCS study design.

1. Each data archive (e.g., electricity, fuel consumption, useful heat recovery) for each month for each project is classified as being either "metered" (at least 90% of any given month's reported impacts are based on metered data) or "unmetered" (less than 90% of any given month's reported impacts are based on metered data) for MCS purposes.
2. An operations status of "Normal" or "Unknown" was assigned to each month for each unmetered system based on a telephone survey of participants.[2]

Generate Sample Data

Actual values for each of the program impact estimates identified above ("Ask Question") are generated for each sample (i.e., "run" or simulation).

If metered data are available for the project, then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the project, the actual values are created using distributions that reflect performance variability assumptions. *A total of 10,000 simulation runs were used to generate sample data.*

Metered Data Available – Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table E-2. The ranges are based on typical accuracy specifications from manufacturers of metering equipment (e.g., specified accuracy of +/- 2%). A uniform distribution with mean equal to zero is assumed for all three measurement types. This distribution implies that any error value within the stated range has an identical probability of occurring in any measurement. This distribution is more conservative than some other commonly assumed distributions (e.g., normal "bell-shaped" curve) because the outlying values are just as likely to occur as the central values.

[2] This research primarily involved contacting site hosts to determine the operational status of unmetered systems. More details are provided in Appendix B.

TABLE E-2: SUMMARY OF RANDOM MEASUREMENT ERROR VARIABLES

Measurement	Range	Mean	Distribution
Electrical Generation	-0.5% to 0.5%	0%	Uniform
Fuel Consumption	-2% to 2%		
Useful Heat Recovered	-5% to 5%		

Metered Data Unavailable – Generating Sample Data from Performance Distributions

In the case of unmetered projects, the sample data are generated by random assignment from distributions of performance values assumed representative of entire groups of unmetered projects. Because measured performance data are not available for any of these projects, the natural place to look first for performance values is similar metered projects.

Specification of performance distributions for the MCS study involves a degree of judgment in at least two areas: first, in deciding whether or not metered data available for a stratum are sufficient to provide a realistic indication of the distribution of values likely for the unmetered projects; second, when metered data available for a stratum are not sufficient in deciding when and how to incorporate the metered data available for other strata into a performance distribution for the data-insufficient stratum.

Table E-3 shows the groups used to estimate the uncertainty in the California Independent System Operator (CAISO) peak hour impact.

TABLE E-3: PERFORMANCE DISTRIBUTIONS DEVELOPED FOR THE 2013 CAISO PEAK HOUR MCS ANALYSIS

Technology Type	Energy Source	PA
Fuel Cell – Combined Heat and Power	Non-Renewable, Renewable	All
Fuel Cell – Electric Only	All	All
Gas Turbine	Non-Renewable[3]	All
Internal Combustion Engine	Non-Renewable, Renewable	All
Microturbine	Non Renewable, Renewable	All
Wind	All	All

Table E-4 shows the groups used to estimate the uncertainty in the yearly energy production. Internal combustion engines, gas turbines, and microturbines are grouped together for the uncertainty analysis of the annual energy production because of the small number of systems within each technology group for which data were available for 90 percent of each month in the year.

[3] There are no renewable fueled gas turbines in the SGIP as of December 31, 2013

TABLE E-4: PERFORMANCE DISTRIBUTIONS DEVELOPED FOR THE 2013 ANNUAL ENERGY PRODUCTION MCS ANALYSIS

Technology Type	Energy Source	PA
Fuel Cell – Combined Heat and Power	All	All
Fuel Cell – Electric Only	All	All
Internal Combustion Engine / Combustion Turbine	Non-Renewable, Renewable	All
Wind	All	All

Performance distributions were developed for each of the groups in Table E-3 and Table E-4 based on metered data and engineering judgment. In the MCS, a capacity factor is randomly assigned from the performance distribution and sample values are calculated as the product of the capacity factor and system size. All of these performance distributions are shown in Figure E-1 through Figure E-16.

Performance Distributions for Coincident Peak Impacts

Performance distributions used to generate sample data for coincident peak demand impacts are shown in Figure E-1 through Figure E-9. Distributions for unknown operational status are shown in red. Distributions for online operational status are shown in yellow. Operational status online distributions are identical to offline distributions but with no probability at zero capacity factor.

FIGURE E-1: MCS DISTRIBUTION-CHP FUEL CELL COINCIDENT PEAK OUTPUT (NON-RENEWABLE FUEL)

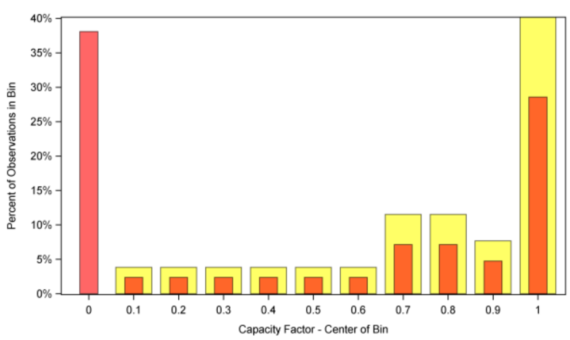


FIGURE E-2: MCS DISTRIBUTION-CHP FUEL CELL COINCIDENT PEAK OUTPUT (RENEWABLE FUEL)

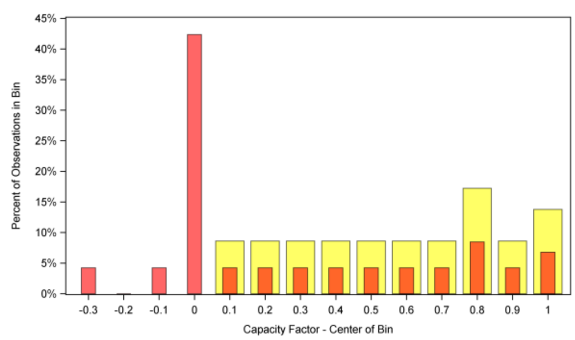


FIGURE E-3: MCS DISTRIBUTION-ELECTRIC-ONLY FUEL CELL COINCIDENT PEAK OUTPUT (ALL FUEL)

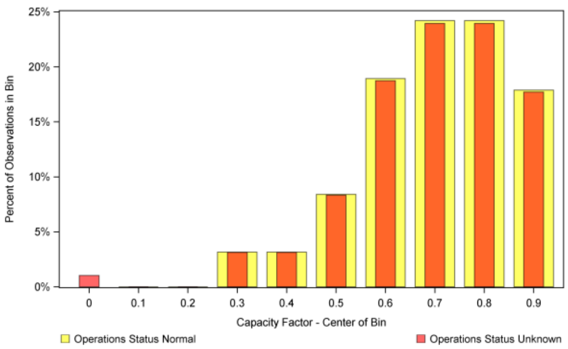


FIGURE E-4: MCS DISTRIBUTION-GAS TURBINE COINCIDENT PEAK OUTPUT (NON-RENEWABLE FUEL)

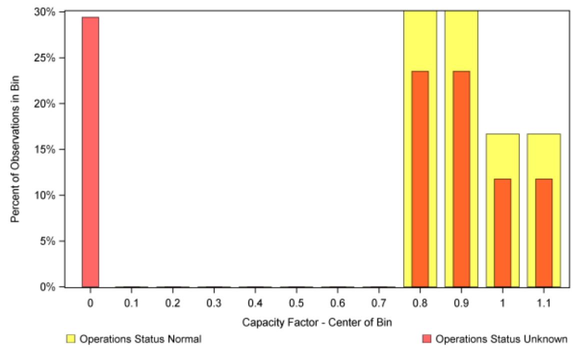


FIGURE E-5: MCS DISTRIBUTION-INTERNAL COMBUSTION ENGINE COINCIDENT PEAK OUTPUT (NON-RENEWABLE FUEL)

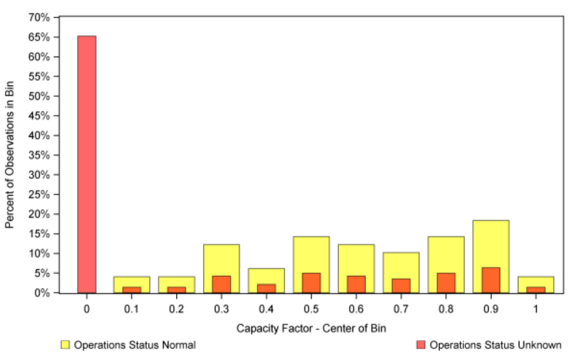


FIGURE E-6: MCS DISTRIBUTION-INTERNAL COMBUSTION ENGINE COINCIDENT PEAK OUTPUT (RENEWABLE FUEL)

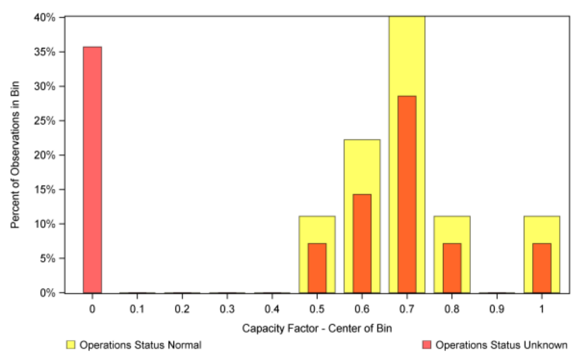


FIGURE E-7: MCS DISTRIBUTION-MICROTURBINE COINCIDENT PEAK OUTPUT (NON-RENEWABLE FUEL)

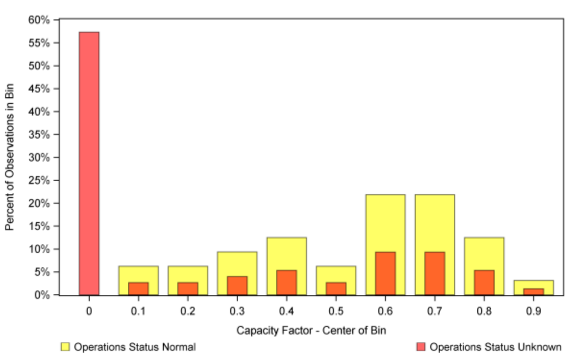


FIGURE E-8: MCS DISTRIBUTION-MICROTURBINE COINCIDENT PEAK OUTPUT (RENEWABLE FUEL)

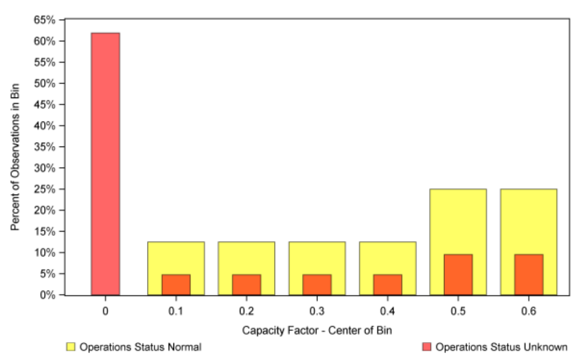
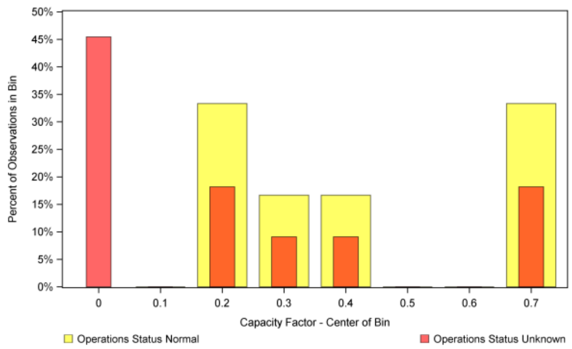


FIGURE E-9: MCS DISTRIBUTION-WIND COINCIDENT PEAK OUTPUT



Performance Distributions for Energy Impacts

Performance distributions used to generate sample data for annual energy impacts are shown in Figure E-10 through Figure E-16. A negative capacity factor indicates energy consumption from the grid to the distributed generator. A capacity factor greater than one indicates generation that exceeds rebated capacity.

FIGURE E-10: MCS DISTRIBUTION-ENGINE/COMBUSTION TURBINE (NON-RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

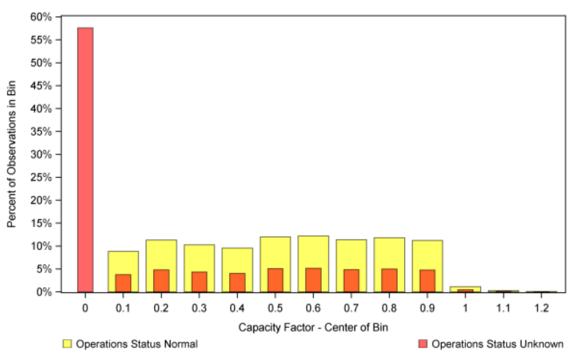


FIGURE E-11: MCS DISTRIBUTION-ENGINE/COMBUSTION TURBINE (RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

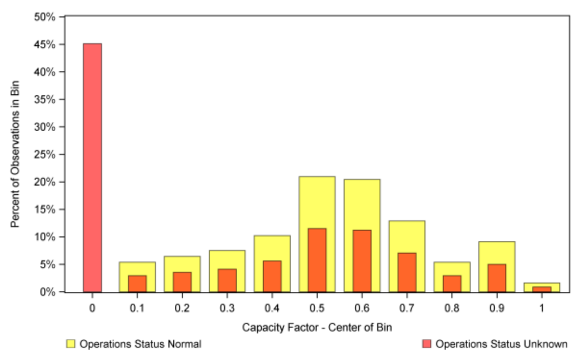


FIGURE E-12: MCS DISTRIBUTION-CHP FUEL CELL (ALL FUEL) ENERGY PRODUCTION (CAPACITY FACTOR)

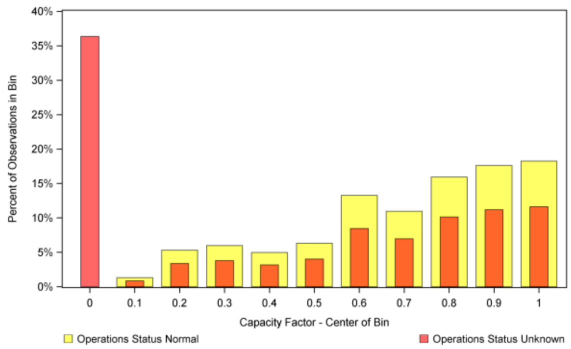


FIGURE E-13: MCS DISTRIBUTION-ELECTRIC-ONLY FUEL CELL (ALL FUEL) ENERGY PRODUCTION (CAPACITY FACTOR)

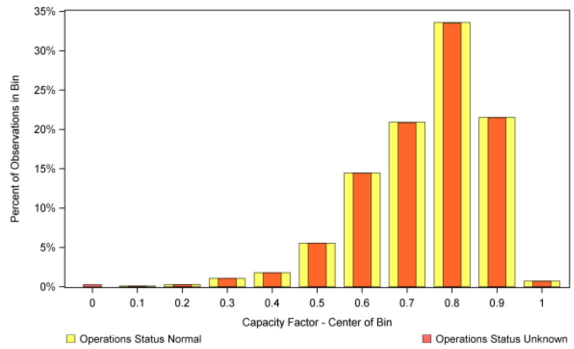


FIGURE E-14: MCS DISTRIBUTION-WIND ENERGY PRODUCTION (CAPACITY FACTOR)

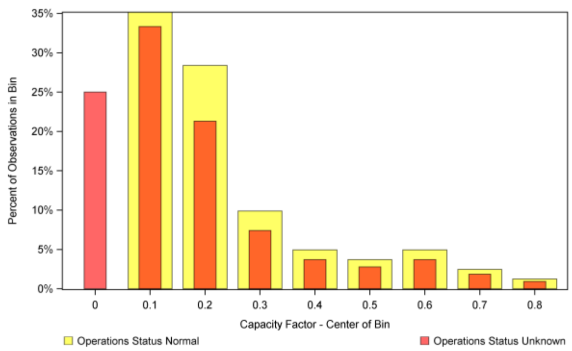


FIGURE E-15: MCS DISTRIBUTION-ENGINE/COMBUSTION TURBINE HEAT RECOVERY RATE (MBTU/KWH)

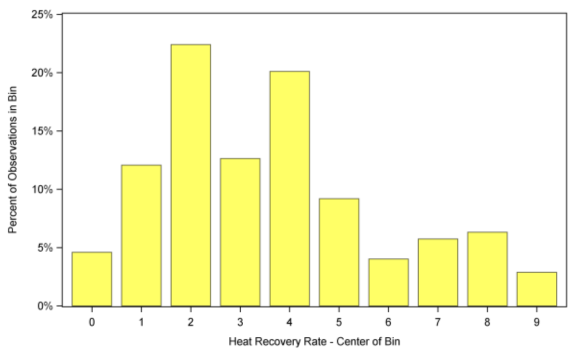
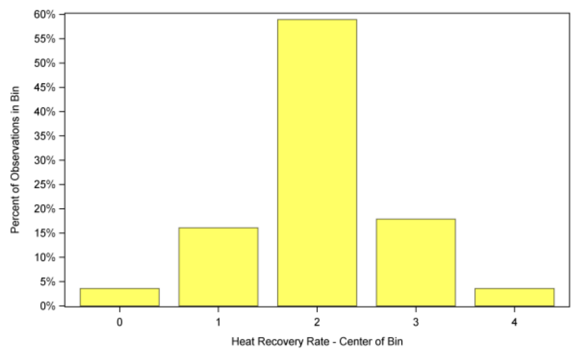


FIGURE E-16: MCS DISTRIBUTION-CHP FUEL CELL HEAT RECOVERY RATE (MBTU/KWH)



Bias

Performance data collected from metered projects were used to estimate program impacts attributable to unmetered projects. If the metered projects are not representative of the unmetered projects, then those estimates will include systematic errors called bias. Potential sources of bias of principal concern for this study include:

Planned Data Collection Disproportionally Favors Dissimilar Groups

Useful heat recovery metering is typically installed on projects that are still under their contract with the SGIP. If the actual useful heat recovery performance of older projects differs systematically from newer metered projects then estimates calculated for older projects will be biased. A similar situation can occur when actual performance differs substantially from performance data assumptions underlying data collection plans.

Actual Data Collection Allocations Deviate from Planned Data Collection Allocations

In program impacts evaluation studies, actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated from unmetered projects may be biased. For example, metered data for a number of fuel cell projects are received from their hosts or the fuel cell manufacturer. The result is a metered dataset that may contain a disproportionate quantity of data received from program participants who operate their own metering. This metered dataset is used to calculate impacts for unmetered sites. If the actual performance of the unmetered projects differs systematically from that of the projects metered by participants, then estimates calculated for the unmetered projects will be biased.

Actual Data Collection Quantities Deviate from Planned Data Collection Quantities

For example, plans called for collection of electrical generation data from all renewable fuel use projects; however, data were actually collected only from a small portion of completed renewable fuel use projects.

Treatment of Bias

In the MCS analysis bias is accounted for during development of performance distributions assumed for unmetered projects. If the metered sample is thought to be biased, then engineering judgment dictates specification of a relatively “more spread out” performance distribution. Bias is accounted for, but the accounting does not involve adjustment of point estimates of program impacts. If engineering judgment dictates an accounting for bias, then the performance distribution assumed for the MCS analysis has a higher standard deviation. The result is a larger confidence interval about the reported point estimate. If there is good reason to believe that bias could be substantial, the confidence interval reported for the point estimate will be larger.

To this point the discussion of bias has been limited to sampling bias. More generally, bias can also be the result of instrumentation yielding measurements that are not representative of the actual parameters being monitored. Due to the wide variety of instrumentation types and data providers involved with this evaluation, it is not possible to say one way or the other whether or not instrumentation bias contributes to error in impacts reported for either metered or unmetered projects. Due to the relative magnitudes involved, instrumentation bias – if it exists – accounts for an insignificant portion of total bias contained in point estimates of program impacts.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered projects. The relative importance of this varies with metering rate. For example, where the metering rate is 90 percent, a 20 percent sampling bias will yield an error of only two percent in total (metered + unmetered) program impacts. All else equal, higher metering rates reduce the impact of sampling bias on estimates of total program impacts.

Calculate the Quantities of Interest for Each Sample

After each simulation run the resulting sample data for individual projects are summed to the program level and the result is saved. The quantities of interest were defined previously:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts

Analyze Accumulated Quantities of Interest

The pools of accumulated MCS analysis results are analyzed to yield summary information about their central tendency and variability. Mean values are calculated and the variability exhibited by the values for the many runs is examined to determine confidence levels (under the constraint of relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

E.5 Results

This section presents the confidence levels in the energy and peak demand impacts results and the precision and confidence intervals associated with those confidence levels. In cases where an accuracy level of 90 percent confidence and 10 percent precision (i.e., 90/10) was not achieved, the reported precision values and confidence intervals are based on a 70 percent confidence level. No results are shown from pressure reduction turbines as there is only one project that has been completed. Results are shown for metered, estimated, and combined impacts.

TABLE E-5: UNCERTAINTY ANALYSIS RESULTS FOR ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS

Technology Type/ Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**1.65%**	**0.507 to 0.524**
Metered	90%	0.04%	0.513 to 0.514
Estimated	70%	12.76%	0.471 to 0.608
Fuel Cell - Electric Only	**90%**	**0.42%**	**0.741 to 0.747**
Metered	90%	0.02%	0.740 to 0.740
Estimated	90%	4.10%	0.741 to 0.804
Gas Turbine	**90%**	**2.10%**	**0.757 to 0.789**
Metered	90%	0.06%	0.770 to 0.771
Estimated	70%	25.37%	0.594 to 0.997
Internal Combustion Engine	**90%**	**3.16%**	**0.196 to 0.209**
Metered	90%	0.02%	0.167 to 0.167
Estimated	90%	7.85%	0.263 to 0.308
Microturbine	**90%**	**3.71%**	**0.266 to 0.287**
Metered	90%	0.03%	0.258 to 0.259
Estimated	70%	13.01%	0.294 to 0.382
Wind	**90%**	**8.20%**	**0.206 to 0.243**
Metered	90%	0.08%	0.223 to 0.223
Estimated	70%	11.73%	0.201 to 0.255

TABLE E-6: UNCERTAINTY ANALYSIS RESULTS FOR ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**2.47%**	**0.499 to 0.524**
Metered	90%	0.05%	0.512 to 0.512
Estimated	70%	13.66%	0.440 to 0.579
Fuel Cell - Combined Heat & Power-R	**90%**	**1.74%**	**0.514 to 0.532**
Metered	90%	0.06%	0.516 to 0.516
Estimated	70%	36.39%	0.478 to 1.025
Fuel Cell - Electric Only	**90%**	**0.42%**	**0.741 to 0.747**
Metered	90%	0.02%	0.740 to 0.740
Estimated	90%	4.10%	0.741 to 0.804
Gas Turbine-N	**90%**	**2.10%**	**0.757 to 0.789**
Metered	90%	0.06%	0.770 to 0.771
Estimated	70%	25.37%	0.594 to 0.997
Internal Combustion Engine-N	**90%**	**3.62%**	**0.181 to 0.194**
Metered	90%	0.03%	0.150 to 0.150
Estimated	90%	8.54%	0.252 to 0.299
Internal Combustion Engine-R	**90%**	**5.79%**	**0.314 to 0.352**
Metered	90%	0.05%	0.315 to 0.315
Estimated	70%	12.54%	0.330 to 0.425
Microturbine-N	**90%**	**3.81%**	**0.288 to 0.310**
Metered	90%	0.04%	0.291 to 0.291
Estimated	70%	15.28%	0.275 to 0.374
Microturbine-R	**70%**	**8.05%**	**0.173 to 0.204**
Metered	90%	0.07%	0.139 to 0.139
Estimated	70%	24.85%	0.301 to 0.501
Wind	**90%**	**8.20%**	**0.206 to 0.243**
Metered	90%	0.08%	0.223 to 0.223
Estimated	70%	11.73%	0.201 to 0.255

TABLE E-7: UNCERTAINTY ANALYSIS FOR CSE ANNUAL ENERGY IMPACT

Technology Type/ Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**0.20%**	**0.562 to 0.564**
Metered	90%	0.07%	0.567 to 0.568
Estimated	70%	17.14%	0.062 to 0.087
Fuel Cell - Electric Only	**90%**	**1.35%**	**0.754 to 0.775**
Metered	90%	0.06%	0.770 to 0.771
Estimated	70%	8.93%	0.654 to 0.783
Gas Turbine	**90%**	**0.10%**	**0.930 to 0.931**
Metered	90%	0.10%	0.930 to 0.931
Internal Combustion Engine	**90%**	**2.93%**	**0.062 to 0.066**
Metered	90%	0.10%	0.065 to 0.065
Estimated	70%	42.11%	0.000 to 0.001
Microturbine	**90%**	**0.08%**	**0.104 to 0.104**
Metered	90%	0.08%	0.104 to 0.104

TABLE E-8: UNCERTAINTY ANALYSIS RESULTS FOR PG&E ANNUAL ENERGY IMPACT

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**1.44%**	**0.518 to 0.533**
Metered	90%	0.05%	0.554 to 0.554
Estimated	70%	14.55%	0.138 to 0.185
Fuel Cell - Electric Only	**90%**	**0.41%**	**0.722 to 0.728**
Metered	90%	0.02%	0.721 to 0.721
Estimated	90%	5.08%	0.733 to 0.812
Gas Turbine	**70%**	**13.63%**	**0.276 to 0.363**
Metered	90%	0.26%	0.036 to 0.036
Estimated	70%	15.33%	0.708 to 0.965
Internal Combustion Engine	**90%**	**5.44%**	**0.202 to 0.225**
Metered	90%	0.03%	0.159 to 0.160
Estimated	70%	7.57%	0.292 to 0.339
Microturbine	**90%**	**5.35%**	**0.354 to 0.394**
Metered	90%	0.04%	0.368 to 0.368
Estimated	70%	23.06%	0.299 to 0.479
Wind	**70%**	**7.76%**	**0.178 to 0.207**
Metered	90%	0.09%	0.176 to 0.176
Estimated	70%	16.50%	0.185 to 0.259

TABLE E-9: UNCERTAINTY ANALYSIS RESULTS FOR SCE ANNUAL ENERGY IMPACT

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**5.78%**	**0.432 to 0.485**
Metered	90%	0.07%	0.421 to 0.422
Estimated	70%	24.17%	0.532 to 0.871
Fuel Cell - Electric Only	**90%**	**0.96%**	**0.786 to 0.801**
Metered	90%	0.03%	0.796 to 0.797
Estimated	90%	8.47%	0.706 to 0.837
Internal Combustion Engine	**90%**	**6.55%**	**0.194 to 0.221**
Metered	90%	0.05%	0.171 to 0.172
Estimated	70%	8.39%	0.248 to 0.293
Microturbine	**70%**	**9.16%**	**0.144 to 0.173**
Metered	90%	0.07%	0.111 to 0.111
Estimated	70%	18.47%	0.218 to 0.317
Wind	**70%**	**6.65%**	**0.229 to 0.261**
Metered	90%	0.11%	0.254 to 0.254
Estimated	70%	15.76%	0.195 to 0.268

TABLE E-10: UNCERTAINTY ANALYSIS RESULTS FOR SCG ANNUAL ENERGY IMPACT

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**5.52%**	**0.473 to 0.528**
Metered	90%	0.09%	0.468 to 0.469
Estimated	70%	22.94%	0.522 to 0.833
Fuel Cell - Electric Only	**90%**	**1.77%**	**0.708 to 0.733**
Metered	90%	0.04%	0.704 to 0.705
Estimated	70%	6.80%	0.742 to 0.850
Gas Turbine	**90%**	**3.43%**	**0.768 to 0.823**
Metered	90%	0.08%	0.799 to 0.800
Estimated	70%	70.48%	0.225 to 1.297
Internal Combustion Engine	**90%**	**4.87%**	**0.204 to 0.225**
Metered	90%	0.04%	0.201 to 0.201
Estimated	70%	9.21%	0.230 to 0.276
Microturbine	**90%**	**2.31%**	**0.263 to 0.275**
Metered	90%	0.06%	0.268 to 0.268
Estimated	70%	14.97%	0.235 to 0.318

TABLE E-11: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**2.99%**	**0.516 to 0.548**
Metered	90%	0.13%	0.538 to 0.539
Estimated	70%	58.70%	0.171 to 0.658
Fuel Cell - Electric Only	**90%**	**1.47%**	**0.696 to 0.717**
Metered	90%	0.06%	0.698 to 0.699
Estimated	70%	9.81%	0.712 to 0.867
Gas Turbine	**70%**	**9.50%**	**0.742 to 0.898**
Metered	90%	0.22%	0.826 to 0.829
Estimated	70%	63.34%	0.290 to 1.294
Internal Combustion Engine	**70%**	**6.59%**	**0.216 to 0.246**
Metered	90%	0.09%	0.198 to 0.198
Estimated	70%	15.69%	0.259 to 0.355
Microturbine	**70%**	**9.46%**	**0.236 to 0.286**
Metered	90%	0.11%	0.244 to 0.244
Estimated	70%	45.74%	0.175 to 0.469
Wind	**70%**	**12.45%**	**0.235 to 0.302**
Metered	90%	0.26%	0.279 to 0.280
Estimated	70%	41.28%	0.143 to 0.345

TABLE E-12: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS FOR CSE

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**0.65%**	**0.661 to 0.669**
Metered	90%	0.28%	0.665 to 0.668
Estimated	70%	70.00%	0.000 to 0.000
Fuel Cell - Combined Heat & Power-R	**90%**	**--**	**0.000 to 0.000**
Metered	90%	--	0.000 to 0.000
Fuel Cell - Electric Only	**90%**	**0.18%**	**0.782 to 0.785**
Metered	90%	0.18%	0.782 to 0.785
Gas Turbine-N	**90%**	**0.34%**	**0.998 to 1.005**
Metered	90%	0.34%	0.998 to 1.005
Internal Combustion Engine-N	**90%**	**7.33%**	**0.077 to 0.089**
Metered	90%	0.37%	0.084 to 0.085
Estimated	70%	100.0%	0.000 to 0.000
Internal Combustion Engine-R	**90%**	**0.45%**	**0.814 to 0.822**
Metered	90%	0.45%	0.814 to 0.822
Microturbine-N	**90%**	**0.34%**	**0.157 to 0.158**
Metered	90%	0.34%	0.157 to 0.158
Microturbine-R	**90%**	**0.45%**	**0.080 to 0.081**
Metered	90%	0.45%	0.080 to 0.081

TABLE E-13: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS FOR PG&E

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**3.43%**	**0.484 to 0.518**
Metered	90%	0.22%	0.539 to 0.541
Estimated	70%	39.91%	0.014 to 0.033
Fuel Cell - Combined Heat & Power-R	**90%**	**0.37%**	**0.535 to 0.539**
Metered	90%	0.37%	0.535 to 0.539
Fuel Cell - Electric Only	**90%**	**1.57%**	**0.659 to 0.680**
Metered	90%	0.07%	0.658 to 0.659
Estimated	70%	10.63%	0.698 to 0.864
Gas Turbine-N	**70%**	**15.79%**	**0.246 to 0.339**
Metered	90%	.	0.000 to 0.000
Estimated	70%	15.79%	0.695 to 0.956
Internal Combustion Engine-N	**70%**	**14.35%**	**0.183 to 0.244**
Metered	90%	0.15%	0.147 to 0.147
Estimated	70%	24.61%	0.245 to 0.405
Internal Combustion Engine-R	**70%**	**20.10%**	**0.196 to 0.294**
Metered	90%	0.28%	0.196 to 0.197
Estimated	70%	58.50%	0.189 to 0.720
Microturbine-N	**70%**	**16.12%**	**0.346 to 0.480**
Metered	90%	0.17%	0.430 to 0.431
Estimated	70%	73.22%	0.102 to 0.658
Microturbine-R	**90%**	**8.23%**	**0.111 to 0.131**
Metered	90%	0.32%	0.108 to 0.108
Estimated	70%	100.0%	0.000 to 1.099
Wind	**70%**	**13.60%**	**0.296 to 0.390**
Metered	90%	0.27%	0.378 to 0.380
Estimated	70%	60.27%	0.099 to 0.400

TABLE E-14: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS FOR SCE

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**21.40%**	**0.560 to 0.865**
Metered	90%	0.36%	0.693 to 0.698
Estimated	70%	98.89%	0.008 to 1.507
Fuel Cell - Combined Heat & Power-R	**90%**	**0.28%**	**0.504 to 0.507**
Metered	90%	0.28%	0.504 to 0.507
Fuel Cell - Electric Only	**90%**	**3.54%**	**0.759 to 0.815**
Metered	90%	0.13%	0.786 to 0.788
Estimated	70%	28.57%	0.560 to 1.008
Internal Combustion Engine-N	**70%**	**14.71%**	**0.237 to 0.318**
Metered	90%	0.17%	0.263 to 0.263
Estimated	70%	33.75%	0.198 to 0.399
Internal Combustion Engine-R	**90%**	**6.37%**	**0.383 to 0.435**
Metered	90%	0.29%	0.371 to 0.373
Estimated	70%	14.29%	0.617 to 0.823
Microturbine-N	**70%**	**25.54%**	**0.127 to 0.214**
Metered	90%	0.33%	0.173 to 0.174
Estimated	70%	75.79%	0.039 to 0.286
Microturbine-R	**70%**	**51.49%**	**0.109 to 0.342**
Metered	90%	0.45%	0.139 to 0.140
Estimated	70%	100.0%	0.000 to 0.743
Wind	**70%**	**20.29%**	**0.181 to 0.273**
Metered	90%	0.44%	0.219 to 0.221
Estimated	70%	54.80%	0.109 to 0.374

TABLE E-15: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS FOR SCG

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**2.98%**	**0.325 to 0.345**
Metered	90%	0.34%	0.353 to 0.355
Estimated	70%	26.76%	0.000 to 0.000
Fuel Cell - Combined Heat & Power-R	**90%**	**0.46%**	**0.410 to 0.413**
Metered	90%	0.46%	0.410 to 0.413
Fuel Cell - Electric Only	**90%**	**6.03%**	**0.644 to 0.726**
Metered	90%	0.15%	0.660 to 0.662
Estimated	70%	20.00%	0.650 to 0.975
Gas Turbine-N	**70%**	**16.16%**	**0.711 to 0.985**
Metered	90%	0.28%	0.870 to 0.874
Estimated	70%	100.0%	0.000 to 1.564
Internal Combustion Engine-N	**70%**	**11.94%**	**0.192 to 0.244**
Metered	90%	0.18%	0.209 to 0.209
Estimated	70%	36.14%	0.155 to 0.331
Internal Combustion Engine-R	**70%**	**33.78%**	**0.331 to 0.670**
Metered	90%	0.45%	0.563 to 0.568
Estimated	70%	71.62%	0.127 to 0.766
Microturbine-N	**90%**	**9.46%**	**0.188 to 0.227**
Metered	90%	0.21%	0.207 to 0.207
Estimated	70%	49.14%	0.106 to 0.312

TABLE E-16: UNCERTAINTY ANALYSIS RESULTS FOR SYSTEM EFFICIENCY BY TECHNOLOGY TYPE AND BASIS

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**2.43%**	**0.603 to 0.633**
Metered	90%	0.48%	0.625 to 0.631
Estimated	90%	3.17%	0.596 to 0.635
Fuel Cell - Electric Only	**90%**	**0.26%**	**0.537 to 0.540**
Metered	90%	0.12%	0.545 to 0.546
Estimated	90%	2.32%	0.520 to 0.544
Gas Turbine	**90%**	**5.99%**	**0.691 to 0.780**
Metered	90%	1.17%	0.781 to 0.800
Estimated	90%	6.77%	0.678 to 0.776
Internal Combustion Engine	**90%**	**2.65%**	**0.515 to 0.543**
Metered	90%	0.85%	0.548 to 0.558
Estimated	90%	2.78%	0.513 to 0.543
Microturbine	**90%**	**4.15%**	**0.359 to 0.390**
Metered	90%	0.74%	0.401 to 0.407
Estimated	90%	4.30%	0.355 to 0.387

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330 Madson Pl.
Davis, CA 95618

Phone: 1.800.635.5461
Fax: 1.509.891.3355