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CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation

Final Report

Submitted to:

PG&E
and
The Self-Generation Incentive Program Working Group

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July 7, 2011

ACKNOWLEDGEMENTS

We would like to acknowledge the following for their contributions to the 2010 Self-Generation Incentive Program (SGIP) Impact Evaluation Report:

- The Itron employees who were engaged on this project;
- Neal Reardon and Melicia Charles at the California Public Utilities Commission and Andrea Riemann at PG&E for providing invaluable guidance, comments on earlier drafts, feedback, and patience;
- The SGIP Program Administrators and IOU representatives (PG&E, SCE, SCG, SDG&E, and CCSE) for their review of earlier versions and their assistance in obtaining required and critical information for this report;
- Those third-party data providers who supplied performance data for this report; and
- Energy and Environmental Economics (E3) for their assistance on updating the 2010 avoided cost information.

Glossary

Abbreviations & Acronyms

Term	Definition
CAISO	California Independent System Operator
CCSE	California Center for Sustainable Energy
CEC	California Energy Commission
CO_2	Carbon Dioxide
CO_2Eq	CO_2 equivalent
CPUC	California Public Utilities Commission
IOU	Investor-owned Utility
NEM	Net Energy Metering
NOx	NOx refers to nitric oxide (NO) and nitrogen dioxide (NO2).
PA	Program Administrator
PG&E	Pacific Gas and Electric Company
PM-10	Particulate matter (PM) with diameter of 10 micrometers or less.
POU	Publicly-owned Utility
PPA	Power Purchase Agreement
PY	Program Year
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SGIP	Self-Generation Incentive Program

Key Terms

Term	Definition
Applicant (as defined for SGIP)	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 the main point of communication between 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 derived from landfills, wastewater treatment facilities, food processing facilities employing digesters and dairy operations employing digesters.
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	The ratio of electrical energy generated to the electrical energy that would be produced by the generating system at full capacity during the same period.
Combined Heat and Power (CHP)	A facility where both electricity and useful heat are produced simultaneously.
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 the CO_2Eq, the global warming potential of a gas as compared to that of CO2 is used as the conversion factor (e.g., The global warming potential of CH_4 is 21 times that of CO_2. Thus, to calculate the CO_2Eq of a given amount of CH4, you multiply that amount by the conversion factor of 21.
Commercial	Commercial entities are defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and for-profit health, social, and educational institutions.
Confidence Interval	A particular kind of interval estimate of a population parameter used to indicate the reliability of an estimate. It is an observed interval (i.e., calculated from observations), in principle different from sample to sample, that frequently includes the parameter of interest, if the experiment is repeated. How frequently the observed interval contains the parameter is determined by the confidence level or confidence coefficient. A confidence interval with a particular confidence level is intended to give the assurance that, if the statistical model is correct, then taken over all the data that might have been obtained, the procedure for constructing the interval would deliver a confidence interval that included the true value of the parameter the proportion of the time set by the confidence level.
Confidence Level (also Confidence Coefficient)	The degree of accuracy resulting from the use of a statistical sample. For example, if a sample is designed at the 90/10 confidence (or precision) level, the resultant sample estimate will be within ±10 percent of the true value, 90 percent of the time.

Term	Definition
Directed Biogas	Biogas delivered through a natural gas pipeline system and its nominal equivalent used at a distant customer's site. This is a renewable fuel.
Electrical Conversion Efficiency	The ratio of electrical energy produced to the fuel (lower heat value) energy used.
Flaring (of Biogas)	Within the context of this report, flaring refers to a basis of how biogas is treated for GHG emission accounting purposes. A basis of flaring 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 CO_2.
Heat Rate	The ratio of heat energy produced to the electrical energy produced.
Lower Heating Value (LHV)	A measure of energy released from a fuel with water in a gaseous state.
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 demand.
Marginal Heat Rate	Heat rate is a measurement used to calculate how efficiently a generator uses heat energy (or its efficiency in converting fuel to electricity). It is expressed as the number of Btus of heat required to produce a kilowatt-hour of energy. The marginal heat rate is the amount of source energy that is saved as a result of a change in generation.
On site Biogas	On site biogas refers to biogas projects where the biogas source is located directly at the host site where the SGIP system is located.
Rebated Capacity	The capacity rating associated with the rebate (incentive) provided to the program participant. The rebated capacity may be lower than the typical "nameplate" rating of the technology.
Recovered Waste Heat	Recovered waste heat refers to the amount of waste heat delivered at the back end of a CHP prime mover and is recoverable for possible end use. However, if heat load at the host site is lower than the amount of recoverable waste heat, the useful waste heat will be lower than the recoverable waste heat.
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	This is the manufacturer rated nominal size that approximates the generator's highest capacity to generate electricity under specified conditions.

Term	Definition
Useful Waste Heat	This is the heat actually delivered and used to meet the on-site heating demand for a specific process or application at the host site. Useful waste heat may differ significantly from recovered waste heat referred to in CHP manufacturer specifications.
Venting (of Biogas)	Within the context of this report, venting refers to a basis of how biogas is treated for GHG emission accounting purposes. A basis of venting 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).*

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Executive Summary

ES.1 On the 2010 SGIP Impact Evaluation

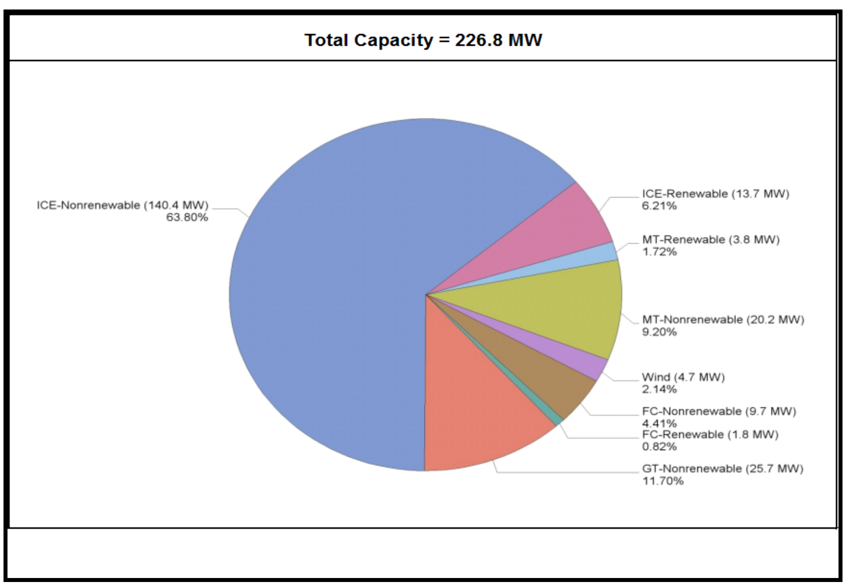
The SGIP 2010 impact evaluation is significantly different from the past nine impact evaluations. Like past evaluations, it examines impacts associated with distributed generation (DG) technologies deployed under the SGIP on California's electricity system and the environment. However, the 2010 SGIP impact evaluation also looks at lessons learned from the past nine years of operation of combined heat and power (CHP) systems. Based on those findings and looking at prospective projects, this evaluation identifies future opportunities and challenges as the SGIP moves forward. To that end, we make specific recommendations to help the SGIP achieve significant reductions in greenhouse gas (GHG) emissions and sustain higher levels of performance from deployed projects.

ES.2 Key Findings

ES.2.1 Program Status

- **Project Status**: As of the end of 2010, there were 441 projects on-line, representing approximately 227 MW of rebated capacity. Internal combustion (IC) engines, gas turbines, and microturbines powered by non-renewable fuels contributed over 186 MW of rebated capacity, or more than three quarters the total on-line capacity of the SGIP.

Figure ES-1: SGIP Completed Projects as of 12/31/2010

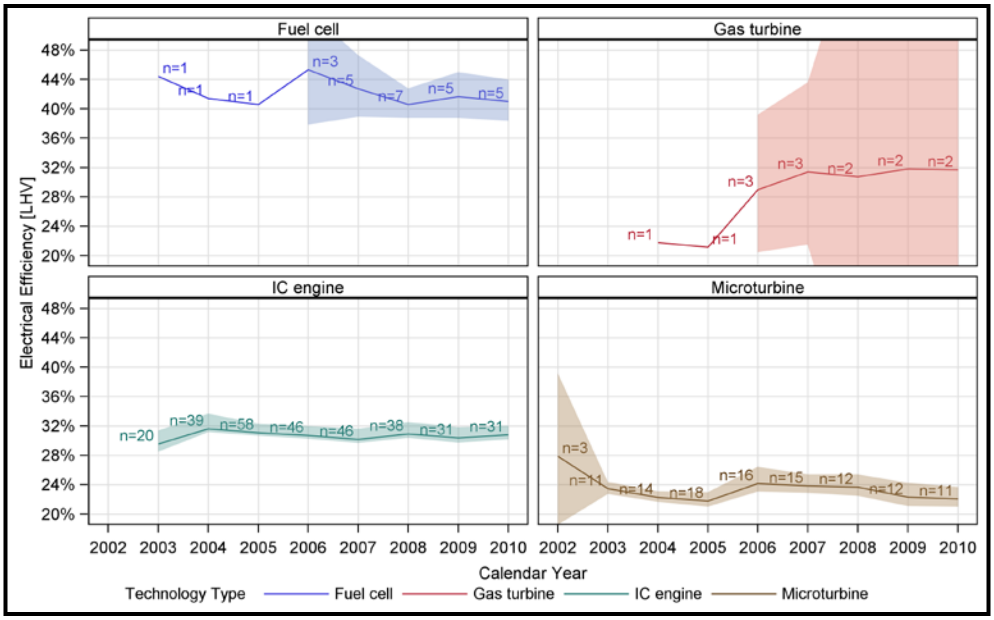


- **Incentives Paid and Reserved**: By the end of 2010, over $185 million in incentive payments had been paid to completed projects. The reserved backlog totaled $210 million, of which $119 million were for directed biogas fuel cells and $30 million for wind projects.
- **Funds Leveraged**: For every $1 of SGIP incentives paid, approximately $2.6 of other funding was leveraged.

ES.2.2 The SGIP Fleet Over Time

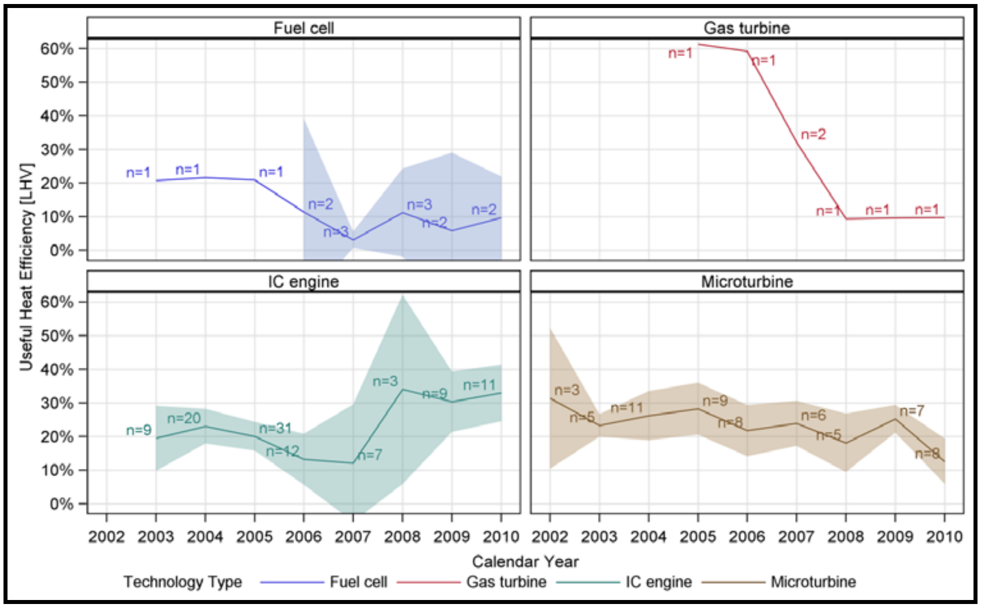
- **Performance of CHP Systems**: Performance of CHP systems in the SGIP fleet should be considered from the basis of efficiencies (electrical, useful waste heat and total system) and utilization.

Figure ES-2: Annual Mean Electrical Conversion Efficiency by CHP Technology



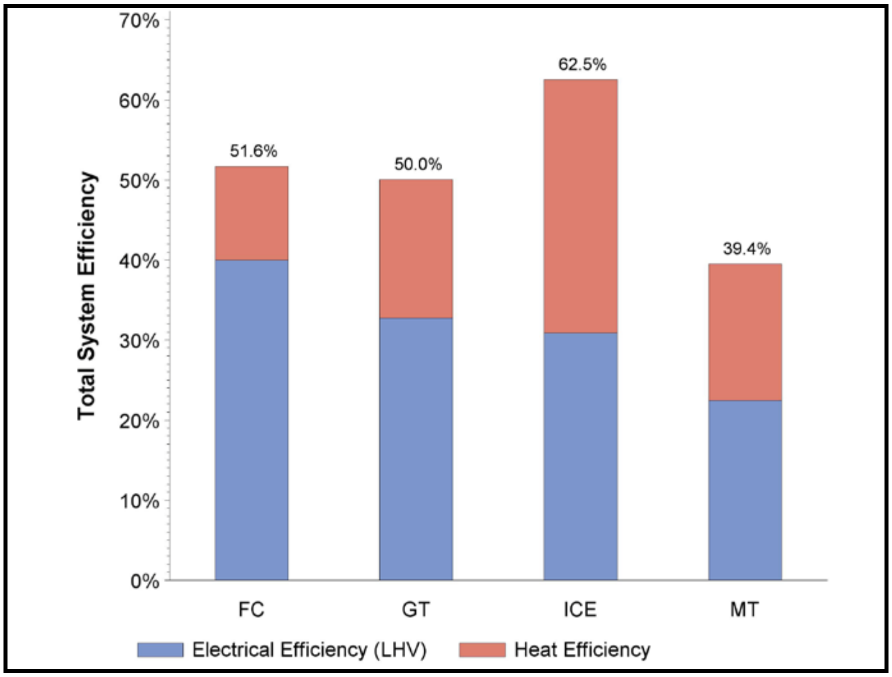
– Overall, electrical conversion efficiencies of CHP systems deployed under the SGIP remained fairly stable over time and matched expected values.

Figure ES-3: Annual Mean Useful Heat Conversion Efficiency by CHP Technology



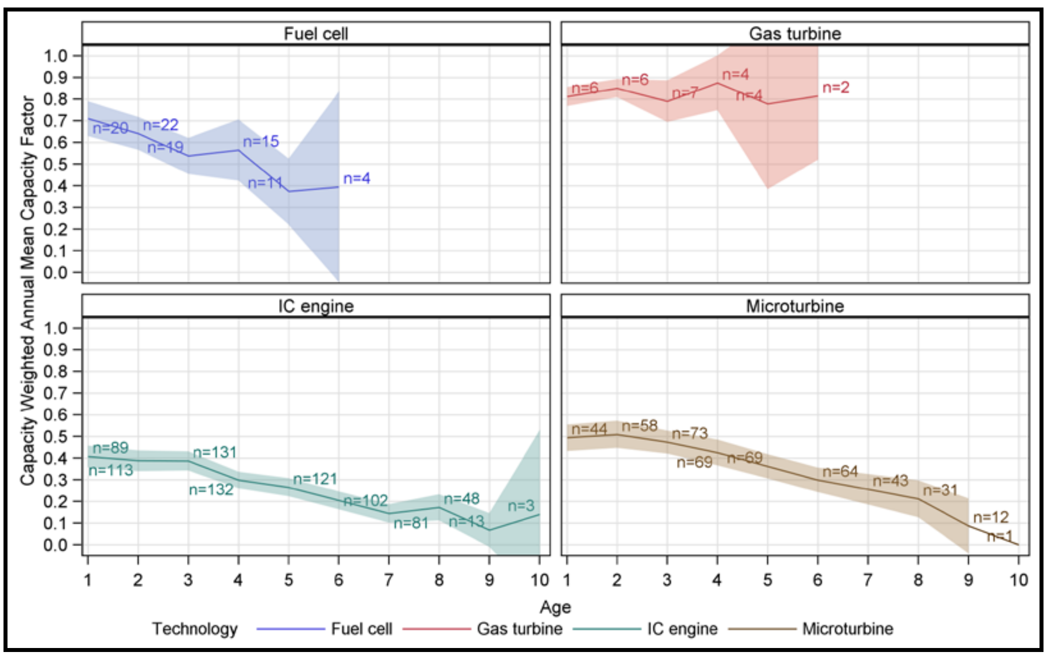
– Useful waste heat recovery efficiencies from CHP systems may be far different than heat recovery estimates provided by manufacturer specifications. Manufacturer specifications refer to heat that could be available for use. However, useful waste heat recovery is dependent not just on the amount of heat provided from the CHP system but also on the heat demand at the site. If the site heat demand is lower than the heat being provided by the CHP system, the heat is dumped and useful waste heat recovery efficiency is reduced.

Figure ES-4: Total System Efficiency Components by CHP Technology (2010)



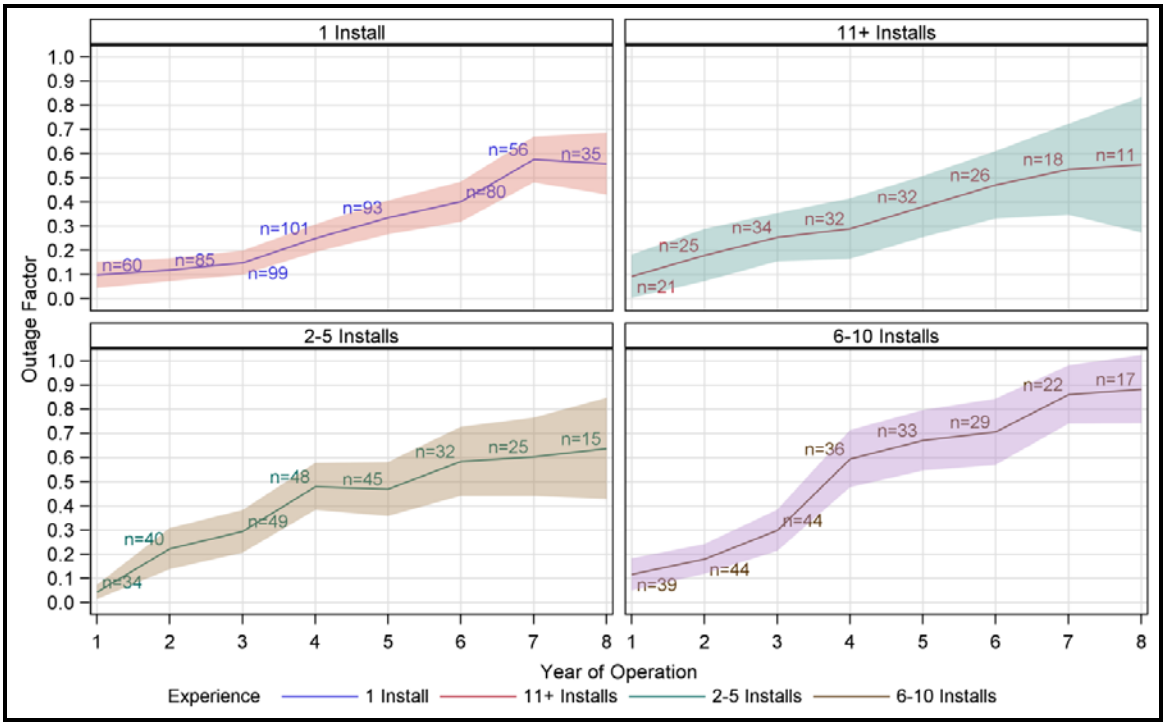
– With the exception of IC engines, total system efficiency for CHP systems at the end of 2010 was substantially below 60%. Unless total system efficiencies increase for CHP systems, they will fall short of the CPUC proposed 60% minimum efficiency target.

Figure ES-5: Annual Mean Capacity Factors by Age and Technology



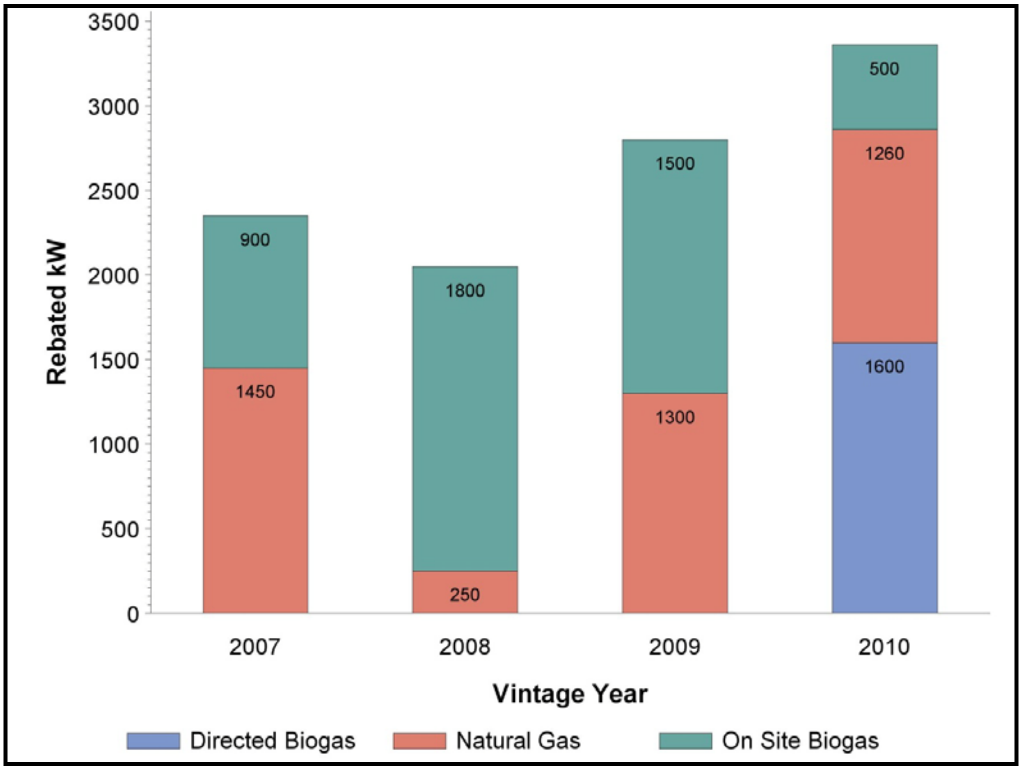
- High annual capacity factor or utilization is critical to achieving electricity system benefits and economic sustainability of CHP projects. All the CHP technologies, with the exception of gas turbines, have suffered rapid declines with age in annual utilization or capacity factor. Extended outages are occurring as early as in the first year of operation. Some systems have been decommissioned after as little as three years of operation. Half of IC engine capacity is unavailable by age five and half of microturbine capacity by age six.

Figure ES-6: Annual Outage Factor by Age and Developer System Completions



- **SGIP Fleet**: Legislative changes to the SGIP occurring in late 2006 made a number of conventional CHP systems ineligible to receive SGIP incentives.
  - Despite being restructured to become primarily a fuel cell and wind program, the SGIP is still mostly made up of IC engines and turbines.
  - Fueled by pending applications of directed biogas fuel cells, the SGIP is slated to grow faster than in previous years. Most of the growth in new fuel cell systems has been occurring in the PG&E service territory.

Figure ES-7: Fuel Cell Capacity Additions by Fuel Type



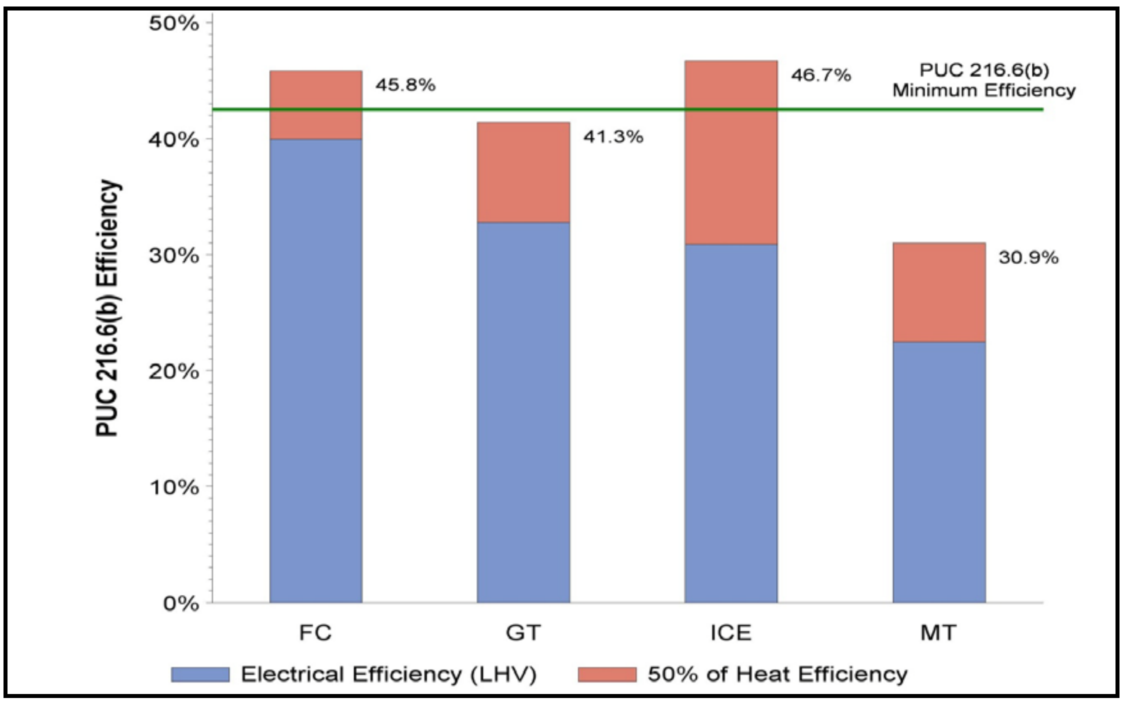
ES.2.3 SGIP 2010 Impacts

- **Annual Energy**: During 2010, SGIP systems generated over 681 GWh; enough electricity to meet the annual requirements of over 102,000 homes. PG&E and SCG have the largest total annual energy impacts at over 237 GWh and 275 GWh, respectively. In comparison, the annual energy impacts for SCE and CCSE were 74 GWh and 92 GWh, respectively.
- **Peak Demand**: In 2010, the CAISO peak of 47,282 MW was reached on August 25, 2010 from 3:00 to 4:00 P.M. Pacific Daylight Time. The total rebated capacity of on-line SGIP projects was nearly 216 MW.

  - The total impact of the SGIP projects coincident with the CAISO peak load was approximately 97 MW. The collective peak hour capacity factor of the SGIP projects on the CAISO 2010 peak was approximately 0.46 kW per kW of rebated capacity.

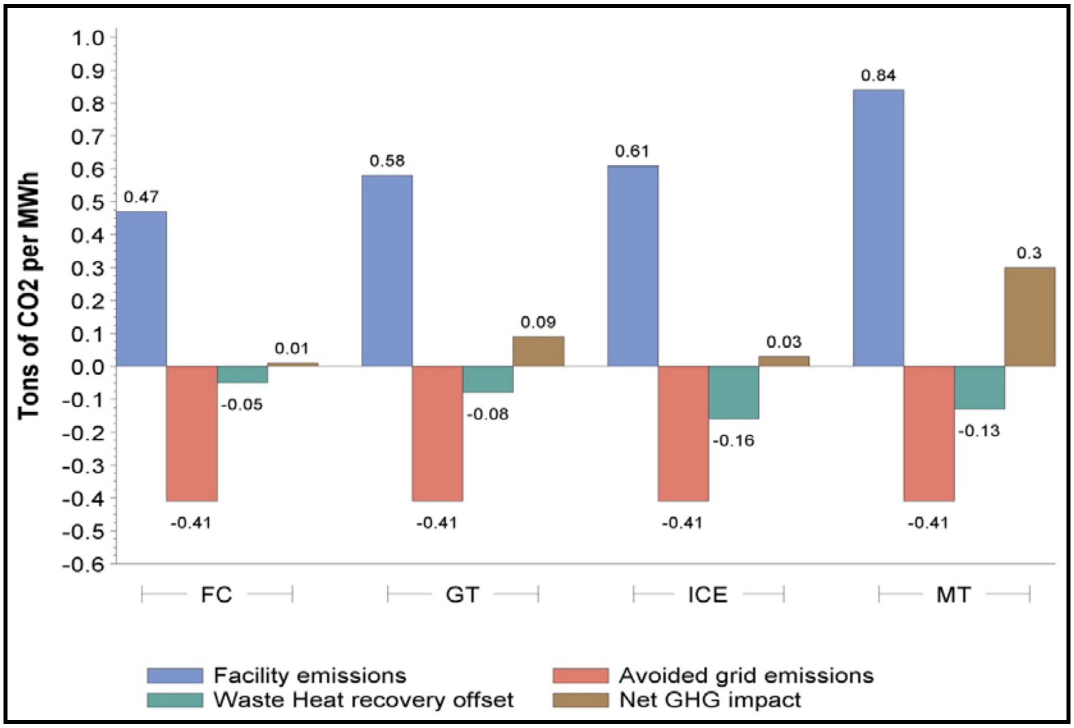
- **Heat and Fuel**: CHP systems consume fuel but they also displace fuel that would otherwise be used to fulfill a facility heat demand.
  - In 2010, an estimated 6,911 billion Btu of natural gas were consumed by SGIP facilities and 1,678 billion Btu of gas were offset from boilers.
- **Performance and Compliance**: Public Utility Code (PUC) 216.6 requires that participating non-renewable-fueled fuel cells and engines/turbines meet minimum levels of annual thermal energy utilization (5%) and overall system efficiency (42.5%).
  - All of the CHP technologies in the SGIP achieved and exceeded the PUC 216.6(a) requirement of providing at least 5% of the output energy as useful heat.
  - Most SGIP CHP technologies have historically had trouble meeting the 216.6(b) minimum efficiency requirements of 42.5%.
  - In 2010, the greatest contributing factor towards the compliance of fuel cell systems is their high electrical efficiency. The opposite is true for IC engines, where high useful heat recovery efficiency sets them apart from other technologies.

Figure ES-8: CHP System Ability to Meet PUC 216.6(b) Efficiencies by Technology



- **Greenhouse Gas (GHG) Emissions:** With the passage of SB 412 in 2009 , a major focus of the SGIP has become GHG emission reductions.
  - At the end of 2010, the SGIP increased GHG emissions relative to the grid. Projects in the SGIP emitted a total of nearly 30,000 tons of net GHG emissions (CO_2 Eq) into the atmosphere.
  - The single largest source of increased GHG emissions in 2010 came from non-renewable CHP systems. These systems produced over 50,000 tons of net positive GHG emissions.
  - The only source of net GHG emission reductions from the SGIP in 2010 came from renewable-fueled dairy biogas projects. These projects were responsible for reducing over 28,000 tons of GHG emissions (CO_2 Eq). GHG emission reduction from these projects was due to capture of methane (contained in the biogas) that would otherwise have been released into the atmosphere.

Figure ES-9: CO_2 Emissions for Non-Renewable CHP Projects in 2010

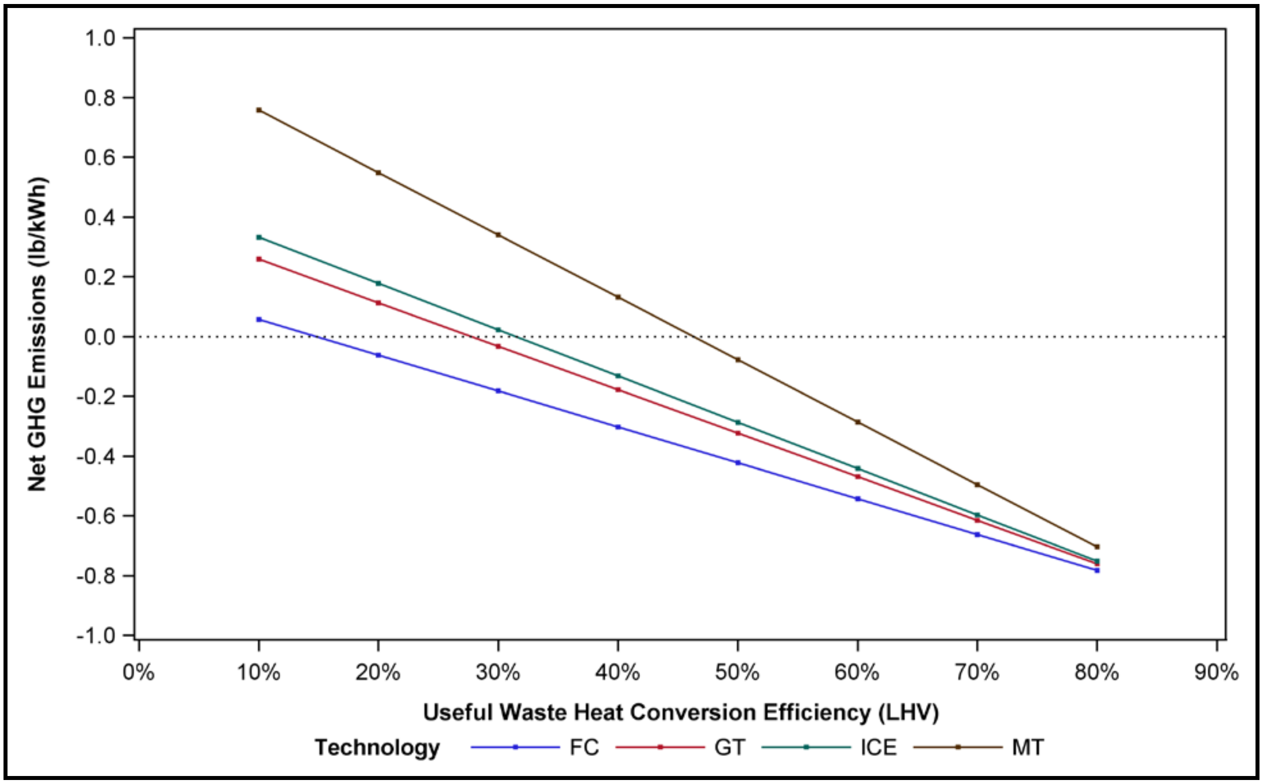


  - In general, CO_2 emissions from non-renewable-fueled SGIP systems exceed CO_2 emissions from the displaced grid-based electricity. Useful waste heat recovery operations act to reduce CO_2 emissions that would have resulted from use of on-site boilers. However, the magnitude of the reduced boiler CO_2 emissions is insufficient to enable non-renewable CHP systems to have net negative GHG emission values.

ES.2.4 The SGIP Fleet Moving Forward

- **Lessons Learned**: Based on 10 years of operational history on CHP systems deployed in the SGIP, three key lessons become evident:
  - CHP systems in the SGIP have shown declining capacity factor over time and increasing amounts of extended outages as the systems age.
  - Most CHP systems in the SGIP have problems achieving the PUC 216.6(b) efficiency threshold of 42.5%.
  - CHP systems in the SGIP are increasing net GHG emissions relative to grid generated electricity rather than resulting in net GHG emission reductions.
- **Improving Capacity Factors/Reducing Outages**
  - Increased outages and reduced capacity factors appear to be directly related to system age. Other studies have indicated that reduced capacity factor is linked to issues with equipment maintenance and warranty; and increased cost of generating electricity.
  - Maintenance agreements and warranties that span a significant amount of the useful life of the critical CHP system equipment will help prevent increased outages.
  - CHP projects that are based on coincident electrical and thermal loads have more attractive economics. As such, these projects may be more likely to be well maintained and kept operating even if fuel prices increase.
- **Improving System Efficiencies**
  - For a CHP system to successfully achieve and exceed the PUC 216.6(b) threshold efficiency, the host site must have sufficiently high thermal demand coincident to the electrical demand.
  - Going forward, PAs may want to consider linking eligibility of CHP projects to minimum useful waste heat conversion efficiencies that reflect thermal demand coincident with the electrical demand at the site.
- **Making the SGIP a Net GHG Emission Reduction Program**
  - Net GHG emissions can be linked quantitatively to electrical conversion and useful waste heat recovery efficiencies of CHP systems. The development of a GHG emissions nomograph allows PAs and the CPUC to set net GHG emission rate targets for CHP systems deployed in the SGIP. These targets will help ensure that SGIP reduces rather than increases net GHG emissions.

Figure ES-10: Net GHG Emissions Nomograph for the SGIP CHP Systems



- CHP systems fueled by non-renewable fuels can be targeted to achieve zero, 10% below zero, and 20% below zero net GHG emissions through increased useful waste heat recovery efficiencies.
- At GHG emission targets of 10% below zero, the SGIP would reduce up to 55,000 tons per year of net GHG emissions. However, these targets require significantly higher useful waste heat efficiencies than currently achieved with SGIP CHP systems.
- Adding 1 MW of new "venting" projects would capture over 50,000 tons per year of GHG emission reductions. This amount of GHG reduction would have made the SGIP a net GHG reduction program in 2010 rather than a net GHG contributor.
- The challenges with adding new renewable "venting" projects include often contradictory policies and regulations regarding permitting of biogas to energy projects; high transaction costs associated with developing small scale projects; lack of capital for project development and confusion over utility interconnection processes.

ES.3 Recommendations

The CPUC and PAs can make changes that will help the SGIP achieve the goal of providing net GHG emission reductions and maintain sustained high levels of project performance. Based on lessons learned and our analyses, we recommend the CPUC and PA take the following actions:

1. Adopt targets set at achieving net GHG emissions at 10% below net zero levels for all CHP technologies. Because electrical conversion efficiencies for CHP systems are not expected to change significantly in the near term, the focus should be on setting useful waste heat recovery efficiencies that correspond to the desired net GHG emission targets. The needed useful waste heat recovery efficiencies can be taken from the developed GHG Emissions Nomograph.
2. Modify the useful waste heat recovery worksheet so it flags and alerts SGIP applicants if the useful waste heat recovery efficiency of the proposed project is below the required efficiency level.
3. Coincidence of thermal and electrical loads is critical to ensuring that SGIP projects actually achieve net GHG emission reductions. While potential sites often have hourly electrical load data, hourly thermal data is less available. Consequently, the CPUC and PAs should consider use of a combined capacity-based and performance-based incentive that focuses on thermal performance. This will encourage project developers to collect thermal load data through short-term metering. At the same time, it will enable the CPUC and PAs to provide rate payer monies only to projects that are achieving the desired goals.
4. The SGIP represents a significant investment of private and public monies. By focusing incentives on thermal performance, this may open the way for existing SGIP projects to repair or upgrade their existing waste heat recovery systems such that they achieve the necessary useful waste heat recovery efficiencies. This extends the number of projects that can receive SGIP incentive funds and increases the amount of net GHG emissions that can be achieved under the total amount of incentive monies. It will also help accelerate the rate at which the SGIP achieves net GHG emission reductions as modifications to waste heat recovery systems can occur under a much shorter timeframe than development of a new project.
5. Require that SGIP projects receiving incentives have a maintenance agreement that covers at least five years of operation of the system (or the number of years under which a performance incentive would be paid). In a number of instances, SGIP projects have failed to achieve net negative GHG emissions due to problems with waste heat recovery operations or maintenance issues. A longer life maintenance agreement can help avoid down time.

6. Re-examine the policy that renewable fuel use projects are not required to employ waste heat recovery processes, especially if the renewable fuel use project has a baseline condition of "flaring." In a number of instances, these projects employ waste heat recovery. Consequently, requiring waste heat recovery may not pose financial hardship on the projects. In addition, metering of waste heat recovery should be required so that the contribution of useful waste heat recovery efficiencies can be used to document net GHG emission reductions from these sources.
7. The CPUC and PAs should consider targeting dairy biogas to energy projects or to other renewable fuel projects that have "venting" as the basis. Due to the capture of methane in the biogas, these projects can provide significant net GHG emission reductions to the SGIP. As indicated in the conclusions, a modest number of renewable fuel use projects with a "venting" basis could provide enough GHG emission benefits to ensure the SGIP overall achieves a net negative GHG emission status.
8. Going forward, the CPUC and PAs should investigate the "venting" versus "flaring" basis for directed biogas projects. If directed biogas projects are obtaining methane from projects where the basis is "flaring," these projects may not provide expected net negative GHG emission reductions. At present, little is known about the basis of out-of-state directed biogas sources.

1

Introduction & Background

1.1 Program Background

The Self-Generation Incentive Program (SGIP) represents one of the largest and longest-lived incentive programs for distributed generation (DG) and combined heat and power (CHP) technologies in the country. Initially created in 2001 with an expected four-year life span, the SGIP is entering its eleventh year of operation. As of the end of 2010, the SGIP had installed 440 DG and CHP projects representing nearly 227 megawatts (MW) of generating capacity.[1]

The SGIP was originally established to help address peak electricity problems facing California. Assembly Bill (AB) 970[2] directed the California Public Utilities Commission (CPUC), in consultation with the California Independent System Operator (CAISO), and the California Energy Commission (CEC) to "adopt energy conservation, demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods." The same legislation required the CPUC to consider establishing incentives for load control and DG technologies to enhance grid reliability using "differential incentives for renewable or super-clean distributed generation resources." The CPUC issued Decision (D.) 01-03-073[3] on March 27, 2001 outlining the provisions of a DG incentive program, which became known as the Self-Generation Incentive Program.

Since its inception in 2001, the SGIP has provided incentives to a wide variety of DG and CHP technologies. Technologies eligible under the SGIP have included solar photovoltaic (PV) systems, wind turbines, fossil- and renewable-fueled internal combustion (IC) engines, fuel cells, microturbines, small-scale gas turbines, and more recently, advanced energy storage systems.

Established as a demonstration program, the SGIP did not set goals for the amount of DG to be installed under the program. In addition, SGIP projects were intended only to offset electricity demand incurred at the utility customer site. SGIP facilities were not intended to export

1 Note that solar PV projects are no longer reported in the SGIP impact evaluation but are instead reported in the California Solar Initiative (CSI) impact evaluation report. As such, total installed SGIP projects and capacities are significantly lower than shown in earlier SGIP impact evaluation reports.

2 AB 970 (California Energy Security and Reliability Act of 2000) (Ducheny, September 6, 2000). http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

3 CPUC D.01-03-073, March 27, 2001. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/6083.htm

electricity into the grid. The program used a variety of performance measures to help ensure SGIP projects performed as expected. SGIP projects were required to meet minimum specified electrical and waste heat recovery efficiencies. Maintenance warranties ranging from three to five years were also required on installed DG and CHP equipment to make sure it remained in good working condition.

The portfolio of SGIP projects has evolved over time. The early "fleet" of DG and CHP technologies deployed through the SGIP consisted primarily of IC engines, the then emerging microturbine systems, some small gas turbines and fuel cells and a promising generation of PV systems. By 2006, the energy landscape had changed dramatically from when the SGIP was first conceived. There was intense interest by the Governor and Legislature in PV technologies. Enacted in August of 2006, Senate Bill 1 (SB1) created the California Solar Initiative (CSI). Budgeted at over $2.1 billion, the CSI targeted a significant growth in new solar generation in the state and transformation of the California solar market. The CSI replaced the SGIP as a PV incentive vehicle. Effective January 1, 2007, PV technologies were no longer eligible to receive SGIP incentives.

Aside from the removal of PV eligibility from the SGIP, other significant changes affected make-up of the SGIP fleet. Growing concerns with the environmental aspects of combustion-based generation technologies prompted changes to the eligibility of DG and CHP technologies.[4] Approval of AB 2778[5] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. These were defined as technologies that met or exceeded emissions standards required under a DG certification program adopted by the California Air Resources Board (CARB). AB 2778 also set minimum system efficiencies for SGIP projects that took into account oxides of nitrogen (NOx) emissions. Effective January 1, 2007 only fuel cells and wind turbines were eligible for the SGIP. Advanced energy storage technologies used in conjunction with wind turbines or fuel cells was added to the list of eligible SGIP technologies in November 2008 by CPUC Decision 08-011-044.[6] In September of 2009, "directed" biogas technologies[7] were made eligible to the SGIP by CPUC Decision 09-09-048.[8]

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4 Details on the CARB DG certification program and rulings can be found at: http://www.arb.ca.gov/energy/dg/dg.htm

5 AB 2778 (Lieber, September 29, 2006). http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

6 CPUC D.08.011.044, November 21, 2008. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/94272.htm

7 Directed biogas is biogas collected from landfills, waster water treatment facilities or dairies located outside the SGIP host site, and delivered into the utility natural gas pipeline system. SGIP facilities can procure quantities of "nominated" biogas for use as a renewable fuel, although none of the biogas is required to be physically delivered to the SGIP site.

8 CPUC D.09.09.048, September 24, 2009. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/107574.htm

More recently, enacted legislation has mandated changes in the overall goals of the SGIP and make up of eligibility technologies. Senate Bill 42 has limited eligibility of SGIP technologies to those the CPUC, in conjunction with the CARB "determines will achieve reduction of greenhouse gas emission pursuant to the California Global Warming Solutions Act of 2006".[9] SB 412 also removed the earlier exclusion of non-fuel cell technologies to the SGIP and requires CPUC staff to re-examine eligibility of CHP technologies. Eligibility of CHP technologies to the SGIP is currently under review by the CPUC.

1.2 Impact Evaluation Requirements

The original 2001 CPUC decision establishing the SGIP also required "program evaluations and load impact studies to verify energy production and system peak demand reductions" resulting from the SGIP.[10] D.01-03-073 also directed the assigned Administrative Law Judge (ALJ), in consultation with the CPUC Energy Division and the PAs, to establish a schedule for filing the required evaluation reports. Since 2001, nine annual impact evaluations have been conducted on the SGIP. Table 1-1 lists the impact evaluation reports prepared up through program year 2009 on the SGIP.

Specific objectives of the impact evaluations have varied each year but generally include impacts on electrical energy production; peak demand; operating and reliability statistics; transmission and distribution system impacts; air pollution emission impacts; and compliance of SGIP projects with thermal energy utilization and system efficiency requirements.

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9 SB 412 (Kehoe, October 11, 2009): http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

10 CPUC D.01-03-073, March 27, 2001, page 37.

Table 1-1: SGIP Impact Evaluation Reports Prepared to Date

Program Year (PY)	Date of Report
2001[11]	June 28, 2002
2002[12]	April 17, 2003
2003[13]	October 29, 2004
2004[14]	April 15, 2005
2005[15]	March 1, 2007
2006[16]	August 30, 2007
2007[17]	September 2008
2008[18]	June 2009
2009[19]	June 2010

11 Regional Economic Research (RER). *California Self-Generation Incentive Program: First Year Impact Evaluation Report*. Submitted to Southern California Edison. June 28, 2002. http://www.energycenter.org/uploads/Selfgen%20First%20Year%20Process%20Report.pdf

12 Itron, Inc. *California Self-Generation Incentive Program: Second Year Impact Evaluation Report*. Submitted to Southern California Edison. April 17, 2003. ftp://ftp.cpuc.ca.gov/puc/energy/electric/selfgen2ndyrimpact.pdf

13 Itron, Inc. *CPUC Self-Generation Incentive Program: Third Year Impact Assessment Report.* Submitted to The Self- Generation Incentive Program Working Group. October 29, 2004. http://www.energycenter.org/uploads/Selfgen%20Third%20Year%20Impacts%20Report.pdf

14 Itron, Inc. *California Self-Generation Incentive Program: Fourth Year Impact Evaluation Report.* Submitted to Southern California Edison. April 15, 2005. ftp://ftp.cpuc.ca.gov/puc/energy/electric/050415_sceitron+sgip2004+impacts+final+report.pdf

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16 Itron, Inc. *California Self-Generation Incentive Program: Sixth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. August 30, 2007. http://www.energycenter.org/uploads/SGIP_M&E_Sixth_Year_Impact_Evaluation_Final_Report_August_30_2007.pdf

17 Itron, Inc. *California Self-Generation Incentive Program: Seventh Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. September 2008. http://www.cpuc.ca.gov/NR/rdonlyres/13D12230-5974-44C7-A90B-4F7C53CAA543/0/SGIP_7thYearImpactEvaluationFinalReport.pdf

18 Itron, Inc. *California Self-Generation Incentive Program: Eighth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. June 2009. http://www.cpuc.ca.gov/NR/rdonlyres/11A75E09-31F8-4184-B3A4-2DCCB5FB0D2D/0/SGIP_Impact_Report_2008_Revised.pdf

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1.3 Scope of this Report

The 2010 Impact Evaluation Report represents the tenth impact evaluation conducted for the SGIP. At the most fundamental level, the overall purpose of all annual SGIP impact evaluation analyses is identical: to produce information that helps policy makers and SGIP stakeholders make informed decisions about the SGIP's design and implementation.

The 2010 SGIP Impact Evaluation Report examines impacts at both the program-wide and utility-specific levels on electrical energy production; coincident peak demand; operating and reliability characteristics; air pollution and greenhouse gas emission (GHG) impacts; and compliance of SGIP projects with thermal energy utilization and system efficiency requirements. Transmission and distribution system impacts are not examined in this impacts evaluation report as they were investigated in the 2010 topical report "Optimizing Dispatch and Location of Distributed Generation."[20]

Unlike past SGIP impact evaluations, the 2010 Impact Report also examines performance of CHP systems over the past nine years. The intent is to identify factors that can help improve and sustain performance of CHP systems deployed under the SGIP. In addition, a key objective is to target specific ways that CHP systems can help the SGIP achieve significant levels of GHG emission reductions.

1.4 Report Organization

This report is organized into six sections and six appendices, as described below.

- The Executive Summary provides key conclusions and recommendations based on the 2010 SGIP impact evaluation analysis.
- Section 1 is this introduction and background.
- Section 2 provides a status of the SGIP as of the end of calendar year 2010.
- Section 3 looks at the SGIP portfolio of CHP projects from 2001 to 2010, including a discussion of the characteristics of the technologies, how performance of the technologies has changed over time, and identifying the possible influence of external factors on performance.
- Section 4 discusses the 2010 impacts associated with SGIP projects at the program-wide and utility-specific levels. The section provides a summary discussion as well as specific information on impacts associated with energy delivery; peak demand reduction;

[20] Itron, Inc. and BEW Engineering, *California Self-Generation Incentive Program: Optimizing Dispatch and Location of Distributed Generation.* Submitted to Pacific Gas & Electric, July 2010. https://www.itron.com/na/PublishedContent/SGIP_Optimizing_DG_Dispatch_Location.pdf

efficiency and waste heat utilization requirements; and impacts from air pollutants (NOx, and PM-10) as well as GHG emission reductions.

- Section 5 discusses the SGIP fleet going forward, including lessons learned from the past nine years of the SGIP; the relationship between SGIP operations and GHG emissions; and possible ways to improve net GHG emission reductions.
- Appendix A provides additional information on capacity factors for the different CHP technologies.
- Appendix B presents the GHG emissions methodology.
- Appendix C contains a discussion of data sources for this impact evaluation and treatment of data.
- Appendix D contains the statistical treatment of performance factors.
- Appendix E provides an explanation and derivation of the net GHG nomograph.
- Appendix F provides additional charts on CHP performance trends.

2

Program Status

This section provides information on the status of the Self-Generation Incentive Program (SGIP) as of the end of December 31, 2010. The SGIP 2010 status is based on project data provided by the Program Administrators (PAs) relative to all applications extending from Program Year 2001 (PY01) through the end of Program Year 2010 (PY10). Status information includes the distribution of SGIP projects by PA and geographically; the status of projects in the SGIP; the associated amount of rebated capacity deployed under the SGIP; incentives paid or reserved; and project costs.

2.1 Distribution of SGIP Projects

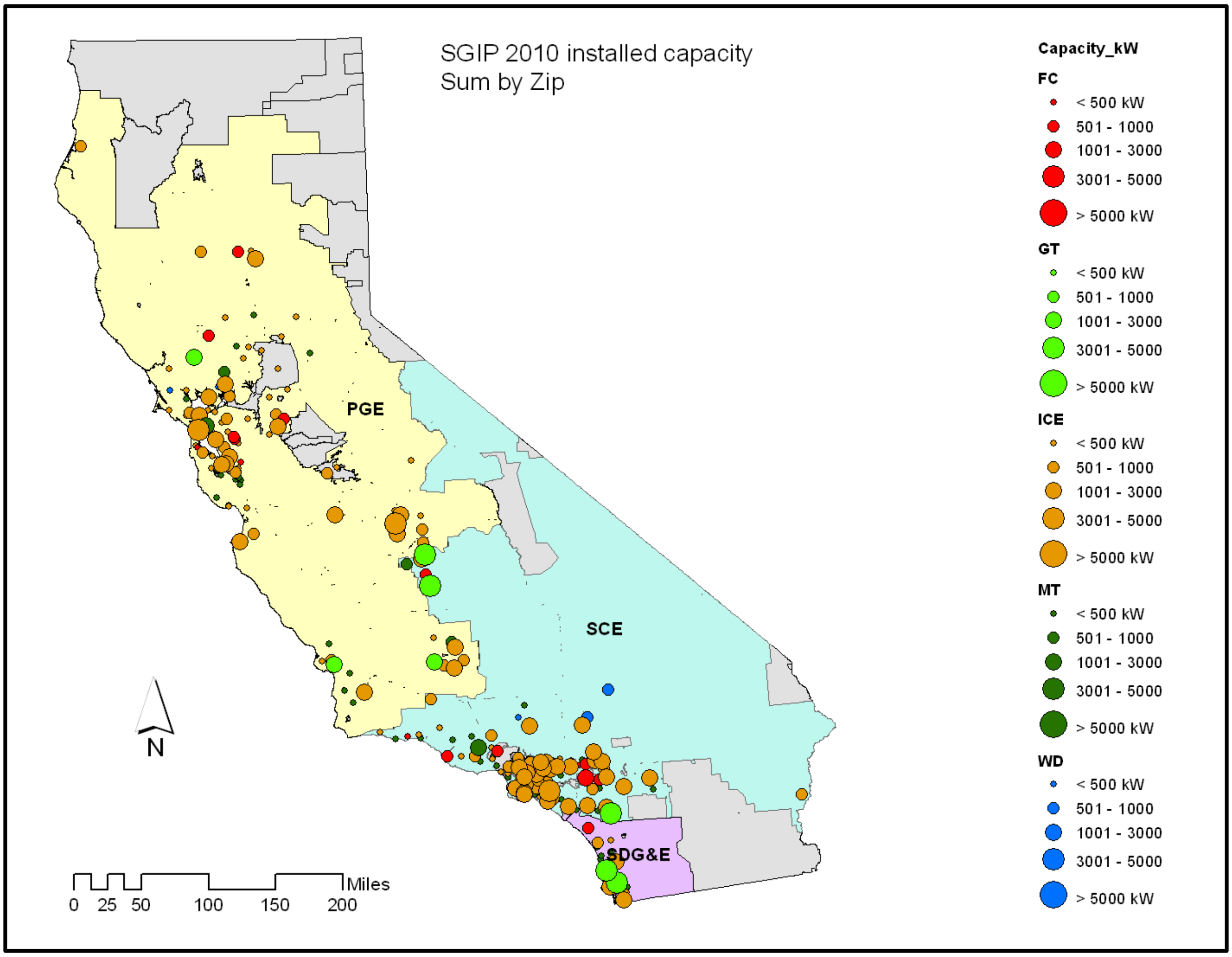
Projects deployed under the SGIP are located throughout the service territories of the major investor-owned utilities (IOUs) in California as well as throughout a number of municipal electric utilities. Table 2-1 provides a summary of the number and rebated capacity of SGIP projects among the four PAs as of the end of 2010.

Table 2-1: SGIP Projects and Rebated On-Line Capacity by PAs as of 12/31/10

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	193	87.1	38%
SCE	93	40.1	18%
SCG	111	75.1	33%
CCSE	44	24.5	11%
Totals	**441**	**226.8**	**100%**

Figure 2-1 shows the geographical distribution of SGIP facilities across California by technology type at the end of calendar year 2010.

Figure 2-1: Distribution of SGIP Facilities as of 12/31/10



2.2 Project Stages and Status

Once applications are received within the SGIP, they proceed to eventually become either "Complete" or "Inactive" projects. Projects are defined in accordance with key stages in the SGIP implementation process as follows.

- ***Complete Projects:*** These represent SGIP projects for which the generation system has been installed, verified through onsite inspections, and an incentive check has been issued. We consider all Complete projects as "on-line" projects for impact evaluation purposes.
- ***Active Projects:*** These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a wait list. Over time, the Active projects will migrate either to

the Complete or to the Inactive category. Some of these projects may have entered normal operations as of the end of 2010. Because an incentive check had not been issued, we do not consider these projects Complete projects. Note that we treat Active projects as "on-line" if they have entered normal operation, even if they have not received an incentive check.

- ***Inactive Projects:*** These represent SGIP projects that are no longer progressing in the SGIP implementation process because they have been withdrawn by the applicants or rejected by the PA.

2.2.1 Complete and Active SGIP Projects

The status of Complete and Active projects within the SGIP is important because these projects represent technologies that can potentially affect the electricity system. Table 2-2 provides a breakdown by technology and fuel type of the Complete and Active projects The "(n)" represents the number of Complete, Active, or total projects. The "(MW)" refers to the total rebated capacity in megawatts (MW) for those "n" projects.

Table 2-2: Quantity and Capacity of Complete and Active Projects (12/31/2010)

Technology & Fuel*	Complete		Active (All)		Total		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg. Size (kW)
WD	8	4.7	18	22.8	26	27.5	1,059
FC–N	19	9.7	20	2.3	39	12.0	308
FC–R	8	5.5	8	15.0	16	20.5	1,278
FC-Directed	5	1.8	52	25.2	57	27.0	474
FC-Electric	4	1.3	-	-	4	1.3	325
ICE-N	229	140.4	4	1.7	233	142.0	610
ICE-R	21	13.7	2	0.8	23	14.4	626
GT-N	8	25.7	1	4.4	9	30.1	3,349
GT-R	-	-	1	0.8	1	0.8	750
MT-N	118	20.2	1	0.8	119	21.0	176
MT-R	21	3.8	1	0.2	22	4.0	181
AES	-	-	3	5.5	3	5.5	1,833
All	**441**	**226.8**	**111**	**79.3**	**552**	**306.1**	

* WD = Wind; FC = Fuel Cell; ICE = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine; AES =Advanced Energy Storage; N = Non-Renewable; R = Renewable

There were 552 Complete and Active projects, representing just over 306 MW of capacity in the SGIP as of December 31, 2010.

SGIP On-Line Projects

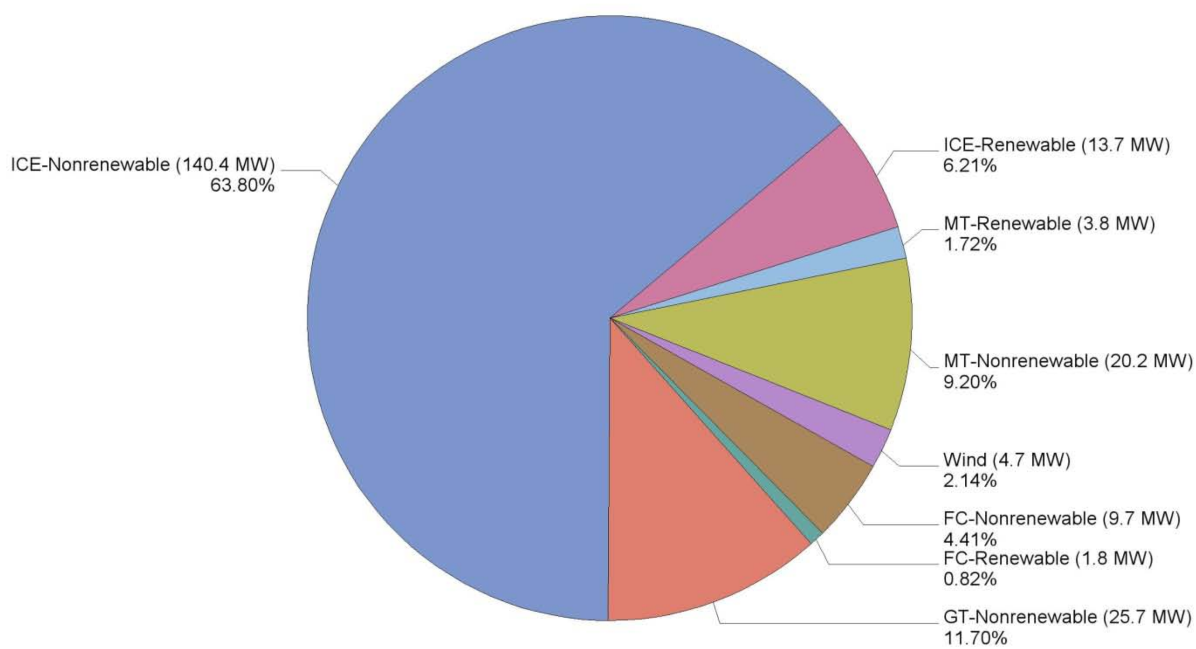
While Complete and Active projects represent SGIP projects with potential impacts, on-line projects are grid-connected and operational; as such, they create actual impacts on the electricity system. For impact purposes, we consider only the subset of projects that were on-line by December 31, 2010. By the end of 2010, on-line projects represented 441 projects and 227 MW of rebated capacity.

Complete SGIP Projects

Statistics on Complete projects serve as a benchmark in evaluating changes in the SGIP with respect to capacity, paid incentives, and technology costs. Figure 2-2 shows a breakout of the SGIP generating capacity for all Complete projects by technology and fuel type at the end of 2010. IC engines, gas turbines, and microturbines powered by non-renewable fuels contributed over 186 MW of rebated capacity, or more than three quarters the total capacity of the SGIP.

Figure 2-2: SGIP Complete Project Capacity (MW) by Technology and Fuel Type as of 12/31/10

Total Capacity = 226.8 MW



2.3 SGIP Project Progress and Incentive Payment Status

Another way to identify project status within the SGIP is by the stage of incentive payment. Incentives are only paid for Complete projects. In comparison, incentives are reserved for Active projects and are not paid until the project reaches the Complete stage. PAs can use incentive payment status to examine the funding backlog of SGIP projects by technology and fuel type.

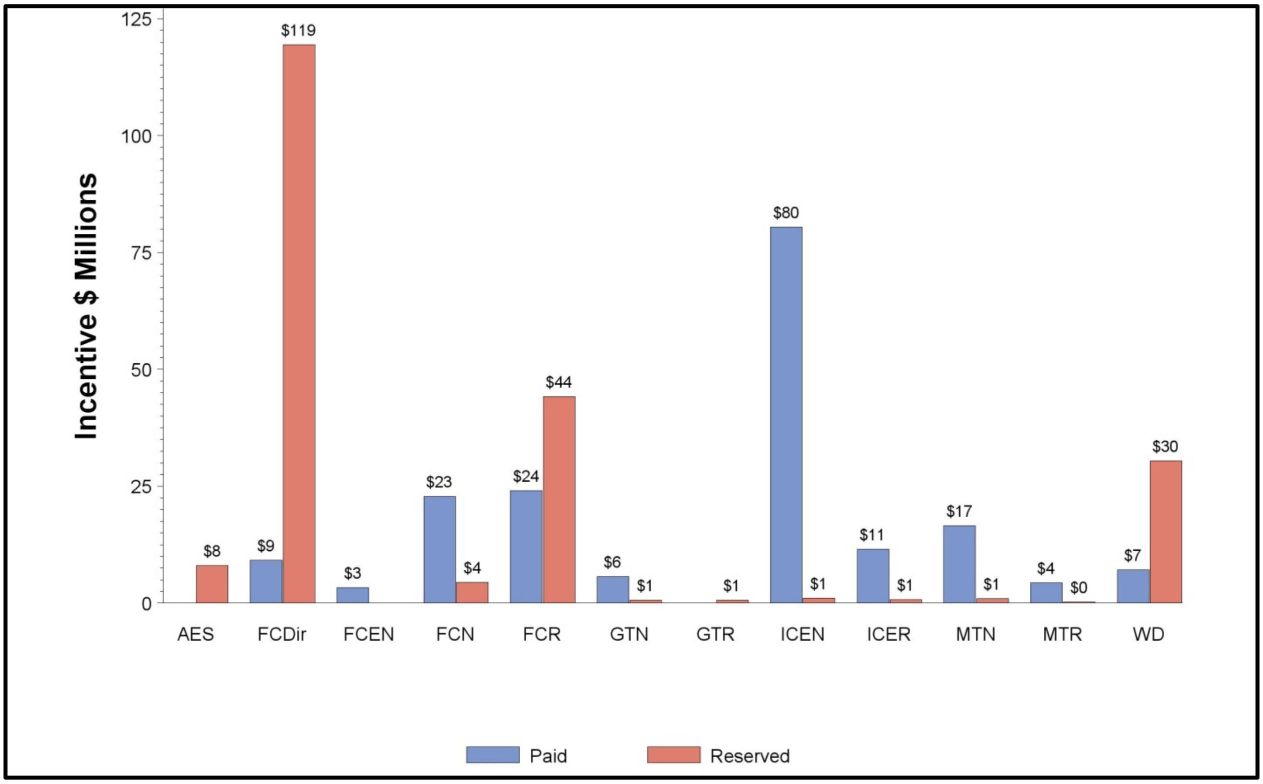
Table 2-4 shows a breakdown of the incentives paid and reserved by each technology as of the end of 2010.

Table 2-3: Incentives Paid and Reserved (as of 12/31/2010)

	Complete Incentives Paid			Active Incentives Reserved		
Technology & Fuel	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
WD	4.7	$1.51	$7	22.8	$1.33	$30
FC-N	9.7	$2.35	$23	2.3	$1.93	$4
FC-R	5.5	$4.42	$24	15.0	$2.95	$44
FC-Directed	1.8	$5.10	$9	25.2	$4.74	$119
FC-Electric	1.3	$2.56	$3	0.0	$0.00	$0
IC Engine–N	140.4	$0.57	$80	1.7	$0.61	$1
IC Engine–R	13.7	$0.84	$11	0.8	$1.00	$1
GT-N	25.7	$0.21	$6	4.4	$0.14	$1
GT-R	0.0	$0.00	$0	0.8	$0.80	$1
MT-N	20.2	$0.82	$17	0.8	$1.30	$1
MT-R	3.8	$1.15	$4	0.2	$1.00	$0
AES	0.0	$0.00	$0	5.5	$1.45	$8
Total	**226.8**	**$0.81**	**$185**	**79.3**	**$2.66**	**$210**

Figure 2-3 is a graphical representation of the SGIP incentives paid or reserved as of December 31, 2010. By the end of PY10, over $185 million in incentive payments had been paid to Complete projects. The reserved backlog totaled $210 million, of which $119 million were reserved for directed biogas fuel cells and $30 million for wind projects.

Figure 2-3: Incentives Paid or Reserved for Complete and Active Projects



Total Eligible Project Costs

Total eligible project costs are regulated by SGIP guidelines and reflect the costs of the installed generating system and its ancillary equipment. Table 2-3 provides total and average project cost data for Complete and Active projects from PY01 through PY10. Average per-Watt eligible project costs represent capacity-weighted averages.

Table 2-4: Total Eligible Project Costs of PY01–PY10 Projects

Technology & Fuel	Complete			Active		
	Total (MW)	Wt.Avg ($/W)	Total ($ MM)	Total (MW)	Wt.Avg ($/W)	Total ($ MM)
WD	4.7	$3.65	$17	22.8	$4.43	$101
FC-N	9.7	$7.55	$73	2.3	$9.09	$21
FC-R	5.5	$7.44	$41	15.0	$3.63	$54
FC-Directed	1.8	$12.38	$22	25.2	$7.08	$179
FC-Electric	1.3	$9.29	$12	-	-	-
IC Engine–N	140.4	$2.33	$327	1.7	$3.05	$5
IC Engine–R	13.7	$2.77	$38	0.8	$1.81	$1
GT-N	25.7	$2.27	$58	4.4	$0.31	$1
GT-R	0.0	$0.00	$0	0.8	$2.28	$2
MT-N	20.2	$3.31	$67	0.8	$3.22	$2
MT-R	3.8	$3.44	$13	0.2	$4.00	$1
AES	-	-	-	5.5	$0.84	$5
Total	**226.8**	**$2.95**	**$669**	**79.3**	**$4.69**	**$372**

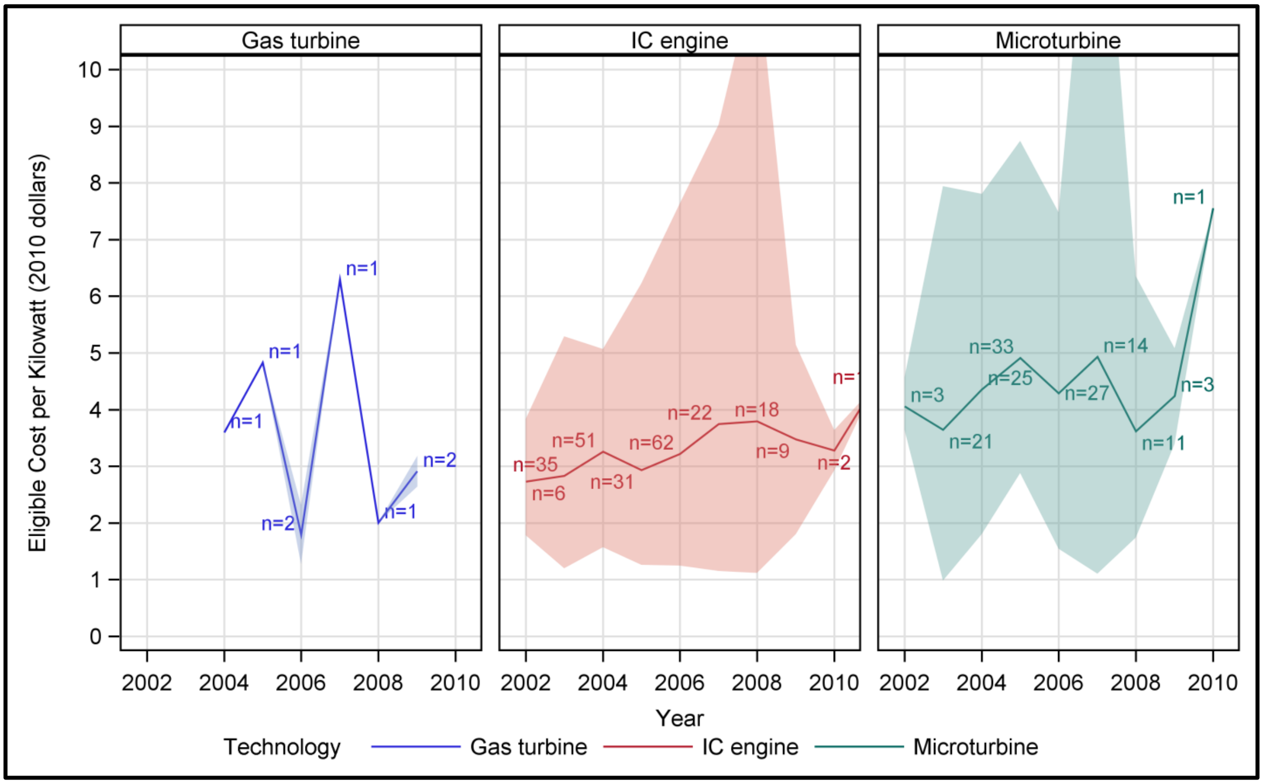
By the end of PY10, total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete projects were $669 million.

2.4 Eligible Cost Trends

During the early program years, eligible system costs per kilowatt (kW) differed considerably for the four different CHP technologies. Figure 2-4 shows the program year annual mean eligible system costs in 2010 adjusted dollars per kW for all technologies but fuel cells. The shading along trend lines in the figure bracket the minimum and maximum costs. After program year PY06 no new applications were taken for gas turbines, IC engines, or microturbines. Fuel cell annual mean costs per kW were in a class of their own, being over twice the cost per kW for IC engines. Figure 2-5 shows annual mean fuel cell costs by program year through 2010, as most SGIP fuel cells were from later program years.

In the early program years annual mean eligible system costs grew slowly but steadily for IC engines and somewhat more quickly but less steadily for microturbines. By comparison, gas turbine annual mean costs fluctuated wildly, peaking in 2007 at almost three times their 2006 cost. For gas turbines, however, the annual means were composed of individual systems and thus could vary widely. The range between minimum and maximum IC engine and microturbine costs was very wide, particularly in 2007 and 2008. The root cause of this especially wide range is not known but may be a result of cost increases in raw material market generally.

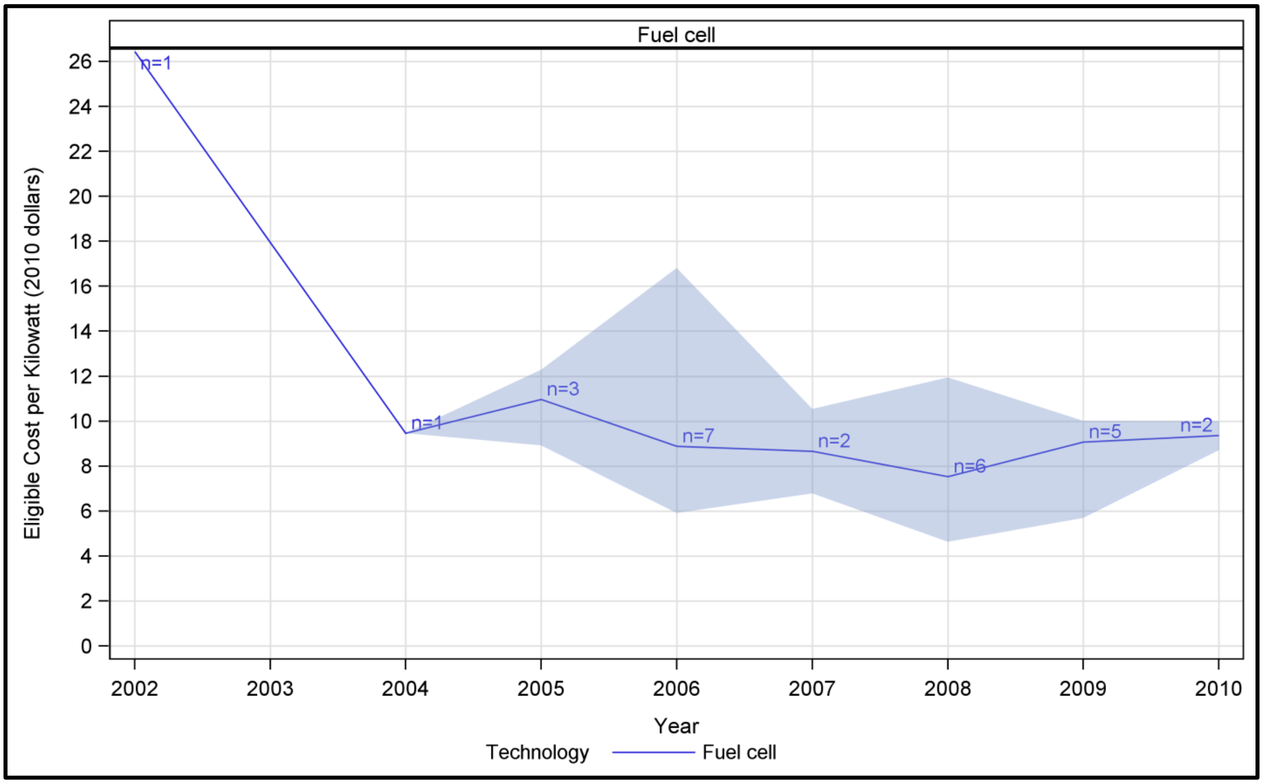
Figure 2-4: System Eligible Costs* per Kilowatt by Technology



* Cost for system components, installation, and warranty as considered eligible for program funding.

Fuel cells stood apart with the most wide-ranging costs, largely due to a single system in 2002. Unlike IC engines and microturbines, fuel cell costs had marked declines during the early program years. After 2007, however, fuel cell costs climbed above 2003 levels and then hit a plateau over 2009 and 2010.

Figure 2-5: Fuel Cell Eligible Cost* per Kilowatt



* Cost for system components, installation, and warranty as considered eligible for program funding.

Participants' Out-of-Pocket Costs after SGIP Incentive

Participants' out-of-pocket costs (total eligible project cost less the SGIP incentive) are summarized in Table 2-5. Insights regarding cost differences between the technologies are speculative, but take into account a combination of assumed project costs, information on additional monies obtained from other incentive programs (when available), and professional judgment.

On a cost-per-Watt basis, all electric fuel cells had the highest costs, averaging close to $7.30 per Watt. Natural gas-powered fuel cells with waste heat recovery had the next highest costs at $5.20 per Watt. Microturbine costs appeared to stay below $2.50 per Watt and IC engine costs stayed below $2.00 per Watt.

Overall, project costs for all Complete projects totaled over $484 million.

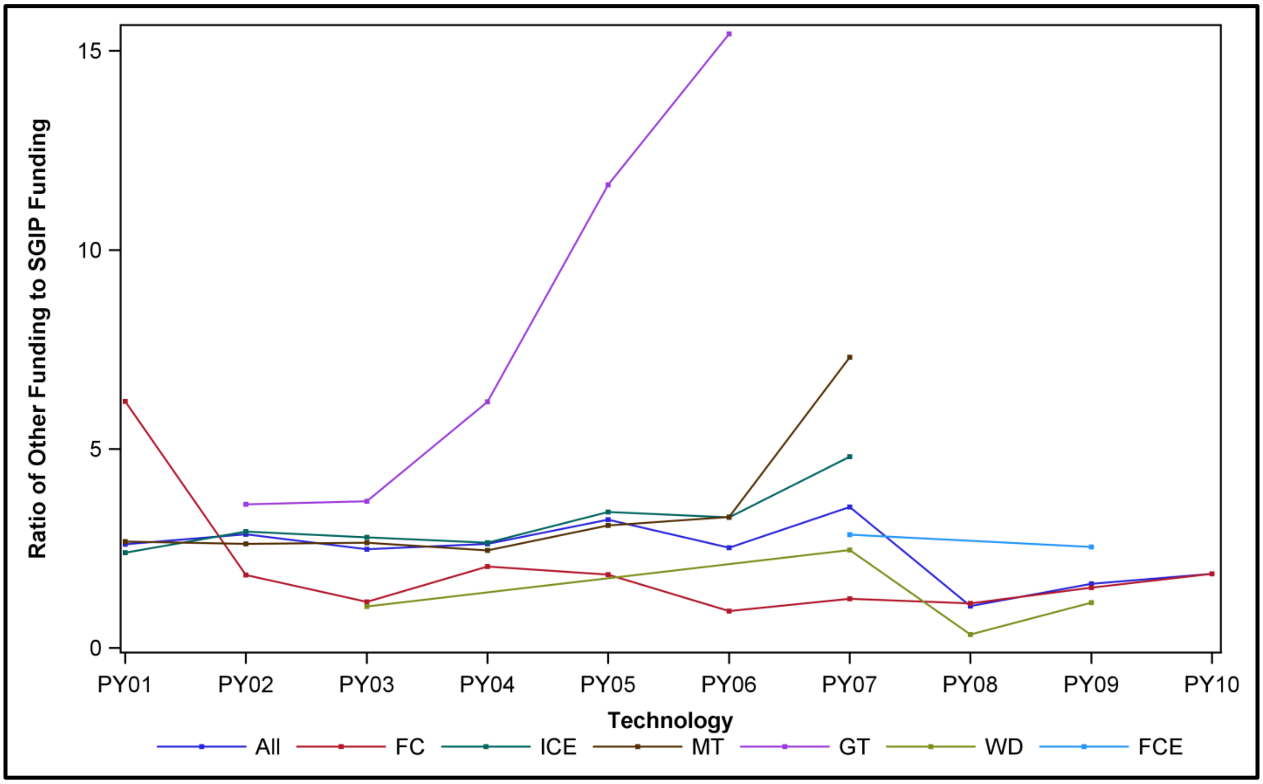
Table 2-5: SGIP Participants' Out-of-Pocket Costs after Incentive

	Complete			Active		
Technology & Fuel	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
WD	4.7	$2.14	$10	22.8	$3.09	$71
FC-N	9.7	$5.20	$50	2.3	$7.16	$17
FC-R	5.5	$3.02	$16	15.0	$0.68	$10
FC-Directed	1.8	$7.27	$13	25.2	$2.34	$59
FC-Electric	1.3	$6.74	$9	0.0	$0.00	$0
IC Engine–N	140.4	$1.76	$247	1.7	$2.45	$4
IC Engine–R	13.7	$1.93	$26	0.8	$0.81	$1
GT-N	25.7	$2.05	$53	4.4	$0.18	$1
GT-R	0.0	$0.00	$0	0.8	$1.48	$1
MT-N	20.2	$2.50	$51	0.8	$1.92	$1
MT-R	3.8	$2.29	$9	0.2	$3.00	$1
AES	0.0	$0.00	$0	5.5	-$0.62	-$3
Total	**226.8**	**$2.14**	**$484**	**79.3**	**$2.04**	**$162**

Leveraging of SGIP Funding

The SGIP is one of the largest CHP incentive programs in the country. As identified earlier, over $185 million in incentive payments were made as of 2010. However, total project costs were over $484 million. Leverage of SGIP incentives is important as it represents the ability of the program to attract support for the deployed projects and the program overall. Figure 2-6 shows the ratio of other funding provided to SGIP technologies as well as the SGIP overall by program year. In general, leverage of the SGIP has been hovering around a ratio of $2 of other funding invested per $1 of SGIP incentive. However, in 2005, there was a sharp increase in leveraging associated with gas turbine projects. This sharp increase in the funding ratio of gas turbines is likely due to their large size (with commensurately large project cost) and reduced amounts being paid for non-renewable gas turbines by the time these projects actually received their incentives. At the end of 2010, leverage on the SGIP was close to $2.6 of other funding per $1 of SGIP incentive funding.

Figure 2-6: Ratio of Other Funding to SGIP Incentive Funding by Program Year



3

The SGIP Fleet of CHP Technologies Over Time

This section provides information on the portfolio of CHP technologies that have made up the SGIP since its inception until the end of 2010. Even though other DG technologies were installed under the SGIP, we focus on CHP as it is a major emphasis of the program going forward.[1] Among the CHP technologies we include are SGIP systems fueled by natural gas, propane, or biogas, whether or not they are required to capture waste heat for some end use. When describing heat recovery, we include only SGIP systems required to capture waste heat.[2] We examine changes in the SGIP CHP portfolio as well as to the CHP technologies over time. We also look at changes in performance of the technologies in terms of efficiency and utilization.[3] We consider several factors that may have influenced performance. Impacts of SGIP projects during 2010 are treated in Section 4. In Section 5, we investigate ways to relate CHP operations to SGIP program objectives, including greenhouse gas (GHG) emission reductions. Lastly, we discuss ways for the CPUC and PAs to use operational characteristics in selecting CHP projects that will have increased probability of meeting and sustaining SGIP goals and objectives.

The SGIP falls neatly into three distinct sections of time that coincide with major changes in policies that affected the makeup of the SGIP. The time period of 2001 to 2006 represents the early years of the SGIP. There was a broad range of technologies eligible under the SGIP during this time period. These early years reflect the SGIP in a start-up mode and with high growth rates for many DG and CHP technologies. Legislative changes towards the end of 2006 significantly restricted eligibility of combustion-based technologies and transferred PV incentives from the SGIP to the newly formed California Solar Initiative (CSI). The time period of 2007 to 2010 reflects an SGIP with significantly fewer eligible DG technologies and a much lower rate of growth. Passage of Senate Bill 412 (SB 412) in late 2009 re-opened the possibility

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[1] Prior to 2007, technologies that were eligible for incentives under the SGIP included solar photovoltaics, wind energy, and fossil fueled as well as biogas fueled internal combustion engines, microturbines, small gas turbines, and fuel cells. Starting in January 1, 2007, eligibility within the SGIP was restricted to fuel cells, wind energy and advanced energy storage used in combination with wind energy or fuel cells. Under Senate Bill 421, the CPUC is currently examining broadened eligibility of combined heat and power technologies within the SGIP.

[2] Under SGIP requirements, renewable fuel use projects are not required to employ waste heat recovery. Similarly, directed biogas projects are not required to recover waste heat. Some fuel cells also have sufficiently high total efficiency from electrical conversion alone that they are not required to recover waste heat to achieve the minimum system efficiency requirements.

[3] Utilization refers to both the achieved power output and the availability of the system.

for a broader group of technologies to once again be eligible for the SGIP. It also established that a primary goal of the SGIP is to reduce GHG emissions. The final time period of 2010 going forward captures future prospects and opportunities for the SGIP. The fleet moving forward is treated in Section 5.

3.1 Early SGIP CHP Systems: 2001–2006

3.1.1 Growth of CHP in the SGIP

Table 3-1 summarizes the number and capacity of CHP systems that reached a "Complete" status in the SGIP from 2001 through the end of 2010.[4] By the end of 2010, over 430 CHP systems representing nearly 222 MW of capacity were complete and operational under the SGIP.

Table 3-1: Counts and Capacity of CHP by Technology in the SGIP (2001-2010)*

Year	Count / Capacity	Fuel Cell	Gas Turbine	IC Engine	Micro-turbine	Total Year	Total Cumulative
2001	**n**	-	-	2	1	3	3
	MW	-	-	0.6	0.1	0.6	0.6
2002	**n**	1	-	19	14	34	37
	MW	0.2	-	11.9	1.9	14.0	14.7
2003	**n**	-	-	53	27	80	117
	MW	-	-	41.3	3.9	45.2	59.9
2004	**n**	1	1	51	22	75	192
	MW	0.6	1.4	29.4	2.9	34.3	94.2
2005	**n**	4	3	48	26	81	273
	MW	2.8	7.1	24.6	5.1	39.6	133.8
2006	**n**	7	1	26	25	59	332
	MW	4.0	4.5	15.8	4.4	28.6	162.5
2007	**n**	4	1	25	12	42	374
	MW	2.4	4.6	15.6	1.8	24.4	186.8
2008	**n**	3	2	8	7	20	394
	MW	2.1	8.1	7.0	1.9	19.1	205.9
2009	**n**	5	-	7	3	15	409
	MW	2.8	-	1.7	1.7	6.2	212.1
2010	**n**	10	-	11	2	23	432
	MW	3.4	-	6.1	0.3	9.7	221.9
Total	**n**	35	8	250	139		432
	MW	18.1	25.7	154.0	24.0		221.9

* "n" refers to project count

[4] "Complete" projects are those for which the generation system has been installed, verified through onsite inspections, and an incentive check has been issued.

Figure 3-1 displays trends in the project counts of newly completed systems added each year for the four CHP technologies. As Figure 3-1 shows, the first four years of the SGIP saw a rapid growth in number of IC engines and microturbines. Annual counts for these systems began to decline in 2005 and fell sharply after 2006. After 2006, IC engines and microturbines were no longer eligible under the SGIP. Note that the declining counts include systems that had been accepted prior to 2007 but did not begin operation until 2007 or later. Fuel cell and gas turbine counts remained relatively small before and after 2006. Fuel cells alone continued to be eligible to the SGIP after 2006. Fuel cell annual counts reached a new peak in 2010 with 10 newly completed systems.

Figure 3-1: Annual Counts of Completed Systems

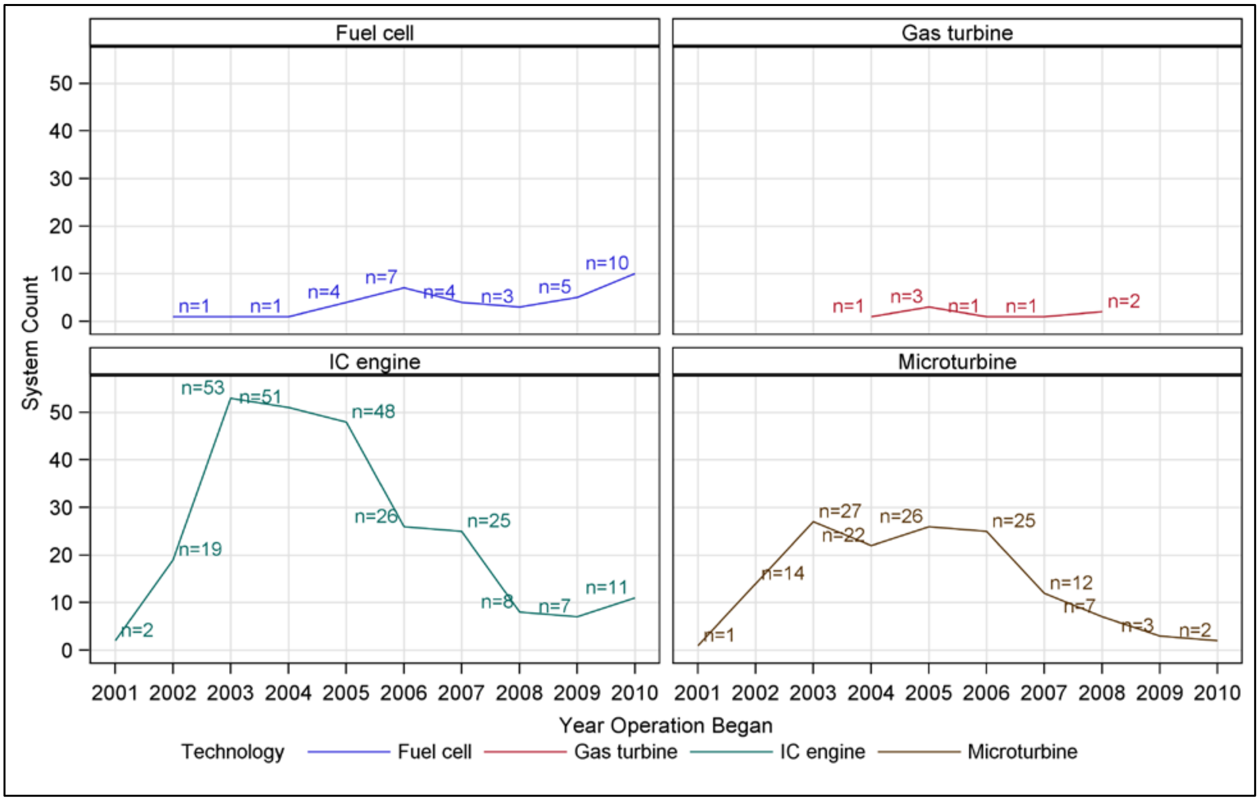
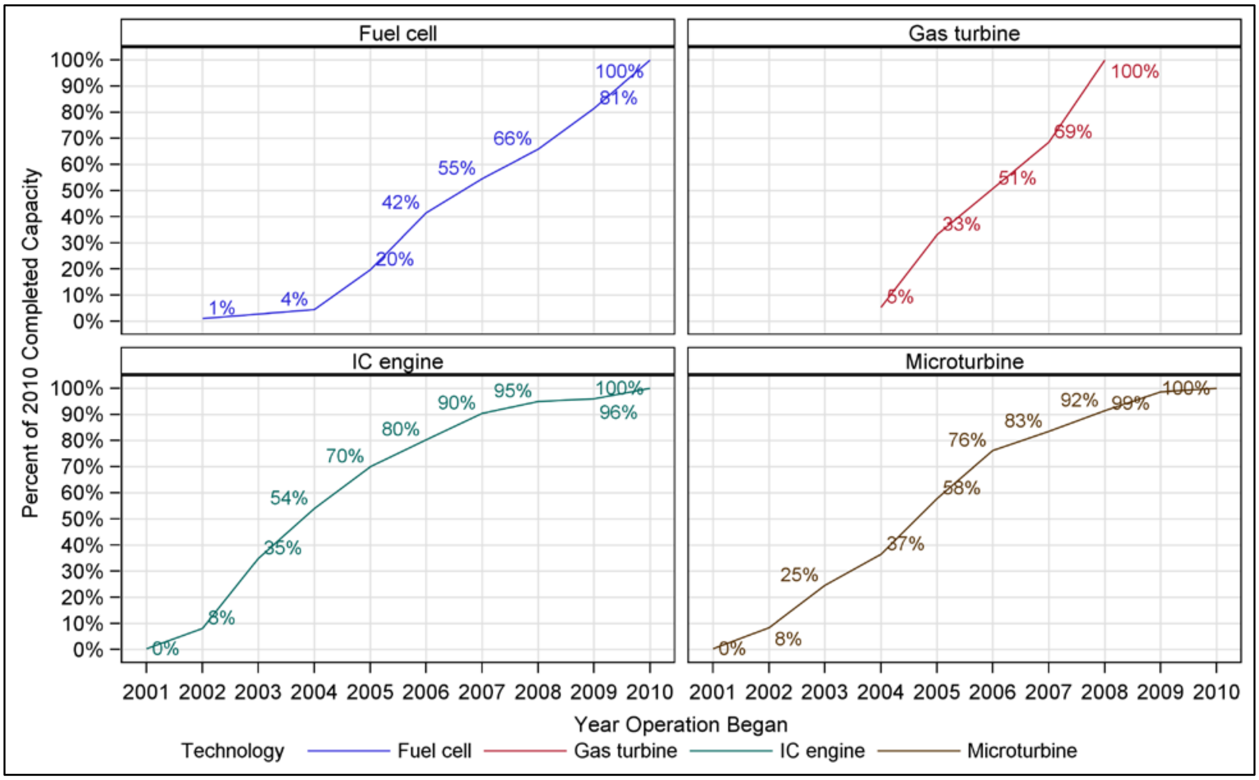


Figure 3-2 shows growth of different CHP systems in terms of percentage of cumulative completed capacity at the end of 2010. The distinction between number of completed systems and completed capacity is important. As discussed below, system capacity often differed greatly between technologies and to a lesser degree within technologies. High system capacities drove up cumulative capacities.

Figure 3-2: Growth in Cumulative Completed Capacity (%)



From 2003 through 2005 IC engines composed almost half of the new CHP systems and no less than 60% of new CHP capacity. In other years, microturbine counts were not much less than those of IC engines. However, added microturbine capacity was much less than that of IC engines in every year but 2009 when they were tied. The large capacity difference is due to the much smaller capacity of the average microturbine system. These large differences in system capacity can be seen in Table 3-2.

Table 3-2: System Mean Capacities by Year (kW)

Year	Fuel Cell	Gas Turbine	IC Engine	Microturbine
2001	-	-	275	84
2002	200	-	626	138
2003	-	-	780	144
2004	600	1,383	577	130
2005	688	2,378	513	197
2006	564	4,527	607	176
2007	588	4,600	625	148
2008	683	4,051	875	275
2009	560	-	244	574
2010	336	-	551	158

Table 3-2 lists the simple mean completed system capacities in kW of the technologies from 2001 to 2010. Several observations can be made from the information in Table 3-2. First, trends in mean capacities within a technology remain fairly steady after its first year. Second, trends between technologies also remain relatively steady. For example, gas turbine systems had by far the largest mean capacities through all years. Fuel cell and IC engine systems generally had mean capacities that were close to one another but significantly larger than microturbines (except for 2009). Third, there was a general upward trend in system capacity. Microturbines and gas turbines both showed some growth in mean capacity in the later years. IC engine mean capacity reached its peak in 2008 only to reach its nadir a year later. 2008 and 2009 had fewest number of new IC engines since the first year of the program. As was the case for microturbines in 2009, small system counts permit individual systems to exert upward or downward pressure on the mean.[5]

As IC engine and microturbine counts slowed in 2006, their cumulative program capacities also began to level off. Figure 3-2 shows that over 70% of IC engine and microturbine capacity that would be installed by 2010 in the SGIP had been completed. However, by the end of 2006, fuel cell and gas turbine cumulative capacities were still below 50% of their 2010 totals. As the SGIP began, fuel cells were beginning to emerge in the CHP market and have progressed substantially since 2005.

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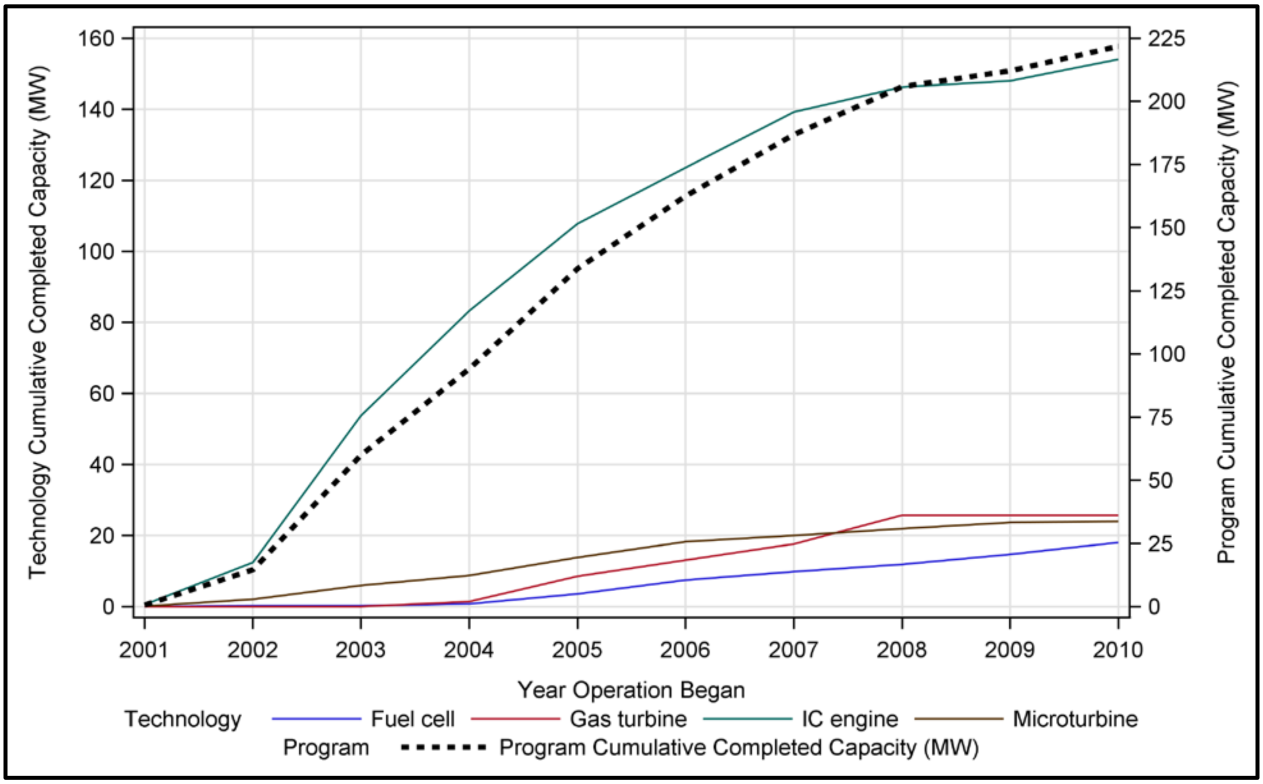
5 It is important to note that these mean capacities are based on system total capacities rather than on individual generator set ("genset") capacities. Since many fuel cell and microturbine systems are composed of multiple gensets, these mean system capacities exaggerate the capacities of individual gensets.

Figure 3-3 shows growth by CHP technology in terms of cumulative completed capacity in megawatts (MW).

Figure 3-3: Growth in Cumulative Completed Capacity (MW)



Despite a late start and very low numbers of completed systems, 2010 gas turbine capacity is on par with microturbine capacity. This is due to the vastly larger capacity of the average gas turbine system. Fuel cells have the least 2010 cumulative capacity of the CHP technologies but it is not as far behind microturbines as it had been in 2006. Figure 3-3 shows that SGIP fuel cells, gas turbines, and microturbines all have 2010 cumulative capacities between 18 and 26 MW.

3.1.2 Performance of CHP Systems

CHP's advantage over the conventional energy services delivery models lies in its potential for higher efficiency overall in the delivery of heat and power. Achievement of that advantage in actual practice requires careful attention to selection of a host facility, and to CHP system design, operation, and maintenance. In this section we discuss the energy efficiency of the early fleet of SGIP CHP systems. We discuss electrical conversion efficiency and useful waste heat recovery as the two components of total CHP system efficiency.

Figure 3-4: System-Level Schematic of a Typical CHP System

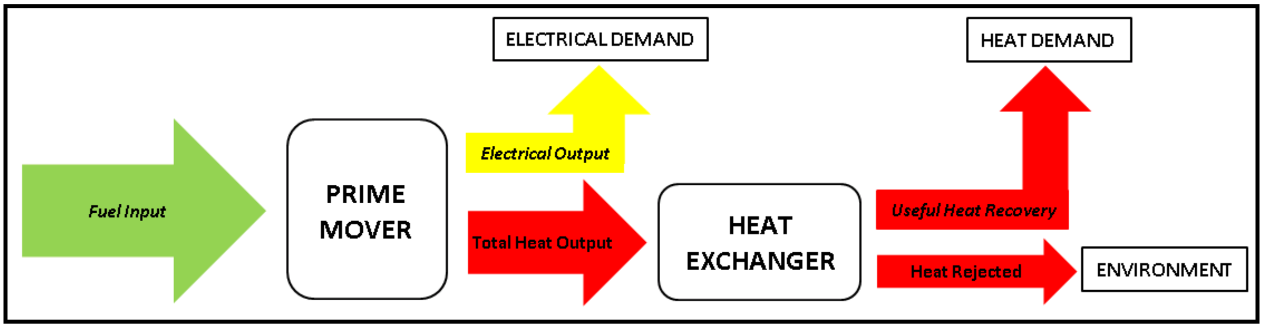


Figure 3-4 graphically depicts the flow of energy in a typical CHP system. Starting from the far left, fuel enters the prime mover which in turn converts a percentage of the fuel energy into electricity. This ratio of electrical output over fuel input is defined as the electrical conversion efficiency. The rest of the energy is dissipated as heat and is sent through a heat exchanger. The percentage of the total heat output can be recovered to fulfill a facility's heat demand is known as the useful waste heat recovered. The useful waste heat recovery efficiency is defined as the ratio of useful heat recovered to the fuel input. Finally, a useful metric of a facility's electrical/heat demand coincidence is the heat recovery rate, defined as the ratio of the useful heat recovery over the electrical output (note that unlike efficiency, the heat recovery rate is not unitless).

An energy efficiency advantage is necessary but not sufficient for CHP system success. A CHP system that is accruing benefits during each hour of operation also must operate for a minimum number of hours to accrue total benefits sufficient to yield satisfactory investment returns. We discuss this utilization aspect of CHP system performance by examining electrical capacity factors and outage trends and factors.

3.1.3 Efficiency of CHP Systems

Electrical Conversion Efficiency

A system's relative ability to convert fuel energy into electrical output energy is its electrical conversion efficiency (ECE). The ECE is a unitless measure defined as the net electrical output divided by the fuel input.[6] CHP technologies in the SGIP each have a range of ECE at which they operate depending on such factors as manufacturer specifications, ambient temperature, and instantaneous capacity factor. Manufacturer specifications provide ECE values in various formats under various assumptions. A representative ECE may be assumed for a technology in

6 Electrical and fuel energy are expressed with same units. The lower heating value of fuel is used rather than the higher heating value.

specific situations, such as estimating spark spread. The ECE of a CHP technology also can be described as a 'heat rate,' a term commonly associated with conventional utility plants.[7]

Table 3-3 lists representative ECE and heat rates for CHP technologies deployed under the SGIP. The representative values in Table 3-3 can be compared against actual values observed in metered data from SGIP systems.

Table 3-3: Representative ECE and Heat Rates for CHP Technologies[8]

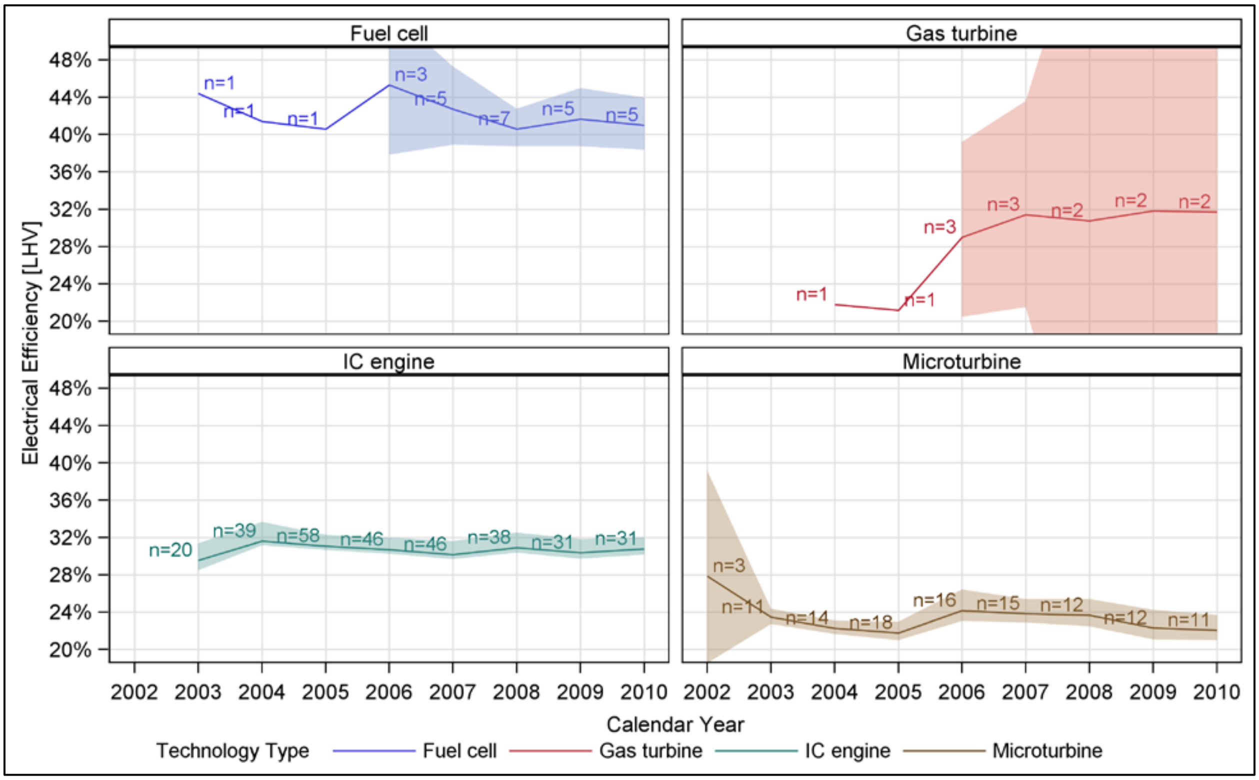
Technology	Electrical Conversion Efficiency	Corresponding Heat Rate (Btu/kWh)
Fuel Cell	43%	8,000
Gas Turbine	34%	10,000
IC Engine	31%	11,000
Microturbine	26%	13,000

7 In general, heat rate is simply 3412 Btu/kWh divided by the decimal value of the ECE (e.g., a prime mover with an ECE of 34% has a heat rate of (3412 Btu/kWh÷0.34) = 10,000 Btu/kWh. Heat rate is expressed as Btu of fuel input per kWh or net electrical output; using a lower heating value basis for the fuel.

8 Sources referenced:
Combined Heat & Power (CHP) Resource Guide, Second Edition, September 2005. Oak Ridge National Laboratory Midwest CHP Application Center. University of Illinois at Chicago Energy Resources Center and Avalon Consulting, Inc. (http://www.chpcentermw.org/pdfs/Resource_Guide_10312005_Final_Rev5.pdf).
Catalog of CHP Technologies, December 2008. US Environmental Protection Agency Combined Heat and Power Partnership (http://www.epa.gov/chp/documents/catalog_chptech_full.pdf).

Figure 3-5 shows trends of the mean annual ECEs of natural gas-fueled CHP systems during the early years of the SGIP.[9] The figure includes only systems where both fuel and electrical metering were available. The shaded bands following the trend lines show the uncertainty about the mean at the 90/10 confidence level. Uncertainty in the mean ECE values can be great where there are small numbers of systems with very different efficiencies.

Figure 3-5: Annual Mean Electrical Conversion Efficiency by CHP Technology



Observed ECE values have generally remained flat over time. Fuel cells consistently achieve the highest ECEs, always above 40%. IC engine ECE values consistently remain between 30 and 35%, while after 2002 microturbine ECE values remained between 20 and 25%. In contrast, gas turbines had a significance increase in ECE from 2005 to 2007, with introduction of new gas turbines with much higher ECE. There also appears to be a fairly good match between the observed ECE values in Figure 3-5 and the representative values listed in Table 3-3.

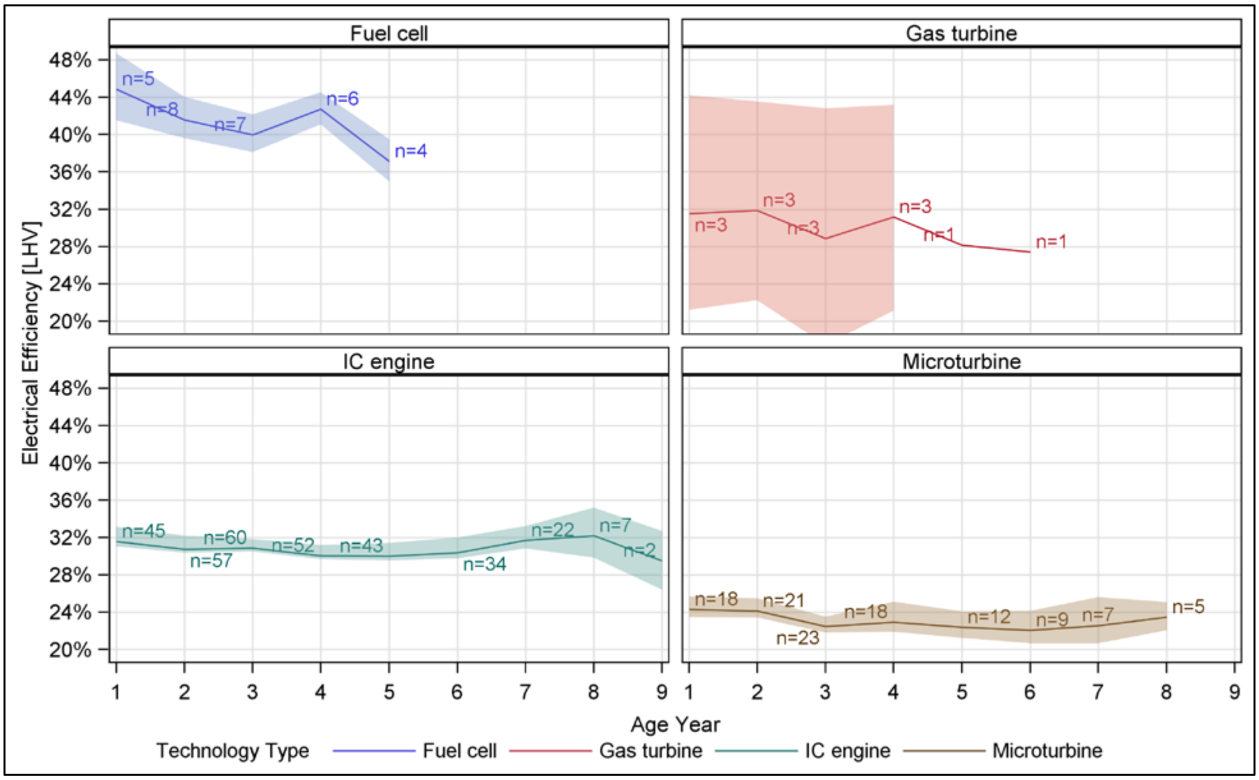
We also examined how ECE values change with the age of the system. Figure 3-6 shows metered annual mean ECEs relative to the age of the system among the early SGIP fleet of natural gas-fueled systems.[10] As before, the shaded bands following the trendlines show the

9 The annual means represent capacity-weighted means.

10 We refer to age year which corresponds to the year of operation of the system. For example, age year two means the system has been in operation for two years.

uncertainty about the mean at the 90/10 confidence level. Overall, ECE values show little variation as systems age. The ECE trendlines are generally flat for all technologies except fuel cells. The metered data suggest a decline in fuel cell ECE with age, with the mean ECE dropping from above 44% to less than 38% by age five. Given the small sample size for fuel cells in general and at age five particularly, we are hesitant to conclude that fuel cell ECE falls 1% per year as indicated by the annual mean values. Instead, we only conclude that fuel cell ECE declines with age at a rate of less than 1% per year. In spite of this decline, fuel cells still maintain the highest ECE of the CHP technologies.

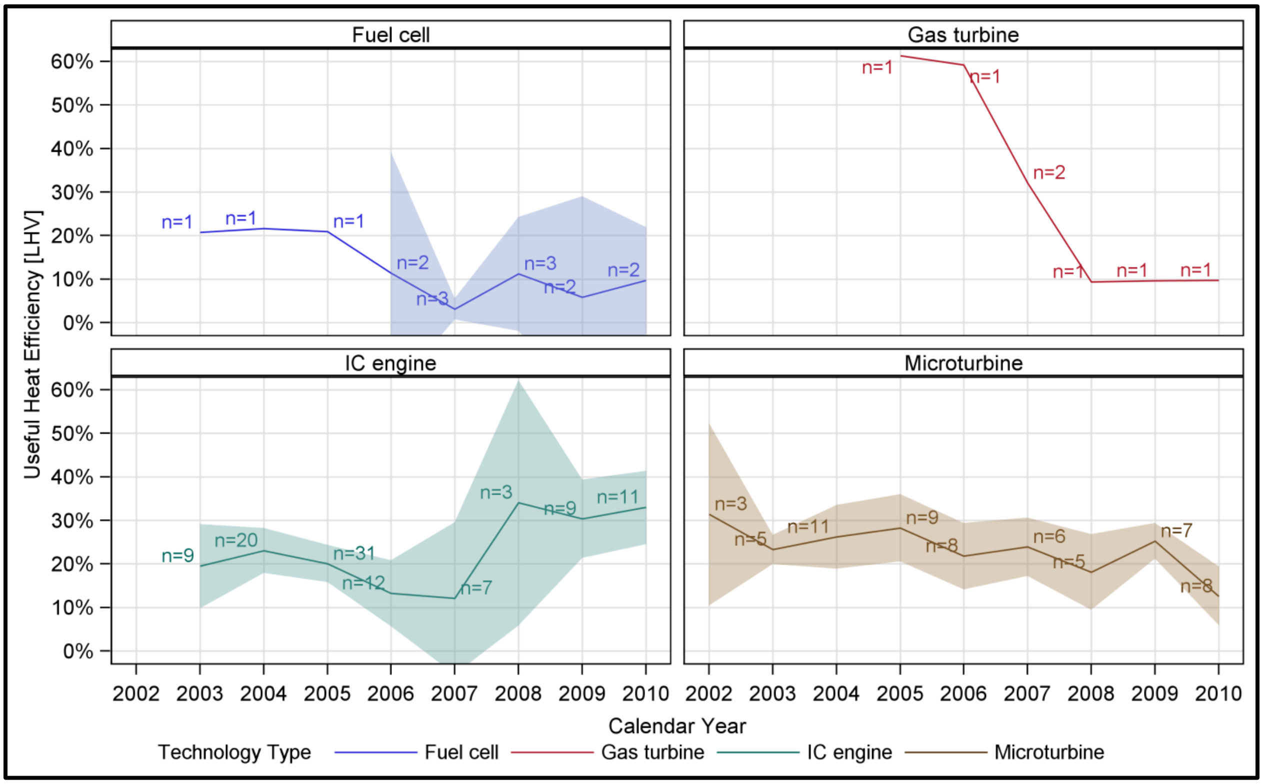
Figure 3-6: Age and Annual Mean Electrical Conversion Efficiency by Technology



Useful Waste Heat Recovery Efficiency

Useful waste heat conversion efficiency is a measure of a system's ability to convert fuel into useful heat. It is defined as the useful recovered heat divided by the fuel input. It is critical to understand that the heat conversion efficiency is not simply a measure of the system's ability to convert fuel into exhaust heat. The useful waste heat recovery efficiency must also account for the ability of the captured waste heat to serve the heat demand at the host facility. In particular, a prime mover may generate a substantial amount of waste heat that is recovered through heat exchangers. However, if the host site has no heat demand at that moment in time, the recovered heat is "dumped" to a radiator and provides no useful heat. Figure 3-7 shows observed annual useful waste heat conversion efficiencies for the early fleet's CHP technologies.[11]

Figure 3-7: Annual Mean Useful Heat Conversion Efficiency by CHP Technology



Unlike the ECE values, the annual mean useful waste heat recovery efficiencies generally do not remain flat from year to year. In addition, due to the small sample sizes for which we had heat data, there can be relatively large uncertainty bands around the annual mean values. In general, we note that useful waste heat recovery efficiencies for IC engines from 2003 to 2006 ranged from 10 to 30% but appear to have increased significantly from 2007 through 2010. Similarly, useful waste heat recovery efficiencies for microturbines deployed under the SGIP generally appear to range from 10 to 35%. While annual mean values for useful waste heat recovery efficiencies for fuel cells range from approximately 5 to 20%, the small sample sizes preclude these from being high certainty values.

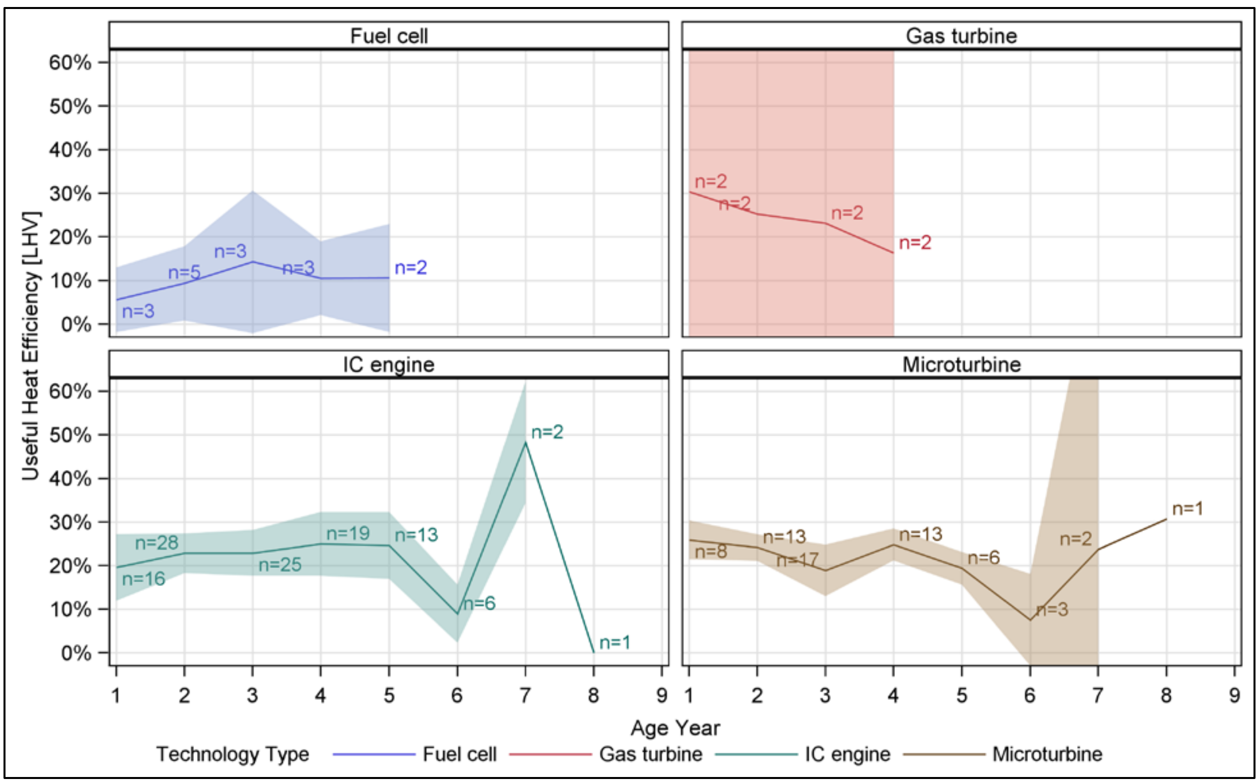
One of the most notable trends demonstrated in Figure 3-7 is the sharp decline in useful waste heat conversion efficiency from gas turbines from 2005 to 2008. This extraordinary decline is a result of metered data in 2005 and 2006 associated with one gas turbine system. The system had a large capacity and was operating at very high useful waste heat conversion efficiency (i.e.,

[11] Note that the lower heating value of natural gas is used as a basis for estimating useful waste heat recovery efficiencies.

almost always in the 50-70% range). All other SGIP gas turbine systems with metered data operating in this same time period achieved useful waste heat efficiencies generally of less than 30%. The gas turbine achieving such high useful waste heat recovery efficiencies did so because it was injecting steam directly into an oil well. Because the gas turbine system did not recover hot steam condensate to be reheated, it could use cool water on the inlet. As such, the system had an almost infinite heating load, which corresponded to very high and not very representative useful waste heat efficiencies. Itron stopped receiving heat data for this system in 2008, thereby dropping the annual mean useful waste heat recovery efficiencies for gas turbines down to 10%.

We also examined the effect of system age on useful waste heat recovery efficiency. Figure 3-8 displays annual mean useful heat conversion efficiency trends with respect to age. The figure extends to age nine although there were no non-zero data beyond age eight. The shaded areas around the trendlines represent the uncertainty of the means at the 90/10 confidence level. The wide range of uncertainty for gas turbines is a result of large variability between only two systems contributing to the trend. Figure 3-8 does not provide clear trends of declining performance with age as seen with annual capacity factor. The trends for IC engines and microturbines do both fall off at age six, and the uncertainty around the IC engine's trend stays relatively narrow at that age. The upward spike of IC engines in year seven is based on just two systems and so is not considered representative of SGIP IC engines generally. Figure 3-8 does demonstrate that annual mean useful heat recovery conversion efficiencies seldom topped 30%.

Figure 3-8: Age and Annual Mean Heat Conversion Efficiency by Technology

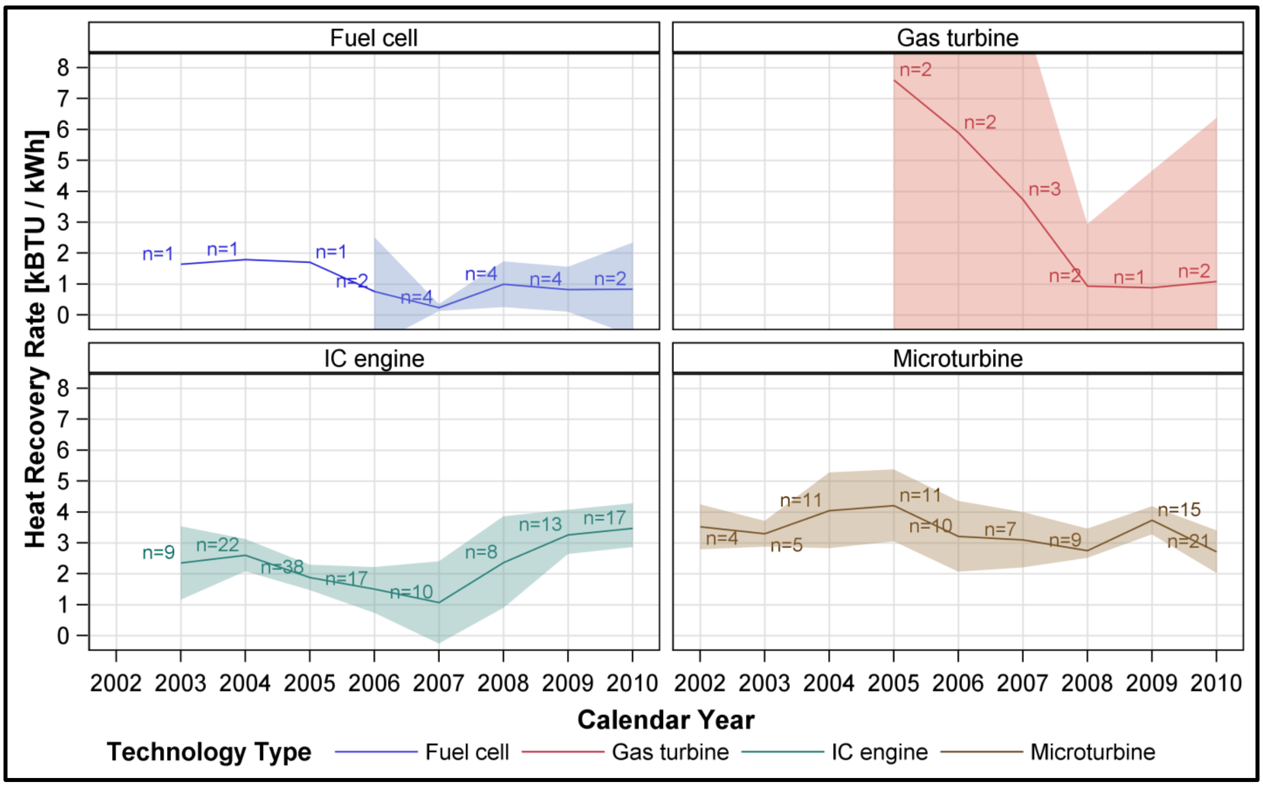


Site-Specific Examination of Useful Heat Recovery

Useful waste heat conversion efficiencies depend on the ability of the CHP system to match generated waste heat to heat demand at the host site. As a result, useful waste heat conversion efficiencies can be expected to exhibit substantial site-to-site variability. Recovery of useful heat depends not only on the facility having heating loads sufficiently large to use all the recoverable heat available, but also require those heating loads occurring when electricity is generated by the CHP prime mover. This section explores the variability underlying observed annual mean useful waste heat conversion efficiency results presented in preceding sections.

Annual heat conversion efficiencies were presented in Figure 3-8 by technology type. The annual waste heat recovery rates, defined as the ratio of useful was heat to electrical output, are depicted graphically in Figure 3-9. Some of the inter-technology variability, shown by the confidence bands, is caused by differences in their ECE. In general, the higher the ECE, the smaller the quantity of waste heat available to be captured. Within technology types useful heat recovery rates exhibit a great deal of variability.

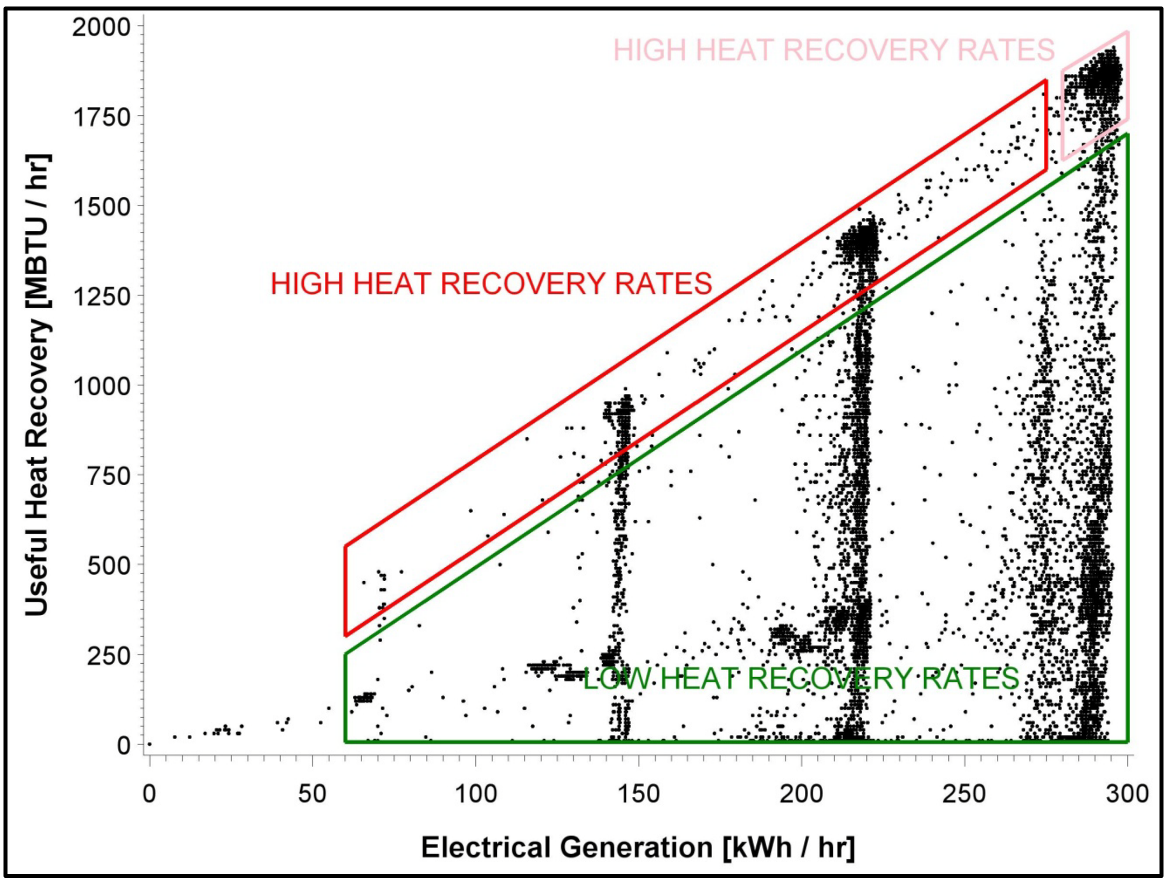
Figure 3-9: Useful Heat Recovery Rates of Metered Systems by Technology



To better understand the factors causing variability depicted in Figure 3-9, heat recovery data for a specific, illustrative project are plotted in Figure 3-10. Three operating regimes are identified in Figure 3-10, which plots actual metered hourly useful heat recovery versus electricity generation data for an SGIP CHP system.

The operating regime denoted in pink at the upper-right corner of the plot (Zone ‘A’) represents full utilization both of electrical generation capacity, and also recovery of useful heat. The engines are operating at near full-capacity, and all of the heat available to be captured and used productively actually is being captured and used (as opposed to being rejected to the atmosphere). The observed ratio of useful heat capture to electricity generation is approximately 6.4 kBtu/kWh. This is virtually identical to the thermal output listed in technical specifications for the CHP modules employed in this system.

Figure 3-10: CHP System Heat Recovery Rate - Operating Regimes for Illustrative System



The operating regime denoted in red (Zone ‘B’) and extending from the lower-left to the upper-right represents partial utilization of electrical generation capacity. Recovery of useful heat (the production of which is approximately proportional to electricity generation), remains at a very high rate. All of the heat available to be captured and used productively actually is being recovered. This CHP system comprises four gensets. The distinct vertical bands represent operation of 2, 3, or 4 of the gensets. While facility-level electrical usage and thermal load data necessary to draw definitive conclusions are not available, several possible explanations for variable electrical output levels include:

- Facility-level electricity usage is reduced. Prohibition against export of electricity to the grid necessitates operation at a reduced level of electricity generation (i.e., electrical load following)
- Facility-level thermal load is reduced. Desire to operate at a very high CHP system efficiency leads to operation at a reduced level of electricity generation (i.e., thermal load following)
- One or more gensets are out of service due to either planned or unplanned maintenance outage.

The heat recovery rate in Zone A and in Zone B is approximately 6.4 kBtu per kWh. Assuming an average ECE for engines (31.2%), this translates into total system efficiency of 89% and PUC 216.6b efficiency of 60%.

The operating regime denoted in green (Zone 'C') represents hours when a portion of heat available for recovery and use is not needed and is therefore rejected to the atmosphere. The resulting heat recovery rate range (from 0 to 6.4 kBtu per kWh) corresponds to total system efficiencies between 32% and 89% and to PUC216.6b efficiencies from 32% to 60%. All else equal, operation in Zone C is associated with lower CHP total system efficiencies and lower GHG emissions reductions. In fact, areas of Zone C corresponding to high electricity generation and low useful heat efficiency (i.e., low heat recovery rate) may actually result in GHG emissions increasing. Figure 3-10 depicts a case where ability to create available thermal energy exceeds need for thermal energy during substantial numbers of hours. Resulting operations at relatively low heat recovery rates create concern for total system efficiency (and corresponding financial performance), as well as for ability to deliver GHG emissions reductions.

The average heat recovery rate for this project is 3.1 kBtu per kWh, which corresponds to an average total efficiency of 59%. This average value falls just short of the key benchmark (60%) for this performance metric. This example illustrates how operating strategy can influence key CHP performance metrics, and the importance of the magnitude and timing of thermal loads. For this particular system, modification of operating strategy could raise average total efficiency from 59% to as high as 89%.

Facility selection largely determines the boundaries within which a CHP system's performance will fall. CHP system design (i.e., electrical generator size) further defines the possibilities. Finally, specification of CHP system operation strategy (e.g., electrical load following, thermal load following) determines what energy efficiency and GHG emissions performance levels will actually be achieved. If CHP is going to fulfill its promise then advances will need to be made in all three areas.

Total System Efficiencies

Two CHP performance metrics of high interest consist of electrical generation and useful waste heat recovery. Together, these determine total CHP system efficiency. Figure 3-11 shows these two efficiency components by CHP technology as observed in 2010.

Figure 3-11: Total System Efficiency Components by CHP Technology (2010)

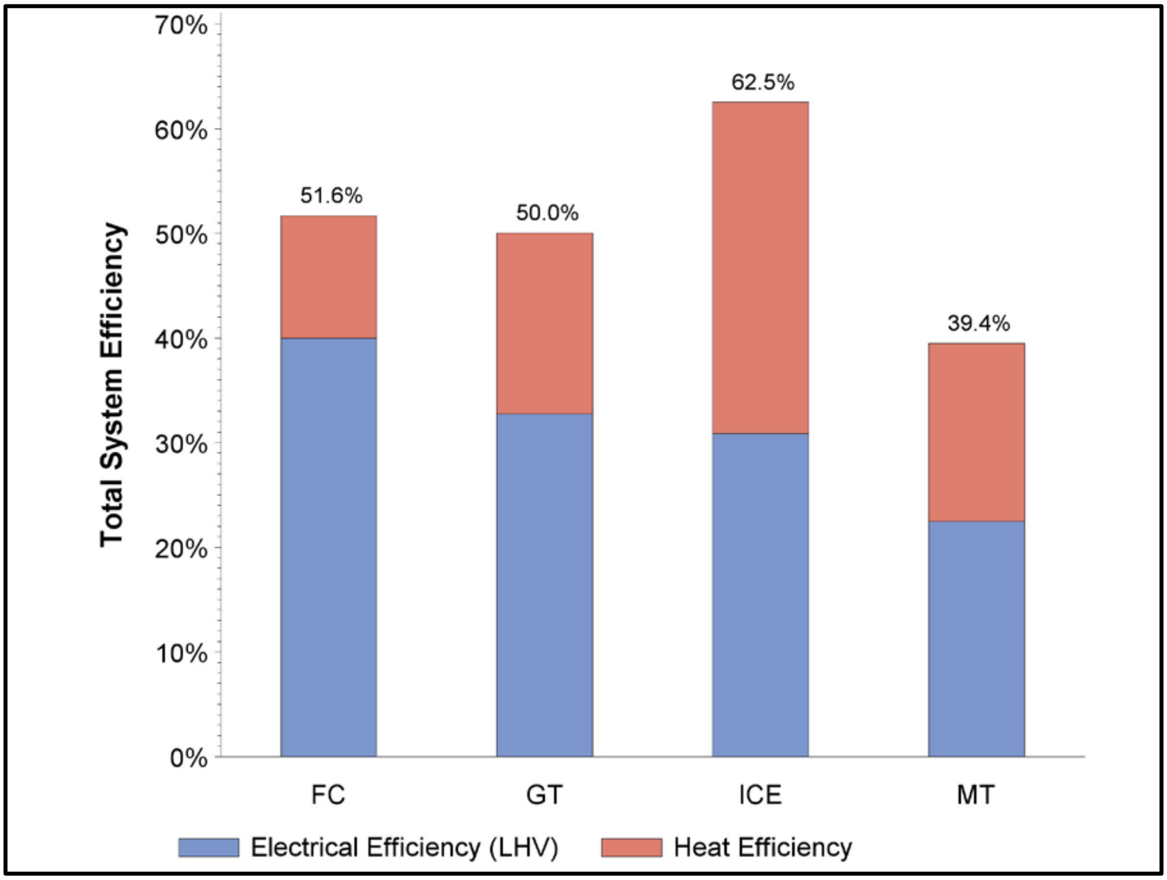


Figure 3-11 reinforces the importance of useful waste heat recovery on total CHP system efficiency. Although fuel cells have significantly higher electrical efficiency than IC engines (i.e., 40% versus 30%) IC engines have observed total system efficiencies significantly higher than fuel cells; due to their higher useful waste heat recovery efficiency. Increased useful waste heat recovery is important not only for economic reasons but as we will see later in Section 3.3, has great importance on GHG emission reductions.

3.1.4 Utilization of CHP Systems

Utilization and Capacity Factor

One useful measure of performance is capacity factor. Capacity factor is the ratio of actual power produced from a generator to its rated capacity at any given point in time.[12] It is useful when comparing the utilization of generators of different capacities. Average annual capacity factor may be thought of as the portion of the year the system would have been utilized at its full nominal capacity. For example, an annual capacity factor of 0.5 can result from operation at full capacity for half the year as well as from operation at half capacity for the whole year. The annual capacity factors of CHP systems during the early years of the SGIP varied widely. Annual capacity factors also varied widely with age, but the predominant trend was a rapid decline in annual capacity factor with age. This trend with age is a focal point of this section.

Capacity Factor and Calendar Year

In examining capacity factors for CHP systems in the early years of the SGIP, we first investigate capacity factor changes by calendar year.[13] Annual mean capacity factors reported for a calendar year are based on metered data from systems that became operational in that year or any earlier year. In the initial years of the program, these systems all were young and most were generating power for a large number of hours in the year. The annual mean capacity factors during those initial years therefore would be expected to be relatively high. However, metered data showed a disturbing trend. By the end of 2006, over a third of the SGIP systems were in their fourth year and some were generating at low capacity factors while others had already been decommissioned. After 2005, the peak year for new CHP system additions, the annual mean capacity factors increasingly represented aging systems as opposed to new systems. Table 3-4 lists the simple and capacity-weighted mean ages of systems from the whole SGIP fleet at the end of 2010. Although fuel cells have maximum ages that are comparable to IC engines and microturbines, the mean age is significantly less as many fuel cell systems were deployed after the start date of IC engines or microturbines.

Table 3-4: Whole Fleet System Mean Ages as of End of 2010

Technology	Mean Age (Years)	Capacity-Weighted Mean Age (Years)	Maximum Age (Years)
Fuel Cells	2.9	3.1	8.6
Gas Turbines	4.4	3.9	6.9
IC Engines	5.7	5.8	9.2
Microturbines	5.7	5.3	9.1

12 Capacity factor should not be confused with availability. The availability factor of a power plant is the amount of time that it is able to produce electricity over a certain period, divided by the amount of the time in the period.

13 In this section we report annual mean capacity factors by CHP technology.

In comparison, Table 3-5 lists these ages for the early fleet of CHP systems. The early fleet's ages are necessarily older, particularly for fuel cells. Note that when we examine just the early SGIP fleet, that the capacity-weighted and simple mean age of fuel cells is much closer to that of IC engines and microturbines. This distinction becomes important because as this section will show, aging systems can have rapidly declining capacity factors.

Table 3-5: Early Fleet System Mean Ages as of End of 2010

Technology	Mean Age (Years)	Capacity-Weighted Mean Age (Years)	Maximum Age (Years)
Fuel Cells	5.2	5.0	8.6
Gas Turbines	5.5	5.1	6.9
IC Engines	6.6	6.7	9.2
Microturbines	6.3	6.1	8.8

Table 3-6 shows capacity-weighted annual mean capacity factors among the entire fleet of metered SGIP CHP systems from 2002 through 2010.[14] These capacity factors indicate the relative extent to which SGIP CHP systems were utilized for generating power. Overall, gas turbines consistently had annual mean capacity factors exceeding 74%, often ranging above 80%. At the other end of the spectrum, microturbines consistently had annual mean capacity factors lower than 40%. In the case of both fuel cells and IC engines, capacity factors declined significantly from 2002 to 2010.

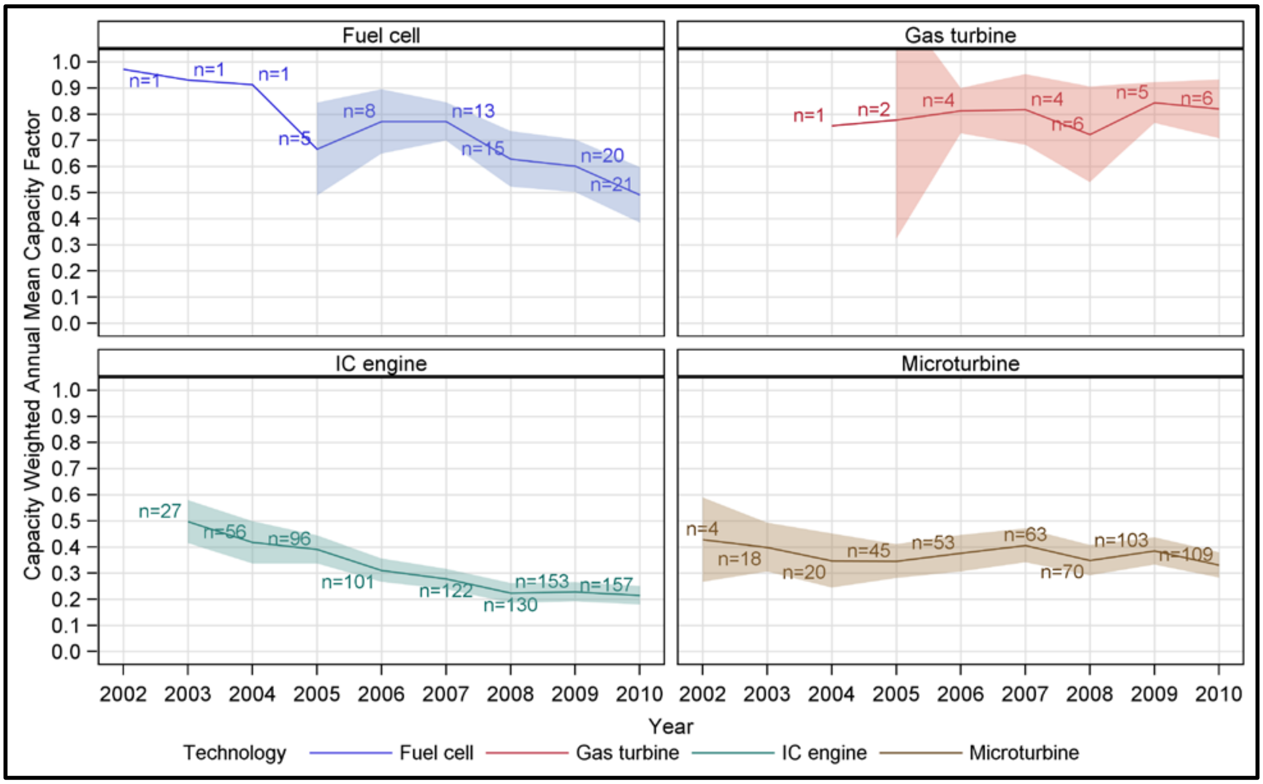
Table 3-6: Calendar Year Annual Mean Capacity Factors by Technology (2002 – 2010)

Year	Fuel Cell	Gas Turbine	IC Engine	Microturbine
2002	0.97	.	.	0.43
2003	0.93	.	0.50	0.40
2004	0.91	0.76	0.42	0.35
2005	0.67	0.78	0.39	0.35
2006	0.77	0.81	0.31	0.38
2007	0.77	0.82	0.28	0.43
2008	0.63	0.72	0.24	0.39
2009	0.60	0.84	0.25	0.44
2010	0.49	0.82	0.23	0.38

[14] Capacity factors for gas turbines are not shown in 2002 and 2003 as no gas turbines had entered operation in the SGIP before 2004 for which there was metered data. Likewise insufficient metered data were available for IC engines in 2002 to create representative means.

Figure 3-12 charts trends in the capacity-weighted annual mean capacity factors for each of the CHP technologies over calendar year for the entire fleet. The small number of gas turbines in all years of the SGIP limits drawing general conclusions about their capacity factor trends. From 2003 onward, annual capacity factors of IC engines and fuel cells generally declined while those of microturbines remained relatively steady. Although their capacity factors fell the most in absolute terms over the course of the program, fuel cells continued to have more utilization than IC engines or microturbines. The 2010 decline in fuel call capacity factor resulted primarily from a prolonged period of electricity consumption for heating an off-line molten carbonate fuel cell. That system was decommissioned in December 2010. In order to better understand capacity factor trends, we next examined how capacity factor changed with system aging.

Figure 3-12: Trends of Annual Mean Capacity Factors by CHP Technology (2002-2010)



Capacity Factor and System Age

Annual capacity factors for any system can be expected to decline somewhat with age. However, barring unusual economic conditions or major system failures that prevent utilization, annual capacity factors should stay relatively flat if a CHP system is well designed and maintained.

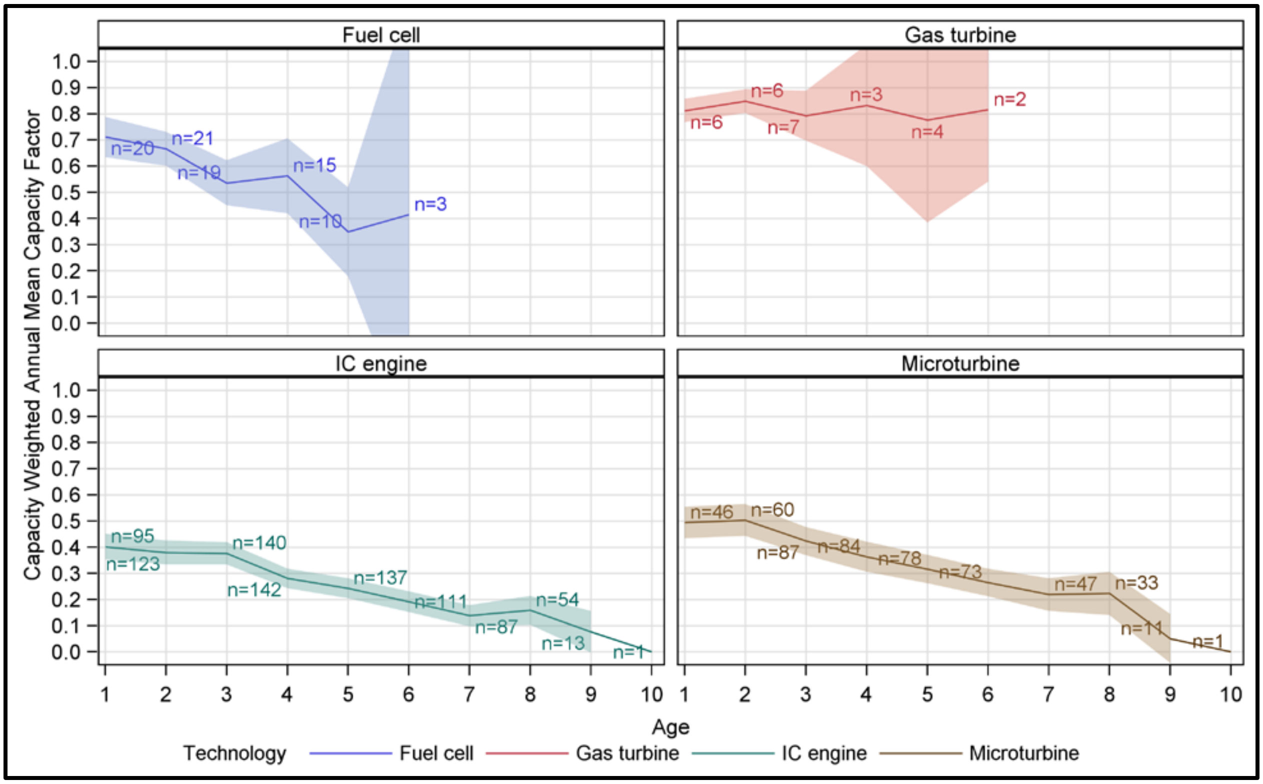
Table 3-7 shows capacity-weighted annual mean capacity factors among the entire fleet of metered SGIP CHP systems by age and technology. No metered data were available beyond age six for fuel cells or gas turbines.

Table 3-7: Annual Mean Capacity Factors by Age and Technology

Age	Fuel Cells	Gas Turbines	IC Engines	Microturbines
1	0.71	0.81	0.40	0.49
2	0.67	0.85	0.38	0.50
3	0.54	0.79	0.38	0.42
4	0.56	0.83	0.28	0.36
5	0.35	0.78	0.24	0.32
6	0.42	0.82	0.19	0.27
7	.	.	0.14	0.22
8	.	.	0.16	0.22
9	.	.	0.08	0.05
10	.	.	0.00	0.00

Figure 3-13 shows trends in capacity-weighted annual mean capacity factors by age for the CHP systems of the entire fleet. Note that year one represents the first full year of system operation regardless of the system installation dates.

Figure 3-13: Annual Mean Capacity Factors by Age and Technology



Except for gas turbine systems, the typical SGIP CHP system had an unexpectedly rapid decline in annual capacity factor with age. The rate and extent of the declines are more precipitous than expected. Similar capacity factor results have been presented in earlier SGIP impact evaluations and by Navigant in its CHP process evaluation report.[15] We examined outage information to see if we could discern possible causes for the very low observed capacity factors.

Utilization and Outages

The Navigant study referred to above concluded that reduction in capacity factor with system age was mainly attributable to increased incidence of outages lasting more than three days. To increase our understanding of outages, we examined their durations and checked for statistically significant differences in lengthy outages among systems sharing similar characteristics.

15 Navigant Consulting, "Self-Generation Incentive Program: Combined Heat and Power Performance Investigation," April 1, 2010.

Outage Durations

The importance of outages longer than three days was described in the Navigant report. The actual durations of these outages could be anywhere from four days to many years. Interviews with participants revealed relatively high incidence rates of breakdowns. It would seem reasonable to assume that a substantial portion of extended outages are caused by such breakdowns that are not quickly remedied. To understand *changing* utilization as systems age we focused on outages exceeding 30 days.

We know little about CHP system breakdowns, apart from the fact that they are occurring more frequently than interview respondents had expected (i.e., the Mean Time Between Failures is shorter than expected). We also know that in a perfect world breakdowns would be repaired quickly (i.e., Mean Time to Repair would be relatively short). Whether 'quickly' is a day, a week, or longer likely depends on the type of system and the type of breakdown. However, if we had to pick a single number of days to define 'quickly' we might pick one week for smaller systems and two weeks for larger systems. That amount of time would seem to be sufficient under typical circumstances to:

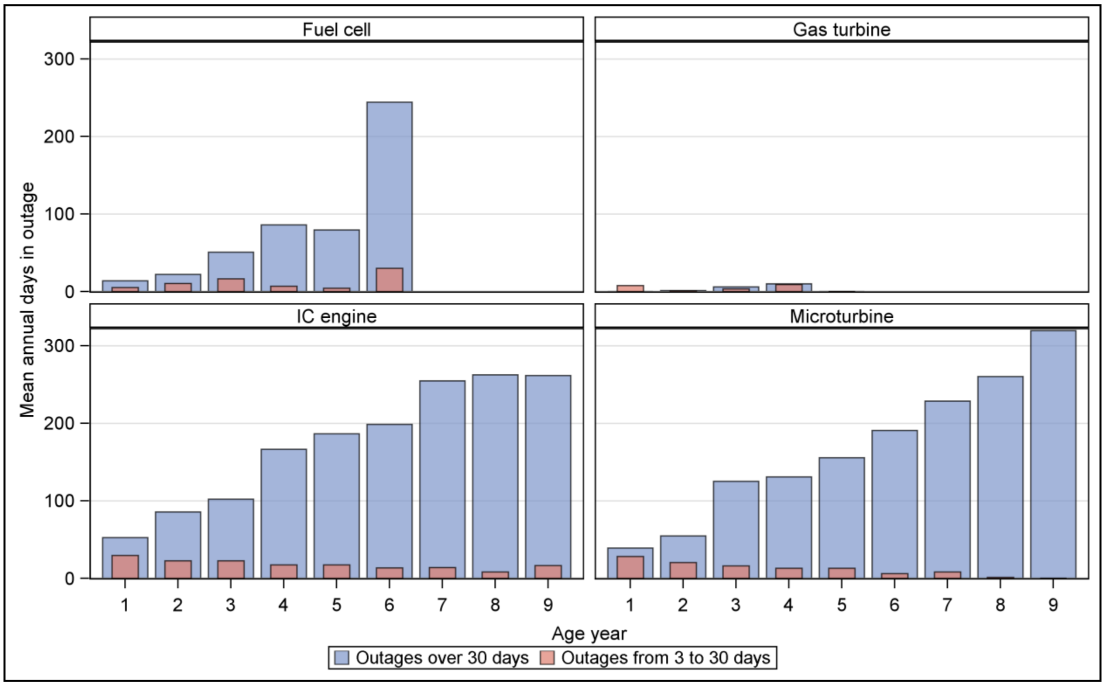
- Fly someone to the site to diagnose the problem;
- Ship parts to the site; and
- Install the parts and return the CHP system to service.

If it is taking longer than 30 days to complete repairs and return systems to service then it would be useful to know if this is occurring and useful to understand why this is occurring. It then follows that if we want to increase our understanding of utilization, a reasonable place to start is with a more detailed review of the lengths of outages exceeding three and exceeding 30 days.

When systems get older, a greater portion of the days in down time is within outages greater than 30 days. We think the 30-day threshold is meaningful. Rather than simply being an arbitrary or 'round' point of demarcation to be used for creating summary statistics or summary graphics, instead it is a length of time beyond which we think there are likely to be important, non-technical issues influencing the response to outages.

Figure 3-14 shows annual mean days in outage by age and technology based on data from metered systems. The means are broken into two categories of duration: outages lasting from three to 30 days and those lasting greater than 30 days. The shorter duration outages may be due to a variety of reasons and may be planned or unexpected. In any case they are resolved in no more than a month. Figure 3-14 demonstrates that, for all technologies except gas turbines, outages from three to 30 days contribute only a small fraction of outage days relative to outages over 30 days.

Figure 3-14: Breakout of Outages by Duration and by Technology



Outage Patterns

For the most part, we do not know the reasons why so many outages are taking over a month to reverse. We know that different CHP system owners experience different challenges where recovery from extended CHP system outages is concerned. Factors that likely influence recovery include:

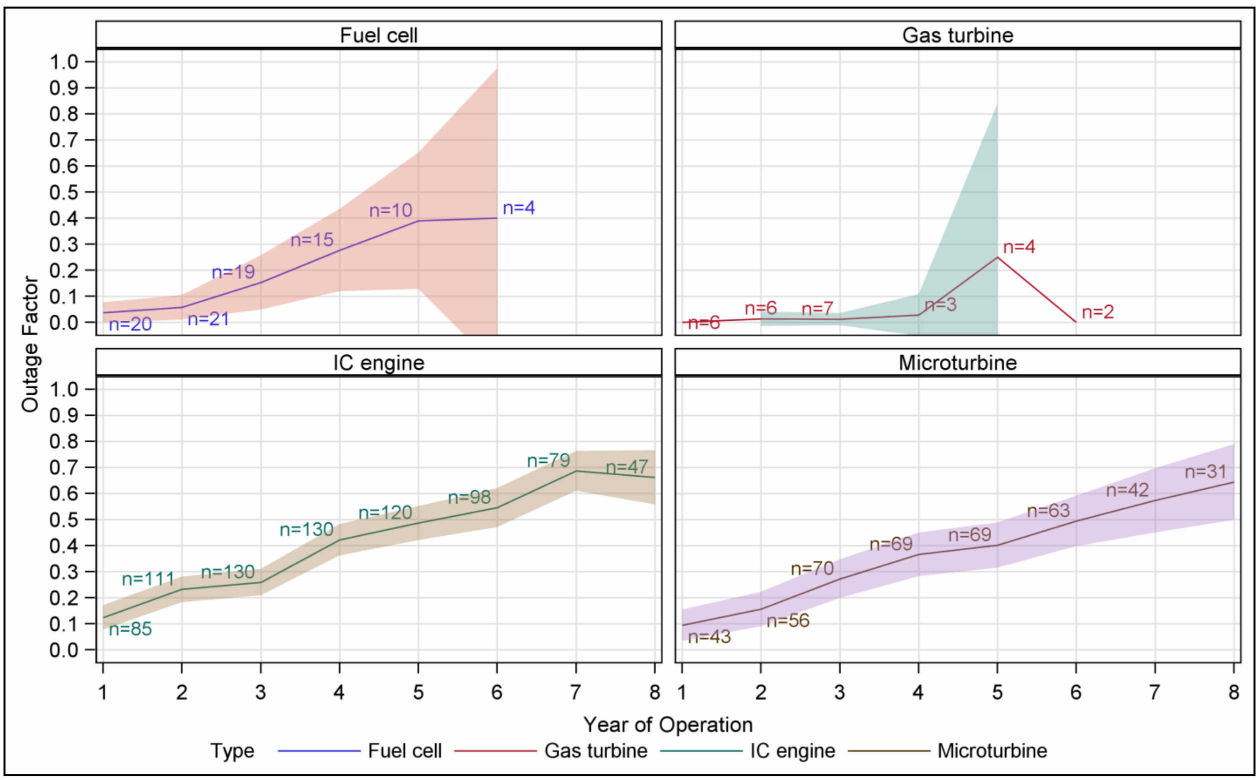
- Expertise of on-site personnel
- Warranty coverage (or not covered)
- Availability of money to repair breakdowns that are not covered by warranty and
- Availability and expertise of resources providing warranty service

If the future is to be better than the past, the incidence of and/or response to outages will need to change. One first step in the direction of change is identifying causes of extended outages. We begin by examining available data for patterns that may link lengthy outages to certain system characteristics. For example, these outages may be more important for certain types of systems sharing readily identifiable characteristics, including host facility type and CHP system size.

Annual mean outage factors versus system age are depicted graphically in Figure 3-15 for each CHP technology. The mean outage factor indicates the average proportion of days in a year that will in an outage lasting over 30 days. The shaded bands superimposed on the trend lines indicate the uncertainty associated with the mean outage factor. Wider bands indicate greater uncertainty that is explained by relatively small sample sizes and/or relatively large variability exhibited by the metered systems. The technology has some bearing on the outage factor over time. As Figure 3-15 shows, the technologies have different rates of growth in outage factor. Although fuel cell and gas turbine systems are few in number, several factors are evident:

- Microturbine outage factors show a linearly increasing trend
- IC engines indicate higher outage factors than microturbines
- Fuel cell outage factor variability is large and increases dramatically at later ages

Figure 3-15: Outage Factors by Age and Technology



We looked at multiple system parameters that might affect outage factors by examining their impact on the variance in outage factor at each age. This analysis of variance (ANOVA) technique used a model shown in the general equation below:

Model equation:

$$\text{Outage Factor} = \text{Year of Operation } X_i + \text{Spark Gap } X_i + \text{System Type } X_i + \text{Size } X_i + \text{Building Type } X_i + \text{Developer Experience } X_i + \text{Fuel Type } X_i + \varepsilon$$

Where:

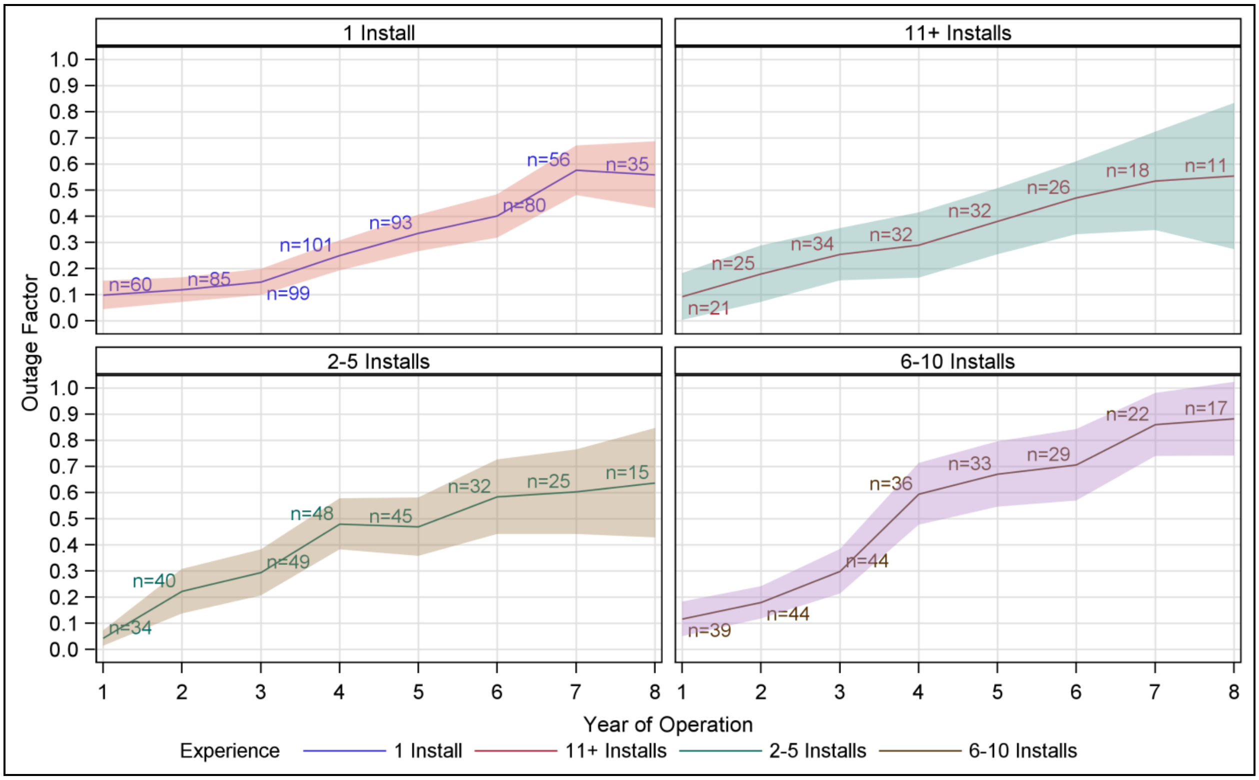
- Outage Factor = annual proportion of days in outages of over 30 day duration
- Year of Operation = system age in years
- Spark Gap = annualized relative benefit of running the CHP system to generate electricity and recoverable heat[16]
- System Type = technology type
- Size = system generating capacity category (e.g., small, medium, or large, category bins defined specific to technology)
- Building Type = host site's facility category as described by host's NAICS or SIC code
- Developer Experience = category based on the total number of systems completed by the developer by the end of 2010
- Fuel Type = fuel variety fed to the system, being natural gas, biogas, or a combination of the two fuels
- ε = error term

The in-depth ANOVA technique and results are described in more detail in Appendix D. The ANOVA analysis generated several key findings. Among them was that the variation in outage factor was significantly influenced by the developer experience parameter. The four developer experience categories were defined as follows: only 1 completed system, 2 to 5 completed systems, 6 to 10 completed systems, and 11 or more completed systems.

[16] Categorical values based on distribution of monthly values calculated using monthly means of commercial and natural gas and electric prices from 2001 to 2010, and technology-specific fuel conversion efficiencies and heat recovery rates.

Figure 3-16 shows the trends in annual outage factor with age for the four developer experience categories. The shaded bands following the trend lines indicate the uncertainty in the annual outage factor.

Figure 3-16: Annual Outage Factor by Age and Developer System Completions



The ANOVA results showed that:

- At most system ages, outage factors are *lower* for developers with only 1 completed system than for developers with 6–10 completed systems.
- At several ages, outage factors are lower for developers with 11 or more completed systems than for those with 6–10 completed systems.
- There is no significant difference in outage factor at any age for developers with 1 completed system compared to those with 11 or more completed systems.

Some of these results are counter-intuitive. Developers with larger numbers of completed systems presumably would have more experience than developers with smaller numbers, and that experience would lead to systems with lower rather than higher outage factors. Developers with 6-10 completed systems tended toward higher outage factors than both those with 11 or more systems as well as those with just one system. At the same time there was no significant difference between developers with one system and those with 11 or more. Underlying these results there may be differences, and similarities, in contractual arrangements for system repair and maintenance. Little is known about those contractual arrangements apart from the warranty required by the SGIP. In any case, developers with individual completed systems delivered lower rather than higher rates of system outages.

No other system parameters were associated with consistency in differences in outage factors at the various system ages. We also examined the effect of system size category on outage. We observed no significant difference in outage factor at any age based on size category.

Additional CHP performance trends are treated in Appendix F.

Conclusion

Outages longer than 30 days are severely reducing ICE and MT CHP system utilization and project viability along with it. Strategic modification of SGIP design to increase utilization performance would require information capable of explaining lengthy outages. Readily available information was not sufficient to explain most of the lengthy outages. Substantial increase in ability to explain lengthy outages would require development of additional information.

- Scope of maintenance agreements (while under warranty, and when out of warranty). The SGIP did require that completed systems have minimum warranty periods of three years for IC engines, microturbines, and gas turbines, and of five years for fuel cells. The expiration of these minimum warranty periods potentially could mark the start of reduced system maintenance.
- Maintenance records. The SGIP does not require SGIP system owners or operators to provide maintenance records on the systems. Consequently, it is difficult to identify and quantify the extent to which CHP systems lack maintenance.
- Failure modes.
- Reasons repairs were not made (while under warranty, and when out of warranty).

3.1.5 The Energy Landscape of the Early SGIP Fleet

In the previous section, we examined possible factors influencing CHP system performance. The energy landscape in which the early SGIP CHP technologies were deployed likely had some influence on CHP system performance and growth. The purpose of this sub-section is to provide background on market events occurring during the growth and deployment of the early SGIP fleet.

Possible SGIP Project Developer Influences

A large number of CHP project developers emerged in the California marketplace in response to the SGIP. There were 194 different CHP developers involved in CHP projects during the early SGIP years alone. Most of these project developers deployed only a single SGIP project. In addition, many of the single developer projects were those developed by the system hosts themselves. However, there were key project developers involved in a large number of projects.

Table 3-8 summarizes the annual system completions of companies that made up the top 10 CHP project developers during these early years. [17]

Table 3-8: Top 10 CHP Developers' Completed Systems by Year (2001–2010)

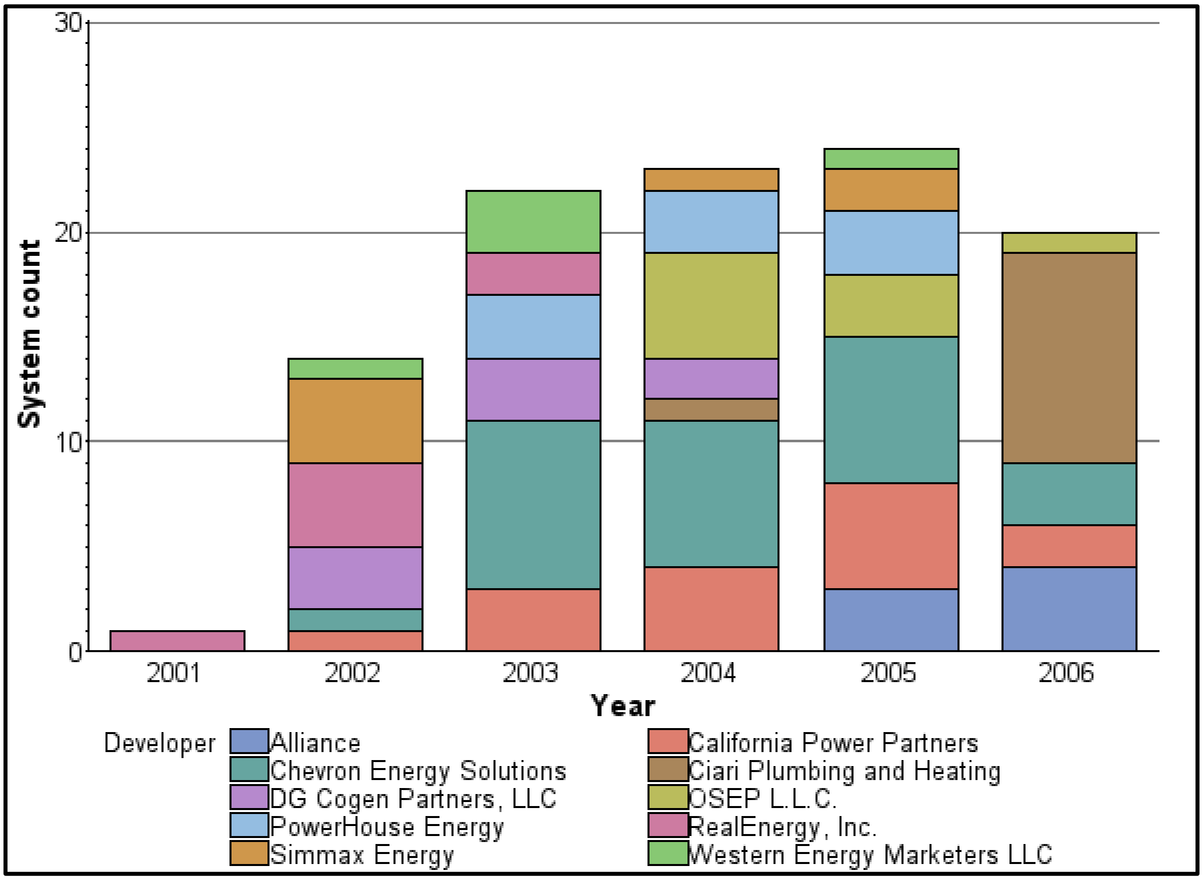
	Developer										
Completion Year	**RealEnergy Inc**	**California Power Partner**	**Chevron Energy Solutions**	**DG Cogen Partners LLC**	**Simmax Energy**	**Western Energy Marketers**	**PowerHouse Energy**	**Ciari Plumbing and Heating**	**OSEP LLC**	**Alliance Energy**	**Total**
2001	1										1
2002	4	1	1	3	4	1					14
2003	2	3	8	3		3	3				22
2004		4	7	2	1		3	1	5		23
2005		5	7		2	1	3		3	3	24
2006		2	3					10	1	4	20
2007			1				2	2		1	6
2008			1				2			2	5
2009			1				1				2
2010		1									1
Total	**7**	**16**	**29**	**8**	**7**	**5**	**14**	**13**	**9**	**10**	**118**

Key CHP project developers during the early years of the SGIP included Chevron Energy, Real Energy, DG Cogen Partners, Alliance Energy and California Power Partners. Some of the key project developers, such as Chevron Energy and California Power Partners were involved in the SGIP across five of the six early years. Other project developers had a more limited involvement, their company names sometimes appearing for only a short time period.

[17] This is the top ten project developers as determined by completed system count through the end of 2006

Figure 3-17 more visually shows the change in the make-up of the top 10 CHP project developers during the early years of the SGIP CHP fleet.

Figure 3-17: Top 10 CHP Developers by Completed System Count (2001–2006)



As shown, there were significant changes in the make up of the top 10 CHP project developers. By 2006 only six of the top 10 project developers during the early years were still completing systems. PowerHouse Energy had no 2006 completions but continued to complete five more SGIP projects in subsequent years. Meanwhile DG Cogen Partners, Simmax, and RealEnergy were no longer developing SGIP CHP projects by 2005, at least under those business names.[18]

As noted earlier, a large number of SGIP projects were associated with single project developers. Of the 342 completed CHP systems by the end of 2010, 185 had project developers with names associated with just one system. Of these 185, 76 had a project developer name that matched the host name, and thus may not have been project developers in the sense that their focus was CHP

[18] Merger and acquisition activity gleaned from various trade journal articles indicate that DG Energy Solutions sold DG Cogen Partners to Simmax in 2005, DG Energy Solutions is now EWP Renewables, and Simmax continues to exist but has sold some of its CHP assets in California to a firm named 808 Energy3.

system design and installation. There were another 50 project developers that had no more than four completed systems in the SGIP.

Both the high change over in project developers and the high number of one-off project developers may have influenced performance of CHP systems. A high change over in project developers may have coincided with a drop in system maintenance, thereby leading to increased downtime. In their evaluation of possible factors affecting CHP performance, Navigant found that a number of CHP host sites were dependent on third-parties for maintenance of the CHP systems. And among all survey respondents, 16% reported poor quality maintenance service.[19] Some project developers also offered maintenance plans. It is not clear if the poor quality service described by Navigant came from project developers also providing maintenance.

Similarly, a project developer with a small number of systems, and who was not also a system host, simply may have been unprepared for the marketplace. In addition, where system host and project developer names were identical, it may be that project development relied heavily on the host's in-house expertise as a means of reducing costs.[20] In some cases, in-house expertise might suffice for development, but in other instances, may have led to poor system design and subsequent poor performance.

[19] Navigant Consulting, "Self-Generation Incentive Program: Combined Heat and Power Performance Evaluation," April 1, 2010, page 57.

[20] There are 89 instances among the 432 CHP systems were host and developer of names were the same.

Possible SGIP Equipment Manufacturer Influences

There was also an assortment of equipment manufacturers active in the SGIP during the early years. There were 25 different CHP manufacturers involved in the 332 CHP projects completed during the early years.

Table 3-9 lists annual completed system counts among the top 10 manufacturers based on their systems completed from 2001 to 2006. By 2010 these ten manufacturers had equipment in 342 of the 432 completed SGIP CHP systems.

Table 3-9: Top 10 CHP Manufacturers' Completed Systems by Year (2001–2010)

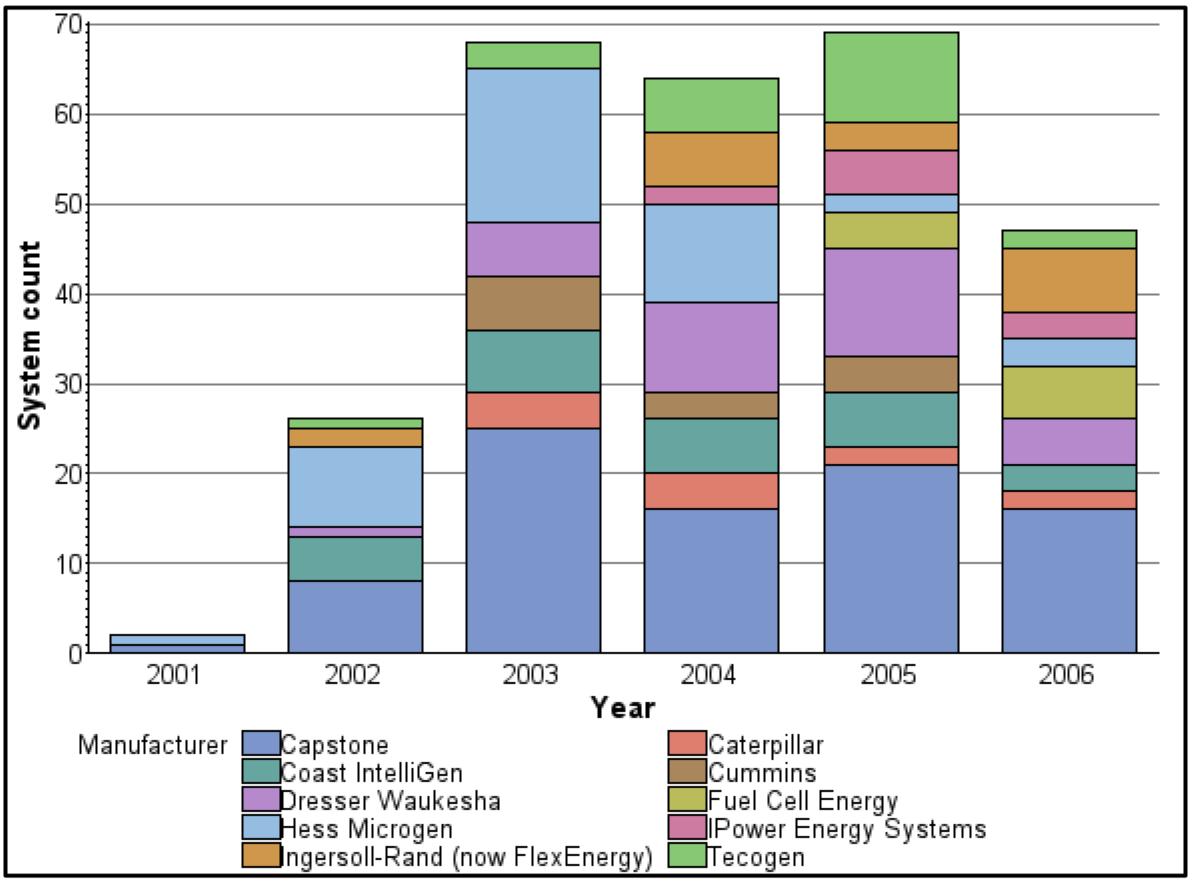
	Manufacturer										
Completion Year	**Capstone**	**Hess Microgen**	**Coast IntelliGen**	**Dresser Waukesha**	**Ingersoll Rand now Flex**	**Tecogen**	**Caterpillar**	**Cummins**	**IPower Energy Systems**	**Fuel Cell Energy**	**Total**
2001	1	1									2
2002	8	9	5	1	2	1					26
2003	25	17	7	6		3	4	6			68
2004	16	11	6	10	6	6	4	3	2		64
2005	21	2	6	12	3	10	2	4	5	4	69
2006	16	3	3	5	7	2	2		3	6	47
2007	5	1	2	6	6	2	2		2	3	29
2008	4			2	3	1	2		2	3	17
2009	2				1	2			3	3	11
2010		1			1		1		4	2	9
Total	**98**	**45**	**29**	**42**	**29**	**27**	**17**	**13**	**21**	**21**	**342**

Among the key manufacturers for CHP prime movers in the SGIP were Capstone and Ingersoll-Rand for microturbines, and for IC engines, Hess Microgen, Coast IntelliGen, Dresser-Waukesha and Cummins.

Figure 3-18 displays the trends among annual counts by the top 10 manufacturers. Similar to the trends noticed with the project developers, there was a significant jump in the number of systems among the top 10 manufacturers involved with the SGIP between 2001 and 2003, followed by a relatively flat number among them from 2003 through 2005 and a decline in 2006. This diminishing presence in the SGIP among the top 10 manufacturers is due in part to the variations in system counts among developers.

As with project developers, a high change over in equipment manufacturers may have resulted in maintenance problems, delays in procuring parts and consequently increased downtime.

Figure 3-18: Top 10 CHP Manufacturers by Completed System Count (2001–2006)



Possible Influence of Host Facility

The economic success of any CHP system is highly dependent on host site characteristics; in particular the amounts and coincidence of electrical and thermal demands at the host site. In general, sites that provide good possibility of CHP economic success have thermal loads that are consistent throughout the year and are matched with electrical demand. In this way, as the prime mover from the CHP generates electricity to meet the electrical demand, the recovered waste heat is used to meet the thermal load at the site. Not all host sites have this good match between electrical and thermal demand. Consequently, we expected CHP systems to go into a narrow band of facility types.

CHP systems during the first six years of the SGIP were completed in an assortment of host sites. We categorized facilities of the 332 CHP projects of the early SGIP years based on their Standard Industrial Classification (SIC) or North American Industry Classification System (NAICS) codes, depending on which had been provided. Some facility type categories were collapsed together or divided to focus on useful distinctions. For example, sites classified as health services would have included hospitals, dentist offices, or doctor's offices, where there would ideally be both thermal and electrical demands served by the CHP system. Lodging/residential refers largely to hotels but also includes residential facilities, where electricity would be used to service electrical demands, such as HVAC or lighting, and where recovered waste heat could serve thermal demand associated with domestic hot water (DHW) loads. Similarly, digesters such as digester/WWTP refer to biogas anaerobic digesters used at wastewater treatment plants where the waste heat recovered from the CHP system might help heat the digester. Another biogas category was "digesterAg" that refers to digesters at dairies or food processing facilities.

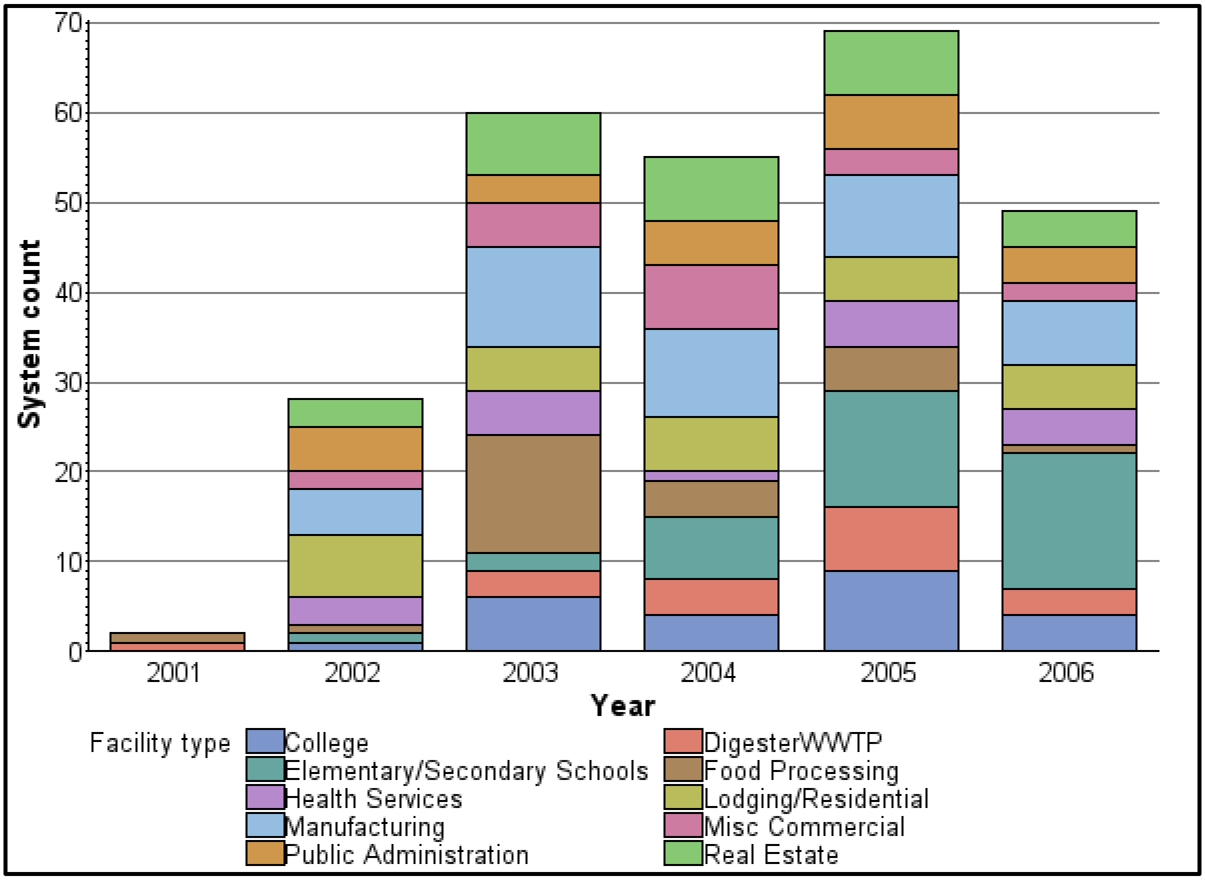
Table 3-10 lists the top facility types and counts of completed systems by year. In general, CHP facility location showed a higher preference for manufacturing and elementary/secondary school sites, with a lesser preference for real estate sites. All the remaining sites showed almost equal levels of preference.

Table 3-10: Top 10 CHP Facility Types' Completed Systems by Year (2001–2010)

	Facility Type										
Completion Year	**DigesterWWTP**	**Food Processing**	**College**	**Elementary Secondary School**	**Health Services**	**Lodging Residential**	**Manufacturing**	**Misc Commercial**	**Public Administration**	**Real Estate**	**Total**
2001	1	1									2
2002		1	1	1	3	7	5	2	5	3	28
2003	3	13	6	2	5	5	11	5	3	7	60
2004	4	4	4	7	1	6	10	7	5	7	55
2005	7	5	9	13	5	5	9	3	6	7	69
2006	3	1	4	15	4	5	7	2	4	4	49
2007	4		3	5	5	1	4	3	5	1	31
2008	2	4			3		1	1	3	2	16
2009	2	1		1	3		1	2		1	11
2010	3		1	1	3			4	2	4	18
Total	**29**	**30**	**28**	**45**	**32**	**29**	**48**	**29**	**33**	**36**	**339**

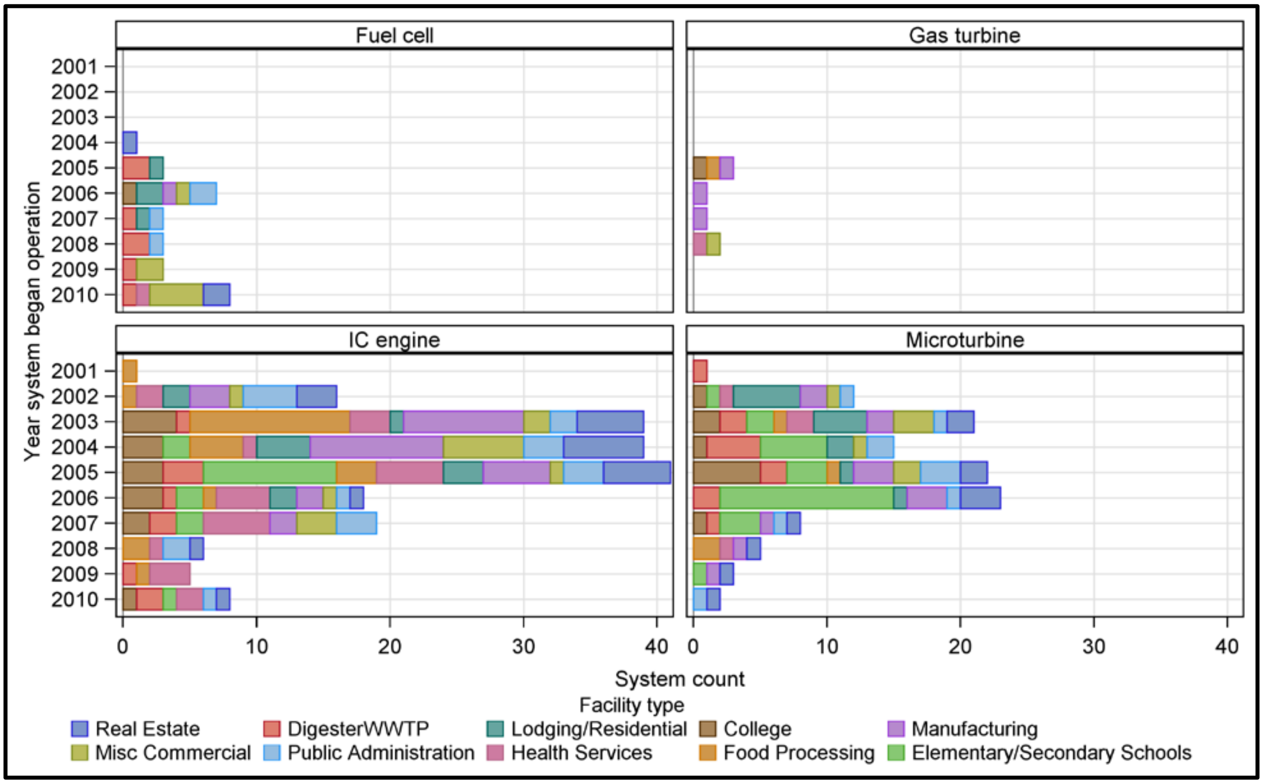
Figure 3-19 shows the trends in composition of annual counts of completed CHP systems by facility type. The figure shows only the facilities among the top 10 counts of total completed systems from 2001-2006.

Figure 3-19: Top 10 CHP Facility Types by Completed System Count (2001–2006)



We also examined the distribution of CHP system type by facility location. Figure 3-20 shows the distributions of completed systems over time for the top 10 facility types. Among these top 10 facility types by count, manufacturing and food processing facilities showed a strong preference for IC engines while elementary/secondary schools chose microturbines. These three also were among the dominant facility types prior to 2007. Hosts in the real estate industry also were among the dominant facilities during that time as well as in subsequent years. Their preference leaned toward IC engines until 2006 when microturbines edged ahead.

Figure 3-20: Technologies Among Top 10 Facility Types by Count (2001 - 2010))



3.1.6 Key Findings of the SGIP Early Years' Fleet

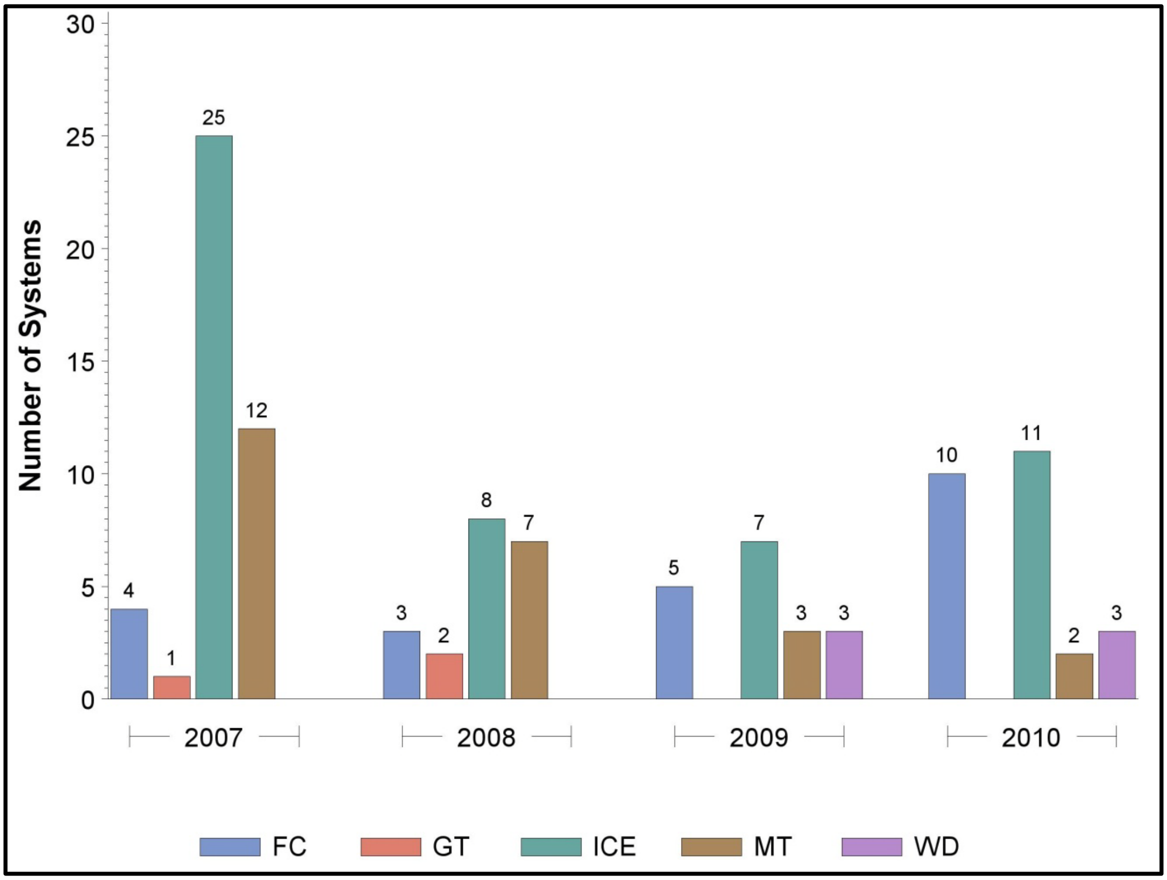
- All the technologies but gas turbines have suffered rapid declines with age in annual utilization. Extended outages are occurring as early as in the first operating year. Some systems have been decommissioned after as little as three years of operation. Half of IC engine capacity is unavailable by age five and half of microturbine capacity by age six.
- IC engine systems have had mixed success- while by far the dominant SGIP technology in terms of numbers of completed systems, total capacity, and highest total system efficiencies, they also have the lowest and fastest declining utilization rates of the four CHP technologies.
- Microturbines also had mixed success- with just over half the numbers but 15% of the capacity of IC engines they contributed less energy overall, and while they had substantially lower electrical conversion efficiency than IC engines they maintained higher utilization rates with age. Microturbines also recovered heat more efficiently than IC engines in part due to their lower electrical conversion efficiency..
- Gas turbines have had good success and continue to do so- although only a handful of have been completed in the SGIP, their very large capacities have led them to outpace microturbines and fuel cells in total capacity and their utilization rates are the highest.
- Fuel cells, a small component of the early fleet, have had good success but are not demonstrating the staying power of gas turbines- they delivered high electrical conversion efficiencies and high utilization rates initially, but utilization rates are falling rapidly.
- Higher than expected maintenance has been reported by system hosts but the nature of the underlying problems remains unknown.
- Many system developers completed only one system, but that small amount of experience has not had led to their systems having lower system utilization than those of developers who have completed dozens of systems. On the contrary, the single system developers had utilizations no different from developers with dozens of completed systems. It is system developers with 6-10 completed systems that have lower system utilization, but the underlying causes for this are unknown.
- Declining utilization with age was common across genset manufacturers and system host industries, apart from the small number of gas turbines.

3.2 The Mid-Term Fleet: 2007–2010

The passage of Assembly Bill (AB) 2778 resulted in significant changes to the make up of the SGIP fleet starting in 2007.[21] It limited program eligibility to qualifying wind and fuel cell DG technologies only. This restructuring of the program marked a significant change in the composition of the mid-term SGIP fleet to one consisting primarily of fuel cells.

Figure 3-21 shows the number of systems completed in the SGIP from 2007 through 2010 by year for each technology. For completeness, wind energy systems completed from 2007 to 2010 have also been included.[22] The number of gas turbine and microturbine projects completed since 2007 has dropped off significantly. To a lesser extent IC engines completions have also slowed down between 2007 and 2010.

Figure 3-21: SGIP Systems Completed since 2007 by Technology Type



21 D.08-01-029, p. 8

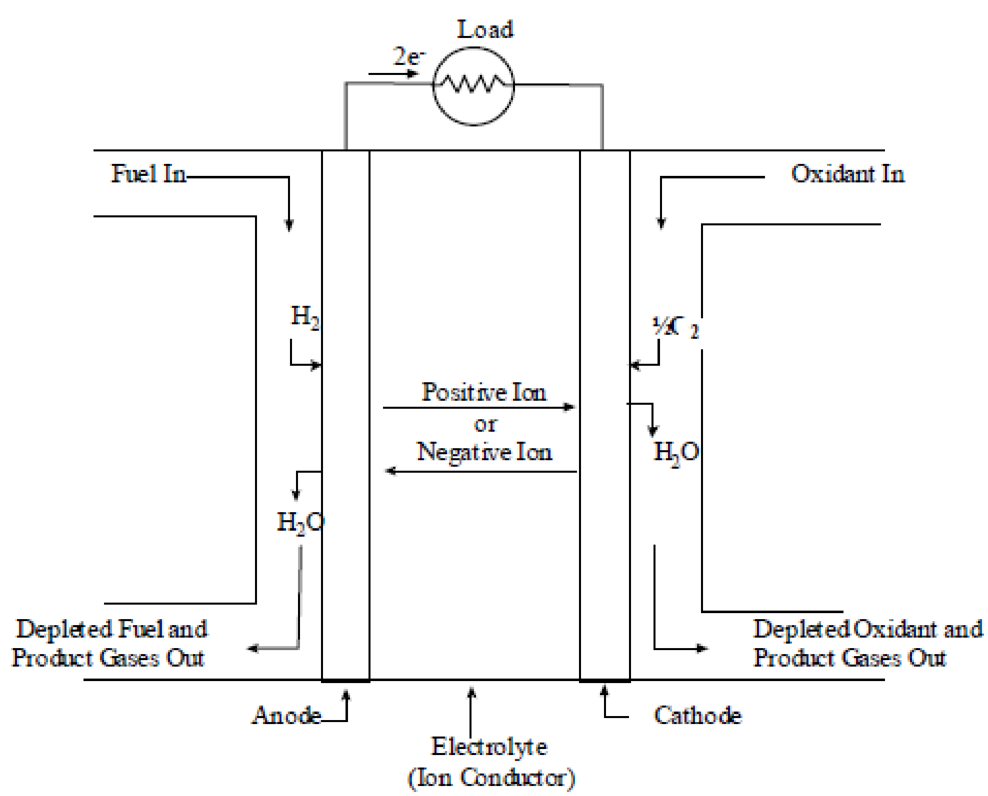
22 As indicated in the introduction of this report, impacts from wind energy systems are not able to be discussed due to lack of metered data.

As expected, fuel cells and wind are the only technology seeing increased completions since the modification of project eligibility rules. Due to the strong influence of fuel cell projects on the mid-term fleet, we provide some additional information on fuel cells.

3.2.1 Fuel Cell Technology Summary

Fuel cells are electrochemical devices that generate electricity by means of a chemical oxidation/reduction reaction. Figure 3-22 shows a simple hydrogen fuel cell schematic.

Figure 3-22: Hydrogen Fuel Cell Schematic



Source: Fuel Cell Handbook, 6th Edition

The operation of most hydrogen fuel cells is represented in Figure 3-22. Hydrogen (or a hydrogen-carrying fuel) is continuously fed at the anode while an oxygen carrier (typically air) is continuously supplied at the cathode. With the help of a catalyst, a chemical reaction takes place that generates an electron charge and transfers a hydrogen ion across the electrolyte. Each individual fuel cell generates a small voltage. Consequently, multiple cells need to be connected with a bipolar plate and combined into a "stack" to produce the desired power output.

There are several types of fuel cells in production today and can be broken down by the type of electrolyte material.

Polymer Electrolyte Membrane (PEM) fuel cells operate at low temperatures (60-80 ºC) and provide low-to-medium power output. The combination of low temperature and low power production generally makes them impractical for CHP operations. However, they can respond to load changes more quickly than other fuel cell designs. As a result, PEM fuel cells have seen moderate penetration in hydrogen vehicle applications. They are also starting to appear in residential DG applications as costs decrease.

PEMs require a very pure fuel supply at the anode to prevent poisoning and fouling of the catalyst (they are particularly intolerant of CO). Ideally the cell should be supplied with pure hydrogen and oxygen. However, most DG applications use hydrogen reformed from natural gas at the anode and ambient air at the cathode; both leading to lower efficiencies and shorter stack life. Two of the largest vendors in the DG market are Ballard Power Systems and Clear Edge Power.

Phosphoric Acid Fuel Cells (PAFC) operate in the same way as PEMs except that the ion carrying electrolyte is 100% concentrated phosphoric acid. PAFCs operate at slightly higher temperatures than PEMs (150–220 ºC) making them more suitable for CHP applications. Carbon monoxide (CO) poisoning at the anode can be an issue as it is with PEMs. Currently, UTC power is one of the most prominent PAFC vendors in the United States.

Molten Carbonate Fuel Cells (MCFC) operate at high temperatures (600-700 ºC) and, therefore, do not require expensive catalysts to reform natural gas (like platinum in PEMs and PAFCs), making them more suitable to CHP applications. Unlike the low temperature cells previously discussed, MCFCs are tolerant of CO and require CO_2 at the cathode to operate, making them a better potential fit for biogas applications. The chemical reaction is also very different and involves a carbonate ion traveling across molten salt instead of a hydrogen ion. FuelCell Energy is currently one of the most prominent MCFC vendors.

Solid Oxide Fuel Cells (SOFC) are also high temperature fuel cells (600–1,000 ºC), making them ideal for CHP. In this case an oxygen ion crosses a solid metal oxide electrolyte. Bloom Energy is one vendor of SOFCs and is aggressively pursuing SOFC sales in the United States.[23]

[23] From CPUC SGIP Cost-Effectiveness of Distributed Generation Technologies Final Report.

3.2.2 Fuel Cell Performance Characteristics and Costs

Table 3-11 summarizes the electrical efficiency values reported by major fuel cell manufacturers for non-residential fuel cells.

Table 3-11: Fuel Cell Electrical Efficiencies from Vendor Specifications

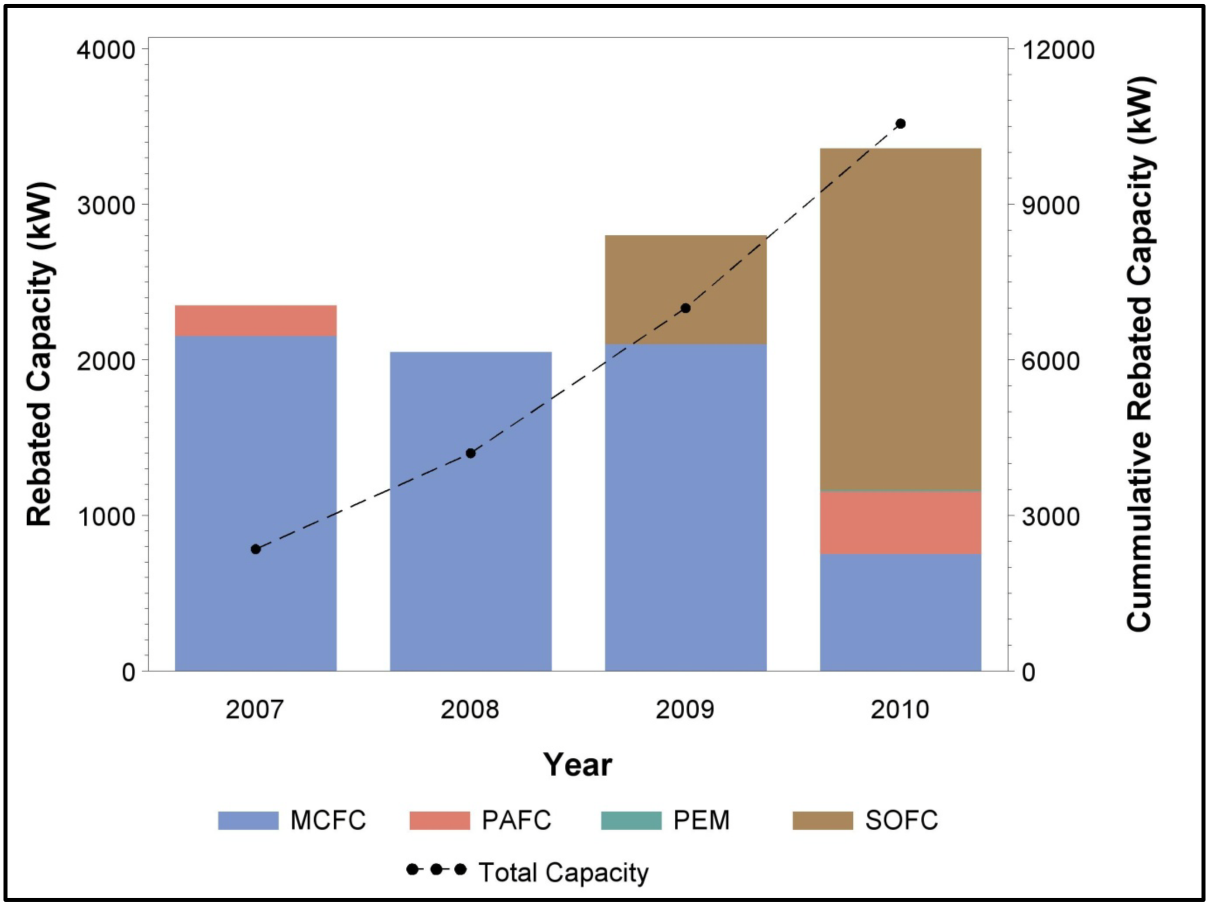
Fuel Cell Technology	Nominal Electrical Efficiency (LHV)
PAFC	42%
SOFC	50%
MCFC	47%
Un-Weighted Average	**46%**

According to vendor specifications, solid oxide fuel cells are able to achieve the highest efficiencies while phosphoric acid fuel cells report the lowest electrical efficiencies among fuel cells.

3.2.3 Fuel Cell Systems Under SGIP

Figure 3-23 shows capacity for fuel cell systems completed from 2007 to 2010 by fuel cell type.

Figure 3-23: Completed Capacity by Fuel Cell Type



Molten carbonate fuel cells played a major role in the SGIP mid-term fleet until 2010, when solid oxide fuel cells emerged as the biggest contributor to new systems. Phosphoric acid and polymer electrolyte fuel cells historically have had smaller roles in the SGIP fuel cell portfolio. The cumulative capacity of fuel cells completed since 2007 has increased at a continuous but moderate pace.

Due to their high electrical efficiencies, molten carbonate and solid oxide fuel cells are theoretically able to meet the SGIP minimum electric efficiency requirements based solely on their electricity efficiencies.[24] Some solid oxide fuel cell systems operate as "electric only" systems. Because they meet the minimum system efficiency requirements, these systems are not

[24] In accordance with SGIP Handbook requirements, all non-renewable energy systems are required to achieve a minimum system efficiency of not less than 42.5%.

required to recover waste heat. There is an increasing trend towards electric only fuel cells, seen by the increase in SOFC capacity.

Figure 3-24 provides an overview of trends in total eligible system costs by fuel cell technology. Except for molten carbonate fuel cells from 2007 to 2008, system costs have been increasing by year. Note that in accordance with SGIP requirements, applicants receiving incentives are required to provide estimates of total installed project costs to the SGIP PAs. The costs presented here reflect only the cost data as reported by the applicants to the PAs.

Figure 3-24: Total Eligible Costs per Watt for SGIP Fuel Cells (2007 -2010)

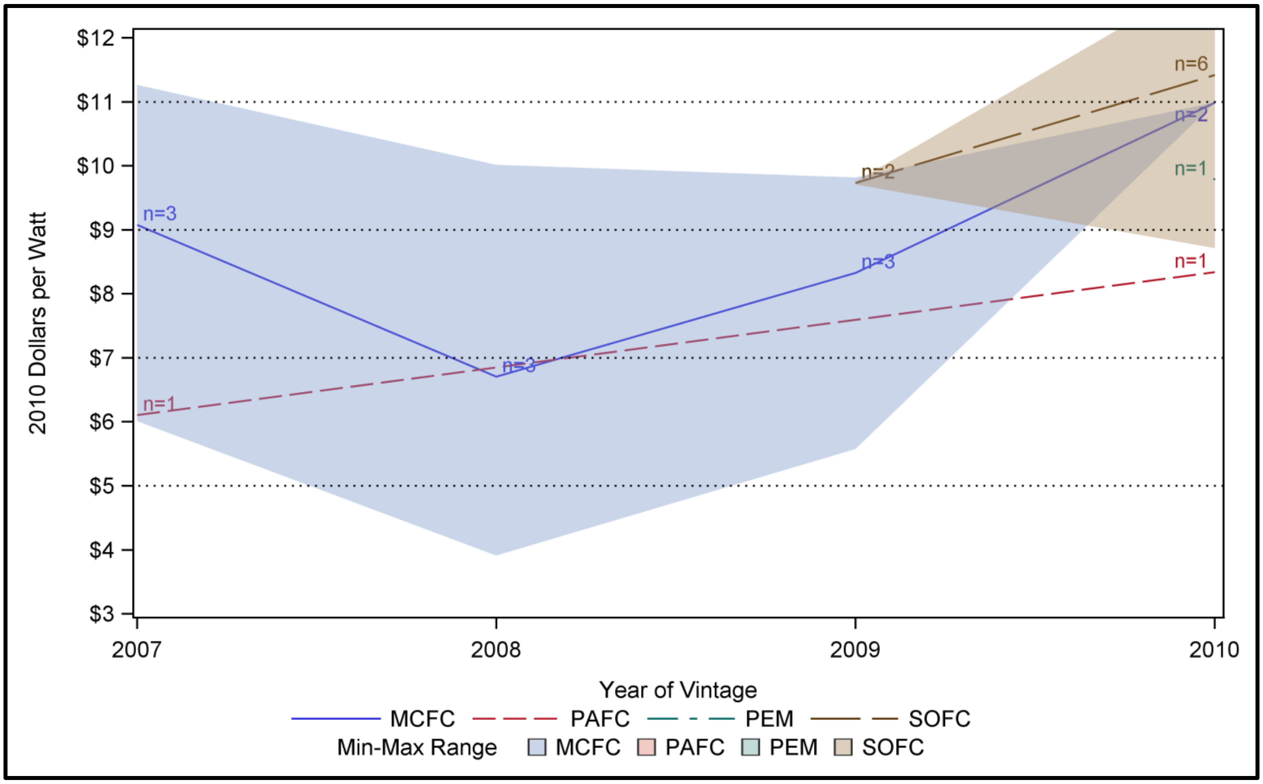
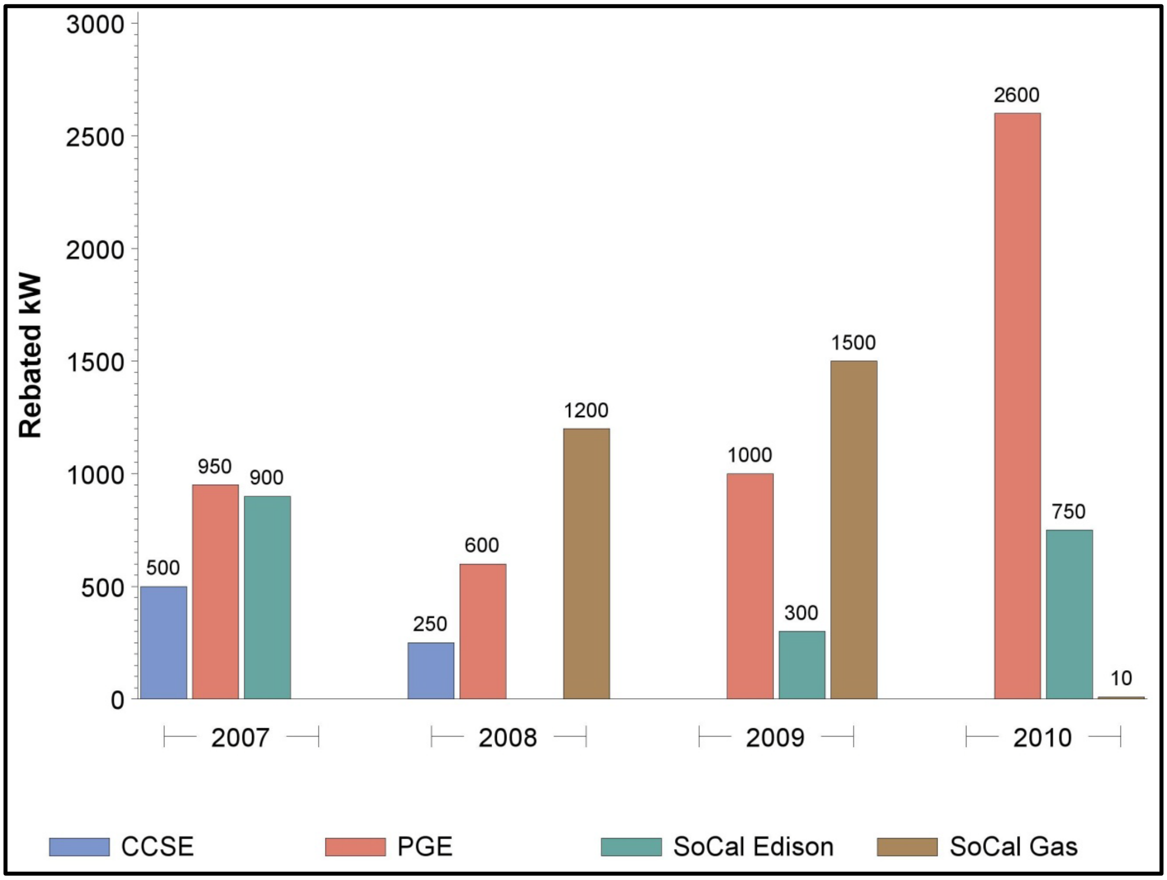


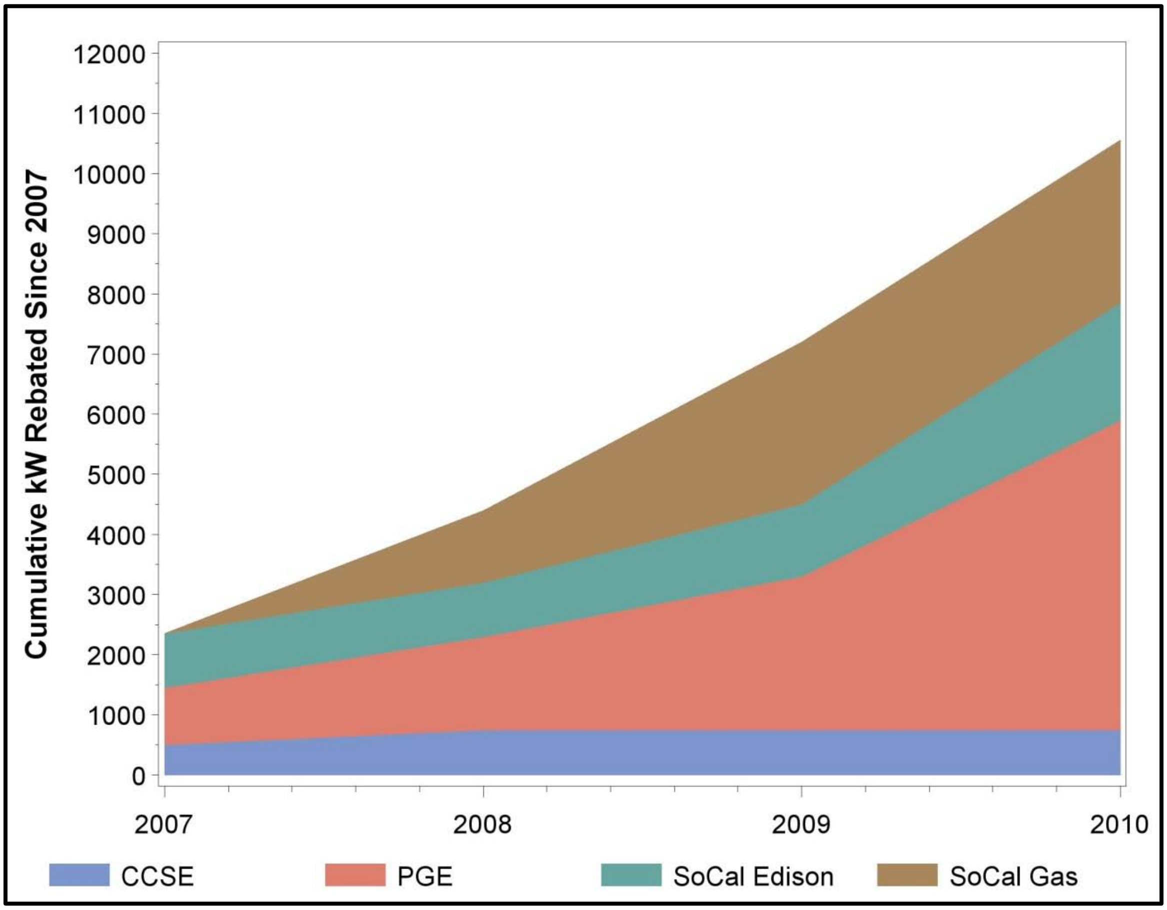
Figure 3-25 shows fuel cell system capacity completed from 2007 through 2010 by Program Administrator (PA). In general, there was modest and comparable growth in fuel cell capacity from 2007 through 2009. A notable increase in capacity in PG&E territory can be observed in 2010 compared to previous years.

Figure 3-25: Fuel Cell Capacity by PA (2007–2010)



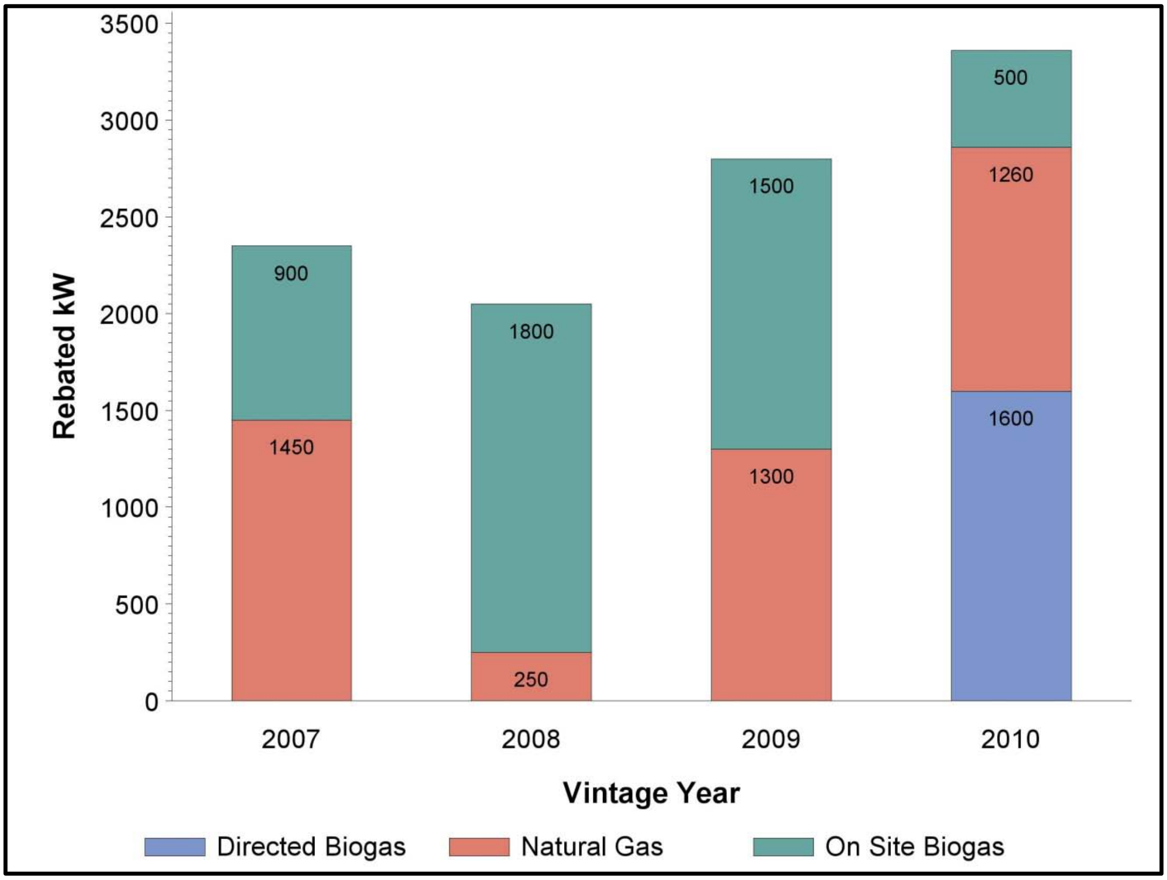
The cumulative fuel cell capacity from 2007 to 2010 by PA is shown in Figure 3-26. The cumulative capacity of systems for SCE and CCSE showed little growth from 2007 to 2010. Most of the growth in SCG systems occurred from 2008 to 2009. In PG&E territory, there was an almost doubling in cumulative capacity per year from 2007 to 2009.

Figure 3-26: Fuel Cell Cumulative Capacity by PA



A breakdown of fuel cell capacity added by fuel type and vintage year is shown in Figure 3-27. The rate of natural gas fuel cell capacity added per year has remained relatively flat except for 2008; where the majority of completed systems used on-site biogas. In 2010, we see the emergence of directed biogas systems; that same year the lowest amount of on-site biogas systems were completed. It is not clear whether the drastic decrease of 2010 in on-site biogas systems was due to the increased convenience of directed biogas or a constraint in the availability of suitable on-site biogas sites.

Figure 3-27: Fuel Cell Capacity Additions by Fuel Type[25]



3.2.4 Key Findings from the Mid-Term Fleet

- Despite being restructured to become primarily a fuel cell and wind program, the SGIP is still primarily made up of IC engines and turbines.
- Fueled by pending applications of directed biogas fuel cells, the SGIP is slated to grow faster than in previous years.

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25 The category "On-Site Biogas" is used for systems where any biogas is consumed, including systems where some natural gas is also used.

4

SGIP 2010 Impacts

This section presents information on the impacts of SGIP systems during the 2010 calendar year. We specifically examine impacts at both the program-wide and utility-specific levels on electrical energy production; coincident peak demand; operating and reliability characteristics; air pollution and greenhouse gas emission impacts; and compliance of SGIP projects with thermal energy utilization and system efficiency requirements.

Note that the 2010 impacts assessment does not present information on wind energy systems installed under the SGIP. There were no available metered performance data available for calendar year 2010 for wind energy systems. As a result, there is no basis upon which to make impacts assessments for wind energy and they have been left out of the 2010 SGIP Impact Report. Among the other technologies are SGIP systems fueled by natural gas, propane, or biogas. We describe these generally as combined heat and power (CHP) technologies, whether or not they are required to capture waste heat for some end use. When describing heat recovery impacts, we include only SGIP systems that are required to capture waste heat.[1]

4.1 Energy and Non-Coincident Demand Impacts

This section will present annual energy and non-coincident demand impacts for the program overall as well as impacts for each PA.

4.1.1 Overall Program Energy Impacts

Electrical energy and demand impacts were calculated for Complete and Active projects that began normal operations prior to December 31, 2010. Impacts were estimated using available metered data for 2010 and known system characteristics. System characteristics data came from program tracking systems maintained by the PAs and augmented with information gathered by Itron. Energy delivery is differentiated by technology (i.e., ICE, MT, GT, and FC) and fuel type (i.e., natural gas (N), renewable biogas (R)). Table 4-1 shows the distribution of the different systems by technology, fuel, and rebated capacity. Internal combustion engines (ICE) fueled with natural gas represented the largest contributors with a total capacity of over 139 MW.

[1] Under SGIP requirements, renewable fuel use projects are not required to employ waste heat recovery. Similarly, directed biogas projects are not required to recover waste heat. Some fuel cells also have sufficiently high total efficiency from electrical conversion alone that they are not required to recover waste heat.

Table 4-1: Program Population System Counts and Total Capacities by Technology and Fuel

Technology	Fuel	Number of Systems (n)	Rebated Electrical Generation (kW)
FC	Natural gas	22	10,010
FC	Natural gas with Biogas	1	1,000
FC	Biogas	1	250
FC	Biogas with Natural gas	7	5,200
FC	Directed Biogas with Natural gas	4	1,600
GT	Natural gas	8	25,744
ICE	Natural gas	227	139,321
ICE	Natural gas with Biogas	1	900
ICE	Propane	1	150
ICE	Biogas	16	11,055
ICE	Biogas with Natural gas	5	2,598
MT	Natural gas	115	19,500
MT	Natural gas with Biogas	3	740
MT	Biogas	20	3,544
MT	Biogas with Natural gas	1	240
TOTAL		**432**	**221,852**

By the end of 2010, there were 432 completed SGIP CHP systems representing over 221 MW of rebated electricity generating capacity.

Figure 4-1 shows electricity delivered by SGIP systems throughout each quarter of calendar year 2010 categorized by non-renewable and renewable fuels. Natural gas-fueled IC engines generated the most energy. There were no renewable fuel gas turbine projects.

Figure 4-1: Statewide 2010 Quarterly Electricity Impacts by Technology and Fuel

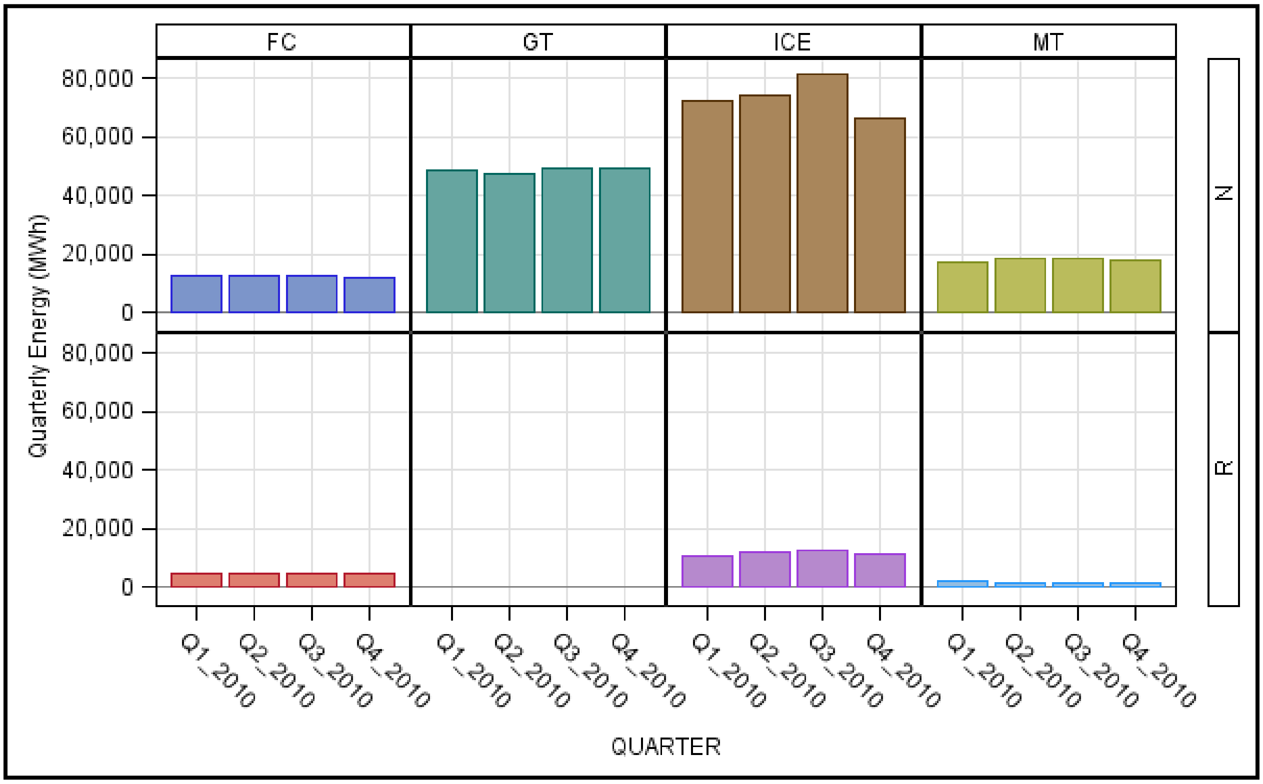


Table 4-2 provides the quarterly values shown in Figure 4-1 as well as annual totals delivered by SGIP systems throughout calendar year 2010. There is no statistical difference in quarterly generation for any of the technology and fuel combinations. Generation is steady throughout the year with very little seasonal variability.

Table 4-2: Statewide 2010 Energy Impact by Quarter (MWh)

Technology	Fuel	Q1-2010 (MWh)	Q2-2010 (MWh)	Q3-2010 (MWh)	Q4-2010 (MWh)	Total* (MWh)
FC	**N**	12,421	12,577	12,658	11,771	49,426
FC	**R**	4,460	4,386	4,530	4,744	18,121
GT	**N**	48,621	47,304	49,537	49,326	194,789
ICE	**N**	72,135	73,975	81,501	66,670	294,281
ICE	**R**	10,599	11,832	12,449	11,219	46,099
MT	**N**	17,426	18,731	18,446	17,685	72,289
MT	**R**	1,883	1,636	1,499	1,477	6,496
	TOTAL	**167,546**	**170,442**	**180,619**	**162,921**	**681,528**

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

During PY10, SGIP systems generated over 681 GWh; enough electricity to meet the annual electricity requirements of over 102,000 homes.[2] SGIP CHP systems are located at customer sites to help meet onsite demand. Consequently, this energy represented electricity that neither had to be generated by central station power plants nor delivered by the transmission and distribution system.[3]

Table 4-3 shows the breakout of electricity generated by technology and fuel type in the SGIP by the end of 2010. IC engines generated about 50% of the electricity in SGIP while gas turbines contributed slightly more than 28%. Furthermore, 90% of the electricity was generated by systems fueled by natural gas.

Table 4-3: Proportion of SGIP Electricity Generation by Technology and Fuel

Technology	Natural Gas (MWh)	Renewable (MWh)	Total (MWh)	Percent
FC	49,426	18,121	67,546	**9.9**
GT	194,789	0	194,789	**28.6**
ICE	294,281	46,099	340,380	**49.9**
MT	72,289	6,496	78,785	**11.6**
Total	610,784	70,716	681,500	**100**
Percent	**90%**	**10%**	**100%**	

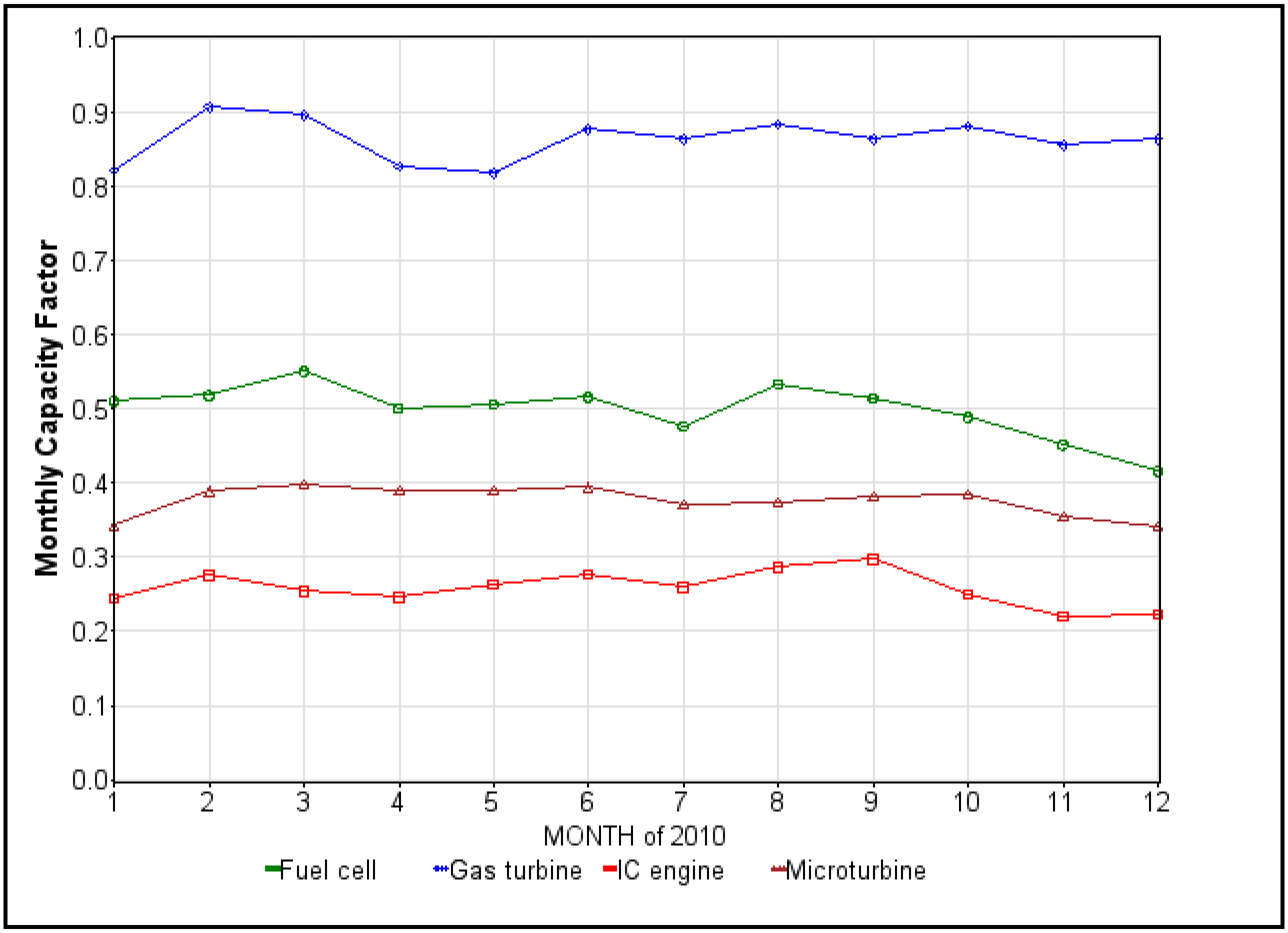
4.1.2 Overall Program Capacity Factors

Capacity factor represents the fraction of the capacity effectively generating over a specific time period. Consequently, capacity factor provides insight into the capability to provide power over that time period. For example, peak hour capacity factors for a technology indicate the fraction of capacity from a technology during that particular peak hour. Figure 4-2 shows the weighted monthly capacity factors for SGIP technologies during the year 2010.

2 Assuming the typical home consumes approximately 6,670 kWh of electricity per year. From Brown, R.E. and Koomey, J.G. *Electricity Use in California: Past Trends and Present Usage Patterns.* Lawrence Berkeley National Laboratory. May 2002. http://enduse.lbl.gov/info/LBNL-47992.pdf. Value derived from Table 2 on page 8.

3 Although rebated through the SGIP, approximately 9% of SGIP projects receive power from municipal electric utilities.

Figure 4-2: Program Monthly Capacity Factors



Annual capacity-weighted average capacity factors were developed for all SGIP technologies by comparing annual generation to maximum generation (i.e., generation at nominal capacity for entire year). Table 4-4 lists weighted average annual capacity factors by technology and the number of systems used to calculate the annual capacity factor. Appendix A provides further discussion of annual capacity factors.

Table 4-4: Annual Capacity Factors by Technology

Technology	Rebated Capacity (kW)	Number of Systems (n)	Annual Capacity Factor* (kWyear $_{actual\_generation}$ kWyear $_{rebated\_generation}$)
FC	18,260	36	0.497
GT	25,744	8	0.864
ICE	154,024	250	0.259
MT	24,024	139	0.377

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Gas turbines have the highest 2010 annual capacity factor, staying above 0.80 in 2010. There were only eight gas turbines in the SGIP at this time. Fuel cells have the second highest annual capacity factor of 0.50 from among 35 systems. IC engines and microturbines have substantially lower capacity factors from among substantially higher numbers of systems. Microturbines have the third highest annual capacity factor at 0.38 from among 139 systems. IC engines are the most common CHP technology deployed in the SGIP with 250 systems and have the lowest annual capacity factor at 0.26.

The CHP technologies listed in Table 4-4 include systems fueled by natural gas and systems fueled primarily by renewable fuels (e.g., biogas). Table 4-5 shows the capacity factors for CHP technologies broken out by fuel types. To distinguish by fuel type, Table 4-5 provides fuel-specific weighted average annual capacity factors for CHP technologies. There were no renewable fuel gas turbines installed as of December 31, 2010.

Table 4-5: Annual Capacity Factors by Technology and Fuel

Technology	Annual Capacity Factor* (kWyear actual $_{generation}$/kWyear rebated $_{generation}$)	
	Natural Gas	Renewable Fuel
FC	0.549	0.397
GT	0.864	0.000
ICE	0.243	0.445
MT	0.411	0.196

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

The capacity factor for the natural gas fuel cells is above 0.5. The renewable fuel cells have a lower capacity factor. Lower capacity factors would be expected for biogas because, without gas storage, biogas may not be continuously available. Biogas generally requires nearly continuous supply of a raw feedstock and a collection and processing (including cleaning) operation which is not required for natural gas systems. Furthermore, biogas production is highly dependant on temperature and is thus season-sensitive. Interruption in feedstock supply, biogas production, or processing may cause an interruption in generation. The lower capacity factor for renewable fuel cells may reflect issues with biogas availability. It also is known that two of the 13 renewable fuel cells are decommissioned[4] while none of the 23 natural gas fuel cells are decommissioned. In contrast to fuel cells, renewable IC engines have a higher annual capacity factor than their natural gas counterparts. Biogas-fueled IC engines can tolerate variations and contaminates present in biogas much more readily than fuel cells. This may in part explain the higher capacity factor for biogas-fueled IC engines compared to biogas-fueled fuel cells. Renewable- and

4 We consider a system decommissioned only when it is physically removed from a site. Systems said to be decommissioned but not physically removed potentially could be restarted, and therefore are considered simply off-line..

natural gas-fueled IC engines have similar percentages of systems known to be decommissioned. Where the two groups differ is in mean age. Renewable IC engines have a capacity-weighted mean age of approximately 4.5 years while their natural gas counterparts are older, at a mean age of 6.5 years. As described earlier in this report, a common trend across CHP technologies is a decline in annual capacity factor with age. The two-year difference favors the younger renewable IC engines in terms of annual capacity factor. Renewable microturbines have an annual capacity factor roughly half that of their natural gas counterparts. While biogas supply disruption may contribute to this difference, the renewable microturbine systems are older than their natural gas counterparts (at 6.7 years versus 5.6 years). While the difference in age is not as large as for IC engines, the age gap in this case favors the annual capacity factor of the natural gas systems.

4.2 PA-Specific Impacts

4.2.1 Annual 2010 Energy Production by PA

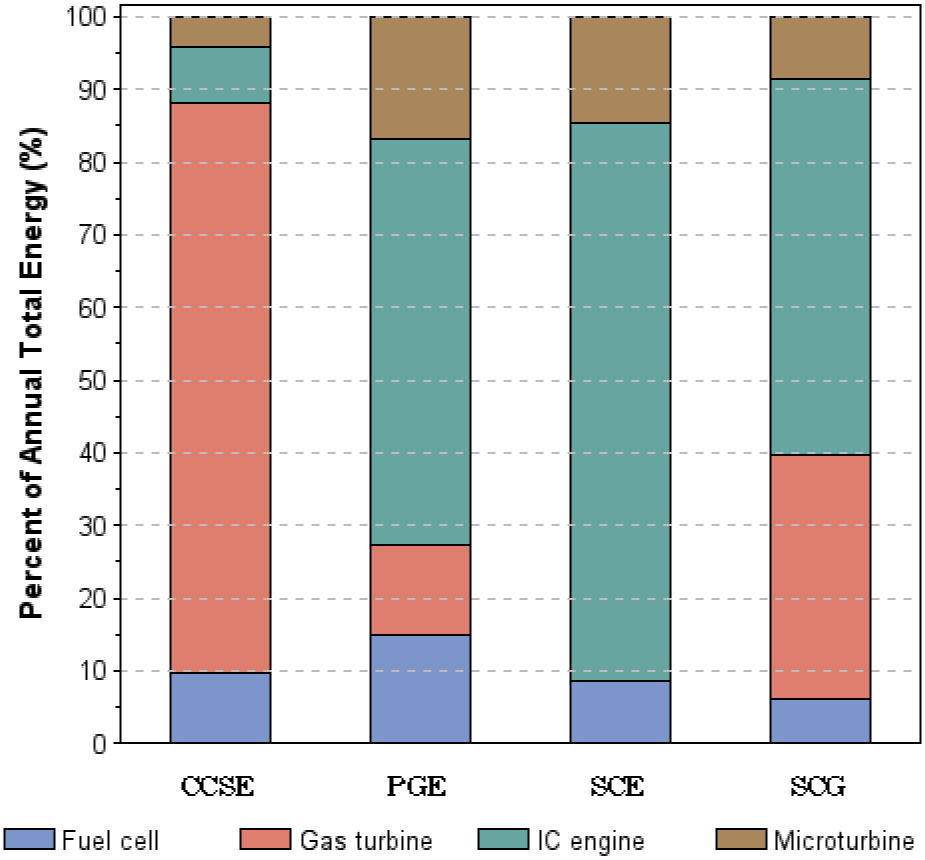
Table 4-6 shows a breakdown in 2010 annual energy impacts by technology for each PA. Figure 4-3 shows annual energy impact proportions by technology for each PA. PG&E and SCG have the largest total annual energy impacts at over 237 GWh and 275 GWh, respectively. In comparison, the annual energy impacts for SCE and CCSE was 74 GWh and 92 GWh each. IC engines are the dominant technology (over 50%) for all PAs except for CCSE. CCSE receives its greatest impact (over 75%) from gas turbines.

Table 4-6: Annual Energy Impacts by PA (MWh)

Technology	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	35,398	6,334	16,885	8,929	67,546
GT	29,205 †	0	93,315	72,269	194,789
ICE	132,768	57,087	143,246	7,279	340,380
MT	40,174	10,773	24,068	3,770	78,785
Total	**237,572**	**74,194**	**277,515**	**92,247**	**681,528**

[a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure 4-3 : Annual Energy Impact Percentages by PA and Technology



IC engines were the dominant technology, generating over 50% of the electricity for all PAs except CCSE. Gas turbines contribute over 75% of CCSE generation. Fuel cells and microturbines each provided about 10% for each PA in 2010.

Table 4-7 presents annual weighted average capacity factors for each technology and PA for the year 2010. Annual capacity factors for gas turbines are fairly similar for all the PAs. The capacity factor for SCE's fuel cells are about half that of the other PAs. PG&E, SCE, and SCG have annual capacity factors for IC engines in the same range. For microturbines, CCSE and SCE had about half the annual capacity factor compared to PG&E and SCG.

Table 4-7: Annual Capacity Factors by Technology and PA

Technology	Annual Capacity Factor* (kWyeargenerated/kWyearrebated)			
	PG&E	SCE	SCG	CCSE
FC	0.597	0.317	0.459	0.453
GT	0.830 †	0.000	0.845	0.904
ICE	0.259	0.224	0.316	0.075
MT	0.445	0.230	0.434	0.226

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

4.3 Coincident Peak Demand Impacts

4.3.1 Overall Peak Demand Impacts

Peak demand is important as it represents the time period when California's electricity system in under the greatest stress for delivery of power. Table 4-8 summarizes by technology the overall SGIP program impact on electricity demand coincident with the 2010 CAISO system peak hour load. The table shows the number of projects on-line at the time of the peak hour, their combined capacities and demand impact, and their peak hour average capacity factor.

Table 4-8: 2010 Peak Demand Impacts by Technology

Technology	On-Line Systems (n)	Operational (Rebated) (kW)	Impact (Generated) (kW)	Hourly Capacity Factor* ($kWh_{generated}$ $kWh_{rebated}$)
FC	28	15,310	7,723	0.504
GT	8	25,744	22,982	0.893 †
ICE	245	150,865	57,957	0.384
MT	139	24,024	8,210	0.342
TOTAL	**420**	**215,943**	**96,872**	**0.449**

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Figure 4-4 illustrates the net energy production by technology during the CAISO peak day. In 2010, the CAISO peak was reached on August 25, 2010 from 3:00 to 4:00 PM Pacific Daylight Time at 47,282 MW. As Figure 4-4 shows, fuel cells, gas turbines, and microturbines showed fairly flat generation profiles over the course of the CAISO peak day. Only IC engines showed any significant change in hourly generation. While the match may be accidental, it is interesting that the average SGIP IC engine fleet profile tracked the CAISO demand profile through much of the peak day.

The total rebated capacity of on-line projects was nearly 216 MW. The total impact of the SGIP projects coincident with the CAISO peak load was estimated to be about 97 MW. In essence, the collective peak hour capacity factor of the SGIP projects on the CAISO 2010 peak was approximately 0.46 kW per kW of rebated electricity generating capacity.

Figure 4-4: CAISO Peak Day Net Production by Technology

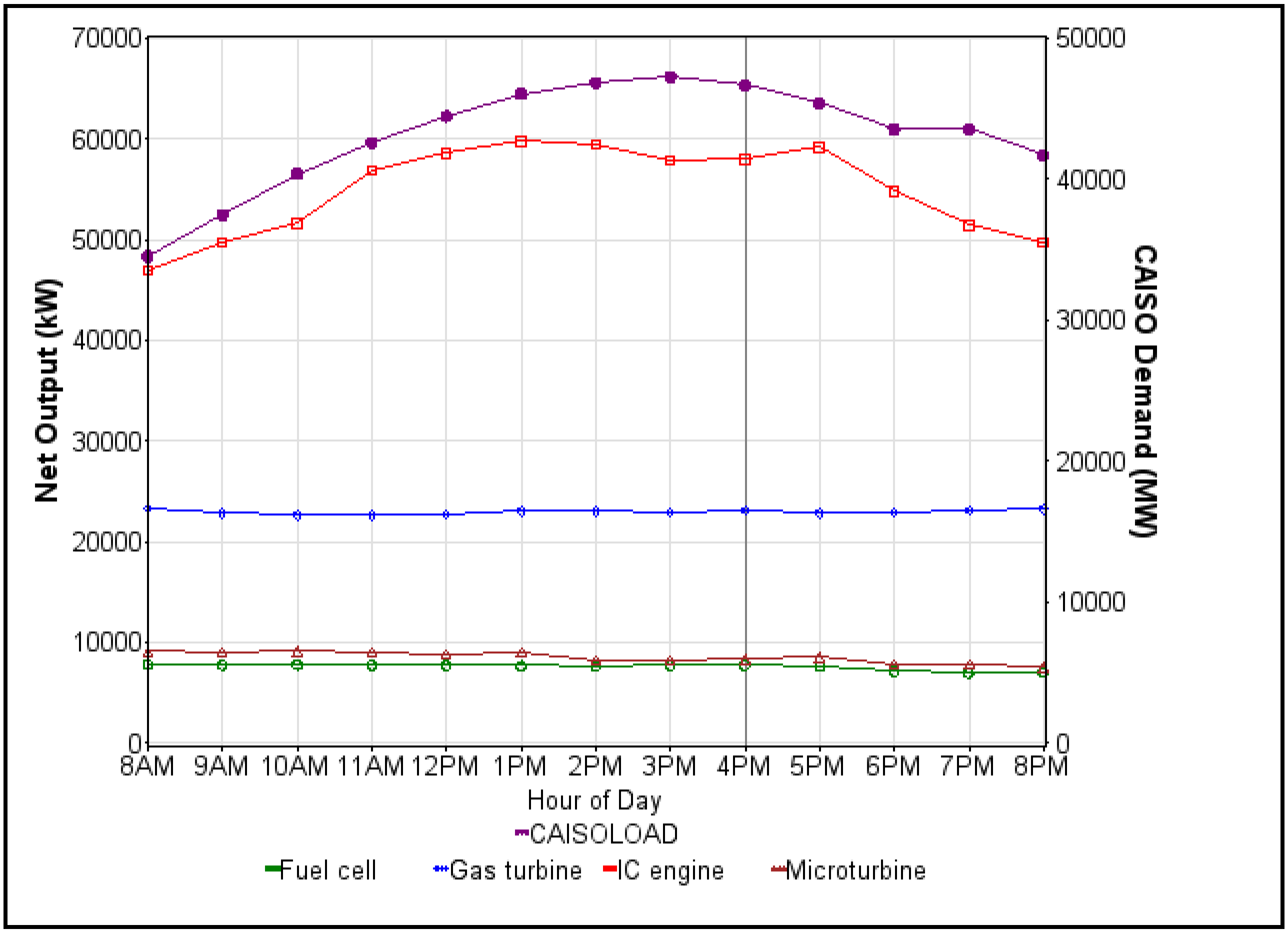
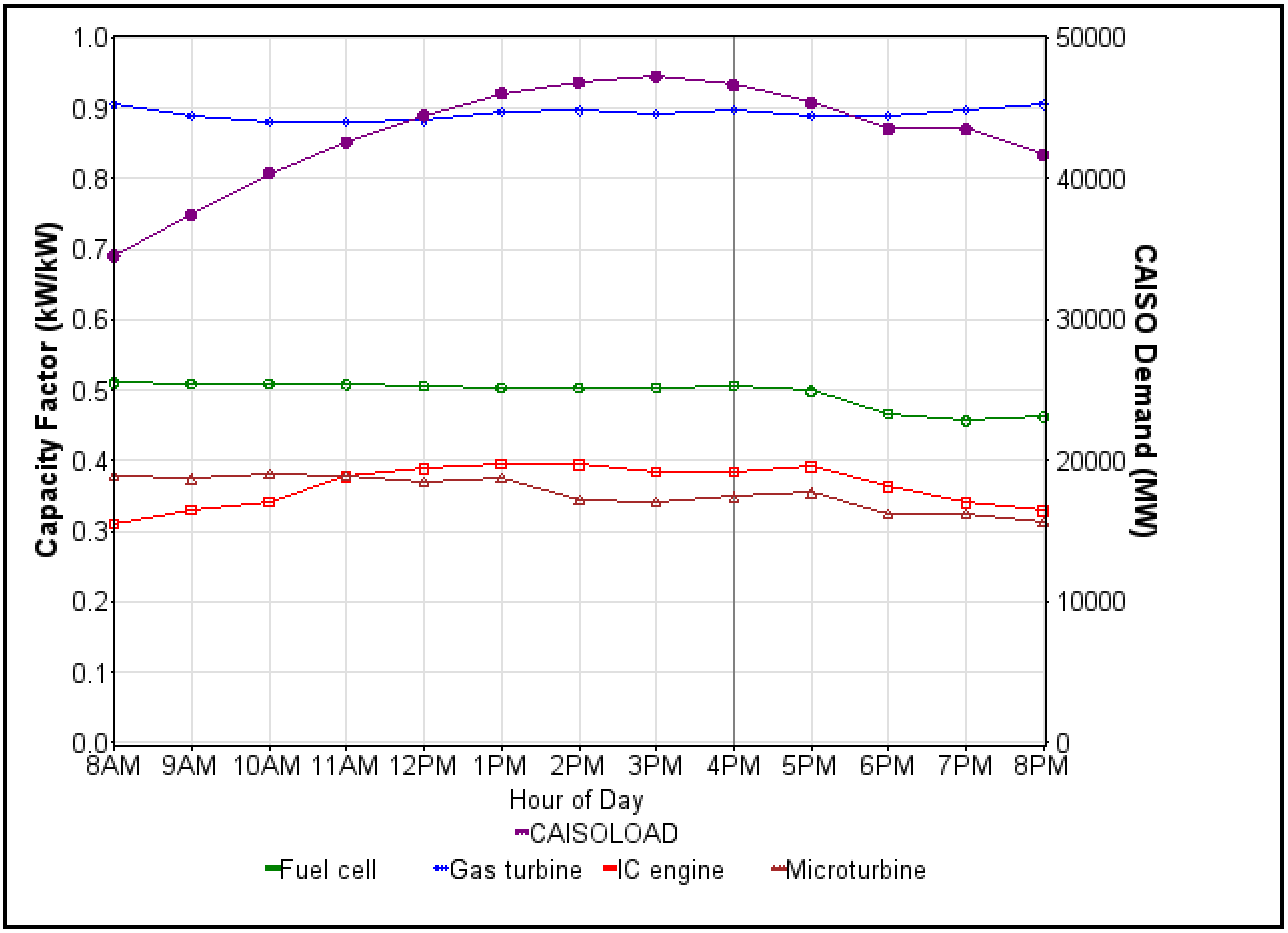


Figure 4-5 profiles the hourly weighted average capacity factor for each technology from morning to early evening during the 2010 peak day. The figure also indicates the hour and magnitude of the CAISO peak load. There is no statistically significant capacity factor response identified to the increased CASIO peak demand observed for any for the four technologies. The electrical generation remains relatively unchanged throughout the peak demand period.

Gas turbines maintain their high capacity factor through the peak demand period and thus may be used to offset the peak demand. The ICE, MT and FC capacity factors remain relatively unchanged and do not seem to impact the peak.

Figure 4-5: CAISO Peak Day Capacity Factors by Technology



The peak hour capacity factor indicates the capability of a technology to provide power when demand is highest and additional generation is most needed. For the summer peak in 2010, gas turbines operating in the SGIP demonstrated the highest peak hour average capacity factor of about 0.90. Fuel cells followed at 0.49. IC engines and microturbines had much lower average peak hour capacity factors of 0.41 and 0.36, respectively.

4.3.2 PA-Specific Peak Demand Impacts

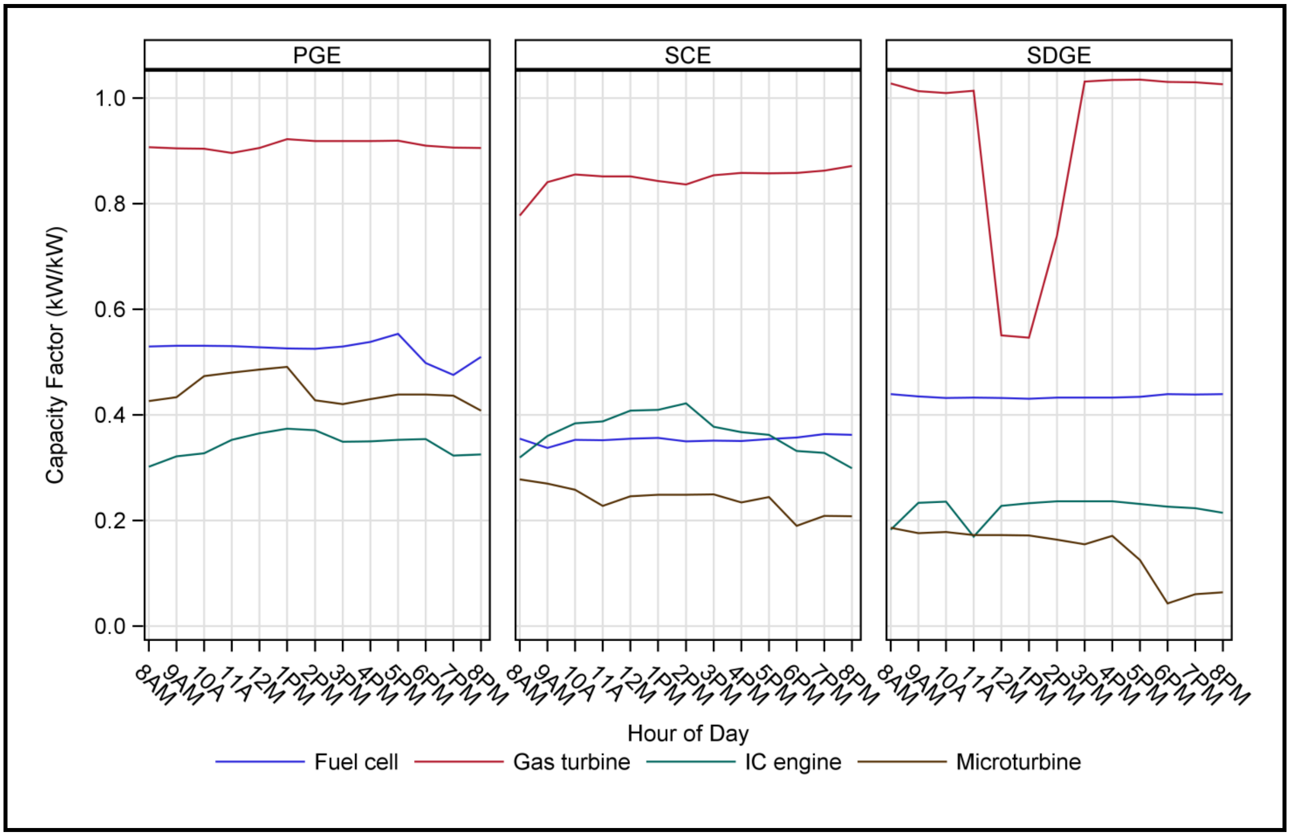
Table 4-9 lists the date, hour, and hourly average load of the peak demand hours for PG&E, SCE, and SDG&E.

Table 4-9: PA-Specific 2010 Peak Demand Hours

Electric PA	Peak (MW)	Date	Hour (PDT hour beginning)
PG&E	21,180	25-Aug-10	4 PM
SCE	23,094	27-Sep-10	2 PM
SDG&E	4,643	27-Sep-10	2 PM

Figure 4-6 shows the capacity factor profile for the respective PA demand day. For SDG&E, there was a significant drop in capacity factor for gas turbines on this particular day.

Figure 4-6: PA-Specific Peak Demand Day Profile



Results presented for the peak days of the three individual electric utilities do not strictly include all SGIP systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

On the following pages, Table 4-10 through Table 4-12 present the total net electrical output during the respective peak hours of California's three large electric IOUs. The tables list the number of SGIP type projects on-line at the time of the peak, the operating capacity at peak, and the demand impact. Tables in Appendix A further differentiate utility peak demand impacts by technology and fuel. Again, results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility.

Table 4-10: Electric Utility Peak Hours Demand Impacts—PG&E

Technology	On-Line Systems (n)	Operational (Rebated Generation) (kW)	Impact (Actual Generation) (kW)	Hourly Capacity Factor (kWh $_{Generated}$ /kWh $_{rebated}$)
FC	13	6,700	3,609	0.539
GT	3	4,016	3,688	0.918
ICE	109	60,175	21,049	0.350
MT	56	10,516	4,523	0.430
Total	**181**	**81,407**	**32,869**	**0.404**

PG&E's 2010 peak hour occurred from 4:00 to 5:00 P.M. on August 26th. Gas turbines had a capacity factor of about 0.92 during that hour and were generally high throughout the day. Fuel cells, microturbines, and IC engines remained steady at the peak hour. Fuel cells had a capacity factor just above 0.54. Microturbines had a capacity factor of 0.43, while the IC engine capacity factor was 0.35. The combined SGIP contribution to peak hour generation was an overall peak hour capacity factor of 0.40.

Table 4-11: Electric Utility Peak Hours Demand Impacts—SCE

Technology	On-Line Systems (n)	Operational (Rebated Generation) (kW)	Impact (Actual Generation) (kW)	Hourly Capacity Factor (kWh $_{Generated}$ /kWh $_{rebated}$)
FC	9	4,160	1,455	0.350
GT	3	12,601	10,541	0.837
ICE	112	77,686	32,791	0.422
MT	62	10,810	2,688	0.249
Total	**186**	**105,257**	**47,475**	**0.451**

SCE's 2010 peak demand occurred from 2:00 to 3:00 P.M. on September 27th. The peak hour for SCE was in September compared to PG&E's in August. As for PG&E, gas turbines in SCE's territory delivered the highest peak hour capacity factor, reaching about 0.84. IC engines had the second highest capacity factor of 0.44 in SCE's service territory. Fuel cells had the next highest peak hour capacity factor for SCE at 0.35, nearly half as much as in PG&E's territory. Microturbines were fourth with a capacity factor of 0.25.

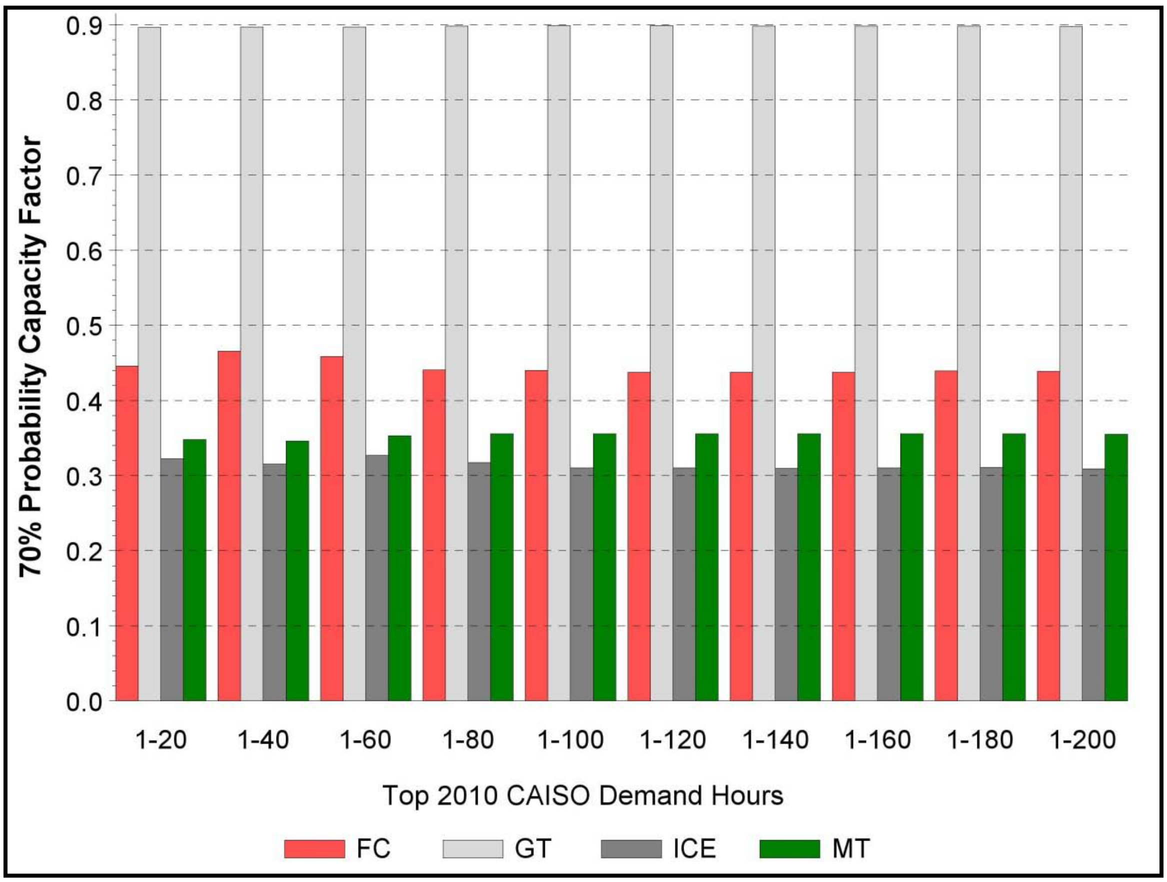
Table 4-12: Electric Utility Peak Hours Demand Impacts—SDG&E/CCSE

Technology	On-Line Systems (n)	Operational (Rebated Generation) (kW)	Impact (Actual Generation) (kW)	Hourly Capacity Factor (kWh $_{Generated}$ /kWh $_{rebated}$)
FC	4	2,250	974	0.433
GT	2	9,127	6,752	0.740
ICE	22	12,684	3,001	0.237
MT	17	1,902	312	0.164
Total	**45**	**25,963**	**11,037**	**0.425**

SDG&E's 2010 peak hour occurred from 2:00 to 3:00 P.M. on September 27th. Gas turbines again had the highest capacity factors with a peak hour capacity factor of 0.74 and fuel cells were the second highest for SDG&E. For SDG&E, fuel cells had a peak hour capacity factor of 0.43. IC engines and microturbines had capacity factors 0.24 and 0.16 respectively. Capacity factors for all four technologies were lower than for both PG&E and SCE.

We also examined the impact of SGIP CHP technologies against additional hours of CAISO demand. Figure 4-7 shows the weighted capacity factors by technology against the top 200 hours of CAISO 2010 demand hours. The top demand profile is split into 10 bins sorted by observed peak demand. The first group represents capacity factors for the peak CAISO demand hour and the next 19 hours; the next set represents the capacity factor for the peak hour and the next 39 hours; and so on. This figure illustrates that for the top 200 CAISO hours there is very little variation in capacity factor within technology although there is significant variation between technologies. From a program-wide perspective, this means that SGIP CHP systems are generally insensitive to the overall system wide peak demands. However, individual SGIP CHP systems may still be responsive to hourly electrical demand at their host sites.

Figure 4-7: Top 2010 CAISO Demand Hours



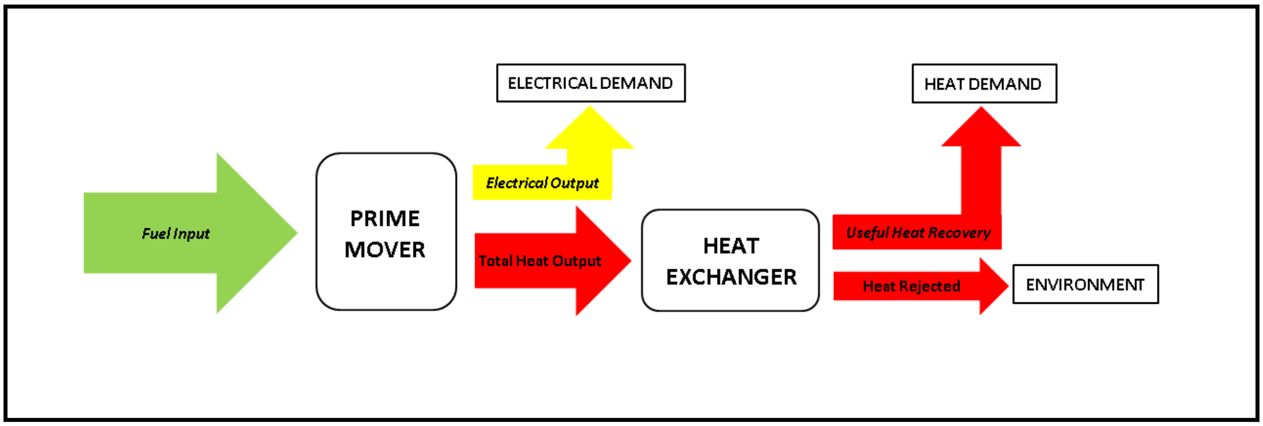
4.4 Heat and Fuel Impacts

In this section we present the results of fuel and useful heat recovery metering of certain CHP systems in the SGIP. The terms and definitions used in the CHP arena have been the cause of a much confusion. Before proceeding with the impacts results we carefully define the terms we will use when discussing rates and efficiencies.

4.4.1 Terms and Definitions

Figure 4-8 is a system level energy flow schematic for a typical SGIP system with heat recovery. Energy flows in italics represent a metered input or output.

Figure 4-8: Energy Flow Schematic



Starting from the left, renewable or non-renewable fuel enters the prime mover (fuel cell, gas turbine, etc.). Any system will convert some of the fuel input energy into electrical output and the rest will be dissipated as heat. A system's ability to convert fuel into electrical output is its Electrical Conversion Efficiency (ECE).

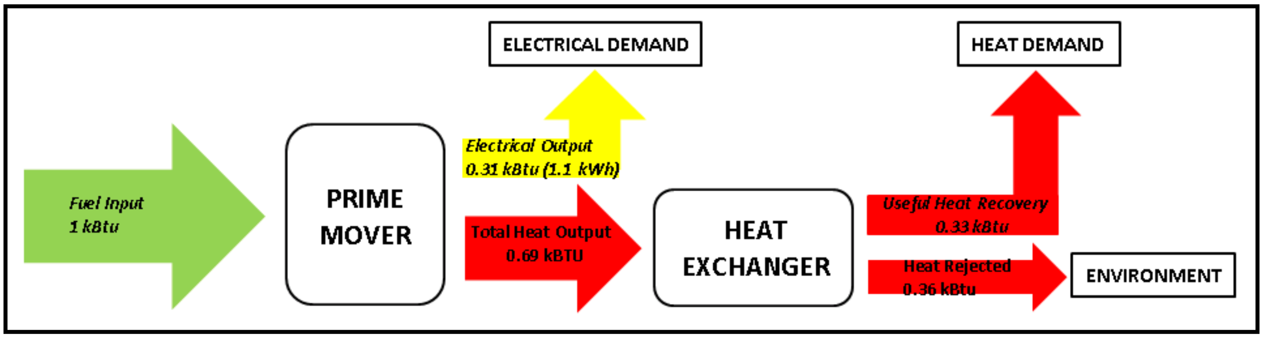
$$ECE = \frac{Electrical\ Output}{Fuel\ Input\ (LHV)}$$

The rest of the fuel energy that is not converted into electricity must be dissipated as heat, some of which goes out the exhaust. This heat output is what is typically listed in a manufacturer specification sheet as available waste heat, but it is not a measure of how much heat is actually recovered and utilized. A heat exchanger or water jacket is used to capture some of the waste heat and transport it to the required end (e.g. a space heater or an absorption chiller). The heat captured by the heat exchanger is metered when possible and defined as the useful heat recovered since it directly offsets gas that would have been burned in a boiler. Note that unless the CHP project developer closes matches the thermal output from the CHP system to the thermal demand at the host site, there is likelihood that more heat will be generated than can be used at the site. A system's ability to generate and capture this useful heat is defined here as its Useful Heat Conversion Efficiency.

$$Useful\ Heat\ Conversion\ Efficiency = \frac{Useful\ Heat\ Recovered}{Fuel\ Input\ (LHV)}$$

For illustrative purposes, consider a natural gas-fueled IC engine with an ECE of 31% and a useful heat conversion efficiency of 33% (typical values observed in 2010). The flow of energy for this hypothetical system is presented graphically in Figure 4-9.

Figure 4-9: Energy Flow Schematic for Hypothetical IC Engine



For every 1,000 Btu of fuel input, this representative IC engine would produce 0.31 kBtu (1.1 kWh) of electrical energy given its 31% ECE. The rest of the energy of the input fuel, 0.69 kBtu in this case, leaves the IC engine in the form of waste heat. At this point, the demand for heat at the facility dictates what percentage of this heat energy will be recovered as *useful* heat. For a system with a 33% useful heat conversion efficiency, meaning one-third of the input fuel energy will be captured and used at the facility, this represents 0.33 kBtu of heat energy for each 1,000 Btu of fuel input. Altogether, 64% of the input energy is recovered as electrical and heat energy. This leaves 36% of the energy to be lost as heat rejected to the environment.

4.4.2 2010 SGIP Fuel Consumption and Savings Estimates

CHP systems consume fuel but they also displace fuel that would otherwise be used to fulfill a facility heat demand. In 2010, an estimated 6,911 billion Btu of natural gas were consumed by SGIP facilities and 1,678 billion Btu of gas were offset from boilers. A breakdown of fuel and heat savings by CHP technology is presented in Table 4-13. Note that estimates of boiler gas displaced do not account for boiler efficiencies (typically ranging from 70-90%) and are therefore considered conservative.

Table 4-13: Total Heat and Fuel Estimates for 2010 by Technology Type

Technology	Estimated Boiler Gas Displaced Billion Btu	Estimated Fuel Consumed Billion Btu
FC	44	459
GT	351	2,030
ICE	1,094	3,314
MT	189	1,107
Total:	**1,678**	**6,911**

SGIP projects use a variety of means to recover heat and apply it to provide a variety of heating and cooling services. Table 4-14 summarizes the end uses served by recovered useful thermal energy and includes all projects subject to heat recovery requirements and completed through December 2010.

Table 4-14: End-Uses Served by Recovered Useful Thermal Energy

End Use Application	Completed Systems (n)	Completed Capacity (kW)
Heating Only	252	100,784
Heating & Cooling	80	61,257
Cooling Only	39	33,811
To Be Determined	7	1,768
Total:	**378**	**197,620**

The majority of SGIP systems utilize the waste heat for heating only. Less than half as many systems use the heat recovered for cooling by means of absorption chillers.

4.4.3 Performance and Compliance

The sample of systems used to calculate electrical conversion efficiencies of metered systems includes those systems where metered fuel input and electrical output were simultaneously available. The summary of ECE by technology for 2010 systems is presented in Table 4-15. In 2010, fuel cells averaged the highest ECE, at just over 40%, while microturbines had the lowest ECE, at slightly less than 23%.

Table 4-15: Electrical Conversion Efficiencies of Metered Systems by Technology

Technology	Number of Metered Projects (n)	Electric Conversion Efficiency (%, LHV)
FC	8	40.2 ± 1.9%
GT	4	33.3 ± 5.7%
ICE	35	31.2 ± 0.8%
MT	14	22.7 ± 1.1%

To calculate useful heat recovery efficiencies of metered systems, the sample was limited to observations with metered electrical output but allowed for metered and estimated fuel values. The results are shown in Table 4-16.

Table 4-16: Useful Heat Conversion Efficiencies of Metered Systems by Technology

Technology	Number of metered projects (n)	Heat Conversion Efficiency (%, LHV)
FC	6	13.8 ± 4.9%
GT	5	18.6 ± 16.8%
ICE	25	33.0 ± 5.8%
MT	27	17.9 ± 3.4%

IC engines were able to recover about one-third of the fuel input as useful heat, compared to fuel cells at less than 14%.

System Efficiency and Public Utility Code 216.6 Compliance

Electrical efficiencies or useful heat recovery efficiencies alone are not enough to quantify a CHP system's performance. The sum of the two aforementioned efficiencies, known as the system efficiency, is a useful metric to assess a CHP system's ability to convert fuel into useful energy. Additionally, to ensure that systems harness waste heat effectively and realize high overall system efficiencies, Public Utility Code (PUC) 216.6[5] requires that participating non-renewable-fueled fuel cells and engines/turbines meet minimum levels of annual thermal energy utilization and overall system efficiency.[6]

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5 PUC 216.6 has replaced PUC 218.5; however the requirements remain the same.

6 Several renewable-fueled projects entering the program during its first years were also subject to heat recovery requirements and are included in the analysis covered in this section.

PUC 216.6(a) requires that recovered useful waste heat from a CHP system exceeds 5% of the combined recovered waste heat plus the electrical energy output of the system. PUC 216.6(b) requires that the sum of the electric generation and half of the heat recovery of the system exceeds 42.5% of the energy entering the system as fuel. Table 4-17 summarizes these requirements and the definition of system efficiency.

Table 4-17: Summary of DG System Efficiency Definitions and Minimum Requirements

Element	Definition	Minimum Requirement (%)
216.6 (a)	Proportion of facilities' total annual energy output in the form of useful heat	5.0
216.6 (b)	Sum of electrical efficiency and half of useful heat conversion efficiency, LHV	42.5
System Efficiency	Sum of electrical efficiency and useful heat conversion efficiency, LHV	NA

Metered data collected from on-line CHP projects were used to estimate performance of similar unmetered projects. Resulting performance data for both metered and unmetered projects were used to calculate system efficiency and PUC 216.6 performance metrics by technology type. Results summarized in Table 4-18 represent capacity weighted averages for each technology type. These results may be thought of as representing the overall performance of a single, very large system if all of the systems were combined. This basis is intended to yield results that can be compared directly with other pertinent reference points (e.g., performance of large, centralized power plants).

Table 4-18: System Efficiency and PUC 216.6 Performances by Technology

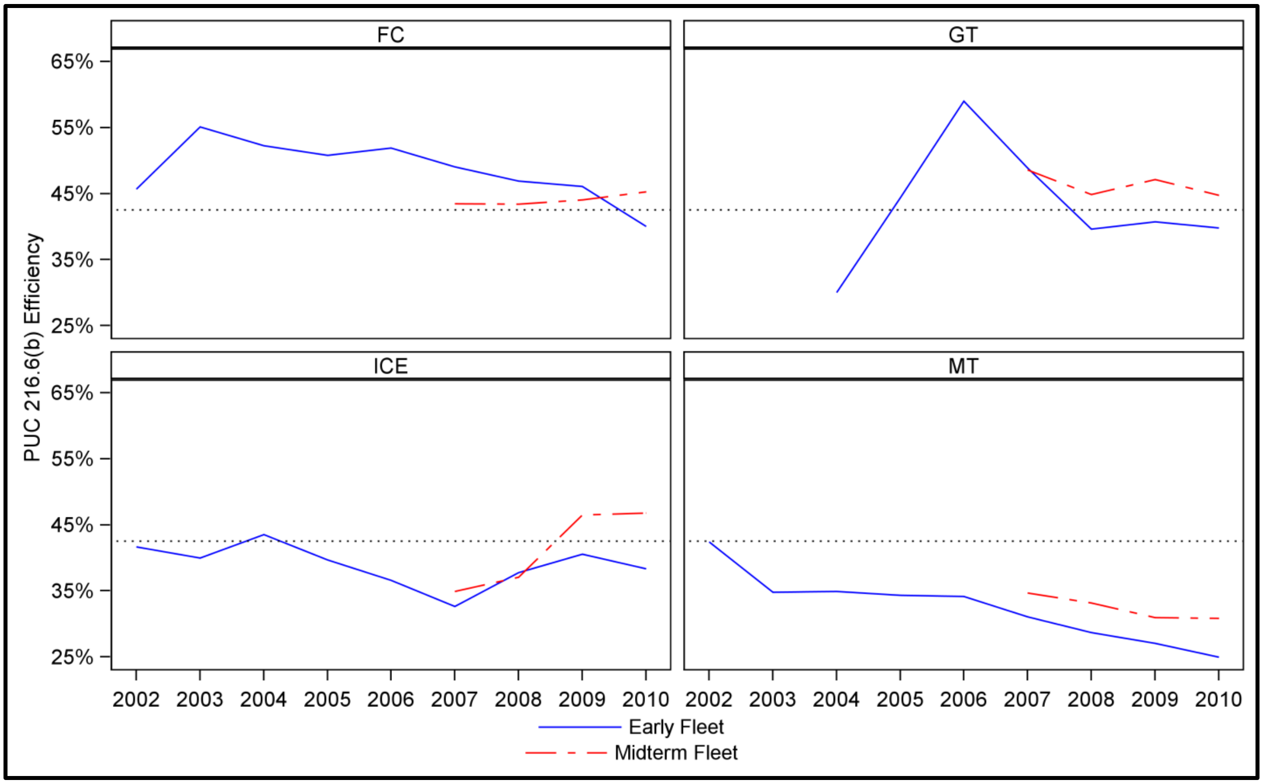
Technology	Number of projects (n)	216.6 (a) Efficiency (%)	216.6 (b) Efficiency (%, LHV)	CHP System Efficiency (%, LHV)
FC	19	22.7%	45.8%	51.7%
GT	8	34.6%	41.4%	50.0%
ICE	230	50.6%	46.7%	62.5%
MT	121	43.1%	31.0%	39.5%

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Within Table 4-18, the PUC 216.6(a) results are expressed as the proportion of the total output energy from the system recovered as useful heat. For example, fuel cells in the SGIP recovered on average 23% of their total output energy as useful heat, whereas IC engines recovered on average 51%. All of the CHP technologies in the SGIP achieved and exceeded the PUC 216.6(a) requirement of providing at least 5% of the output energy as useful heat.

The PUC 216.6(b) results in Table 4-18 are expressed as the sum of the electrical conversion efficiency and half the useful heat recovery efficiency. The 216.6(b) results for FC and IC engines exceeded the 42.5% threshold in the code. The gas turbine 216.6(b) results were slightly below the threshold, and the microturbine results fell substantially short of the requirement. Most SGIP CHP technologies have historically had trouble meeting the 216.6(b) minimum efficiency requirements. Figure 4-10 shows the 216.6(b) trends by technology and fleet vintage over time. All systems that entered normal operations on or before 2006 are considered part of the "Early Fleet", and more recent systems are part of the "Midterm Fleet". The 42.5% threshold is shown as a dotted line.

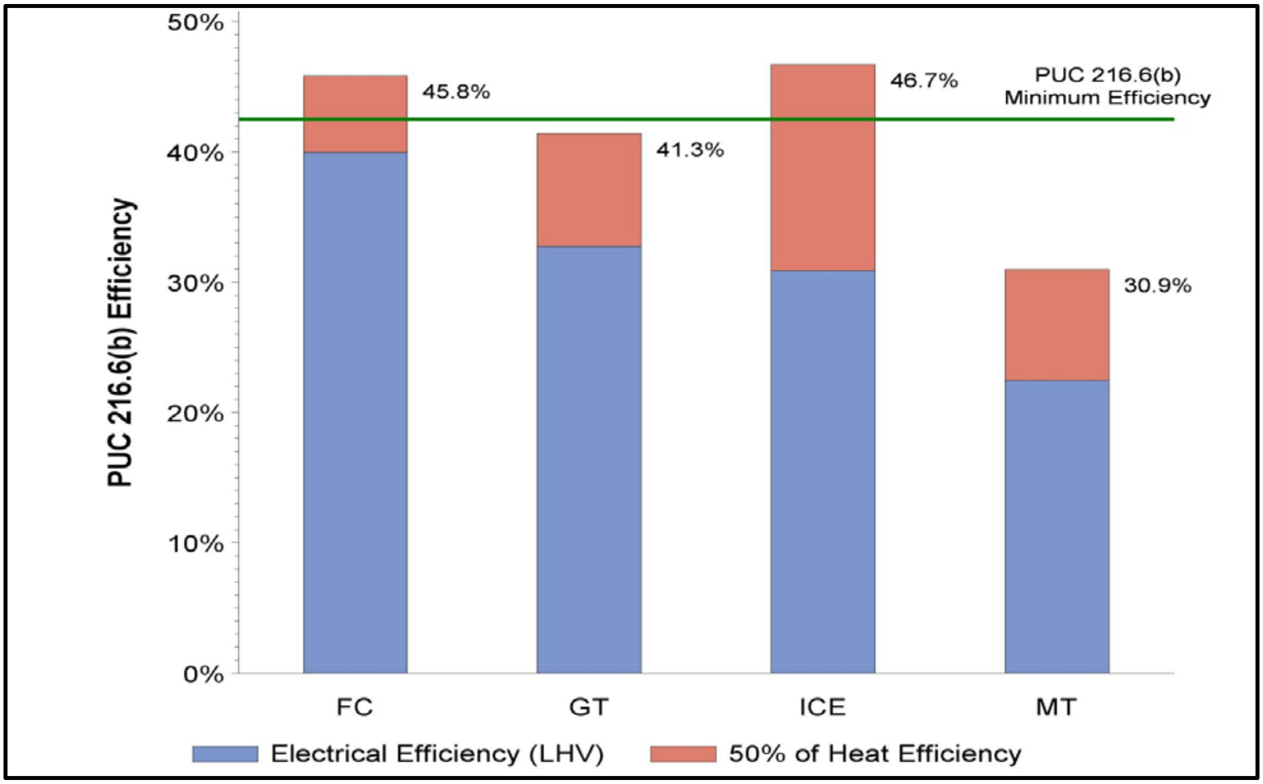
Figure 4-10: PUC 216.6(b) Efficiency by Technology and Vintage Over Time



Except for fuel cells, all technologies in the early fleet were usually unable to meet the 216.6(b) minimum requirements. The only exceptions are IC engines in 2004 and gas turbines in 2006. The long-term trend is mostly flat or slightly decreasing. The high volatility of gas turbine values is likely due to the low number of metered systems. The pattern changes significantly when looking at the midterm fleet; only microturbines and IC engines before 2009 were unable to meet the requirements.

Figure 4-11 presents the 2010 PUC 216.6(b) results for each technology graphically, providing a breakdown of electrical efficiency and useful heat conversion efficiency contributions towards the 42.5% minimum performance requirement (shown in green for reference). It would appear that the greatest factor contributing towards the compliance of fuel cell systems is their high electrical efficiency. The opposite seems true for IC engines, where high useful heat recovery efficiency sets them apart from other technologies.

Figure 4-11: PUC 216.6(b) Efficiencies by Technology



For the most part, electrical conversion efficiencies for each technology have remained unchanged by system vintage. It follows that if a system is expected to meet PUC 216.6(b) performance requirements, the useful heat recovery efficiency must increase. Table 4-19 shows what the actual useful heat conversion efficiency would need to be for technologies that did not meet minimum PUC 216.6(b) performance in 2010.

Table 4-19: Efficiency Contributions and Required Useful Heat Conversion Efficiency

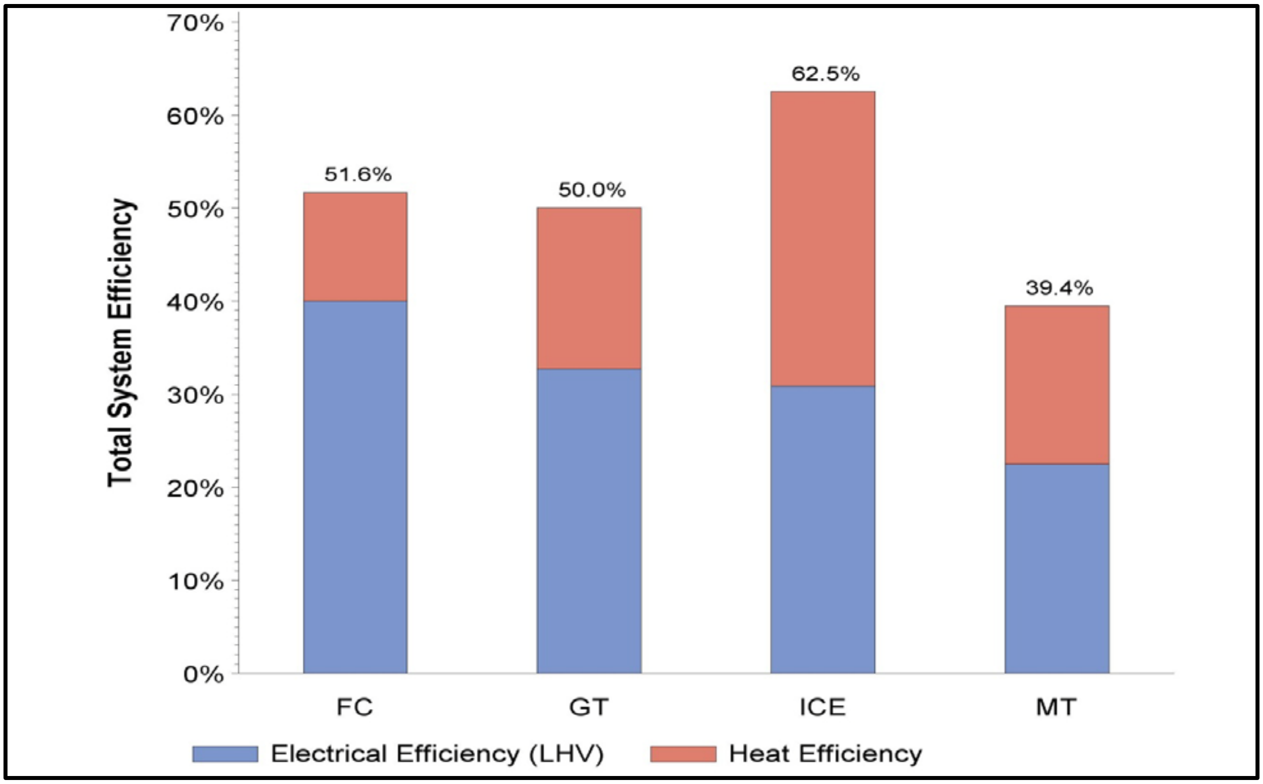
Technology	Electrical Conversion Efficiency (%,LHV)	Useful Heat Conversion Efficiency (%,LHV)	216.6 (b) Efficiency (%, LHV)	Required Useful Heat Conversion Efficiency (%, LHV)
FC	40.0%	11.7%	45.8%	NA
GT	32.7%	17.3%	41.4%	19.6%
ICE	30.9%	31.6%	46.7%	NA
MT	22.5%	17.0%	31.0%	40.0%

In order for gas turbines to meet the PUC 216.6(b) requirement in 2010, their useful heat conversion efficiency had to increase from 17.3% to 19.6%. Microturbines generally have lower electrical efficiencies and thus their useful heat conversion efficiency would have to increase to 40% from 17%. No values are reported for fuel cells or IC engines since they exceeded the minimum PUC performance requirements.

The system efficiency is a more common metric for CHP performance as it accounts for all the useful energy extracted from the system; it is presented graphically in Figure 4-12. IC engines had the highest overall efficiency among technologies (63%) due to their high useful heat efficiency compared to all other technologies. The combination of low electrical efficiency and low useful heat recovery of microturbines adds up to the lowest overall efficiency among SGIP CHP technologies.

A threshold of 60% has been recommended by the PUC as the minimum system efficiency in future iterations of the SGIP program. Based on the weighted average performance of systems in 2010, only IC engines would exceed that criterion.

Figure 4-12: System Efficiency by Technology



4.5 Greenhouse Gas Emission Impacts

Interest in climate change has continued to increase over the last several years, with special emphasis being placed on greenhouse gas (GHG) emission impacts. Obtaining accurate measures of GHG emission impacts will increase in importance, particularly in the event of a cap and trade program for carbon credits. GHG emission impacts have been presented in SGIP impact reports since 2005 and over the years the accuracy of GHG emissions impacts estimates have increased as calculation methods have been improved and more electrical and heat data have become available.

This section presents the impact the installation of SGIP projects had on GHG emissions in 2010 by technology and fuel type, measured in CO_2 equivalent units to facilitate comparisons. This allows the examination of relationships between net changes in GHG emission impacts and technology and fuel type. As in all prior SGIP Impact Evaluation Reports, the focus on GHG emission impacts is on carbon dioxide and methane (CO_2 and CH_4, respectively) as these are the main GHG emissions pertaining to SGIP facilities and baseline scenarios.

4.5.1 GHG Analysis Approach

GHG emission impacts are calculated per SGIP site as the difference between the GHG emissions produced by the rebated DG system and the baseline GHG emissions. Baseline GHG emissions are the sum of the emissions that would have occurred in the absence of the SGIP to satisfy facility loads currently satisfied by the rebated DG system; and in the case of renewable (biogas)-fueled SGIP systems, the emissions associated with the treatment of the CH_4 gas prior to it being consumed in the SGIP system. The components associated with baseline CO_2 emissions are: the electric power plant CO_2 emissions, CO_2 emissions corresponding to electric chiller operation, natural gas boiler CO_2 emissions, and the emissions from biogas treatment (venting biogas or capturing and flaring biogas). Not all of the baseline components pertain to all projects and, at a minimum, depend on the SGIP system type. Table 4-20 below shows which components are associated with which SGIP systems by technology and fuel type.

Table 4-20: Baseline CO_2 Emission Components per Technology/Fuel

Technology/Fuel	SGIP System CO_2 Emissions	Electric Power Plant CO_2 Emissions	CO_2 Emissions Associated with Heating Services	CO_2 Emissions Associated with Cooling Services	CO_2 Emissions From Biogas Treatment
Non–Renewable CHP	X	X	X	X	
Renewable DG	X	X	X		X

Baseline GHG emissions are calculated using emission values from the E3 avoided cost calculation workbook,[7,8] and technology efficiency assumptions. SGIP GHG emissions are calculated based on the hourly electrical data for the SGIP site and the electrical conversion efficiency associated with the technology type. This is the same general approach as in the SGIP Eighth-Year Impact Evaluation Final Report; however, there are a few assumptions that changed in the 2009 analysis and are carried forward into 2010. Detailed documentation of the PY10 GHG emissions impact evaluation methodology, including these changes, is included as Appendix B.

4.5.2 GHG Analysis Results

Due to the varying number of baseline GHG emission components associated with each SGIP system, results for non-renewable CHP facilities and renewable fuel (i.e., biogas-fueled) SGIP facilities are presented independently. An overall summary of the total GHG emission impacts and PA-specific GHG emission impacts are presented at the end of this section.

CO_2 Emission Impacts from Non-Renewable CHP Projects

In addition to realizing CO_2 emission impacts from direct displacement of grid-based electricity, non-renewable CHP facilities realize CO_2 emission impacts due to displacement of natural gas burned in boilers to provide process heating. The natural gas is displaced through the use of waste heat recovery equipment that is part of the SGIP CHP systems. In addition, some of the non-renewable CHP SGIP facilities use recovered waste heat in absorption chillers to provide facility cooling. If the absorption chillers replaced electric chillers, then CO_2 emission impacts accrue from the displaced electricity that would otherwise have driven the electric chiller.

Table 4-21 provides a breakdown of CO_2 emissions associated with the SGIP CHP system and each of the baseline components, and the overall impact on CO_2 emissions per technology type. The net effect of all non-renewable CHP technology types was a 50,107 ton increase in CO_2 emissions. This represents the CO_2 emissions added by the deployment of SGIP CHP systems. In 2009, the program impact from non-renewable SGIP projects was 54,516 tons of CO_2 emissions. The small decrease can be attributed to more CHP projects with better heat recovery and electrical efficiency added to the program in 2010. Comparing the magnitude of the CO_2 emission values associated with heating and cooling services across technologies illustrates the importance of waste heat recovery. The baseline CO_2 emissions associated with heating services for IC engines and gas turbines are much higher than those seen for microturbines. This is

7 The E3 avoided cost calculation workbook is an 8,760 hourly data set that captures day and time variability in GHG emissions associated with online power plant technologies.

8 Energy and Environmental Economics. *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*. Prepared for the CPUC. October 25, 2004. http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

consistent with the higher overall efficiency rates of IC engines and gas turbine systems seen in Section 4.4

Table 4-21: CO_2 Emission Impacts from Non-Renewable CHP Projects in 2010 (Tons of CO_2 Per Year)

Technology Type*	SGIP System CO_2 Emissions (Tons of CO_2 per yr)	Avoided Emissions (Tons of CO_2 Per Year)				GHG Emissions Impact (Tons of CO_2 per yr)
		Electric Power Plant CO_2 Emissions	Waste Heat Recovery offset		Total Avoided Emissions	
			Heating Services	Cooling Services		
	A	B	C	D	E=B+C+D	F=A-E
FC	23,682	20,505	2,608	22	23,135	546
GT	112,659	79,840	13,164	1,818	94,822	17,838
ICE	179,536	122,042	42,875	4,489	169,405	10,130
MT	60,763	29,704	8,882	584	39,170	21,593
Total	**376,640**	**252,089**	**67,530**	**6,913**	**326,533**	**50,107**

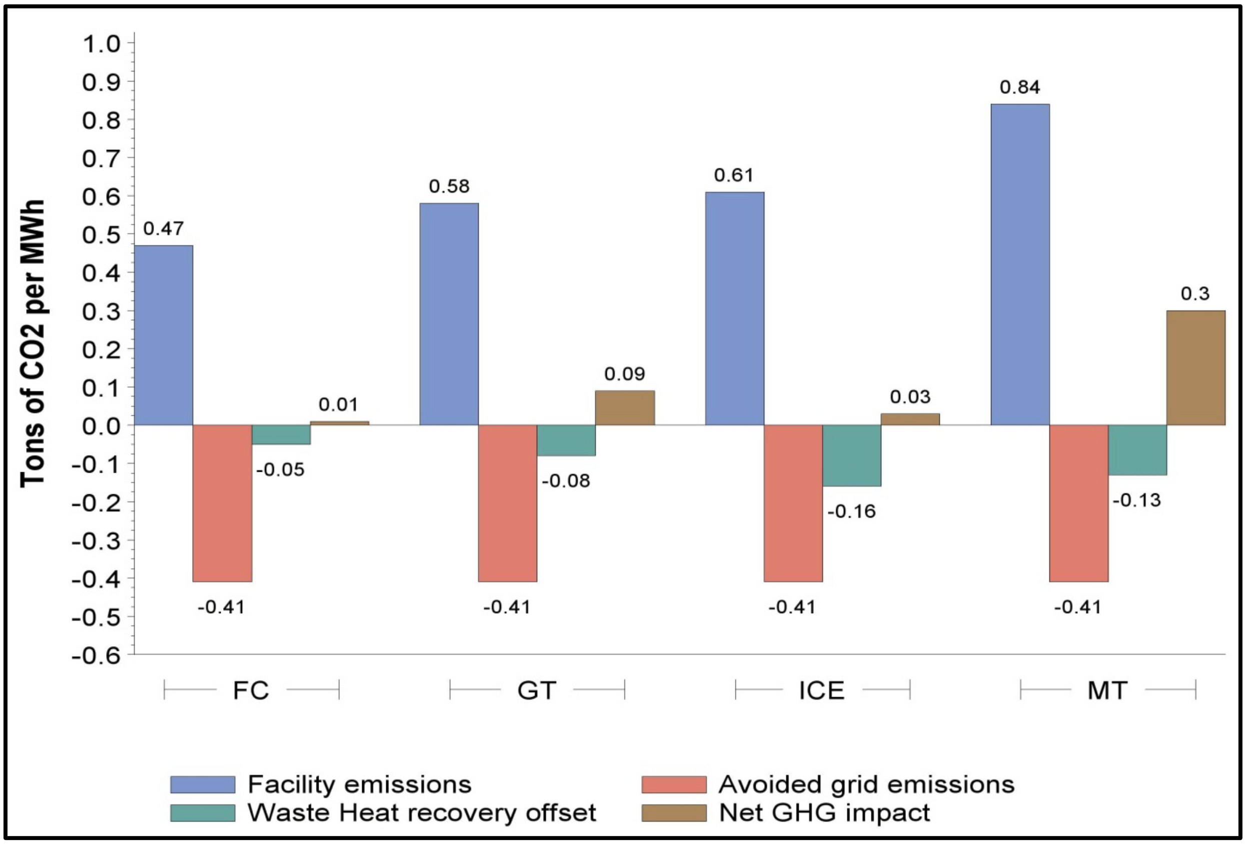
* FC = Fuel Cell; ICE = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine

Table 4-22: CO_2 Emission Impact Factor for Non-Renewable CHP Projects in 2010 (Tons of CO_2 Per MWh)

Technology Type	Annual Energy Produced (MWh)	SGIP System CO_2 Emissions (Tons of CO_2Per MWh)	Avoided Emissions Impact Factor (Tons CO_2 Per MWh)				GHG Emissions Impact Factor (Tons CO_2 Per MWh)
			Electric Power Plant CO_2 Emissions Impact Factor	Waste Heat Recovery offset		Total Avoided Emissions	
				Heating Services	Cooling Services		
FC	50,087	0.47	0.41	0.05	0.00	0.46	0.01
GT	194,789	0.58	0.41	0.07	0.01	0.49	0.09
ICE	294,281	0.61	0.41	0.15	0.02	0.58	0.03
MT	72,289	0.84	0.41	0.12	0.01	0.54	0.30

* FC = Fuel Cell; IC Engine = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine

Figure 4-13: CO_2 Emission Impact Factor for Non-Renewable CHP Projects in 2010 (Tons of CO_2 per MWh)



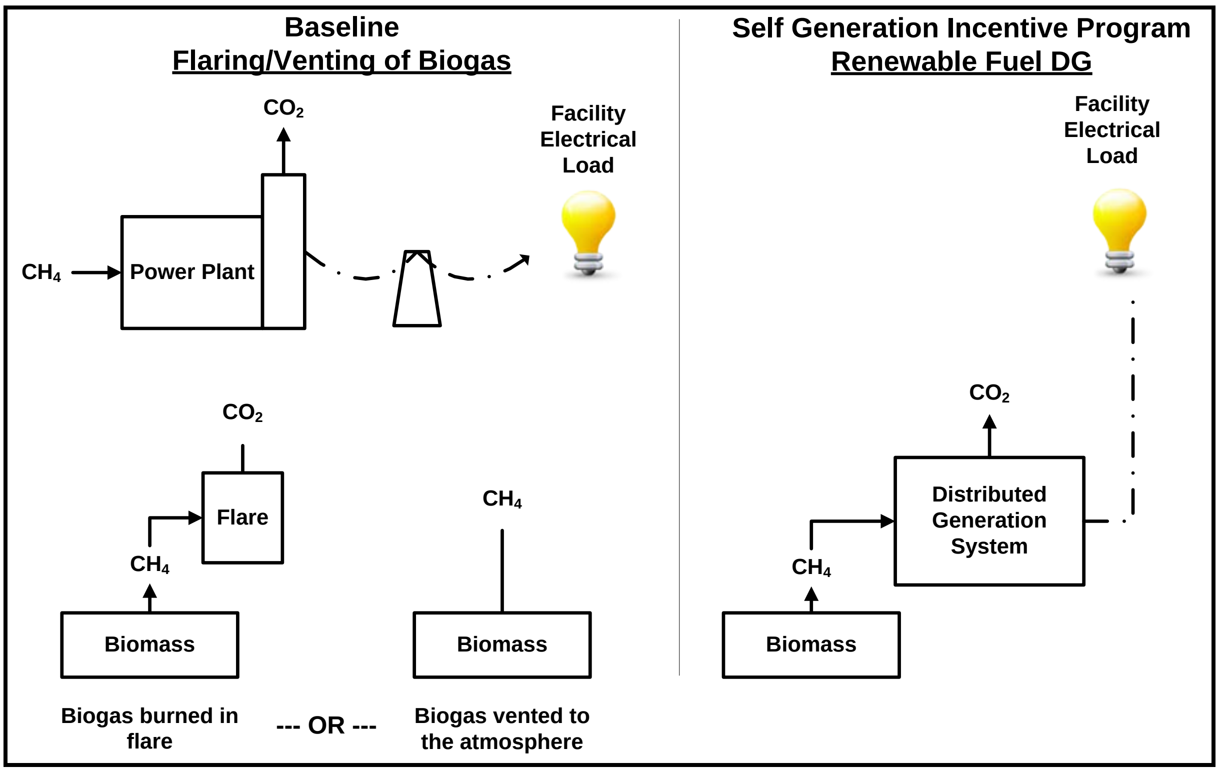
By normalizing the CO_2 emission impacts by the annual energy production, comparisons can be made between different CHP technologies. In this report, this normalized CO_2 emission variable is called the annual CO_2 impact factor. Table 4-22 presents the annual CO_2 impact factors (in tons of CO_2 reduced per MWh of electricity generated) for non-renewable CHP technologies. Positive CO_2 impacts represent an increase in CO_2 as a result of the installation of the SGIP projects. The CO_2 impact factors for non-renewable projects range from a high of 0.30 tons per MWh for microturbines to a low of 0.01 tons per MWh for fuel cells.

GHG Emission Impacts (CO_2 and CH_4) from Renewable (Biogas) Projects

Analysis of the GHG emission impacts associated with fuel cells, microturbines, and IC engines using renewable biogas is more complex than that for non-renewable CHP projects. This is due in part to the additional baseline component associated with the need to quantify the GHG emissions of the biogas treatment prior to the SGIP system installation. In addition, some systems only generate electricity while others are CHP systems that use waste heat to meet building heating or cooling loads. Consequently, biogas-powered CHP systems can directly impact CO_2 emissions the same way as non-renewable CHP systems, but they also include GHG emission impacts due to captured CH_4 contained in the biogas.

Biogas-powered SGIP facilities capture and use CH_4 that otherwise may have either been emitted to the atmosphere (vented) or captured and burned (flared). This is hereafter referred to as the biogas baseline. The concept of biogas baseline is depicted in Figure 4-14. When reporting emission impacts from different types of greenhouse gases, total GHG emissions are reported in terms of tons of CO_2 equivalent (CO_2Eq) so that direct comparisons can be made. The global warming potential of CH_4 is 21 times that of CO_2. The biogas baseline estimation in the vented case (CH_4 emission impacts from biogas powered SGIP facilities) is converted to CO_2Eq by multiplying the quantity of CH_4 by this conversion factor. In the following tables CO_2Eq emissions are reported if systems with a biogas baseline of venting are included; otherwise CO_2 emissions are reported.

Figure 4-14: GHG Emission Impacts Associated with Renewable Fuel DG



Prior to the 2009 Impact Report, in absence of the SGIP all landfill gas facilities were assumed to have captured and flared CH_4, all dairies were assumed to have vented CH_4, and other digesters were assumed to have vented digester gas if under 150 kW of rebated capacity and flared otherwise. Starting in 2009 with new information gathered from SGIP facilities, all facilities except dairies are assumed to capture and flare methane. The changes per facility type in the biogas baseline assumptions are shown in Table 4-23 below.

The assumption is that flaring CH_4 (which converts CH_4 to CO_2) results in the same amount of CO_2 emissions that would occur if the CH_4 was captured and used by the SGIP system. The total electricity generated by these facilities was multiplied by the technology-specific emission factor for $CH_{4,}$ in order to calculate the total CH_4 emissions avoided by relying upon that CH_4 to generate power at these SGIP facilities.[9] Of the biogas systems that were assumed to have vented CH_4 prior to participation in the SGIP, all were IC engine facilities.

In general, by changing this assumption the number of sites which vent CH_4 has been reduced starting in PY09. The effect is an overall reduction in GHG impact of renewable fueled SGIP systems because CH_4 has a higher global warming potential than that of CO_2 if compared to the impact reports of 2008 and prior .

Table 4-23: Biogas Baseline Assumption

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

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

9 See Appendix B for the derivation of renewable fuel technology-specific CH_4 emission factors.

Table 4-24 and Table 4-25 provide the GHG emission impacts occurring from biogas-powered facilities. Separate tables are shown for the flaring and venting CH_4 baseline, as venting CH_4 results are provided in tons of CO_2Eq, and flaring CH_4 results are given as tons of CO_2. Tons of CO_2Eq results can directly be compared to all other results given in tons of CO_2.

Table 4-24: CO_2 Emission Impacts from Biogas Projects in 2010—Flared CH_4 (Tons of CO_2 per Year)

Technology Type*	SGIP System CO_2 Emissions (Tons of CO_2 per Year)	Avoided Emissions (Tons of CO_2 per Year)				GHG Emissions Impact (Tons of CO_2 per Year)
		Electric Power Plant CO_2 Emissions	Waste Heat Recovery offset		Total Avoided Emissions	
			Heating Services	Cooling Services		
	A	B	C	D	E=B+C+D	F=A-E
FC	8,255	7,152	0	0	7,152	1,103
ICE	24,288	16,375	4,066	0	20,441	3,847
MT	5,460	2,651	96	0	2,747	2,713
Total	**38,004**	**26,179**	**4,162**	**0**	**30,341**	**7,663**

* FC = Fuel Cell; ICE = Internal Combustion Engine; MT = Microturbine

Table 4-25 includes the CH_4 emission impacts and equivalent CO_2 emission impacts from the biogas facilities that previously vented CH_4. The values in the table indicate that venting CH_4 (CO_2Eq Emissions (converted from CH_4)) produces CO_2Eq emissions that are an order of magnitude greater than the electric power plant GHG emissions or the SGIP CHP system emissions.

Table 4-25: CO_2 Emission Impacts from Biogas Projects in 2010—Vented CH_4 (Tons of CO_2Eq per yr)

Technology Type*	SGIP System CO_2 Emissions (Tons of CO_2 per yr)	Avoided Emissions (Tons CO_2 per yr)			GHG Emissions Impact (tons CO_2 per yr)
		Electric Power Plant CO_2 Emissions	CO_2 Emissions from Biogas Treatment	Total Avoided Emissions	
	A	B	C	D=B+C	E=A-D
ICE	3,836	2,570	29,311	31,881	-28,045

* ICE = Internal Combustion Engine; ** Biogas projects powered by fuel cells and microturbines operating in PY10 did not impact CH4 emissions due to the assumptions regarding the baseline.

Table 4-26 shows the impact of biogas projects that are assumed to have flared CH_4. Annual CO_2 emissions impacts are expressed with respect to baseline CO_2 emissions that would have occurred in the program's absence. The results range from -33% for microturbines to -46% for fuel cells. These CO_2 emission impacts are substantially larger than those achieved by their natural gas counterparts described in Table 4-21. This is because flaring is an effective means of converting CH_4 into CO_2, and, in terms of the total SGIP GHG emission impact, flaring biogas offsets the emissions from the SGIP DG system. However, flaring represents a lost opportunity to use the CH_4's energy content.

Table 4-26: CO_2 Emission Impact Factors from Biogas Projects in 2010—Flared CH_4 (Tons of CO_2 per MWh)

Technology Type	Annual Energy Produced (MWh)	SGIP System CO_2 Emissions (Tons of CO_2 per MWh)	Avoided Emissions Impact Factor (Tons CO_2 per MWh)				GHG Emissions Impact Factor (Tons CO_2 per MWh)
			Electric Power Plant CO_2 Emissions Impact Factor	Waste Heat Recovery offset		Total Avoided Emissions	
				Heating Services	Cooling Services		
FC	17,460	0.47	0.41	0.00	0.00	0.41	0.06
ICE	39,811	0.61	0.41	0.10	0.00	0.51	0.10
MT	6,496	0.84	0.41	0.01	0.00	0.42	0.42

* FC = Fuel Cell; ICE = Internal Combustion Engine; MT = Microturbine

Table 4-27 shows the impact of biogas projects that are assumed to have vented CH_4 as part of the baseline. The annual CO_2Eq impact factor associated with SGIP systems that previously vented CH_4 is much larger than the annual CO_2 impact factor for facilities that previously captured and flared CH_4, because the global warming potential of CH_4 is 21 times that of CO_2. Therefore, offering an incentive program which encourages facility owners who currently vent CH_4 to install a biogas project could have very large impacts on GHG emissions.

Table 4-27: CO_2 Emission Impact Factor from Biogas Projects in 2010 (Includes Tons of CO_2 and CO_2Eq per MWh)—Vented CH_4 under Baseline

Technology Type	Annual Energy Produced (MWh)	SGIP Facility emissions (tons CO_2 per MWh)	Avoided Emissions Impact Factor (tons CO_2 per MWh)			GHG Emissions Impact Factor (tons CO_2 per MWh)
			Grid Electricity offset	CO_2 Emissions from Biogas Treatment	Total Avoided Emissions (tons CO_2 per MWh)	
ICE	6,288	0.61	0.41	4.66	5.07	-4.46

* ICE = Internal Combustion Engine; ** Biogas projects powered by fuel cells and microturbines operating in PY10 did not impact CH4 emissions due to the assumptions regarding the baseline.

Figure 4-15 and Figure 4-16 show the biogas emissions impact of flared and vented CH_4 facilities, respectively. The biogas offset due to venting is a major offset component, which makes it a net emissions impact reducer for facilities that vent.

Figure 4-15: CO_2 Emission Impact Factors from Biogas Projects in 2010—Flared CH_4 (Tons of CO_2 per MWh)

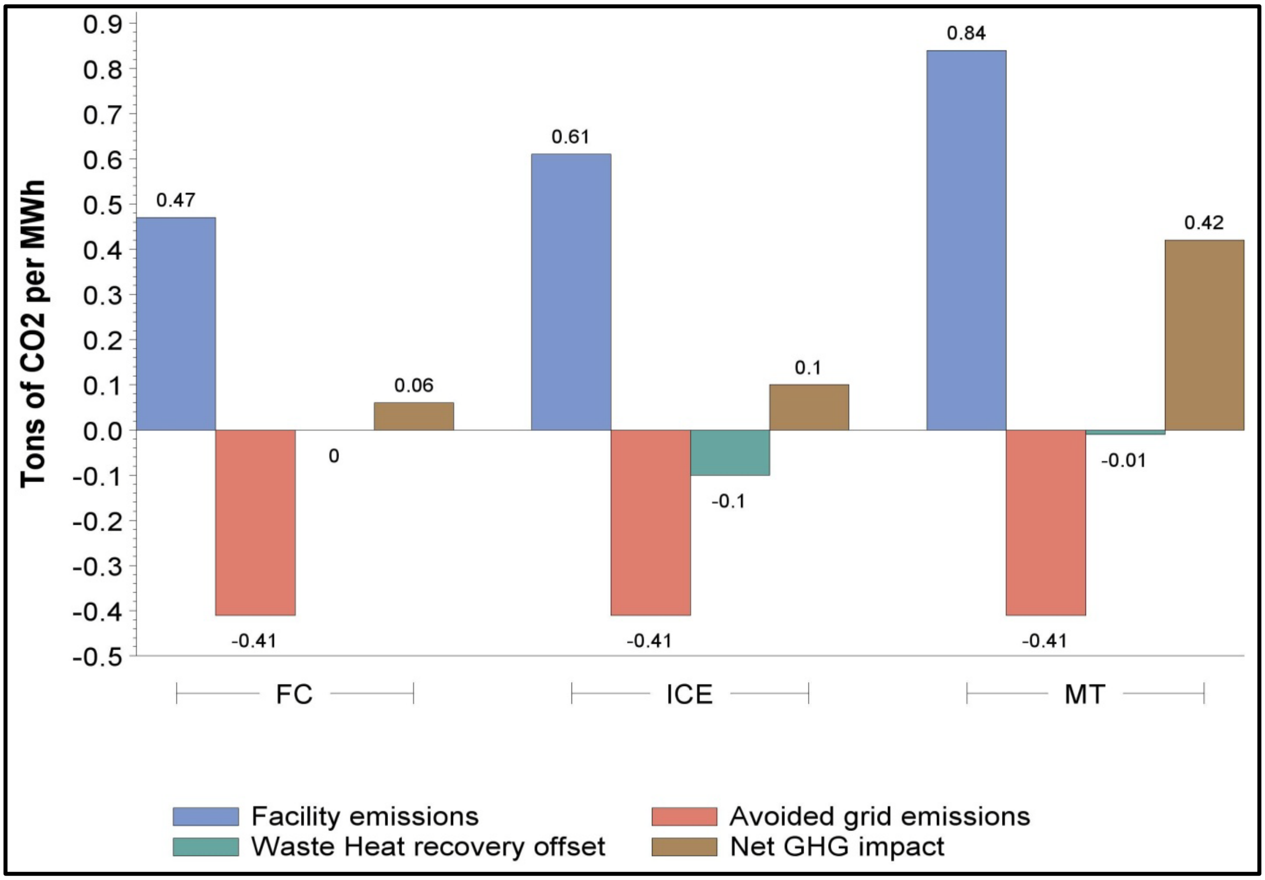
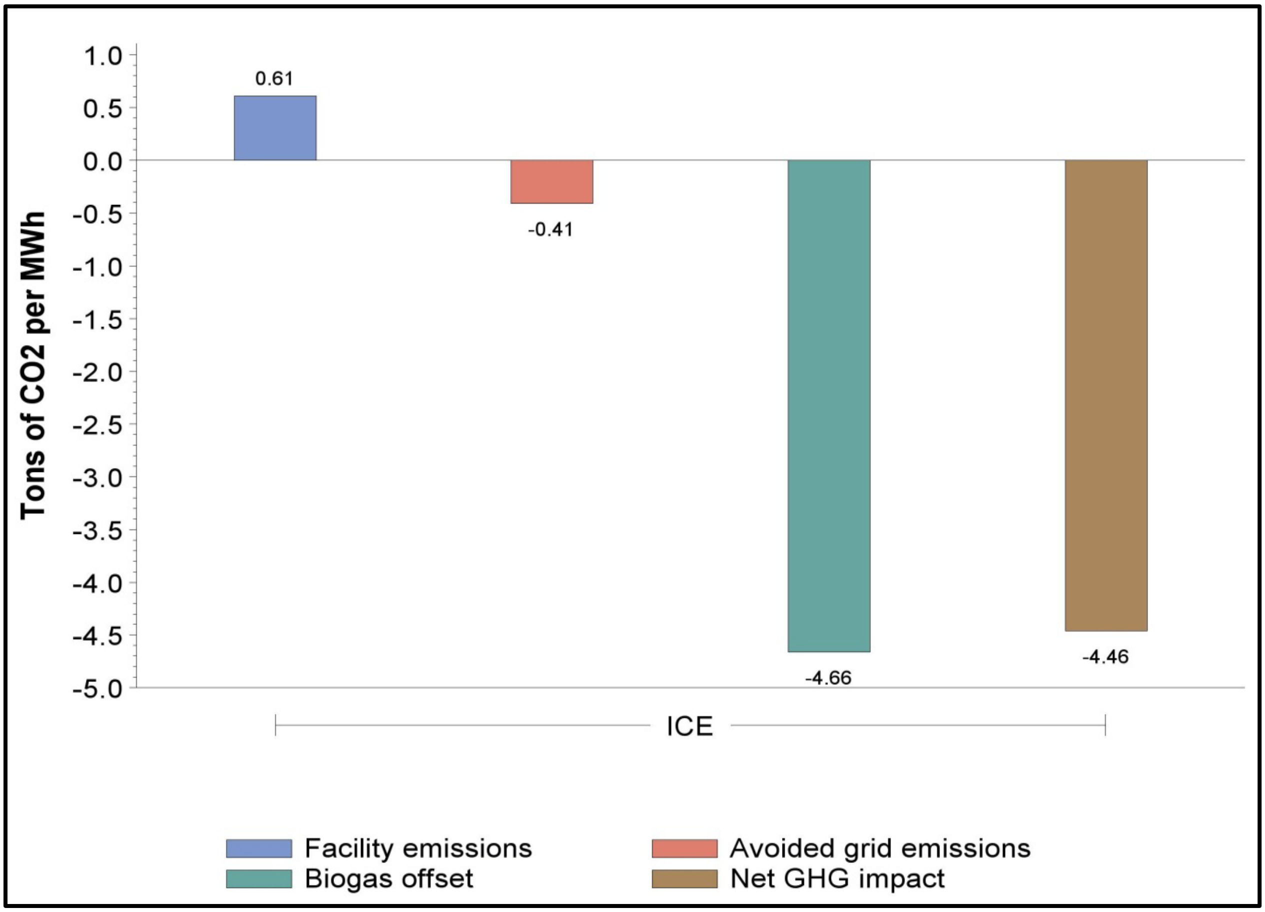


Figure 4-16: CO_2 Emission Impact Factor from Biogas Projects in 2010 (Includes Tons of CO_2 and CO_2Eq per MWh)—Vented CH_4 under Baseline



<u>Total GHG Emission Impacts</u>

Table 4-28 presents a summary of GHG emission impacts from the installation of SGIP projects, measured in tons of CO_2 equivalent, and broken down by different SGIP technologies. During the 2010 program year, the total GHG emission impacts calculated for the SGIP projects was a net increase of 29,725 tons of CO_2Eq. Only vented biogas IC engines contributed to reduced GHG emissions; as seen in Table 4-29. The last column presents the tons of GHG emissions per MWh generated by each fuel and technology category. All non-renewable fueled CHP systems, along with flared biogas systems, resulted in a GHG emission increase.

Table 4-28: GHG Emission Impacts from SGIP Systems Operating in Program Year 2010 (Tons of CO_2 Equivalent) by Fuel and Technology and Ratios of Tons of GHG Emission Impacts per Year

Tech-nology Type	SGIP System CO_2 Emissions (Tons of CO_2 per yr)	Avoided Emissions (Tons of CO_2 per yr)					GHG Emissions Impact (Tons of CO_2 per yr)
		Electric Power Plant CO_2 Emissions	Waste Heat Recovery offset		CO_2 Emissions from Biogas Treatment	Total Avoided Emissions	
			Heating Services	Cooling Services			
	A	**B**	**C**	**D**	**E**	**F=B+C+D+E**	**G=A-F**
FC	31,937	27,657	2,608	22	0	30,288	1,649
GT	112,659	79,840	13,164	1,818	0	94,822	17,838
ICE	207,660	140,987	46,941	4,489	29,311	221,728	-14,068
MT	66,223	32,355	8,978	584	0	41,917	24,306
Total	**418,479**	**280,838**	**71,692**	**6,913**	**29,311**	**388,754**	**29,725**

FC = Fuel Cell; IC Engine = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine

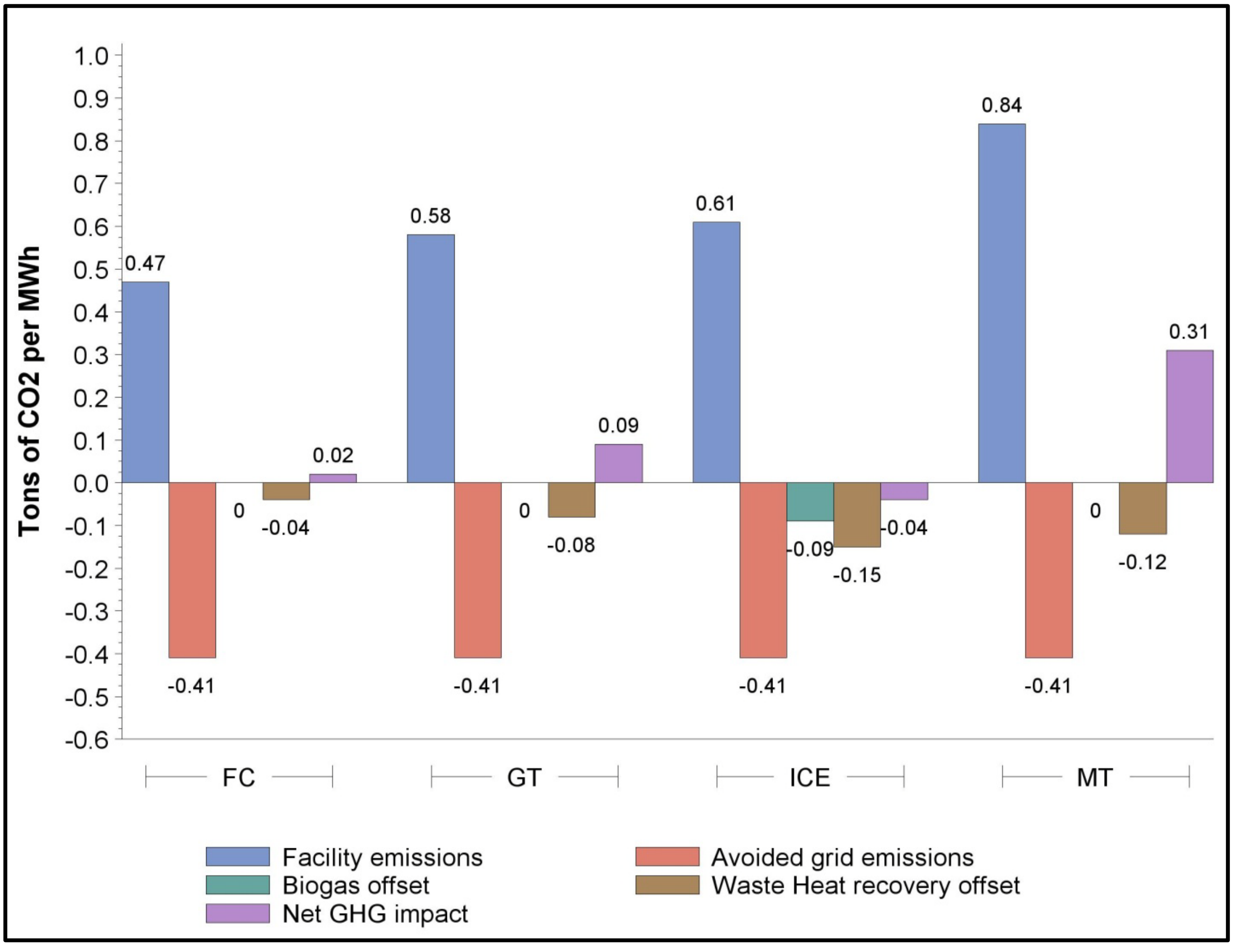
† Wind values were not available because valid metered data were not received.

Table 4-29: GHG Emission Impact Factors from SGIP Systems Operating in Program Year 2010 (Tons of CO_2 Equivalent) by Fuel and Technology and Ratios of Tons of GHG Emission Impacts per MWh

Technology/ Fuel	Annual GHG Emissions Impact (tons of CO_2)	Annual Energy Impact (MWh)	Annual GHG Impact Factor (tons CO_2 per MWh)
FC	**1,599**	**67,546**	**0.02**
Biogas-Flared	1,103	17,460	0.06
NatGas	496	50,087	0.01
GT	**17,838**	**194,789**	**0.09**
NatGas	17,838	194,789	0.09
ICE	**-14,068**	**340,380**	**-0.04**
Biogas-Flared	3,847	39,811	0.10
Biogas-Vented	-28,045	6,288	-4.46
NatGas	10,130	294,281	0.03
MT	**24,306**	**78,785**	**0.31**
Biogas-Flared	2,713	6,496	0.42
NatGas	21,593	72,289	0.30
Total	**29,675**	**681,500**	**0.04**

Figure 4-17 shows the annual CO_2 Eq. impact factors per technology. From this figure it is clear that the annual CO_2 reduction associated with IC engines is the only one which contributes to net reduction in emissions. This is because renewable-fueled IC engines are the only technology with associated CH_4 reductions due to the venting as baseline treatment of CH_4. Therefore, installation of CHP systems in instances where CH_4 is being vented to the atmosphere represents the greatest GHG emission reduction potential when compared to other technology and fuel type combinations installed under the SGIP. The baseline emissions are seen as the negative bars of the avoided emissions and are a combination of the electric power plant or grid related emissions that would have occurred in the absence of the generation facility, as well as the energy recovered from waste heat and its impact.

Figure 4-17: Annual CO_2Eq Impact Factor (Tons per MWh)

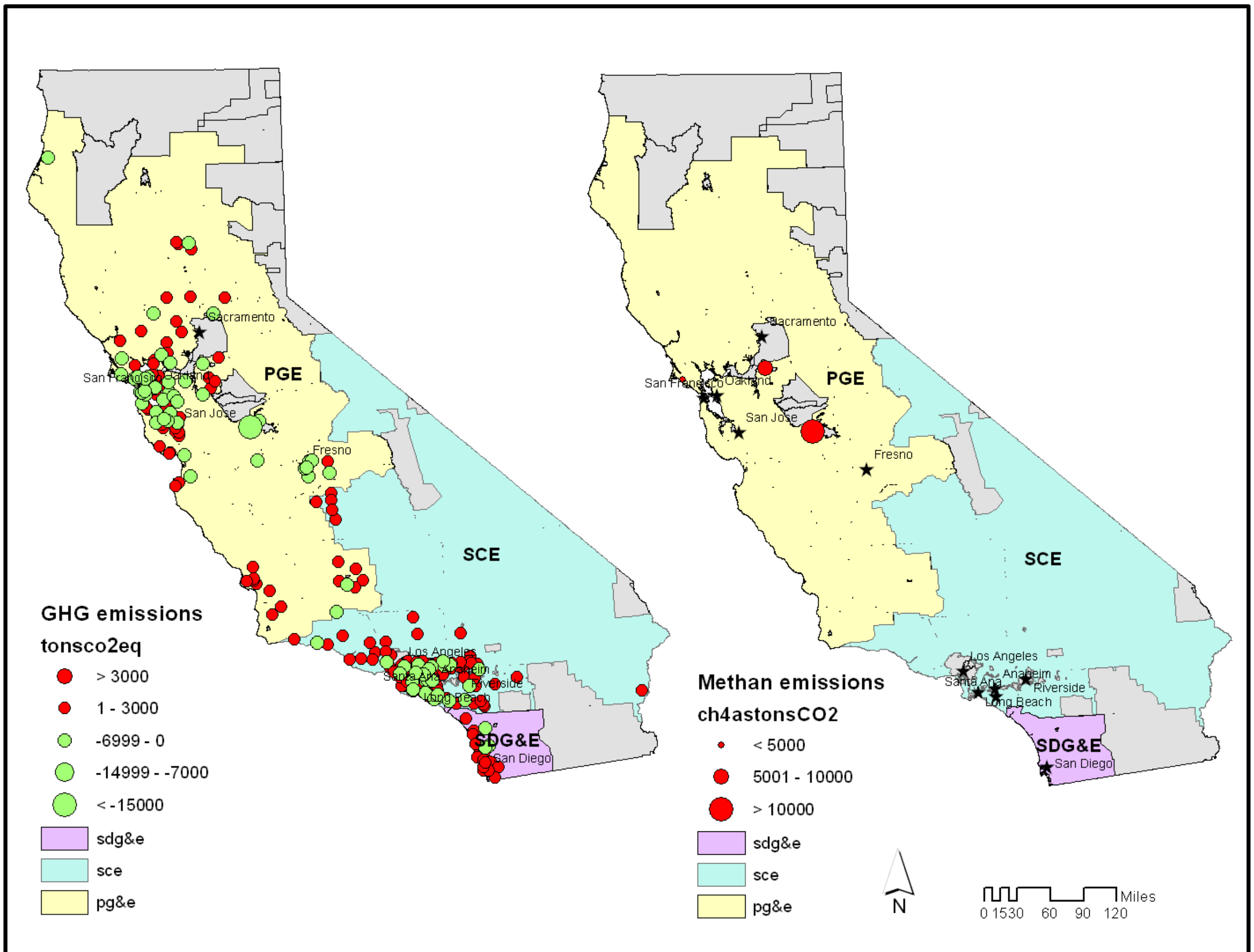


FC = Fuel Cell; ICE = Internal Combustion Engine; GT = Gas Turbine; MT = Microturbine

GHG emissions may increase pollution in stagnant areas. If these areas are urban this could have adverse effects on human health. Because of this and the increased interest in the impact of DG on GHG emissions, it is important to identify the geographical distribution of GHG emission impacts associated with the SGIP.

Figure 4-18 shows the geographical distribution of GHG emission impacts associated with SGIP facilities throughout California summed by zip code area. The figure on the left depicts the total GHG emission impacts from all sources within the SGIP facilities. The green dots imply a net reduction in emissions as summed in a zip code, while the red dots imply an increase in emissions due to the generation facilities in the zip code. The figure on the right shows only the locations of those biogas-fueled SGIP facilities providing CH_4-based GHG emission impacts. The GHG emission impacts (CO_2 and CH_4) associated with SGIP are scattered throughout California with the largest geographical impacts on areas where there are a higher number of SGIP facilities. The relatively large GHG emission impacts due to CH_4 capture occur from those few dairy digester-fueled systems that previously vented CH_4.

Figure 4-18: Geographic Distribution of GHG Emissions Impacts



GHG Emission Impacts by Program Administrator

Table 4-30 presents a summary of CO_2 emission reductions in 2010 by PA and technology group. A comparison of these tables show that the PA responsible for the largest impact of annual CO_2Eq emissions is PG&E (12,177 ton-decrease in CO_2 emissions) followed by SCE, CCSE, and SCG; all of which contributed to an increase in emissions. PG&E is also the only PA managing projects that include CO_2Eq emission impacts from CH_4, which was responsible for the net reduction.

Table 4-30: Technology-CO_2 Emission Impacts and Impact Factors for each PA

PA	Tons CO_2 Per Year		
Technology Type*	**SGIP Facility Emissions**	**Avoided Emissions**	**Net GHG Emissions**
PGE	**148,395**	**160,261**	**-12,178**
FC	16,737	15,912	512
GT	16,891	15,078	1,813
ICE	80,999	107,659	-26,656
MT	33,768	21,612	12,157
SCE	**46,878**	**39,754**	**7,124**
FC	2,995	2,588	407
ICE	34,828	31,434	3,394
MT	9,056	5,733	3,323
SCG	**169,577**	**147,434**	**22,137**
FC	7,984	7,419	565
GT	53,970	48,515	5,455
ICE	87,392	78,903	8,489
MT	20,230	12,603	7,627
CCSE	**53,629**	**41,038**	**12,591**
FC	4,222	4,108	114
GT	41,798	31,229	10,569
ICE	4,440	3,731	709
MT	3,169	1,967	1,198

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

In Table 4-31, PG&E is also the only one with a negative impact factor on a MWh basis (lowest impact factor -0.05), followed by SCE and SCG, both of which though positive are fairly low. CCSE has the highest impact factor (0.14), reflecting the maximum GHG emission impacts on a per MWh energy generation basis; this appears to be due to more gas turbines in the territory. Detailed tables of technology and fuel combination GHG values for each PA are available in Appendix B.

Table 4-31: Technology-CO_2 Emission Impacts and Impact Factors for each PA

PA / Technology Type*	Annual Energy (MWh)	Tons CO_2 per MWh: SGIP Facility Emission	Tons CO_2 per MWh: Avoided Emissions	Tons CO_2 per MWh: Net GHG Emissions
PGE	**237,544**	**0.62**	**0.67**	**-0.05**
FC	35,398	0.47	0.45	0.01
GT	29,205	0.58	0.52	0.06
ICE	132,768	0.61	0.81	-0.20
MT	40,174	0.84	0.54	0.30
SCE	**74,194**	**0.63**	**0.54**	**0.10**
FC	6,334	0.47	0.41	0.06
ICE	57,087	0.61	0.55	0.06
MT	10,773	0.84	0.53	0.31
SCG	**277,515**	**0.61**	**0.53**	**0.08**
FC	16,885	0.47	0.44	0.03
GT	93,315	0.58	0.52	0.06
ICE	143,246	0.61	0.55	0.06
MT	24,068	0.84	0.52	0.32
CCSE	**92,247**	**0.58**	**0.44**	**0.14**
FC	8,929	0.47	0.46	0.01
GT	72,269	0.58	0.43	0.15
ICE	7,279	0.61	0.51	0.10
MT	3,770	0.84	0.52	0.32

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

4.6 Overall Findings

4.6.1 Energy and Non-Coincident Demand Impacts

- Excluding wind, there is a total of 440 rebated systems in the SGIP, representing a generating capacity of 227 MW.
- Ninety percent of the electricity generated in SGIP projects is fueled by natural gas, while the balance is fueled by renewable resources.
- Fifty percent of the electricity is generated by IC engines and 28% by gas turbines, with both technologies contributing over 75% of the generation.
- IC engines have the lowest annual capacity factor, suggesting that successfully increasing the capacity factor could result in a significant increase in electricity generated by the SGIP.

4.6.2 PA-Specific Impacts

- Total energy generation was about 681 GWh.

- Two PAs (PG&E and SCE) represented over 75% of the energy generated within the SGIP during 2010.

4.6.3 Coincident Peak Demand Impact

- There was approximately 215 MW of SGIP CHP systems rebated during the CAISO 2010 peak day, and approximately 97 MW of CHP generation was on-line during the peak hour of the peak day. Overall, SGIP CHP systems had a CAISO peak hour capacity factor of 0.45 kW of peak hour generation per kW of rebated capacity.
- The SGIP CHP systems generally showed little sensitivity to CAISO hourly peak demand during the CAISO 2010 peak day. .
- Gas turbines had the highest annual capacity factor by technology.

4.6.4 Heat and Fuel Impacts

- SGIP CHP systems saved 1,678 billion Btu of gas through use of waste heat recovery operations.
- In 2010, fuel cells achieved the highest electrical efficiencies, while IC engines achieved the highest heat efficiencies. IC engines also achieved the highest overall system efficiencies.
- All technologies met the PUC 216.6(a) 5% requirement. Fuel cells and IC engines were the only technologies that achieved the 216.6(b) 42.5% efficiency requirement.

4.6.5 Greenhouse Gas Emission Impacts

- Overall, the program had positive GHG emissions for 2010 (29,725 tons of CO_2).
- Only renewable-fueled IC engines with a "vented" biogas basis had net negative GHG emissions.
- In general, the CO_2 emissions from the SGIP systems are greater than the CO_2 emissions from the grid-based electricity being displaced. Although useful waste heat recovery operations reduce CO_2 emissions that would have resulted from use of on-site boilers, the magnitude of the CO_2 emissions is insufficient to enable the non-renewable CHP systems to have net negative GHG emission values.
- With the exception of dairy biogas projects, SGIP CHP systems have net positive GHG emissions. Therefore, as currently configured, these systems are not contributing to the SGIP being a net GHG emission reduction program.
- Even if SGIP CHP systems were re-configured in order to have net negative GHG emissions, their low capacity factors would limit total annual GHG emission reductions.

5

The SGIP Fleet Moving Forward

California's experience with CHP systems has been a mixed bag of successes and challenges. On one hand, the SGIP has demonstrated that CHP systems provide clear benefits to California's electricity system. By providing electricity directly at utility customer site, CHP systems help reduce the need to use expensive peaking generators and help reduce congestion on the T&D system. CHP systems can also provide valuable GHG emission reduction benefits by displacing natural gas that would have otherwise been used to fuel on-site boilers. However, CHP performance has fallen short of expectations in a number of areas. Most CHP systems deployed under the SGIP have failed to meet required PUC 216.6(b) efficiency standards. In addition, the persistent decline in annual capacity factors across the range of CHP technologies indicate more systemic problems with sustaining benefits from CHP systems over the long-term.

In this section, we identify lessons learned from 10 years of operational history on CHP systems deployed under the SGIP. We use the lessons learned to help target potential ways to ensure sustained benefits from deployed CHP systems, including improving net GHG emission reductions. Lastly, we propose possible approaches for integrating biogas and directed biogas systems to help capture increased levels of GHG emission reductions.

5.1.1 Lessons Learned

Based on 10 years of operational history on CHP systems deployed in the SGIP, three key lessons become evident:

1. CHP systems in the SGIP have shown declining capacity factor over time and increasing amounts of extended outages as the systems age.
2. Most CHP systems in the SGIP have problems achieving the PUC 216.6(b) efficiency threshold of 42.5%.
3. CHP systems in the SGIP are increasing net GHG emissions relative to grid generated electricity rather than resulting in net GHG emission reductions.

Declining Capacity Factor Over Time and Increasing Amounts of Extended Outages

The previous sections provided information on the performance of CHP systems deployed under the SGIP. We observed that average annual capacity factor declined for most CHP technologies with aging of the system. Capacity factor can be influenced by a number of items including the design approach, economic conditions and maintenance of the system. As indicated in Section 3, we used ANOVA statistical analyses to investigate the possible influence of multiple factors on outage. Among the factors examined included age of the system, spark gap, technology type, building type, system size, developer experience and fuel type. Interestingly, the results indicated that project developers with multiple project experience had no fewer problems with outage than developers who only developed one project.

Our analysis was inconclusive on the impact of spark spread on outage even though earlier observations seemed to indicate a relationship. Moreover, Navigant seemed to establish a connection between the cost of generating electricity and capacity factor.[1] We also observed that nearly all CHP systems, regardless of generator type or facility type, showed an increase in non-operational time with aging. The consistently upward trend in the amount of non-operational time suggests that a decision to operate a CHP system or take it out of operation is influenced by more than just spark gap. Again, the Navigant interview results indicate that maintenance issues and slowness in response time from maintenance contractors were factors influencing system operation.[2]

The SGIP administrators may not have the ability to effect changes in spark spread. Natural gas and electricity prices are set by conditions that exceed the magnitude of the CHP market. However, program administrators (PAs) can establish screening criteria for selection of CHP projects that take into account the influence of spark spread. In Massachusetts, PAs considering potential CHP projects require the projects to pass benefit/cost tests as part of the eligibility criteria. If used in conjunction with actual electrical and thermal load data from prospective CHP sites, a benefit/cost screening test could help identify if the site has matching thermal and electrical loads sufficient to operate most of the year at close to the capacity of the system. Sites that have little matching coincident electrical and thermal loads may only capture one savings stream, or operate at fewer hours of the year, thereby reducing the return on the invested capital. Conversely, sites with high coincidence of electrical and thermal loads may be in a better position to weather changes in spark spread.

We also observed that CHP electrical efficiency and useful waste heat recovery efficiency in the SGIP appeared to be reasonably stable over the warranty period of the CHP system. However, performance appeared to often decline rapidly for IC engines and microturbines once the system went out of warranty. In addition, there was significant change in the make-up of project developers and equipment manufacturers over the first six years of the SGIP. One result of these changes may have been a decrease in the CHP industry infrastructure and therefore the ability to provide timely maintenance support across the large number of CHP systems operating in the

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[1] Navigant Consulting, *Self-Generation Incentive Program: Combined Heat and Power Performance Investigation*, April 1, 2010, pg. 56.

[2] Ibid, pg. 58.

SGIP. The CPUC staff proposal on the SGIP includes recommendations on longer-term service warranties that may help address equipment service issue.

Problems Achieving the PUC 216.6(B) Efficiency Threshold of 42.5%

As discussed in section 4, IC engines, gas turbines and microturbines consistently had problems achieving the threshold efficiency levels required under PUC 216.6(b). PUC 216.6(b) reflects the combined electrical and thermal efficiency of CHP systems. In general, we observed that the electrical conversion efficiency of most CHP systems remained relatively flat over time. In addition, with the exception of gas turbine technologies, we did not see any significant increases in electrical conversion efficiency with new generator technologies by vintage (i.e., calendar year the CHP generator went into service). Consequently, any flexibility in the ability of a CHP system to achieve the PUC 216.6(b) efficiency threshold is influenced primarily by the system's ability to recover useful thermal energy. However, the thermal and electrical performance of CHP systems is interwoven. For most CHP systems, achieving a high electrical efficiency requires the generator to be operating close to full rated capacity. When the generator is operating at close to full capacity, it is producing a significant amount of waste heat. If the produced waste heat is not captured and harnessed for useful purposes, the useful thermal efficiency of the system is low, and the system will likely fail to achieve the PUC 216.6(b) threshold efficiency. For the CHP system to successfully achieve and succeed the PUC 216.6(b) threshold efficiency, the host site must have sufficiently high thermal demand coincident to the electrical demand. Table 5-1 shows that in 2010, CHP systems using gas turbines fell slightly below PUC 216.6(b) requirements while microturbines would require approximately a 23% increase in useful heat conversion efficiency to achieve the PUC 216.6(b) efficiency threshold.[3]

Table 5-1: Efficiency Contributions and Required Useful Heat Conversion Efficiency

Technology	Electrical Conversion Efficiency (%,LHV)	Useful Heat Conversion Efficiency (%,LHV)	216.6 (b) Efficiency (%, LHV)	Required Useful Heat Conversion Efficiency (%, LHV)
FC	40.0%	11.7%	45.8%	NA
GT	32.7%	17.3%	41.4%	19.6%
ICE	30.9%	31.6%	46.7%	NA
MT	22.5%	17.0%	31.0%	40.0%

Going forward, PAs may want to consider linking eligibility of CHP projects to minimum useful waste heat conversion efficiencies that reflect thermal demand coincident with the electrical demand at the site. In 2006, Itron prepared and submitted to the SGIP administrators a

[3] Additional information on CHP electrical and thermal efficiency is contained in Section 4.4.

workbook on useful thermal waste heat recovery. The workbook can be used by CHP system developers to identify and document coincident electrical and thermal demands at sites considering installation of CHP systems under the SGIP. It can also be used to flag if the project will exceed PUC 216.6(b) requirements based on the CHP system meeting coincident electrical and thermal loads.

<u>CHP Systems in the SGIP Are Increasing Net GHG Emissions</u>

As of the end of 2010, SGIP projects generated close to 30,000 tons per year (CO_2 equivalent) of net increases in GHG emissions. Review of the net GHG emissions showed that only "vented" biogas projects resulted in net GHG emission reductions. Clearly, if the SGIP is to become a net GHG emission reduction program, steps must be taken to ensure the majority of CHP systems have net negative GHG emissions. We began investigating sources of the GHG emissions for the different CHP systems deployed in the SGIP.

In general, CHP systems in the SGIP can be classified into three groups:

- Natural gas fueled systems
- Biogas fueled systems with a basis of "flared"; and
- Biogas fueled systems with the basis of "venting"

As described in Section 4, biogas systems with a basis of "venting" have net negative GHG emissions due to capture of methane that would otherwise have been emitted to the atmosphere. Unlike "vented" biogas projects, biogas projects with a basis of "flared" do not get credit for captured methane. In addition, biogas-fueled systems in the SGIP do not receive credit for CO_2 emission reductions associated with waste heat recovery operations. This is due to the treatment of renewable fuel use projects early in the SGIP. In particular, renewable fuel use projects were not required to install waste heat recovery systems. Also, because renewable fuel projects are not required to recover waste heat, only limited metering of waste heat recovery operations has been conducted. Consequently, there is no basis upon which to estimate GHG emission reductions possibly due to useful waste heat recovery. Nonetheless, 34 of the 50 installed renewable fuel use projects employ waste heat recovery.[4] Because biogas-fueled projects with a basis of "flared" cannot get credit for captured methane, they can only achieve net GHG emissions by either increases in electrical conversion efficiency or increased useful waste heat recovery.

[4] Itron,Inc., *Self-Generation Incentive Program: Semi-Annual Renewable Fuel Use Report, Number 17 for the Six-Month Period Ending December 31, 2010,* pg. 11.

Natural gas-fueled CHP systems currently represent the largest source of increased GHG emissions for the SGIP. Like "flared" biogas projects, these systems must either realize increased electrical conversion efficiency or increased useful waste heat recovery to achieve net GHG emission reductions.

Developing a Net GHG Emissions Nomograph

In order to determine if SGIP CHP systems could be re-configured so as to have net negative GHG emissions, we examined the relationship between GHG emissions and CHP electrical and useful waste heat recovery efficiencies.

Based on our examination, we have found that the rate of net GHG emission reductions is related to the electrical efficiency of the prime mover[5], the useful waste heat recovery efficiency of the CHP system and the average electrical efficiency of grid-supplied electricity as follows:[6]

Equation 5-1

$$net\ GHG\ \left(\frac{lb\ of\ CO_2}{kWh}\right) \propto 0.43\ \left(\frac{1}{\eta_{\mathrm{PM\ elec}}} - \frac{1}{\eta_{\mathrm{GridElec}}} - 1.125\ \frac{\eta_{\mathrm{WHR\ TU}}}{\eta_{\mathrm{PM\ elec}}}\right)$$

Where:

$\eta_{\mathrm{PM\ elec}}$ = electrical conversion efficiency of the CHP prime mover

$\eta_{\mathrm{WHR\ TU}}$ = useful waste heat recovery efficiency

η_{GridElec} = average electrical efficiency of grid-supplied electricity

Several important observations result from examining Equation 5-1 in light of electrical grid efficiencies during peak and off-peak hours. We assumed the average electrical efficiency of grid-supplied power is 48% during off-peak hours.[7] Consequently, if there is no waste heat recovery (i.e.,$\eta_{\mathrm{WHR\ TU}} = 0$), the efficiency of the CHP prime mover must be at least 48% for the CHP system to have net GHG emissions of zero or be negative. If the efficiency of the prime mover is less than 48%, then the efficiency of the waste heat recovery system must make up for any net positive GHG emissions due to the difference in net CO_2 emissions between the prime mover and the grid-based electricity sources.

5 Prime mover refers to the specific equipment used to generate electricity from the CHP system. For the SGIP, prime movers consist of IC engines, microturbines, fuel cells and small gas turbines.

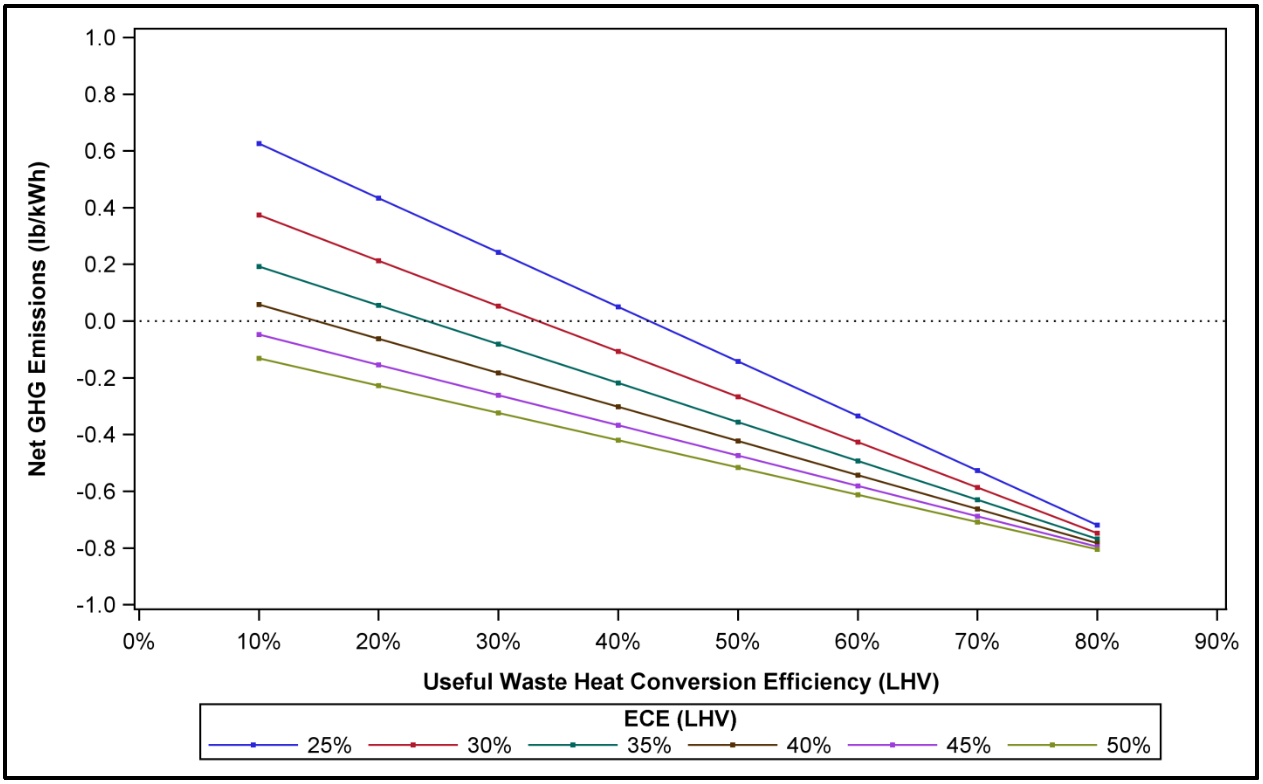
6 A more complete discussion of the derivation of this equation and critical assumptions is found in Appendix E.

7 This is the average electrical efficiency of the mix of electricity sources during off-peak hours used in the E3 avoided cost workbooks and is the basis of the GHG analysis in the SGIP impact evaluation.

By assuming that the electrical conversion efficiency of off-peak electricity is 48%, Equation 5-1 can be used to determine the impact of different useful waste heat recovery efficiencies on net GHG emissions for different prime mover efficiencies during off-peak hours.

Figure 5-1 is a nomograph showing the relationship of CHP prime mover electrical conversion efficiencies and useful waste heat recovery efficiencies on net GHG emissions. The horizontal axis represents the useful waste heat recovery efficiency. The diagonal lines represent the different prime mover electrical efficiencies of 25%, 30%, 35%, 40%, 45% and 50%, respectively. The vertical axis represents the corresponding net GHG emission rate in pounds of CO_2 equivalent per kilowatt-hour of generated electricity (lb/kWh). For example, a prime mover with an electrical conversion efficiency of 25% and a useful waste heat recovery efficiency of 40% would have a net positive GHG emission rate of 0.05 lb/kWh; and would be a net GHG emission contributor. However, if the same prime mover had a useful waste heat recovery efficiency of 45%, the net GHG emission rate would be negative 0.05 lb/kWh and result in GHG emission reductions.

Figure 5-1: Net GHG Emissions as a Function of Electrical Conversion Efficiency and Useful Waste Heat Recovery Efficiency



To test the validity of the nomograph, we examined observed values of electrical efficiencies against estimated net GHG emissions for the all metered systems in the SGIP. The results are shown below in Figure 5-2. The thin narrow red band refers to on-peak hour observances, while the thicker blue band refers to off-peak observances. In general, the electrical efficiency that is associated with net zero GHG emissions during on-peak hours is approximately 28% and for off-peak hours is approximately 40%. This compares relatively well with the model results, which predicated that 48% electrical efficiencies would have to be achieved to obtain net zero GHG emissions on off-peak hours and 27% electrical efficiencies would have to be achieved to obtain net zero GHG emissions on on-peak hours.

Figure 5-2: Observed Electrical Efficiencies and Estimated GHG Emission Reduction Rates for On-Peak and Off-Peak Hours

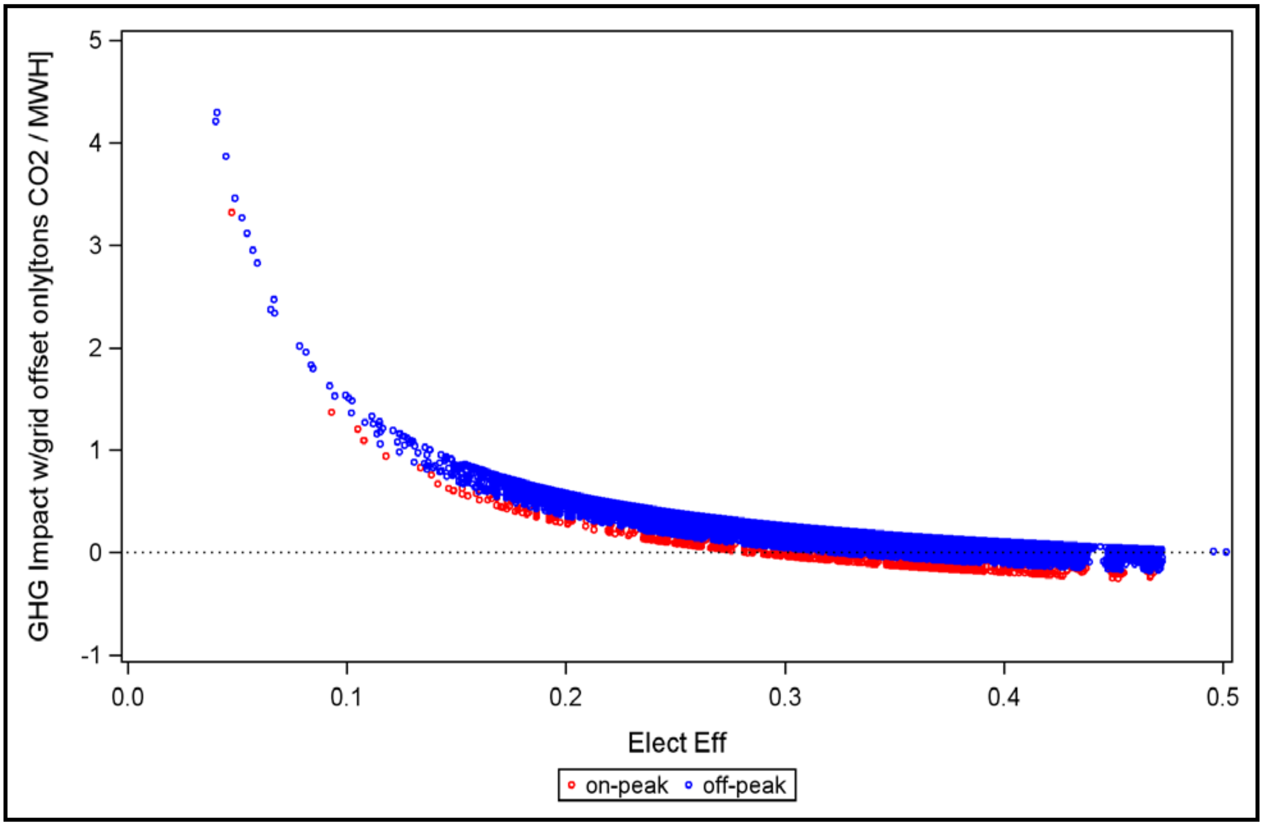
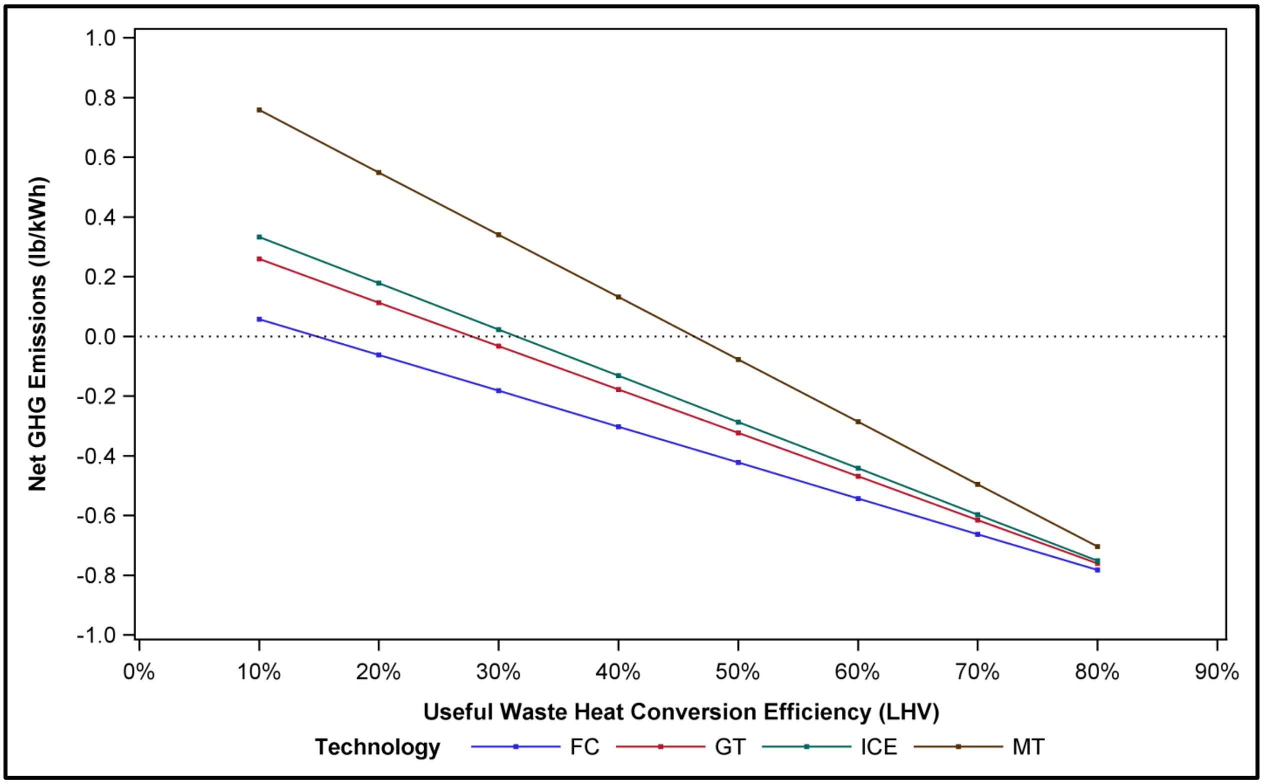


Figure 5-3 is a GHG emissions nomograph specific to the CHP technologies being deployed in the SGIP. The nomograph allows us to develop net GHG emission targets for natural gas powered fuel cells, microturbines, IC engines, and gas turbines at different levels of useful waste heat recovery efficiency.

Figure 5-3: Net GHG Emissions for SGIP CHP Technologies as a Function of Electrical Conversion Efficiency and Useful Waste Heat Recovery Efficiency



<u>*Developing Net Zero and Negative GHG Emission Rates for Natural Gas-Fueled CHP Systems*</u>

We do not expect significant changes in the electrical conversion efficiency of CHP prime movers in the near term. Consequently, the role of waste heat recovery efficiency on net GHG emission rates is critical. The same approach used in developing the nomograph can be used to examine the levels of useful waste heat recovery for existing SGIP CHP systems to reach net zero GHG emission rates. This approach uses the observed electrical conversion efficiencies of the CHP prime movers.

Table 5-2 is a listing of the useful waste heat recovery efficiencies needed for SGIP CHP systems to achieve net zero GHG emissions at currently observed prime mover electrical conversion efficiencies. Values of needed useful waste heat recovery efficiencies are provided for both peak and off-peak hours.[8]

Table 5-2: Useful Waste Heat Recovery Efficiencies Needed to Achieve Net Zero GHG Emission Rates for SGIP CHP Systems

Technology	Avg Electrical Efficiency (%)	Grid Source Efficiency (%)	WHR_{TU} Efficiency (%)	WHR_{TU} Ratio (kBtu/kWh)
		On Peak Hours		
Microturbines	23%	27%	15%	1.95
Small Gas Turbines	27%	27%	0%	0.00
IC Engines	28%	27%	-3%	-0.40
Fuel Cells with WHR	46%	27%	-37%	-4.64
		Off Peak Hours		
Microturbines	23%	48%	97%	6.87
Small Gas Turbines	27%	48%	69%	4.91
IC Engines	28%	48%	63%	4.51
Fuel Cells with WHR	46%	48%	4%	0.27

The useful waste heat recovery efficiencies in Table 5-2 can be compared to the observed 2010 mean useful waste heat recovery efficiencies reported in section 4. Because off-peak hours constitute the vast majority of operating hours during the year, we focus only on off-peak hours.

- For microturbines, with an observed electrical conversion efficiency of 23%, a useful waste heat recovery efficiency of 97% would be needed to achieve a net zero GHG emission rate. At present, microturbine-based CHP systems in the SGIP show useful waste heat recovery efficiencies ranging from 15% to 30% (and showed a 2010 efficiency of 17.9%)
- For small gas turbines, with an observed electrical conversion efficiency of 27%, a useful waste heat recovery efficiency of 69% would be needed to achieve a net zero GHG emission rate. At present, small gas turbine-based CHP systems in the SGIP show useful waste heat recovery efficiencies ranging from 15% to 60% (and showed a 2010 efficiency of 18.6%).

[8] Again, from the E3 avoided cost workbook, the electricity conversion efficiency of off-peak grid sources is 48% (essentially the efficiency of combined cycle systems) and 27% for peak grid sources (essentially the electrical conversion efficiency of simple cycle combustion turbines). The values in the table and nomograph would change accordingly with changes in the electrical conversion efficiencies of on-peak and off-peak grid sources.

- For IC engines, with an observed electrical conversion efficiency of 28%, a useful waste heat recovery efficiency of 63% would be needed to achieve a net zero GHG emission rate. At present, IC engine-based CHP systems in the SGIP show useful waste heat recovery efficiencies ranging from 10% to 35% (and showed a 2010 efficiency of 33.0%).
- For fuel cells employing waste heat recovery, with an observed electrical conversion efficiency of 46%, a useful waste heat recovery efficiency of 4% would be needed to achieve a net zero GHG emission rate. At present, fuel cell-based CHP systems in the SGIP employing waste heat recovery show useful waste heat recovery efficiencies ranging from 5% to 20% (and showed a 2010 efficiency of 13.8%).

Note that the above useful waste recovery efficiencies are based on several critical assumptions including:

- We assume there is coincidence[9] of electrical and thermal loads being serviced by the CHP system; and
- We assume the CHP system is sized appropriately to ensure there is no significant dumping of recovered waste heat from the prime mover.

We can also use the SGIP GHG 2010 results to identify the total level of net GHG emissions that would be associated with achieving net zero GHG emission levels and then net negative GHG emission of 10% and 20% lower than net zero GHG emission levels.

[9] Coincidence of electrical and thermal loads is critical because as the prime mover operates, it generates waste heat. If there is no thermal load at the site when the generator is being operated to produce electricity, the generated waste heat is dumped to the environment. As a result, on-site boiler fuel is not offset and so there are no associated reductions in CO_2 emissions.

Table 5-3 summarizes the different useful waste heat recovery efficiencies that would need to be realized for SGIP non-renewable-fueled CHP systems to achieve target levels of zero, 10% below zero and 20% below zero net GHG emissions. Note that the net GHG targets are based on the 2010 impact year and as such illustrate the useful waste heat recovery efficiencies that would have to been realized for this portfolio of systems to achieve the targets.

Table 5-3: Useful Waste Heat Recovery Efficiencies at Different Net GHG Targets for Non-Renewable CHP Systems

Technology Type	2010		Zero Net GHG	
	Useful Waste Heat η_{WHR}	GHG Emissions (Tons/yr)	Useful Waste Heat η_{WHR}	GHG Emissions (Tons/yr)
FC	12%	546	25%	0
GT	17%	17,838	51%	0
ICE	32%	10,130	57%	0
MT	17%	21,593	87%	0
Total	NA	50,107	NA	0
Technology Type	**10% GHG Below Zero**		**20% GHG Below Zero**	
	Useful Waste Heat η_{WHR}	**GHG Emissions (Tons/yr)**	**Useful Waste Heat η_{WHR}**	**GHG Emissions (Tons/yr)**
FC	27%	-601	28%	-656
GT	65%	-19,621	66%	-21,405
ICE	62%	-11,143	62%	-12,156
MT	118%	-23,752	121%	-25,912
Total	NA	-55,118	NA	-60,129

To achieve a net negative GHG emission target of 10% below zero, the useful waste heat recovery efficiency of the non-renewable CHP technologies would have to increase as follows:

- Fuel cells: increase from 14% to 27%
- Gas turbines: increase from 19% to 65%
- IC engines: increase from 33% to 62%
- Microturbines: increase from 18% to 121%

If non-renewable CHP systems operating at the end of 2010 had realized a 10% GHG emission rate below the net zero level, the end result would have been a net reduction of over 55,000 tons per year of GHG emissions (CO_2Eq). Fuel cell systems would have had to realize useful waste heat recovery efficiencies of nearly 30%, while gas turbines and IC engines would have had to realize useful waste heat recovery efficiencies of over 60% to achieve this goal. While the useful waste heat recovery efficiencies for gas turbines and IC engines may be challenging, a 30% target for fuel cells is currently achieved by other CHP systems in the SGIP. In contrast, microturbines as currently configured would not be able to realize the theoretical useful waste heat recovery efficiency of over 100% needed to achieve a net GHG emission target of 10% below net zero.

Developing Net Zero and Negative GHG Emission Rates for Biogas "Flared" CHP Systems

Due to the lack of metered heat data, we do not know the useful waste heat recovery efficiency of biogas systems that are basis of "flared" and use waste heat recovery systems. Nonetheless, we can still estimate the amount of useful waste heat recovery these systems would have to realize to achieve zero or negative GHG emission rates.

Table 5-4 is a summary of the different useful waste heat recovery efficiencies needed for SGIP renewable fueled (basis of "flared") systems to achieve target levels of zero, 10% below zero and 20% below zero net GHG emissions.

Table 5-4: Useful Waste Heat Recovery Efficiencies at Different Net GHG Targets for Renewable "Flared" SGIP Systems

	2010		Zero Net GHG	
	Useful Waste Heat	GHG Emissions	Useful Waste Heat	GHG Emissions
Technology Type	η_{WHR}	(Tons/yr)	η_{WHR}	(Tons/yr)
FC	UNK	1,103	25%	0
ICE	UNK	3,847	57%	0
MT	UNK	2,713	88%	0
Total	NA	7,663	NA	0
	10% GHG Below Zero		**20% GHG Below Zero**	
	Useful Waste Heat	**GHG Emissions**	**Useful Waste Heat**	**GHG Emissions**
Technology Type	η_{WHR}	**(Tons/yr)**	η_{WHR}	**(Tons/yr)**
FC	37%	-1,213	38%	-1,323
ICE	71%	-4,232	72%	-4,616
MT	131%	-2,984	135%	-3,256
Total	NA	-8,429	NA	-9,195

At present the amount of useful waste heat recovery efficiency at these sites is unknown (UNK). However, renewable fueled projects with a "flared" basis can realize net zero GHG emission levels by achieving the following useful waste heat recovery efficiencies:

- Fuel cells: 25%
- IC engines: 57%
- Microturbines: 88%

If renewable fuel, "flared" fuel cell and IC engine projects operating at the end of 2010 had realized a 10% GHG emission rate below the net zero level, the end result would have been a net GHG emission reduction close to 5,500 tons per year of GHG emissions (CO_2 Eq). However, net GHG emission reductions of somewhat less than 5,500 tons per year are more realistic given the high useful waste heat recovery efficiency required for IC engines.

Estimating the Impact of Increased Biogas "Vented" Projects on Net GHG Emissions

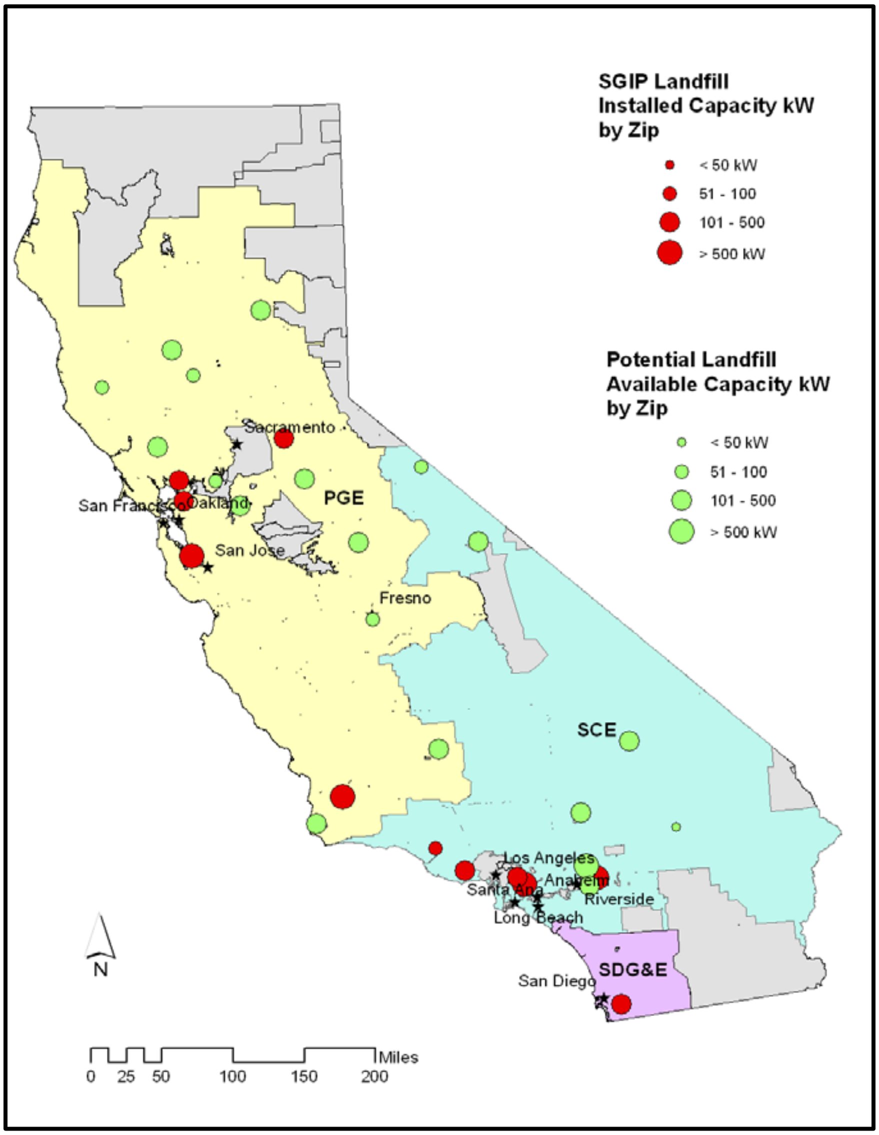
As noted earlier, the only SGIP systems in 2010 that achieved net GHG emission reductions were renewable fueled projects that had a basis of "venting." At present, the only renewable fueled SGIP projects with a "venting" basis are dairy digester systems. These projects have a "venting" basis because diaries are not required to collect and flare biogas generated from dairy waste disposal operations. Instead, methane generated from the naturally occurring decomposition of dairy waste is released directly into the atmosphere. As such, dairies employing digesters are able to claim credit for capture of methane contained in the biogas that would otherwise have been emitted to the atmosphere. However, in addition to dairy digester projects, it is feasible that very small landfill gas to energy projects could qualify as renewable "venting" projects.

We examined statewide biogas potential in order to assess the ability for additional renewable "venting" projects to be deployed under a future SGIP.

Potential for Landfill Gas to Energy Projects

California has over 500 active landfills and about 10% of these are small scale sites; many of which currently do not collect landfill gas for energy purposes. To qualify as renewable "venting" projects, these landfills would have to be exempt from landfill gas collection and flaring requirements. Figure 5-4 depicts locations of aggregated small landfill gas to energy project capacities for landfills that could potentially have a "venting" basis. While it may not be economically or politically feasible to add a CHP system to all these small landfills, Figure 5-4 clearly shows that there is more potential capacity at landfills than what is currently deployed under the SGIP. We estimate that a minimum of 3-5 MW of potential "venting" landfill gas projects could be available for possible deployment in a future SGIP.

Figure 5-4: California Small Landfill Gas to Energy Potential and Existing SGIP Rebated Capacity



Source: Department of Resources, Recycling, and Recovery – Solid Waste Information System

Potential for Dairy Biogas Projects

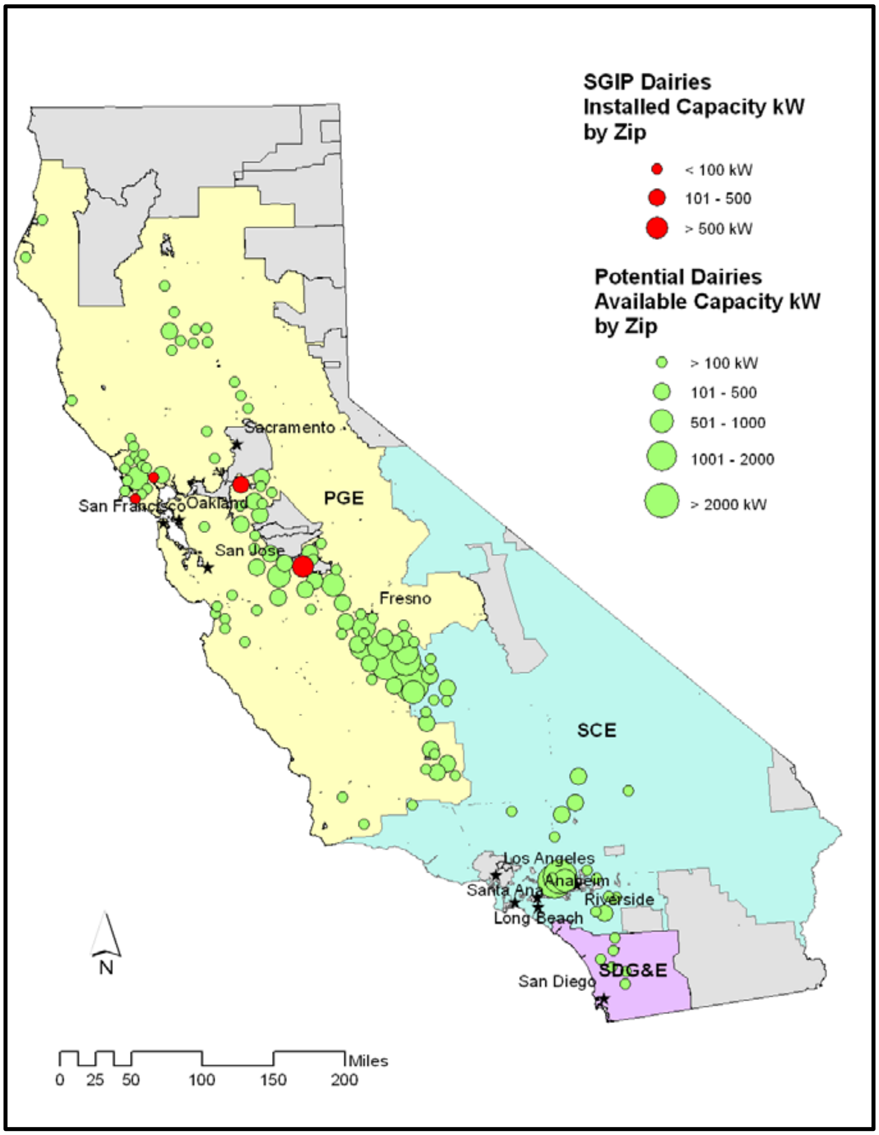
California is the largest dairy state in the country with close to 1,800 diaries. Although the average herd size is over 1,000 cows, there are many dairies with dairy herd sizes of 600 to 800 cows.[10] A dairy herd of 600 cows could generate approximately 30 kW of power from a dairy biogas project.[11] We examined the potential for additional dairy biogas projects in the state.

[10] California Department of Food and Agriculture, "California Dairy Statistics: 2010," http://www.cdfa.ca.gov/dairy/dairystats_annual.html.

[11] Conversion of dairy wastes from an average cow is approximately equal to 50 to 100 Watts depending on digester type and operation.

Figure 5-5 depicts the locations and potential aggregated dairy digester gas project capacities in California. As with landfills, there is an untapped renewable "venting" project potential in California. We estimate that nearly 35 MW of potential dairy digester gas projects could be available for possible deployment in a future SGIP.

Figure 5-5: California Dairy Digester Gas to Energy Potential and Existing SGIP Rebated Capacity



Source: California Energy Commission; personal communication with Z. Zhang on 5/3/2011

Given the potential for renewable "venting" projects, we examined the impact of adding "venting" projects on net GHG emission reductions. Table 5-5 shows the additional renewable "venting" capacity needed to achieve 10%, 20% and 200% reductions in net GHG emissions relative to the 2010 levels already achieved by SGIP "venting" projects. In general, the addition of approximately 100 kW of new "venting" projects would capture an additional 2,800 tons per year of GHG emission reductions. Adding 1 MW of new "venting" projects would capture over 50,000 tons per year of GHG emission reductions. This amount of GHG reduction would have made the SGIP in 2010 a net GHG reduction program. To put this in perspective, 1 MW of new "venting" projects is roughly equal to 33 new dairy biogas projects located at diaries with at least 600 cows.

Table 5-5: Increases Needed to Achieve Different Net GHG Targets for Renewable "Vented" SGIP Systems

Target	Electricity Generated (MWh/yr)	Capacity (kW)	Net GHG (Tons/yr)
2010 Basis	6,287	1,015	-28,045
10% GHG reduction	6,917	1,117	-30,850
20% GHG reduction	7,546	1,218	-33,654
200% GHG reduction	12,576	2,030	-56,090
Makes up all SGIP net	17,743	2,865	-79,135

There are challenges to locating new dairy or small landfill gas projects in California. A thorough discussion of the barriers to developing small scale "venting" biogas projects is outside the scope of this report. However, the challenges include often contradictory policies and regulations regarding permitting of biogas to energy projects; high transaction costs associated with developing small scale projects; lack of capital for project development and confusion over utility interconnection processes.

In spite of these challenges, renewable "venting" project can help the SGIP achieve significant reductions in GHG emissions. In addition, CHP projects fueled by on-site biogas were found to have among the highest societal and participant benefit-to-cost ratios of a variety of DG technologies examined in a recently conducted DG cost-effectiveness study.[12]

[12] Itron, "Self-Generation Incentive Program: Cost-Effectiveness of Distributed Generation Technologies," Final Report, February 9, 2011

Table 5-6 presents a summary of the SGIP-wide impacts of targeting non-renewable, biogas "flared" and biogas "venting" projects to achieve GHG emissions at zero, 10% below zero and 20% below zero levels. At the end of 2010, the SGIP generated nearly 30,000 tons per year of GHG emissions (CO_2Eq.). By instituting targets to achieve zero net GHG emissions, the SGIP would achieve a net GHG emission reduction of over 28,000 tons per year (CO_2Eq.). At targets of 10% below zero, the SGIP would achieve over 94,000 tons per year of GHG emission reductions (CO_2Eq.).

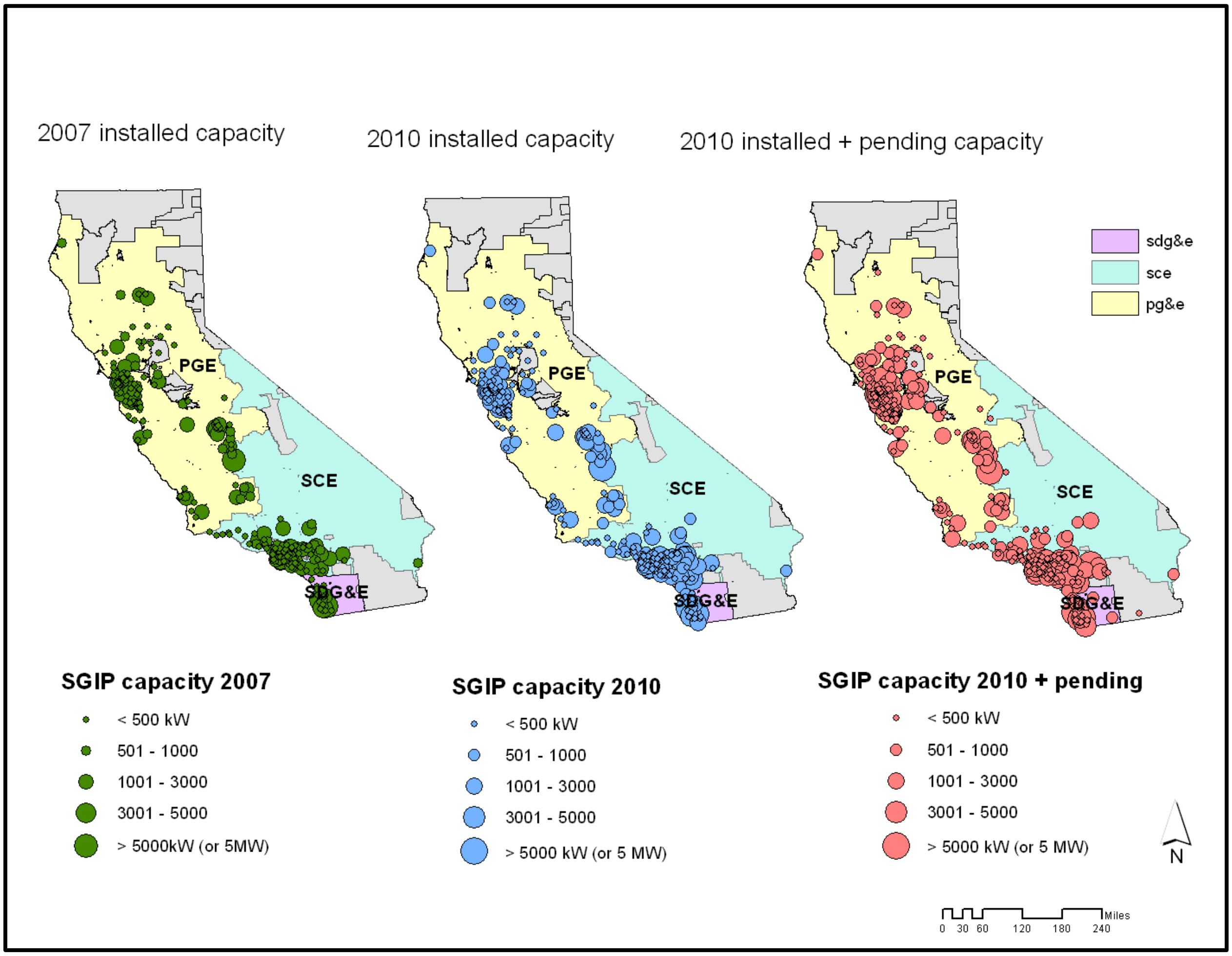
Table 5-6: Overall Impact of Targeting SGIP Projects on Net GHG Emissions

Observed/Goals	BioGas-Vented	Biogas-Flared	NatGas	Total (Tons CO_2/yr)	Net Total (Tons CO_2/yr)
2010 Net GHG (tons CO_2/yr)	-28,045	7,663	50,057	29,675	29,675
Zero emissions	Already below				
Needed reductions	0	7,663	50,057	57,720	-28,045
10% reduction					
Needed reductions	2,804	8,429	55,062	66,296	-94,341
20% reduction					
Needed reductions	5,609	16,858	110,125	132,592	-132,592

5.1.2 The Future of the SGIP

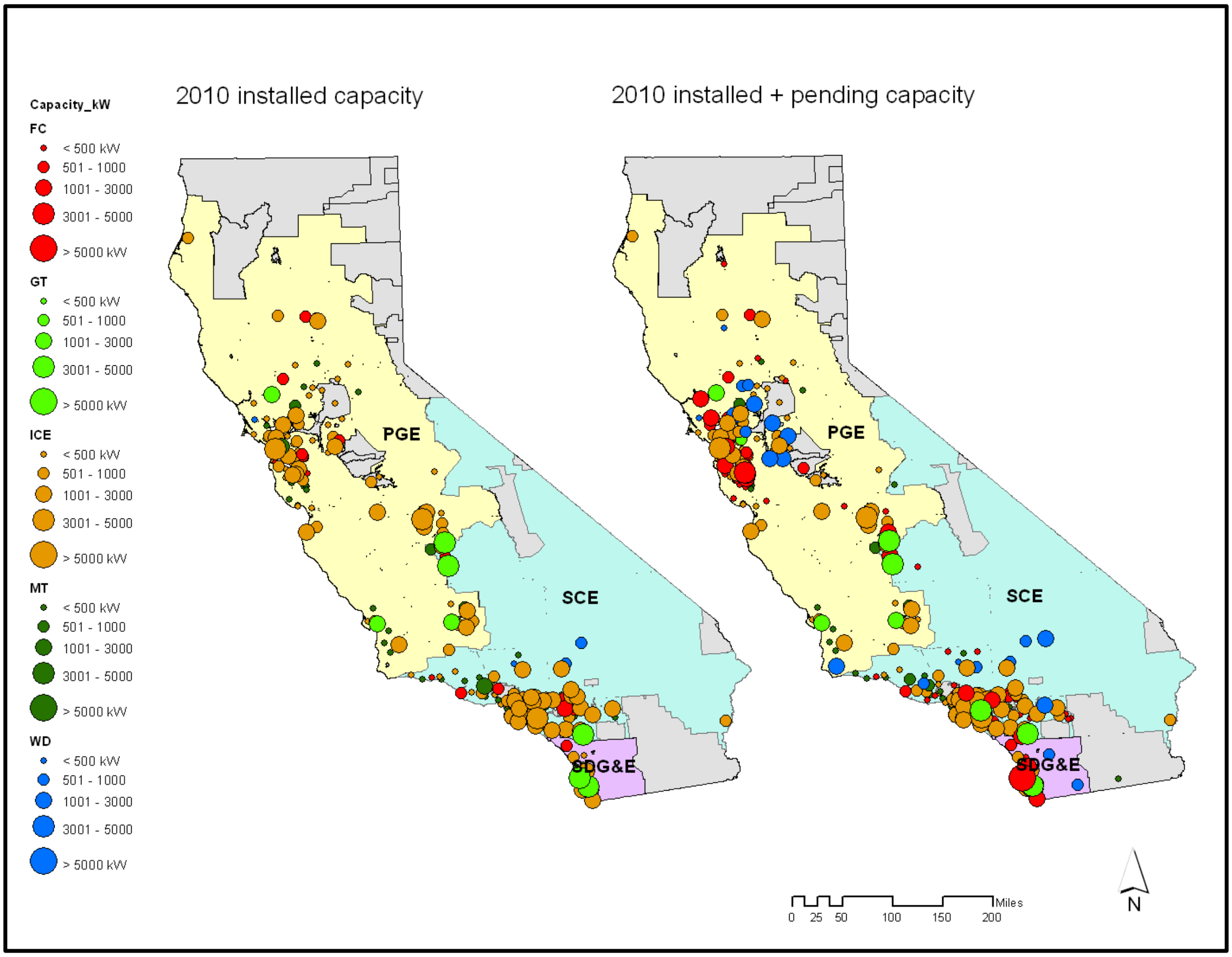
The rebated capacity of the SGIP fleet from 2007 through the future is presented graphically in Figure 5-6 summed by zip code.

Figure 5-6: Past, Current, and Future Potential SGIP Rebated Capacity



Since the restructuring of the program in 2007 to allow only fuel cell and wind projects, the program has shown moderate growth in rebated capacity. However, when accounting for all the active potential capacity waiting to enter "Check Issued" stage, it becomes clear that large capacity additions are on the way both in PG&E territory and in Southern California. Figure 5-7 provides a closer look at future potential capacity by type of technology.

Figure 5-7: SGIP 2010 and Future Rebated Capacity by Technology



Legislative changes in late 2006 restricted eligibility of projects in the SGIP largely to fuel cells and wind technologies. However, the map on the left side of Figure 5-7 shows that in 2010 the program still consisted primarily of IC engines and turbines. Looking at the active capacity with reserved incentives on the map on the right side of Figure 5-7, it shows a large amount of fuel cells and wind turbines are slated to enter the program; primarily in PG&E and SDG&E territories. The vast majority of these fuel cell systems will be fueled by directed biogas.

Directed biogas technologies have some key advantages relative to on-site biogas projects. First, because directed biogas projects can be developed outside of California, they avoid most of the regulatory and policies challenges that face biogas projects being developed within the state. Second, directed biogas projects focus on obtaining biogas supplies from large biogas sources; such as large landfills. As such, they avoid the high transaction costs typically associated with small scale “venting” biogas projects. However, it is unclear if directed biogas projects will provide high levels of GHG emission reductions. As noted, directed biogas projects focus on securing supplies of biogas from large biogas sources. Federal regulations regarding collection and flaring of landfill gas from these sources may result in the basis of the directed biogas projects being “flared.” If the basis of directed biogas projects becomes one of “flared,” the projects will not have GHG emission benefits associated with capture of methane. This would significantly reduce the GHG emission benefits of directed biogas projects.

The CPUC and PAs should investigate the basis of directed biogas projects to determine the feasibility of these projects providing expected levels of net GHG emission reductions.

5.2 Key Findings

- Increased outages and reduced capacity factors appear to be directly related to system age. Other studies have indicated that reduced capacity factor is linked to issues with equipment maintenance and warranty; and increased cost of generating electricity.
- Maintenance agreements and warranties that span a significant amount of the useful life of the critical CHP system equipment will help prevent increased outages.
- CHP projects that are based on coincident electrical and thermal loads have more attractive economics. As such, these projects may be more likely to be well maintained and kept operating even if fuel prices increase.
- For a CHP system to successfully achieve and succeed the PUC 216.6(b) threshold efficiency, the host site must have sufficiently high thermal demand coincident to the electrical demand.
- Going forward, PAs may want to consider linking eligibility of CHP projects to minimum useful waste heat conversion efficiencies that reflect thermal demand coincident with the electrical demand at the site.
- Net GHG emissions can be linked quantitatively to electrical conversion and useful waste heat recovery efficiencies of CHP systems. The development of a GHG emissions nomograph allows PAs and the CPUC to set net GHG emission rate targets for CHP systems deployed in the SGIP. These targets will help drive ensure the SGIP reduces rather than increases net GHG emissions.
- CHP systems fueled by non-renewable fuels can be targeted to achieve zero, 10% below zero and 20% below zero net GHG emissions through increased useful waste heat recovery efficiencies.

- At GHG emission targets of 10% below zero, the SGIP would reduce up to 55,000 tons per year of net GHG emissions. However, these targets require significantly higher useful waste heat efficiencies than currently achieved with SGIP CHP systems.
- Adding 1 MW of new “venting” projects would capture over 50,000 tons per year of GHG emission reductions. This amount of GHG reduction would have made the SGIP a net GHG reduction program in 2010 instead of a net GHG contributor.
- The challenges to adding new renewable “venting” projects include often contradictory policies and regulations regarding permitting of biogas to energy projects; high transaction costs associated with developing small scale projects; lack of capital for project development; and confusion over utility interconnection processes.

Appendix A

Energy and Capacity Factor Impacts

A.1 Overview

This appendix summarizes energy and demand impacts, and relative capacity factors performance of the tenth-year impact evaluation. It describes demand impacts and capacity factors for the CAISO peak day as well as for the individual electric utility peak days. This appendix presents results for the program annual energy impacts, peak demand and annual capacity factors.

Reporting of overall program results and of annual energy by technologies includes a distinction between metered and estimated values. Metered values have very little uncertainty, with most meters having accuracies within 1%. The uncertainty of an estimated value is greater and is the primary determinant of the margin of error in results.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of the systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

This appendix summarizes relative performance of groups of systems in terms of their weighted average capacity factors for specific time periods. These measures describe electric net generation output relative to a unit of system-rebated capacity. For example, an hourly capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system-rebated capacity.

A.1.1 Annual Energy

Table A-1 presents annual total net electrical output in MWh for the program and for each PA. It also shows subtotals for each PA and technology. Later tables in this appendix differentiate by natural gas versus renewable biogas fuel. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites, and the subtotal estimated where metered electrical energy data were not available.

Table A-1: Annual Electric Energy Totals by Technology and PA

2010 Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	**Total***	**35,398**	**6,334**	**16,885**	**8,929**	**67,546**
	M*	25,949	4,219	15,786	8,929	54,883
	E*	9,449 †	2,115 †	1,100 [a]	0	12,664 †
GT	**Total***	**29,205 †**		**93,315**	**72,269**	**194,789**
	M*	3,613		69,009	72,269	144,891
	E*	25,592 †		24,306 †	0	49,898 †
ICE	**Total***	**132,768**	**57,087**	**143,246**	**7,279**	**340,380**
	M*	64,578	28,895	71,564	6,156	171,192
	E*	68,190	28,192 †	71,683	1,123 [a]	169,187
MT	**Total***	**40,174**	**10,773**	**24,068**	**3,770**	**78,785**
	M*	25,547	5,709	17,196	3,770	52,222
	E*	14,627 †	5,064 †	6,872 †	0	26,563
	Total	**237,572**	**74,194**	**277,515**	**92,247**	**681,528**

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-2 presents quarterly total net electrical output in MWh for the program. It also shows subtotals for each technology and fuel, natural gas versus renewable biogas. Additionally, it shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites, and the subtotal estimated where metered electrical energy data were not available.

Table A-2: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2010 (MWh)	Q2-2010 (MWh)	Q3-2010 (MWh)	Q4-2010 (MWh)	Total* (MWh)
FC	**N**	**Total**	**12,421**	**12,577**	**12,658**	**11,771**	**49,426**
		M	10,116	9,813	10,018	9,031	38,978
		E	2,304	2,764	2,640	2,740	10,448 †
	R	**Total**	**4,460**	**4,386**	**4,530**	**4,744**	**18,121**
		M	3,933	3,822	4,426	3,724	15,905
		E	528	564	104	1,020	2,216 †
GT	**N**	**Total**	**48,621**	**47,304**	**49,537**	**49,326**	**194,789**
		M	36,392	35,042	35,869	37,588	144,891
		E	12,230	12,262	13,668	11,738	49,898 †
ICE	**N**	**Total**	**72,135**	**73,975**	**81,501**	**66,670**	**294,281**
		M	31,838	34,763	39,019	29,389	135,009
		E	40,297	39,211	42,482	37,281	159,271
	R	**Total**	**10,599**	**11,832**	**12,449**	**11,219**	**46,099**
		M	7,653	9,399	9,806	9,325	36,183
		E	2,946	2,434	2,643	1,894	9,916 †
MT	**N**	**Total**	**17,426**	**18,731**	**18,446**	**17,685**	**72,289**
		M	12,390	12,994	12,229	11,384	48,998
		E		5,737	6,218	6,301	23,291
	R	**Total**	**1,883**	**1,636**	**1,499**	**1,477**	**6,496**
		M	895	795	776	757	3,224
		E	988	841	723	720	3,272 †
		TOTAL	**167,546**	**170,442**	**180,619**	**162,921**	**681,528**

* In rightmost column only , [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

A.1.2 Peak Demand

Table A-3 presents total net electrical output in kW for the program during the peak hour of 3:00 to 4:00 P.M. (PDT) on August 25, 2010. The table also shows for each technology and basis the subtotals of output, counts of systems, and total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate peak demand impacts by natural gas versus renewable biogas fuel.

Table A-3: CAISO Peak Hour Demand Impacts

CAISO Peak (MW)	Date	Hour (PDT hour beginning)
47,282	**25-Aug-10**	**3 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	**Total**	**28**	**15,310**	**7,723**	0.504
	M	21	13,200	6,659	0.504
	E	7	2,110	1,064	0.504 [a]
GT	**Total**	**8**	**25,744**	**22,982**	0.893 †
	M	4	18,227	16,196	0.889
	E	4	7,517	6,786	0.903 [a]
ICE	**Total**	**245**	**150,865**	**57,957**	0.384
	M	152	91,740	30,527	0.333
	E	93	59,125	27,430	0.464 †
MT	**Total**	**139**	**24,024**	**8,210**	0.342
	M	89	16,548	5,300	0.320
	E	50	7,476	2,909	0.389 †
WD	**Total**	**7**	**3,212**	**0**	0.000
	M	1	950	0	0.000
	E	6	2,262	0	0.000
	TOTAL	**427**	**219,155**	**96,872**	**0.442**

* In column with hourly capacity factor only, [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-4, Table A-5, and Table A-6 list for each electric utility the hourly total net electrical output in kW during the annual peak hour from 3:00 to 4:00 P.M. (PDT) on August 25, 2010.

The tables also list the number of systems online, their combined capacities, and their hourly capacity factors. The last three rows of each table summarize the results across all technologies and fuels. Results presented for the three individual electric utilities for the CAISO peak hour do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table A-4: CAISO Peak Hour Output by Technology, Fuel, and Basis—PG&E

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**12**	**6,100**	**3,029**	0.497 †
		M	7	4,300	2,134	0.496
		E	5	1,800	896	0.498 [a]
FC	**R**	**Total**	**1**	**600**	**518**	0.863
		M	1	600	518	0.863
		E	0	0	0	0.000
GT	**N**	**Total**	**3**	**4,016**	**3,689**	0.919 [a]
		M	0	0	0	0.000
		E	3	4,016	3,689	0.919 [a]
ICE	**N**	**Total**	**97**	**54,287**	**17,454**	0.322 †
		M	60	31,404	7,622	0.243
		E	37	22,883	9,833	0.430 †
ICE	**R**	**Total**	**12**	**5,888**	**3,575**	0.607
		M	10	5,653	3,364	0.595
		E	2	235	211	0.898 †
MT	**N**	**Total**	**43**	**8,546**	**4,265**	0.499 †
		M	19	5,340	2,523	0.472
		E	24	3,206	1,742	0.543 †
MT	**R**	**Total**	**13**	**1,970**	**157**	0.080 †
		M	9	1,340	75	0.056
		E	4	630	82	0.130 [a]
WD		**Total**	**3**	**519**	**0**	0.000
		M	0	0	0	0.000
		E	3	519	0	0.000
		TOTAL	**184**	**81,926**	**32,688**	0.399
		M	106	48,637	16,235	0.334
		E	78	33,289	16,453	0.494

* In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-5: CAISO Peak Hour Output by Technology, Fuel, and Basis—SCE

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**4**	**1,010**	**169**	0.167
		M	2	700	0	0.000
		E	2	310	169	0.545
FC	**R**	**Total**	**5**	**3,150**	**1,276**	0.405
		M	5	3,150	1,276	0.405
		E	0	0	0	0.000
GT	**N**	**Total**	**3**	**12,601**	**10,828**	0.859
		M	2	9,100	7,731	0.850
		E	1	3,501	3,097	0.885
ICE	**N**	**Total**	**105**	**72,177**	**30,736**	0.426 †
		M	54	38,310	14,643	0.382
		E	51	33,867	16,093	0.475 [a]
ICE	**R**	**Total**	**7**	**5,509**	**3,023**	0.549 †
		M	5	3,929	2,081	0.530
		E	2	1,580	942	0.596 [a]
MT	**N**	**Total**	**58**	**9,770**	**3,015**	0.309 †
		M	38	6,800	1,953	0.287
		E	20	2,970	1,062	0.358 [a]
MT	**R**	**Total**	**4**	**1,040**	**23**	0.022 [a]
		M	2	370	0	0.000
		E	2	670	23	0.035 [a]
WD	**0**	**Total**	**4**	**2,693**	**0**	0.000
		M	1	950	0	0.000
		E	3	1,743	0	0.000
		TOTAL	**190**	**107,950**	**49,070**	0.455
		M	109	63,309	27,684	0.437
		E	81	44,641	21,386	0.479

* In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-6: CAISO Peak Hour Output by Technology, Fuel, and Basis—SDG&E

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**4**	**2,250**	**1,187**	0.527
		M	4	2,250	1,187	0.527
		E	0	0	0	0.000
FC	**R**	**Total**	**0**	**0**	**0**	0.000
		M	0	0	0	0.000
		E	0	0	0	0.000
GT	**N**	**Total**	**2**	**9,127**	**8,465**	0.927
		M	2	9,127	8,465	0.927
		E	0	0	0	0.000
ICE	**N**	**Total**	**21**	**12,124**	**2,682**	0.221
		M	21	12,124	2,682	0.221
		E	0	0	0	0.000
ICE	**R**	**Total**	**1**	**560**	**351**	0.627 [a]
		M	0	0	0	0.000
		E	1	560	351	0.627 [a]
MT	**N**	**Total**	**13**	**1,128**	**388**	0.344
		M	13	1,128	388	0.344
		E	0	0	0	0.000
MT	**R**	**Total**	**4**	**774**	**40**	0.051
		M	4	774	40	0.051
		E	0	0	0	0.000
WD		**Total**	**0**	**0**	**0**	0.000
		M	0	0	0	0.000
		E	0	0	0	0.000
		TOTAL	**45**	**25,963**	**13,113**	0.505
		M	44	25,403	12,762	0.502
		E	1	560	351	0.627

* In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-7, Table A-8, and Table A-9 present the total net electrical output in kilowatts (kW) during the respective peak hours of the three large, investor-owned electric utilities. Preceding each of these are small tables listing the date, hour, and load of the utility’s peak hour day. The tables also show for each technology and basis the subtotals of output, counts of systems, and total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate electric utility peak demand impacts by natural gas versus renewable biogas fuel.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of the systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E; the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table A-7: Electric Utility Peak Hours Demand Impacts—PG&E

Electric PA	Peak (MW)	Date	Hour (PDT)
PG&E	**21,180**	**25-Aug-10**	**4PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**13**	**6,700**	**3,609**	**0.539**
	M	8	4,900	2,692	0.549
	E	5	1,800	917	0.509
GT	**Total**	**3**	**4,016**	**3,688**	**0.918**
	M	0	0	0	0.000
	E	3	4,016	3,688	0.918
ICE	**Total**	**109**	**60,175**	**21,049**	**0.350**
	M	70	37,057	11,000	0.297
	E	39	23,118	10,050	0.435
MT	**Total**	**56**	**10,516**	**4,523**	**0.430**
	M	28	6,680	2,650	0.397
	E	28	3,836	1,873	0.488
WD	**Total**	**3**	**519**	**0**	**0.000**
	M	0	0	0	0.000
	E	3	519	0	0.000
Total		**184**	**81,926**	**32,869**	**0.401**

Table A-8: Electric Utility Peak Hours Demand Impacts—SCE

Electric PA	Peak (MW)	Date	Hour (PDT)
SCE	**23,094**	**27-Sep-10**	**2PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**9**	**4,160**	**1,455**	**0.350**
	M	7	3,850	1,303	0.338
	E	2	310	152	0.491
GT	**Total**	**3**	**12,601**	**10,541**	**0.837**
	M	2	9,100	7,726	0.849
	E	1	3,501	2,815	0.804
ICE	**Total**	**112**	**77,686**	**32,791**	**0.422**
	M	59	42,239	16,298	0.386
	E	53	35,447	16,493	0.465
MT	**Total**	**62**	**10,810**	**2,688**	**0.249**
	M	39	7,110	1,688	0.237
	E	23	3,700	999	0.270
WD	**Total**	**4**	**2,693**	**0**	**0.000**
	M	1	950	0	0.000
	E	3	1,743	0	0.000
Total		**190**	**107,950**	**47,475**	**0.440**

Table A-9: Electric Utility Peak Hours Demand Impacts—SDG&E

Electric PA	Peak (MW)	Date	Hour (PDT)
SDG&E	**4,643**	**27-Sep-10**	**2PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**4**	**2,250**	**974**	**0.433**
	M	4	2,250	974	0.433
	E	0	0	0	0.000
GT	**Total**	**2**	**9,127**	**6,752**	**0.740**
	M	2	9,127	6,752	0.740
	E	0	0	0	0.000
ICE	**Total**	**22**	**12,684**	**3,001**	**0.237**
	M	21	12,124	2,639	0.218
	E	1	560	362	0.646
MT	**Total**	**17**	**1,902**	**312**	**0.164**
	M	17	1,902	312	0.164
	E	0	0	0	0.000
WD	**Total**	**0**	**0**	**0**	**0.000**
	M	0	0	0	0.000
	E	0	0	0	0.000
Total		**45**	**25,963**	**11,037**	**0.425**

A.1.3 Capacity Factors

The following tables describe weighted average capacity factors that indicate system performance relative to system-rebated kW for specific time periods. For example, an hourly weighted average capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system-rebated capacity.

Table A-10 presents annual weighted average capacity factors for each technology for the year 2010. The table shows the annual weighted average capacity factors for each technology using all metered and estimated values, and by bases of metered and of estimated. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. The distinction by basis indicates simply that different sets of observations were used in the calculations, not that estimated capacity factors were systematically lower or higher than metered capacity factors.

Table A-10: Annual Capacity Factors

Technology	Basis	Annual Capacity Factor* ($kWyear_{actual\ generation}$ / $kWyear_{rebated\ generation}$)
FC	**Total**	0.497
	M	0.488
	E	0.545 †
GT	**Total**	0.864
	M	0.869
	E	0.849 †
ICE	**Total**	0.259
	M	0.215
	E	0.325
MT	**Total**	0.377
	M	0.351
	E	0.440

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-11 presents annual weighted average capacity factors for each technology and PA for the year 2010. These values arise from the combination of all metered and estimated values. Where entries are blank the PA had no operational systems of the technology type. Table A-12 differentiates capacity factors by natural gas versus renewable biogas fuel.

Table A-11: Annual Capacity Factors by Technology and PA

Technology	Annual Capacity Factor* ($kWyear_{actual\ generation}$/$kWyear_{rebated\ generation}$)			
	PG&E	**SCE**	**SCG**	**CCSE**
FC	0.597	0.317	0.459	0.453
GT	0.830 †	0.000	0.845	0.904
ICE	0.259	0.224	0.316	0.075
MT	0.445	0.230	0.434	0.226

[a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Table A-12 presents annual weighted average capacity factors for the technologies that can be fueled with either natural gas or renewable biogas gas. Where entries are blank the PA had no operational systems of the technology type. This table allows easy comparison of these technologies by fuel type.

Table A-12: Annual Capacity Factors by Technology and Fuel

	Annual Capacity Factor* ($kWyear_{actual\ generation}/kWyear_{rebated\ generation}$)	
Technology	**Natural Gas**	**Renewable Fuel**
FC	0.549	0.397
GT	0.864	0.000
ICE	0.243	0.445
MT	0.411	0.196

* [a] indicates confidence is less than 70/30.
† indicates confidence is better than 70/30.
No symbol indicates confidence is better than 90/10.

Appendix B

Greenhouse Gas Emissions Impacts Methodology

This appendix describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of SGIP systems on-line during 2010. GHG emissions considered in this analysis are limited to carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants whose emissions are potentially affected by the operation of SGIP systems. The operation of wind turbines, and non-renewable microturbines, gas turbines and internal combustion (IC) engines directly affect CO_2 emissions. Microturbines, gas turbines, and IC engines powered by biogas resources can directly affect both CH_4 and CO_2 emissions. GHG emissions are reported in units of tons of CO_2 equivalents for easy comparison.[1] One metric ton of emitted CH_4 is equivalent to 21 metric tons of emitted CO_2.

B.1 Overview

GHG emission impacts are calculated for each SGIP site and then summed by SGIP technology. Emission impacts are calculated as the difference between the GHG emissions produced by the rebated DG system and the "baseline" GHG emissions. Baseline GHG emissions are those that would have been produced by utility generators in the absence of the SGIP facility. SGIP generators displace CO_2 emissions produced by the utility generators by acting to satisfy facility electric loads at the site as well as heat loads, in some cases. In the case of SGIP DG systems powered by biogas, the SGIP facility may reduce emissions of CH_4 that would have otherwise been released to the atmosphere. Each baseline component is described below including its variable reference for the GHG impacts equation:

- SGIP System CO_2 Emissions ($SgipGHG$): The operation of renewable and non-renewable-fueled DG systems (besides PV and wind) emits CO_2 as a result of combustion of the fuel powering the system. Emissions of CO_2 from SGIP DG systems are estimated based on the hour-by-hour electricity generated from SGIP facilities throughout the 2010 year.

[1] CO_2 equivalent is a metric measure used to compare the emissions of various GHG based upon their global warming potential (GWP). The CO_2 equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP.
OECD Glossary of Statistical Terms: http://stats.oecd.org/glossary/detail.asp?ID=285

- Electric Power Plant CO_2 Emissions ($BasePpEngo$): When in operation, power generated by all SGIP technologies directly displaces electricity that would have been generated from a central station power plant in the absence of the SGIP to satisfy the site's electrical loads.[2] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The CO_2 emissions from these conventional power plants are estimated on an hour-by-hour basis over all 8,760 hours of 2010.[3] The estimates of utility-generated CO_2 are based on a methodology developed by Energy and Environmental Economics, Inc. (E3) and made publicly available on its website as part of its avoided cost calculator.[4]

- CO_2 Emissions Associated with Cooling Services ($BasePpChiller$): SGIP systems 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. Estimates of avoided CO_2 emissions are based on the hour-by-hour electricity savings from reduced reliance on central station power plants.

- CO_2 Emissions Associated with Heating Services ($BaseBlr$): Waste heat is recovered from the operation of cogeneration systems. The recovered heat may displace natural gas that would have been used to fuel boilers to satisfy the heating loads at the site in the absence of the SGIP. This displaces accompanying CO_2 emissions from the boiler's combustion process. 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 the estimated reduction in GHG emissions attributable to SGIP systems.

- CO_2 Emissions from Biogas Treatment ($BaseBio$): Biogas-powered SGIP facilities capture and use CH_4 that otherwise may have been emitted to the atmosphere (vented), or captured and burned, producing CO_2 (flared). In the past two impact reports, in absence of the SGIP, all landfill gas facilities were assumed to have captured and

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2 In this analysis, GHG emissions from SGIP facilities 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 facilities have no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP facilities to nuclear or hydroelectric facilities is not made as neither of these facilities is subject to dispatch.

3 Consequently, during those hours when a SGIP facility is not in operation, displacement of CO_2 emissions from central station power plants is equal to zero.

4 Energy and Environmental Economics. *Methodology and Forecast 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

flared the CH_4; all dairies were assumed to have vented the CH_4; and other digesters were assumed to have vented digester gas if under 150 kW of rebated capacity and flared otherwise. In this report, all facilities except dairies are assumed to capture and flare CH_4. The avoided CH_4 emissions in the case of venting represent a direct reduction of GHG emissions. Flaring was assumed to have essentially the same degree of combustion completion as SGIP prime movers (e.g., IC engines, microturbines, fuel cells).

GHG emissions impacts were calculated as:

$$DeltaGHG_{ih} = SgipGHG_{ih} - \left(BasePpEngo_{ih} + BasePpChiller_{ih} + BaseBlr_{ih} + BaseBio_{ih}\right)$$

where:

$DeltaGHG_{ih}$ is the change in GHG emissions attributable to the SGIP for participant *i* for hour *h*.

Units: metric tons of CO_2 eq.

Therefore, a negative change in GHG emissions (*DeltaGHG)* indicates a reduction in GHG emissions. Not all SGIP sites include all of the above variables. Inclusion is determined by the SGIP DG technology and fuel type and is discussed further in the sections B.2 and B.3. Section B.2 further describes GHG emissions from SGIP DG systems (*SgipGHG*), as well as heating and cooling services associated with combined heat and power (CHP) systems. In Section B.3, baseline GHG emissions are described in detail.

B.2 SGIP System GHG Emissions

The following description of SGIP DG system operations covers two areas. The first area covers GHG emissions from electricity generated from rebated SGIP systems. The second area involves GHG emissions associated with heating and cooling services provided by CHP SGIP systems. The amount of heating and cooling service estimated for CHP SGIP systems is used later in the analysis to estimate the baseline GHG emissions that would have resulted if conventional means (i.e., natural gas boiler, electric chiller) were used to provide those services. Because the baseline GHG emissions from heating and cooling services are estimated from the actual quantity of useful waste heat recovered from the SGIP system, the associated heating and cooling services are discussed here, rather than in Section B.3.

B.2.1 Emissions from Rebated SGIP Systems

Some SGIP sites emit CO_2; this must be taken into account when calculating the GHG emission impacts for SGIP facilities. The following assumptions were made regarding the CO_2 emissions per kWh of electricity generated for the various cogeneration technologies: Wind and PV SGIP sites do not emit CO_2, and the electrical efficiency values for each technology type reflect the electrical efficiencies observed in PY10.

CO_2 emission factors were calculated as:

$$(CO_2)_T \cong \left(\frac{3412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO_2}\right)$$

where:

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

Units: $\frac{lbs\ of\ CO_2}{kWh}$

EFF_T is the electrical efficiency of technology T.

Value: Value dependent on technology type

Technology Type	EFF_T
Microturbine	0.225
Gas Turbine	0.327
IC Engine	0.310
Fuel Cell	0.400

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV).
Metered data collected from SGIP CHP systems

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

$$SgipGHG_{ih} = \left((CO_2)_T \times engohr_{ih}\right) \times \left(\frac{metrictonCO_2}{2{,}205lbs}\right)$$

where:

$SgipGHG_{ih}$ is the CO_2 emitted for participant *i* during hour *h*.

Units: metric tons of CO_2

B.2.2 Heating and Cooling Services Provided by SGIP CHP Systems

The SGIP's CHP systems use heat recovered from prime movers to provide host facilities with heating and/or cooling services. The total quantity of heat recovered from each SGIP CHP system during each hour of the year is quantified via either direct measurement or estimation. The translation of these data into estimates of heating and/or cooling services provided is described below. This information is required later in the analysis to support the calculation of GHG emissions that would have occurred in the SGIP's absence, if these services had been provided by natural gas boilers and electric chillers.

Recovered heat from SGIP CHP systems serves heating and cooling loads. The heat data are allocated to heating, cooling, or both, depending on site-specific characteristics. As only total heat recovery data are available, the distribution between heating and cooling is assumed to be 50/50, if a SGIP facility uses recovered heat for both heating and cooling loads.

Heating Services

A heat exchanger is typically used to transfer waste heat recovered from SGIP CHP systems to building heating loads. The below equation represents the process by which the SGIP participant hourly heating services are calculated.

$$HEATING_{ih} = BOILER_i \times heathr_{ih} \times EffHx$$

where:

$HEATING_{ih}$ is the heating services provided by SGIP CHP participant *i* for hour *h*.

Units: kBtu

$BOILER_i$ is an allocation factor whose value depends on SGIP CHP system design (e.g., Heating Only, Heating & Cooling, or Cooling Only)

Value:

System Design	$BOILER_i$
Heating Only	1.0
Heating & Cooling	0.5
Cooling Only	0.0

Units: Dimensionless

Basis: System design as represented in Installation Verification Inspection Report

heathr is the quantity of useful heat recovered from the SGIP unit and used for heating services for SGIP CHP participant *i* for hour *h*.

Units: kBtu

Basis: Metering or ratio analysis depending on HEAT metering status

EffHx is the efficiency of the SGIP CHP primary heat exchanger

Value: 0.9

Units: Dimensionless fractional efficiency

Basis: Assumed

Cooling Services

An absorption chiller is typically used to convert waste heat recovered from SGIP CHP systems into chilled water to serve building cooling loads.

$$COOLING_{ih} = CHILLER_i \times heathr_{ih} \times COP$$

where:

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

Units: kBtu

$CHILLER_i$ is an allocation factor whose value depends on SGIP CHP system design (e.g., Heating Only, Heating & Cooling, or Cooling Only)

Value:

System Design	$CHILLER_i$
Heating Only	0.0
Heating & Cooling	0.5
Cooling Only	1.0

Units: Dimensionless

Basis: System design as represented in Installation Verification Inspection Report

heathr is the quantity of useful heat recovered for SGIP CHP participant *i* for hour *h*.

Units: kBtu

Basis: Metered or estimated data depending on HEAT metering status (e.g., metered or non-metered)

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

Value: 0.6

Units: $\dfrac{kBTU_{out}}{kBTU_{in}}$

Basis: Assumed

B.3 Baseline GHG Emissions

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

B.3.1 Electric Power Plant GHG Emissions

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 DG system during PY09 in the absence of the program. The methodology involves combining emission factors (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 DG systems or displaced by absorption chillers operating on heat recovered from CHP SGIP systems.

The service territory of the SGIP site is considered in the development of emission factors by accounting for whether the facility is located in PG&E's territory (northern California) or in SCE/SDG&E's territory (southern California). Variations in climate and electricity market conditions have an effect on the demand and use of electricity. This in turn affects the emission factors used to estimate the avoided CO_2 released by conventional power plants. Lastly, the date and time (hereafter referred to as 'hour') that electricity is generated affects the emission factors because the mix of high and low efficiency plants used differs throughout the day. The larger the proportion of low efficiency plants used to generate electricity, the greater the avoided CO_2 emissions.

Electric Power Plant Hourly CO_2 Emission Factor

The basic methodology used to formulate hourly CO_2 emission factors for this analysis is based on methodology developed by E3 and found in its avoided cost calculation workbook.[5] The E3 avoided cost calculation workbook assumes:

- The emissions of CO2 released from a conventional power plant depend upon its heat rate, which in turn is dictated by the power 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 factors 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 natural gas 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 factor for CO_2. In other words, one can expect an emission factor representing the release of CO_2 from the central grid to be higher during peak hours than during off-peak hours.

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5 The filename of the workbook that contains the data used to generate hour-specific emission factors for CO_2 is "cpucAvoided26.xls" and can be downloaded from www.ethree.com/CPUC.

$BaseCO2EF_{ht}$ is the hourly CO_2 emission factor for northern or southern California, *i*, for every hour, *h*.

Source: E3 workbook

Units: metric tons of CO_2 per kWh

<u>Electric Power Plant Operations Corresponding to Electric Chiller Operation</u>

The third bullet presented in Section B.1 described the additional GHG reduction benefit associated with a cogeneration facility that uses recovered waste heat for cooling in an absorption chiller. Since absorption chillers replace the use of standard efficiency centrifugal electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions associated with these cogeneration facilities.

This avoided electricity that would have been serving a centrifugal chiller in the absence of the cogeneration system was calculated as:

$$ChlrElec_{ih} = COOLING_{ih}\ kBtu \times \left(EffElecChlr \frac{kWh}{ton-hr\ of\ cooling} \right) \left(\frac{ton-hr\ of\ cooling}{12\ kBtu} \right)$$

where:

$ChlrElec_{ih}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for participant *i* for hour *h*.

Units: kWh

$COOLING_{ih}$ is the cooling service provided by SGIP CHP participant i for year y, month m, day d, and hour h, as calculated in section B.2.

Units: kBtu

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

Value: 0.634

Units: $\frac{kWh}{Ton-hr\ of\ cooling}$

Basis: Assumed

Baseline GHG Emissions from Power Plant Operations

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

$$BasePpChiller_{ih} = \left(BaseCO2EF_{ih} \times ChlrElec_{ih}\right)$$

$$BasePpEngo_{ih} = \left(BaseCO2EF_{ih} \times engohr_{ih}\right)$$

where:

$BasePpChiller_{ih}$ is the GHG emissions generated by a power plant to provide for a baseline electric chiller for participant *i* for hour *h*.

Units: metric tons CO_2

$BasePpEngo_{ih}$ is the GHG emissions generated by a power plant to provide electricity to serve site electrical loads for participant *i* for hour *h*.

Units: metric tons CO_2

B.3.2 Natural Gas Boiler GHG Emissions

The fourth bullet presented in Section B.1 described additional GHG reduction benefits derived from cogeneration. These benefits come in the form of waste heat recovered from SGIP facilities that is then used to provide heating services, thereby reducing reliance on natural gas boilers. The quantity of heating services provided by SGIP CHP systems was discussed in a section B.2. Use of these data to estimate the baseline natural gas use corresponding to these heating services is described below.

SGIP CHP systems that are required to meet PUC 216.6 levels of performance and SGIP renewable landfill facilities with waste heat recovery systems have a GHG emission reduction benefit due to the offsetting emissions associated with a natural gas boiler. In prior impact reports only SGIP CHP systems that were required to meet PUC 216.6 levels of performance included this baseline term. However, this year CHP systems supplied with landfill gas were included because recent research has found that the heat recovered from these CHP systems is used to meet building heating loads and in the absence of the SGIP these loads would have been satisfied by conventional means (i.e. natural gas). There are other renewable SGIP CHP systems that are fueled by digester-produced CH_4 gas, and the waste heat serves to maintain the temperature of the digester and maintain CH_4 production rates associated with the anaerobic digestion process. These loads would not have been served by a natural gas boiler in the absence of the SGIP; this baseline term is therefore not included for these CHP systems.

Baseline natural gas boiler CO_2 emissions (measured in metric tons) were calculated based upon hourly heat recovery values for the SGIP CHP projects active in 2009 as follows:

$$BaseBlr_{ih} = \left(HEATING_{ih}\ \text{kBtu}_{\text{out}} \times \left(\frac{1}{EffBlr\ \dfrac{\text{kBtu}_{\text{out}}}{\text{kBtu}_{\text{in}}}} \right) \left(\frac{ft^3 of\ CH_4}{1\, kBtu_{in}} \right) \left(\frac{lbmole\ of\ CO_2}{360\, ft^3\ of\ CH_4} \right) \left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO_2} \right) \right) \times \left(\frac{metrictonCO_2}{2{,}205\ \ lbsCO_2} \right)$$

where:

$BaseBlr_{ih}$ is the CO_2 emissions of the baseline natural gas boiler for participant *i* for hour *h*.

Units: metric tons of CO_2

EffBlr is the efficiency of the baseline natural gas boiler

Value: 0.8

Units: $\dfrac{kBtu_{out}}{kBtu_{in}}$

Basis: Previous program cost-effectiveness evaluations.

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

B.3.3 Biomass GHG Emissions

Calculation of CH_4 emission reductions from cogeneration facilities was carried out for the subset of 46 renewable fuel use SGIP facilities. These facilities used biogas exclusively or predominately as the generation fuel source. These included the following facility types:

- Renewable-fueled fuel cells,
- Renewable-fueled microturbines, and
- Renewable-fueled IC engines.

The baseline treatment of biogas is an influential determinant of GHG emission impacts for renewable-fueled SGIP systems. Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared). There are two common sources of biogas found within the SGIP: landfills or digesters. Digesters in the SGIP program to date have been associated with wastewater treatment plants (WWTPs), 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 baseline treatment of biogas for dairy digesters, and flaring is the baseline for all other renewable fuel sites. For dairy digesters, landfills, WWTPs, and food processing facilities larger than 150 kW, this is consistent with past SGIP impact evaluation reports. However, for WWTPs and food processing facilities smaller than 150 kW, past SGIP impact evaluations have assumed a venting baseline, whereas now 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, CH_4, and water. 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 control of volatile organic compounds. This information and the facility contacts support a venting biogas baseline.

[6] Most dairies manage their wastes 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 systems).

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 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 past 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 past 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 is used as the biogas baseline.

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 the generated 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. However, installation verification inspection reports and renewable-fueled DG landfill facility contacts verified that they would have flared their CH_4 in the absence of the SGIP. Therefore, the biogas baseline for landfill facilities is to flare the CH_4.

The GHG emissions characteristics of biogas flaring and biogas venting are very different and, therefore, are discussed separately below.

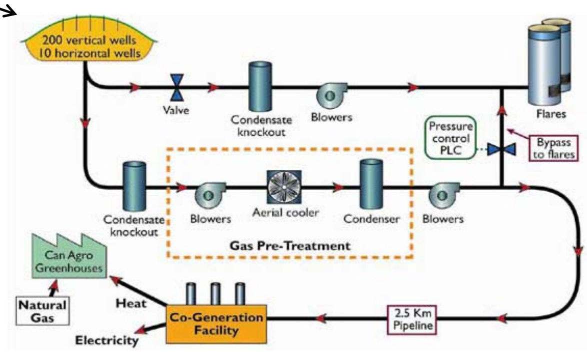
[7] California Energy Commission. *Landfill Gas-to-Energy Potential in California*. 500-02-041V1. September 2002. http://www.energy.ca.gov/reports/2002-09-09_500-02-041V1.PDF

GHG Emissions of Flared Biogas

Figure B-1 provides a depiction of a biogas facility that captures and flares CH_4. The CH_4 is assumed to be captured by the facility and then flared, destroying the CH_4 but still resulting in the release of CO_2. A facility that vents the CH_4 will have lower direct CO_2 emissions than a facility that flares the CH_4. This is due to the global warming potential of CH_4 vented directly into the atmosphere, which is much higher than the global warming potential of CO_2 resulting from the flaring of CH_4. One ton of emitted CH_4 is equivalent to 21 tons of emitted CO_2.

Figure B-1: Landfill Gas with CH_4 Capture Diagram

Landfill gas (containing approximately 50% methane) is collected (captured) at the landfill using collection wells



When not being used to create power, the landfill gas is flared, which results in carbon dioxide emissions

Methane is naturally created at landfill gas facilities, wastewater treatment plants and dairies. If not captured, the methane escapes into the atmosphere contributing to greenhouse gas (GHG) emissions. Capturing the methane provides an opportunity to use it as fuel. When the methane is not used to create energy, it is burned in a flare. Because the resulting CO_2 has much less GHG potency than methane, the use of the flare reduces the CO_2 equivalent emissions. Distributed generation, such as SGIP projects, deliver additional economic and environmental benefits by reducing the need to generate electricity at central station power plants.

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

- All facilities using digester gas except for dairies, and
- All landfill gas facilities.

$BaseBio_{ih} = 0$ The assumption is that the flaring of CH_4 results in the same amount of CO_2 emissions as would occur if CH_4 was captured and used in the SGIP system to produce electricity so there is no offset.

GHG Emissions of Vented Biogas

CH_4 captured and used at renewable fuel use facilities where the biogas baseline is venting represents CH_4 emissions that are no longer emitted to the atmosphere. The venting baseline was assumed for all dairy digester SGIP facilities.

Biogas consumption is not metered at SGIP facilities. Therefore, CH_4 emission factors were calculated for each renewable fuel technology type by assuming electrical efficiencies for each technology:

$$CH4EF_T \cong \left(\frac{3412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3 of\ CH_4}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m\ of\ CH_4}\right)$$

where

$CH4EF_T$ is the CH_4 capture rate for SGIP DG systems of type T

Value: Value dependent on technology type

Technology Type	***$CH4EF_T$***
Microturbine	307
IC Engine	220
Fuel Cell	175

Units: $\frac{grams}{kWh}$

EFF_T is the electrical efficiency of technology *T*.

Value: Value dependent on technology type

Technology Type	***EFF_T***
Microturbine	0.224
Gas Turbine	0.326
IC Engine	0.313
Fuel Cell	0.393

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV).
Metered data collected from SGIP CHP systems.

The derived CH_4 emission factors (*CH_4EF*) are multiplied by the total electricity generated from the SGIP renewable fuel use sites to estimate the annual avoided CH_4 emissions. Since GHG emissions are often reported in terms of tons of CO_2 equivalent,[8] each facility's avoided CH_4 emissions were converted first from grams to pounds and then pounds to metric tons. Baseline CH_4 emissions in tons for participant i and hour h were calculated as follows:

$$BaseBioCH4_{ih} = \left(\left(\frac{CH_4EF_T\,grams}{kWh} \right) (engohr_{ih}) \left(\frac{0.002204 lbs}{grams} \right) \right) \times \left(\frac{metrictonCH_4}{2{,}205 lbsCH_4} \right)$$

The avoided metric tons of CH_4 emissions were then converted to metric tons of CO_2 equivalent by multiplying the avoided CH_4 emissions by 21, which represents the Global Warming Potential (GWP) of CH_4 (relative to CO_2) over a 100-year time horizon.

$$BaseBio_{ih} = BaseBioCH4_{ih} * \left(\frac{21 metrictons\,CO_2}{metricton\ CH_4} \right)$$

8 CO_2 equivalent is a metric measure used to compare the emissions of various GHG based upon their global warming potential (GWP). The CO_2 equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP.
OECD Glossary of Statistical Terms: http://stats.oecd.org/glossary/detail.asp?ID=285

B.4 Emission Details by PA, Technology and Fuel

Table B-1: Emission Impacts for all PAs by Technology Type and Fuel (Tons of CO_2)

PA	SGIP Facility Emissions (Tons CO_2)	Avoided Emissions (Tons CO_2)				GHG Emissions Impact (Tons CO_2)
Technology Type		Avoided Grid Emissions (Tons CO_2)	Waste Heat Recovery (Tons CO_2)	Biogas (Tons CO_2)	Total Avoided Emissions (Tons CO_2)	
PG&E	**148,395**	**98,374**	**32,838**	**29,311**	**160,261**	**-12,178**
FC	16,737	14,504	1,670	0	15,912	512
Biogas-Flared	1,971	1,715	0	0	1,715	255
NatGas	14,766	12,789	1,670	0	14,197	257
GT	16,891	12,053	3,025	0	15,078	1,813
NatGas	16,891	12,053	3,025	0	15,078	1,813
ICE	80,999	55,243	23,105	29,311	107,659	-26,659
Biogas-Flared	8,123	5,473	1,686	0	7,159	964
Biogas-Vented	3,836	2,570	0	29,311	31,881	-28,045
NatGas	69,041	47,201	21,418	0	68,619	422
MT	33,768	16,573	5,038	0	21,612	12,157
Biogas-Flared	3,410	1,665	0	0	1,665	1,745
NatGas	30,358	14,908	5,038	0	19,947	10,412
SCE	**46,878**	**30,546**	**9,209**	**0**	**39,754**	**7,124**
FC	2,995	2,585	3	0	2,588	407
Biogas-Flared	2,203	1,902	0	0	1,902	302
NatGas	791	683	3	0	686	105
ICE	34,828	23,521	7,913	0	31,434	3,394
Biogas-Flared	8,597	5,792	2,380	0	8,171	426
NatGas	26,231	17,729	5,533	0	23,263	2,968
MT	9,056	4,440	1,293	0	5,733	3,323
Biogas-Flared	757	364	0	0	364	393
NatGas	8,298	4,075	1,293	0	5,368	2,930

Table B–1: Emission Impacts for all PAs by Technology Type and Fuel (Tons of CO_2) (continued)

PA	SGIP Facility Emissions (Tons CO_2)	Avoided Emissions (Tons CO_2)				GHG Emissions Impact (Tons CO_2)
Technology Type		Avoided Grid Emissions (Tons CO_2)	Waste Heat Recovery (Tons CO_2)	Biogas (Tons CO_2)	Total Avoided Emissions (Tons CO_2)	
SCG	**169,577**	**114,049**	**33,390**	**0**	**147,440**	**22,137**
FC	7,984	6,911	507	0	7,418	565
Biogas-Flared	4,081	3,535	0	0	3,535	546
NatGas	3,902	3,376	507	0	3,883	19
GT	53,970	38,123	10,391	0	48,515	5,455
NatGas	53,970	38,123	10,391	0	48,515	5,455
ICE	87,392	59,217	19,686	0	78,903	8,489
Biogas-Flared	6,216	4,195	0	0	4,195	2,021
NatGas	81,176	55,022	19,686	0	74,709	6,467
MT	20,230	9,797	2,806	0	12,603	7,628
NatGas	20,230	9,797	2,806	0	12,603	7,628
CCSE	**53,629**	**37,869**	**3,169**	**0**	**41,038**	**12,592**
FC	4,222	3,656	451	0	4,108	114
NatGas	4,222	3,656	451	0	4,108	114
GT	41,798	29,663	1,566	0	31,229	10,569
NatGas	41,798	29,663	1,566	0	31,229	10,569
ICE	4,441	3,005	726	0	3,731	709
Biogas-Flared	1,352	916	0	0	916	436
NatGas	3,088	2,089	726	0	2,815	273
MT	3,169	1,544	426	0	1,970	1,199
Biogas-Flared	1,293	622	96	0	718	575
NatGas	1,876	923	330	0	1,252	623

Table B-2: Emission Impact Factors for All PAs by Technology Type and Fuel ($Tons\ of\ CO_2$ per MWh)

PA	Annual Energy MWh	SGIP Facility Emission Impact (Tons CO_2/MWh)	Avoided Emissions (Tons CO_2 per MWh)				GHG Impact Factor (Tons CO_2/MWh)
Technology Type			Avoided Grid Emissions (Tons CO_2/MWh)	Waste Heat Recovery (Tons CO_2/MWh)	Biogas (Tons CO_2/MWh)	Total Avoided Emissions (Tons CO_2/MWh)	
PG&E	**237,544**	**0.625**	**0.663**	**0.221**	**0.198**	**0.675**	**-0.051**
FC	35,398	0.473	0.867	0.100	0.000	0.450	0.014
Biogas-Flared	4,829	0.473	0.866	0.000	0.000	0.355	0.053
NatGas	30,569	0.473	0.867	0.116	0.000	0.464	0.008
GT	29,205	0.578	0.714	0.179	0.000	0.516	0.062
NatGas	29,205	0.578	0.714	0.179	0.000	0.516	0.062
ICE	132,768	0.610	0.682	0.285	0.362	0.811	-0.201
Biogas-Flared	13,314	0.610	0.674	0.208	0.000	0.538	0.072
Biogas-Vented	6,288	0.610	0.670	0.000	7.641	5.070	-4.460
NatGas	113,166	0.610	0.684	0.310	0.000	0.606	0.004
MT	40,174	0.841	0.491	0.149	0.000	0.538	0.303
Biogas-Flared	4,057	0.841	0.488	0.000	0.000	0.410	0.430
NatGas	36,117	0.841	0.491	0.166	0.000	0.552	0.288
SCE	**74,194**	**0.632**	**0.652**	**0.196**	**0.000**	**0.536**	**0.096**
FC	6,334	0.473	0.863	0.001	0.000	0.409	0.064
Biogas-Flared	4,660	0.473	0.863	0.000	0.000	0.408	0.065
NatGas	1,674	0.473	0.863	0.003	0.000	0.410	0.063
ICE	57,087	0.610	0.675	0.227	0.000	0.551	0.059
Biogas-Flared	14,092	0.610	0.674	0.277	0.000	0.580	0.030
NatGas	42,995	0.610	0.676	0.211	0.000	0.541	0.069
MT	10,773	0.841	0.490	0.143	0.000	0.532	0.308
Biogas-Flared	901	0.841	0.481	0.000	0.000	0.404	0.436
NatGas	9,873	0.841	0.491	0.156	0.000	0.544	0.297

Table B–2: Emission Impact Factors for All PAs by Technology Type and Fuel ($Tons of CO_2$ per MWh) (continued)

PA	Annual Energy MWh	SGIP Facility Emission Impact (Tons CO_2/MWh)	Avoided Emissions (Tons CO_2per MWh)	GHG Impact Factor (Tons CO_2/MWh)	PA	Annual Energy MWh	SGIP Facility Emission Impact (Tons CO_2/MWh)
SCG	**277,515**	**0.611**	**0.673**	**0.197**	**0.000**	**0.531**	**0.080**
FC	16,885	0.473	0.866	0.064	0.000	0.439	0.033
Biogas-Flared	8,632	0.473	0.866	0.000	0.000	0.410	0.063
NatGas	8,254	0.473	0.865	0.130	0.000	0.470	0.002
GT	93,315	0.578	0.706	0.193	0.000	0.520	0.058
NatGas	93,315	0.578	0.706	0.193	0.000	0.520	0.058
ICE	143,246	0.610	0.678	0.225	0.000	0.551	0.059
Biogas-Flared	10,189	0.610	0.675	0.000	0.000	0.412	0.198
NatGas	133,057	0.610	0.678	0.243	0.000	0.561	0.049
MT	24,068	0.841	0.484	0.139	0.000	0.524	0.317
NatGas	24,068	0.841	0.484	0.139	0.000	0.524	0.317
CCSE	**92,247**	**0.581**	**0.706**	**0.059**	**0.000**	**0.445**	**0.136**
FC	8,929	0.473	0.866	0.107	0.000	0.460	0.013
NatGas	8,929	0.473	0.866	0.107	0.000	0.460	0.013
GT	72,269	0.578	0.710	0.037	0.000	0.432	0.146
NatGas	72,269	0.578	0.710	0.037	0.000	0.432	0.146
ICE	7,279	0.610	0.677	0.163	0.000	0.513	0.097
Biogas-Flared	2,216	0.610	0.678	0.000	0.000	0.413	0.197
NatGas	5,062	0.610	0.676	0.235	0.000	0.556	0.054
MT	3,770	0.841	0.487	0.134	0.000	0.523	0.318
Biogas-Flared	1,538	0.841	0.481	0.074	0.000	0.467	0.374
NatGas	2,232	0.841	0.492	0.176	0.000	0.561	0.279

Appendix C

Data Sources and Data Analysis

This appendix discusses data sources and data availability by Program Administrator (PA) and the data analysis methodology, including the bases of the impact estimates uncertainty characterizations. Several key types of data sources are presented first. This is followed by a description of metered data collection issues. The last section describes the data analysis.

C.1 Overview of Key Data Types

There are three key data types:

1. Project lists maintained by the Program Administrators (PAs),
2. Reports from monitoring planning and installation verification site visits, and
3. Metered data received from project Hosts, Applicants, third-party metering, or metering installed by Itron.

C.1.1 Project Lists Maintained by Program Administrators

SGIP PAs maintain project tracking database files containing information essential for designing and conducting SGIP impact evaluation activities. The PAs provided Itron with regular updates of their program tracking database files, usually on a monthly basis. Information of particular importance includes basic project characteristics (e.g., technology type, rebated capacity of the project, fuel type) and key participant characteristics (e.g., Host and Applicant names[1], addresses, phone numbers). The project's technology type, program year, and project location (by PA area) were also used in developing a sample design to ensure collection of data necessary

[1] The Host is the customer of record at the site where the generating equipment is or will be located. An Applicant is a person or entity who applies to the PA for incentive funding. Third parties (e.g., a party other than the PA or the utility customer) such as engineering firms, installing contractors, equipment distributors or Energy Service Companies (ESCO) are also eligible to apply for incentives on behalf of the utility customer, provided consent is granted in writing by the customer.

to develop statistically significant estimates of program impacts. Updated SGIP Handbooks were used for planning and reference purposes.[2]

C.1.2 Reports from Monitoring Planning and Installation Verification Site Visits

Information contained in the PA project database files was updated through visits to the SGIP project sites conducted by independent consultants hired by the PAs to perform verification of SGIP installations. Project-specific information is reported in Inspection Reports produced by these independent consultants. The PAs regularly provided copies of the Inspection Reports. In addition, site visits were conducted by Itron engineers in preparing monitoring plans for on-site data collection activities. The types of information collected during site inspections or in preparation of monitoring plans include meter numbers, nominal nameplate rating, and the date the system entered normal operation.

C.1.3 Metered Performance Data

In addition to information collected from the PA project database and from project site visits, metered data were also used when available. The metered data collected and used for evaluation purposes include electric net generator output (ENGO) data, useful thermal energy (HEAT) data, and fuel use (FUEL) data.

Electric Net Generator Output (ENGO) Data

ENGO data provide information on the amount of electricity generated by the metered SGIP project. This information is needed to assess annual and peak electricity contributions from SGIP projects. ENGO data were collected from a variety of sources, including meters Itron installed on SGIP projects under the direction of the PAs and meters installed by project Hosts, Applicants, electric utilities, and third parties. Some electric utilities may install different types of ENGO metering depending on project type. In some cases, this impeded Itron’s ability to assess peak demand impacts. For example, some of the installed meters did not record electricity generation data in intervals shorter than one month. These types of meters were encountered with some cogeneration systems installed in schools, as well as with some renewable-fueled engine/turbine projects eligible for net metering. As a result, peak demand impacts could not be determined for these projects. Itron has been working with the affected PAs and electric utility companies to equip a sample of SGIP projects with interval-recording electric metering to enable development of statistically significant peak demand impacts.

2 SGIP Handbooks are available on PA websites.

Useful Thermal Energy (HEAT) Data

Useful thermal energy is that energy captured by heat recovery equipment and used at the utility customer site for process heat and/or cooling. Useful thermal energy (also referred to as HEAT) data were used to assess compliance of SGIP cogeneration facilities with required levels of efficiency and useful waste heat recovery. In addition, useful thermal energy data for SGIP facilities enabled estimation of baseline electricity and natural gas use that would have otherwise been provided by the utility companies. This information was used to assess energy efficiency impacts as well as determine net GHG emission impacts. HEAT data were collected from metering systems installed by Itron as well as metering systems installed by Applicants, Hosts, or third parties.

Over the course of the SGIP, the approach for collecting HEAT data has changed. Collecting HEAT data has historically involved installation of invasive monitoring equipment (i.e., insertion-type flow meters and temperature sensors). Many third parties or Hosts had this type of HEAT metering 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 was able to obtain the relevant data being collected by these Hosts and third parties. Itron initially adopted an approach of obtaining HEAT data from others in an effort to minimize both the cost- and disruption-related aspects of installing HEAT monitoring equipment. The majority of useful thermal energy data for 2003 to 2004 were obtained in this manner.

Itron began installing HEAT meter systems in the summer of 2003 for SGIP projects that were included in the sample design but for which data from existing HEAT metering were not available. As the HEAT data collection effort grew, it became clear that Itron could no longer rely on data from third-party or Host customer metering. In numerous instances agreements and plans concerning these data did not translate into validated data records available for analysis. Uninterrupted collection and validation of reliable metered performance data was labor-intensive and required examination of the collected data by more expert staff, thereby increasing costs. In addition, reliance on HEAT data collected by SGIP Host customers and third parties created evaluation schedule impacts and other risks that more than outweighed the benefits of lower metering installation costs.

In mid-2006, Itron responded to the HEAT data issues by changing the approach to collection of HEAT data. Itron continued to collect HEAT data from others in those instances where the data could be obtained easily and reliably. In all other instances, an approach has been adopted of installing HEAT metering systems for those projects in the sample design. Itron adopted the installation of non-invasive metering equipment such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications to reduce the time and invasiveness of the installations and increase data communication reliability. The increase in equipment costs was offset by the decrease in installation time and a decrease in maintenance problems. This non-invasive approach has been used to obtain HEAT data throughout 2010.

Fuel Usage (FUEL) Data

Fuel usage (also called FUEL) data were used in the impact evaluation to determine overall system efficiencies of SGIP cogeneration facilities, to determine compliance of renewable fuel use facilities with renewable fuel use requirements, and to estimate net GHG emission impacts. To date, fuel use data collection activities have focused exclusively on monitoring consumption of natural gas by SGIP generators. In the future it may also be necessary to monitor consumption of gaseous renewable fuel (i.e., biogas) to more accurately assess compliance of SGIP projects using blends of renewable and non-renewable fuels with renewable fuel use requirements.

FUEL data used in the impact evaluation were obtained mostly from FUEL metering systems installed at SGIP projects by natural gas utilities, SGIP participants, or by third parties. Itron reviewed FUEL data obtained from others, and their bases were documented prior to processing the FUEL data into a data warehouse. Reviews of data validity included combining fuel usage data with power output data to check for reasonableness of gross engine/turbine electrical conversion efficiency. In cases where validity checks failed, the data provider was contacted to further refine the basis of data. In some cases it was determined that data received were for a facility-level meter rather than from metering dedicated to the SGIP cogeneration system. These data were excluded from the impact analysis.

Most of the FUEL data being obtained from others were collected and reported on in time intervals much greater than one hour (e.g., daily or monthly). In most instances hourly FUEL consumption was estimated based on the associated ENGO readings. While these data enable calculation of monthly and annual operating efficiencies they do not provide information about cogeneration system efficiency during peak electricity demand. To address this issue Itron has recommended to the PAs installation of pulse recorders on a subset of existing gas meters to enable collection of hourly FUEL data.

C.2 Data Processing Methods

This section discusses the ENGO, HEAT, and FUEL data processing and validation methodology for fuel cells and engines/turbines operating on non-renewable or renewable fuel.

C.2.1 ENGO Data Processing

For fuel cells, engines, and turbines, ENGO data refers to a measure of system output that excludes electric parasitic loads (e.g., onsite controls, pumps, fans, compressors, generators, and heat recovery systems). In some cases it is not possible to measure ENGO directly with a single meter. In those cases ENGO is calculated by subtracting the electrical parasitic loads from the gross generator output. Due to the wide variety of formats in which raw data are received, conversion of raw data to a common format is essential in order to ensure that all data received are treated consistently. After converting the data to a common format, all data files are reviewed to identify suspicious data (low or high capacity factors). Data providers are contacted when data validity cannot be determined internally. In cases where anomalous behavior cannot be explained, the metered data are excluded from the analysis.

C.2.2 HEAT Data Processing

The main sources of thermal data are Applicants and Itron-installed heat meters. If the data come from Itron data loggers, processing time is minimal because the raw data are already stored in 15-minute intervals. However, if the raw data come from Applicants, then the data are converted to the standard format of 15-minute interval kBtu data. When data are received from an Applicant, Host, or some other party, certain validation steps must be passed before the data are incorporated into the analysis. These steps include comparing the HEAT data with the ENGO and FUEL data when available. HEAT data are validated when the heat recovery rate (kBtu/kWh) falls within an expected range based on system type and size.

C.2.3 FUEL Data Processing

The two main sources of fuel data for non-renewable projects are natural gas utilities and program participants. These raw data are typically reported in monthly or billing cycle intervals. Monthly electrical conversion efficiencies are calculated to validate the monthly fuel data. Validated monthly data are transformed into 15-minute data based on the monthly electrical efficiencies and 15-minute ENGO data. In this case, the fuel data are allocated to 15-minute intervals using a ratio, so a flag in the permanent dataset is set to “R” in order to distinguish between monthly metered data that has been transformed into 15-minute data, and actual 15-minute interval metered data, which are flagged as “M”.

C.3 Estimating Impacts of Unmetered Systems

Data from metered systems were used to estimate impacts for unmetered systems of the same technology and fuel. In most cases, the metered data were for the exact same hour of the year and from systems of same technology, fuel, and PA.

By limiting the metered data used to those with the same PA, factors that can influence operational performance were better matched between the metered and unmetered systems. These PA-related factors include local economic climate, available tariffs, and, to some degree, the local meteorological climate.

All estimated hourly impacts were based on no fewer than five metered observations of the same technology and fuel type. For some unmetered systems there were hours with fewer than five metered observations with like technology, fuel, and PA. To estimate impacts for these, metered data from one or more of the other PAs were included until there were at least five metered observations for the same hour. For example, metered data from SCE could be used to estimate impacts for similar systems at the same hour for SCG unmetered systems when too few metered observations existed from SCG systems alone. If there still were fewer than five metered observations, then data from CCSE were allowed to be used. If inclusion of CCSE data did not provide enough metered observations, then data from PG&E were allowed.

The inclusion of metered data from other PAs did not always satisfy the minimum requirement of five metered observations for the same hour of the year and same technology and fuel. In these cases the metered data were restricted again to the same PA but the time component of the metered data was allowed to include same hours of the day from like weekday types (weekday or weekend) from the same month. For example, an hourly estimate for 3:00 to 4:00 P.M. on Monday, July 24 for a renewable IC engine system administered by SCE might be based on metered observations from renewable IC engine systems administered by SCE from all July weekday hours of 3:00 to 4:00 P.M.

In less than 0.7% of the system hours needing to be estimated, the relaxation of the metered data time component did not satisfy the minimum requirement of five metered observations. Thus, estimates for these system hours were allowed to be based on metered observations during like weekday hours of the same month and from other PAs.

A ratio representing average power output per unit of rebated system capacity was calculated using at least five metered observations for each system hour needing an impact estimate. Two sets of these ratios were calculated, one set based on all available metered data, and one set based only on metered data for systems that were online. The latter set of ratio estimators were used to calculate impacts estimates for unmetered projects that operations status research determined to be online.

The operations status of each metered system and each unmetered system was defined on a month by month basis. For metered systems, monthly average capacity factors were used as the basis of operations status assignment. System-months associated with monthly average capacity factors less than 0.5% were classified as offline; monthly average capacity factors greater than or equal to 0.5% were classified as online. Hourly estimates of impacts were calculated as the product of the ratio estimator and the size of the unmetered system as shown below.

$$EN\hat{G}O_{psdh} = \left(S_{ps}\right)_{Unmetered} \times \left(\frac{\sum ENGO_{psdh}}{\sum S_{ps}}\right)_{Metered}$$

Where:

$EN\hat{G}O_{psdh}$ = Predicted net generator output for project *p* in strata[3] *s* on date *d* during hour *h*

Units: kWh

Source: Calculated

S_{ps} = System size for project *p* in strata *s*

Units: kW

Source: SGIP Tracking Database

$ENGO_{psdh}$ = Metered net generator output for project *p* in strata *s* on date *d* during hour *h*

Units: kWh

Source: Net Generator Output Meters

C.4 Assessing Uncertainty of Impacts Estimates

Program impacts covered include those on electricity and fuel, as well as those on greenhouse gas (GHG) emissions. The principal factors contributing to uncertainty in those reported results are quite different for these two types of program impacts. The treatment of those factors is described below for each of the two types of impacts.

[3] Strata are always defined by like technology and fuel and like hour of like weekday in like month. As described in text, however, strata may be more specific by additional like technology details, like PA or like group of PAs, and by exact hour of the year.

C.4.1 Electricity, Fuel, and Heat Impacts

Electricity, fuel, and heat impact estimates are affected by at least two sources of error that introduce uncertainty into the 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 impact estimates are based on results of this analysis.

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact 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.”[4]

A principle advantage of this approach is that it readily accommodates complex analytic questions. This is an important advantage for this project because numerous factors contribute to variability in impact 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 usage, while still others might have other combinations of data available.

[4] Webster’s dictionary

C.4.2 GHG Emission Impacts

Electricity and fuel impact estimates represent the starting point for the analysis of GHG emission impacts; thus, uncertainty in those electricity and fuel impact estimates flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impacts 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.

<u>Baseline Central Station Power Plant GHG Emissions</u>

Estimation of net GHG emissions impacts of each SGIP system involves comparing emissions of the SGIP system 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 system had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and, hence, GHG emissions factors) were obtained from E3. Quantitative assessment of uncertainty in E3's avoided GHG emissions database is outside the scope of this SGIP impact evaluation.

<u>Baseline Biogas Project GHG Emissions</u>

Biomass material (e.g., trash in landfills, manure at 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).

For this GHG impact evaluation Itron used the CH_4 disposition baseline assumptions summarized in Table C-1. Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, Itron continues collecting additional site-specific information about CH_4 disposition and incorporating it into impacts analyses. Modification of installation verification inspection forms will be recommended, and information available from air permitting and other information sources will be compiled.

Table C-1: CH_4 Disposition Baseline Assumptions for Biogas Projects

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

C.4.3 Data Sources

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 systems for which impact estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include PA, project status, project location, system type, and system size. This information is obtained from project lists that PAs update monthly for the CPUC. More detailed project information (e.g., heat exchanger configuration) is obtained from Verification Inspection Reports developed by PAs just prior to issuance of incentive checks.

Metered Data for SGIP DG Systems

Collection and analysis of metered performance data collected from SGIP DG systems is a central focus of the overall program evaluation effort. In the MCS study the metered performance data are used for three 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 central tendencies of groups of metered data are used to estimate the actual performance of unmetered systems.

3. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study to explore the likelihood that actual performance 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 values and actual performance.

C.4.4 Analytic Methodology

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

- 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 is being 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 PUC216.6 (b) Cogeneration 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 systems came on-line during 2010 and, therefore, contributed to energy impacts for only a portion of the year. Some of the systems for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2010. 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 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 on-line during 2010 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 labor- and 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 system is metered. However, for many of the SGIP systems metered data are available for a portion—but not all—of 2010. This complicates any analysis that requires classification of systems 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, heat) for each month of each project is classified as being either "metered" (at least 90% 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 of each unmetered system based on research performed.

<u>Generate Sample Data</u>

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

Metered Data Available—Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table C-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.

Table C-2: Summary of Random Measurement-Error Variables

Measurement	Range	Mean	Distribution
Electricity	-0.5% to 0.5%	0%	Uniform
Natural gas	-2% to 2%		
Heat recovered	-5% to 5%		

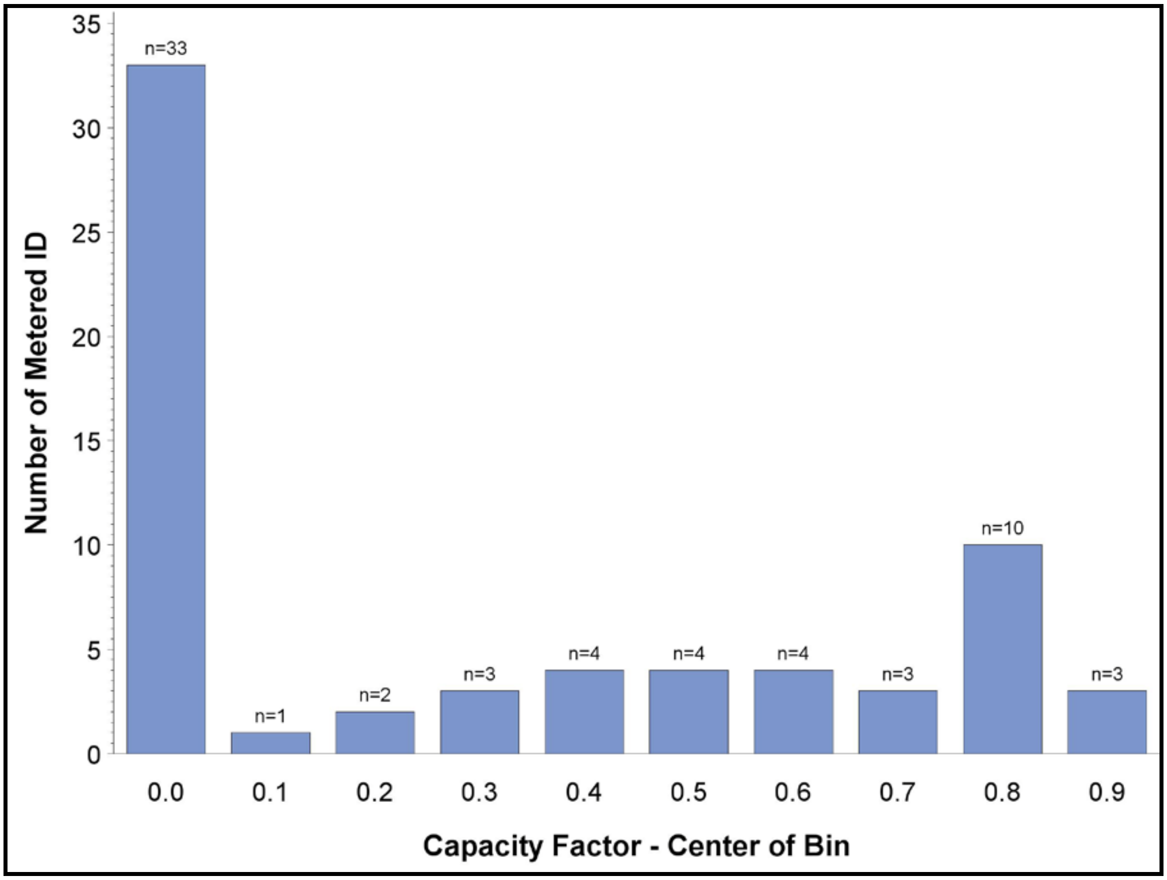
Metered Data Unavailable—Generating Sample Data from Performance Distributions

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

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 systems; 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.

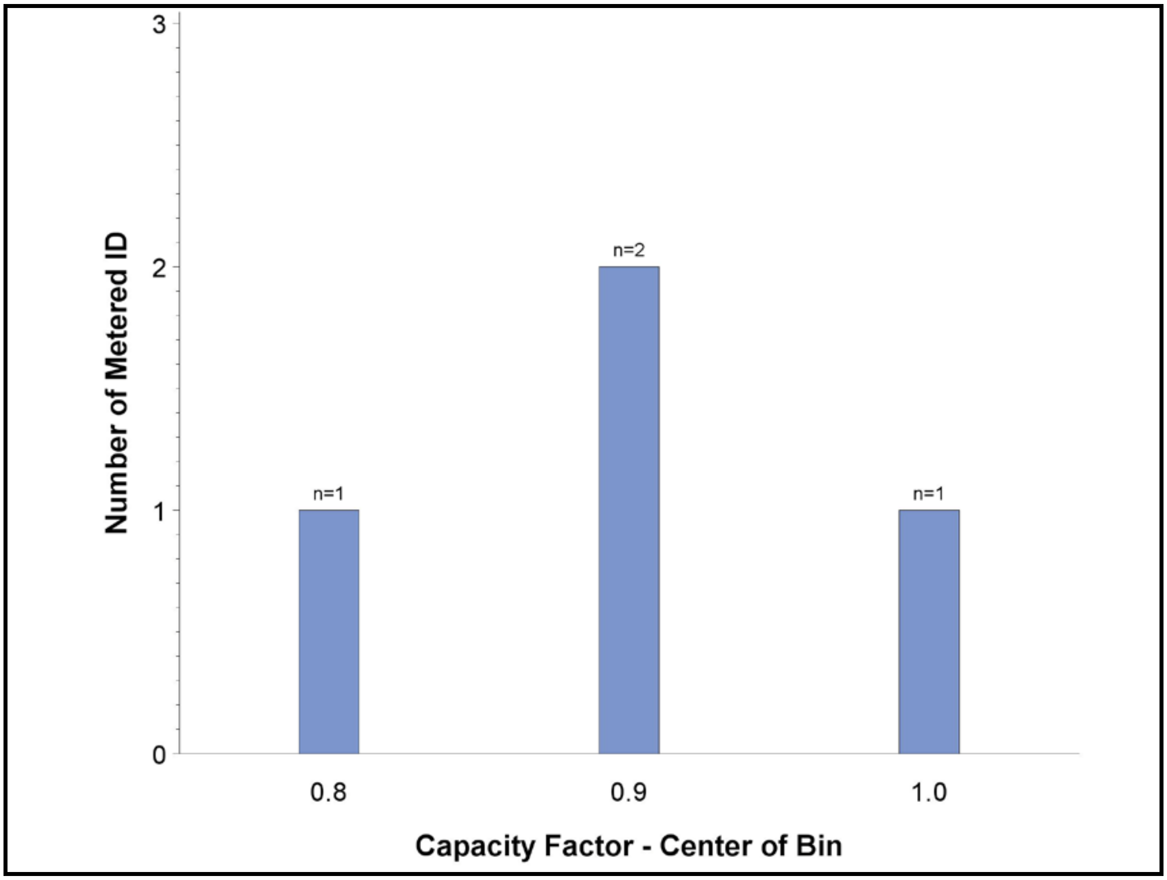
The assessment of the suitability of available metered data for use in MCS performance distributions is illustrated below with an example using recent data from 2008. The output of a group of non-renewable-fueled microturbines during the hour when CAISO system load reached its annual peak value is illustrated in Figure C-1. In this figure microturbine system output is expressed as metered power output per unit of system rebated capacity (Capacity Factor). Metered data were available for 67 systems. There were 72 systems for which metered data were not available for this hour. For each MCS run the actual performance of each of these systems had to be assigned from an MCS performance distribution. The metered data available for this group of systems appear to provide a good general indication of the distribution of values likely for unmetered systems.

Figure C-1: Non-Renewable-Fueled Microturbine Measured Coincident Peak Output



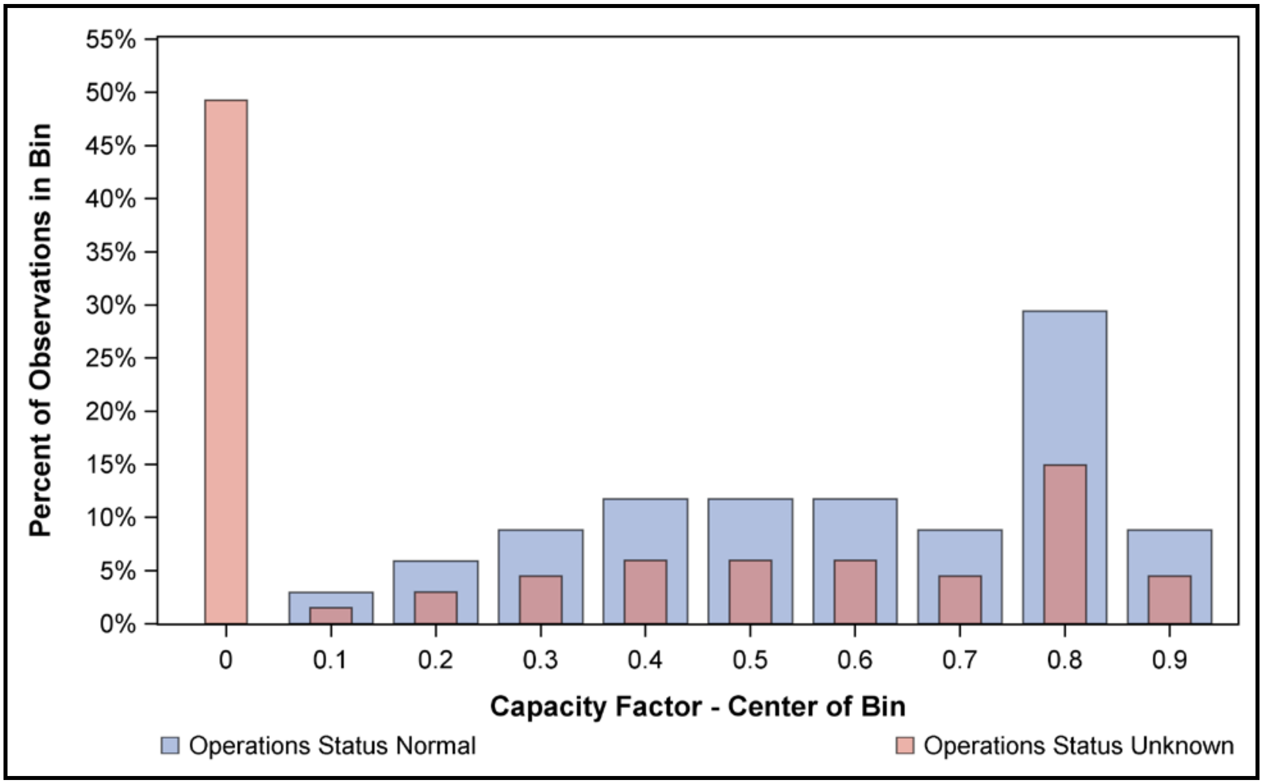
There are other sample design strata for which the quantity of metered data available is insufficient to provide a good indication of the distribution of values likely for unmetered projects. For example, there were only four metered non-renewable-fueled gas turbines during the CAISO peak hour in 2010. The measured performance of these four systems is shown in Figure C-2.

Figure C-2: Non-Renewable-Fueled Gas Turbine Measured Coincident Peak Output



If 10, 24, or 31 systems were metered it is unlikely that all of them would fall in this exact same distribution. Instead some systems would be expected to have a CF of 0.1 and 0.2, and other systems could have been running at full capacity (CF = 1). The metered data available for this group of systems do not appear to provide a good general indication of the distribution of values likely for unmetered systems. Figure C-3 shows the distribution used in the MCS for non-renewable-fueled gas turbines at the CAISO peak hour.

Figure C-3: Peak CF Distribution used in MCS for Non-Renewable-Fueled Gas Turbines



Use of a distribution shown in Figure C-3 emphasizes the fact that the performance of the unmetered systems is not known, and that in the MCS the assumed distribution of peak CF values is based on judgment. Lastly, the modification introduces a small measure of additional conservatism into MCS results. Review of metered data availability for all technology and fuel sample design strata revealed numerous instances such as that described above. Consequently, in some instances simplifying assumptions were made.

Table C-3 shows the groups used to estimate the uncertainty in the CAISO peak hour impact.

Table C-3: Performance Distributions Developed for the 2010 CAISO Peak Hour MCS Analysis

Technology	Fuel	PA
Wind[5]	N/A	N/A
IC Engine	Non-renewable, Renewable	All
Microturbine	Non-renewable, Renewable	All
Gas Turbine	Non-renewable[6]	All
Fuel Cell	Non-renewable, Renewable	All

Table C-4 shows the groups used to estimate the uncertainty in the yearly energy production. Internal combustion (IC) 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% of each month in the year and because a significant difference was not seen between the annual capacity factors of these systems.

Table C-4: Performance Distributions Developed for the 2010 Annual Energy Production MCS Analysis

Technology	Fuel
Wind	N/A
Engine/Turbine	Non-renewable, Renewable
Fuel Cell	All

Performance distributions were developed for each of the groups in the tables 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 capacity factor and system size. All of these performance distributions are shown in Figure C-4 through Figure C-27.

5 As of December 31, 2010, there are eight Complete wind turbine projects in the SGIP. MCS analysis was not conducted for wind turbine impacts due to lack of available metered data.

6 There are no renewable-fueled gas turbines in the program as of December 31, 2010.

<u>*Performance Distributions for Coincident Peak Demand Impacts*</u>

Figure C-4: Fuel Cell Measured Coincident Peak Output (Non-Renewable Fuel)

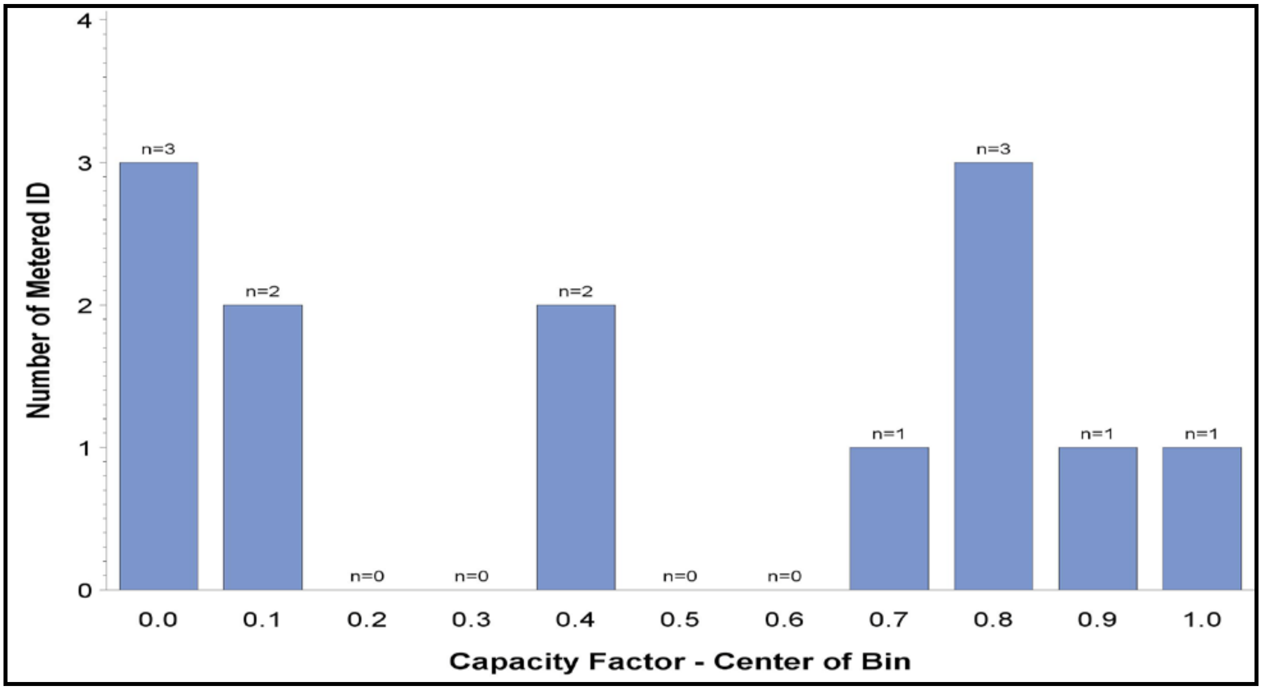


Figure C-5: MCS Distribution –Fuel Cell Coincident Peak Output (Non-Renewable Fuel)

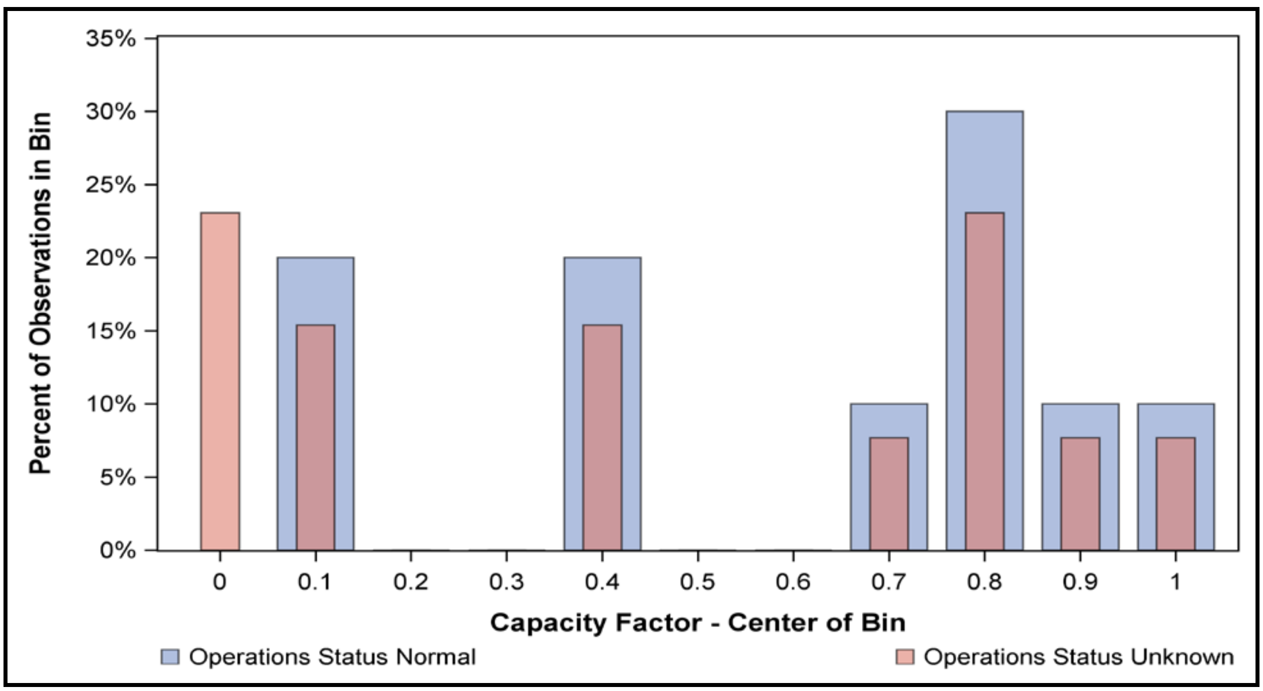


Figure C-6: Fuel Cell Measured Coincident Peak Output (Renewable Fuel)

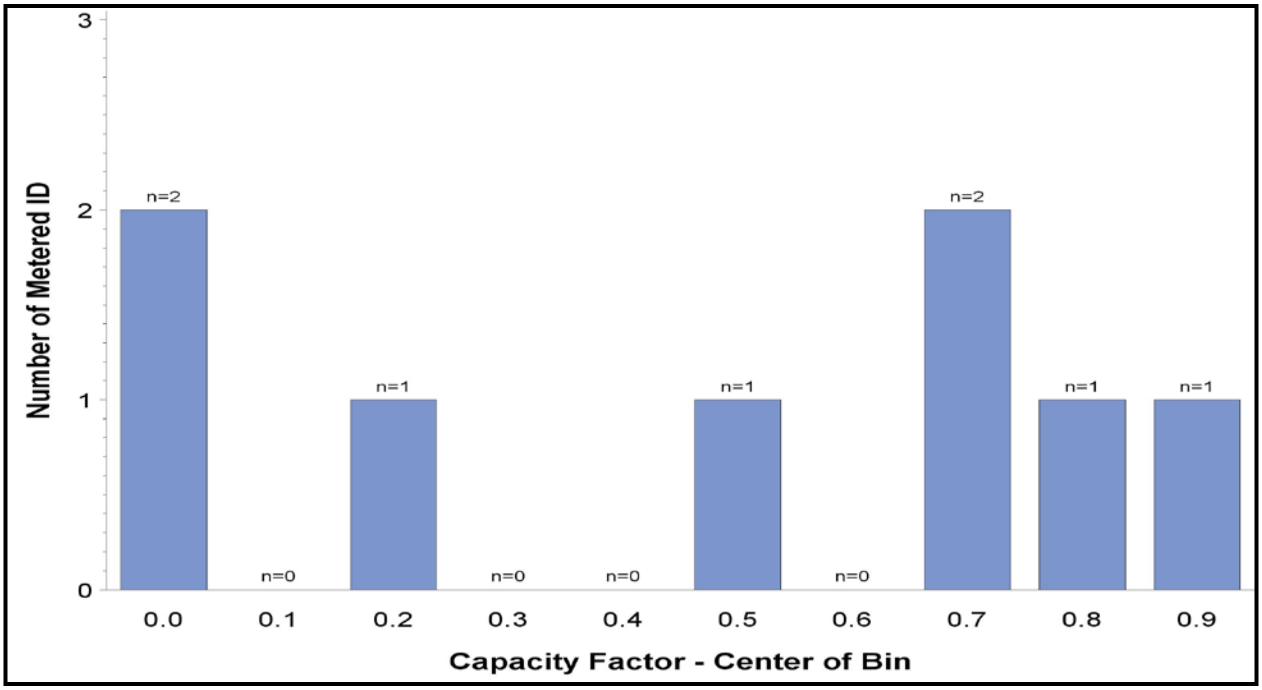


Figure C-7: MCS Distribution –Fuel Cell Coincident Peak Output (Renewable Fuel)

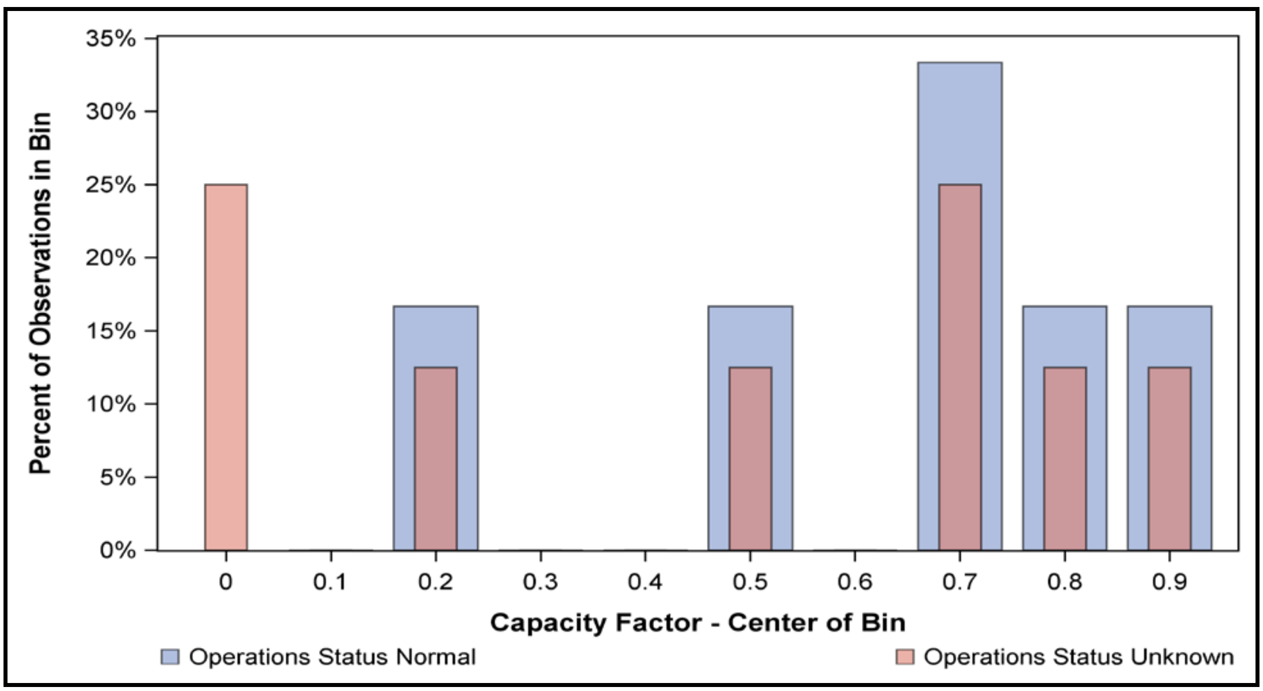


Figure C-8: IC Engine Measured Coincident Peak Output (Non-Renewable Fuel)

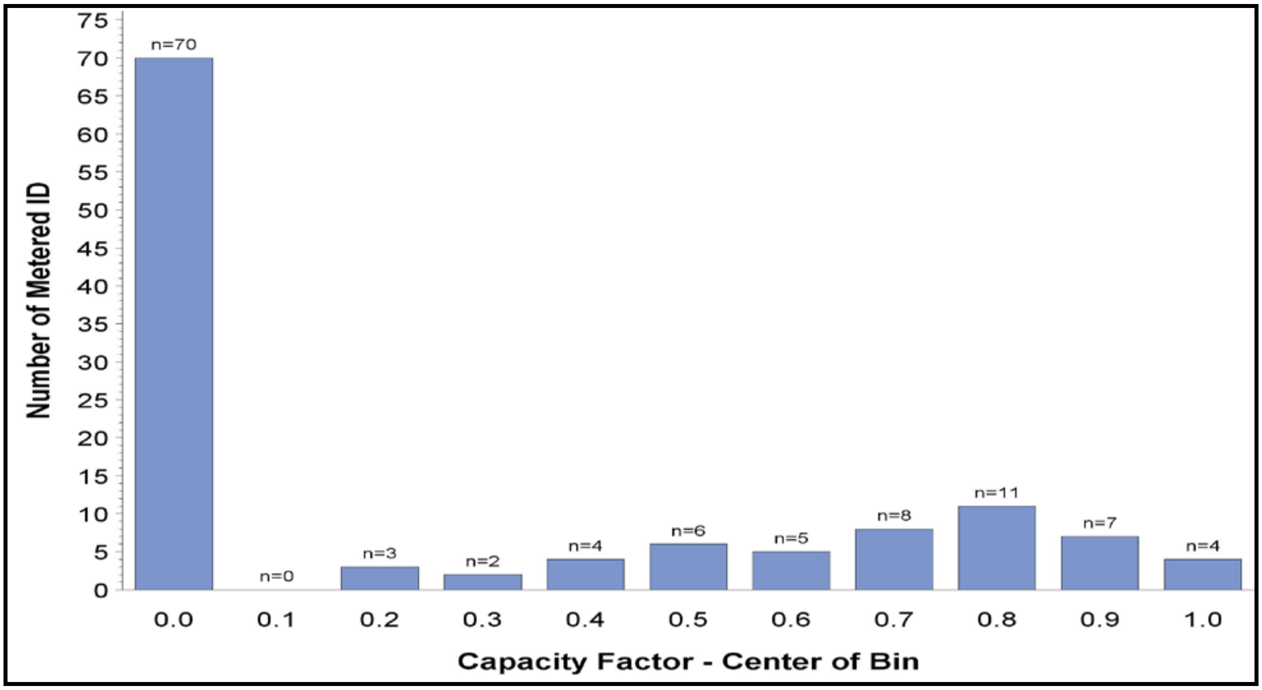


Figure C-9: MCS Distribution—IC Engine Coincident Peak Output (Non-Renewable Fuel)

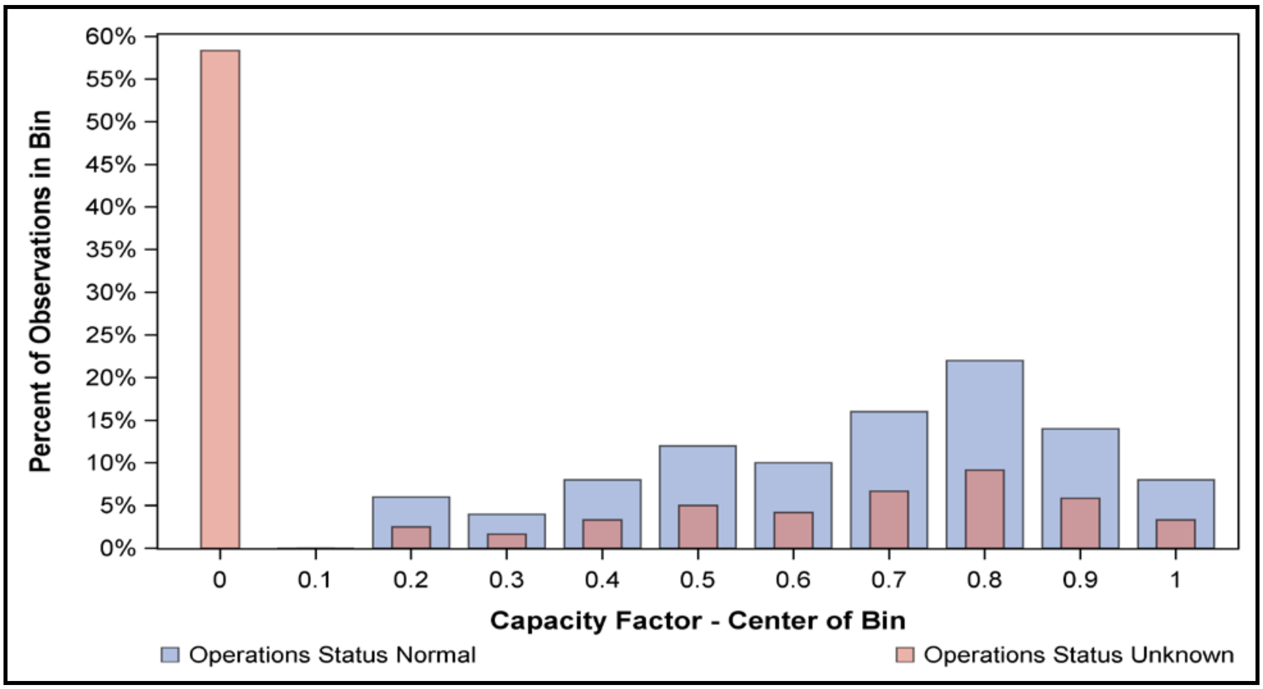


Figure C-10: IC Engine Measured Coincident Peak Output (Renewable Fuel)

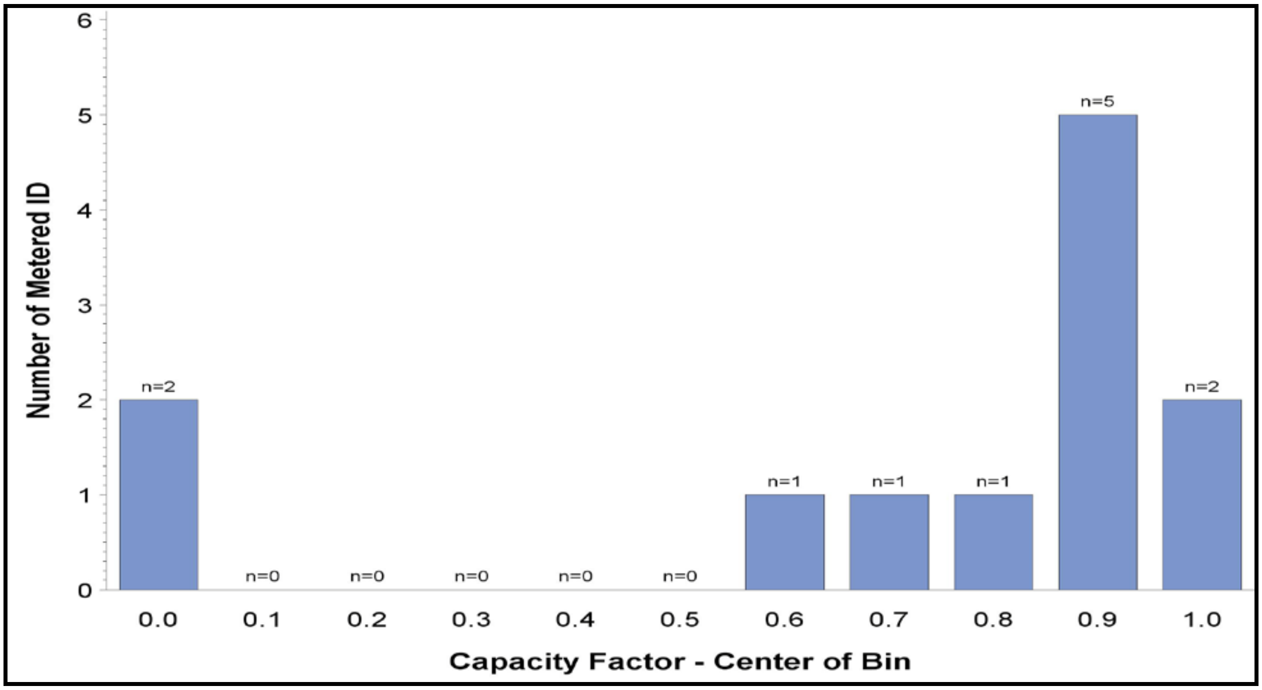


Figure C-11: MCS Distribution—IC Engine Coincident Peak Output (Renewable Fuel)

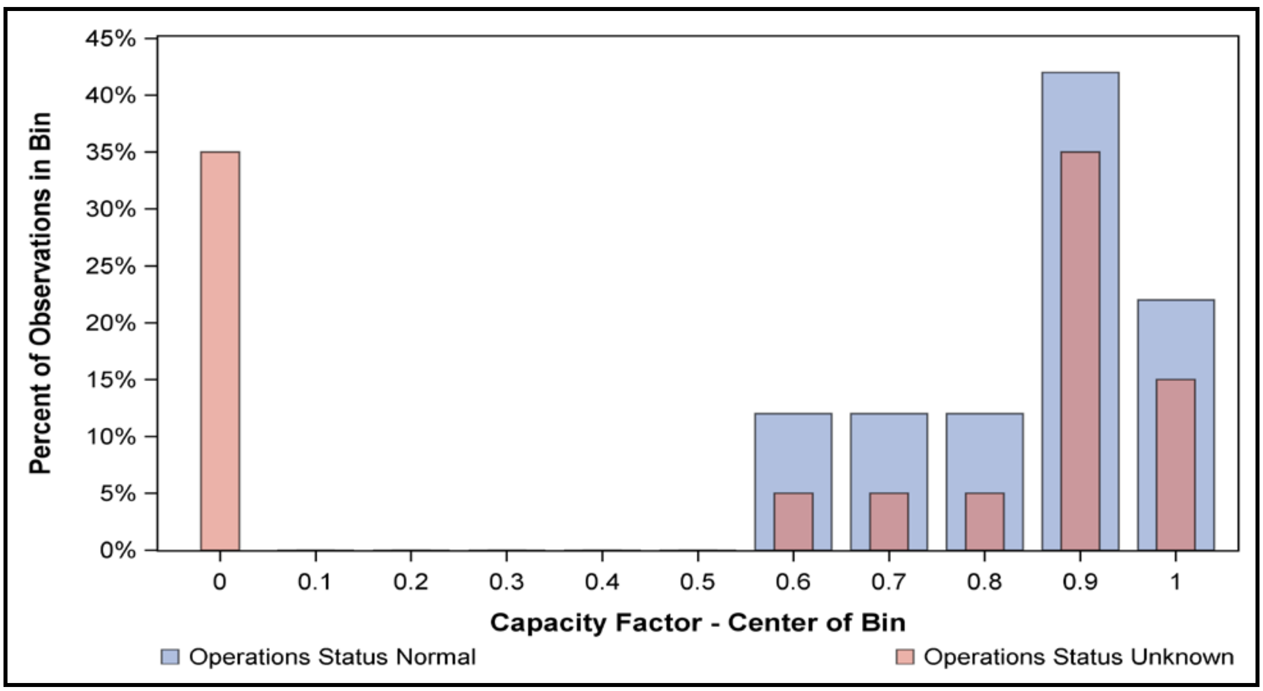


Figure C-12: Gas Turbine Measured Coincident Peak Output (Non-Renewable Fuel)

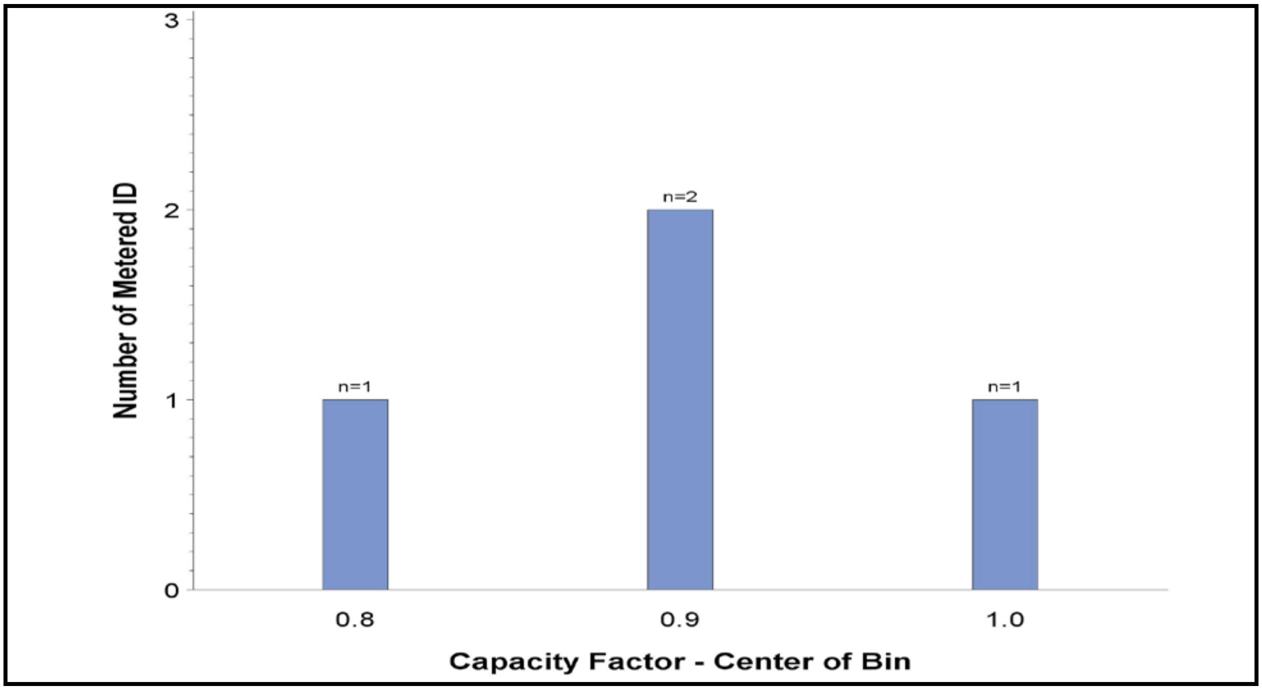


Figure C-13: MCS Distribution—Gas Turbine Coincident Peak Output (Non-Renewable Fuel)

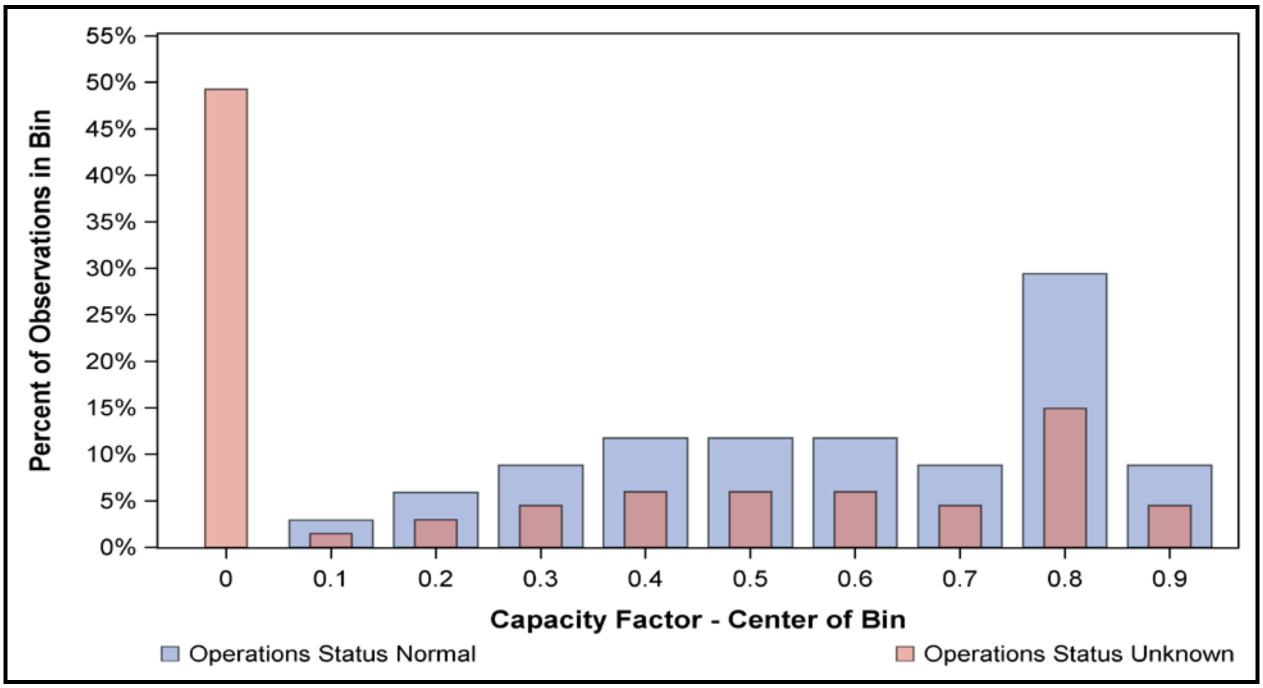


Figure C-14: Microturbine Measured Coincident Peak Output (Non-Renewable Fuel)

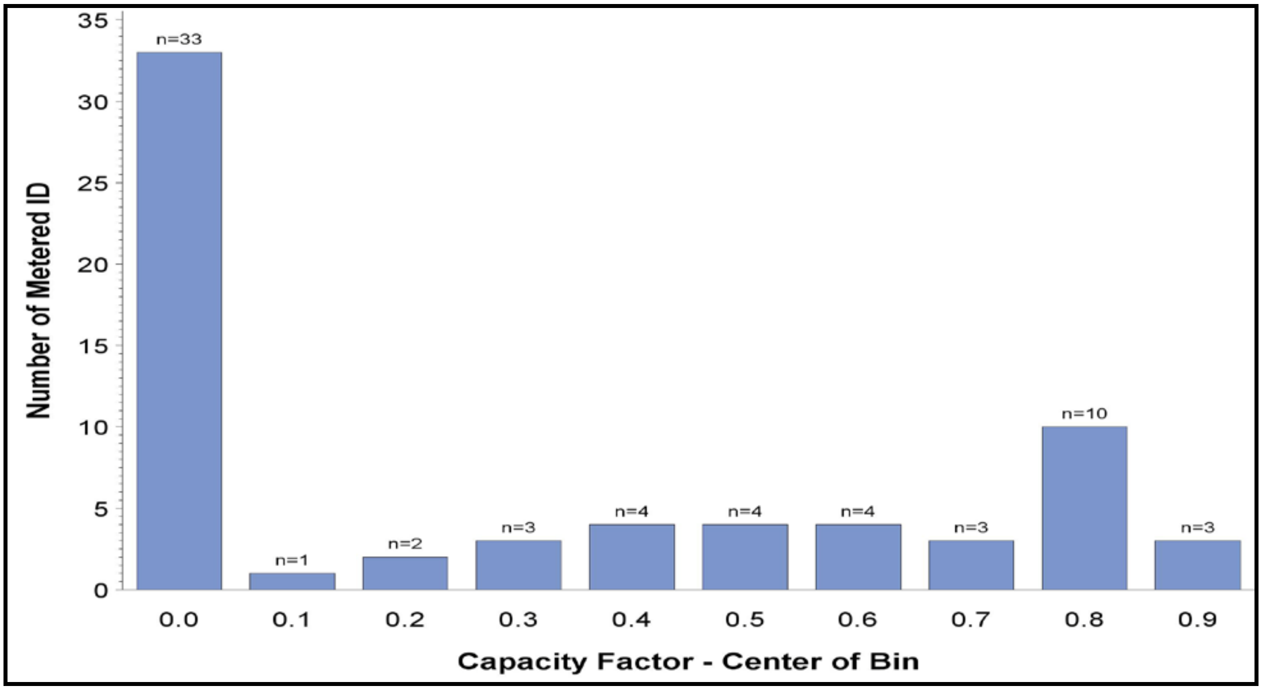


Figure C-15: MCS Distribution—Microturbine Coincident Peak Output (Non-Renewable Fuel)

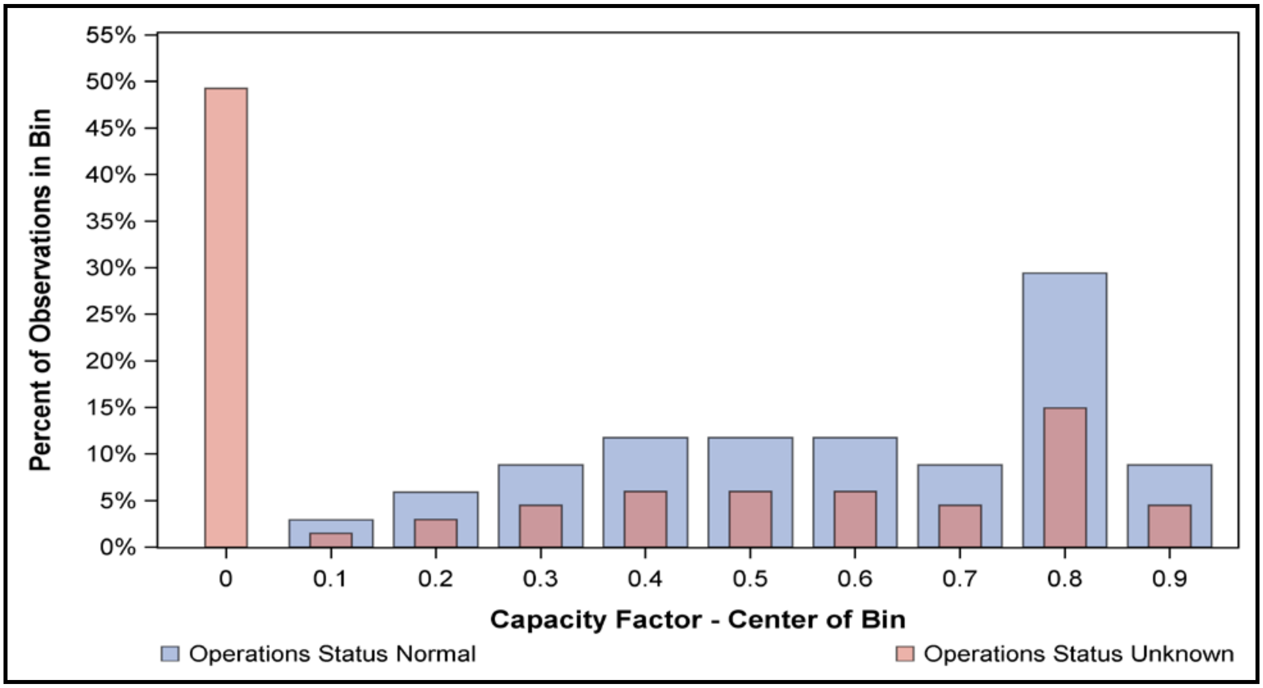


Figure C-16: Microturbine Measured Coincident Peak Output (Renewable Fuel)

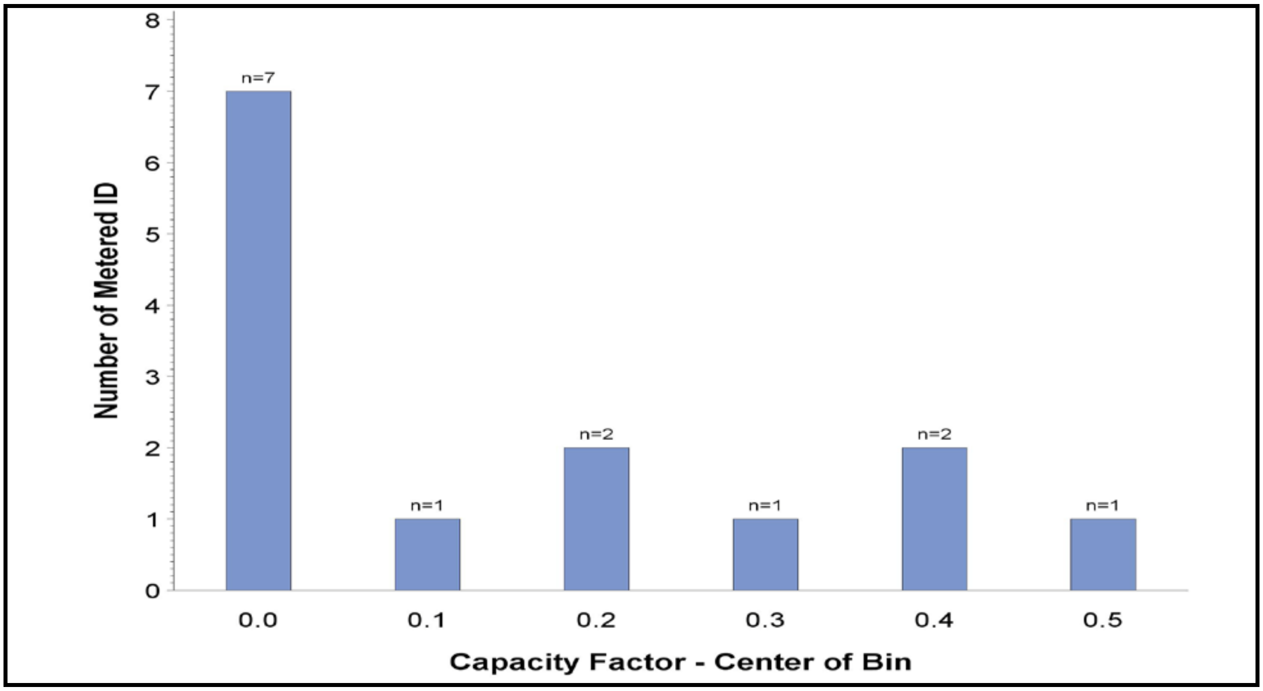
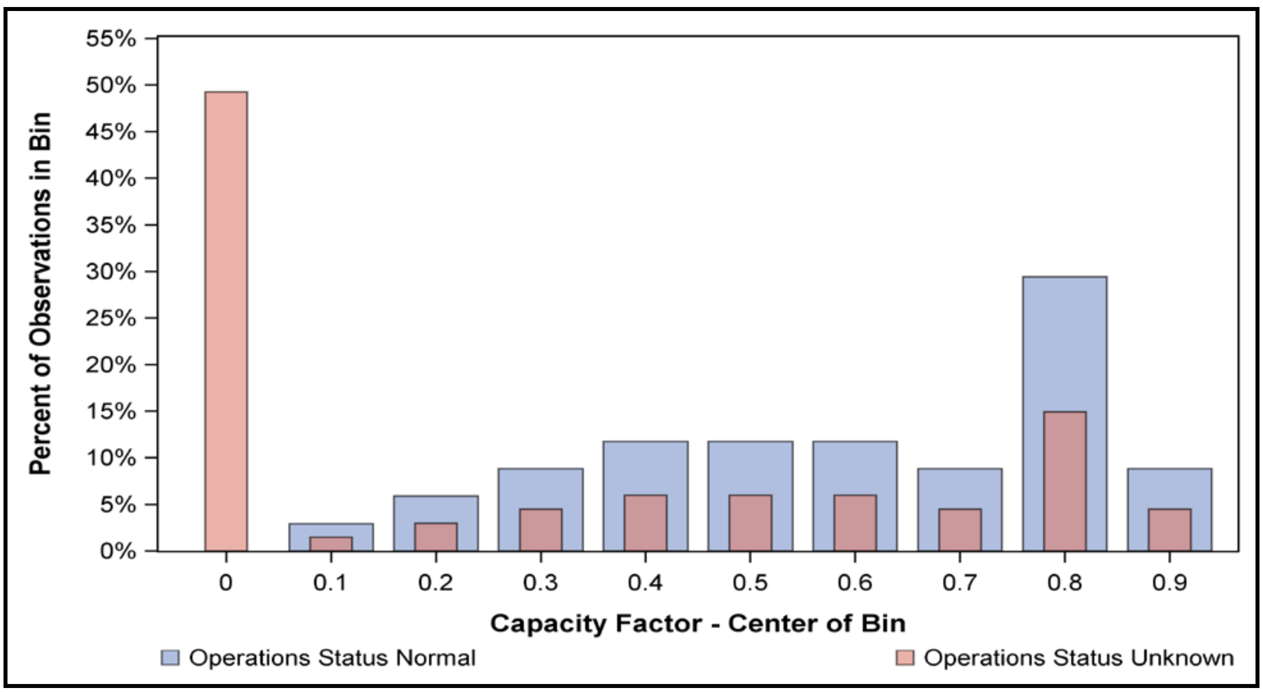


Figure C-17: MCS Distribution—Microturbine Coincident Peak Output (Renewable Fuel)



Performance Distributions for Energy Impacts

Figure C-18: Fuel Cell Measured Energy Production (Capacity Factor)

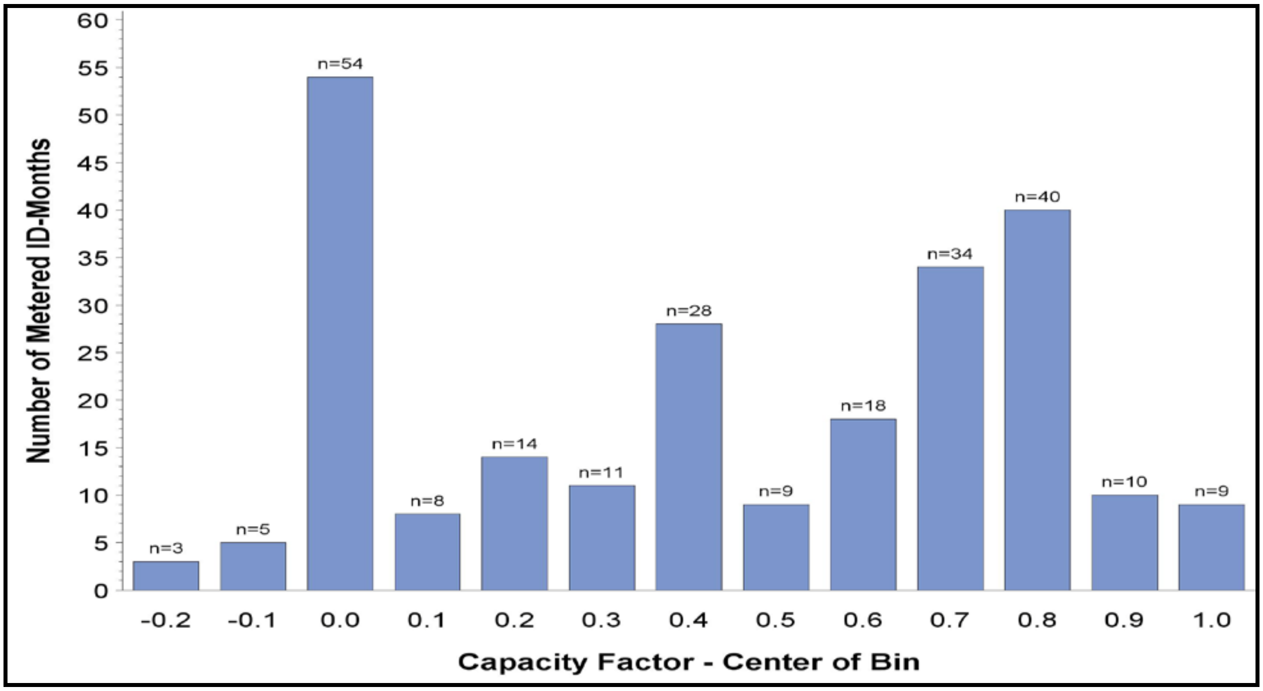


Figure C-19: MCS Distribution—Fuel Cell Energy Production (Capacity Factor)

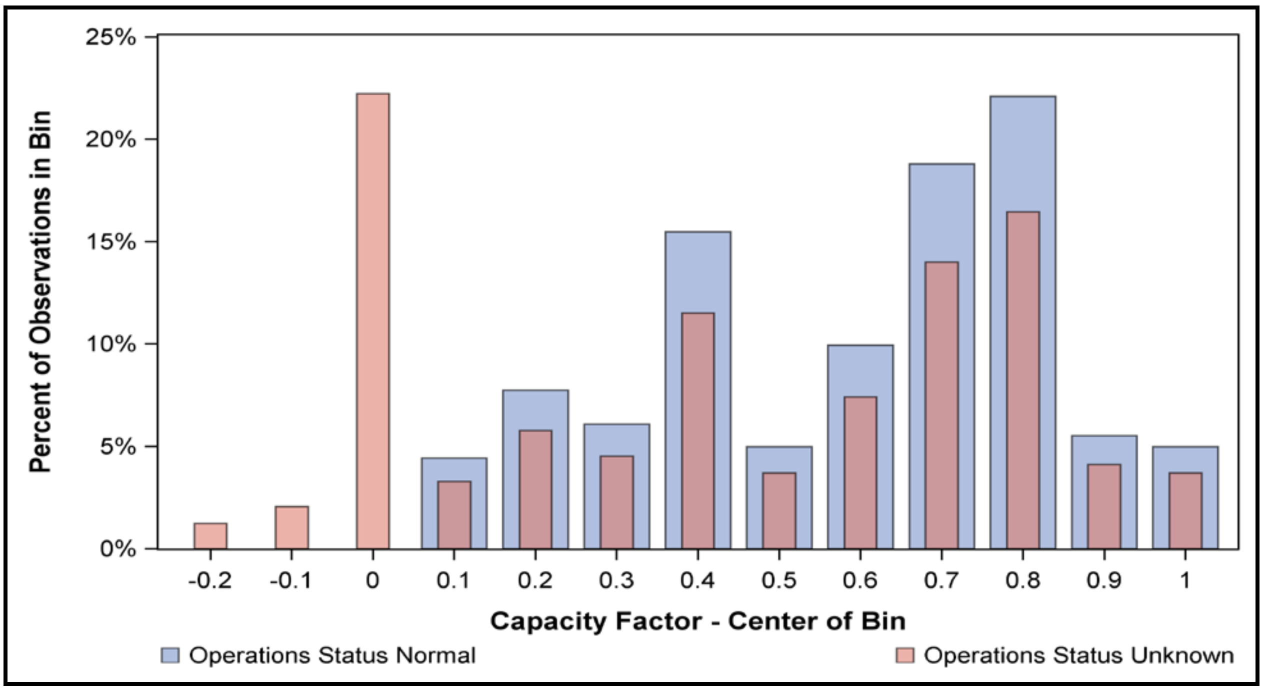


Figure C-20: Engine/Turbine (Non-Renewable) Measured Electricity Production (Capacity Factor)

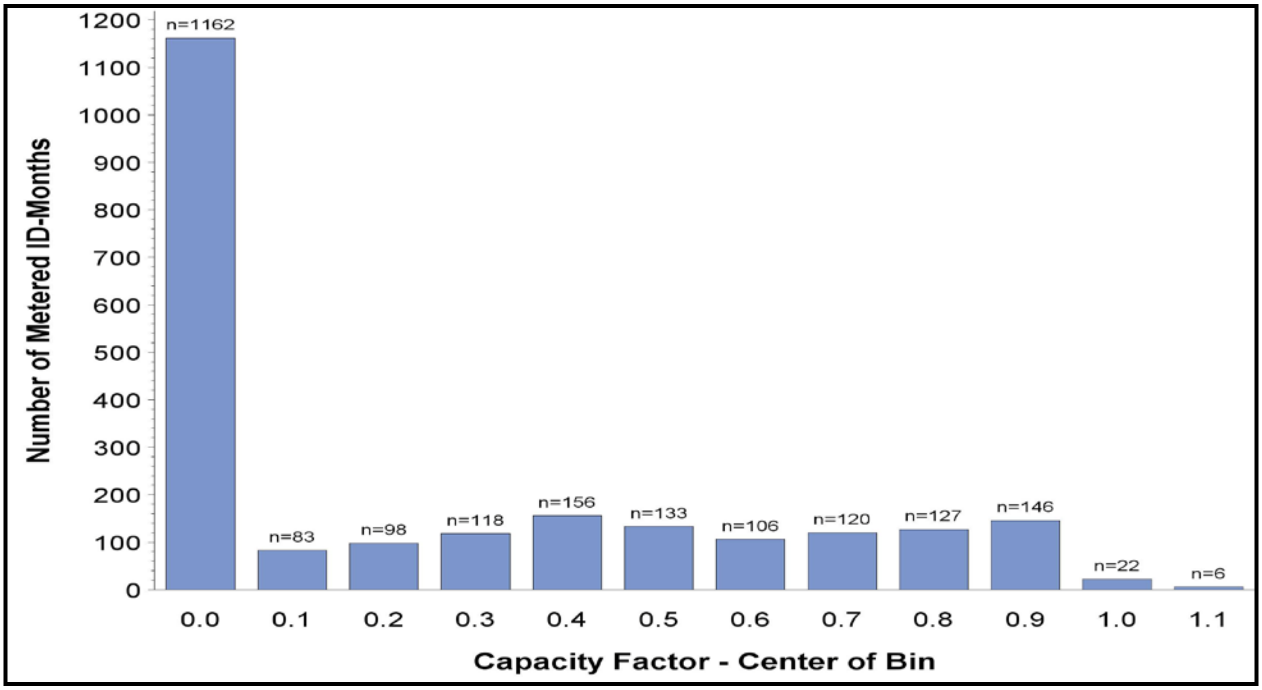


Figure C-21: MCS Distribution—Engine/Turbine (Non-Renewable) Electricity Production (Capacity Factor)

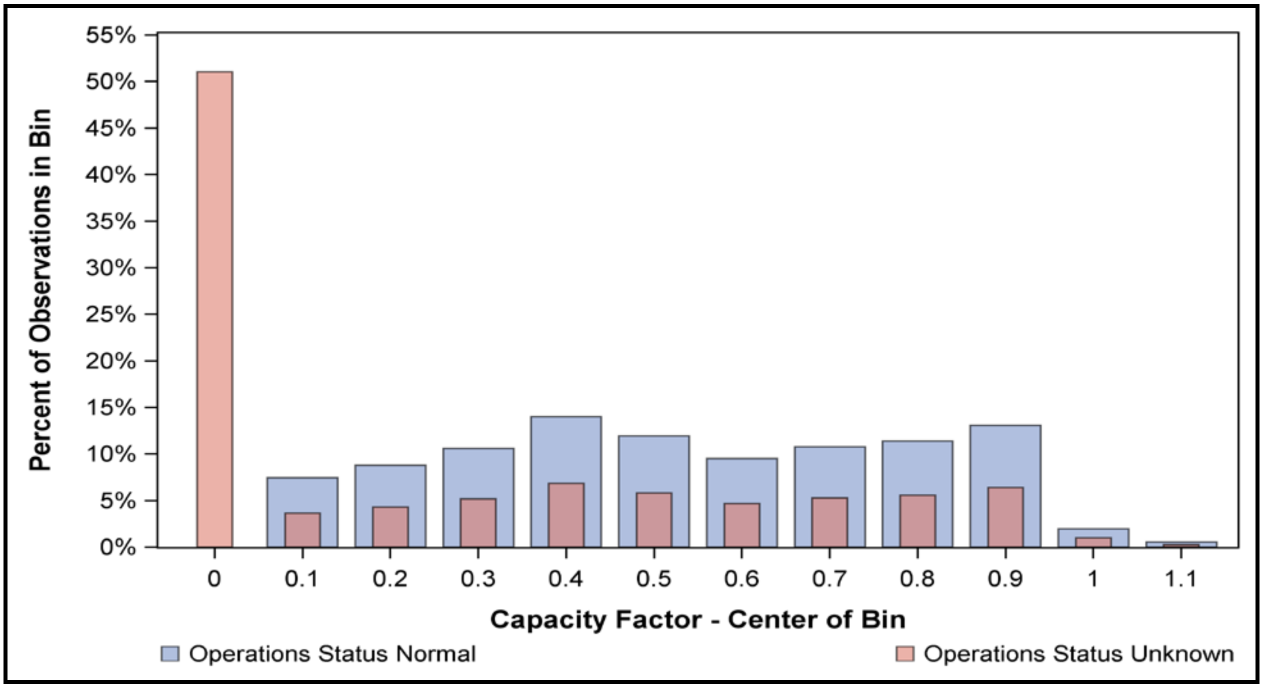


Figure C-22: Engine/Turbine (Renewable) Measured Electricity Production (Capacity Factor)

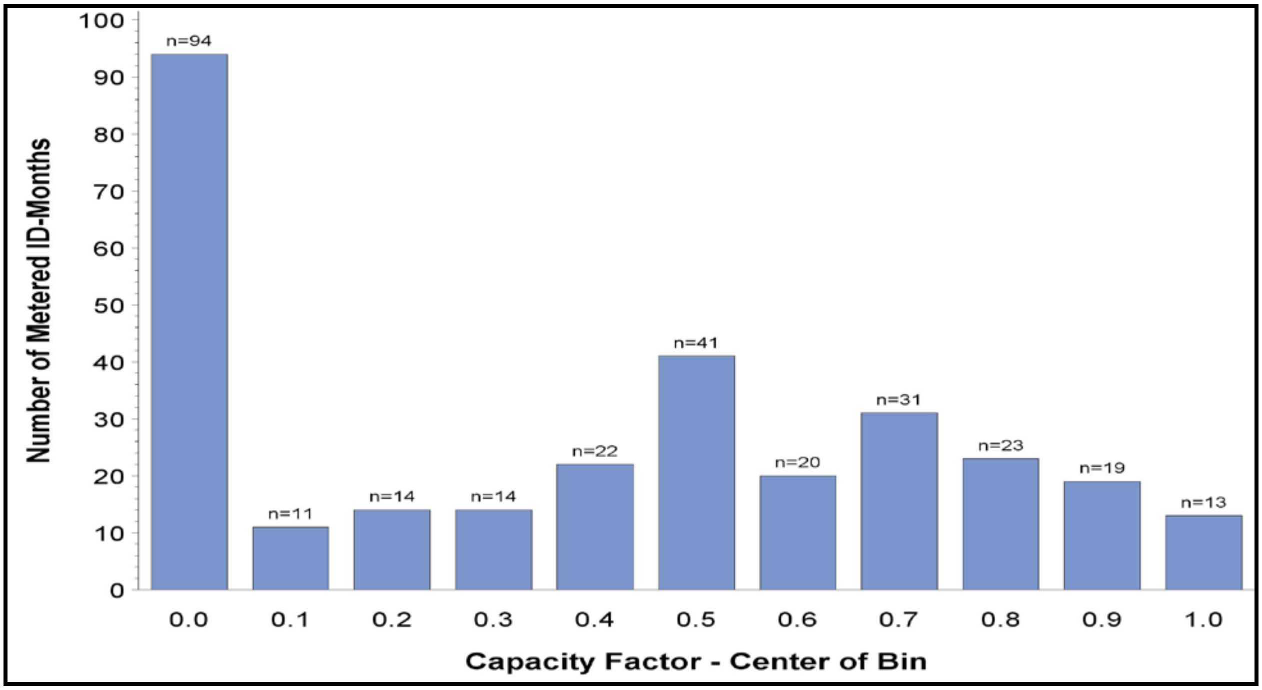


Figure C-23: MCS Distribution—Engine/Turbine (Renewable) Electricity Production (Capacity Factor)

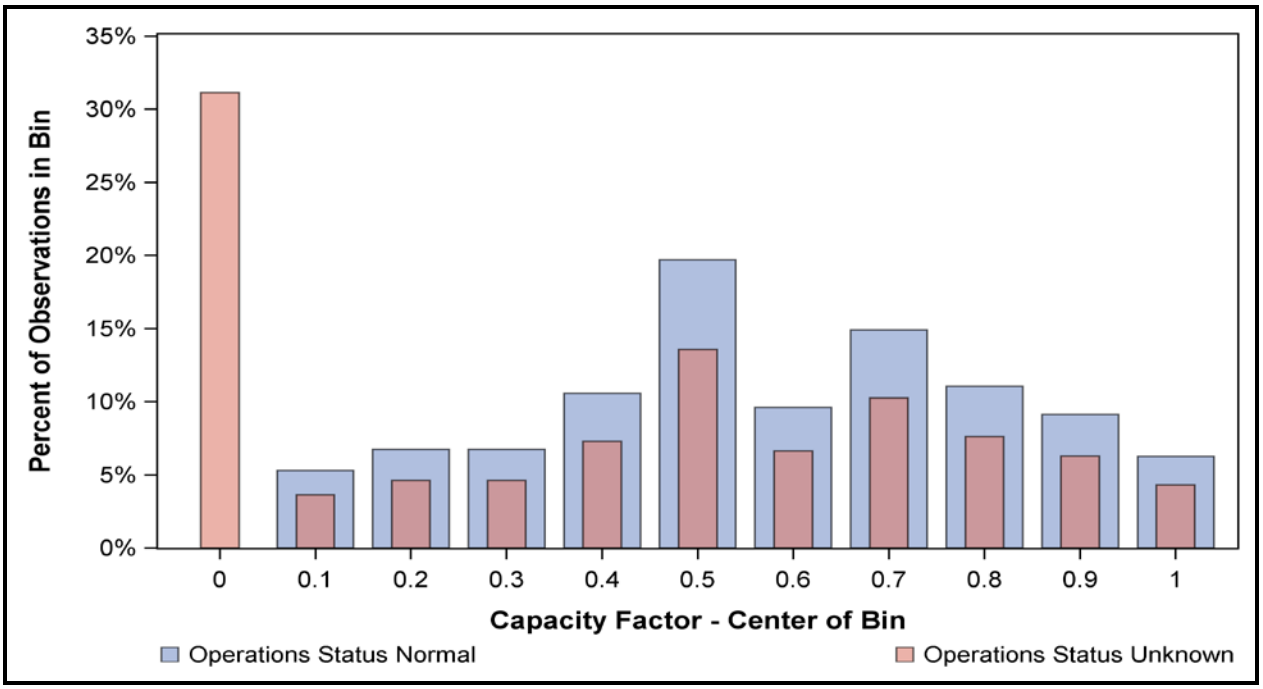


Figure C-24: Fuel Cell (Non-Renewable) Measured Heat Recovery Rate

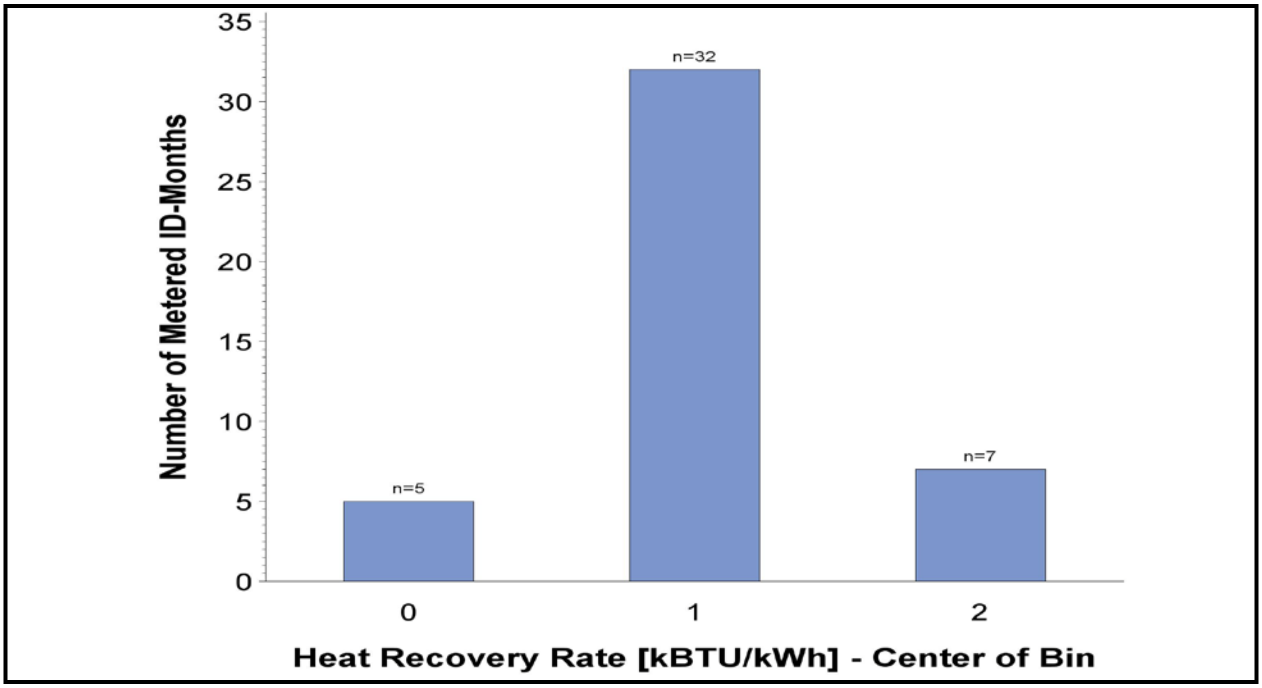


Figure C-25: MCS Distribution—Fuel Cell (Non-Renewable) Heat Recovery Rate

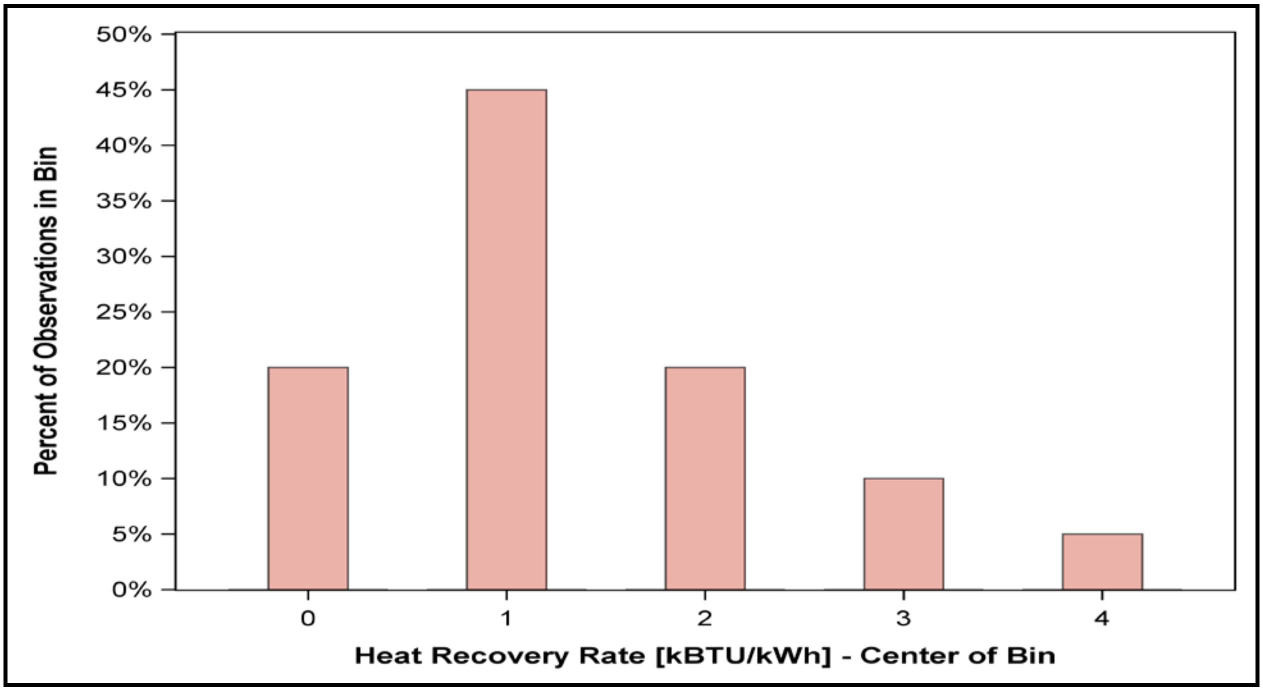


Figure C-26: Engine/Turbine Measured Heat Recovery Rate in 2006

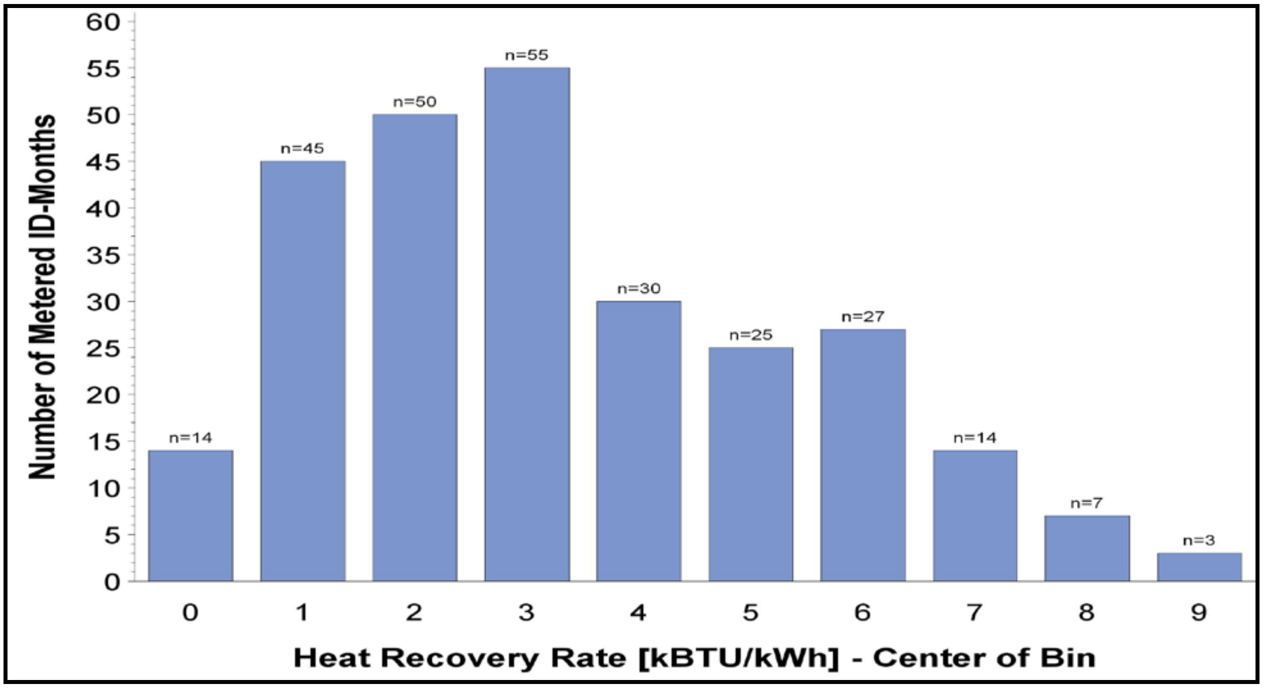
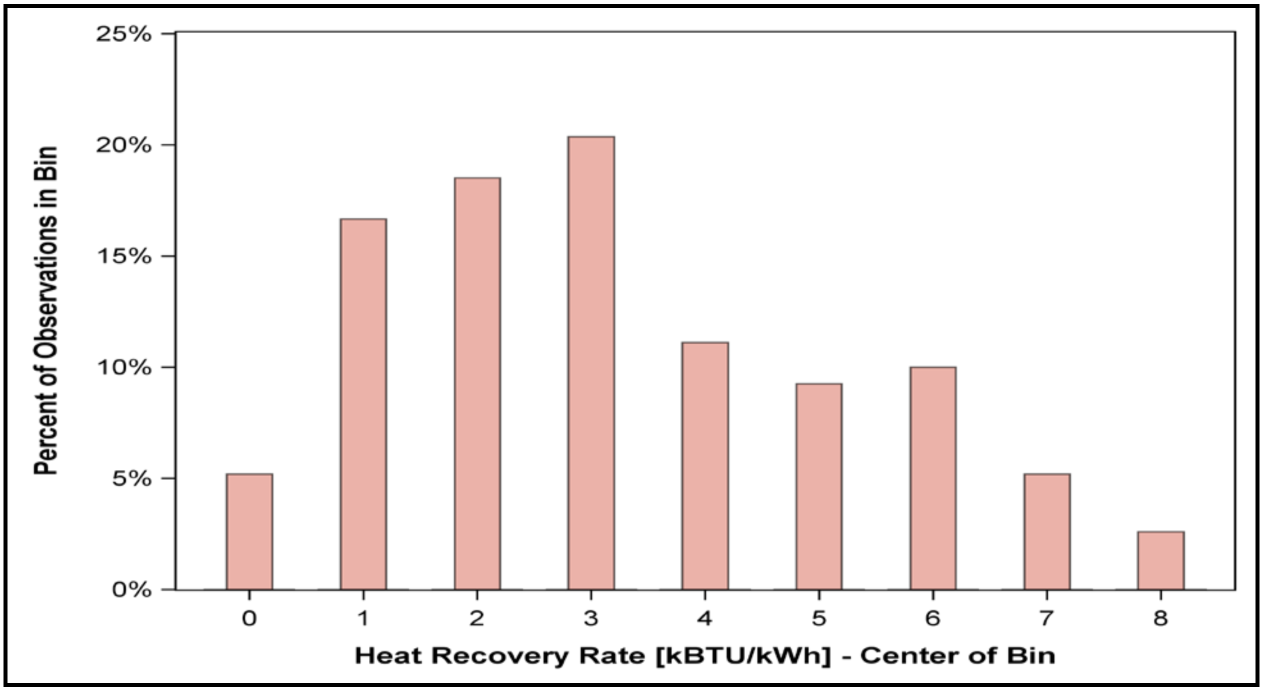


Figure C-27: MCS Distribution—Engine/Turbine Heat Recovery Rate



<u>*Bias*</u>

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

Planned data collection disproportionally favors dissimilar groups. HEAT metering is generally being installed on projects which are still under their three-year contract (or five-year contract for fuel cells) with SGIP. If the actual heat recovery performance of the older systems differs systematically from the newer metered systems then estimates calculated for the older systems will be biased. A similar situation can occur when actual performance differs substantially from performance assumptions underlying data collection plans.

Actual data collection allocations deviate from planned data collection allocations. In program impact evaluation studies, actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated for unmetered systems may be biased. For example, metered data for a number of fuel cell systems 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 systems differs systematically from that of the systems metered by participants then estimates calculated for the unmetered systems will be biased. One example of this is if a participant metered system's output decreases unexpectedly the participant will know almost immediately and steps can be taken to get the system running normally again. However, a similar situation with an unmetered system could go unnoticed for months.

Actual data collection quantities deviate from planned data collection quantities. For example, plans called for collection of ENGO data from all RFU systems; however, data were actually collected only from a small proportion of completed RFU systems.

In the MCS analysis bias is accounted for during development of performance distributions assumed for unmetered systems. 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 project 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 sites. Due to the relative magnitudes involved, instrumentation error—if it exists—accounts for an insignificant portion or total bias contained in point estimates.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered sites. The relative importance of this varies with metering rate. For example, where the metering rate is 90%, a 20% sampling bias will yield an error of only 2% 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 sites 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
- Program Total PUC216.6 (b) Cogeneration System Efficiency

Cogeneration system efficiency is a calculated value that is based on sample data for electricity production, fuel consumption, and heat recovery. The efficiency values for each simulation run were calculated as:

$$PUC216.6b_r = \frac{\left(\sum ELEC_{rs} \times \mathrm{KWH2KBTU}\right) + \left(\sum \mathrm{C1} \times HEAT_{rs}\right)}{\sum FUEL_{rs}} \times \frac{100\%}{1}$$

Where:

$PUC216.6b_r$ is program total PUC216.6 (b) cogeneration system efficiency for run *r*

Units: %

$ELEC_{rs}$ is total electricity production for run *r* and system *s*

Units: kWh

KWH2KBTU is a conversion factor

Value: 0.2931 (i.e., 1/3.412)

Units: kWh/kBtu

C1 is a constant

Value: 0.5

Units: none

Basis: Cogeneration system efficiency definition of CPUC

$HEAT_{rs}$ is total useful waste heat recovery for run r and system s

Units: kBtu

$FUEL_{rs}$ is total fuel consumption for run r and system s

Units: kBtu

Basis: Lower Heating Value of fuel

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 constant relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

C.4.5 Results

The confidence levels in the energy impacts, demand impacts, and PUC 216.6 compliance results have been presented along with those results. This section will present the precision and confidence intervals associated with those confidence levels in more detail. Three bins were used for Confidence Levels: 90/10 or better, 70/30 or better (but worse than 90/10), and worse than 70/30.

Table C-5: Uncertainty Analysis Results for Annual Energy Impact Results by Technology and Basis

Technology* / Basis	Confidence Level	Precision†	Confidence Interval†
FC	**90%**	**2.3%**	**0.470 to 0.492**
Metered	90%	0.1%	0.488 to 0.489
Estimated	70%	8.5%	0.408 to 0.484
GT	**90%**	**3.1%**	**0.711 to 0.755**
Metered	90%	0.1%	0.871 to 0.872
Estimated	70%	15.1%	0.298 to 0.404
IC Engine	**90%**	**2.7%**	**0.273 to 0.288**
Metered	90%	0.1%	0.215 to 0.215
Estimated	90%	5.0%	0.360 to 0.398
MT	**90%**	**2.4%**	**0.352 to 0.369**
Metered	90%	0.1%	0.351 to 0.352
Estimated	90%	7.5%	0.354 to 0.411

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine

† Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-6: Uncertainty Analysis Results for Annual Energy Impact Results by Technology, Fuel, and Basis

Technology* & Fuel/ Basis	Confidence Level	Precision†	Confidence Interval†
FC-N	**90%**	**3.1%**	**0.481 to 0.512**
Metered	90%	0.1%	0.511 to 0.512
Estimated	70%	9.0%	0.409 to 0.490
FC-R	**90%**	**3.0%**	**0.442 to 0.469**
Metered	90%	0.1%	0.458 to 0.459
Estimated	70%	25.2%	0.322 to 0.538
GT-N	**90%**	**3.1%**	**0.711 to 0.755**
Metered	90%	0.1%	0.871 to 0.872
Estimated	70%	15.1%	0.298 to 0.404
IC Engine-N	**90%**	**3.0%**	**0.258 to 0.274**
Metered	90%	0.1%	0.190 to 0.190
Estimated	90%	5.2%	0.356 to 0.395
IC Engine-R	**90%**	**4.1%**	**0.420 to 0.456**
Metered	90%	0.1%	0.435 to 0.435
Estimated	70%	9.5%	0.403 to 0.488
MT-N	**90%**	**2.5%**	**0.366 to 0.385**
Metered	90%	0.1%	0.379 to 0.379
Estimated	90%	8.6%	0.336 to 0.398
MT-R	**90%**	**6.8%**	**0.278 to 0.318**
Metered	90%	0.1%	0.234 to 0.234
Estimated	70%	9.5%	0.402 to 0.486

* FC = Fuel Cell; GT = Gas Turbine; IC Engine = Internal Combustion Engine; MT = Microturbine; N = Non-Renewable; R = Renewable

† Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-7: Uncertainty Analysis Results for PG&E Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**3.7%**	**0.542 to 0.583**
Metered	90%	0.1%	0.608 to 0.609
Estimated	70%	10.2%	0.401 to 0.493
GT	**70%**	**12.6%**	**0.349 to 0.449**
Metered	90%	0.3%	0.729 to 0.733
Estimated	70%	15.0%	0.311 to 0.421
IC Engine	**90%**	**4.5%**	**0.273 to 0.298**
Metered	90%	0.1%	0.209 to 0.209
Estimated	90%	8.0%	0.369 to 0.433
MT	**90%**	**3.4%**	**0.392 to 0.419**
Metered	90%	0.1%	0.411 to 0.412
Estimated	70%	6.9%	0.365 to 0.419

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-8: Uncertainty Analysis Results for SCE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**7.9%**	**0.288 to 0.337**
Metered	90%	0.2%	0.272 to 0.273
Estimated	70%	15.5%	0.379 to 0.519
IC Engine	**90%**	**6.4%**	**0.249 to 0.283**
Metered	90%	0.1%	0.207 to 0.207
Estimated	70%	7.1%	0.314 to 0.361
MT	**90%**	**8.2%**	**0.251 to 0.296**
Metered	90%	0.1%	0.206 to 0.206
Estimated	70%	9.2%	0.335 to 0.403

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-9: Uncertainty Analysis Results for SCG Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**3.9%**	**0.438 to 0.474**
Metered	90%	0.1%	0.457 to 0.458
Estimated	< 70%	33.9%	0.288 to 0.584
GT	**90%**	**5.3%**	**0.678 to 0.755**
Metered	90%	0.1%	0.844 to 0.846
Estimated	70%	28.5%	0.239 to 0.430
IC Engine	**90%**	**4.0%**	**0.315 to 0.341**
Metered	90%	0.1%	0.284 to 0.284
Estimated	90%	7.7%	0.353 to 0.411
MT	**90%**	**3.4%**	**0.389 to 0.416**
Metered	90%	0.1%	0.410 to 0.411
Estimated	70%	8.9%	0.343 to 0.411

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-10: Uncertainty Analysis Results for CCSE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**0.1%**	**0.453 to 0.453**
Metered	90%	0.1%	0.453 to 0.453
Estimated	N/A	N/A	N/A
GT	**90%**	**0.1%**	**0.903 to 0.905**
Metered	90%	0.1%	0.903 to 0.905
Estimated	N/A	N/A	N/A
IC Engine	**90%**	**7.2%**	**0.068 to 0.078**
Metered	90%	0.1%	0.066 to 0.066
Estimated	< 70%	37.0%	0.226 to 0.492
MT	**90%**	**0.1%**	**0.226 to 0.226**
Metered	90%	0.1%	0.226 to 0.226
Estimated	N/A	N/A	N/A

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-11: Uncertainty Analysis Results for Peak Demand Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**7.6%**	**0.462 to 0.538**
Metered	90%	0.1%	0.504 to 0.505
Estimated	< 70%	37.2%	0.298 to 0.650
GT	**70%**	**8.5%**	**0.675 to 0.801**
Metered	90%	0.2%	0.886 to 0.891
Estimated	< 70%	57.5%	0.159 to 0.589
IC Engine	**90%**	**7.1%**	**0.349 to 0.402**
Metered	90%	0.1%	0.332 to 0.333
Estimated	70%	9.7%	0.399 to 0.484
MT	**90%**	**8.2%**	**0.306 to 0.361**
Metered	90%	0.1%	0.320 to 0.321
Estimated	70%	15.4%	0.307 to 0.419

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-12: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for PG&E

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**70%**	**15.6%**	**0.377 to 0.516**
Metered	90%	0.3%	0.429 to 0.432
Estimated	< 70%	41.5%	0.278 to 0.672
FC-R	**90%**	**0.3%**	**0.767 to 0.772**
Metered	90%	0.3%	0.767 to 0.772
Estimated	N/A	N/A	N/A
GT-N	**< 70%**	**47.3%**	**0.213 to 0.594**
Metered	N/A	N/A	N/A
Estimated	< 70%	47.3%	0.213 to 0.594
IC Engine-N	**70%**	**9.0%**	**0.309 to 0.370**
Metered	90%	0.1%	0.251 to 0.252
Estimated	70%	15.8%	0.390 to 0.536
IC Engine-R	**90%**	**6.7%**	**0.524 to 0.599**
Metered	90%	0.2%	0.504 to 0.507
Estimated	70%	15.9%	0.669 to 0.921
MT-N	**70%**	**8.8%**	**0.405 to 0.484**
Metered	90%	0.2%	0.479 to 0.481
Estimated	70%	25.6%	0.290 to 0.489
MT-R	**70%**	**16.5%**	**0.136 to 0.190**
Metered	90%	0.3%	0.133 to 0.134
Estimated	< 70%	40.6%	0.143 to 0.338

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-13: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for SCE

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**< 70%**	**100.0%**	**0.000 to 0.540**
Metered	90%	0.1%	0.000 to 0.000
Estimated	< 70%	100.0%	0.000 to 0.900
FC-R	**90%**	**0.5%**	**0.388 to 0.391**
Metered	90%	0.5%	0.388 to 0.391
Estimated	90%	0.0%	0.000 to 0.000
GT-N	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A
IC Engine-N	**70%**	**14.2%**	**0.287 to 0.382**
Metered	90%	0.2%	0.296 to 0.298
Estimated	70%	25.6%	0.278 to 0.468
IC Engine-R	**70%**	**10.6%**	**0.470 to 0.581**
Metered	90%	0.3%	0.528 to 0.531
Estimated	< 70%	100.0%	0.000 to 1.000
MT-N	**70%**	**17.1%**	**0.235 to 0.332**
Metered	90%	0.3%	0.214 to 0.215
Estimated	< 70%	32.8%	0.271 to 0.535
MT-R	**< 70%**	**52.5%**	**0.065 to 0.209**
Metered	90%	0.4%	0.119 to 0.021
Estimated	< 70%	100.0%	0.000 to 0.313

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-14: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for SCG

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**90%**	**0.8%**	**0.637 to 0.647**
Metered	90%	0.4%	0.640 to 0.646
Estimated	< 70%	100.0%	0.000 to 0.900
FC-R	**90%**	**0.3%**	**0.448 to 0.451**
Metered	90%	0.4%	0.640 to 0.646
Estimated	N/A	N/A	N/A
GT-N	**70%**	**15.4%**	**0.613 to 0.835**
Metered	90%	0.3%	0.847 to 0.852
Estimated	< 70%	100.0%	0.000 to 0.800
IC Engine-N	**70%**	**6.8%**	**0.404 to 0.463**
Metered	90%	0.1%	0.437 to 0.439
Estimated	70%	16.0%	0.359 to 0.496
IC Engine-R	**< 70%**	**34.4%**	**0.487 to 0.996**
Metered	90%	0.5%	0.993 to 1.002
Estimated	< 70%	100.0%	0.000 to 1.000
MT-N	**70%**	**8.0%**	**0.333 to 0.391**
Metered	90%	0.2%	0.344 to 0.346
Estimated	70%	28.6%	0.297 to 0.535
MT-R	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-15: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for CCSE

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
FC-N	**90%**	**0.3%**	**0.526 to 0.529**
Metered	90%	0.3%	0.526 to 0.529
Estimated	N/A	N/A	N/A
FC-R	**N/A**	**N/A**	**N/A**
Metered	N/A	N/A	N/A
Estimated	N/A	N/A	N/A
GT-N	**90%**	**0.3%**	**0.924 to 0.931**
Metered	90%	0.3%	0.924 to 0.931
Estimated	N/A	N/A	N/A
IC Engine-N	**90%**	**0.4%**	**0.117 to 0.118**
Metered	90%	0.4%	0.117 to 0.118
Estimated	N/A	N/A	N/A
IC Engine-R	**< 70%**	**100.0%**	**0.000 to 0.900**
Metered	N/A	N/A	N/A
Estimated	< 70%	100.0%	0.000 to 0.900
MT-N	**90%**	**0.2%**	**0.343 to 0.345**
Metered	90%	0.2%	0.343 to 0.345
Estimated	N/A	N/A	N/A
MT-R	**90%**	**0.5%**	**0.051 to 0.052**
Metered	90%	0.5%	0.051 to 0.052
Estimated	N/A	N/A	N/A

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-16: Uncertainty Analysis Results for Annual PUC 216.6(b)

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
FC	**90%**	**1.8%**	**0.460 to 0.477**
Metered	90%	0.5%	0.449 to 0.454
Estimated	90%	2.4%	0.462 to 0.484
GT	**90%**	**2.8%**	**0.428 to 0.452**
Metered	90%	0.8%	0.433 to 0.440
Estimated	90%	6.9%	0.413 to 0.475
IC Engine	**90%**	**1.5%**	**0.452 to 0.466**
Metered	90%	0.6%	0.471 to 0.476
Estimated	90%	1.6%	0.450 to 0.465
MT	**90%**	**2.8%**	**0.311 to 0.329**
Metered	90%	4.4%	0.292 to 0.318
Estimated	90%	3.6%	0.315 to 0.339

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Appendix D

Statistical Analysis of Extended Outages

D.1 Background

This section explores the statistical analysis of extended outages using nearly 10 years of historical metered data. Previous studies have looked at annual capacity factor over time as an indicator of performance or outages lasting more than three days. This analysis examines factors that could influence the increase with age of extended outages wherein capacity factor is zero.

This analysis focuses on a long-term perspective of system outages with respect to system age, specifically to outages lasting more than 30 days. This vantage point examines systems that have not generated due to some decision to keep the systems off rather than due to some technical issue. Any technical issue can be resolved given a decision to expend funds. Decisions to keep a system off may be due to high costs for major system repair, for continued system maintenance, or for buying natural gas to generate rather than to simply buy electricity, to name a few. This extended outage approach ignores short-term outages of a few days or weeks, leading toward a better understanding of long-term decision-making issues with CHP systems.

The analysis of extended outages is intended to make available to policy makers information useful to determine appropriate strategic policy decisions, if need be, for the long-term viability of the SGIP. Several types of analysis are performed using the basis of long-term outages, namely those over 30 days. This section includes a summary analysis providing general trends and statistical analysis examining averages of the key variable of the annual proportions of days in outages over 30 days.

D.2 Overview of the Analysis

The analysis undertaken in the evaluation of extended outages is a statistical summary level and an in-depth statistical analysis of variance technique (described in more detail below in Section D.4). Each part of the analysis considers performance with regard to days spent in extended outages, that is outages over 30 days. The key variable is referred to as the outage factor.

The statistical findings of the overall analysis are:

- The spread or variance of outages increases with age for most systems
- Outage factor of systems dramatically increase, some more evident than others with age
- Many systems have their own unique mean outage factor and standard deviations
- Most systems are difficult to group together due to multitude of differing characteristics
- The outage factor varies accordingly to the experience level of a developer

D.3 Statistical Summary Analysis

The summary analysis enables a high-level approach, examining means and standard deviations, to understand basic trends in the data. System host's building type (based on industrial classification code), developer's number of completed SGIP systems, system technology type, fuel type and size category of system are some the variables examined. This summary analysis describes general trends of outage factors with age and several conclusions of the analysis.

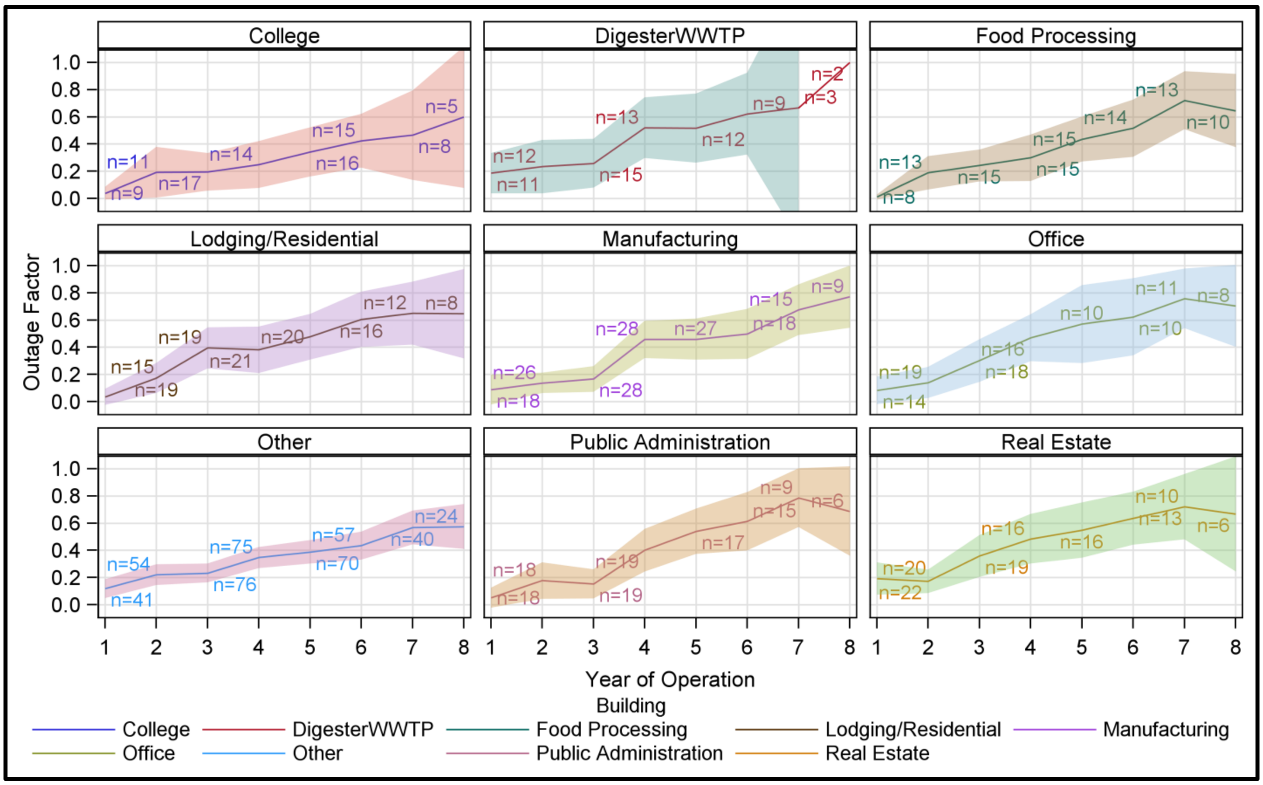
One of the fundamental questions considered here is: do system outages differ with age by host building type?

Figure D-1 shows the many host building types categorized into top eight by count in the SGIP and a ninth category of 'Other' for the remaining types. It shows annual mean outage factor by age. The shaded bands following the trendlines indicate the upper and lower confidence limits of the mean outage factor, with wider bands indicating increased greater variability in outage factor among systems. Each building type has a somewhat different trend of outage factor and varying confidence intervals. Several common trends are evident.

- The variability of outage factor disproportionately increases over time, especially in the later years
- The outage factors, while different on a year-to-year basis, are relatively the same across the years for the different building types
- Most building types indicate the least outage factor in the earlier years, namely in the second and third years

The analysis indicated that differences in mean outage factors between building types were not significant.

Figure D-1: Annual Mean Outage Factor by Age and Building Type

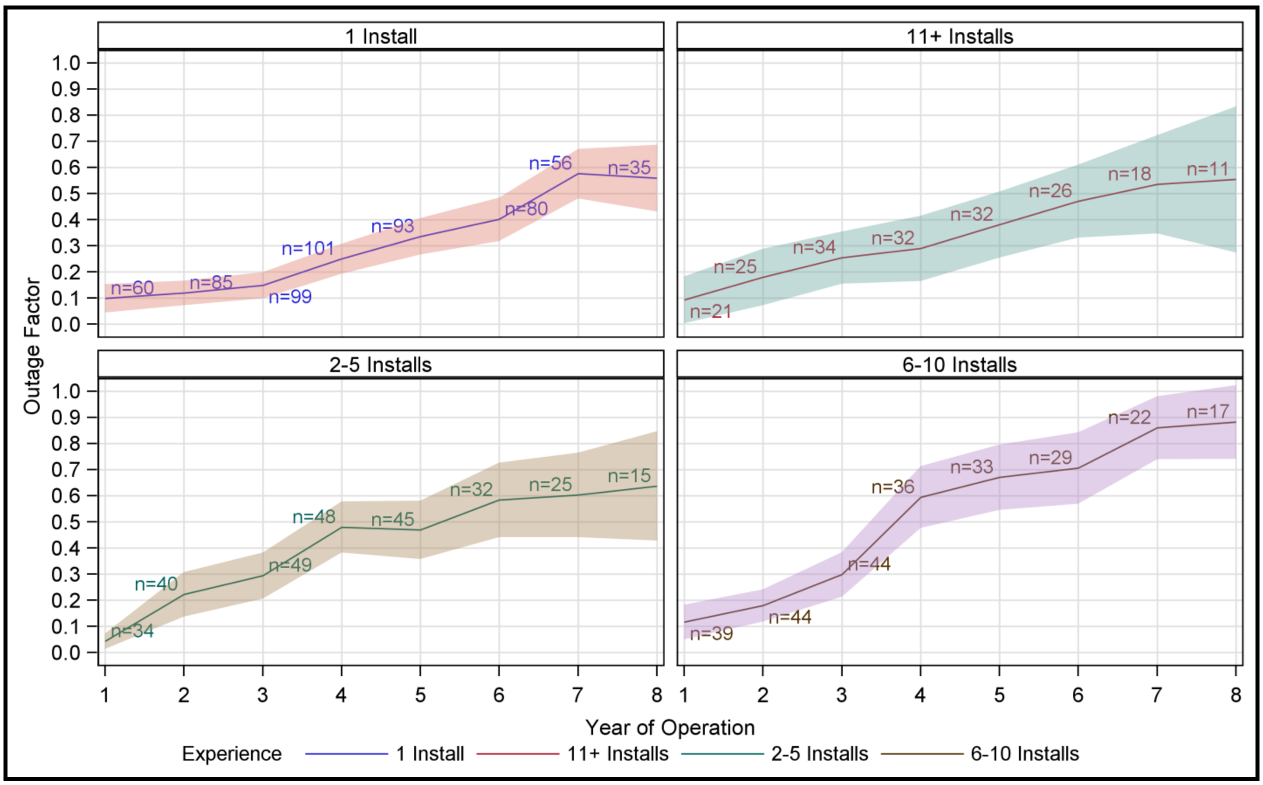


An examination of influence on outage factor of the number of systems completed by a developer reveals some unexpected trends, contrary for example to typical economies of scale. The number of completed systems were considered a proxy for a developer's experience, and greater experience was hypothesized to be associated with lower outage factors. Developers were classified into four categories of count of completed systems: 1, 2 to 5, 6 to 10, and 11 or more. Figure D-2 shows their outage factor trends with age. The results yielded the following observations.

- The 1 completed system developer group over time shows a tighter variability of outage factor than the other three groups
- The 6-10 completed system group indicates a higher outage factor starting as early in the third year with a seemingly constant outage variability after the fourth year
- The 11 or more completed system group exhibits a clear, smooth outage factor over the years

The analysis indicated that differences in mean outage factors between category of developer completed system counts were significant.

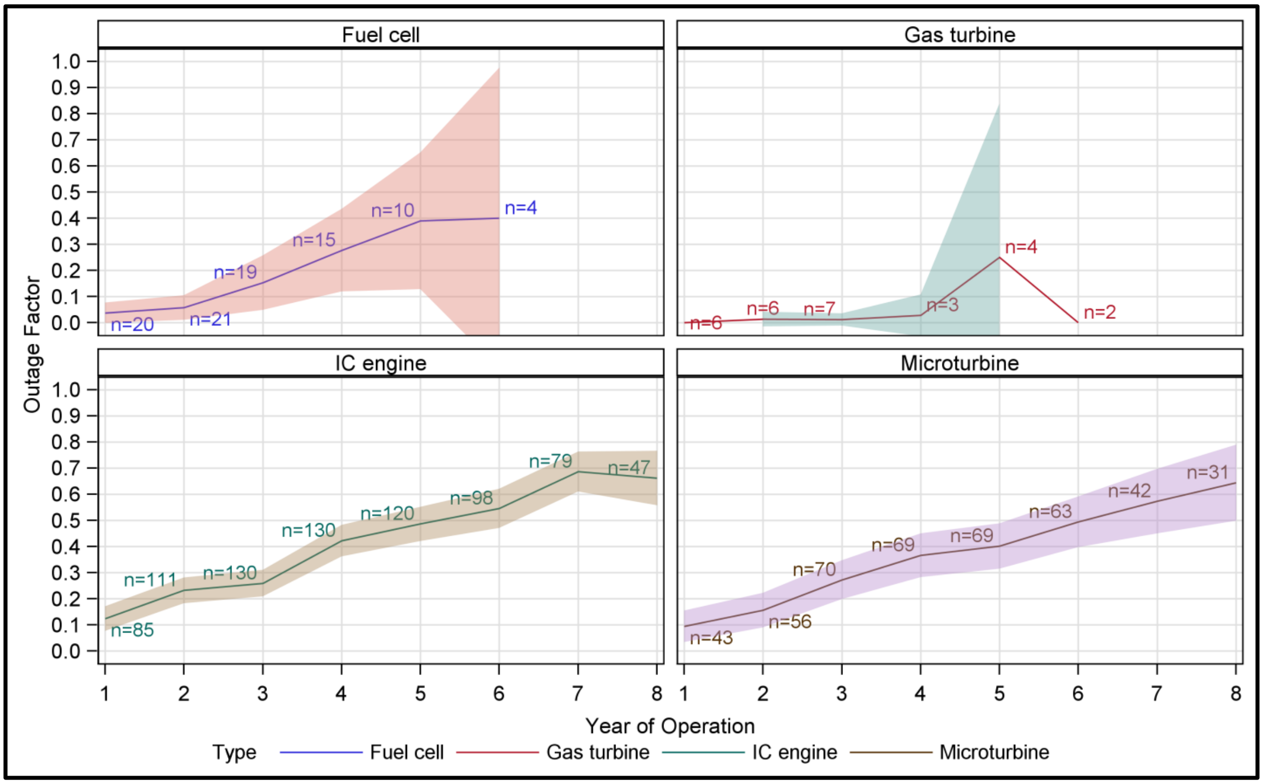
Figure D-2: Annual Mean Outage Factor by Age and Developer System Count



The type of system has a bearing on the rate of performance over time. As seen from the figure below, the type of the system whether fuel, gas turbine, IC engine, or microturbine, determines the degree and spread of outage factor over the life of the system. While fuel cell and gas turbine systems are few in numbers, several factors are evident.

- Microturbine outage factor show an increasing linear trend
- IC engines indicate higher outages than microturbines systems
- Fuel cell systems' outage factor variability increases dramatically

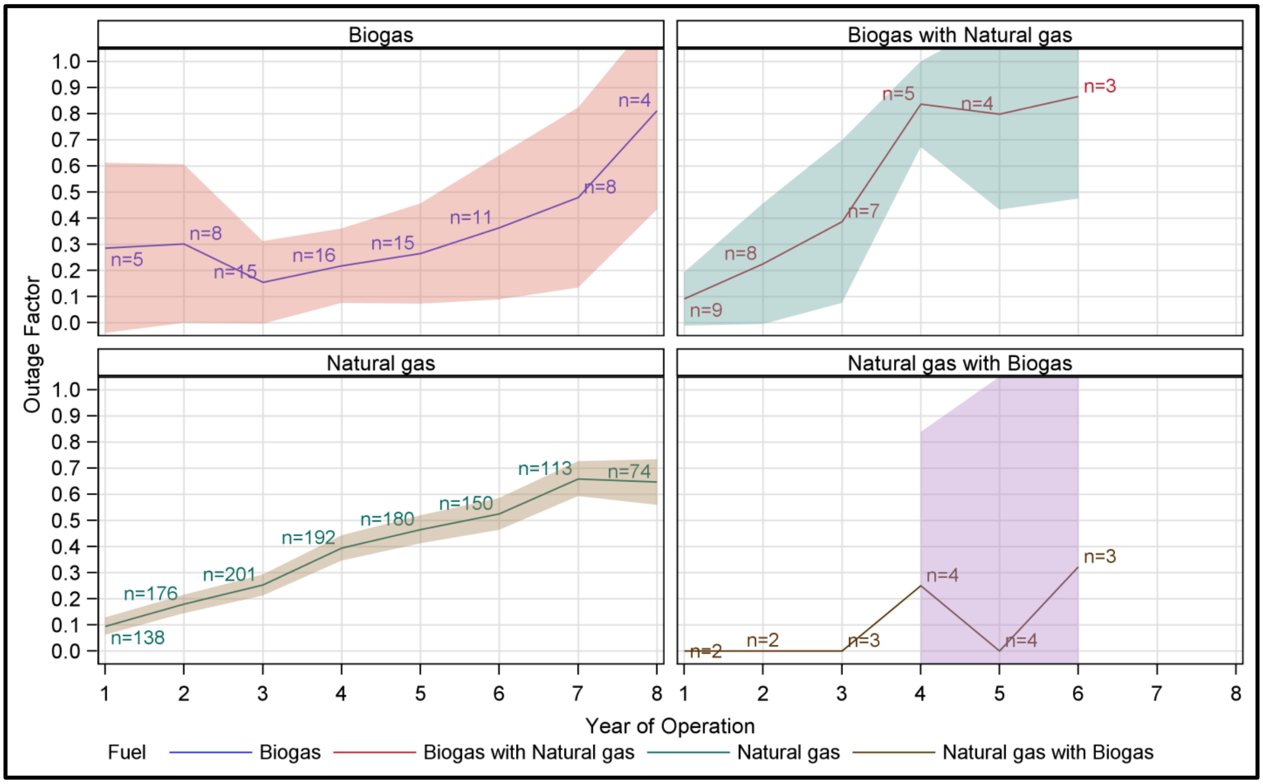
Figure D-3: Annual Mean Outage Factor by Age and Technology Type



An analysis of fuel type over time provides a clearer picture of performance over time. There seems to be a notable difference in outage factor of the type of fuel used in a system. According to the panel below, some trends show that each fuel type has a different outage factor trend.

- Natural gas systems outage factor steadily increase over time with slight variability
- Biogas with natural gas systems displays a steep rate of outage factor with great spread
- Biogas systems exhibit a decreasing outage factor then accelerates in later years

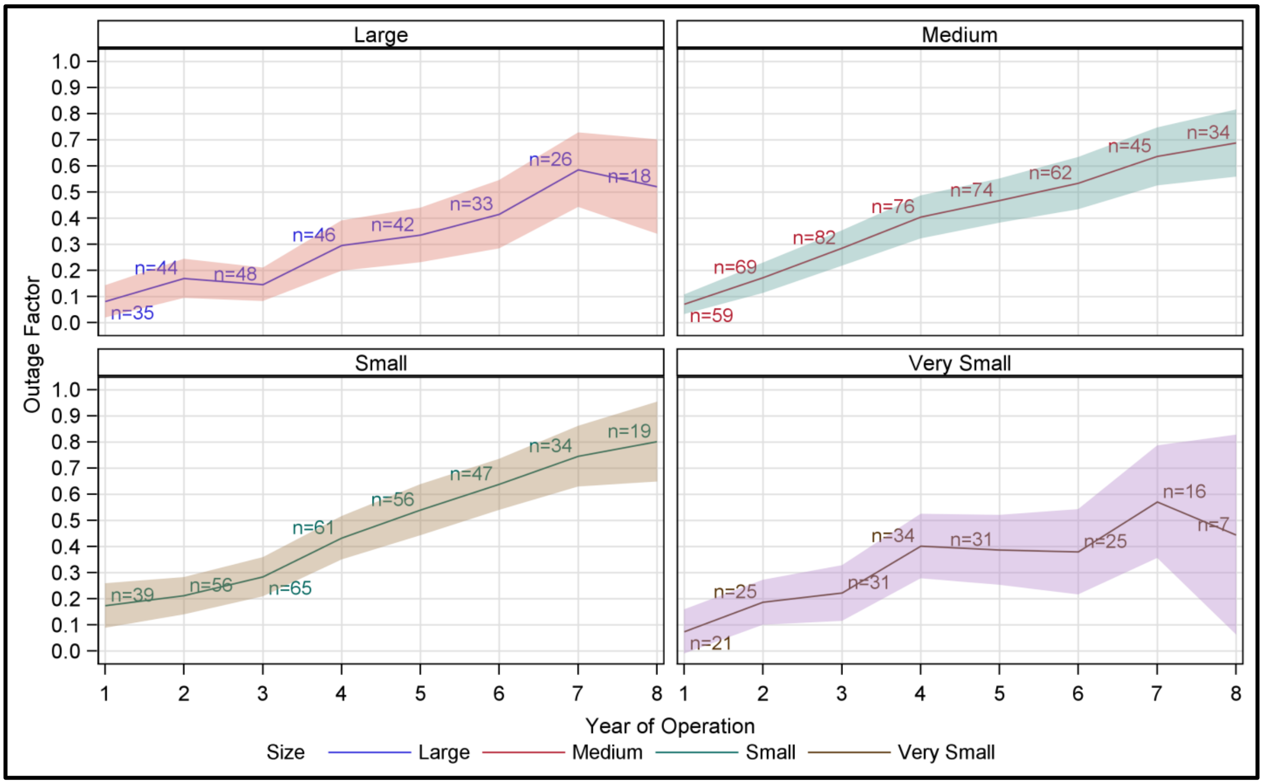
Figure D-4: Annual Mean Outage Factor by Age and Fuel Type



The size of the system seems to have an effect on the performance over time. This section has two parts. One part examines the size alone of the system. The second part looks at how fuel type and size perform over time. A few highlights of outage factor stand out for the size of the system.

- Very small systems show several plateaus of outage factors with great variability
- Small-size systems indicate a steep outage trend than that of medium-size systems
- Large and small systems' rates decrease in the last years, yet with increasing variability

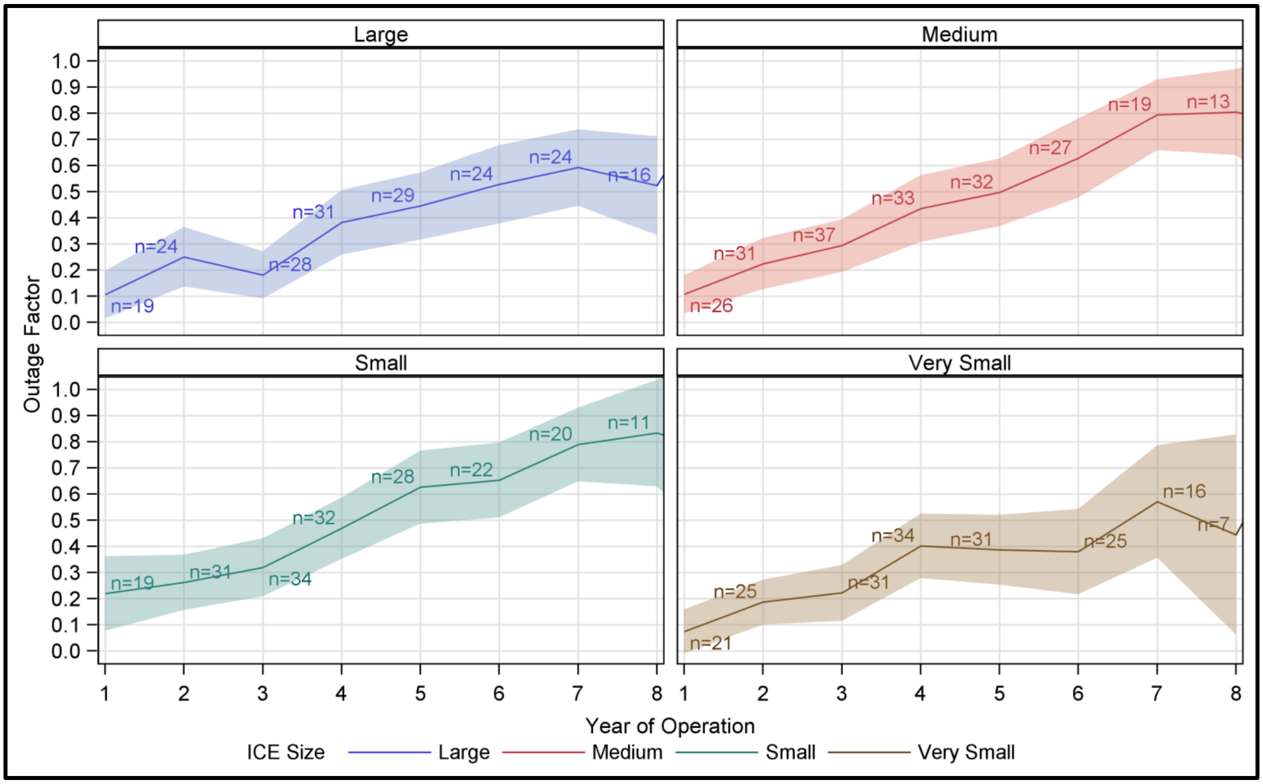
Figure D-5: Annual Mean Outage Factor by Age and Size



Further analysis is conducted on the type relative to the size category of the system, showing additional insight into the trends of outage factor. Highlights are indicated above each figure.

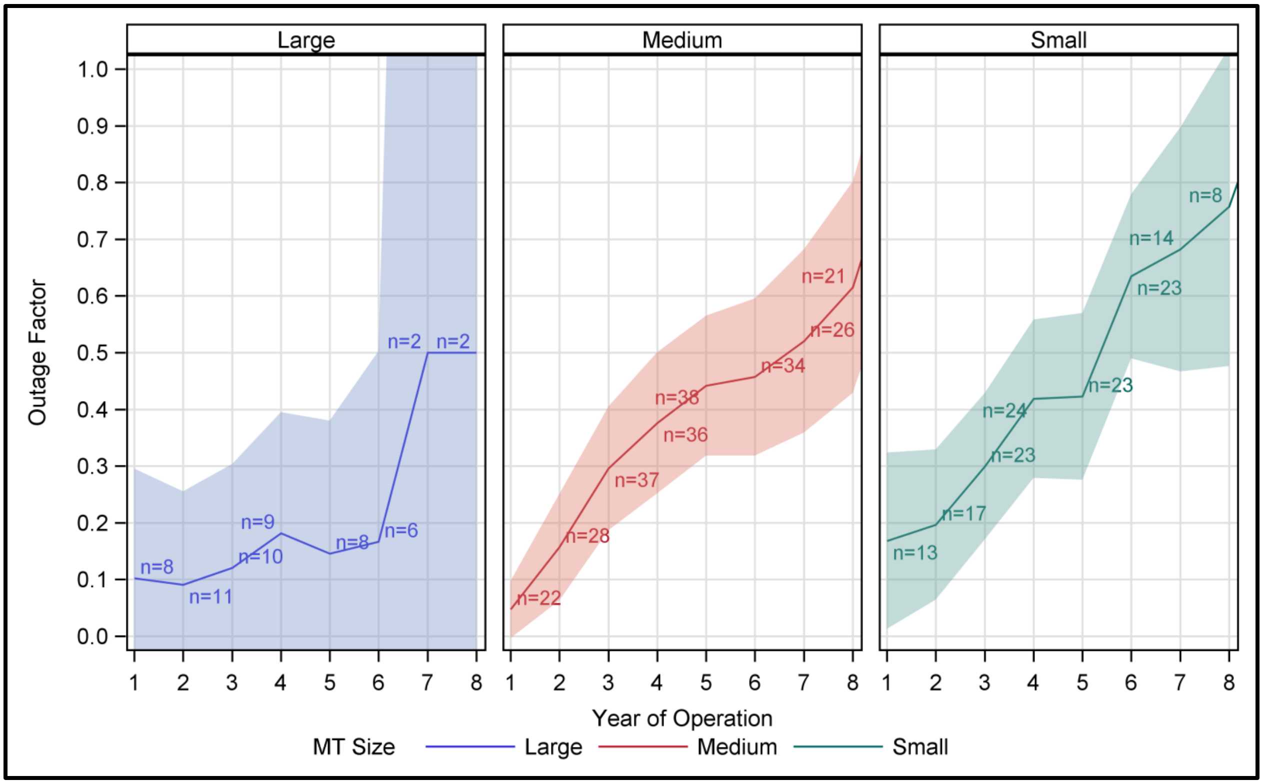
- IC Medium-size engines show narrower spreads compared to other size engines
- IC Medium-size engines also indicate a higher outage factor over the years
- Very small and large IC engines exhibit lower overall outage trends

Figure D-6: IC Engine Annual Mean Outage Factor by Age and Size



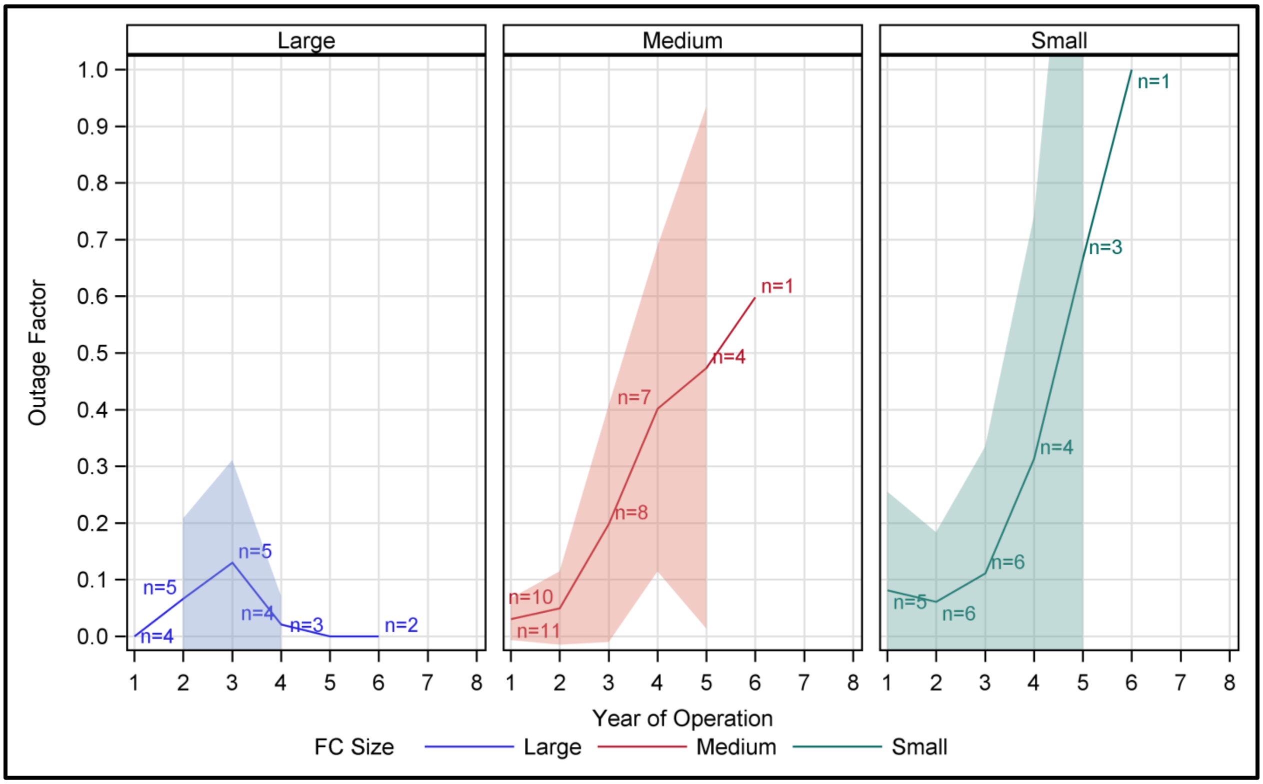
- Small microturbines show a steeper outage factor trend
- The outage variability in general increases over time

Figure D-7: Microturbine Annual Mean Outage Factor by Age and Size



- All fuel cell groups – small, medium, and large – are relatively few in number
- The lower number explains the larger variance in outage factor for fuel cell systems
- The gas turbine systems also have limited numbers, not allowing for general conclusions

Figure D-8: Fuel Cell Annual Mean Outage Factor by Age and Size



D.4 Analysis of Variance – ANOVA

Analysis of variance (ANOVA) is a statistical technique testing for the significant difference between the means and levels of variables. Its strength shows forth through hypothesis testing on categorical variables and their levels. ANOVA also allows for several types of analysis or effects to explain the variability of the dependent variable. When comparing means of variables or levels of variables, non-significant results are just as meaningful as significant results.

The model used in the ANOVA analysis to test many types of hypothesis is as follows:

Outage factor = Year of Operation X_i + + Building Type X_i + Developer Experience X_i
+ Fuel Type X_i + Size of System X_i + Spark Gap X_i + System Type X_i
+ Interactive Terms X_i + ε

Hypothesis tests consist of the main effects and level analysis of each year of operation, or age. Each year was looked at independently of others, determining significant differences in outage factors of any variables and their levels for that one year.

D.4.1 Main Effects

Is building type significant over any of the years of operation? Might the experience of the developer affect outage factor over time? Does the size of the system have any bearing on outage factor? To address these and other similar questions, the main effects technique of an ANOVA analysis enables testing of the hypothesis that the mean of the dependent variable is the same for each level of the independent variable of interest, holding the other independent variables constant. In Table D-1 below, the analysis shows an 'S' for variables determined to be significant with regard to variation in outage factor with age.

- The experience level of developers becomes significant after the second year.
- The size of the system shows significance only in the later years.
- Building type is not significant in any of the years.

On the whole, the variable with a value 'S' indicates that the main effect of the levels of variables has shows statistical significance in explaining the variation of the dependent variable of outage factor.

Table D-1: Variables Significant Across the Years

Year of Operation	1	2	3	4	5	6	7	8
Building Type								
Developer Experience			S	S	S	S	S	S
Fuel Type				S	S			
Size Category of System	S				S	S	S	S
Spark Gap								
Technology Type		S		S				

'S' indicates significance at 90/10 confidence level, that is with $\alpha = 0.10$

The discussion below provides a more in-depth analysis of each of the levels of variables with their relationship to outage factor.

D.4.2 Level Analysis

Categorical variables have different levels, and an ANOVA analysis allows for the hypothesis testing of difference in means for each level. Do colleges have a higher outage factor than real estate buildings? Do smaller systems perform better than larger systems in any of the years of operation? What kind of impact does the experience level of a developer have on outage factor?

Each level of a variable to that of other variables from the model is tested for a significant difference between the means of outage factor across the years of operation.

An ANOVA analysis conducted on building type revealed several salient points. While each level of means appear quite different from one another, there is no statistical difference in the means of any of the levels across the years. This suggests that building types operate with similar outage factors.

Table D-2: Outage Factor by Building Type over Time

Year Of Operation		1	2	3	4	5	6	7	8
College	**n**	9	11	17	14	16	15	8	5
	Mean	0.032	0.175	0.186	0.231	0.316	0.396	0.410	0.600
DigesterWWTP	**n**	11	12	15	13	12	9	3	2
	Mean	0.148	0.214	0.242	0.472	0.513	0.613	0.667	1.000
Food Processing	**n**	8	13	15	15	15	14	13	10
	Mean	0.003	0.155	0.198	0.266	0.397	0.491	0.689	0.640
Lodging/Residential	**n**	15	19	19	21	20	16	12	8
	Mean	0.033	0.145	0.364	0.362	0.441	0.595	0.634	0.637
Manufacturing	**n**	18	26	28	28	27	18	15	9
	Mean	0.085	0.120	0.153	0.433	0.448	0.489	0.668	0.756
Office	**n**	14	19	18	16	10	10	11	8
	Mean	0.078	0.131	0.279	0.450	0.556	0.614	0.756	0.702
Other	**n**	41	54	76	75	70	57	40	24
	Mean	0.110	0.197	0.214	0.324	0.366	0.416	0.547	0.557
Public Administration	**n**	18	18	19	19	17	15	9	6
	Mean	0.047	0.150	0.133	0.367	0.513	0.604	0.750	0.659
Real Estate	**n**	20	22	19	16	16	13	10	6
	Mean	0.174	0.145	0.326	0.465	0.541	0.607	0.708	0.667

The ANOVA analysis conducted on the level of experience of the developer reveals several key findings. The developer categories are developed based on counts of completed systems follows: only 1 , 2 to 5 , 6 to 10 , and 11 or more.

- Developers with only 1 completed system show a lower outage factor than developers with 6–10 for most of the years
- Developers with 11 or more completed systems also have lower outage factors than those with 6–10 in several years
- Developers with 1 completed system perform no differently than those with 11 or more

Table D-3: Outage Factor by Developer Experience over Time

Year Of Operation		1	2	3	4	5	6	7	8
11+ Installs	**n**	21	25	34	32	32	26	18	11
	Mean	0.093	0.180	0.254	0.290 [c]	0.380 [c]	0.471	0.535 [c]	0.554
6-10 Installs	**n**	39	44	44	36	33	29	22	17
	Mean	0.116	0.180	0.299[a]	0.595[a, c]	0.670[a,c]	0.706[a]	0.861[a,c]	0.882[a]
2-5 Installs	**n**	34	40	49	48	45	32	25	15
	Mean	0.043	0.222	0.294[b]	0.480[b]	0.469	0.584	0.603	0.637
1 Install	**n**	60	85	99	101	93	80	56	35
	Mean	0.099	0.119	0.149[a,b]	0.250[a,b]	0.336[a]	0.401[a]	0.576[a]	0.559[a]

Key: [a] 1 completed system indicated a lower outage factor than 6-10.
[b] 1 completed system indicated a lower outage factor than 2-5.
[c] 11 or more completed systems indicated a lower outage factor than 6-10.

Testing of the difference of the means for each fuel type yields only one notable significant finding. Only in year four is biogas significantly different (lower outage factor) than biogas with natural gas. While it appears that biogas exhibits a lower outage factor compared to other fuel types, there is not enough evidence to conclude that this is necessary the case. This suggests the following.

- The numbers are too few in all but natural gas category to make any inferences on outage factors across the years.
- Natural gas follows similar upward trend in outage factors in other variables.

Table D-4: Outage Factor by Fuel Type over Time

Year Of Operation		1	2	3	4	5	6	7	8
Biogas	**n**	5	8	15	16	15	11	8	4
	Mean	0.250	0.282	0.144	0.198[a]	0.247	0.364	0.461	0.790
Biogas with Natural Gas	**n**	9	8	7	5	4	3	.	.
	Mean	0.063	0.196	0.362	0.731[a]	0.791	0.838	.	.
Natural Gas	**n**	138	176	201	192	180	150	113	74
	Mean	0.087	0.157	0.230	0.371	0.443	0.507	0.639	0.636
Natural Gas with Biogas	**n**	2	2	3	4	4	3	.	.
	Mean	0.000	0.000	0.000	0.228	0.000	0.290	.	.

Key: [a] Biogas systems indicated a lower outage factor than Biogas with Natural Gas systems.

Applying ANOVA to test the difference of the means of the levels of the size of the system indicates that the size of the system does not matter over time.

The size of the systems is defined by technology type. Fuel cell systems are ‘Small’ if they are less than 300 kW in size, ‘Medium’ less than 1,000 kW, and ‘Large’ greater than 1,000 kW. Gas turbine systems are ‘Small’ if they are less than 3,000 kW in size and ‘Large’ for those 3,000 kW and greater. IC engines systems are ‘Very Small’ if they are less than 250 kW, ‘Small’ less than 500 kW, ‘Medium less than 1,000 kW, and ‘Large’ for all else. Microturbine systems are ‘Small’ less than 75 kW, ‘Medium’ up to 300 kW, and ‘Large’ greater than 300 kW.

Not once in any of the years did any size perform any better than other sizes. It appears that very small systems on average indicate lower outage factors to other size systems, this is not statistically significant.

Table D-5: Outage Factor by Size of System over Time

Year Of Operation		1	2	3	4	5	6	7	8
Large	**n**	35	44	48	46	42	33	26	18
	Mean	0.073	0.149	0.129	0.272	0.320	0.398	0.569	0.499
Medium	**n**	59	69	82	76	74	62	45	34
	Mean	0.061	0.152	0.265	0.377	0.448	0.522	0.617	0.683
Small	**n**	39	56	65	61	56	47	34	19
	Mean	0.162	0.190	0.256	0.409	0.514	0.610	0.724	0.787
Very Small	**n**	21	25	31	34	31	25	16	7
	Mean	0.066	0.149	0.204	0.379	0.362	0.372	0.546	0.442

An ANOVA statistical technique allows for the testing of means in the relative difference between the cost of generating electricity and heat with a CHP system compared to buying electricity and natural gas for a boiler. Referred to here as 'spark gap' it is also known as 'alternative CHP spark spread' in that it includes the value of natural gas purchases required to generate heat when the CHP system is off. The hypothesis from the onset is that spark gap does affect outage factor over the age of the system of natural gas systems. Average differences in prices are sectioned into quartiles and compared to one another accordingly. A lowest spark gap, Quartile 1, reflects a low benefit from running a CHP system whereas Quartile 4 indicates a high benefit.

- There is no indication that spark gap affects natural gas systems' outage factor over time. Only in 3 of the 8 years is there any statistical difference between the lowest and highest quartiles, indicating little sensitivity to spark gap in most of the years of operation.
- Most quartiles showed little statistical difference in the means of outage factor. This suggests that on average natural gas systems are not sensitive to spark gap over the age of the system.

Table D-6: Outage Factor by Spark Gap over Time of Natural Gas Systems

Year Of Operation		1	2	3	4	5	6	7	8
Quartile 1	**n**	40	78	84	51	54	26	5	.
	Mean	0.168 [a]	0.216 [a]	0.244	0.416	0.514 [a, b]	0.581	0.849	.
Quartile 2	**n**	59	56	68	59	36	37	10	.
	Mean	0.069	0.115	0.249	0.379	0.505	0.635	0.812	.
Quartile 3	**N**	21	29	26	54	42	47	53	19
	Mean	0.048	0.149	0.203	0.390	0.485	0.450	0.588	0.797 [c]
Quartile 4	**n**	18	13	23	28	48	40	45	55
	Mean	0.013 [a]	0.000 [a]	0.152	0.237	0.280 [a,b]	0.408	0.637	0.581 [c]

Key: [a] Quartile 4 indicated a lower outage factor than Quartile 1.
[b] Quartile 4 indicated a lower outage factor than Quartile 2.
[c] Quartile 4 indicated a lower outage factor than Quartile 3.

The testing of the difference of the means for each technology type yields only one significant difference. In the second year, fuel cells had a significant lower outage factor than IC engines. It does appear that gas turbine systems perform better in the first several years, but the numbers are too few to draw any inferences. This suggests the following.

- IC engines and microturbine engines are not statistically different in outage factors over the years
- The numbers are too few gas turbines to make any comparison of the means, despite the lower relative outage factors.

Table D-7: Outage Factor by System Type over Time

Year Of Operation		1	2	3	4	5	6	7	8
Fuel Cell	**n**	20	21	19	15	10	4	.	.
	Mean	0.027	0.044	0.133	0.229	0.359	0.379	.	.
Gas Turbine	**n**	6	6	7	3	4	2	.	.
	Mean	0.000	0.003	0.012	0.027	0.250	0.000	.	.
IC Engine	**n**	85	111	130	130	120	98	79	47
	Mean	0.113	0.205	0.235	0.396	0.464	0.530	0.661	0.649
Microturbine	**n**	43	56	70	69	69	63	42	31
	Mean	0.086	0.139	0.254	0.347	0.383	0.475	0.565	0.636

Key: [a] Fuel cell systems indicated a lower outage factor than IC engine systems.

Appendix E

Development of GHG Emissions Nomograph

The purpose of this appendix is to establish an easy-to-use but accurate means of relating net greenhouse gas (GHG) emissions to efficiencies of CHP systems. A nomograph is a graphical estimation tool that allows generally complex relationships to be made into easy-to-see solutions that cover a wide variety of situations. A GHG Emissions Nomograph is a chart or diagram that can be used to estimate net GHG emission rates for a variety of CHP systems at different operating situations.

Generally, net GHG emissions from natural-gas fueled CHP systems can be related to the following sources:

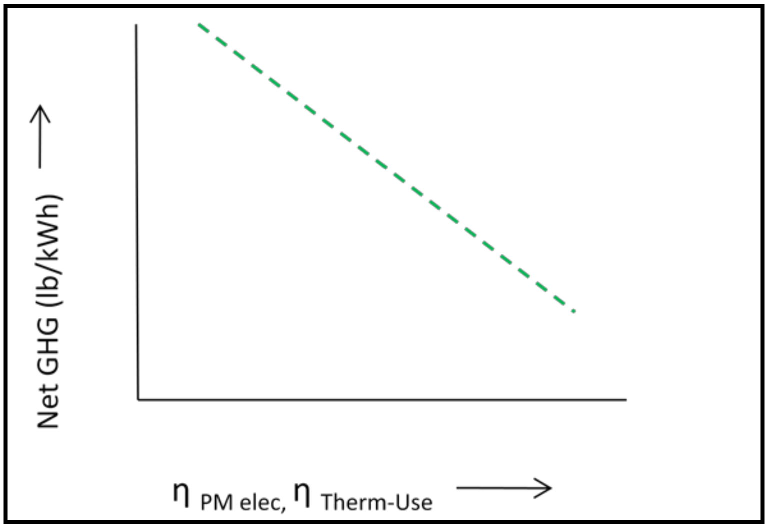
- CO_2 emissions from combustion of the natural gas used to power the prime mover[1] of the CHP system;
- CO_2 emissions that are offset by not burning fuel used to power grid-based electricity when the CHP prime mover is instead supplying the needed electricity to the host site;
- CO_2 emissions that are offset by not burning fuel used by on-site boilers to provide heating and cooling needs that are instead supplied by the waste heat recovery process within the CHP system.

The amount of CO_2 emitted from grid-based sources varies depending on if the electricity is supplied during peak versus off-peak hours. In general, electricity supplied from the grid during peak hours is generated by simple cycle combustion turbines. Electricity supplied from the grid during off peak hours is generally generated from more efficient combined cycle power plants. More efficient power plants consume less fuel to generate the same amount of power, and so have lower emissions of CO_2. The extent to which CHP systems can help reduce GHG emissions (via reduced CO_2) depends on the efficiency with which the CHP prime mover generates electricity in comparison to grid-based sources or provides useful thermal energy to the host site.

[1] Prime mover refers to the specific equipment used to generate electricity from the CHP system. Within the SGIP, prime movers consist of IC engines, microturbines, fuel cells and small gas turbines.

From a planning perspective, it is beneficial to relate GHG emissions from CHP systems to capacity factor, availability, electrical conversion efficiency and useful thermal conversion efficiency. Figure E-1 below shows an idealized relationship between these different factors.

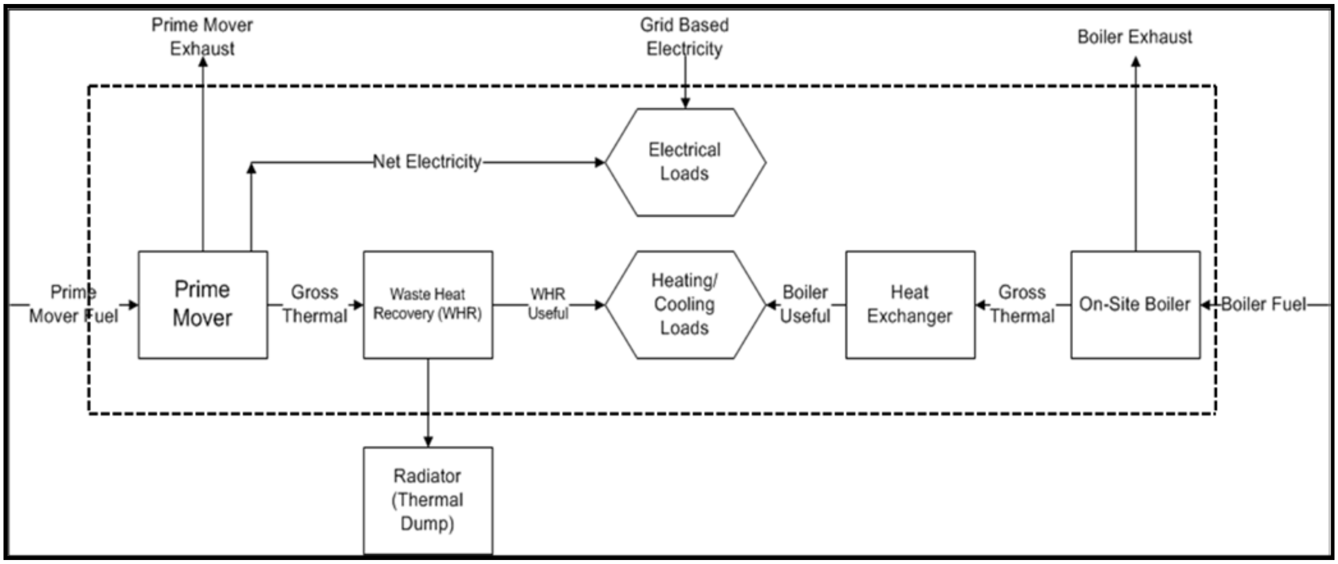
Figure E-1: Idealized Relationship Between Net GHG Emissions and Efficiencies



The factor $\eta_{PM\ elec}$ refers to the electrical conversion efficiency of the prime mover and $\eta_{Therm\text{-}Use}$ refers to the useful thermal conversion efficiency of the waste heat recovery process used in the CHP system. As the electrical efficiency of the prime mover increases, less fuel is consumed and so CO_2 emissions are reduced from the CHP system. Similarly, as the amount of waste heat recovered and used to displace boiler fuel increases, CO_2 emissions from the on-site boiler are decreased. Capacity factor and availability do not affect the rate of CO_2 emissions, but impact the total amount of CO_2 reduced over a set timeframe (e.g., over the course of a year).

Figure E-2 represents a simplified schematic of a CHP system. The figure shows possible sources of GHG emissions from the CHP prime mover and on-site boiler as well as the energy flows between the CHP prime mover, the waste heat recovery system, the boiler and grid electricity being provided to the host site.

Figure E-2: Simplified Schematic of a CHP System



Using the simplified schematic, we identify net GHG emissions as follows:

Equation E-1

Net GHG = (GHG emissions from CHP sources) – (GHG emissions from non-CHP sources)

GHG sources from the CHP system consist of:

- GHG from the prime mover = GHG_{PM} which is due to CO_2 emissions from the prime mover

GHG from non-CHP sources:

- GHG from grid electricity = $GHG_{GridElec}$ which is due to CO_2 emissions from utility power plants
- GHG from the on-site boiler = GHG_{Boiler} which is due to CO_2 emissions from the on-site boiler

By substituting in these values, we obtain:

Equation E-2

Net GHG = $GHG_{PM} - GHG_{GridElec} - GHG_{Boiler}$

We can break GHG emissions into peak and off-peak hours as follows:

Equation E-3

$$\sum_{i=0}^{8760} net\ GHG_i = \sum_{0}^{peak\ hrs} \{(GHG_{PM}) - (GHG_{GridElec})\}_{ipeak} - \sum_{0}^{off\ peak\ hrs} \{(GHG_{PM}) - (GHG_{GridElec})\}_{i-offpeak} + \sum_{i=0}^{8760} (GHG_{Boiler})_i$$

As noted above, GHG emissions are proportional to the amount of CO_2 released from the combustion processes of the prime mover, the on-site boiler and the utility power plants. This means we can relate the CO_2 emissions (and therefore the GHG emissions) to the efficiencies of these processes.

Equation E-4

GHG_{PM} = (CO_2 conversion factor, lb/Btu)*($PM_{HeatRate}$, Btu/kWh)

But $PM_{HeatRate} = \left(3412\,\frac{Btu}{kWh}\right) * \left(\frac{1}{\eta \text{PM elec}}\right)$

Therefore, $GHG_{PM} = \frac{CO2\ factor}{\eta \text{PM elec}}$ (lb/kWh)

Similarly, $(GHG_{PM})_{ipeak}$ = (CO2 conversion factor, lb/Btu)*($GridElec_{HeatRate,}$ Btu/kWh)

Giving, $(GHG_{PM})_{ipeak} = \frac{CO2\ factor}{\eta \text{GridElec}-\text{peak}}$

And $(GHG_{PM})_{i-off\ peak} = \frac{CO2\ factor}{\eta \text{GridElec}-\text{off peak}}$

For the boiler, we can relate the boiler fuel feed rate (and therefore the CO_2 emissions) to the prime mover fuel rate. For any CHP system, we can assume that as long as the waste heat recovery system is not dumping heat, it is supplying useful thermal energy that would have otherwise been supplied by the on-site boiler. In particular, this means:

$WHR_{ThermUse} = Boiler_{ThermUse}$

Where $WHR_{ThermUse}$ = useful thermal energy from the Waste Heat Recovery (WHR) process

$Boiler_{ThermUse}$ = useful thermal energy from the on-site boiler/heat exchanger sub-systems

We also assume that the average boiler efficiency is 80% and the average heat exchanger efficiency is 90%. This means:

$\text{Boiler}_{\text{Energy}} = \frac{0.9}{0.8}\,\text{Boiler}_{\text{ThermUse}}$

Because $\text{WHR}_{\text{ThermUse}} = \text{Boiler}_{\text{ThermUse}}$, this means:

$\text{Boiler}_{\text{Energy}} = \frac{0.9}{0.8}\,\text{WHR}_{\text{ThermUse}}$

By definition, $\eta_{WHR-TU=}\frac{thermal\,useful\,output}{energy\ in} = \frac{WHR_{Therm-Useful}}{PM_{Energy\ in}}$

This provides an expression for $\text{GHG}_{\text{Boiler}}$:

Equation E-5

$$GHG_{Boiler}\ (CO2, lb/kWh) = \ (CO2\ conv\ factor)\left(\frac{energy\ in\ boiler}{WHR}\right)\left(\frac{WHR}{energy\ into\ PM}\right)(PM_{Heat\ Rate})$$

From the energy balance:

$$WHR_{Therm-Useful} = \frac{.8}{.9}\ Boiler_{Energy}$$

$$\frac{Boiler_{Energy}}{WHR_{Therm-Useful}} = \frac{.8}{.9} = 1.125$$

Because $\eta_{WHR-TU} = \frac{WHR_{Therm-Useful}}{PM_{Energy\ in}}$

$$GHG_{Boiler}\left(CO2, \frac{lb}{kWh}\right) = \ 1.125 * (CO2\ conv\ factor)(PM_{Heat\ Rate})(\eta_{WHR-TU})$$

But $(PM_{Heat\ Rate}) = \left(3412\ \frac{Btu}{kWh}\right)(\eta_{PM\ elec})$

Equation E-6

$$GHG_{Boiler}\left(CO2, \frac{lb}{kWh}\right) = \frac{1.125\left(3412\ \frac{Btu}{kWh}\right)(CO2\ conv\ factor)}{\eta_{PM\ elec}}\ (\eta_{WHR-TU})$$

In order to see the impacts of efficiency on net GHG, we can examine net GHG during on-peak and off-peak hours. For simplicity, the efficiency of the prime mover can be assumed to stay constant during on-peak and off-peak hours.[2] This means the prime mover GHG emission rate stays the same during peak and off-peak hours.

$$GHG_{PMi} = GHG_{peak} = GHG_{off-peak}$$

For on-peak hours, the net GHG emissions are related to the prime mover and grid-based electricity supplies by:

Equation E-7

$$net\ GHG\ \left(CO2, \frac{lb}{kWh}\right) \propto GHG_{PM} - GHG_{GridElec-peak}$$

But GHG emissions from the prime mover are inversely proportional to the electrical efficiency of the prime mover, while GHG emissions from the grid-based sources are inversely proportional to their electrical efficiencies via:

$$GHG_{PM} \propto \frac{CO2\ factor}{\eta_{PM\ elec}}$$

$$GHG_{Grid-peak} \propto \frac{CO2\ factor}{\eta_{Grid-peak}}$$

Equation E-8

$$net\ GHG\ \left(CO2, \frac{lb}{kWh}\right) \propto CO2\ factor\left(\frac{1}{\eta_{PM\ elec}} - \frac{1}{\eta_{GridElec-peak}}\right)$$

Based on observations of electrical efficiency of prime movers in the SGIP in comparison to the electrical efficiency of the grid-supplied electricity during peak hours:

$$\eta_{GridElec-peak} \geq \eta_{PM\ elec}$$

Meaning that $\frac{1}{\eta_{PM\ elec}} \geq \frac{1}{\eta_{GridElec-peak}}$

When (i.e., when $\eta_{PM\ elec} = \eta_{GridElec-peak}$), net GHG emissions will be zero. Otherwise, if the electrical conversion efficiency of the prime mover is less than the grid-supplied electricity, the net GHG emissions will increase. During peak hours, the grid-supplied electricity had an apparent electricity of 27%. During calendar year 2010, only microturbines had electrical

[2] Peak and off-peak hours refer to the CAISO demand. While load-following CHP systems may show reduction in efficiency when ramping down due to reduced host site electrical demand, we have generally seen electrical generation from SGIP CHP systems to be insensitive to changes in CAISO demand.

conversion efficiencies less than 27%. Consequently, SGIP CHP systems, excluding those involving microturbine prime movers, could be expected to have net GHG emission reductions during CAISO peak hours. Where the electrical conversion efficiency of the prime mover is less than the electrical efficiency of the grid-supplied sources during peak hours, we can calculate the ratio of the amount of useful waste heat recovery efficiency to the electrical conversion efficiency of the prime mover (i.e., $\frac{\eta_{WHR-TU}}{\eta_{PM\ elec}}$) needed to achieve a net zero GHG emission rate.

Using the microturbine example (i.e., $\eta_{PM\ elec} = 0.23$), we obtain:

Equation E-9

$$net\ GHG = 0 = (1.125)\frac{\eta_{WHR-TU}}{\eta_{PM\ elec}}\left(3214\frac{Btu}{kWh}\right)$$

By setting net GHG to zero this gives:

$$\left(\frac{1}{\eta_{PM\ elec}} - \frac{1}{\eta_{GridElec-offpeak}}\right) = \frac{(4.3 - 3.7)}{1.125} = \frac{\eta_{WHR-TU}}{\eta_{PM\ elec}}\left(3214\frac{Btu}{kWh}\right) = 1.8\ \frac{Btu}{kWh}$$

Or η_{WHR-TU}= 0.99

This means that in order for a CHP system using a microturbine prime mover to achieve a zero net GHG emission rate, the waste heat recovery process must achieve 99% useful waste heat recovery efficiency.

We can also examine off-peak hours to see the impact of prime mover electrical efficiency on net GHG emissions relative to the electrical efficiency of grid-supplied sources. The electrical efficiency of grid-supplied sources during off-peak hours is relatively high (i.e., 48% during 2010). Consequently, with the exception of all-electric fuel cells (i.e., with a reported electrical efficiency of 50%), the net GHG emissions will increase.

Development of Generalized Net GHG Equation:

From the above, we have:

$$net\ GHG\ \left(as\ CO2\frac{lb}{kWh}\right) = \ (GHG_{PM} - \ GHG_{Grid}) - GHG_{Boiler}$$

$$GHG_{PM} = (CO_2\ converion\ factor, lb/Btu)\left(\frac{3412\ Btu/kWh}{\eta_{PM}}\right)$$

$$GHG_{Grid} = \ (CO_2\ converion\ factor, lb/Btu)\left(\frac{3412\ Btu/kWh}{\eta_{GridElec}}\right)$$

$$GHG_{Boiler} = \ (CO_2\ converion\ factor, lb/Btu)\left(\frac{(1.125)\eta_{WHR}}{\eta_{PM}}\right)(3412\ Btu/kWh)$$

Substituting in the above values, we get:

Equation E-10

$$net\ GHG\ \left(as\ CO2\frac{lb}{kWh}\right) = 0.427\left(\frac{1}{\eta_{PM}} - \ \frac{1}{\eta_{GridElec}} - \ 1.125\frac{\eta_{WHR}}{\eta_{PM}}\right)$$

This equation serves as the basis for the nomograph.

Appendix F

Trends of CHP Performance

This appendix contains a variety of performance trends that were investigated in assessing factors that could influence CHP performance.

F.1 Fuel Costs, Electricity Costs, and Spark Spread

Most CHP systems in the SGIP are fueled with natural gas.[1] To generate power these system owners must purchase natural gas, primarily from utilities on a non-core basis. By paying this cost they avoid the cost of purchasing some of their electricity and also avoid the cost of purchasing some natural gas to meet their heating loads. If the cost of natural gas is high and the cost of purchased electricity is low, however, the CHP system owner may face lower costs overall by not running the system. Instead the system owner could purchase electricity and natural gas from the utilities to separately meet their electric and heating loads. These electricity and natural gas cost conditions may explain some periods of higher percentages of systems off, or conversely, of low capacity factor.

The difference between the cost of a purchased kWh of electricity and the cost of natural gas to generate a kWh is known as spark spread. Because CHP systems have different electrical conversion efficiencies, they have different natural gas costs to generate a kWh. Spark spread therefore differs between technologies. When the cost of a purchased kWh is much higher than the cost of natural gas to generate it, spark spread is high. With a high spark spread CHP system owners may lower their overall costs by buying natural gas to run their systems.

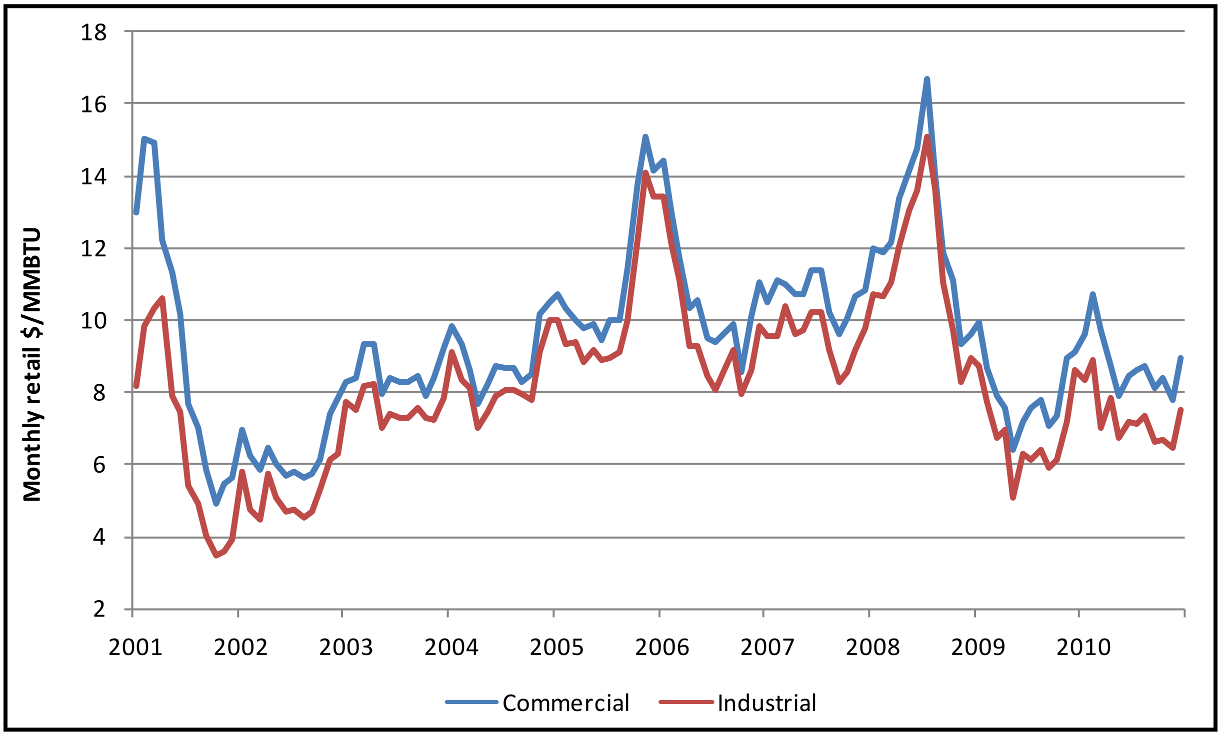
Traditionally spark spread does not include the value of useful recovered heat. For CHP systems, the value of useful recovered heat is very important. That value is defined as the natural gas purchase costs avoided by recovering useful heat from their generation of a kWh. Like their electrical conversion efficiencies, different CHP technologies have different rates of heat recovery from the generation of a kWh. For CHP systems, an alternative spark spread adds the natural gas costs avoided by recovering useful heat associated with the generation of a kWh.

[1] A small fraction (approximately 9% by rebated capacity) of the CHP facilities in the SGIP as of the end of 2006 was fueled by biogas. Biogas for these facilities was usually obtained from landfill gas projects, wastewater treatment facilities or anaerobic digesters at dairies or food processing facilities.

Calculation of an alternative CHP spark spread thus considers both the technology's electrical conversion efficiency and its ability to recover waste heat.

Figure F-1 shows monthly commercial and industrial prices for natural gas across California from 2001–2010[2]. These statewide prices are proxies for the prices faced by CHP hosts. Actual prices faced by CHP hosts may differ and may involve gas purchase contracts such as 'take or pay' arrangements. The figure shows that late 2005 and mid-2008 brought substantial natural gas price spikes that would have added to the cost of self-generated power from CHP systems.

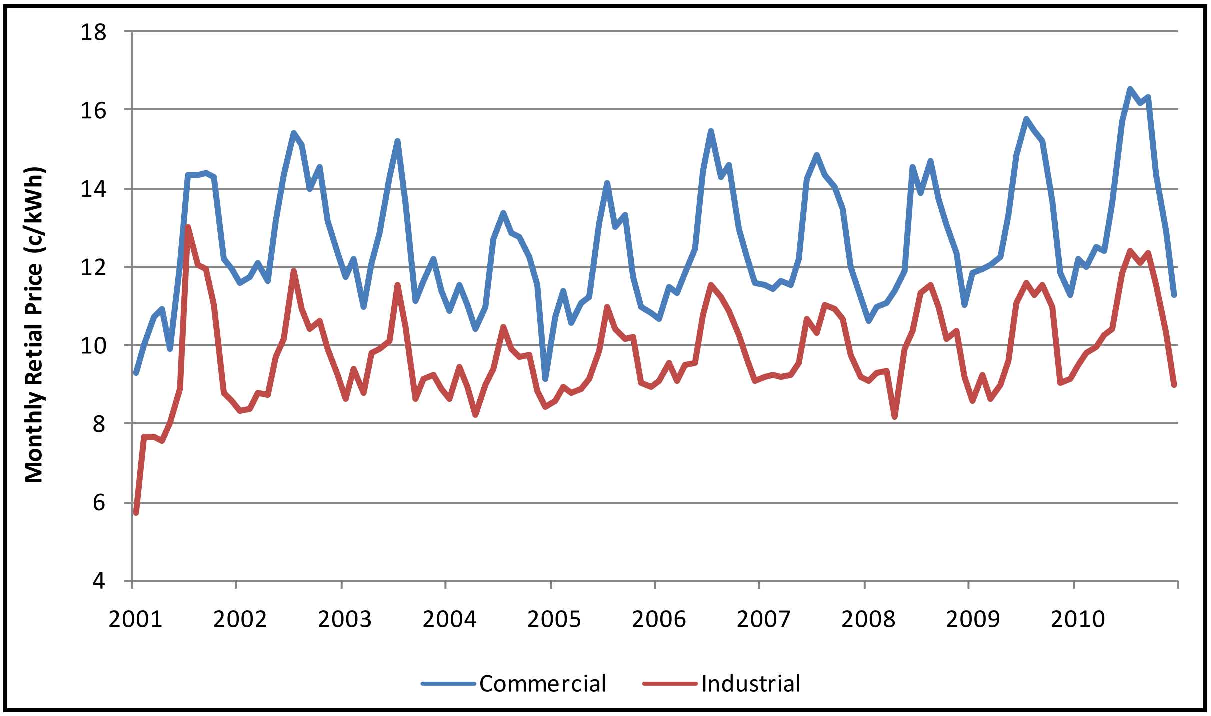
Figure F-1: California Monthly Commercial and Industrial Natural Gas Prices (2001–2010)



[2] Source data from the U.S. Energy Information Administration: http://www.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SCA_m.htm

Figure F-2 shows the monthly retail electric prices across California from 2001-2010 across its commercial and industrial sectors. These statewide prices are proxies for the actual prices faced by CHP owners. Actual prices are tariff-dependent. Most SGIP systems fall into a special TOU classification for electricity rates.[3] Figure F-2 shows electricity prices oscillate with notable regularity around the summer season. These electricity prices did not show sharp spiking as natural gas prices had, although like natural gas the industrial sector price was often substantially less than the commercial sector.

Figure F-2: California Commercial and Industrial Electricity Price Trends (2001–2010)[4]

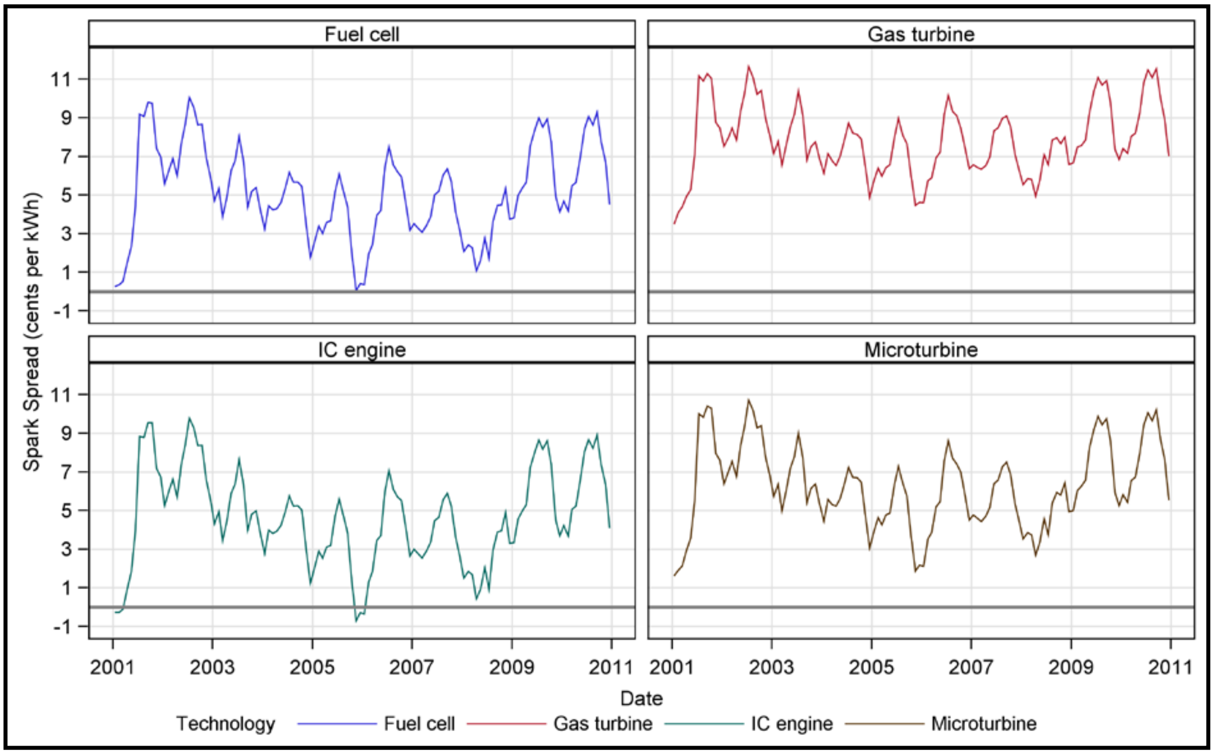


[3] In general, CHP facilities in the SGIP offset electricity prices in the following TOU rate structures: GS2TOU within SCE, A10TOU within PG&E, and A6TOU within SDG&E.

[4] Source data from the U.S. Energy Information Administration http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html

The economics of CHP system operation depends heavily on spark spread, and Figure F-3 shows monthly values of alternative CHP spark spread by technology in cents per kWh. The values are based on the monthly average of commercial and industrial prices for gas and electricity and representative electrical conversion efficiencies and heat recovery rates for the different technologies.

Figure F-3: Alternative CHP Spark Spread by Technology (2001–2010)



Periods of low CHP capacity factors might be due to low spark spread. When spark spread is low , CHP system owners may be expected to respond by reducing capacity factor or stopping their systems. To reduce costs they may instead purchase electricity and meet their heating loads by running a natural gas boiler. Operating costs are not included in the alternative CHP spark spread shown here. These include variable and fixed operating and maintenance costs and the costs involved in transitioning system operations from running to off and back to running. No costs are included either for high temperature fuel cells that need to maintain high temperatures in molten stacks even though not generating electricity.

If hosts do respond to low spark spread by reducing self-generation, the periods of low spark spread in 2005, 2007, and 2008-2009 would correspond to periods of low capacity factor. To assess response to low spark spread we compared percents of systems off among natural gas technologies between periods of high and low spark spread.

Figure F-4 shows alternative CHP spark spread and monthly percent of systems off by natural gas technology. Figure F-4 does not show units for the alternative CHP spark spread but the scales for spark spread are the same in the figure's four panels.

Figure F-4: Monthly Percent of Systems Off and Alternative CHP Spark Spread by Natural Gas Technology (2001–2010)

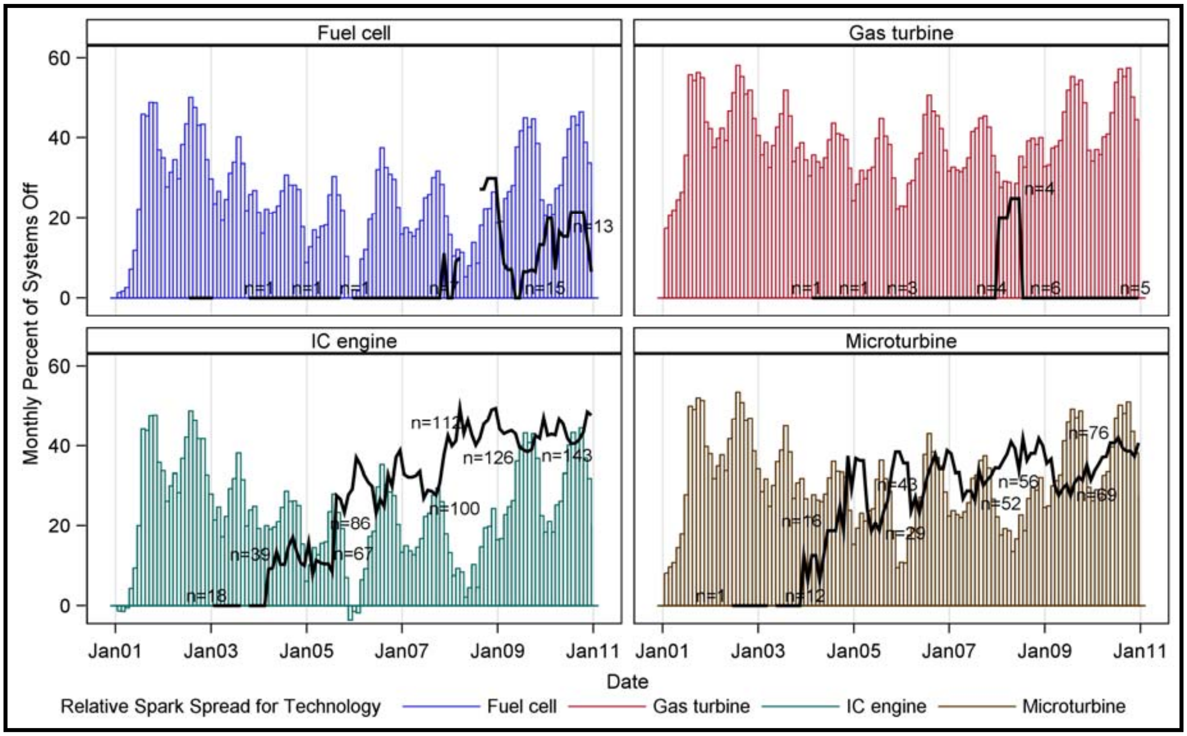


Figure F-4 shows natural gas IC engines had precipitous declines in spark spread around start of 2006 and middle of 2008 and overall declines in monthly capacity factors over the 2002 through 2010 period. Both also had brief, higher rates of decline during the three periods of negative spark spread lasting more than one month, but upward rebound only immediately after the short period of negative spark spread in 2005. The absence of upward rebound when spark spread again exceeds zero suggests little response to falling natural gas prices despite what might have been a response to higher prices. A clear distinction exists for gas turbines and fuel cells in that they have consistently higher monthly capacity factors. But they too do not show capacity factors responding to rising and falling spark spread. Gas turbines appear to respond to the 2008 fall and 2009 rise in spark spread, but their variability over other periods provides little support for a relationship to spark spread.

Natural gas fuel cells and gas turbines, both technologies more often put into baseload rather than load following operation, showed little reduction in utilization during their periods of low spark spread. But the number of metered systems for both technologies were relatively small, so we are not inclined to draw definitive conclusions for these two technologies with regard to spark spread.