2018-2019 SELF-GENERATION INCENTIVE PROGRAM IMPACT EVALUATION

Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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TABLE OF CONTENTS

VERDANT

VERDANT

LIST OF FIGURES

VERDANT

VERDANT

VERDANT

LIST OF TABLES

VERDANT

EXECUTIVE SUMMARY

This report is an evaluation of the impacts of the Self-Generation Incentive Program (SGIP) for calendar years 2018 and 2019. The report provides energy, demand, and environmental impacts of the SGIP as estimated for each of the reporting years. Impacts are reported for the SGIP as a whole and by other categories such as technology type, fuel type, program administrator (PA), and electric utility. In some cases, the data are further categorized by program year (PY) to recognize the different program goals and rules in effect at the time of project development.

Specific metrics reported in this evaluation include:

- Generation energy impacts including electricity generated, fuel consumed, and useful heat recovered. Efficiency and utilization metrics include annual capacity factor, electrical conversion efficiency, useful heat recovery rate, and system efficiency.
- Energy storage charge and discharge impacts, as well as round-trip efficiency calculations.
- Utility and CAISO system coincident peak demand impacts (average reduction and capacity factor) during top demand hour and top 200 hours.
- Noncoincident customer peak impacts that identify the effect of the SGIP systems on customer peak demand, and
- Greenhouse gas (GHG) emissions.

The SGIP includes a significant number of projects that were installed as early as 2001 and have continued to operate, providing benefits to both the host customer and the utility. As such, while the focus of this report is on impacts occurring during 2018 and 2019, these impacts result from a portfolio of projects with online dates that can span many years. Changes in program policies and requirements have created significant differences in operation and performance of SGIP projects. In particular, Senate Bill (SB) 412 (Kehoe, October 11, 2009) established GHG requirements that resulted in substantial changes in performance of combined heat and power (CHP) technologies installed under the SGIP following SB 412. These changes required projects 30kW and greater to comply with performance-based incentive (PBI) rules rather than the upfront payment the program previously implemented. Most recently, CPUC D. 16-06-055 implemented major changes to the SGIP. These changes included minimum biogas blending requirements. These minimum biogas blending requirements state that beginning in PY 2017, all natural gas-consuming generation projects must use a minimum of 10 percent biogas to be eligible for an SGIP incentive. The minimum requirement increases to 25 percent in 2018, 50 percent in 2019, and 100 percent in 2020. Perhaps most noticeably, this decision shifted the program focus to energy storage, allocating 75 percent of the SGIP budget to energy storage technologies with the remaining 25 percent going to generation technologies.[1]

Impact evaluations are useful in assessing actual versus expected performance of a program and the associated technologies. In doing so, impact evaluations can help identify where corrective actions should be considered by policy makers. This evaluation report is based on a robust sample of metered data covering calendar years 2018 and 2019. Below we summarize the program status at the end of 2019 and highlight key findings from this impact evaluation report.

SGIP SUMMARY AND IMPACTS DURING 2018 AND 2019

By the end of 2019, the SGIP provided incentives to 9,860 projects, representing 718 MW of rebated capacity. Rebated technologies include energy storage, fuel cells (CHP and electric-only), internal combustion (IC) engines, gas turbines, microturbines, pressure reduction turbines, wind turbines, and waste-heat-to-power. Generation technologies can be fueled by non-renewable natural gas or renewable biogas produced from sources including landfills, waste-water treatment plants, dairy digesters, or food processing facilities. Over $979 million has been paid in incentives for completed projects (excluding PV).[2] By the end of 2019, eligible costs[3] reported by applicants surpassed $3.5 billion.

1 The 2020 Program Handbook shows updated budget allocations of 88 percent going towards the energy storage technologies and the remaining 12 percent going towards generation technologies.

2 For the purposes of this report, all projects are assumed to receive their entire reserved incentive amount, regardless of PBI performance. Also note that while the SGIP originally offered incentives to solar PV technologies, these technologies are no longer eligible for SGIP incentives. Consequently, we no longer report the impacts of SGIP rebated PV projects in impact evaluation reports.

3 Eligible costs are defined in the SGIP handbook.

TABLE ES-1: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR AS OF DECEMBER 31, 2019

Program Administrator	All Projects			Non-Decommissioned Projects Only*	
	Project Count	Rebated Capacity [MW]	Percent of Rebated Capacity	Project Count	Rebated Capacity [MW]
CSE	2,084	91.6	13%	2,047	81.4
PG&E	3,755	278.5	39%	3,628	245.5
SCE	3,371	198.0	28%	3,329	186.4
SCG	650	149.9	21%	592	127.8
Total	**9,860**	**718**	**100%**	**9,596**	**641**

* These columns exclude projects known to be decommissioned (physically removed from the premise) prior to 2020. See Section 2 for more information.

The SGIP program administrators are the Center for Sustainable Energy (CSE), Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and Southern California Gas Company (SCG). Table ES-1 summarizes total project counts and rebated capacities by PA as of December 31, 2019. Note that over time, as SGIP projects age, SGIP host customers may elect to no longer operate their SGIP systems and physically remove them from the premise. Table ES-1 also lists project counts and rebated capacities for projects that are not known to be decommissioned and therefore continue to generate program impacts (e.g., electrical energy).

PG&E has issued incentives for the largest number of projects (3,755) and rebated capacity (278.5 MW) of all PAs, followed by SCE. Table ES-2 shows the project counts, average rebated capacity, and total rebated capacity by technology type as of December 31, 2019. Energy storage systems make up 90 percent of the SGIP fleet by count, but account for only 26 percent of the rebated capacity. Electric-only fuel cells and internal combustion engines are the most common generation technology by project count and together represent 47 percent of the program's rebated capacity.

TABLE ES-2: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY TECHNOLOGY TYPE AS OF DECEMBER 31, 2019

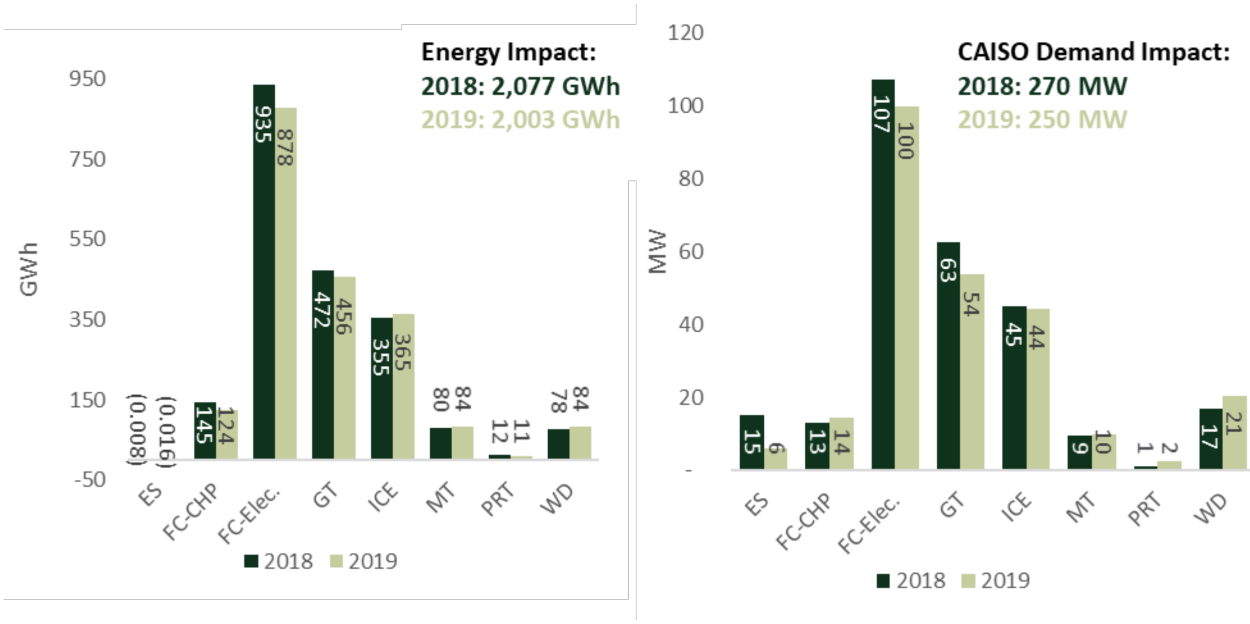
Technology Type	Project Count	Percent of Project Count	Total Rebated Capacity [MW]	Percent of Rebated Capacity
Energy Storage	8,895	90%	187.1	26%
Fuel Cell - CHP	127	1%	43.1	6%
Fuel Cell - Electric Only	321	3%	131.3	18%
Gas Turbine	15	<1%	69.4	10%
Internal Combustion Engine	300	3%	205	29%
Microturbine	160	2%	38.3	5%
Pressure Reduction Turbine	9	<1%	3.9	1%
Wind	32	<1%	39.5	5%
Waste Heat to Power	1	<1%	0.1	<1%
Total	**9,860**	**100%**	**718**	**100%**

The following subsections provide a summary of impacts for SGIP projects during 2018 and 2019.

Energy and Demand Impacts

Figure ES-1 shows SGIP annual electricity generation and the CAISO gross peak hour demand impact by technology type. Figure ES-1 (A) on the left displays the annual generation impact, showing that SGIP electricity impact decreased approximately 4 percent during 2019 relative to 2018. SGIP projects generated 2,077 GWh during 2018 and 2,003 GWh during 2019. Electric-only fuel cells made up about 45 percent of the generation, followed by gas turbines at just over 20 percent. Due to round trip efficiency losses, energy storage projects consume more energy than they discharge, so their contributions to annual electricity generation impacts are shown as negative values. The magnitude of their annual energy impacts are minor compared to the overall generation impacts of the program.

FIGURE ES-1: ANNUAL ELECTRICITY GENERATION (A, LEFT, GWH) AND CAISO PEAK HOUR DEMAND IMPACT (B, RIGHT, MW) BY TECHNOLOGY TYPE AND CALENDAR YEAR



* ES = Energy Storage; FC-CHP = Combined Heat and Power Fuel Cell; FC-Elec. = Electric Only Fuel Cell; GT = Gas Turbine; MT = Microturbine; PRT = Pressure Reduction Turbine; WD = Wind Turbine

Figure ES-1 (B) on the right displays generation coincident with the CAISO annual gross peak hour.[4] SGIP projects that generate or discharge electricity during the CAISO peak hour result in coincident peak demand reduction. Ideally, SGIP projects generate or discharge at full capacity during these peak hours, thereby reducing utility need to generate and transfer power to meet peak electricity demands. The total CAISO peak hour impact was 270 MW for 2018 and 250 MW for 2019, equivalent to 0.55 percent of the 2018 and 2019 gross CAISO peak hour load. As with the overall annual generation, the largest contributor to the CAISO peak hour impact was electric-only fuel cells, making up about 40 percent of the SGIP impacts during the CAISO peak hour, followed by gas turbines.

Energy impacts are a function of system size and utilization. Capacity factor (CF) is a measure of system utilization and defined as the amount of energy generated or discharged during a given time period divided by the maximum possible amount of energy that could have been generated or discharged during that time period. A high capacity factor (near 1.0) indicates that the system is being utilized to its maximum potential.

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4 The 2018 CAISO Gross Peak Demand occurred on July 25th between 4:00-5:00PM local time. The 2019 CAISO Gross Peak Demand occurred on August 15th between 4:00-5:00PM local time.

The system efficiency for generation projects is defined as the ability of a generation project to convert fuel into useful electrical and thermal energy. The higher the system's overall efficiency the less fuel input is needed to produce the combination of the generated electricity and useful heat. A system's ability to meet efficiency requirements is almost always tied to its heat recovery system. This is also the most complicated engineering challenge when implementing CHP. If the CHP generator is not appropriately sized to the annual heating and cooling loads of a building, then much of the excess heat must be dumped to the atmosphere through a radiator. Useful heat recovery loops may also require unplanned maintenance. These types of events can lead a technology to have a low useful heat recovery rate and therefore a low system efficiency.

Table ES-3 below displays the weighted annual average capacity factors and the different components of system efficiency for 2019 by technology type for generation projects. Electric-only fuel cells and gas turbines were found to have the highest capacity factors, with electric-only fuel cells achieving 81 percent and gas turbines at 78 percent during 2019. Gas turbines were found to have the highest system efficiencies. Electric-only fuel cells followed with efficiencies around 53%, even without any useful heat recovery. Further discussion can be found in Section 4.

TABLE ES-3: 2019 CAPACITY FACTORS AND EFFICIENCIES BY TECHNOLOGY TYPE

Technology Type	Capacity Factor*	Efficiency**		
		Electrical Conversion Efficiency	Thermal Efficiency	System Efficiency
Energy Storage (Non-Res.)	8%	--	--	--
Energy Storage (Res.)	6%	--	--	--
Fuel Cell – Electric Only	59%	53%	--	53%
Fuel Cell – CHP	76%	40%	13%	53%
Gas Turbine	75%	34%	26%	60%
Internal Combustion Engine	34%	36%	22%	58%
Microturbine	37%	28%	21%	49%
Pressure Reduction Turbine	36%	--	--	--
Wind	24%	--	--	--

* These system performance indicators are for projects known to be online during 2019. The evaluation team confirmed, through metered data and customer interviews that at least 322 projects had been physically removed from their original customer sites by the end of 2019.

** Energy storage does not report electrical, thermal, and system efficiencies. Instead, energy storage projects report round-trip efficiencies (RTE), which is defined as the total kWh discharge of the system divided by the total kWh charge. More information about energy storage RTE results can be found in Section 4.4.

SGIP projects impact customer demand in addition to system coincident peak demand. A customer's annual or monthly peak demand will not necessarily fall on the CAISO or IOU peak hour. This peak customer demand is referred to as noncoincident peak (NCP) customer demand. Examining this aggregate

NCP customer demand provides a way to identify the extent of the impact SGIP projects have on customer demand and customer bills.

Figure ES-2 displays the average monthly percent customer demand reduction of the gross load for 2019, broken down by technology for PBI and non-PBI projects. For most technologies, there is a higher customer demand reduction in PBI projects, with the exception of gas turbines and wind. In general, customer NCP demand was found to decrease up to 60 percent for SGIP generation projects. More about NCP demand can be found in Section 4.

FIGURE ES-2: 2019 NCP CUSTOMER DEMAND REDUCTION BY TECHNOLOGY

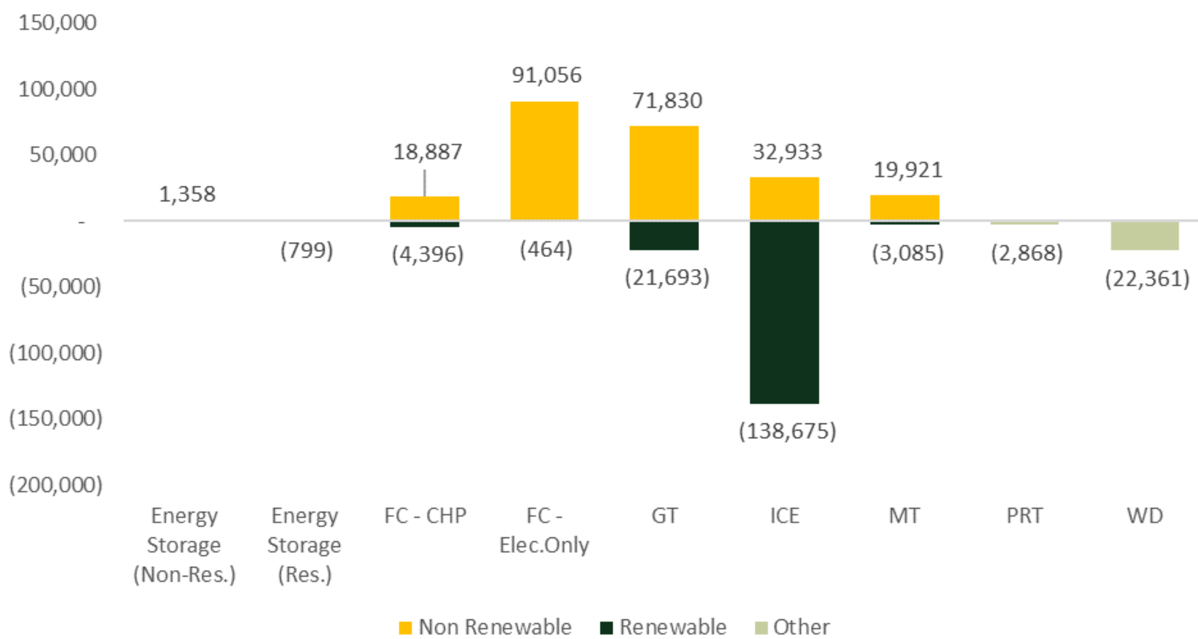
	Energy Storage	Fuel Cell - CHP	Fuel Cell - Elec. Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind
January	6%	41%	51%	55%	30%	17%	20%	25%
February	5%	65%	52%	76%	28%	29%	23%	30%
March	8%	42%	49%	55%	33%	30%	18%	33%
April	10%	45%	45%	36%	36%	26%	14%	33%
May	9%	37%	46%	27%	47%	25%	18%	32%
June	9%	28%	41%	47%	27%	26%	23%	32%
July	9%	39%	41%	37%	21%	25%	8%	25%
August	9%	35%	41%	48%	28%	24%	7%	19%
September	6%	33%	41%	24%	30%	24%	5%	23%
October	4%	39%	44%	49%	37%	29%	8%	21%
November	6%	40%	44%	36%	38%	29%	13%	23%
December	4%	44%	49%	3%	27%	32%	3%	25%
PBI	N/A	42%	47%	34%	41%	46%	14%	25%
Non-PBI	N/A	29%	37%	60%	21%	7%	0%	35%

SGIP Greenhouse Gas Impacts

SGIP projects increased GHG emissions by 42,072 metric tons of CO_2eq during 2018 and 44,109 metric tons of CO_2eq during 2019. Figure ES-3 displays the 2019 annual GHG impacts by technology type and fuel source.

Renewable fueled internal combustion engines achieved the largest reductions in GHG emissions during both 2018 and 2019. Non-renewable fueled technologies and non-residential energy storage systems all showed a positive GHG emissions impact, indicating that these SGIP technologies emitted greater GHG emissions than their conventional baselines (i.e., grid electricity). Additional details on GHG impacts are provided in Section 5.

FIGURE ES-3: ANNUAL GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE AND FUEL TYPE (2019)



KEY FINDINGS

Finding 1: SGIP year-over-year trends indicate that the SGIP continues to provide benefits. During both 2018 and 2019, SGIP projects delivered coincident and noncoincident peak demand reductions, provided energy benefits, and renewable-fueled projects provided GHG emissions reductions.

Energy Generation: The SGIP generated 2,077 GWh of energy in 2018 and 2,003 GWh in 2019, making up just about 1 percent of California's total in-state generation for 2018 and 2019.

CAISO Peak Demand: CAISO peak hour load was reduced 270 MW in 2018 and 248 MW in 2019. This reflects 0.55 percent of the 2018 and 2019 gross CAISO peak load.

GHG Emissions Reductions: While the overall SGIP program increased GHG emissions by over 42 thousand metric tons in 2018 and 44 thousand in 2019, renewably fueled projects continue to provide GHG emissions reductions. Renewably-fueled SGIP projects reduced GHG emissions by over 200 thousand metric tons of CO_2eq in 2018 and 168 thousand metric tons of CO_2eq in 2019.

Finding 2: A significant portion of the energy and demand impacts summarized in Finding 1 are due to non-renewable fueled projects. About 70 percent of the total energy generated by SGIP projects during both 2018 and 2019 came from non-renewable fueled projects.

Finding 3: SGIP project growth is driven almost entirely by energy storage projects. During 2018 and 2019 there were 8,090 new projects added to the SGIP population. Twenty-two of these were non-energy storage projects. Although generation projects made up less than 1 percent of the total number of new projects, the accounted for about 20 percent of the new rebated capacity in 2018 and 2019.

Finding 4: Reduction in SGIP project generation is likely driven by the phase out of non-renewable fuel projects. Since 2017, the SGIP no longer allows fully non-renewable fueled projects. As of 2020, all projects are required to consume 100% renewable fuel. This change in eligibility rules is likely the largest driver of the reduction in generation projects applying for SGIP incentives. There are only 11 fuel-consuming generation projects in the current SGIP queue. Out of these, seven of them are pre-2017 legacy projects, meaning they are not required to have utilize any biofuel.

Finding 5: Directed biogas (DBG) projects are almost all out of contract. Directed biogas projects with a program year of 2010 or earlier were required to have a 5-year DBG contract (i.e., procure directed biogas for a period of no less than five years). Those with a program year of 2011 or later were required to have a 10-year DBG contract. This means that most of the DBG projects in SGIP are completely out of contract and are no longer required to procure DBG. Interviews with host customers suggest that after DBG projects complete their renewable fuel use procurement term they continue to operate on 100% non-renewable fuel. Transitioning a system from renewable to non-renewable fuel impacts the GHG emissions reductions of that system and the program overall.

Finding 6: SGIP non-renewable projects will face increasing headwinds in achieving greenhouse gas emission reductions as California transitions to a carbon free electricity supply. California Senate Bill 100 accelerates the state's current renewable portfolio standard program to 50% by 2025 and 60% by 2030. In addition, SB 100 sets a 100% clean, zero carbon, and renewable energy policy for California's electricity system by 2045. As California's grid transitions to 100% renewable fuel, it will become increasingly difficult for SGIP non-renewable projects to achieve GHG emission reductions relative to grid electricity. On the other hand, renewable fueled SGIP projects, whether on-site biogas projects or directed biogas projects, will continue to achieve greenhouse gas reductions. Projects with a flared biogas baseline would at worst achieve GHG neutrality (i.e., no reduction) in a zero-carbon grid scenario. Projects with a vented biogas baseline (e.g., projects installed at small dairies that are not required to flare methane) would achieve considerable greenhouse gas reductions, even under a zero-carbon grid.

Finding 7: SGIP GHG emissions have increased. The drivers of this increase are not all related to changes in program participant behavior. The SGIP increased emissions by 42,072 metric tons of CO_2eq during 2018 and 44,109 metric tons of CO_2eq during 2019. The reasons for this change are not all attributable to program changes or changes in participant behavior. Verdant's assumption that out-of-contract directed biogas projects continue to operate on natural gas beyond their 5-year contract period leads to a relative increase GHG emissions. However, the input values used to calculate the marginal emissions rate, such as gas delivery costs and locational marginal prices, have also changed. Changes in these values over time have resulted in a considerably lower implied marginal emissions rate during this evaluation period relative to the 2016 – 2017 SGIP Impact Evaluation Report. More information about the marginal emissions rate calculation can be found in Appendix C.

Finding 8: The timing and duration of charge and discharge patterns for energy storage is far more important from a GHG reduction or avoided cost perspective than simply increasing storage utilization and roundtrip efficiency. There is a strong relationship between utilization and RTE. However, increasing utilization for the sake of increasing RTE alone will likely not turn SGIP nonresidential systems into net GHG reducers. A GHG signal like the one being implemented through the SGIP GHG working group can help storage systems improve the timing and duration of charge/discharge. Analysis shows that such a signal can be implemented to significantly reduce GHG emissions without a material impact on customer bills.

Finding 9: The federal Investment Tax Credit (ITC) is an effective mechanism for aligning storage system charging with periods of lower marginal emissions. Charging from on-site solar generation is critically important from an avoided cost and GHG emissions reduction perspective. The evaluation team observed an overall decrease in GHG emissions from residential projects and nonresidential systems paired with on-site solar. These systems were almost exclusively charging during solar generation hours early in the morning – when marginal emissions are low. Customers should continue to be motivated to charge their storage systems during early PV generation hours.

Finding 10: Large nonresidential systems without on-site solar consistently provide benefits to customers in the form of billed demand (kW) savings, are discharging throughout CAISO top hours, but increase GHG emissions. These results demonstrate that, under current retail rates, the incentives for nonresidential customers to dispatch energy to minimize bills are not well aligned with the goals of minimizing GHG emissions. More dynamic rates and a GHG signal, that better align customer and grid benefits, could provide substantial ratepayer and environmental benefits that are currently unrealized. No projects operational during 2019 were required to follow the recently created GHG signal.

RECOMMENDATIONS

Recommendation 1: Identify Ways to Increase Participation of Biogas Projects – Particularly Those That Would Have Otherwise Vented Biogas to the Atmosphere: As noted in the SGIP Biogas Generation Cost-Effectiveness and Market Assessment Report, the SGIP has been so focused on energy storage that it is hard for potential customers to gather any more information about generation incentives. Yet, biogas projects represent a significant source of GHG reductions for the SGIP. During 2019, biogas projects contributed 168 thousand metric tons of CO_2eq GHG reductions. To ensure continued program wide GHG reductions, we recommend that the PAs identify ways to increase adoption of self-generation technologies at dairies, landfills, wastewater treatment plants, and other facilities that produce excess biogas or decrease barriers to directed biogas projects. Emphasis should be placed on facilities that would otherwise have vented methane to the atmosphere like dairy digesters since this vented methane has far greater global warming potential than biogas that would have otherwise been flared.

Recommendation 2: The program has evolved significantly since its inception in 2001 and the benefits of quantifying energy, demand, and greenhouse gas impacts for pre-PY2011 non-PBI projects are diminishing. The SGIP is one of the largest and longest-lived distributed energy resource (DER) incentive programs in the country. Annual and biennial impact evaluations provide critical knowledge to program implementers and regulators in other jurisdictions involved in DER program design. While determining the impacts of older generation projects is a unique characteristic of SGIP impact evaluations, the benefits may no longer be worth the effort associated with data collection from legacy non-PBI projects. There have been substantial changes to the program, including PBI metering, changes in warranty and contractual permanence, changes in directed biogas contracts, and changes in fuel use requirements. Future program evaluations may provide the maximum benefit from reporting energy, demand, and greenhouse gas impacts only from the post-2011 PBI projects. Doing so will maximize the use of evaluation funds and will reflect the most recent program changes. We recommend that future evaluations continue to evaluate the persistence of legacy pre-PBI SGIP projects (e.g., how many projects remain online vs. decommissioned).

1 INTRODUCTION AND OBJECTIVES

Established legislatively in 2001[5] to help address peak electricity problems facing California, the Self-Generation Incentive Program (SGIP) represents one of the longest-lived and broadest distributed energy resource (DER) incentive programs in the country. The SGIP is funded by California electricity rate payers and managed by Program Administrators (PAs) representing California's major investor-owned utilities (IOUs).[6] The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

The SGIP has provided financial incentives to a wide variety of distributed energy technologies including gas turbines, internal combustion (IC) engines, fuel cells, and microturbines. These technologies can be fueled by non-renewable natural gas or renewable fuels such as biogas or syngas. Furthermore, technologies can be operated in combined heat and power (CHP) mode with useful heat recovery, or as standalone electric-only technologies if they meet certain efficiency criteria.

Beginning in 2011, the program also offered financial incentives for energy storage technologies. At first these technologies had to be paired with another technology to be eligible for incentives. In 2011, program rules were changed, and standalone energy storage became eligible for SGIP incentives. Other eligible technologies include wind turbines, pressure reduction turbines (PRT), and waste-heat-to-power (WHP) technologies. During its first years the SGIP also offered incentives to solar photovoltaic (PV) technologies. Impacts of solar PV projects rebated by the SGIP are no longer reported in SGIP impact evaluations due to the creation of the California Solar Initiative (CSI).[7]

Eligibility rules for SGIP technologies are constantly in flux as PAs and the CPUC respond to policy changes, energy legislation, and an evolving energy landscape. Section 2 provides additional discussion about changes in technology eligibility within SGIP over time. Table 1-1 summarizes the technologies eligible for incentives and within this report's evaluation scope.

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5 During the summer and fall of 2000, California experienced a number of rolling blackouts that left thousands of electricity customers in Northern California without power and shut down hundreds of businesses. In response, the California legislature passed Assembly Bill 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. The SGIP was established the following year as one of several programs to help address peak electricity problems.

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

7 The CSI General Market Program closed on December 31st, 2016.

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TABLE 1-1: SGIP ELIGIBLE TECHNOLOGIES DURING THE 2018-2019 EVALUATION PERIOD

Category	Technology Type
Non-Fueled and Waste Energy Recovery Technologies	Wind Turbine
	Waste Heat to Power
	Pressure Reduction Turbine
Renewable and Non-renewable Combined Heat and Power Technologies	Internal Combustion Engine
	Fuel Cell
	Microturbine
	Gas Turbine
Electric-Only Generation Technologies	Electric Only Fuel cell
Energy Storage	Battery Energy Storage

1.1 PURPOSE AND SCOPE OF REPORT

The original CPUC Decision (D.) 01-03-073 establishing the SGIP required "program evaluations and load impact studies to verify energy production and system peak demand reductions" resulting from the SGIP.[8] That March 2001 decision also directed the assigned the Administrative Law Judge (ALJ), in consultation with the CPUC Energy Division (ED) and the PAs, to establish a schedule for filing the required evaluation reports. Since 2001, fourteen annual or biennial SGIP impact evaluations have been conducted.[9]

On January 13, 2017, the CPUC ED submitted an updated plan to measure and evaluate the progress and impacts of the SGIP for Program Years 2016 – 2020. The CPUC M&E plan calls for the creation of a series of annual impact evaluations that are focused on energy storage. Furthermore, the M&E plan calls for biennial impact evaluations of all technologies in the SGIP. This report is prepared in response to the M&E Plan requirement for a 2018-2019 SGIP Impact Evaluation Report.

The SGIP has evolved to meet the changing energy and policy needs of California. Annual or biennial SGIP impact evaluation reports reflect changes in SGIP eligibility criteria and success metrics. The primary purpose of this report is to quantify the energy, demand, and environmental impacts of SGIP projects during calendar years 2018 and 2019. Impacts are reported for the SGIP as a whole for each calendar year and by other categories such as technology type, fuel type, PA, and electric utility. Some reported impacts are further categorized by program year to recognize the different program goals and rules in effect at the time of project development.

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

9 A listing of past SGIP impact reports can be found on the CPUC's website: http://www.cpuc.ca.gov/General.aspx?id=7890

Per the CPUC M&E Plan, SGIP energy storage impacts are addressed separately in their own annual reports. These annual reports include a discussion on net greenhouse gas (GHG) emissions for residential and non-residential systems, and between systems paired with renewable generation and non-paired systems. This SGIP biennial impact evaluation report brings in key findings from the 2018 and 2019 SGIP Energy Storage Impact Evaluation Reports and presents those impacts alongside the impacts of all other technologies in the program.

The specific objectives for this 2018-2019 SGIP impact evaluation include:

- Energy impacts including electricity generated, fuel consumed, and useful heat recovered. Efficiency and utilization metrics include annual capacity factor (CF), electrical conversion efficiency, useful heat recovery rate, and system efficiency.
- Energy impacts are treated separately for energy storage and include breakouts by charge and discharge impacts. We also assess round trip efficiency and discharge performance for energy storage in light of SGIP handbook requirements.
- Demand impacts (average reduction and capacity factor) during the top demand hour and top 200 load hours of the California Independent System Operator (CAISO) and California's three electric IOUs. This evaluation also examines aggregate noncoincident customer peak demand impacts.
- GHG emissions.

The SGIP includes a significant number of projects that were installed early on in the program and have continued to operate; providing benefits to both the host customer and the utility. As such, while the focus of this report is on impacts occurring during 2018 and 2019, these impacts result from a portfolio of projects that can span many years. Changes in program policies and requirements have created significant differences in operation and performance of SGIP projects. In particular, Senate Bill (SB) 412 (Kehoe, October 11, 2009) established GHG requirements that resulted in substantial changes to the SGIP. Among the changes implemented by SB 412 was the requirement that projects over 30kW take performance-based incentives (PBI). Where appropriate, we differentiate impacts between PBI projects and non-PBI projects.

In 2016, CPUC D. 16-06-055 implemented major changes to the SGIP. These changes included minimum biogas blending requirements. These minimum biogas blending requirements stated that beginning in program year (PY) 2017, all natural gas-consuming generation projects must use a minimum of 10 percent biogas to receive an SGIP incentive. The minimum requirement increases to 25 percent in 2018, 50 percent in 2019, and 100 percent in 2020. Perhaps most noticeably, this decision shifted the program focus to energy storage, allocating 75 percent of the SGIP budget to energy storage technologies with the remaining 25 percent going to generation technologies. This report highlights the effect of this decision on the SGIP.[10]

Finally, the impacts reported in this evaluation are based directly on metered performance data collected from a sample of SGIP projects. We use sampling methods and expand the results from the samples to the SGIP population using statistical approaches that conform to industry standards for impact evaluations. Sources of data and the estimation methodologies we use in treating the data are described in Section 3. Further explanation of the sources of data, our estimation methodologies and sources of uncertainties are contained in the appendices of the report.

1.2 REPORT ORGANIZATION

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

- Section 1 lays out the purpose, scope, and organization of the report.
- Section 2 provides background and program status including project counts, rebated capacities, and incentive payment totals by technology type, energy source, and PA.
- Section 3 summarizes the sources of data and statistical methods used to quantify impacts.
- Section 4 presents energy and demand impacts for SGIP technologies including electricity generated, waste heat recovered, and fuel consumed.
- Section 5 presents and discusses the GHG impacts of all technologies.
- Appendix A provides supplementary program statistics not presented in Section 2.
- Appendix B describes in detail the methodology used to quantify energy and demand impacts and provides additional impacts not presented in Section 3.
- Appendix C describes in detail the methodology used to quantify greenhouse gas impacts and provides additional impacts not shown in Section 5.
- Appendix D describes the sources of uncertainty in impact estimates, the methodology used to quantify the uncertainty, and the results of the uncertainty analysis.

10 The 2020 Program Handbook shows updated budget allocations of 88 percent going towards the energy storage technologies and the remaining 12 percent going towards generation technologies.

2 PROGRAM BACKGROUND AND STATUS

This section provides background on program policy and information on the status of the Self-Generation Incentive Program (SGIP) as of December 31, 2019. The status information is based on project data obtained from the Statewide Database provided by the Program Administrators (PAs). This section also summarizes active projects in the SGIP queue, which contains projects that may receive payments and become operational in future years. This report does not include impacts from photovoltaic (PV) projects that had been eligible to receive incentives under the SGIP prior to 2007.[11]

2.1 PROGRAM BACKGROUND AND RECENT CHANGES RELEVANT TO THE IMPACTS EVALUATION

In response to the electricity crisis of 2001, the California Legislature passed several bills to help reduce the state's electricity demand. In September 2000, Assembly Bill (AB) 970[12] (Ducheney, September 6, 2000) established the SGIP as a peak-load reduction program. In March 2001, the California Public Utilities Commission (CPUC) formally created the SGIP and received the first SGIP application in July 2001.

The SGIP was originally designed to reduce energy use and demand at host customer sites. The program included provisions to help ensure that projects met certain performance specifications, such as requiring minimum efficiencies and manufacturer warranties. Originally, the SGIP did not establish targets for a total rebated installation capacity, reductions in energy use and demand, or contributions to greenhouse gas (GHG) emissions reductions.

By 2007, growing concerns with potential air quality impacts prompted changes to the eligibility of technologies under the SGIP. In particular, approval of AB 2778[13] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Beginning January 1, 2007, only fuel cells and wind turbines were eligible under the SGIP. Passage of Senate Bill (SB) 412[14]

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11 Effective January 1, 2007, PV technologies installed on the customer side of the meter were eligible to receive incentives under the California Solar Initiative (CSI). Impacts from PV installed under the SGIP are reported in the CSI impacts evaluation studies. Electronic versions of the CSI impacts studies are located on the CPUC's website under Energy -> Consumer Energy Programs -> California Solar Initiative (CSI): http://www.cpuc.ca.gov/General.aspx?id=7623

12 Assembly Bill 970. Ducheny, Battin, and Keeley. September 6th, 2000. http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html. Date accessed: 10/31/2020.

13 Assembly Bill 2778. Lieber. September 29th. 2006. http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html. Date accessed: 10/31/2020.

14 Senate Bill 412. Kehoe. October 11th, 2009. http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf. Date accessed: 10/31/2020.

(Kehoe, October 11, 2009) refocused the SGIP toward Greenhouse Gas (GHG) emission reductions and led to a re-examination of technology eligibility by the CPUC. As a result of that re-examination, the list of technologies eligible for the SGIP expanded again to include combined heat and power (CHP), pressure reduction turbines, and waste heat-to-power technologies. In addition, SB 412 required fossil fueled combustion technologies to be adequately maintained so that during operation they continue to meet or exceed the established efficiency and emissions standards. The passage of SB 412 marked a significant change in the composition of SGIP applications toward fuel cells and advanced energy storage projects.

On July 1, 2016, the CPUC issued Decision 16-06-055 revising the SGIP pursuant to SB 861, AB 1478, and implementing other changes.[15] The Decision made several changes to the SGIP, including administering funds continuously rather than incrementally each year, and allocating 75 percent of program funds to energy storage. In 2016, the SGIP administrators allocated 75 percent of the annual incentive budget to renewable and emerging technology projects (including energy storage) and 25 percent to non-renewable fueled conventional CHP projects. Starting in 2017, per the 2017 SGIP handbook, 80 percent of the incentive budget was allocated to storage technologies and 20 percent to generation. Additionally, this decision created minimum zero emission fuel blending requirements as part of California's long term GHG reduction and market transformation goals. Beginning with program year (PY) 2017, generation projects consuming natural gas required a minimum of 10 percent biogas to receive an SGIP incentive. The minimum requirement increased to 25 percent in 2018, 50 percent in 2019, and 100 percent in 2020.

In SB 412 a sunset date of January 1, 2016, was set for the SGIP. SB 861[16] revised this date, and authorized collections for the SGIP through 2019 and administration through 2020. In January 2020, CPUC decision D.20-01-021[17] again extended the SGIP through 2024. The SGIP continues to be one of the largest and longest-lived distributed energy resource (DER) incentive programs in the nation. The projects rebated by the SGIP since its inception reflect program objectives that have evolved over time.

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15 Decision Revising the Self-Generation Incentive Program Pursuant to Senate Bill 861, Assembly Bill 1478, and Implementing Other Changes. Decision 16-06-055. Issued July 1st, 2016. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF. Date Accessed: 10/31/2020

16 Senate Bill 861, Public resources trailer bill, June 20, 2014. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB861. Date Accessed: 10/31/2020

17 Self-Generation Incentive Program Revisions Pursuant to Senate Bill 700 and Other Program Changes. Decision 20-01-021. Issued 01/27/2020. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF. Date Accessed: 10/31/2020

2.2 PROGRAM STATISTICS IN 2019

Each SGIP project advances through a series of stages during its application process. The scope of this impact evaluation is limited to completed projects. Completed projects have been installed and begun operating, have passed their eligibility inspection, and were issued an incentive payment on or before December 31, 2019.[18,19] As of December 31, 2019 the SGIP provided incentives to 9,860 projects representing a total system size of 718 MW. This incentivized system size is referred to as the rebated capacity.

Table 2-1 shows counts and rebated capacities of completed projects for each Program Administrator as of December 31, 2019. Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and Southern California Gas Company (SCG) administer the SGIP within their electric and/or gas distribution service territories. The Center for Sustainable Energy (CSE) administers the program within San Diego Gas and Electric's (SDG&E's) service territory.

TABLE 2-1: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR (2019)

Program Administrator	Project Count	Rebated Capacity [MW]	Percent of Rebated Capacity
CSE	2,084	91.6	13%
PG&E	3,755	278.5	39%
SCE	3,371	198.0	28%
SCG	650	149.9	21%
Total	**9,860**	**718**	**100%**

PG&E administers the largest number of projects (3,755) and rebated capacity (278.5 MW) of all PAs, followed by SCE. Table 2-2 displays the project counts, average rebated capacity, and total rebated capacity by technology type as of December 31, 2019. Although energy storage projects represent the smallest average project capacity among SGIP technologies, they have grown to become the largest portion of the SGIP by project count. Energy storage projects represent over 90 percent of all projects and around 26 percent of all rebated capacity. Internal combustion engines, followed by electric-only fuel

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

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

cells, make up 29 percent and 18 percent of the rebated capacity (but each make up only 3 percent of the total rebated projects).

TABLE 2-2: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY TECHNOLOGY TYPE (2019)

Technology Type	Project Count	Percent of Project Count	Total Rebated Capacity [MW]	Percent of Rebated Capacity
Energy Storage	8,895	90%	187.1	26%
Fuel Cell - CHP	127	1%	43.1	6%
Fuel Cell - Electric Only	321	3%	131.3	18%
Gas Turbine	15	<1%	69.4	10%
Internal Combustion Engine	300	3%	205	29%
Microturbine	160	2%	38.3	5%
Pressure Reduction Turbine	9	<1%	3.9	1%
Wind	32	<1%	39.5	5%
Waste Heat-to-Power	1	<1%	0.1	<1%
Total	**9,860**	**100%**	**718**	**100%**

* Energy storage rebated capacity represents the average discharge across two hours.

The cumulative growth in SGIP capacity since its inception in 2001 is shown below in Figure 2-1. There were 147 MW of rebated capacity added in 2018 and 2019. The SGIP continues to see a steady increase in rebated capacity of at least 10 percent year over year.[20]

[20] This does not consider the capacity of projects that are decommissioned each year.

FIGURE 2-1: CUMULATIVE REBATED CAPACITY BY CALENDAR YEAR

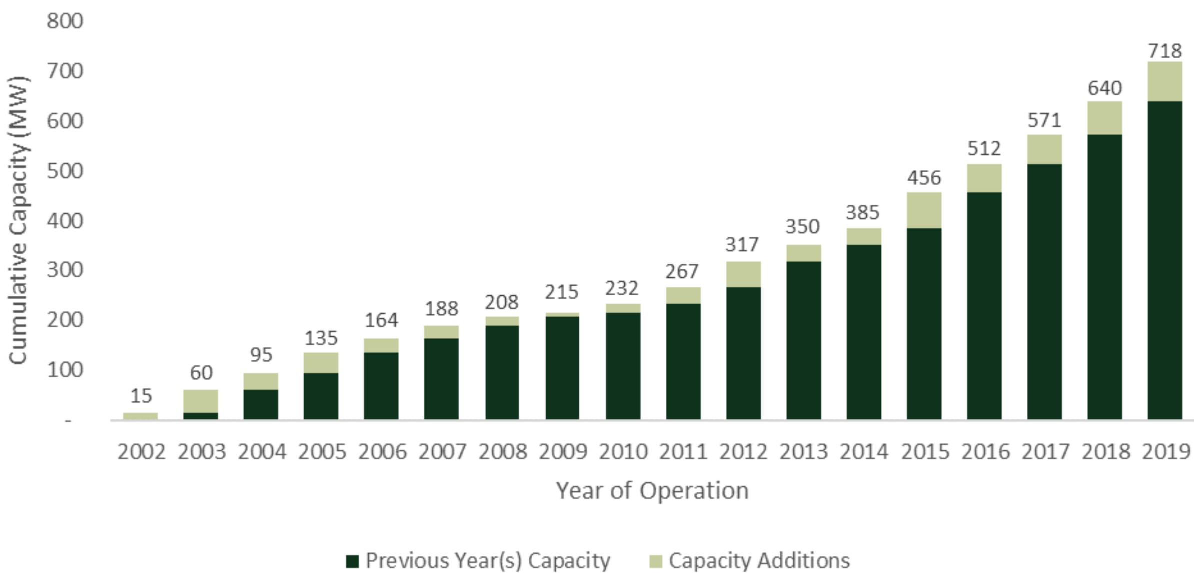
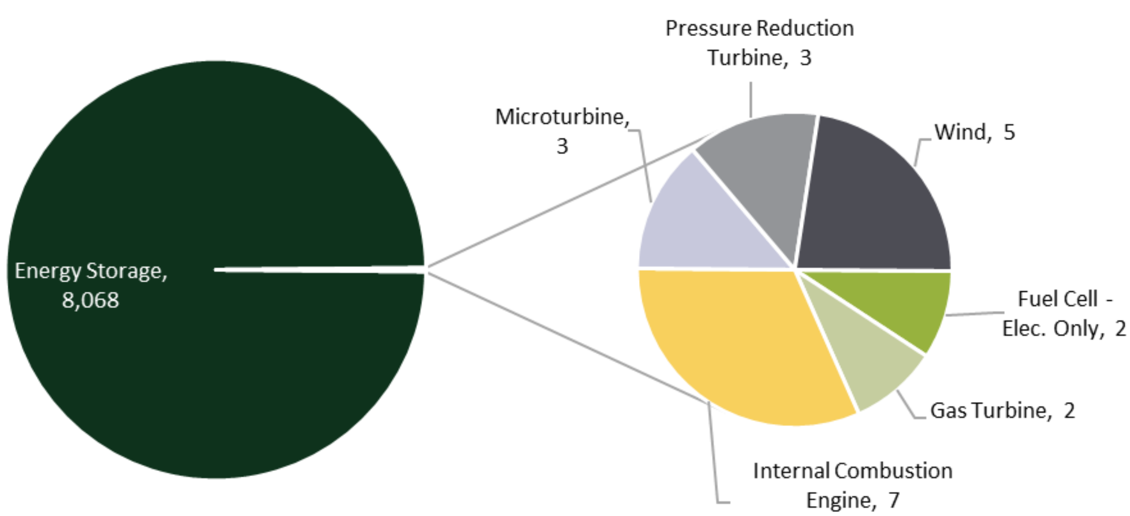


Figure 2-2 shows the breakdown of projects rebated during 2018 and 2019 by technology type. Over 99 percent of all projects receiving incentives during 2018 and 2019 were energy storage projects. Ninety percent of all energy storage projects in the SGIP population were rebated in the last two years. Only 22 generation projects were added during 2018 and 2019 and 14 of them are combustion technologies.

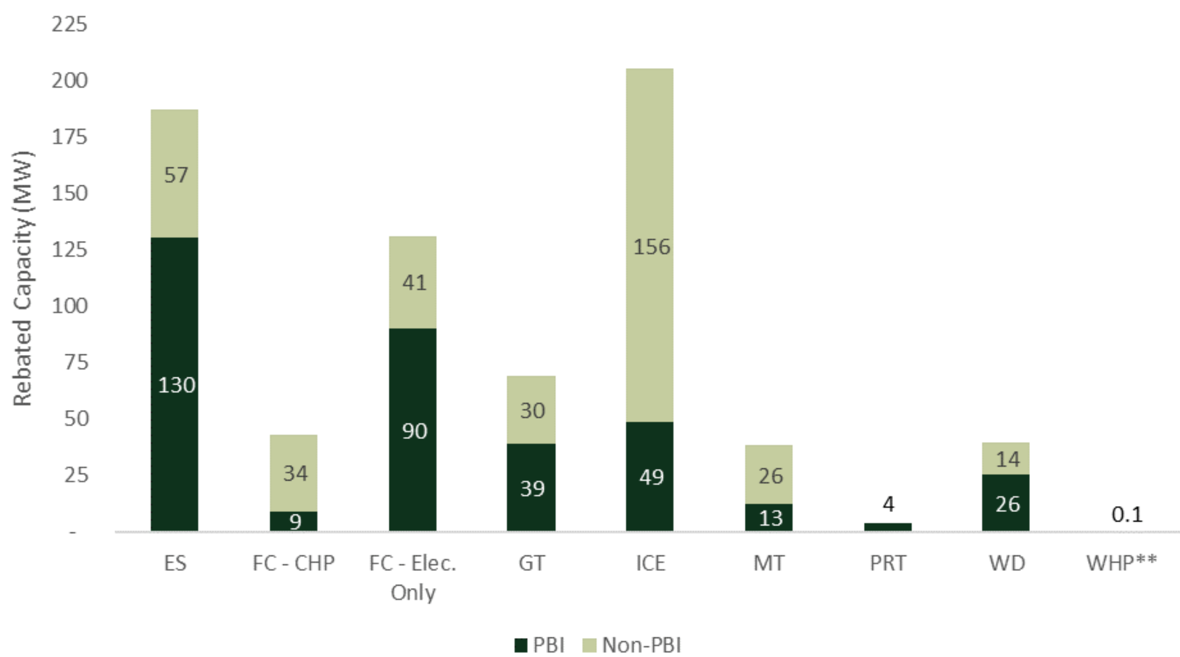
FIGURE 2-2: COUNT OF PROJECTS REBATED DURING 2018 AND 2019 (COMBINED)



One of the most important changes to the SGIP design targeted its incentive structure. Completed projects from PY 2010 or earlier received their entire SGIP incentive at the time of project completion. This incentive structure is referred to as a capacity-based incentive. However, beginning in PY 2011 as a result of SB 412, new projects 30 kW and larger receive half of their SGIP incentive upfront and the remainder in annual payments following each of the first five years of operation. This incentive structure is known as a performance-based incentive (PBI).

Figure 2-3 below displays the rebated capacities of each technology type grouped by PBI and non-PBI status. In this report, PBI projects are defined as any project subject to the PBI payment rules, regardless of whether they have completed their five-year PBI term. Non-PBI projects are projects that applied on or before PY 2010, or projects that applied after PY 2010 but are less than 30 kW. Performance-based incentive projects represent 360 MW of rebated capacity, whereas the remaining 358 MW of rebated capacity are not subject to PBI payment rules. Forty-four percent of the non-PBI rebated capacity consists of internal combustion engines. Energy storage systems make up over one-third of the PBI rebated capacity, followed by electric-only fuel cells making up almost one-quarter. Energy storage projects also made up 99.7 percent of the projects, and 80 percent of the program capacity completed in 2018 and 2019.

FIGURE 2-3: REBATED CAPACITY BY TECHNOLOGY TYPE (PBI VERSUS NON-PBI)



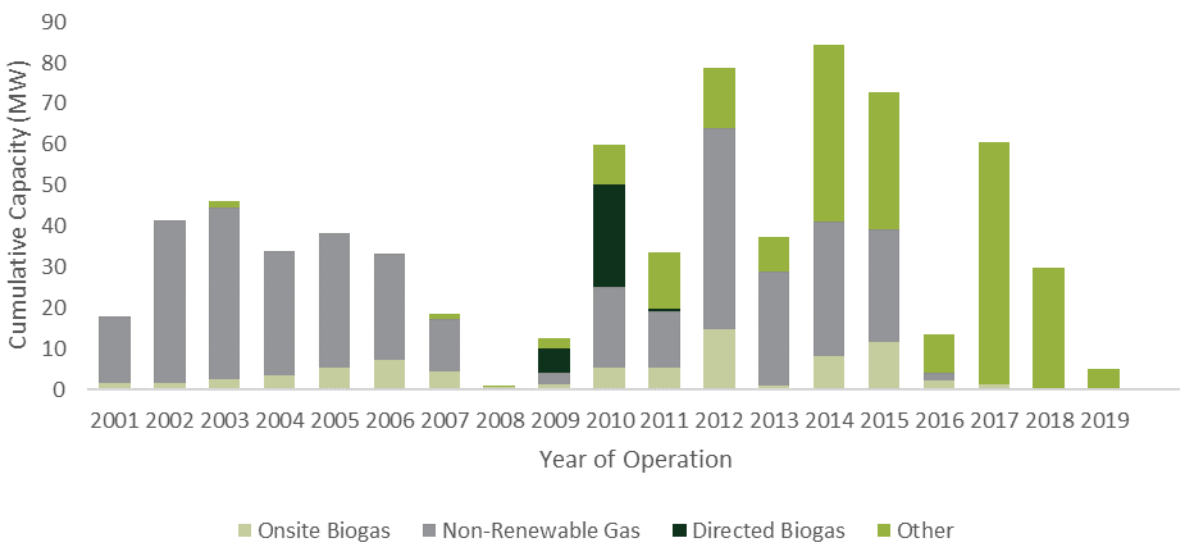
* ES = Energy Storage, FC-CHP = Fuel Cell – CHP, FC-Elec. Only = Fuel Cell – Electric Only, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine, WHP = Waste Heat to Power

** The WHP project is subject to PBI payment rules.

SGIP projects are powered by a variety of renewable and non-renewable energy sources, as shown in Figure 2-4. The majority of the SGIP projects are powered by natural gas. Onsite biogas uses biogas diverted from landfills or anaerobic digestion processes that convert biological matter to renewable fuel. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert waste from these facilities to biogas.

In CPUC Decision 09-09-048 (September 24, 2009), SGIP eligibility was expanded to include directed biogas projects. Directed biogas projects use biogas fuel that is produced at a location outside the project site. The procured biogas is processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased biogas is not likely to be delivered and used by the SGIP renewable fuel project, the directed biogas is notionally delivered and the SGIP is credited with the overall use of biogas resources. Beginning in PY 2011, the SGIP limited the eligibility for directed biogas projects to in-state biogas sources only. In 2016, the eligibility was expanded to directed biogas within the western interconnect. Since 2011 there has only been one directed biogas project installed.

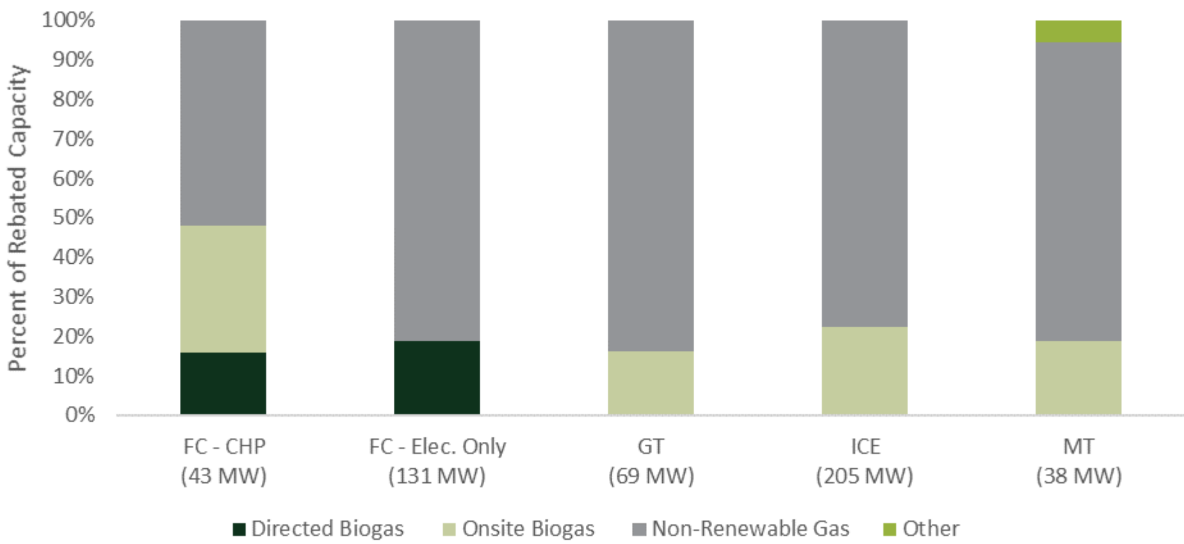
FIGURE 2-4: CUMULATIVE REBATED CAPACITY BY ENERGY SOURCE BY PROGRAM YEAR



*'Other' energy source group includes energy storage, wind turbines, waste heat-to-power and pressure reduction turbines.

Figure 2-5 shows energy sources for each SGIP technology type as of December 31, 2019. All SGIP fuel-consuming technology types include projects powered by non-renewable natural gas and renewable biogas. All of the biogas used for electric-only fuel cells is directed biogas. Some CHP fuel cells are also fueled by directed biogas, but most are fueled by natural gas or renewable, onsite biogas. Energy storage, pressure reduction turbines, and wind technologies do not consume fuel. The 'Other' fuel type includes projects where the fuel type was "waste gas", a continuous source of natural gas from an oil platform which was previously being flared.

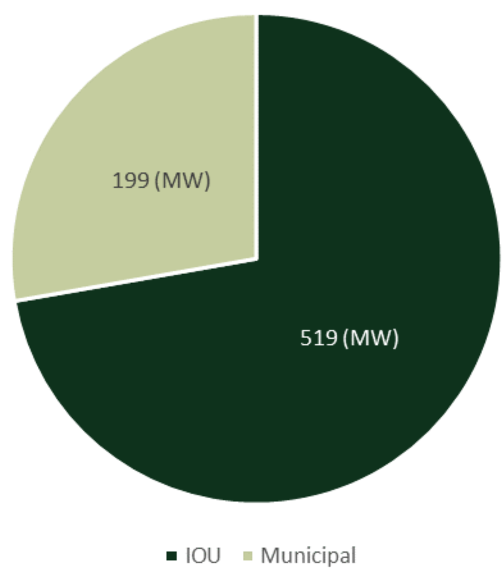
FIGURE 2-5: REBATED CAPACITY BY SGIP TECHNOLOGY TYPE AND ENERGY SOURCE



* FC-CHP = Fuel Cell – CHP, FC-Elec. Only = Fuel Cell – Electric Only, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine.

SGIP projects are electrically interconnected to load serving entities that are either investor owned (IOU) or municipal utilities. Figure 2-6 shows each PA's rebated capacity by electric utility type as of December 31, 2019. Thirty-one percent of the SGIP rebated capacity is interconnected to municipal utilities; the remaining capacity offsets IOU electricity purchases.

FIGURE 2-6: REBATED CAPACITY BY PROGRAM ADMINISTRATOR AND ELECTRIC UTILITY TYPE (2019)



Contractual Permanence (Permanence)

The intent of the SGIP is to provide incentives for equipment installed and functioning for the duration of its useful life. Only permanently installed systems are eligible for incentives, which means that the system must meet assurances of contractual permanence prior to receiving an incentive. The contractual permanence requirement has changed over the years. Up through PY 2011, the program required that a system meet a contractual permanence period of 2 times the length of the system's warranty. Starting in 2012, this contractual permanence period was updated to reflect the extended warranty requirement of 10 years. Table 2-3 shows the length in years of the warranty period by program year and technology.

TABLE 2-3: SGIP CONTRACTUAL PERMANENCE PERIODS FOR GENERATION EQUIPMENT BY TECHNOLOGY AND PROGRAM YEAR

Technology Type	Program Years	Permanence Period (Years)
Fuel Cell	PY01-PY10	10
	PY11-PY19	10
Gas Turbine	PY01-PY10	6
	PY11-PY19	10
Internal Combustion Engine	PY01-PY10	6
	PY11-PY19	10
Microturbine	PY01-PY10	6
	PY11-PY19	10
Pressure Reduction Turbine	All	10
Wind	PY01-PY10	10
	PY11-PY19	20

* PY 2011 slightly differed from what is listed above. The actual program handbook in 2011 still requires a permanence period that is twice the length of the warranty. However, PY 2011 was also the year that extended the required warranty period. It is the evaluation team's understanding that the program did not intend to require a contractual permanence period of twice the length of the warranty period after the required warranty was extended to 10 years.

Over time, host customers may decide to physically remove or decommission SGIP systems from their premise. Verdant tracks the number of SGIP projects that have been decommissioned for impact evaluation purposes. The decommissioned status is determined through Operational Status Research (OSR)[21] and through conversations with PAs. Since the program's inception, 322 systems are known to be decommissioned, totaling 80 MW of rebated capacity. These systems are all energy storage, CHP fuel cells, IC engines, or microturbines.

21 Operational Status Research is described in greater detail in Section 3 and Appendix B.

Verdant has also tracked whether a system met its contractual permanence requirement or not based on the age of the system at the time of decommissioning. Results are summarized below in Table 2-4.

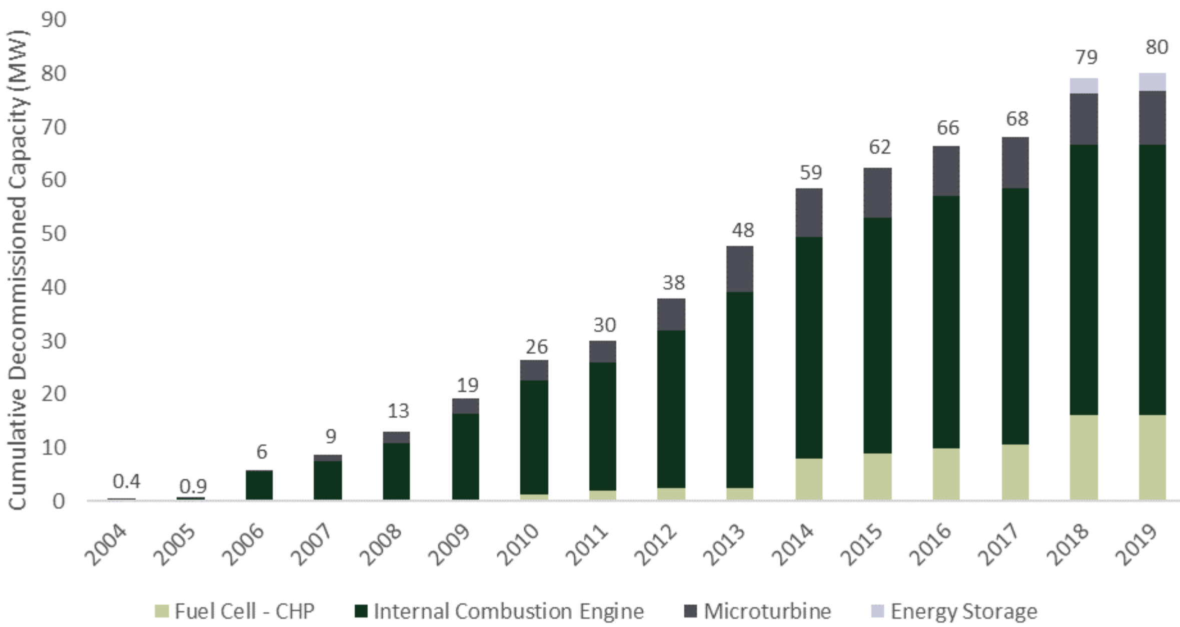
TABLE 2-4: SHARE OF DECOMMISSIONED SYSTEMS THAT MET THEIR CONTRACTURAL PERMANACE

Technology Type	Share that Met Permanence Requirement at Time of Decommissioning
Energy Storage	0%
Fuel Cell – CHP*	85%
Internal Combustion Engine	61%
Microturbine	71%

* While the large majority of CHP Fuel Cells were removed prior to meeting their contractual permanence requirements, these systems also returned their incentive. Therefore, they are listed as “meeting” their contractual permanence requirement.

Figure 2-7 displays the rebated capacity of decommissioned systems by technology type and year the system was decommissioned, while Figure 2-8 shows the count of these systems by the age of the system at the time of decommissioning. Over half of the projects were less than six years old when they were decommissioned. The remaining decommissioned projects were found to be between six and fifteen years old.

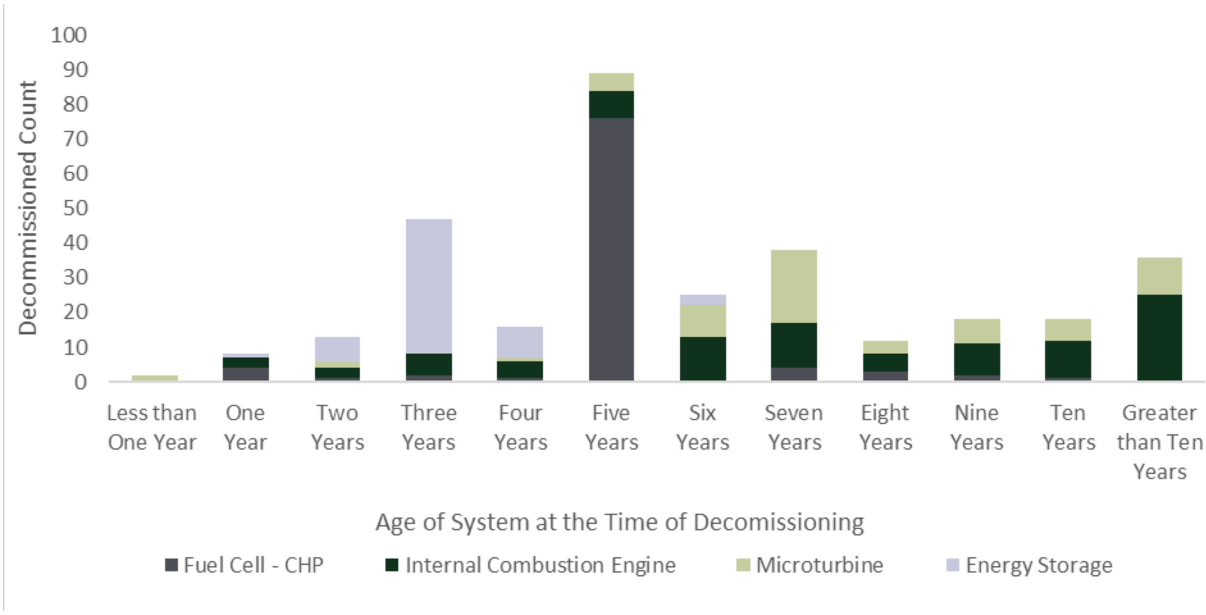
FIGURE 2-7: CUMULATIVE REBATED CAPACITY OF DECOMMISSIONED SYSTEMS BY YEAR AND SYSTEM TYPE



* Many poorly performing CHP Fuel Cells were decommissioned at approximately the same time. Many of these projects repaid their incentives to the PAs. Their exact date of removal is not known, but it was estimated to be around the end of 2014.

** 2018 saw a large increase as the year of decommissioned systems was unknown for energy storage systems, and all the decommissioned systems prior to 2019 were listed as 2018. Prior to 2019, the year a system was decommissioned was not tracked for energy storage systems.

FIGURE 2-8: REBATED CAPACITY OF DECOMMISSIONED SYSTEMS BY AGE OF SYSTEM AT TIME OF DECOMISSIONING



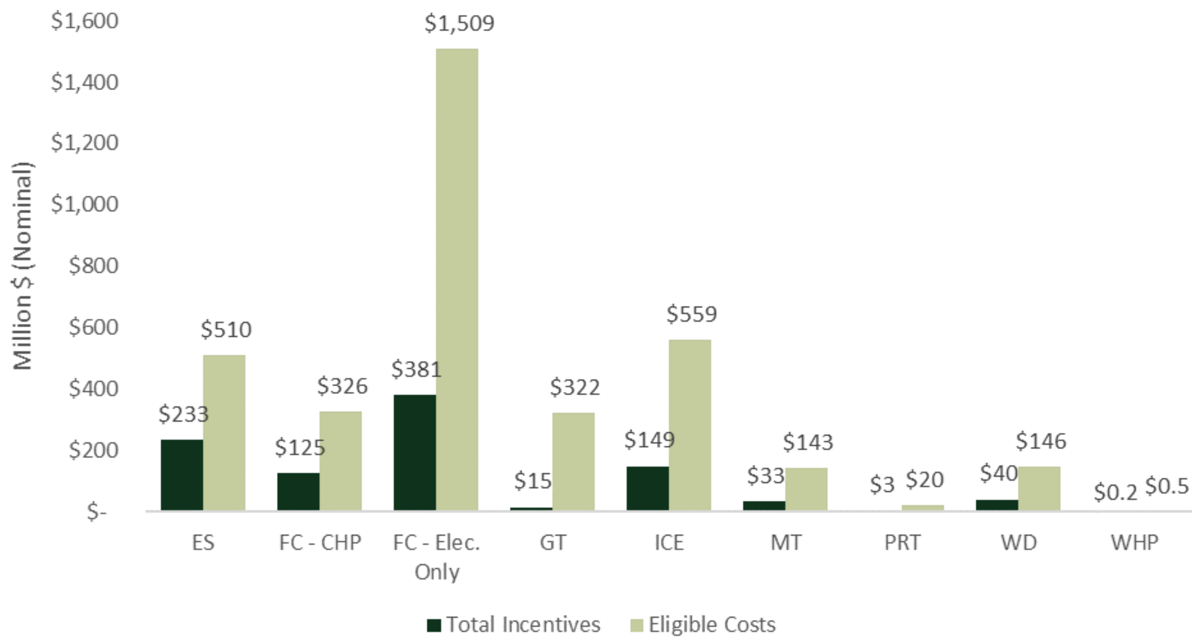
2.3 INCENTIVES PAID AND ELIGIBLE COSTS TO DATE

By the end of 2019, the SGIP had allocated $979 million in incentives for completed projects (excluding PV).[22] Eligible costs[23] reported by applicants surpassed $3.5 billion. Figure 2-9 shows the breakdown of the incentives paid by the SGIP and costs reported by applicants for each technology type. Electric-only fuel cells, while representing 17 percent of the entire program's rebated capacity, also represented over twice the eligible costs on a per rebated capacity basis of other technologies (with the exception of CHP fuel cells).

22 For the purposes of this analysis, all projects are assumed to receive their entire reserved incentive amount, regardless of PBI performance.

23 Eligible costs are defined in the SGIP handbook.

FIGURE 2-9: CUMULATIVE INCENTIVES PAID AND REPORTED ELIGIBLE COSTS BY TECHNOLOGY TYPE

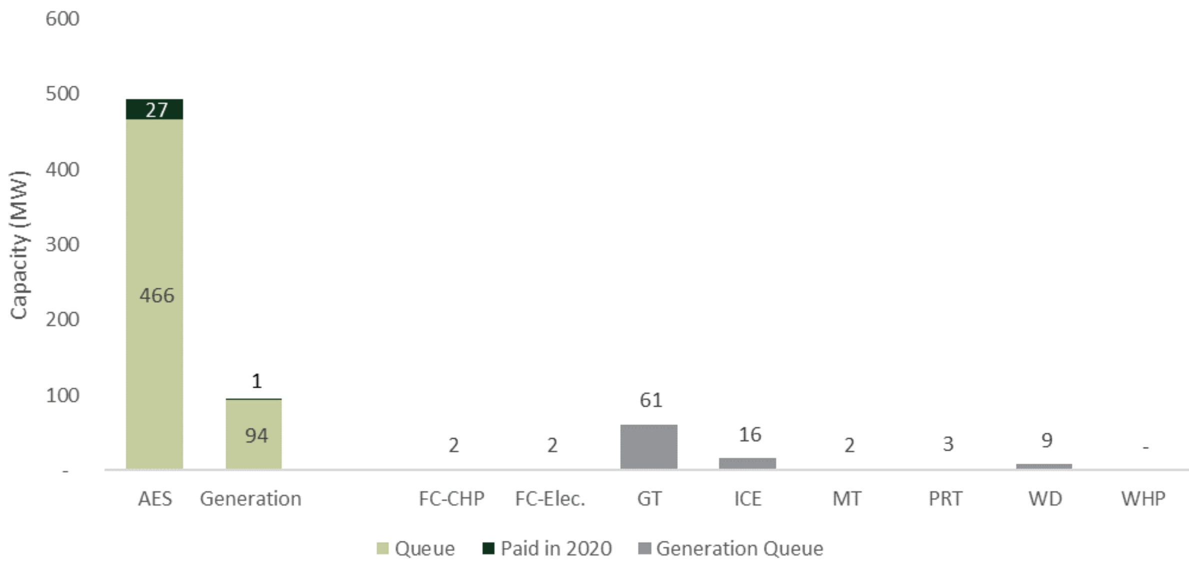


* ES = Energy Storage, FC-CHP = Fuel Cell – CHP, FC-Elec. Only = Fuel Cell – Electric Only, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, Wind = Wind Turbine, WHP = Waste Heat to Power

2.4 STATUS OF THE QUEUE

Projects that have not had their applications cancelled, rejected, suspended, or recalled remain in the SGIP queue. These projects are not subject to evaluation in this report, but if completed, will become part of the SGIP population for future evaluation studies. The evaluation team accessed the SGIP statewide project list on August 4th, 2020. As of that date, there were 15,294 projects representing 587 MW of capacity in the SGIP queue. Over 80 percent of the queue capacity are energy storage projects, while 13 percent of the capacity is made up of gas turbines and internal combustion engines, as seen in Figure 2-10. By count, energy storage projects make up 99.8 percent of the projects in the SGIP queue. Of the 19 combustion projects in the queue, 13 of them are from program years prior to 2017, meaning they are not required to use any biofuel.

FIGURE 2-10: SGIP QUEUE BY TECHNOLOGY TYPE AS OF AUGUST 4TH, 2020



Of the over 15,000 projects in the queue, 2,293 were completed in 2020 and are therefore not included in the analysis of energy, demand, and environmental impacts occurring during 2018 and 2019. The remaining 13,001 projects are making their way through the queue and may either receive incentive payments or exit the queue. Projects may exit the queue if a developer decides to recall the application, or if the application is rejected. There are only 25 generation projects that are part of this non-completed queue making up 94 MW of capacity.

3 SOURCES OF DATA AND METHODOLOGY

This section provides an overview of primary data sources and of the methodology used to quantify the energy and peak demand impacts of the Self-Generation Inventive Program (SGIP). While this report includes performance metrics for SGIP energy storage projects, the approaches and methodologies used to evaluate storage are fundamentally different. These methodologies are described in detail in the 2018 and 2019 SGIP Energy Storage Impact Evaluation Reports.[24]

The primary sources of data leveraged for this evaluation effort include:

- The statewide project list managed by the Program Administrators (PAs),
- Site inspection and verification reports completed by the PAs or their consultants,
- Metered electricity, fuel, and useful heat recovery data provided by the utilities, applicants, performance data providers (PDPs), and meters installed during prior evaluations,
- Interval load data provided by electric utilities and program participants,
- Responses from the Operational Status Research (OSR) conducted by Verdant.

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

3.1 STATEWIDE PROJECT LIST AND SITE INSPECTION VERIFICATION REPORTS

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

- Project tracking information such as the reservation number, facility address, program year, payment status/date, and eligible/ineligible cost information.

[24] The CPUC website provides a link to all CPUC approved M&E reports going back to 2002. These can be found listed under the page “Self Generation Incentive Program Reports”. http://www.cpuc.ca.gov/General.aspx?id=7890.

- Project characteristics including technology/fuel type, rebated capacity, and equipment manufacturer/model.

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

3.2 METERED DATA

Metered electricity, fuel consumption, and useful heat recovery data form the basis of this impacts evaluation. Metered data are requested and collected from electricity/gas distribution companies, system manufacturers, host customers, performance data providers (PDPs), and applicants. Supplemental metering was also installed by the evaluation team and its subcontractors. The data are processed, validated, and converted into standard format datasets. The processing and validation steps include:

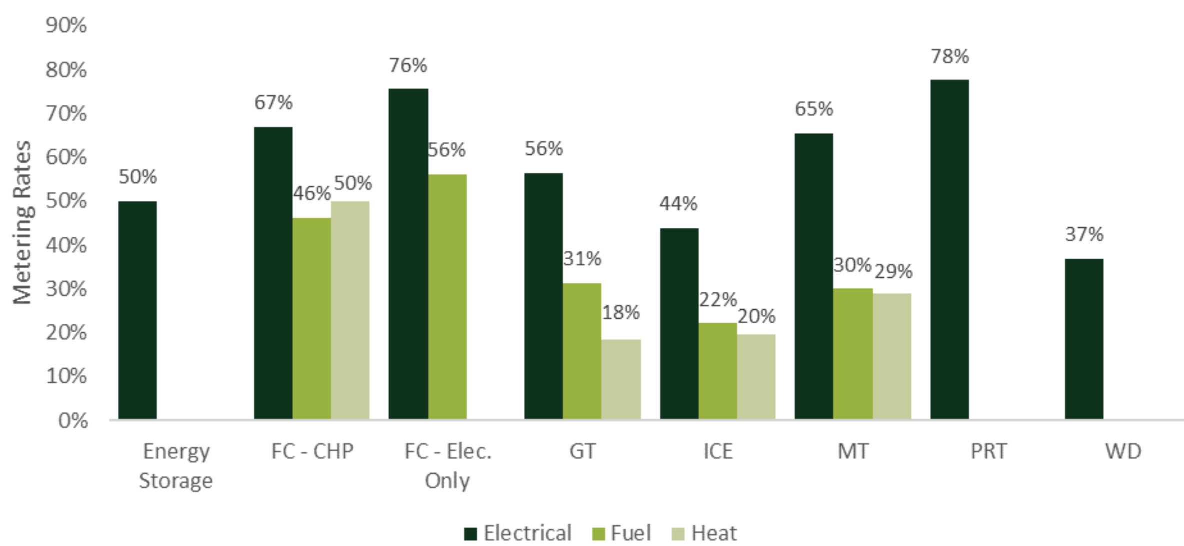
- Conversion of timestamps to Pacific Standard Time, including adjustment for Daylight Savings Time
- Standardization of interval length and units of measure:
  - All electrical generation data are converted to 15-minute net generator output, kWh
  - All storage charge/discharge data are converted to 15-minute kWh
  - All fuel consumption data are converted to 15-minute MBtu[25]LHV assuming 935 Btu/SCF[26]
  - All useful heat recovery data are converted to 15-minute Mbtu
- Suspect observations are flagged, investigated, and removed if necessary

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

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

All valid metered data are cataloged in a library and added to the backbone of projects built from the statewide project list. The result is a backbone that is partially fleshed out with metered data but has gaps that result from metering equipment issues or projects outside the metered sample. Figure 3-1 shows metering rates for calendar year 2019. Metering rate is defined as the number of hours for all projects during 2019 with metered data divided by the total number of hours in 2019. These metering rates are unweighted and do not reflect the relative importance of metering large projects.

FIGURE 3-1: METERING RATES BY TECHNOLOGY TYPE (2019)



*Projects known to be decommissioned have been removed from this figure.

For generation projects, missing values (either due to gaps in metered data or due to the sample design) are estimated using the findings from the operations status survey and ratio estimation approaches described below.

3.3 OPERATIONAL STATUS RESEARCH

Operational Status Research (OSR) is one of the two methodologies used to fill data gaps. OSR surveys target SGIP customers lacking large amounts of metered data. One hundred and fifty projects were targeted for the 2018-2019 OSR effort, which had a success rate of 47 percent. The survey seeks to determine if periods without metered data fit into one of three categories:

- Normal: The system was online and operating normally during the period in question.

- Off: The system did not generate electricity during the period in question but is still installed at the host site.
- Decommissioned: The system has been physically removed from the host site and will never operate again.

Hosts that respond with an “Off” operational status have zero energy generation assigned during the time period in question. Similarly, hosts who respond with a decommissioned operational status have zeros added starting from the date the system was decommissioned through the remainder of the evaluation period. Missing observations are estimated for generation projects whose operational status is “Normal” as well as projects with data gaps without operational status information.

3.4 RATIO ESTIMATION

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

Ratio estimation is used to generate hourly estimates of performance for periods where observations would otherwise contain missing values. The premise of ratio estimation is that the performance of unmetered projects (projects outside the sample or projects in the sample with gaps in metered data) can be estimated from projects with metered data using a ratio estimator and an auxiliary variable. The ratio estimator is calculated from the metered sample and the auxiliary variable is used to apply the estimator to the unmetered portion of the backbone. Table 3-1 summarizes the characteristics of the ratio estimation.

TABLE 3-1: RATIO ESTIMATION PARAMETERS

Variable Estimated	Ratio Estimator	Auxiliary Variable	Stratification
Electricity Generation [kWh]	Capacity Factor [kWh/kW·hr]	Rebated Capacity [kW]	Hourly, by warranty status, technology type, incentive structure, system size, fuel type, and PA.
Fuel Consumption [MBtu]	Electrical Conversion Efficiency [unitless]	Electricity Generation [kWh]	Annual, by technology
Useful Heat Recovered [MBtu]	Useful Heat Recovery Rate [MBtu/kWh]	Electricity Generation [kWh]	Annual, by technology

The outcome of the ratio estimation process is fully fleshed out backbones with all metered data gaps filled with estimated electricity, fuel, and useful heat recovery values. These datasets form the basis of the energy, demand, and environmental impacts evaluation findings for generation and energy storage projects that are presented in Section 4 and Section 5. A discussion of the treatment of measurement and sampling uncertainty is included in Appendix D. Detailed discussion of the estimation methodology for advanced energy storage projects is discussed in the 2018 and 2019 SGIP Energy Storage Impact Evaluation Reports.

3.5 INTERVAL LOAD DATA

Interval load data for each project in our metered sample was requested from Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) for 2018 and 2019. These data were requested to allow analysis of noncoincident peak (NCP) demand impacts and to better analyze energy storage dispatch. Once load data were received and validated, Verdant matched them to available generation or charge/discharge events to allow project-by-project analysis of the customer demand impacts of SGIP. Verdant performed quality control of the load data by comparing it to the generation or charge/discharge data to confirm that the received load data matches the SGIP project data.

4 ENERGY AND DEMAND IMPACTS

This section describes the electrical, fuel, and thermal (heat recovery) impacts and related performance measures for program populations at ends of 2018 and 2019 as well as trends since 2003.[27] This section includes annual program totals as well as various subtotals by Program Administrator (PA), technology, incentive payment type, and fuel type.

4.1 ENERGY IMPACTS

Electric energy impacts for generation systems are defined as kilowatt-hours that SGIP systems generate onsite. The electricity generated from these SGIP projects displaces electricity from the grid. For energy storage systems, these energy impacts reflect the net energy in kilowatt-hours that energy storage systems consume. Due to losses, energy storage systems over the course of a year will consume slightly more energy than they discharge.

The energy impacts described here do not include losses or auxiliary loads SGIP projects may have such as cooling pumps and fuel compressors. Impacts described here also do not include secondary electrical impacts. Secondary impacts include avoided electric chiller demand where recovered useful heat serves an absorption chiller. These impacts are captured in the analysis of environmental impacts. Furthermore, impacts described here also do not include transmission and distribution losses that electric utilities avoid by not having to supply the kWh that SGIP participants generate. These impacts are quantified through utility avoided costs later in this section.

4.1.1 Annual Electric Generation

The annual electric generation program totals and PA subtotals for 2018 and 2019 are listed in Table 4-1.

[27] This excludes legacy PV projects.

TABLE 4-1: 2018 AND 2019 ANNUAL ENERGY IMPACT BY PA

Program Administrator	2018		2019	
	Energy Impact [GWh]	Percent of Total	Energy Impact [GWh]	Percent of Total
CSE	279	13%	265	13%
PG&E	893	43%	850	42%
SCE	370	18%	378	19%
SoCalGas	535	26%	509	25%
Total	**2,077**	**100%**	**2,003**	**100%**

SGIP projects generated 2,077 GWh during 2018 and 2,003 GWh during 2019. This represented approximately 1 percent of California's total in-state generation each year.[28] The overall SGIP generation decreased by 74 GWh between 2018 and 2019. PG&E projects contributed the largest portions of energy generation with over 40 percent of the annual generation in both 2018 and 2019, generating 850 GWh in 2019, down 43 GWh from 2018. SoCalGas projects followed with the second largest generation contributions, totaling 509 GWh in 2019 (down 26 GWh from 2018) and making up about 25 percent of the total annual electricity generated. SCE project contributions totaled 378 GWh in 2019, making up 19 percent of the total annual electricity generated. SGIP projects in SCE's territory increased their energy generated between 2018 and 2019. CSE project contributions totaled 265 GWh in 2019, making up the remaining 13 percent of the total annual electricity generated.

All new generation projects rebated during 2018 and 2019 were greater than 30 kW and therefore subject to PBI payment and data reporting rules. However, a significant proportion of SGIP generation continues to come from non-PBI projects. Table 4-2 shows contributions to annual generation by incentive payment type (PBI vs. Non-PBI). Over one-third of contributions to statewide energy generation for both 2018 and 2019 came from Non-PBI systems, which is down from previous years.[29]

28 The California Energy Commission reports that 195 and 200 TWh were generated in-state in 2018 and 2019 respectively. See the California Energy Commission's Electric Generation Capacity and Energy, In-State Electric Generation by Fuel Type (GWh).

https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy.

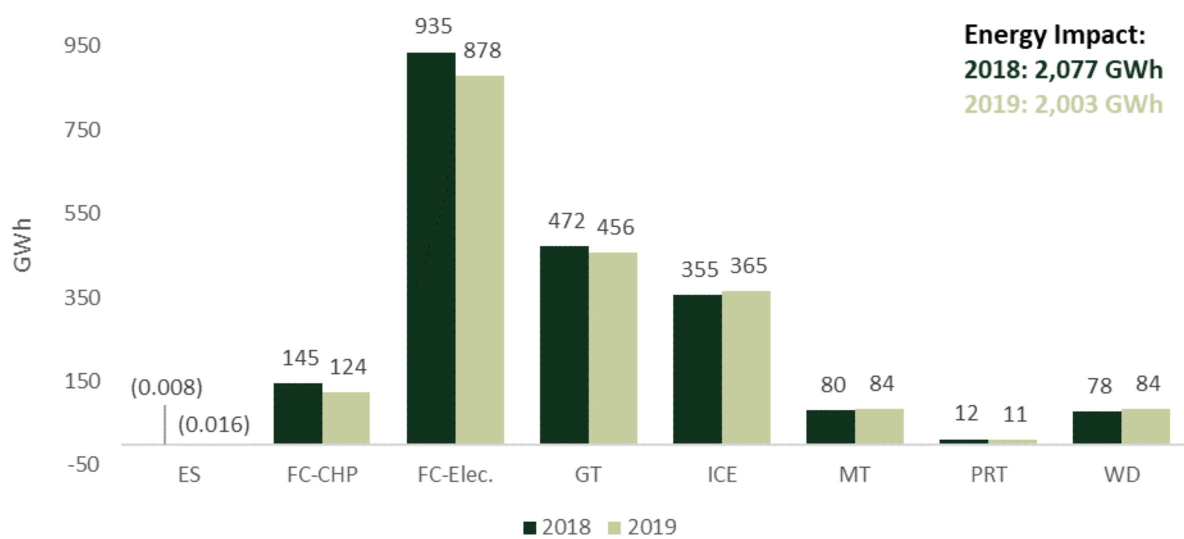
29 Non-PBI projects made up about 50 percent of total program generation in 2016 and about 45 percent of the total program generation in 2017.

TABLE 4-2: 2018 AND 2019 ANNUAL ENERGY IMPACT BY PA AND INCENTIVE TYPE [GWH]

Program Administrator	2018 GWh			2019 GWh		
	PBI	Non-PBI	PBI Percent	PBI	Non-PBI	PBI Percent
CSE	149	129	54%	144	121	54%
PG&E	605	288	68%	607	243	71%
SCE	250	120	67%	259	119	69%
SoCalGas	311	224	58%	307	203	60%
Total	**1,315**	**761**	**63%**	**1,316**	**686**	**66%**

Figure 4-1 shows the 2018 and 2019 annual generation by technology.[30] Electric-only fuel cells continued to contribute the largest portions to annual generation in 2018 and 2019. Electric-only fuel cell generation decreased in 2019 by almost 60 GWh relative to 2018. Gas turbines made up the second highest generation contribution, with over 450 GWh generated each year.

FIGURE 4-1: 2018 AND 2019 ANNUAL ELECTRIC GENERATION BY TECHNOLOGY [GWH]



* ES = Energy Storage, FC-CHP = Fuel Cell – CHP, FC-Elec. Only = Fuel Cell – Electric Only, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, Wind = Wind Turbine, WHP = Waste Heat to Power

All technologies except electric-only fuel cells experienced relatively minor changes in electrical output between 2018 and 2019, showing approximately a 10 percent or less difference in generation between the two years. As noted above, over the course of a year, energy storage systems require slightly more

30 No data were available for the single waste heat to power system in the program.

energy to charge than is being discharged, due to losses. Annual generation by PA and technology is shown for 2018 and 2019 in Table 4-3 and Table 4-4.

TABLE 4-3: 2018 ANNUAL ELECTRIC GENERATION BY PA AND TECHNOLOGY [GWH]

Program Admin.	Energy Storage	Fuel Cell – CHP	Fuel Cell – Elec.	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	(0.001)	55	77	126	11	1	5	4	279
PG&E	(0.002)	45	451	105	211	39	3	40	893
SCE	(0.004)	19	237	-	62	14	5	34	370
SoCalGas	(0.000)	27	169	241	72	26	-	-	535
Total	**(0.008)**	**145**	**935**	**472**	**355**	**80**	**12**	**78**	**2,077**

TABLE 4-4: 2019 ANNUAL ELECTRIC GENERATION BY PA AND TECHNOLOGY [GWH]

Program Admin.	Energy Storage	Fuel Cell – CHP	Fuel Cell – Elec.	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	(0.003)	52	73	119	12	1	4	4	265
PG&E	(0.004)	32	425	101	206	39	4	44	850
SCE	(0.008)	17	219	-	86	17	3	36	378
SoCalGas	(0.001)	24	161	236	61	27	-	-	509
Total	**(0.016)**	**124**	**878**	**456**	**365**	**84**	**11**	**84**	**2,003**

Fuel cells (both CHP and electric-only), gas turbines, and pressure reduction turbines saw a decrease in generation between 2018 and 2019. The remaining technologies saw an increase in generation. Overall, there was a total reduction of 73 GWh between 2018 and 2019. The largest decrease came from electric-only fuel cells, and the greatest increase came from internal combustion engines.

SGIP generation projects are fueled by a variety of energy sources like natural gas, renewable biogas (onsite and directed), and syngas. Other technologies like pressure reduction turbines and wind turbines are not fueled. For purposes of this report, natural gas is listed as non-renewable and biogas/syngas fueled projects are grouped as onsite biogas. Directed biogas (DBG) projects are classified separately, while wind turbine, pressure reduction turbine, and energy storage technologies are classified as 'Other'. Figure 4-2 shows the 2018 and 2019 annual electric generation by the above categories and PA.

FIGURE 4-2: 2018 AND 2019 ANNUAL ELECTRIC GENERATION BY PA AND FUEL SOURCE

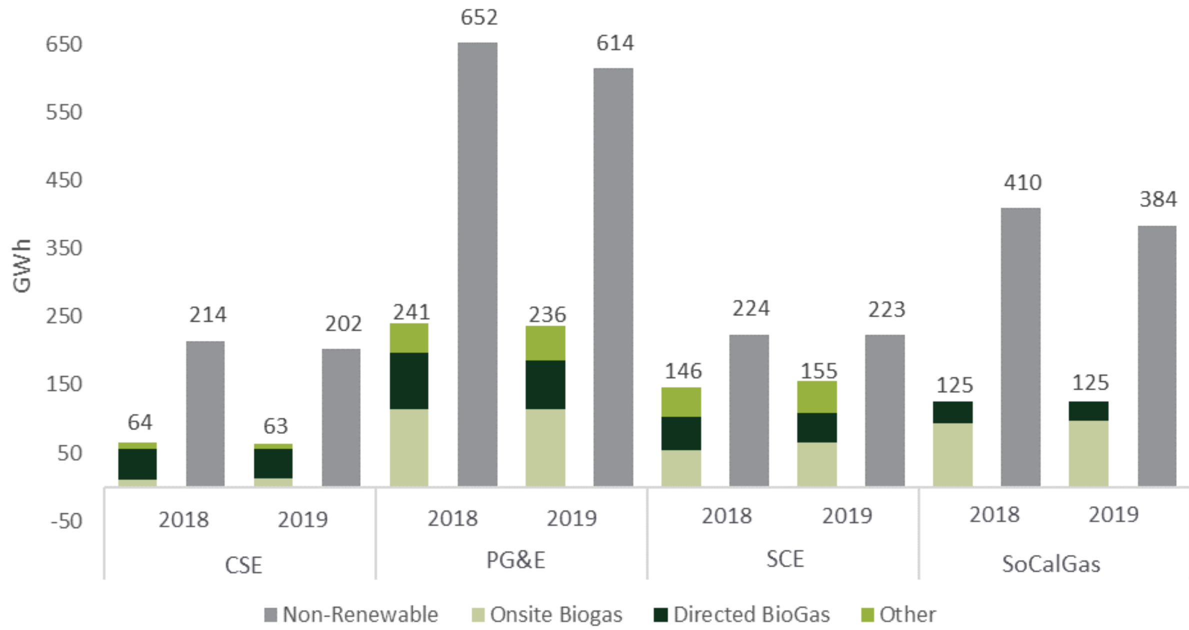


Table 4-5 shows non-renewable project contributions to total annual generation. While non-renewable fuel still makes up close to three-quarters of all generation from the program, the percent of generation from non-renewable fueled projects has decreased across all PAs except CSE.

TABLE 4-5: PERCENT OF ANNUAL ENERGY IMPACTS FROM NON-RENEWABLE FUEL

Program Admin.	2016	2017	2018	2019
CSE	76%	76%	77%	76%
PG&E	70%	73%	73%	72%
SCE	67%	67%	60%	59%
SoCalGas	92%	90%	77%	75%
Total	**76%**	**77%**	**72%**	**71%**

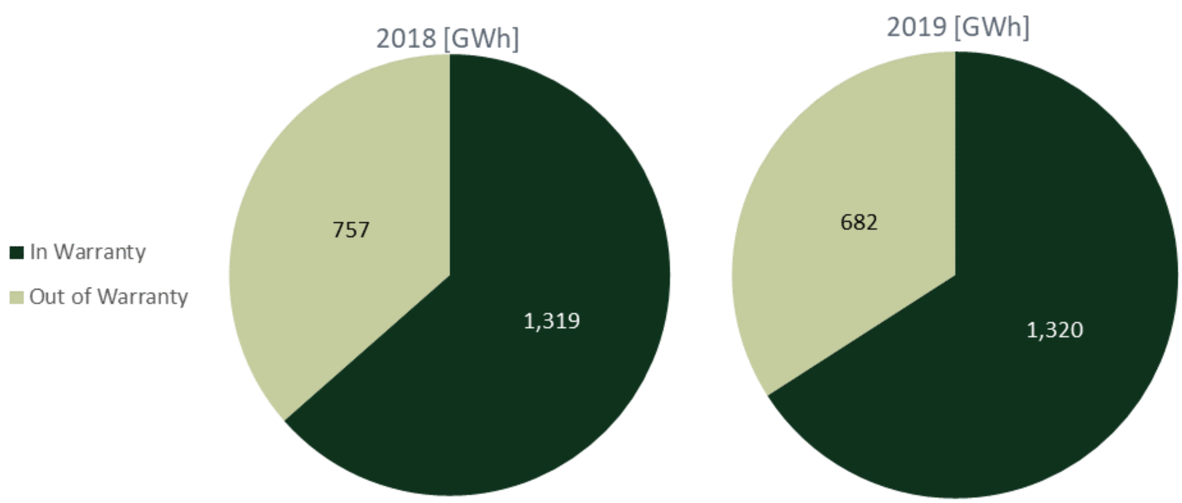
The SGIP requires that project developers provide proof of a service warranty for generation equipment. The required warranty period varies by technology type and it has also changed over time. Table 4-6 below shows historical warranty requirements by technology.

TABLE 4-6: SGIP REQUIRED WARRANTY PERIODS FOR GENERATION EQUIPMENT BY TECHNOLOGY AND PROGRAM YEAR

Technology Type	Program Years	Warranty Period (Years)
Fuel Cell	PY01-PY10	5
	PY11-PY19	10
Gas Turbine	PY01-PY10	3
	PY11-PY19	10
Internal Combustion Engine	PY01-PY10	3
	PY11-PY19	10
Microturbine	PY01-PY10	3
	PY11-PY19	10
Pressure Reduction Turbine	All	10
Wind	PY01-PY10	5
	PY11-PY19	20

Warranty period for a project is estimated using the upfront payment date as a proxy for the start of the warranty. Projects that continue operating past their warranty period contributed to approximately one-third of the total energy generation in both 2018 and 2019, as shown in Figure 4-3.

FIGURE 4-3: 2018 AND 2019 ANNUAL ELECTRIC GENERATION BY WARRANTY PERIOD[31]



Most SGIP systems operating past their warranty period were IC engines, followed by microturbines and then fuel cells. Fuel cell technologies were generally two to three years past their warranty periods, and both IC engines and microturbines were generally found to be operating over eight years past their

31 Includes generation systems only.

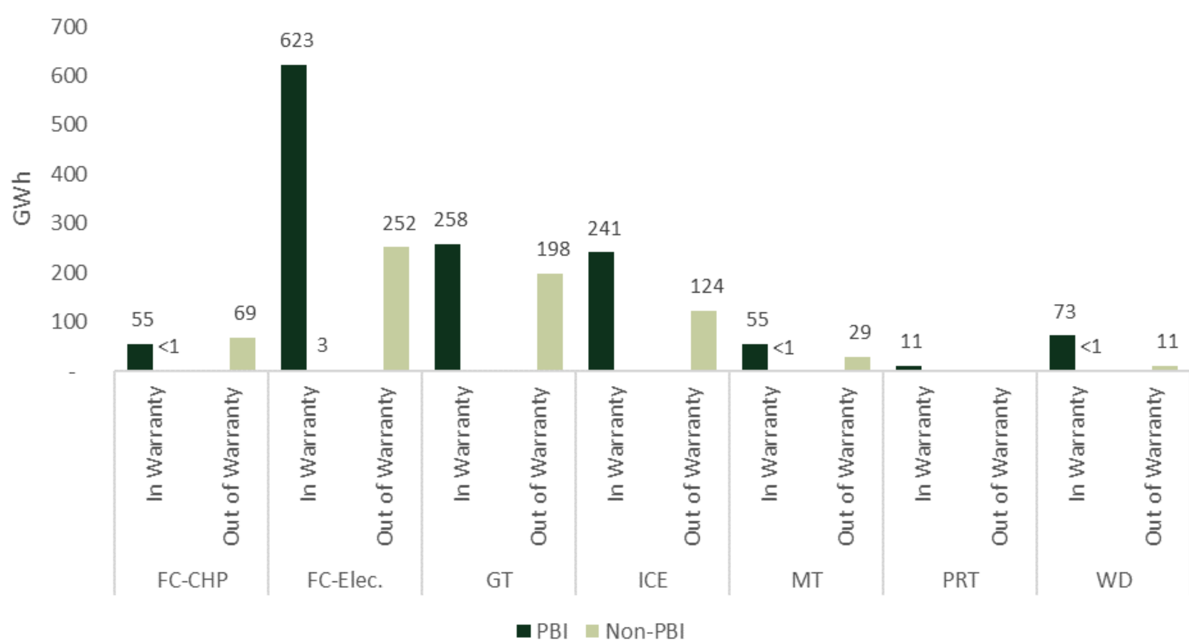
warranty period, as displayed in Table 4-7. All technologies shown in the table were subject to warranty requirements of either three or five years.

TABLE 4-7: COUNT OF PROJECTS OPERATING PAST THEIR WARRANTY PERIOD AT END OF 2019

	Years Past Warranty Period						
Technology Type	**0-1**	**2-3**	**4-5**	**6-8**	**8-10**	**>10**	**Total**
Fuel Cell - CHP	3	13	4	2	2	0	**24**
Fuel Cell - Electric Only	5	76	8	0	0	0	**89**
Gas Turbine	0	0	1	2	4	2	**9**
Internal Combustion Engine	0	0	7	16	65	69	**157**
Microturbine	0	0	2	6	26	44	**78**
Wind	2	5	6	0	2	0	**15**

Almost all non-PBI projects were found to be out of warranty by the end of 2019. There were a few exceptions to this – a few fuel cells along with a small number of non-PBI microturbines and wind turbines remained under warranty at the end of 2019. The breakdown of projects by technology type, warranty status, and PBI versus non-PBI is shown below in Figure 4-4 for 2019.

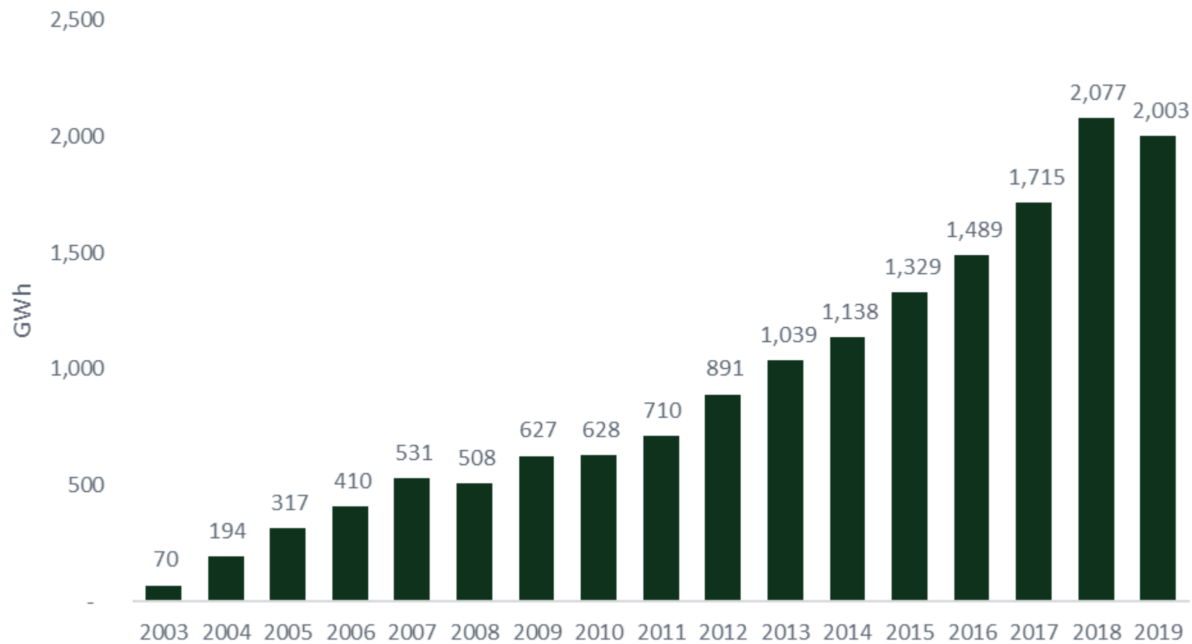
FIGURE 4-4: 2019 ANNUAL GENERATION BY TECHNOLOGY TYPE, WARRANTY STATUS, AND PBI VS NON-PBI[31]



Annual Energy Impact Trends

Historically, the program's annual energy impacts due to electric generation have grown every year except 2008 when generation declined slightly due to factors outside the program's control.[32] Calendar year 2018 saw the largest increase in energy impacts of any year, with 2018 seeing 362 GWh more energy generated than 2017. In 2019, the program saw energy impacts decline from the previous year by 73 GWh. As natural gas fueled projects are being phased out of the program, the increase in new projects coming online are being outpaced by the number of existing systems being decommissioned. Figure 4-5 shows the annual trend in growth from 2003 to 2019.

FIGURE 4-5: ANNUAL ENERGY IMPACTS DUE TO ELECTRIC GENERATION BY CALENDAR YEAR



During 2012 the program issued its first upfront incentive to a PBI project. Projects applying to the SGIP on or after 2011 with a rebated capacity of 30 kW or greater are required to comply with PBI program rules. The PBI incentive structure requires projects to maintain high capacity factors for at least five years. Figure 4-6 shows the annual generation by PBI versus non-PBI projects between 2003 and 2019.

PBI projects quickly ramped up electrical generation after 2012. Non-PBI generation projects are generally older. After peaking in 2013, the annual energy generated by non-PBI projects has experienced a general decline. PBI annual generation first surpassed non-PBI generation during 2017 and increased greatly

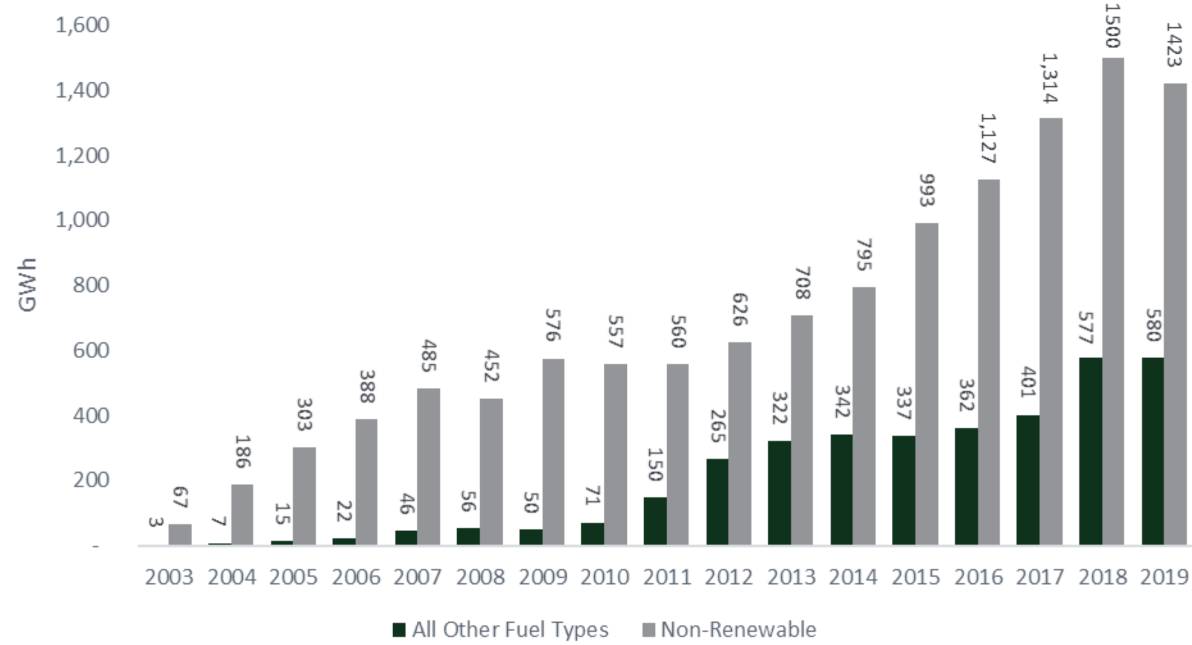
32 Increases in natural gas price and air emissions regulations contributed to generation declines in 2008.

between 2017 and 2018. We expect that PBI project generation impacts to stay relatively constant for the next few years while non-PBI generation continues to decline quite significantly.

FIGURE 4-6: ANNUAL ELECTRIC GENERATION BY PBI VS. NON-PBI

Since its inception, the SGIP has offered incentives for both renewable and non-renewable generation technologies. Beginning in 2017, the SGIP was modified such that all non-renewable generation projects must consume at least 10 percent biogas. This percentage of biogas increases each year, ultimately leading to the phaseout of non-renewable generation as an eligible technology in the SGIP. By the end of 2019, 22 new projects came online, but only one was a fueled generation project that required a portion of the fuel to come from biofuel. The remainder were wind turbine projects. Figure 4-7 shows the annual generation between 2003 and 2019 by two groups: non-renewable fueled projects and the combination of all other fuel types (including other technologies with no fuel).

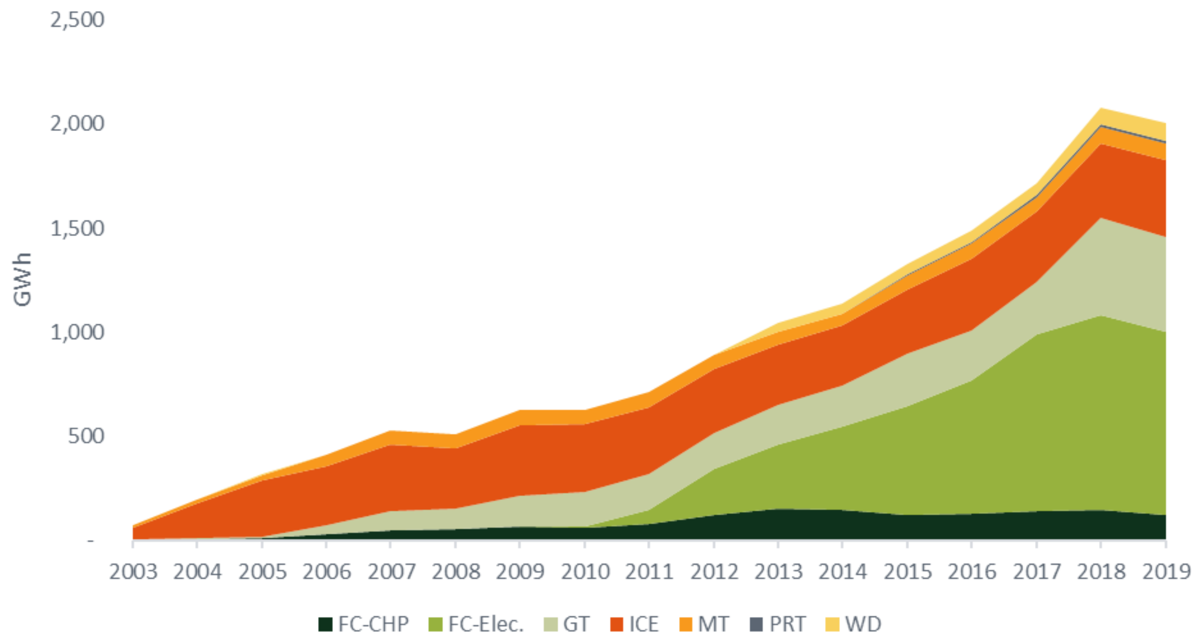
FIGURE 4-7: ANNUAL ELECTRIC GENERATION BY FUEL SOURCE



Non-renewable annual generation has exceeded generation by the combination of all other fuel types every year. Non-renewable generation surpassed 1 TWh for the first time during 2016, while all other fuel types finally surpassed 500 GWh for the first time in 2018, with a 50 percent increase in generation from 2017.

Figure 4-8 shows the composition of annual electric generation by technology type from 2003 to 2019. Growth in the annual generation since 2011 has been driven primarily by electric-only fuel cells. Electric-only fuel cells will likely continue to be the predominant contributor to the annual generation for several more years. Gas turbines have continued to increase their total capacity as several large systems have been installed in the last few years. CHP fuel cell annual generation peaked during 2013 and has declined overall slightly since then. Wind turbines, microturbines, and internal combustion engines are the only technologies to have seen an increase in the overall generation between 2018 and 2019. Electric-only fuel cells and CHP fuel cells are the drivers behind the reduction in generation in 2019. The largest share of these were electric-only fuel cells, which resulted in a 57 GWh reduction in generation.

FIGURE 4-8: ANNUAL ELECTRIC GENERATION BY TECHNOLOGY



4.1.2 Coincident Peak Demand Impacts

Coincident peak demand impacts are defined as the generation from SGIP projects during hours of CAISO or IOU peak demands. The single greatest annual CAISO or IOU peak hours provide brief snapshots of program coincident demand impacts. However, analyzing peak demand over the top 200 peak hours can provide a greater insight into how SGIP projects impact the grid during hours of highest load.

By coincidentally generating during CAISO or IOU peak hours, SGIP project hosts allow their electric utility to avoid the purchase of high cost wholesale energy. At the same time, the electric utility reduces its transmission and distribution losses during hours of high system congestion. Ideally, SGIP system hosts are generating at full capacity and avoiding system maintenance during peak hours and thus contributing the greatest possible demand impacts. It should be noted however, that these hours are not necessarily when an SGIP system host has its highest load or otherwise might want to be generating, therefore a host may not always operate their SGIP system optimally during the grid peak hours.

In this section, we examine generation during CAISO and IOU annual peak load hours as well as their top 200 load hours. We also look at the year-to-year trends in program impacts. Table 4-8 lists hours and magnitudes of CAISO and IOU peak demands in 2018 and 2019.

TABLE 4-8: 2018 AND 2019 CAISO AND IOU PEAK HOURS AND DEMANDS [MW]

IOU	2018			2019		
	Peak Demand [MW]	Date	Hour Beginning [Local Time]	Peak Demand [MW]	Date	Hour Beginning [Local Time]
CAISO (Gross)	46,487	July 25th	4:00 PM	43,872	August 15th	4:00 PM
CAISO (Net)	42,830	August 9th	6:00 PM	39,646	August 14th	6:00 PM
PG&E	19,159	July 25th	5:00 PM	21,039	August 15th	4:00 PM
SCE	24,091	July 6th	3:00 PM	22,585	September 4th	2:00 PM
SDG&E	4,353	August 8th	4:00 PM	4,036	September 3rd	4:00 PM

CAISO Peak Hour Impacts - Generation Technologies

Generation coincident with the gross and net CAISO annual peak hours in 2018 and 2019 is shown by PA in Table 4-9. The generation from SGIP projects of 255 MW coincident with the 2018 gross CAISO peak hour is equivalent to 0.55 percent of the 2018 gross CAISO peak load. During 2019, SGIP projects generated 244 MW during the CAISO peak hour, equivalent to 0.55 percent of the 2019 gross CAISO peak load. Generation during the gross CAISO peak hour decreased almost 5 percent in 2019.

PG&E projects contributed the largest portions of the gross CAISO peak hour generation in both 2018 and 2019. SoCalGas followed with a quarter of the 2019 peak gross generation. The net CAISO peak hour generation followed a very similar trend.

TABLE 4-9: 2018 AND 2019 GROSS CAISO PEAK HOUR GENERATION BY PA – GENERATION TECHNOLOGIES

Program Administrator	2018 Gross		2018 Net		2019 Gross		2019 Net	
	Peak Hour Generation [MW]	Percent of Total	Peak Hour Generation [MW]	Percent of Total	Peak Hour Generation [MW]	Percent of Total	Peak Hour Generation [MW]	Percent of Total
CSE	32	13%	30	12%	32	13%	34	14%
PG&E	111	43%	112	44%	103	42%	95	41%
SCE	46	18%	46	18%	48	20%	44	19%
SoCalGas	66	26%	66	26%	61	25%	63	27%
Total	**255**	**100%**	**253**	**100%**	**244**	**100%**	**235**	**100%**

Figure 4-9 and Table 4-10 on the following page show peak hour generation by PA for PBI versus non-PBI projects. Many of the trends observed during gross CAISO peak hours are similar to those observed for annual generation impacts.

FIGURE 4-9: NON-PBI VS PBI CAISO GROSS PEAK HOUR GENERATION BY PA AND YEAR – GENERATION TECHNOLOGIES [MW]

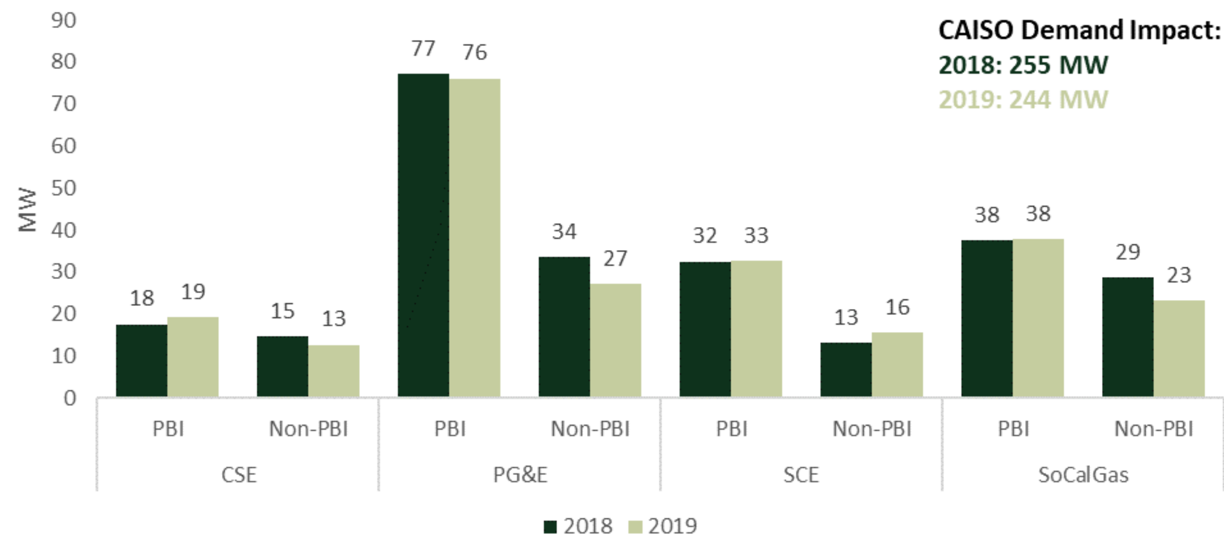


Table 4-10 shows non-PBI projects generated 90 MW during the 2018 gross CAISO peak. By the 2019 gross CAISO peak, coincident generation from these projects dropped 13 percent to only 78 MW. CSE, PG&E, and SoCalGas had declining contributions from non-PBI projects, while SCE saw a minor increase.

TABLE 4-10: 2018 AND 2019 GROSS CAISO PEAK HOUR GENERATION BY PA AND PBI VS NON-PBI – GENERATION TECHNOLOGIES [MW]

Program Administrator	2018			2019		
	PBI	Non-PBI	PBI Percent	PBI	Non-PBI	PBI Percent
CSE	18	15	54%	19	13	60%
PG&E	77	34	70%	76	27	74%
SCE	32	13	71%	33	16	68%
SCG	38	29	57%	38	23	62%
Total	**165**	**90**	**65%**	**166**	**78**	**68%**

PBI projects made up 65 percent of the total 2018 gross CAISO peak hour coincident generation and 68 percent of the total 2019 gross CAISO peak hour coincident generation. While there was a slight increase in the gross CAISO peak hour coincident generation from 2018 to 2019, most of this difference came from the decreasing share of non-PBI peak hour coincident generation.

Figure 4-10 shows 2018 and 2019 gross CAISO peak hour generation by technology for 2018 and 2019. During 2018 and 2019, electric-only fuel cells led gross CAISO peak hour generation by a significant amount.

FIGURE 4-10: 2018 AND 2019 CAISO PEAK HOUR GENERATION BY TECHNOLOGY [MW] – GENERATION TECHNOLOGIES

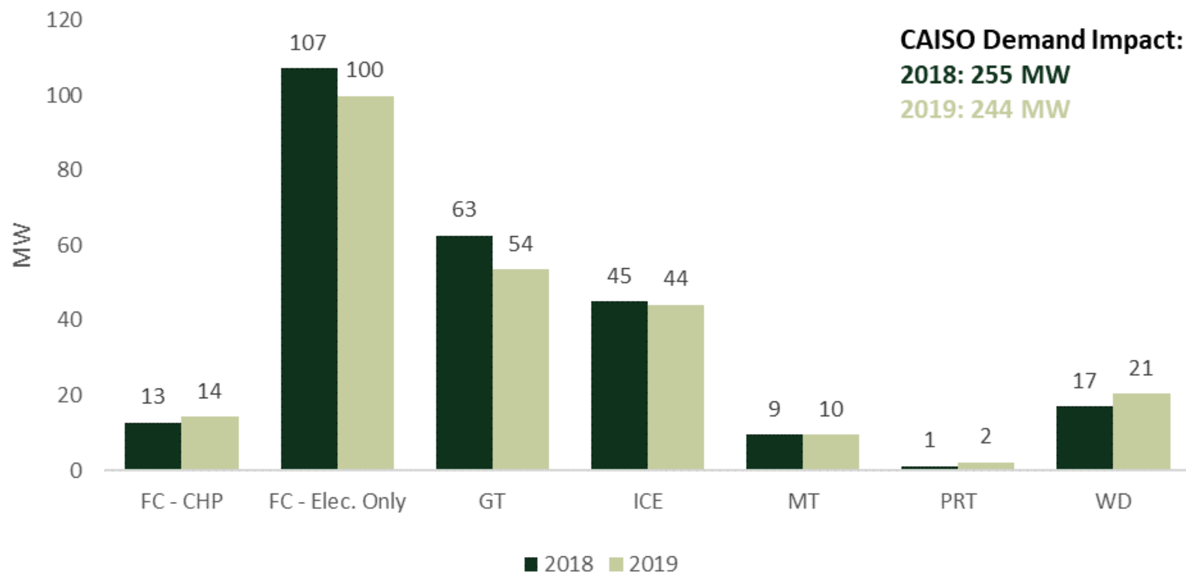


Table 4-11 and Table 4-12 list the gross CAISO peak hour generation by PA and technology for 2018 and 2019, respectively.

TABLE 4-11: 2018 CAISO PEAK HOUR GENERATION BY PA AND TECHNOLOGY [MW]

Program Admin.	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	Total
CSE	4	9	17	2	0.2	1	0.4	**32**
PG&E	5	52	14	26	5	0.2	9	**111**
SCE	2	27	0	8	2	0.5	7	**46**
SoCalGas	3	19	32	9	3	0	0	**66**
Total	**13**	**107**	**63**	**45**	**9**	**1**	**17**	**255**

TABLE 4-12: 2019 CAISO PEAK HOUR GENERATION BY PA AND TECHNOLOGY [MW]

Program Admin.	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	Total
CSE	6	8	12	2	0.1	0.9	2	32
PG&E	3	48	13	24	5	1	10	103
SCE	2	25	0	11	2	1	8	48
SoCalGas	3	18	29	8	3	0	0	61
Total	**14**	**100**	**54**	**44**	**10**	**2**	**21**	**244**

Across all PAs, electric-only fuel cells generated the highest output during the 2018 and 2019 gross CAISO peak hours. PG&E electric-only fuel cells lead the generation output, producing 52 MW and 48 MW for 2018 and 2019 respectively. PG&E IC engines followed in both years, with 26 MW and 24 MW. Overall, microturbines, CHP fuel cells, and pressure reduction turbines made relatively small contributions to peak hour generation for all PAs.

Figure 4-11 and Table 4-13 show CAISO peak hour generation for 2018 and 2019 by PA and fuel type.

FIGURE 4-11: 2018 AND 2019 CAISO PEAK HOUR GENERATION BY PA AND FUEL – GENERATION TECHNOLOGIES

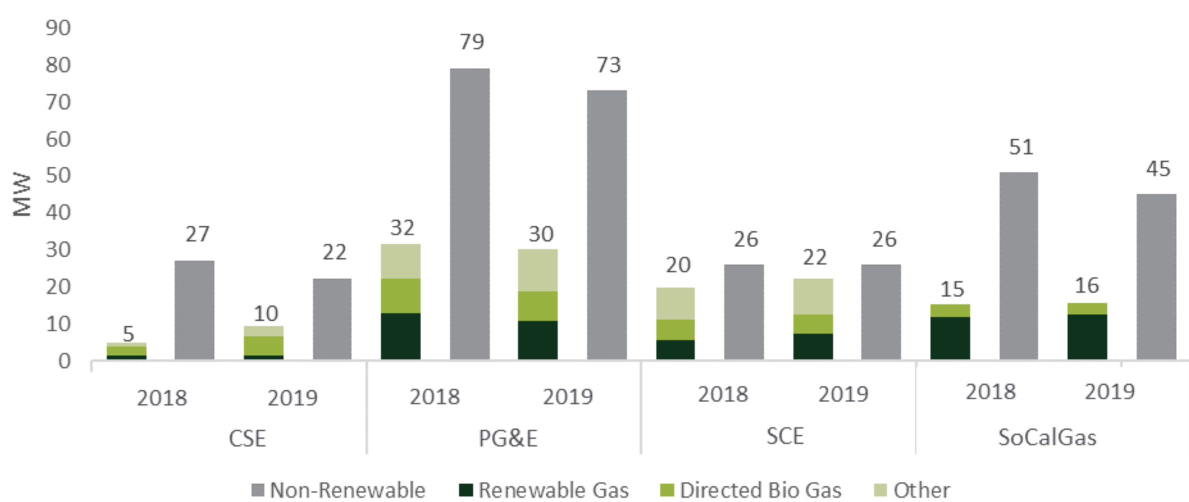


TABLE 4-13: 2018 AND 2019 CAISO PEAK HOUR GENERATION BY PA AND FUEL SOURCE – GENERATION TECHNOLOGIES [MW]

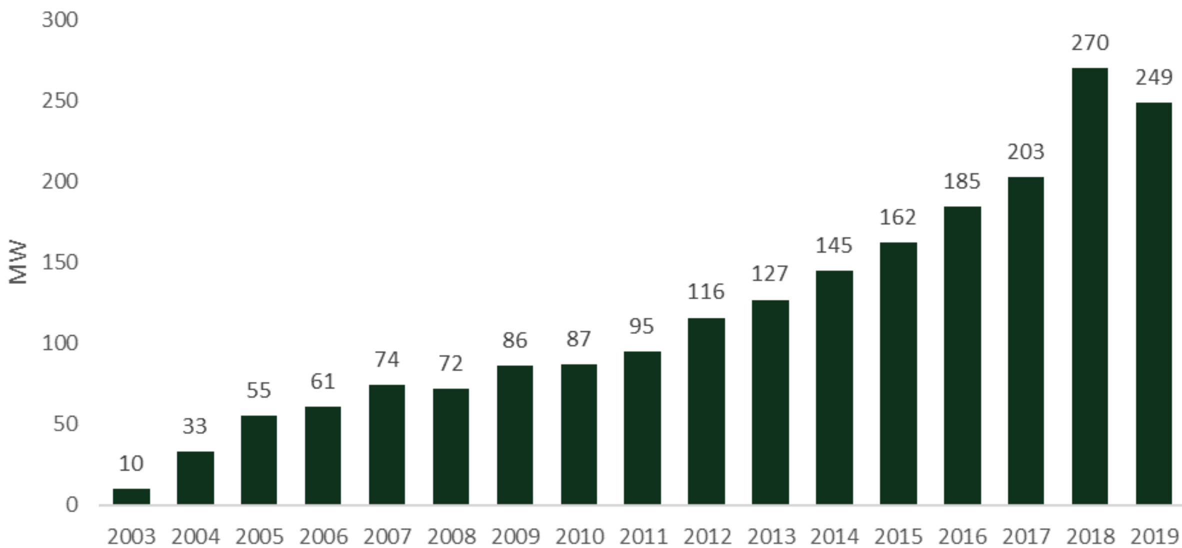
Program Admin.	2018					2019				
	Renew.	DBG	Other	Non-Renew.	% Non-Renew.	Renew.	DBG	Other	Non-Renew.	% Non-Renew.
CSE	1	3	1	27	84%	1	5	3	22	70%
PG&E	13	9	9	79	71%	11	8	12	73	71%
SCE	6	5	9	26	57%	7	5	10	26	54%
SoCalGas	12	4	0	51	77%	12	3	0	45	74%
Total	**32**	**21**	**19**	**183**	**72%**	**32**	**22**	**24**	**167**	**68%**

Non-renewable fueled projects continue to be the main contributors to CAISO peak hour generation, making up over 72 percent of the total impact in 2018 and 68 percent in 2019. The remaining fuel types contributed 72 MW in 2018 and 78 MW in 2019. The overall program saw a small decrease in the share of generation during CAISO peak hours from non-renewable fuel.

SGIP Total CAISO Peak Hour Impacts – All SGIP Technologies

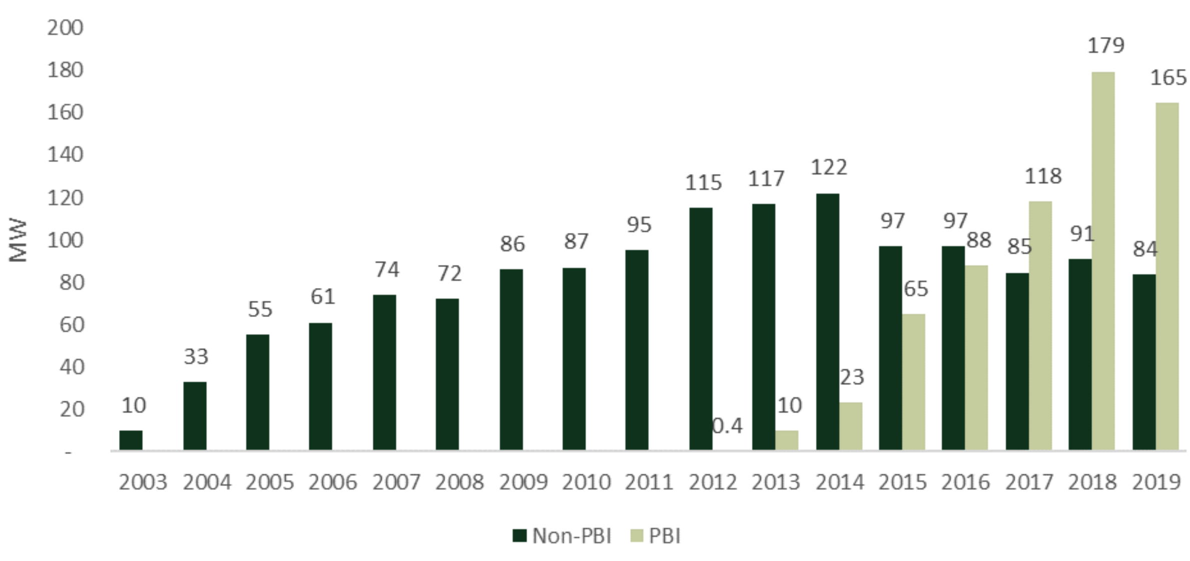
Over time, peak hour impacts from SGIP projects coincident with the CAISO peak hour has grown. Contributions from various categories of projects have changed with the addition of new projects and the retirement of old projects. Figure 4-12 through Figure 4-15 shows overall CAISO peak hour impact trends, which include the energy impact from advanced energy storage projects from 2003 to 2019 by key project categories. Figure 4-12 shows the CAISO peak hour generation growth. CAISO peak impact growth has been generally consistent with a steady increase, however, 2018 showed a sharp increase in peak hour generation followed by a decrease in 2019.

FIGURE 4-12: CAISO PEAK HOUR IMPACTS TOTAL BY CALENDAR YEAR



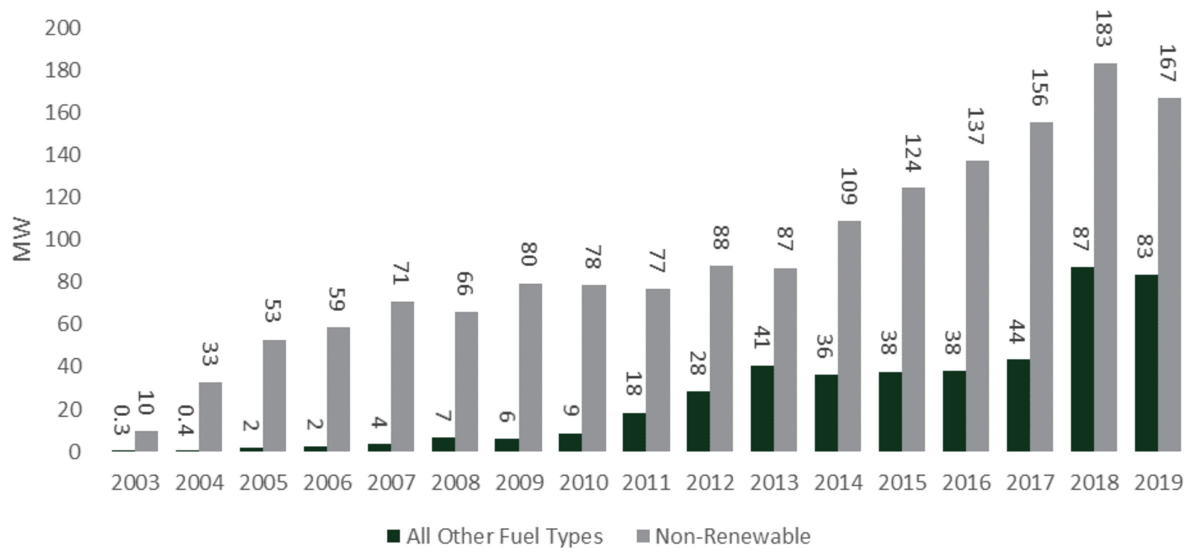
The share of CAISO peak hour generation for PBI projects exceeded those of non-PBI projects for the first time in 2017, while the share from non-PBI projects has been generally decreasing since 2014 (Figure 4-13).

FIGURE 4-13: CAISO PEAK HOUR GENERATION BY PBI VERSUS NON-PBI



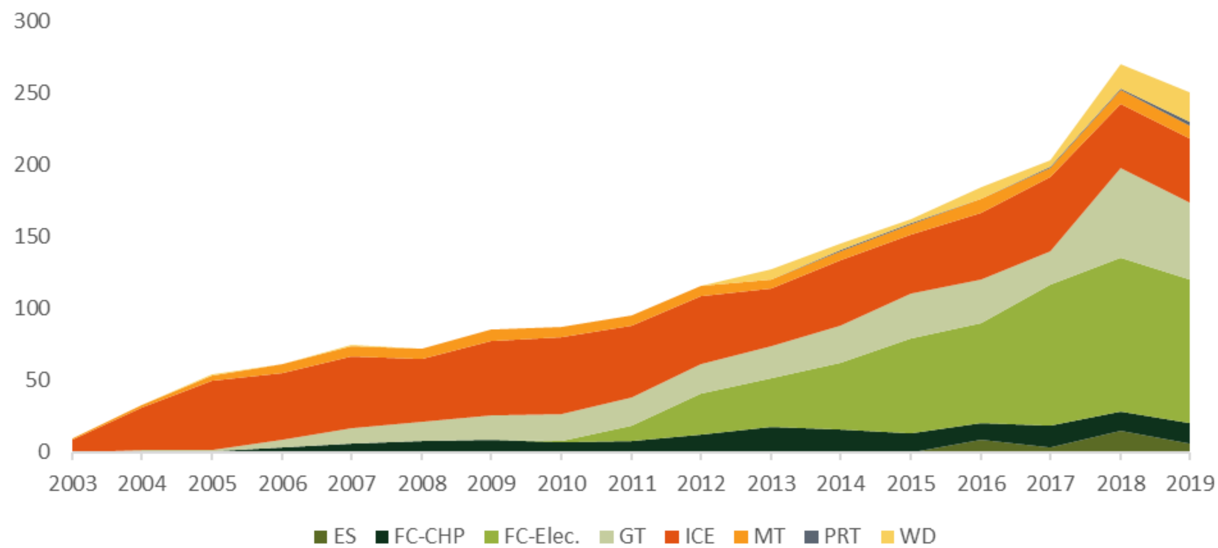
Gross CAISO peak hour generation from non-renewable fueled projects decreased in 2019, as seen in Figure 4-14. The contribution from the combination of all other fuel types increased rather significantly in 2018.

FIGURE 4-14: CAISO PEAK HOUR GENERATION BY FUEL TYPE



Finally, the trend in CAISO peak hour generation by technology shown in Figure 4-15 below mimics the trend shown in Figure 4-8 for the trend in annual electric generation. Electric-only fuel cell growth has increased CAISO peak hour program impact totals since 2010 but has been relatively constant over the last few years. Gas turbines saw a sharp increase in 2018, but decreased slightly in 2019, driving the overall peak hour generation lower in 2019.

FIGURE 4-15: CAISO PEAK HOUR GENERATION BY TECHNOLOGY



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

IOU Peak Hour

Peak hour impacts coincident with IOU annual peak hours for 2018 is shown below in Figure 4-16 while results for 2019 are displayed in Figure 4-17. Peak hour impacts from SGIP systems are assigned to the IOU providing the electrical service, which is not necessarily the same as the PA. SoCalGas projects may be electrically interconnected to a municipal utility rather than an IOU.

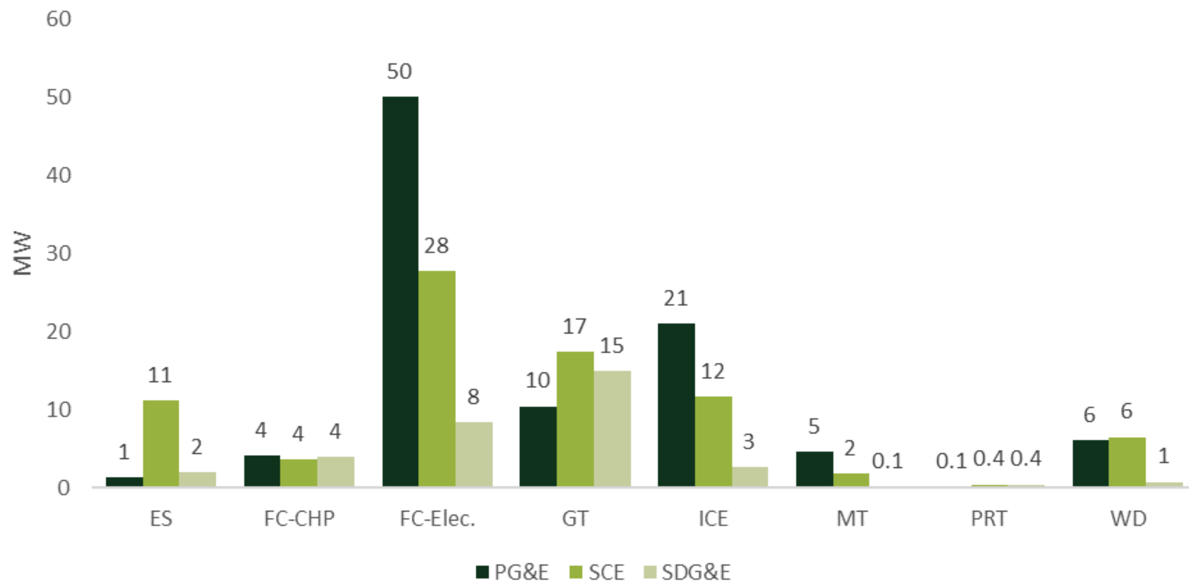
The 2018 PG&E peak hour generation occurred on July 25th between 4 and 5 PM. During this hour, projects electrically interconnected to PG&E's system generated 98 MW. SCE's 2018 peak hour was on July 6th between 3 and 4 PM, where coincident generation was 80 MW. Projects interconnected to SDG&E's electrical system reached 33 MW of generation during the peak hour on August 8th, 2018 between the hours of 4 and 5 PM.[33]

Electric-only fuel cells followed by IC engines contributed to 73 percent of the PG&E peak hour generation. For SCE, 71 percent of the peak hour generation was driven by electric-only fuel cells, gas turbines, and IC engines, with another 14 percent from advanced energy storage systems. For SDG&E's peak hour

[33] The defined peak hours are all in local time.

generation, 45 percent of the load reductions were from gas turbines, followed by 26 percent from electric-only fuel cells.

FIGURE 4-16: 2018 IOU PEAK HOUR GENERATION BY TECHNOLOGY

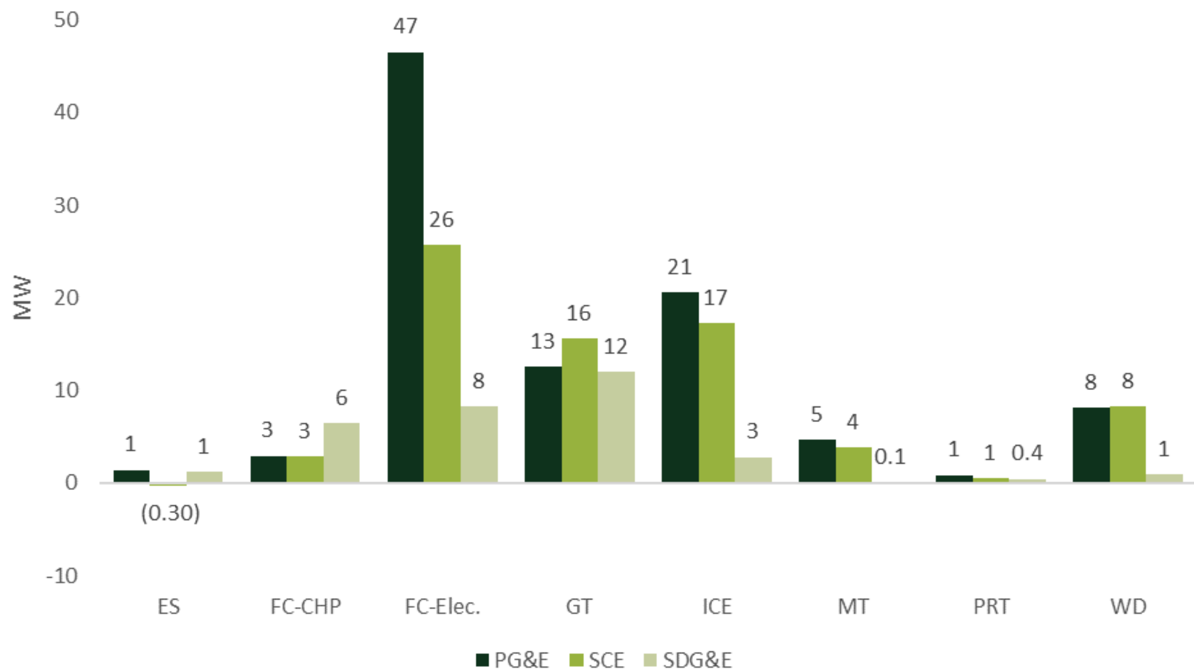


* ES = Energy Storage, FC-CHP = Fuel Cell – CHP, FC-Elec. Only = Fuel Cell – Electric Only, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, Wind = Wind Turbine, WHP = Waste Heat to Power

During 2019, the peak load for PG&E occurred on August 15th between 4 and 5 PM. SCE saw its peak load on September 4th between 2 and 3 PM, and SDG&E was September 3rd between 4 and 5 PM. During those hours, PG&E projects had a peak impact of 98 MW, SCE project impacts reached 74 MW, and SDG&E saw an impact of 32 MW.[33]

The contribution to the IOU peak hour generation for 2019 by technology did not change much relative to 2018. Electric-only fuel cells and IC engines contributed to 69 percent of the PG&E peak hour generation. For SCE, the major change was that energy storage saw a negative impact (increase in load on the grid) during the peak hour. For SDG&E's peak hour generation, 63 percent came from gas turbines and electric-only fuel cells.

FIGURE 4-17: 2019 IOU PEAK HOUR GENERATION BY TECHNOLOGY



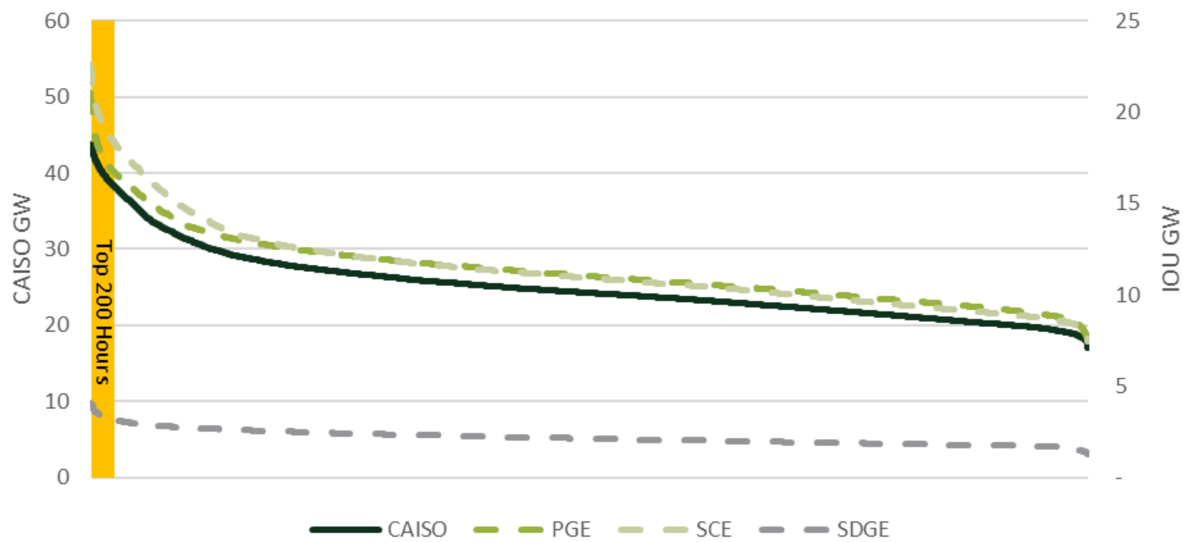
* ES = Energy Storage, FC-CHP = Fuel Cell – CHP, FC-Elec. Only = Fuel Cell – Electric Only, GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, Wind = Wind Turbine, WHP = Waste Heat to Power

Over time, program generation coincident with IOU peak hours has grown. Contributions by various categories of projects have changed with the addition of new and retirement of old capacity. Additional information on peak hour impact trends is presented in Appendix B.

Top 200 Peak Hours

CAISO and IOU annual peak hour coincident generation is a snapshot of beneficial program impacts. Analysing the top 200 peak hours results in a more robust measure of impacts during CAISO and IOU peak grid loads. Representing just 2.3 percent of all the hours in a year, the top 200 peak hours capture the steepest part of load distribution curves. Figure 4-18 shows the 2019 CAISO and IOU load distribution curves and indicates the 200-hour mark as the solid orange bar on the left side.

FIGURE 4-18: 2019 CAISO AND IOU LOAD DISTRIBUTION CURVES



* Axes are scaled on the left for CAISO and on the right for the IOUs

The distributions of the top 200 hours over the course of a year differ between CAISO and the three IOUs, as well as from year to year. While generally mid-to-late summer weekday afternoon occurrences, a top-200 hour can occur on weekends and into October. Table 4-14 through Table 4-17 display the distribution of the top 200 peak hours for months and weekday types of 2018 and 2019.

TABLE 4-14: 2018 TOP 200 PEAK HOUR DISTRIBUTIONS BY MONTH

	May	June	July	August	September	October
CAISO	0	0	125	75	0	0
PG&E	0	19	127	54	0	0
SCE	0	0	117	83	0	0
SDG&E	0	0	83	117	0	0

TABLE 4-15: 2018 TOP 200 PEAK HOUR DISTRIBUTIONS BY WEEKDAY

	Weekday	Weekend
CAISO	187	13
PG&E	176	24
SCE	181	19
SDG&E	164	36

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TABLE 4-16: 2019 TOP 200 PEAK HOUR DISTRIBUTIONS BY MONTH

	May	June	July	August	September	October
CAISO	0	18	50	84	48	0
PG&E	0	33	50	89	28	0
SCE	0	9	55	77	59	0
SDG&E	0	0	41	51	97	11

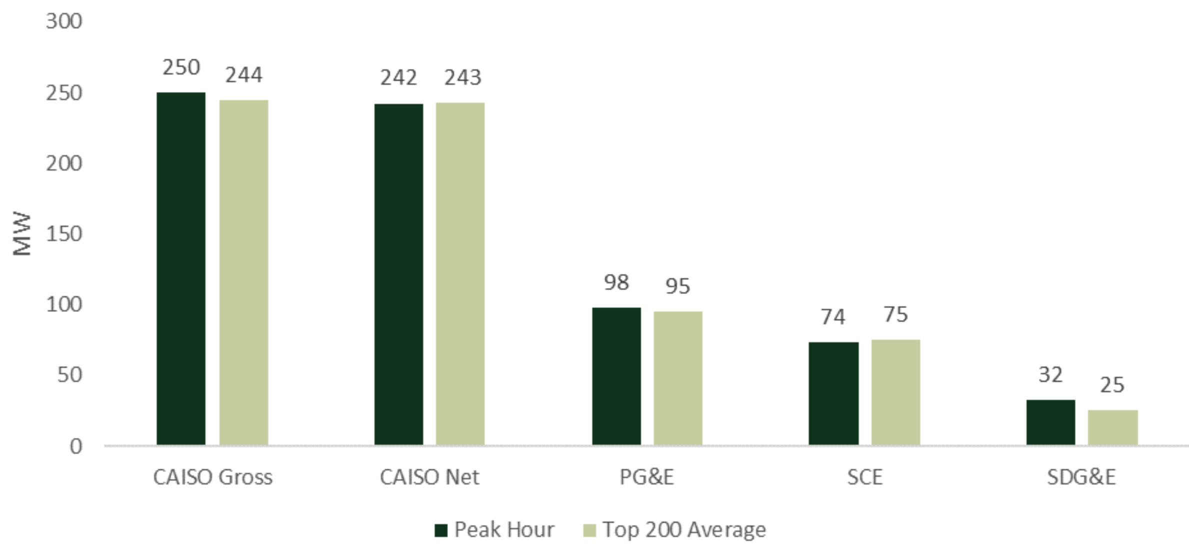
TABLE 4-17: 2019 TOP 200 PEAK HOUR DISTRIBUTIONS BY WEEKDAY

	Weekday	Weekend
CAISO	182	18
PG&E	180	20
SCE	185	15
SDG&E	164	36

During 2018, the top 200 peak hours occurred almost entirely in July and August. In contrast, 2019 also saw a significant number of hours occurring during September. For CAISO and all IOUs, weekdays dominated top hours, but weekends included some top hours in both 2018 and 2019. Between 7 percent and 22 percent of peak hours occurred during the weekends during both years.

Figure 4-19 shows total program generation coincident with the three IOU and CAISO gross and net 2019 peak hours, alongside average program generation coincident with the 2019 top 200 peak hours. Peak hour generation and top 200 average generation during 2019 were within a few percent of each other in all cases.

FIGURE 4-19: 2019 CAISO AND IOU PEAK AND TOP 200 PEAK HOUR GENERATION BY SGIP PROJECTS



CAISO peak hour and top 200 average generation impacts by technology are shown in Table 4-18 for 2018 and 2019. PG&E comparisons for 2018 and 2019 are shown in Table 4-19, SCE comparisons in Table 4-20, and SDG&E comparisons in Table 4-21.

To compare peak hour values to averages across the top 200 peak hours, the tables below show percentages of average to peak hour generation. Although many of the technologies that contribute the least to the peak hours show a large variation between peak hour and top 200 averages, technologies like electric-only fuel cells, IC engines, gas turbines, and microturbine percentages are mostly within ±10 percent of the top 200 hours, indicating that for the overall program, the peak hour impact is a fairly robust measure of top 200-hour, and looking at the total average to peak for CAISO and each utility, the average top 200 is 6 percent or less compared to the peak values.

TABLE 4-18: CAISO PEAK HOUR AND TOP 200 HOUR GENERATION IMPACT

Technology Type	2018			2019		
	Peak Hour	Top 200 Average	Average to Peak	Peak Hour	Top 200 Average	Average to Peak
Energy Storage	15.1	5.8	38%	5.8	3.9	67%
Fuel Cell - CHP	12.8	14.3	111%	14.3	13.7	96%
Fuel Cell - Electric Only	107.1	106.8	100%	99.8	99.8	100%
Gas Turbine	62.6	59.0	94%	53.6	56.0	104%
Internal Combustion Engine	45.0	42.4	94%	44.2	42.0	95%
Microturbine	9.5	8.9	94%	9.7	9.5	98%
Pressure Reduction Turbine	1.2	1.3	111%	2.2	1.6	73%
Wind	17.0	15.8	93%	20.5	18.1	88%
Total	**270**	**254**	**94%**	**250**	**244**	**98%**

TABLE 4-19: PG&E PEAK HOUR AND TOP 200 PEAK HOUR GENERATION IMPACT

Technology Type	2018			2019		
	Peak Hour	Top 200 Average	Average to Peak	Peak Hour	Top 200 Average	Average to Peak
Energy Storage	1.2	0.7	60%	1.4	0.6	42%
Fuel Cell - CHP	4.1	5.2	127%	2.9	3.1	106%
Fuel Cell - Electric Only	50.2	50.2	100%	46.9	46.9	100%
Gas Turbine	10.4	13.1	126%	12.6	12.4	99%
Internal Combustion Engine	21.0	21.6	103%	20.6	19.3	94%
Microturbine	4.6	4.6	99%	4.7	4.6	98%
Pressure Reduction Turbine	0.1	0.2	205%	0.9	0.7	83%
Wind	6.1	7.0	114%	8.1	7.6	94%
Total	**98**	**103**	**105%**	**98**	**95**	**97%**

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TABLE 4-20: SCE PEAK HOUR AND TOP 200 PEAK HOUR GENERATION IMPACT

Technology Type	2018			2019		
	Peak Hour	Top 200 Average	Average to Peak	Peak Hour	Top 200 Average	Average to Peak
Energy Storage	11.2	3.9	35%	-0.3	1.6	-524%
Fuel Cell - CHP	3.6	2.5	68%	2.8	2.9	101%
Fuel Cell - Electric Only	27.7	27.8	100%	25.7	25.6	100%
Gas Turbine	17.4	16.7	96%	15.6	17.3	111%
Internal Combustion Engine	11.7	13.8	118%	17.2	16.6	96%
Microturbine	1.9	2.7	144%	3.8	3.7	99%
Pressure Reduction Turbine	0.4	0.5	113%	0.5	0.4	84%
Wind	6.5	6.6	102%	8.3	7.1	86%
Total	**80**	**74**	**93%**	**74**	**75**	**102%**

TABLE 4-21: SDG&E PEAK HOUR AND TOP 200 PEAK HOUR GENERATION IMPACT

Technology Type	2018			2019		
	Peak Hour	Top 200 Average	Average to Peak	Peak Hour	Top 200 Average	Average to Peak
Energy Storage	2.0	0.7	33%	1.2	0.5	43%
Fuel Cell - CHP	4.0	4.8	121%	6.5	8.3	128%
Fuel Cell - Electric Only	8.5	8.7	103%	8.3	13.1	159%
Gas Turbine	15.0	15.5	104%	12.0	2.0	17%
Internal Combustion Engine	2.6	2.3	89%	2.8	0.1	4%
Microturbine	0.1	0.1	91%	0.1	0.5	405%
Pressure Reduction Turbine	0.4	0.6	147%	0.4	0.6	140%
Wind	0.8	0.4	52%	1.0	0.0	0%
Total	**33**	**33**	**99%**	**32**	**25**	**78%**

4.1.3 Noncoincident Customer Peak Demand Impacts

SGIP projects impact customer demand in addition to the system (IOU or CAISO) coincident peak demand. It is not always the case that a customer's peak demand falls on the CAISO or IOU peak load hour. The peak customer demand during any stated period is called the customer noncoincident peak (NCP) demand. The first metric this sub-section looks at is the impact on customer's annual peak demand, which is important for understanding the total reduction SGIP has on customer loads.

The demand portion of customer bills is based on the monthly peak kW. Thus, in addition to the reduction in annual peak demand, the monthly demand reduction illustrates how SGIP impacts customer energy costs.

Approach for Noncoincident Customer Peak Demand Impacts

To analyze the impact of SGIP on NCP customer demand, the available load and the generation data are aligned on an hourly basis. The gross demand without the presence of the SGIP generation is then calculated with these formulae:[34]

$$\boldsymbol{Gross\ Load\ \left(\overline{kW}\right) = Metered\ Load\left(\overline{kW}\right) + Generation\left(\overline{kW}\right)} \qquad \textbf{EQUATION 4-1}$$

$$\boldsymbol{Net\ Load\ \left(\overline{kW}\right) = Metered\ Load\left(\overline{kW}\right)} \qquad \textbf{EQUATION 4-2}$$

The potential impact of SGIP generators on gross and net load can be seen graphically in the following figures. Figure 4-20 shows an example of how metered NCP customer demand, represented by net load, is reduced by SGIP generation. Over the year, the daily maximum electrical generation brought the maximum gross peak down by 30 to 40 percent each month. Figure 4-21 illustrates the impact an SGIP generator outage has on NCP customer demand. Depending on the customer load profile, a generator outage or reduced electrical production can likely set the monthly or annual peak demand. During the later half of the year, the maximum electrical production from the generator was significantly reduced, almost doubling the net peak load.

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[34] For this analysis, demand is calculated as the average power draw within a one-hour period. This is an approximate calculation, as demand is measured in 15-minute intervals and may differ from the hourly average.

FIGURE 4-20: EXAMPLE DEMAND IMPACTS FROM GENERATOR

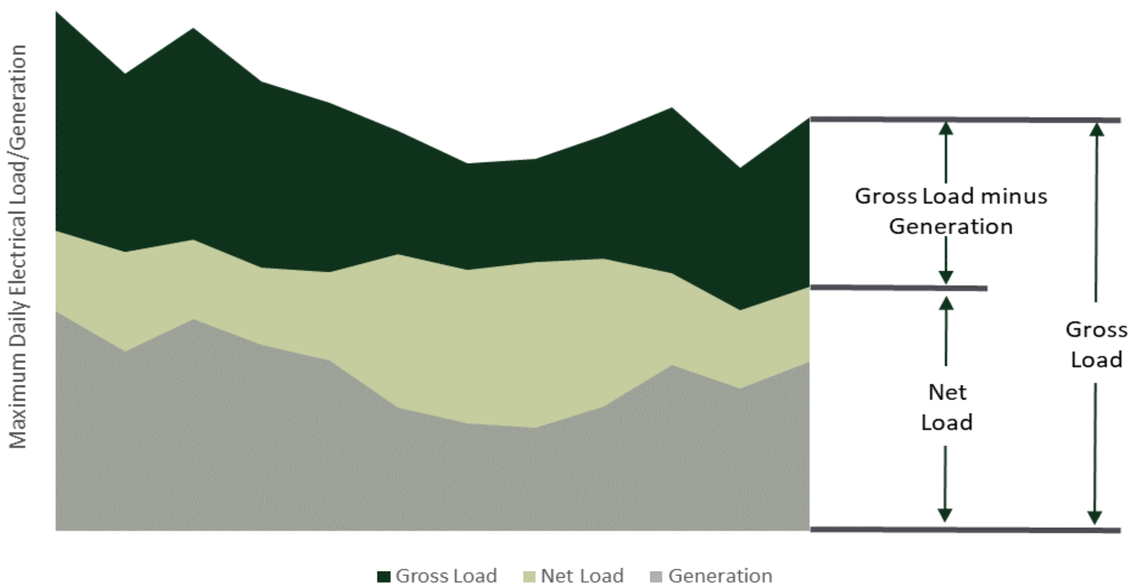
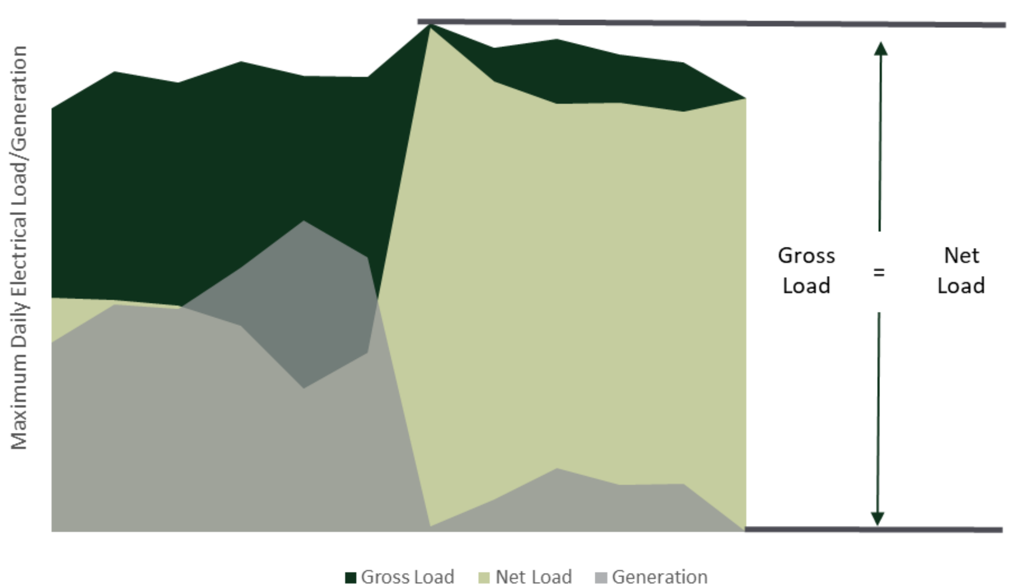


FIGURE 4-21: EXAMPLE DEMAND IMPACTS FROM GENERATOR WITH REDUCED ELECTRICITY PRODUCTION



The monthly impact of SGIP generation on the demand can be estimated using the formula:

$$\boldsymbol{Max\left[Gross\ Load\ (\overline{kW})\right]_{month} - Max\left[Net\ Load\ (\overline{kW})\right]_{month}}$$ **EQUATION 4-3**

Annually, the impact of SGIP generation on the demand can be estimated using the formula:

$$\boldsymbol{Max\left[Gross\ Load\ (\overline{kW})\right]_{year} - Max\left[Net\ Load\ (\overline{kW})\right]_{year}}$$ **EQUATION 4-4**

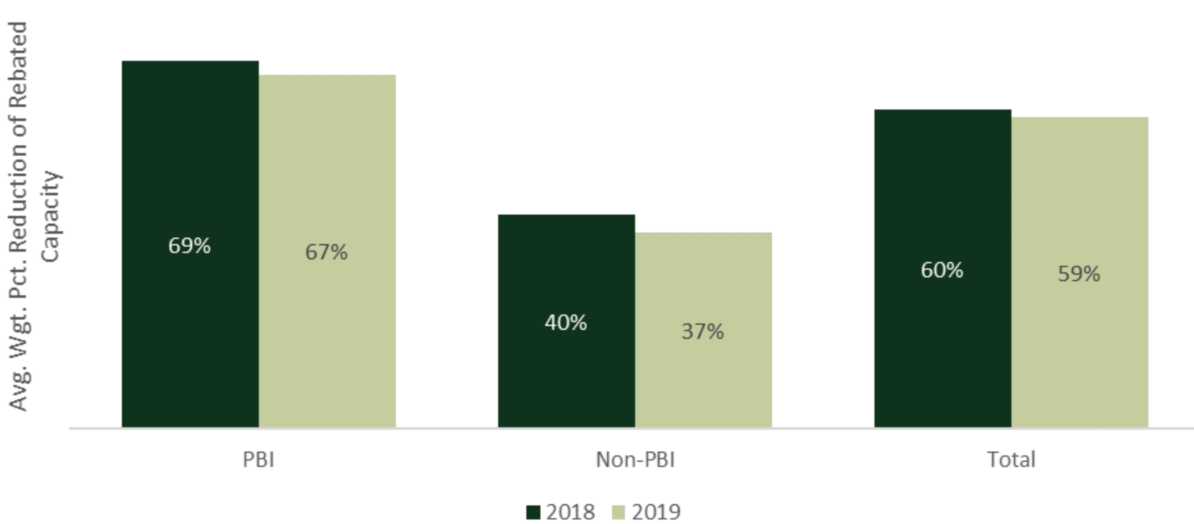
Annual NCP Customer Demand Impacts

The weighted average impacts of non-AES technologies on NCP customer demand are shown below in Figure 4-22 as a fraction of rebated capacity. PBI projects delivered, on average, demand savings of about 67 percent to 69 percent of their capacity; so a 1 MW project would, on average, reduce NCP customer demand by about 670-690 kW. Non-PBI projects show a much lower percentage, 37-40 percent, in part due to these being older systems.

The percent reduction of rebated capacity shown in the figures below is calculated as:

$$\boldsymbol{Percent\ Reduction_{year} = \left[\frac{Monthly\ Peak\ Reduction\ (\overline{kW})}{Rebated\ Capacity}\right]}$$ **EQUATION 4-5**

FIGURE 4-22: ANNUAL WEIGHTED AVERAGE NCP IMPACTS AS PERCENT OF CAPACITY



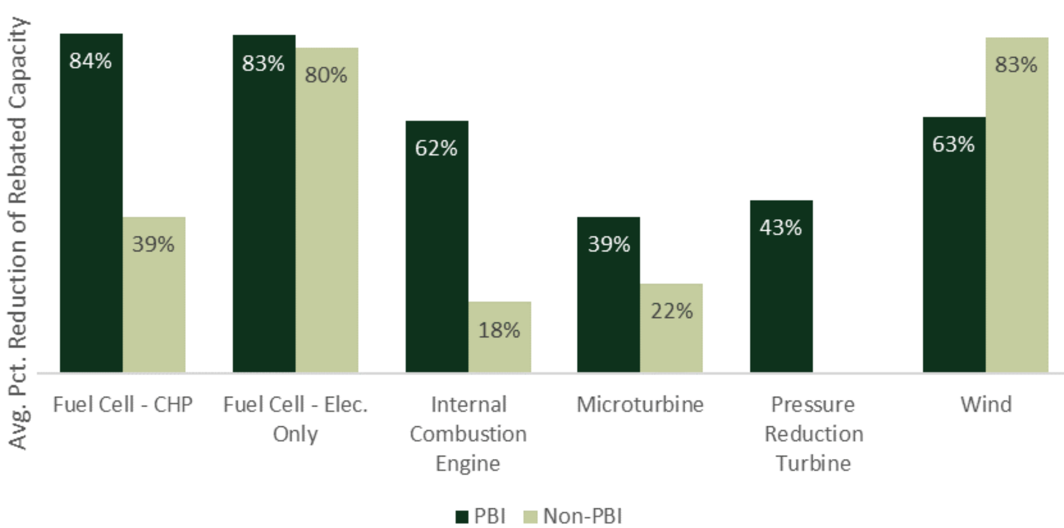
* These only reflect projects which have at least 6 months of generation and load data.

The weighted average reduction in annual NCP across the population was 59 percent in 2018 and 60 percent in 2019.

Annual NCP Customer Demand Impacts by Technology

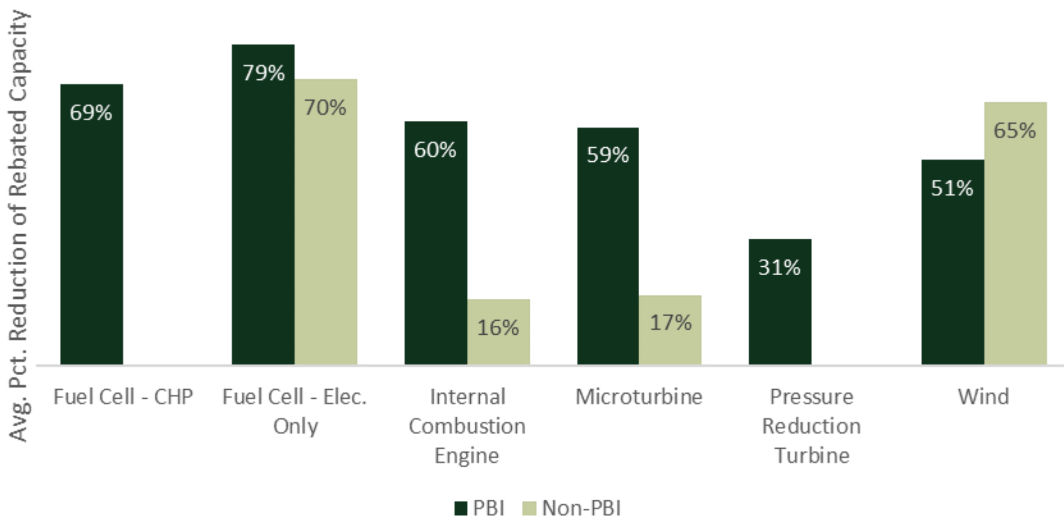
Different technologies have significantly different impacts on annual NCP customer demand. Like Figure 4-22 above, Figure 4-23 and Figure 4-24 (on the following page) show the average demand impact as a percent of rebated capacity, displayed by non-AES technology type and incentive payment type. Figure 4-23 shows NCP demand impacts for 2018, and Figure 4-24 shows impacts for 2019. For generation projects, PBI projects exhibit larger NCP demand reductions relative to non-PBI projects. One exception is Wind projects for both years. There were two large non-PBI wind projects which performed exceptionally well in both 2018 and 2019.

FIGURE 4-23: 2018 WEIGHTED AVERAGE NCP IMPACTS AS PERCENT OF CAPACITY BY TECHNOLOGY



* This figure and the associated analysis exclude technology/incentive type pairings where the sample size was less than three. These only reflect projects which have at least 6 months of generation and load data.

FIGURE 4-24: 2019 WEIGHTED AVERAGE NCP IMPACTS AS PERCENT OF CAPACITY BY TECHNOLOGY



* This figure and the associated analysis exclude technology/incentive type pairings where the sample size was less than three. These only reflect projects which have at least 6 months of generation and load data.

Average Monthly NCP Customer Demand Reductions

Reduction to annual NCP customer demand is one metric to measure the demand savings of SGIP that aligns with some policy decisions (NEM and AB 162 (Gordon/Skinner)). Another useful metric relevant to the host customers is the average monthly demand reduction since demand charges are billed monthly.

The percent reduction of demand shown in the figures below is calculated as:

$$Percent\ Reduction_{year} = \left[\frac{\overline{Monthly\ Peak\ Reduction\ (kW)}}{Monthly\ Gross\ Load\ (kW)}\right] \qquad \textbf{EQUATION 4-6}$$

Figure 4-25 and Figure 4-26 show similar results to the annual demand reductions. SGIP technologies, on average, provided monthly reductions in noncoincident customer peak demand. For the most part, the monthly reductions did not generally vary by month or by season. Except for the gas turbines and wind turbines, PBI systems showed a greater reduction in customer NCP demand than non-PBI systems did. While most technologies did not see much of a change from month to month, gas turbines saw a large swing in NCP customer demand reduction, from almost zero to over 100 percent. As gas turbines are so large in size, if a system was not operating for a month, or only operating at partial capacity, it could significantly affect the NCP customer demand.

FIGURE 4-25: 2018 AVERAGE MONTHLY NCP CUSTOMER DEMAND REDUCTION BY TECHNOLOGY

	Energy Storage	Fuel Cell - CHP	Fuel Cell - Elec. Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind
January	8%	51%	51%	2%	33%	24%	17%	33%
February	7%	62%	52%	103%	34%	24%	28%	37%
March	6%	48%	52%	13%	34%	20%	28%	37%
April	8%	43%	49%	52%	32%	19%	13%	36%
May	7%	53%	49%	13%	31%	20%	20%	38%
June	8%	49%	48%	29%	25%	16%	33%	36%
July	7%	58%	44%	26%	24%	16%	12%	34%
August	7%	55%	45%	47%	25%	13%	26%	33%
September	3%	51%	47%	16%	29%	18%	21%	33%
October	6%	56%	47%	46%	35%	26%	33%	29%
November	8%	37%	45%	48%	32%	15%	31%	29%
December	8%	47%	51%	80%	33%	21%	21%	30%
PBI	8%	59%	49%	25%	49%	31%	24%	25%
Non-PBI	6%	32%	43%	63%	9%	7%	0%	48%

* This figure and the associated analysis exclude technology/incentive type pairings where the sample size was less than three. These only reflect projects which have at least 6 months of generation and load data.

FIGURE 4-26: 2019 AVERAGE MONTHLY NCP CUSTOMER DEMAND REDUCTION BY TECHNOLOGY

	Energy Storage**	Fuel Cell - CHP	Fuel Cell - Elec. Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind
January	6%	41%	51%	55%	30%	17%	20%	25%
February	5%	65%	52%	76%	28%	29%	23%	30%
March	8%	42%	49%	55%	33%	30%	18%	33%
April	10%	45%	45%	36%	36%	26%	14%	33%
May	9%	37%	46%	27%	47%	25%	18%	32%
June	9%	28%	41%	47%	27%	26%	23%	32%
July	9%	39%	41%	37%	21%	25%	8%	25%
August	9%	35%	41%	48%	28%	24%	7%	19%
September	6%	33%	41%	24%	30%	24%	5%	23%
October	4%	39%	44%	49%	37%	29%	8%	21%
November	6%	40%	44%	36%	38%	29%	13%	23%
December	4%	44%	49%	3%	27%	32%	3%	25%
PBI	N/A	42%	47%	34%	41%	46%	14%	25%
Non-PBI	N/A	29%	37%	60%	21%	7%	0%	35%

* This figure and the associated analysis exclude technology/incentive type pairings where the sample size was less than three. These only reflect projects which have at least 6 months of generation and load data.

** Energy Storage Impacts were not calculated by PBI and Non-PBI for 2019.

4.2 UTILIZATION AND CAPACITY FACTORS

Energy impacts are a function of generating capacity and utilization. Capacity factor (CF) is a metric of system utilization. For generation technologies, the capacity factor is defined as the amount of energy generated during a given period divided by the maximum possible amount of energy that could have been generated during that period. For energy storage technologies, the capacity factor is the sum of the storage discharge (in kWh) divided by the maximum possible discharge within a given period. The capacity factor closer to one indicates that the system is being utilized to its maximum potential.

Host customers utilize their systems at capacity factors according to their individual needs. Some facilities only need full capacity during weekday afternoons and some might need full capacity 24/7. Annual capacity factors are useful when comparing utilization between or across varieties of project sizes and technologies. To the extent that SGIP projects are cleaner (in regards to greenhouse gases) than the grid energy they displace, high annual capacity factors are desirable. A capacity factor of 1.0 is full utilization regardless of a project's generating capacity.

The annual capacity factor of a generation project, CF_a, is defined in Equation 4-7 as the sum of hourly electric net generation output, $ENGO_h$, during all 8,760 hours of the year divided by the product of the project's capacity and 8,760. If a project was completed mid-year, then the annual capacity factor is evaluated from the completion date through the end of the year.

$$\boldsymbol{CF_a} = \frac{\sum \boldsymbol{ENGO_h}[\boldsymbol{kWh}]}{\boldsymbol{Capacity}\ [\boldsymbol{kW}] \times \boldsymbol{Hours\ of\ Data\ Available}\ [\boldsymbol{hr}]}$$ **EQUATION 4-7**

The capacity factor for an energy storage project is calculated differently and is shown in Equation 4-8. The energy storage capacity factor assumes maximum hours of operation in a year to be 60 percent of the full year or 5,200 hours.

$$\boldsymbol{CF_a} = \frac{\sum \boldsymbol{kWh\ Discharge}\ [\boldsymbol{kWh}]}{\boldsymbol{Hours\ of\ Data\ Available}\ [\boldsymbol{hr}] \times \boldsymbol{Rebated\ Capacity}\ [\boldsymbol{kW}] \times \boldsymbol{60}\%}$$ **EQUATION 4-8**

When aggregating the results up to the program or technology level, projects which have been decommissioned or projects with an annual capacity factor of less than 3% were removed from the analysis. This allows the capacity factors to be calculated based only on projects which are known to be fully operating.

Figure 4-27 shows the annual capacity factors for the program's seven rebated generation technologies as well as energy storage technologies for non-residential and residential systems separately during 2018 and 2019. Electric-only fuel cells and gas turbines showed the highest capacity factors across the two years, followed by CHP fuel cells. IC engines, microturbines, and pressure reduction turbines all showed capacity factors in the 30 percent to 40 percent range. Residential and non-residential energy storage systems saw capacity factors in the range of 6 to 8 percent.

FIGURE 4-27: 2018 AND 2019 ANNUAL CAPACITY FACTORS BY TECHNOLOGY – OPERATIONAL ONLY SYSTEMS

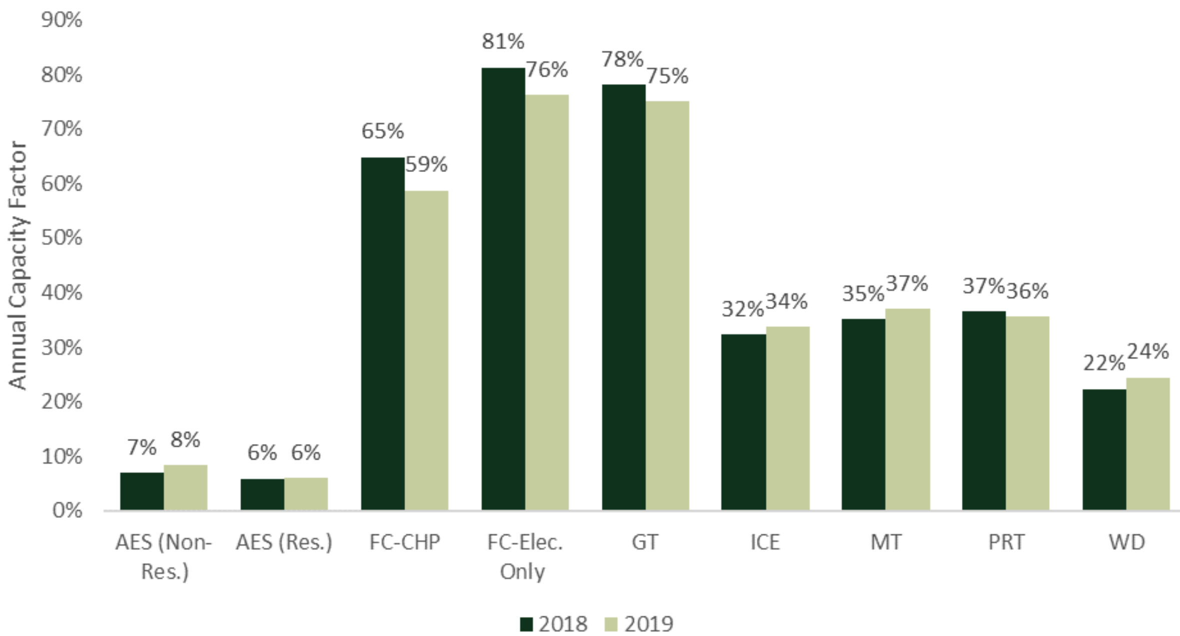


Figure 4-28 shows the annual 2019 capacity factors for the program generation technologies as well as energy storage residential and non-residential, split by PBI and non-PBI projects. Across all technologies, PBI projects showed higher capacity factors, except for gas turbines where the capacity factors were the same for both incentive types. CHP fuel cells, internal combustion engines, microturbines, and wind projects all showed substantial differences in capacity factors between PBI and non-PBI incentive types. It is expected that PBI projects see higher capacity factors than non-PBI projects, as they are being incentivized based on their capacity factors. There were no non-PBI pressure reduction turbines or non-residential non-PBI energy storage systems.

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FIGURE 4-28: 2019 ANNUAL CAPACITY FACTORS BY TECHNOLOGY FOR PBI VERSUS NON-PBI – OPERATIONAL ONLY SYSTEMS

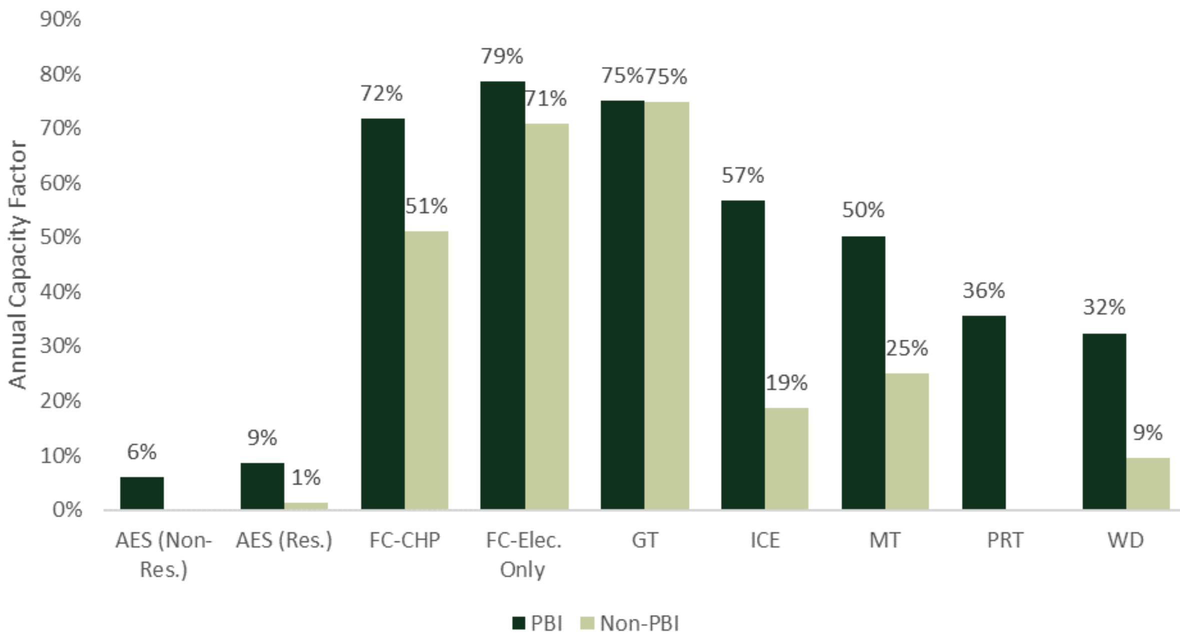
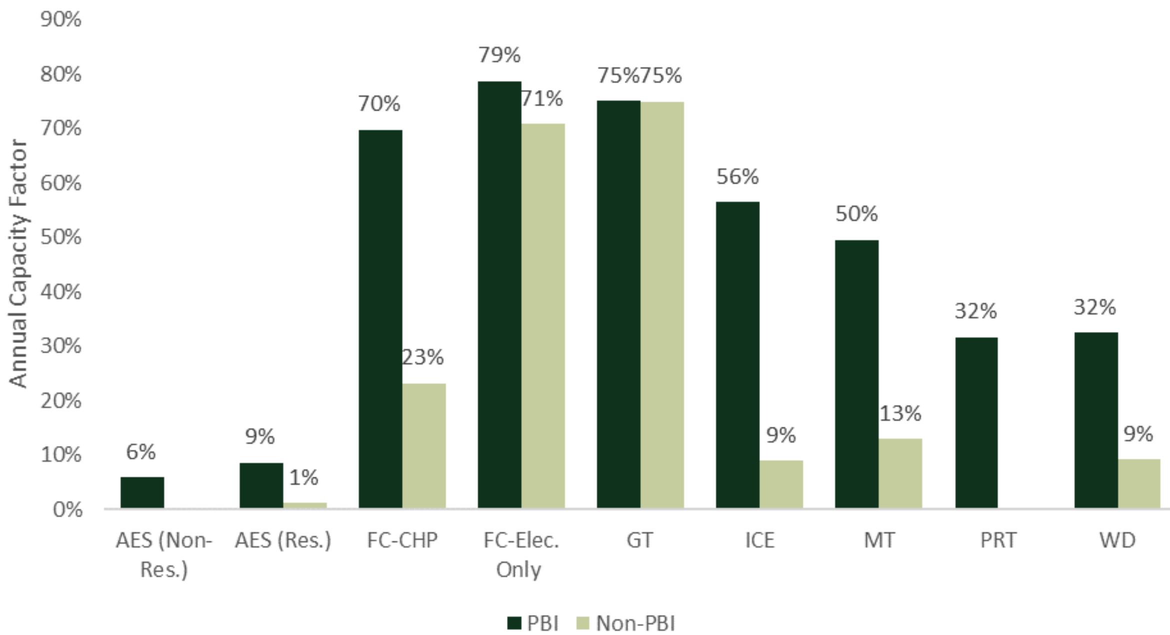


Figure 4-29 shows the 2019 capacity factors for each of the program technologies but includes all projects in the population, including those that have been decommissioned or temporarily turned off. Non-PBI capacity factors are greatly reduced for CHP fuel cells due to the number of retired projects, which therefore have capacity factors of 0. Internal combustion engines and microturbines also saw reductions in capacity factors for non-PBI projects, although those were quite low already, as these are much older projects in general. PBI projects are mostly less than five years old and are in active use.

FIGURE 4-29: 2019 ANNUAL CAPACITY FACTORS BY TECHNOLOGY FOR PBI VERSUS NON-PBI (INCLUDES DECOMISSIONED AND OFF PROJECTS)



Higher utilization coincident with CAISO and IOU peak hours yields higher benefits to the grid than during other hours. The capacity factors for each technology during CAISO and IOU annual peak hours are shown by PA in Figure 4-30 and Figure 4-31 for 2018 and 2019 respectively. Gas turbines and electric-only fuel cells had the highest peak hour capacity factors in 2018 and 2019 across all utilities. Internal combustion engines and microturbines both saw very low capacity factors, below 30 percent for both years.

FIGURE 4-30: 2018 CAISO AND IOU PEAK HOUR CAPACITY FACTORS BY TECHNOLOGY – ALL SYSTEMS

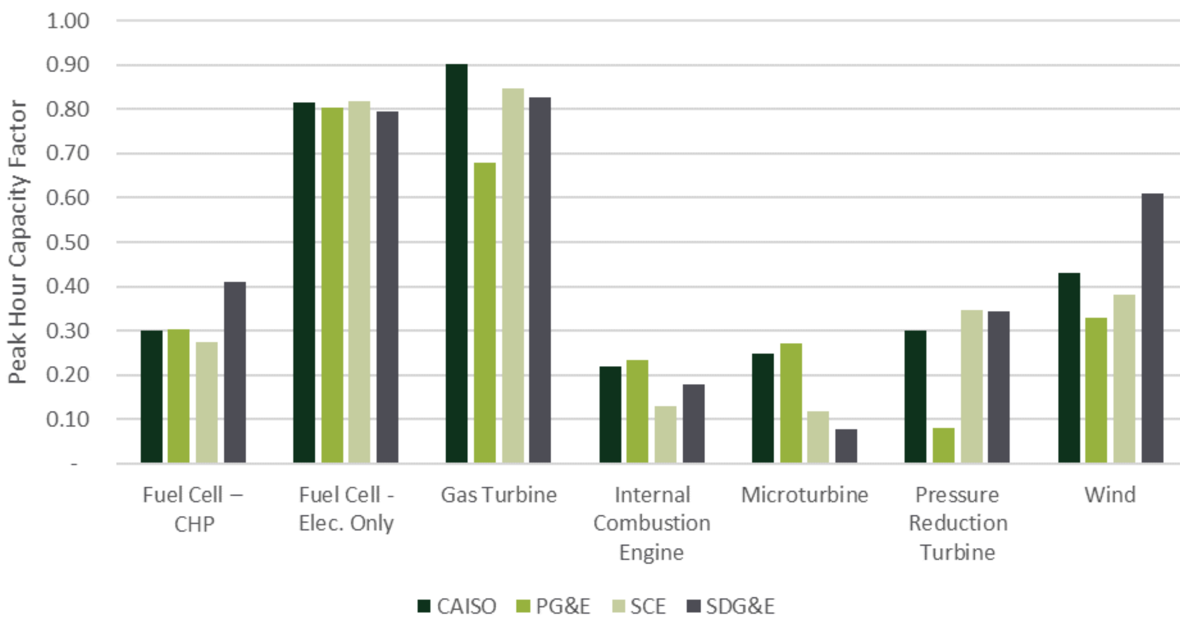
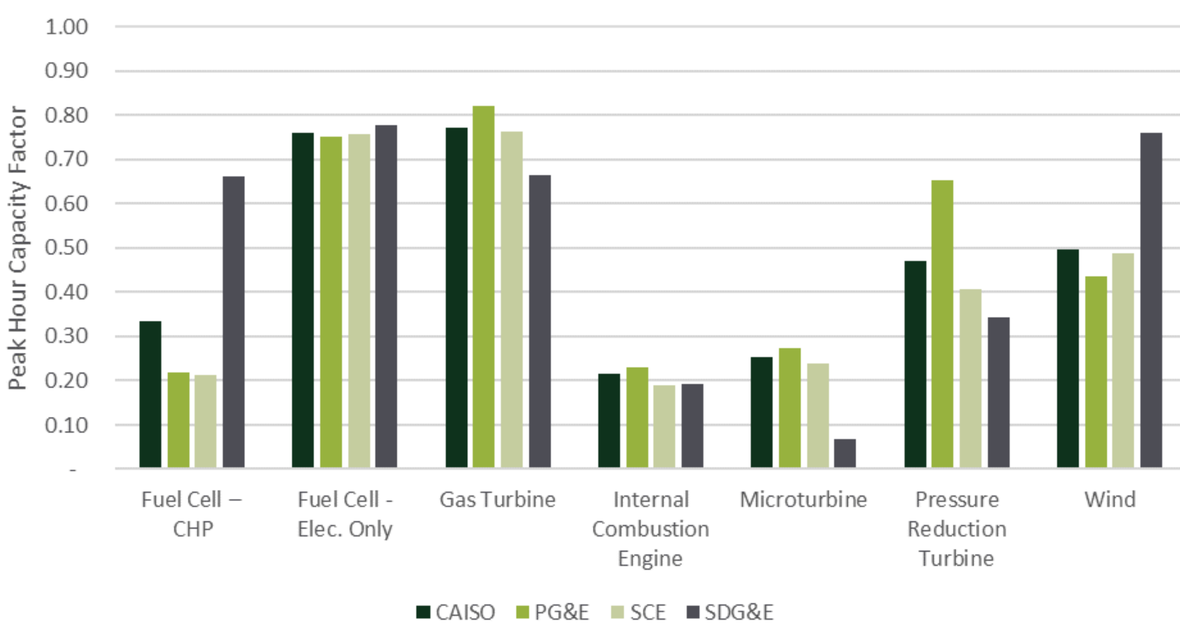


FIGURE 4-31: 2019 CAISO AND IOU PEAK HOUR CAPACITY FACTORS BY TECHNOLOGY – ALL SYSTEMS



4.3 USEFUL HEAT RECOVERY

Fuel energy that enters SGIP systems is converted into electricity and heat. Certain SGIP technologies are capable of capturing this heat to usefully serve on-site end uses instead of dissipating it to the atmosphere. Except for electric-only fuel cells that achieve high fuel-to-electric conversion efficiencies, the SGIP requires useful heat recovery where natural gas is the predominant fuel. Where the predominant fuel is renewable biogas, the SGIP system is exempt from the heat recovery requirement. The biogas exemption from heat recovery was introduced in the program's first year.

The end uses served by heat recovery, heating and cooling have important implications for net greenhouse gas emissions. The comparable baseline measures for heating and cooling are a natural gas boiler and a grid-served electric chiller respectively. Useful heat recovery that displaces a baseline boiler will reduce emissions more than if it displaces a baseline electric chiller. The distribution of end uses served by useful heat recovery from SGIP systems is summarized in Table 4-22.

The rebated capacity of projects utilizing heat recovery has steadily declined over the last few evaluation cycles. During 2018 and 2019 there were 11 new projects, with a rebated capacity of 19.5 MW.[35] Out of these 11 projects, five of them utilized only natural gas while the remaining six were fueled by a combination of natural gas and renewable fuel.

TABLE 4-22: 2019 END USES SERVED BY USEFUL RECOVERED HEAT

Useful Heat End Use	Project Count	Rebated Capacity [MW]	Percent of Rebated Capacity
Cooling Only	32	36.1	14%
Heating Only	223	161.5	61%
Heating and Cooling	62	66.0	25%
Total	**317**	**263.6**	**100%**

* Technologies excluded from total capacity are Energy Storage, Pressure Reduction Turbines, Wind, and other generation technologies exempt from CHP requirements.

[35] There was one project, a gas turbine, which contributed 11 MW to this total.

4.4 EFFICIENCIES

Generation Equipment System Efficiencies

The ability to convert fuel into useful electrical and thermal energy is measured by the system's combined efficiency in doing both. The combined or overall system efficiency is defined in Equation 4-8 as the ratio of the sum of electrical generation and useful recovered heat[36] to the fuel energy input.

$$\eta_{system} = \frac{ENGO_{kWh} \times 3.412 + HEAT_{MBtu}}{FUEL_{MBtu,LHV}}$$ **EQUATION 4-9**

The higher the system's overall efficiency the less fuel input is required to produce the sum of electricity and useful recovered heat. Electric-only fuel cells do not require useful heat recovery capabilities; therefore, their system overall efficiency has only an electrical component. Technologies that recover useful heat have electrical and thermal component efficiencies. All efficiencies are reported on a lower heating value (LHV) basis.[37]

The observed overall system and component efficiencies for non-renewable projects in 2018 and 2019 are shown in Figure 4-32 and Figure 4-33. The electrical conversion efficiency is shown in light orange, thermal efficiency is shown in burnt orange, and the overall system efficiency is represented by the sum of both components. Both figures below also display green bars over each technology, which represent the program minimum overall efficiency targets of 54.1 percent LHV (or 60 percent HHV) for CHP and 36.1 percent LHV (40 percent HHV) for electric-only fuel cells.

During 2018 and 2019, microturbines lagged behind their efficiency targets by less than 10 percent, while electric-only fuel cell technologies and gas turbines exceeded their targets. CHP fuel cells and ICE engines both exceeded their efficiency targets one year but didn't quite meet them the other year. Deficiencies in system efficiency are almost always related to useful heat recovery and utilization. The electrical efficiency of CHP prime movers is not typically variable but there are some minor variances in efficiency as a function of air inlet temperature and therefore seasons.

Heat recovery is the most complicated engineering challenge when implementing CHP. If the CHP generator is not appropriately sized to the annual heating and cooling loads of a building, then much of the excess heat must be dumped into the atmosphere through a radiator. Useful heat recovery loops may

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36 In the context of this report, useful heat is defined as heat that is recovered from CHP projects and used to serve on-site thermal loads. Waste heat that is lost to the atmosphere or dumped via radiators is not considered useful heat.

37 This evaluation report assumes a natural gas lower heating value energy content of 934.9 Btu/SCF and higher heating content of 1036.6 Btu/SCF for an LHV/HHV ratio of 0.9019 (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.)

also be temporarily shut down due to maintenance issues. These types of events can cause this technology to have a low useful heat recovery rate and therefore a low system efficiency.

FIGURE 4-32: 2018 OVERALL AND COMPONENT LHV EFFICIENCIES BY TECHNOLOGY

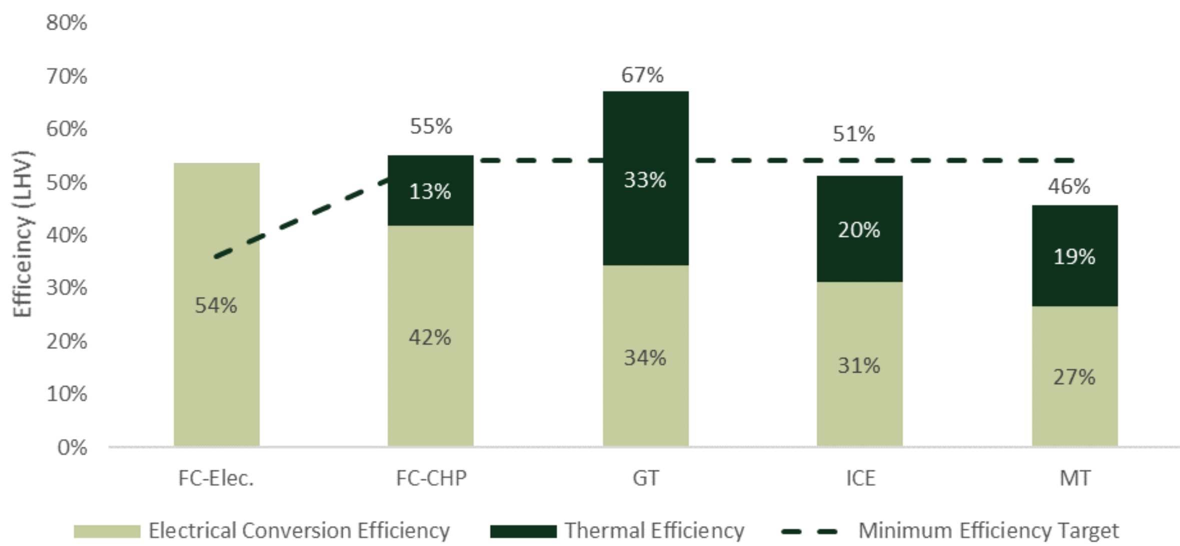
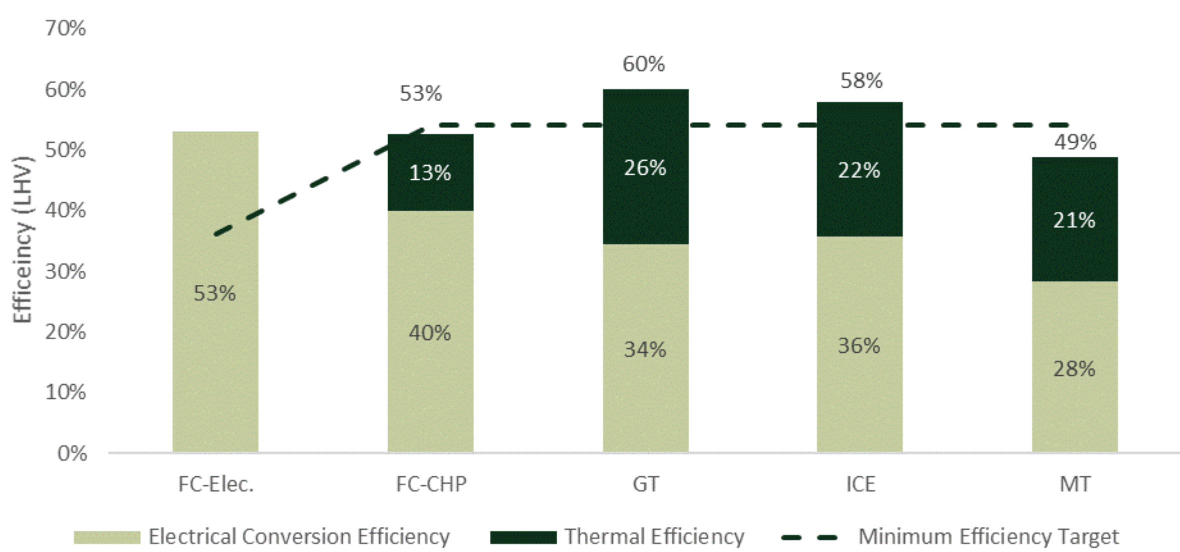


FIGURE 4-33: 201 OVERALL AND COMPONENT LHV EFFICIENCIES BY TECHNOLOGY



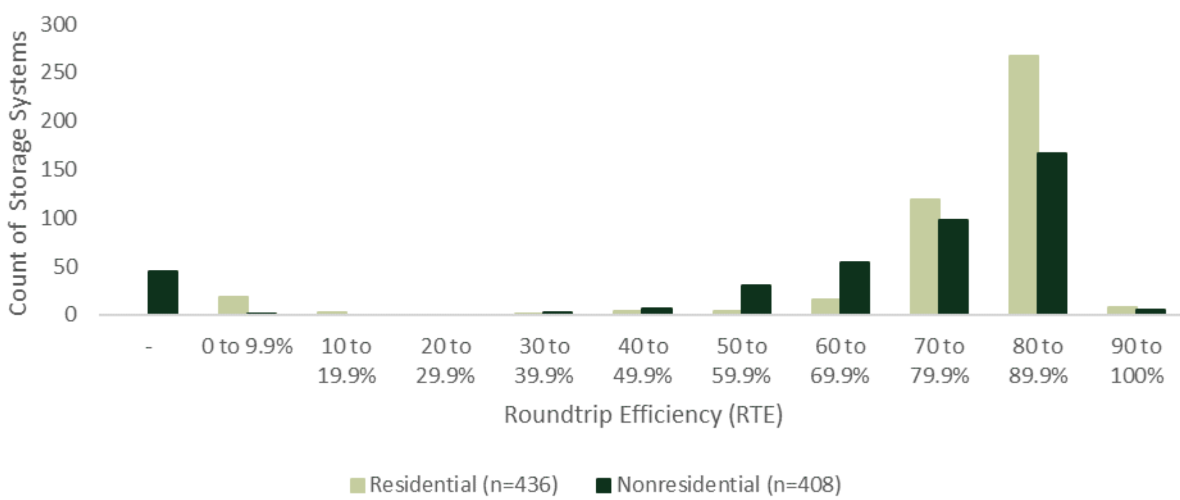
Energy Storage Round Trip Efficiencies

For energy storage systems, efficiency is specified as the roundtrip efficiency (RTE), which is an eligibility requirement for the SGIP.[38] The RTE is defined as the total kWh discharge of the system divided by the total kWh charge. For SGIP evaluation purposes, this metric was calculated for each system over the whole period for which dispatch data were available and deemed verifiable.

$$Roundtrip\ Efficiency = \frac{\sum kWh\ Discharge\ (kWh)}{\sum kWh\ Charge\ (kWh)} \quad \textbf{EQUATION 4-10}$$

Figure 4-34 presents the distribution of RTEs for both customer sectors. Besides offline and decommissioned systems, few projects exhibit an annual RTE of less than 50 percent. Most systems are within the 70 to 90 percent range. Sixty percent of residential systems exhibited an RTE in the 80 to 90 percent range alone. The average RTE was 81 percent for nonresidential projects and 83 percent for residential systems over the entire evaluation period.

FIGURE 4-34: HISTOGRAM OF ANNUAL DISCHARGE CYCLES BY CUSTOMER SECTOR



4.5 NATURAL GAS IMPACTS

The use of natural gas fuel by many SGIP systems results in increased pipeline transport of natural gas in California. The useful recovery of heat that displaces natural gas boilers mitigates this increase to some extent. Figure 4-35 shows the gross and net natural gas consumption from 2003 to 2019 in millions of

38 Energy storage systems must maintain a round trip efficiency equal to or greater than 69.6 percent in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5 percent, assuming a 1 percent annual degradation rate.

Therms. The total column height is the gross consumption by SGIP systems. The yellow upper portion of the column is consumption avoided by recovering waste heat to displace boilers. The green lower portion of the column then is the net consumption. The values shown on the lower portions are net consumption.

FIGURE 4-35: ANNUAL NATURAL GAS CONSUMPTION BY SGIP PROJECTS

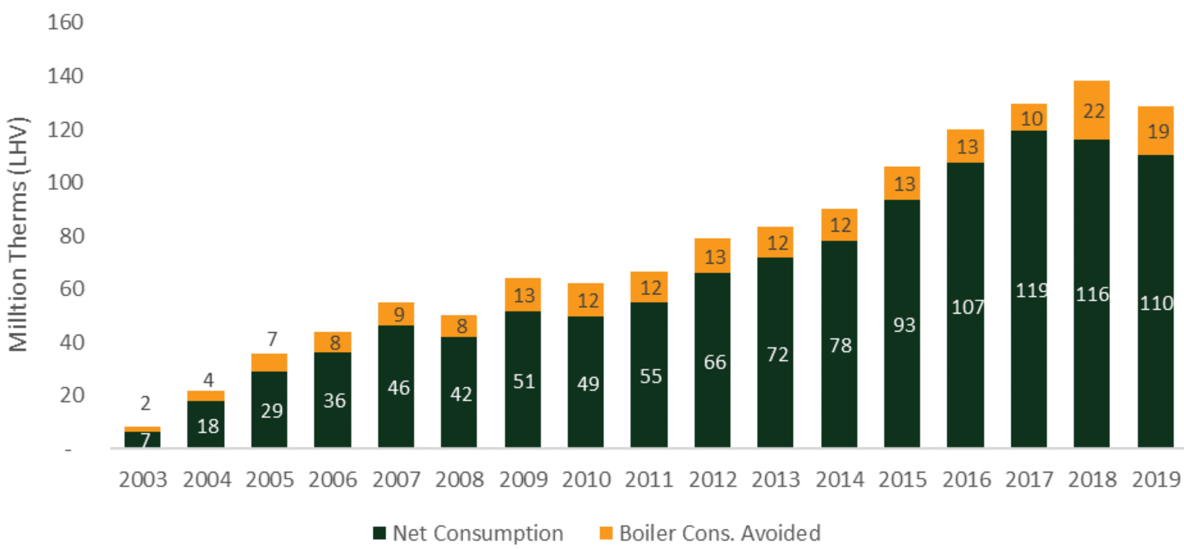
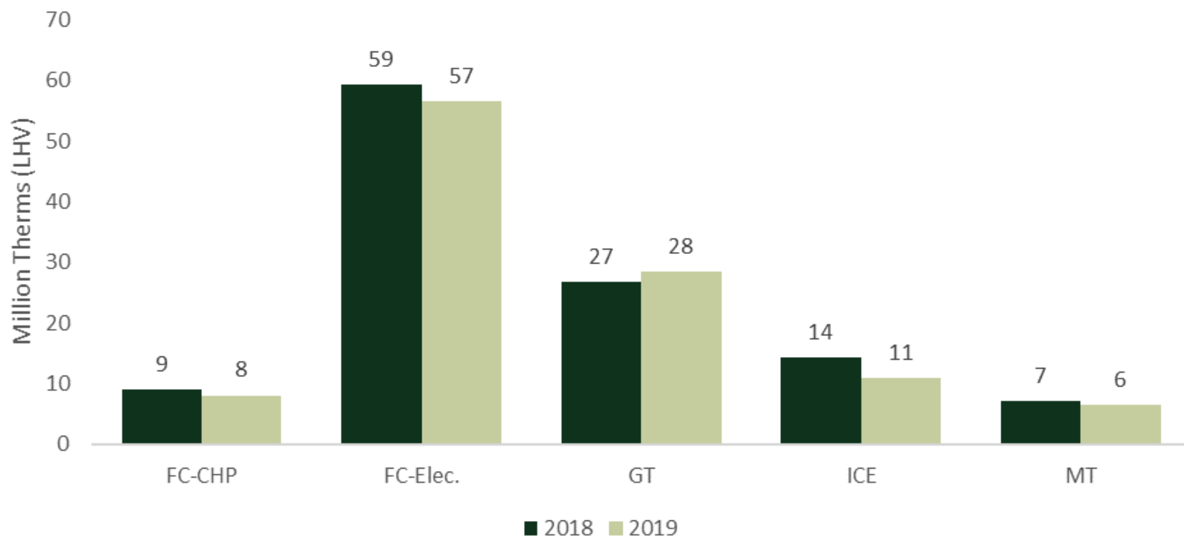


Figure 4-36 shows natural gas impacts during 2018 and 2019 by technology. All-electric fuel cells showed the highest natural gas impact, almost double that of gas turbines, which makes sense as the electrical energy generated by all-electric fuel cells made up almost 50 percent of all electrical impacts during both 2018 and 2019. On a per-electrical energy generation basis, microturbines had a higher natural gas impact at a rate of 0.8 million therms per GWh. IC engines showed the lowest rate at 0.03 million therms per GWh while all other technologies saw a rate of 0.06 million therms per GWh.

FIGURE 4-36: 2018 AND 2109 NATURAL GAS NET IMPACTS BY TECHNOLOGY



4.6 MARGINAL COST IMPACTS

Utility marginal cost impacts were calculated for each technology type. The marginal costs used in our analysis are based on the Energy and Environmental Economics (E3) Distributed Energy Resource (DER) Avoided Cost Calculator.[39] Utility marginal cost impacts are a function of the annual energy generated. The components of the total utility marginal costs include ancillary services, distribution costs, energy costs, capacity costs, GHG costs, and 'Other' costs. In 2018, the E3 calculator included Renewable Portfolio Standard (RPS) costs, however, this was dropped in the 2019 calculator and replaced with cost of losses, cap and trade costs, and transmission costs.

The different components of the total utility marginal costs are shown below in Figure 4-37 by IOU and year, on an avoided cost per rebated kW basis. SDG&E saw the highest avoided costs per rebated kW, achieving well over $400 per rebated kW in both 2018 and 2019. PG&E saw avoided costs of $318 per rebated kW, and SCE saw almost $300 per rebated kW in 2019.

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[39] The 2019 DER Avoided Cost can be found on E3's website at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

FIGURE 4-37: MARGINAL AVOIDED COSTS $ PER REBATED CAPACITY [KW] BY IOU AND YEAR

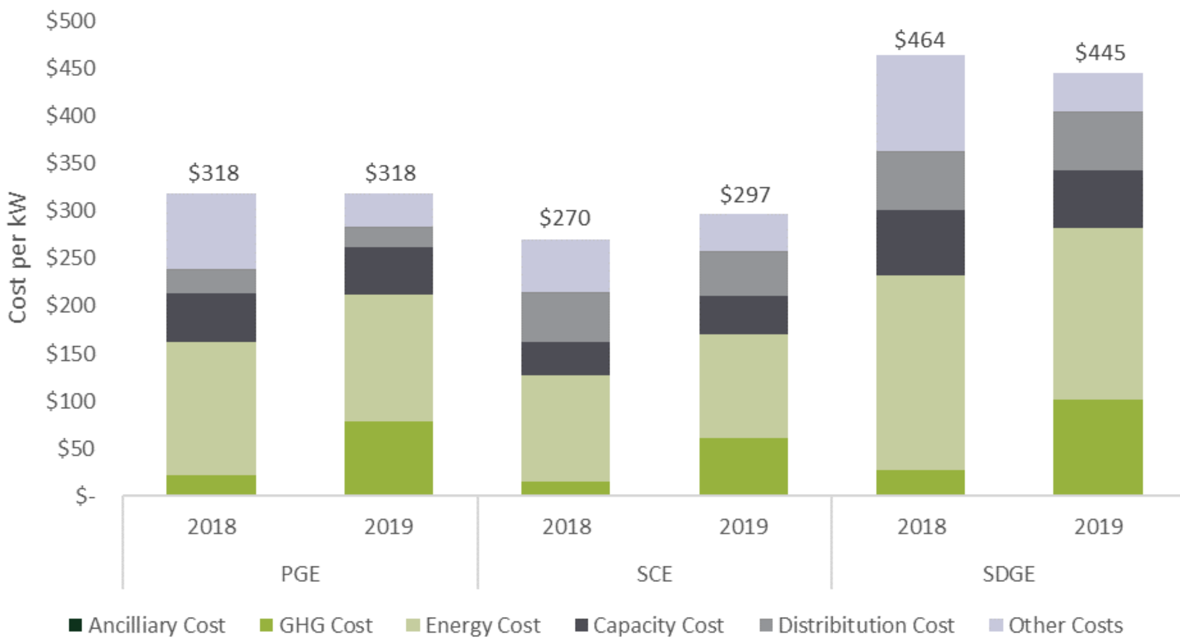
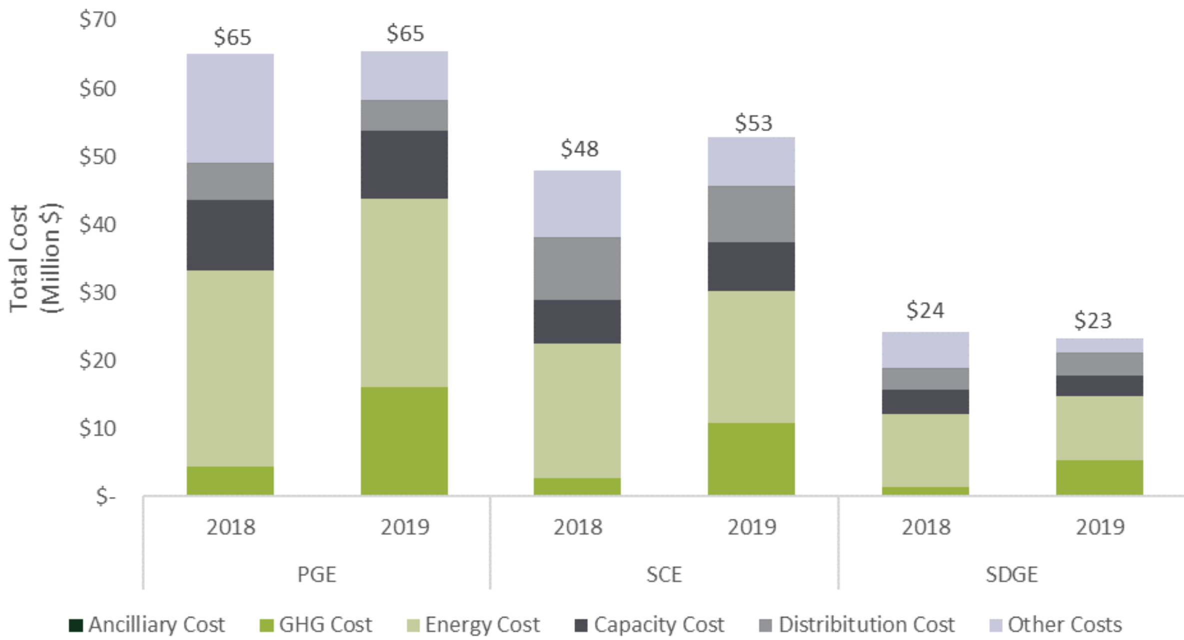


Figure 4-38 shows the total utility marginal avoided costs, in millions of dollars, by IOU and year. PG&E saw the overall highest total marginal avoided costs, avoiding over $65 million in 2018 and 2019. The avoided costs did not change significantly from year to year within each IOU.

FIGURE 4-38: TOTAL MARGINAL AVOIDED COSTS [MILLIONS $] BY IOU AND YEAR



5 ENVIRONMENTAL IMPACTS

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

This section discusses the GHG impacts of the SGIP during calendar years 2018 and 2019. The fleet of projects whose impacts are evaluated in this section includes all projects in the SGIP population that are not known to be decommissioned.[40] The GHG impact analysis is limited to carbon dioxide (CO_2) and CO_2 equivalent (CO_2eq) methane (CH_4) emissions impacts associated with SGIP projects. The discussion is organized into the following subsections:

- Methodology Overview and Summary of Environmental Impacts
- Non-renewable Generation Project Impacts
- Renewable Biogas Generation Project Impacts
- Wind and Pressure Reduction Turbine (PRT) Project Impacts
- Energy Storage Project Impacts

The scope of this analysis is further limited to the operational impacts of SGIP projects and does not discuss any lifecycle emissions impacts that occur during the manufacturing, transportation, and construction of SGIP projects. A more detailed discussion of the environmental impacts methodology is included in Appendix C.

5.1 BACKGROUND AND BASELINE DISCUSSION

Emission impacts are calculated as the difference between the emissions generated by SGIP projects and baseline emissions that would have occurred in the absence of the program. The sources of these emissions (generated and avoided) vary by technology and fuel type. For example, all distributed

40 This does not include PV projects. While the SGIP originally offered incentives to solar PV technologies, these technologies are no longer eligible for SGIP incentives. Consequently, we no longer report the impacts of SGIP rebated PV projects in impact evaluation reports.

generation technologies avoid emissions associated with displacing central station grid electricity, but only those that recover useful heat avoid emissions associated with displacing boiler use.

5.1.1 Grid Electricity Baseline

The passage of SB 412 established a maximum GHG emissions rate for SGIP generation technologies. Beginning in 2011, eligibility for SGIP generation projects was limited to projects that did not exceed an emissions rate of 379 kg CO_2/MWh over ten years. Later, the CPUC revised the maximum GHG emission rate for eligibility to 350 kg CO_2/MWh over ten years for projects applying to the SGIP in 2016.

When developing these emission factors for eligibility, the CPUC and the SGIP PAs must look forward and forecast what baseline grid conditions will look like during an SGIP project's life. These forecasts must make assumptions about power plant efficiencies and the useful life of SGIP projects. By contrast, an impact evaluation has the benefit of being backward-looking and can leverage historical data to quantify the grid electricity baseline.

Consequently, the avoided grid emissions rates used in this impact evaluation report to assess project performance are different than the avoided grid emissions factors used to screen SGIP applications for program eligibility requirements. This evaluation relies on avoided grid emissions rates developed by WattTime as part of the SGIP GHG Signal efforts.[41]

41 The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: https://sgipsignal.com/.

MARGINAL EMISSIONS CALCULATIONS

The avoided grid emissions rate, or marginal emissions rate is calculated using the following equations:

$$Heat\ Rate\ \left[\frac{Btu}{kWh}\right] = \frac{(MP - VOM)}{GasPrice + Gas\ Transportation\ Cost + (EF \times CO_2 Cost)}$$

$$Marginal\ Emissions\ Rate\left[\frac{\$}{kWh}\right] = Heat\ Rate\ \times EF$$

Where:

- **MP**: Market price of electricity (including cap and trade costs) [$]
- **VOM**: Variable O&M cost for a natural gas plant [$]
- **Gas Price**: Cost of natural gas delivered to an electric generator [$/MMBtu]
- **Gas Transportation Cost**: Cost to deliver gas to the power plant [$/MMBtu]
- **EF**: Emissions factor for tons of CO_2 per MMBtu of natural gas [metric ton CO_2/MMBtu]
- **CO_2Cost**: Cost of carbon in the Cap & Trade program [$/metric ton CO_2]

More information about this equation and the inputs that go into it can be found in Appendix C.

5.1.2 Greenhouse Gas Impact Summary

Overall, the SGIP increased GHG emissions by 42,072 metric tons of CO_2eq in both 2018 and 44,109 metric tons of CO_2eq 2019.

Figure 5-1 shows the GHG impacts of the technologies rebated by the SGIP, including both generation and energy storage. The impacts shown in Figure 5-1 represent program level impacts for all fuel types (renewable and non-renewable). However, the environmental impacts for renewable and non-renewable projects vary greatly for any given technology. Detailed breakdowns of environmental impacts by technology and fuel type are provided in subsequent figures and tables.

Internal combustion engines achieved the largest reductions in GHG emissions during both 2018 and 2019. Fuel cells, gas turbines, microturbines, and energy storage projects all showed a positive GHG emissions impact, indicating that these SGIP technologies emitted greater GHG emissions than their conventional baselines. Subsequent sections will explore potential reasons for the observed GHG impacts.

FIGURE 5-1: GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE AND CALENDAR YEAR

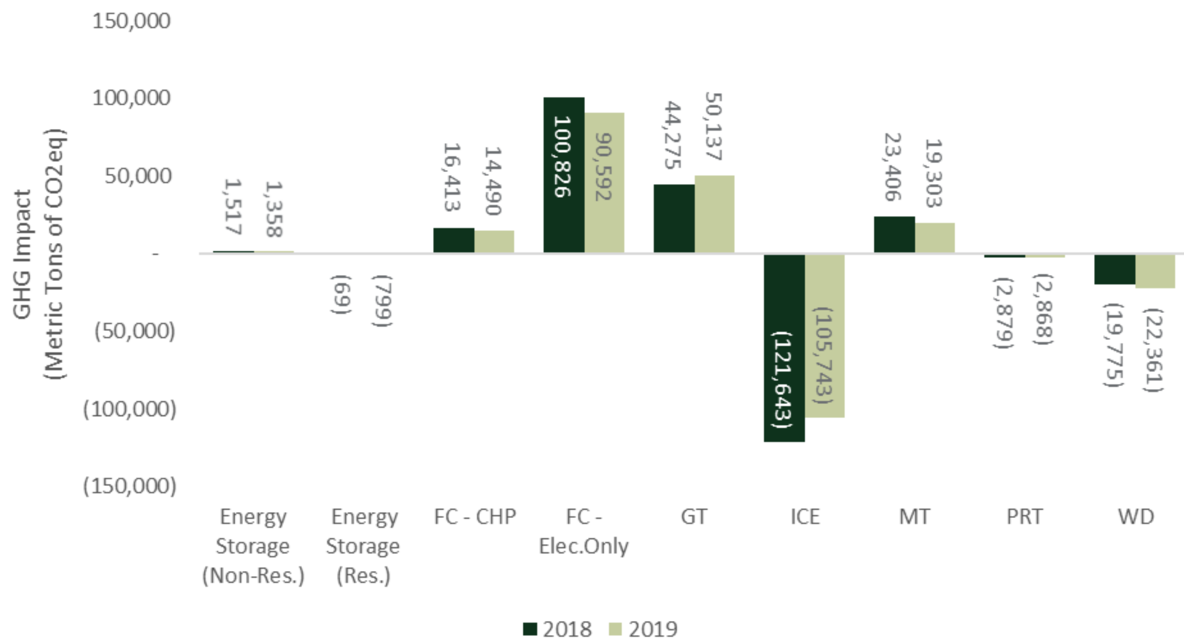


Figure 5-2 below shows the GHG impacts of the program in 2018 and 2019 by their fuel energy source. Renewable biogas fueled technologies (both on-site and directed), residential energy storage systems, and generation technologies with no fuel input (e.g., wind and pressure reduction turbines) reduced GHG emissions on average. Non-renewable generation technologies increased emissions across both years on average. Subsequent sections will explore each fuel type in detail. There was a slight increase in GHG emissions between 2018 and 2019 due to the reduced energy generation IC engines with a vented biogas baseline, which contributed to the majority of the GHG emissions reductions.

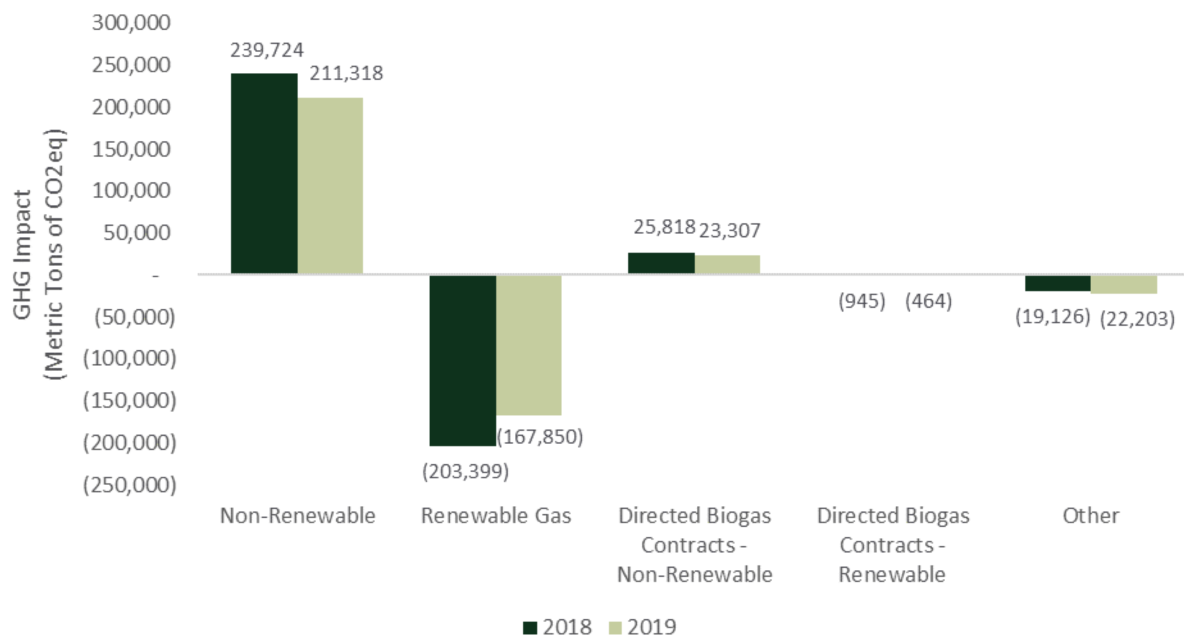
Directed biogas projects are required to procure directed biogas for 5 years (program years pre-2011), or 10 years (program years 2011 and later). However, the requirement to procure directed biogas is not always the same as the contractual permanency period, which was required to be twice as long as the warranty (until PY 2012), and then equal to the warranty period (PY 2012 and later).[42] Once these directed biogas contract periods have been completed, the evaluation team assumes that SGIP customers no longer procure directed biogas due to the increased cost of the biogas procurement.[43] Directed biogas contracts which have come to an end are shown in subsequent tables as “Directed Biogas Contracts –

[42] See Table 4-6 for warranty and permanency period requirements.

[43] Verdant reached out to every directed biogas customer to determine whether they continued to procure directed biogas after their procurement term ended. None of the customers who responded have continued to procure directed biogas. These respondents represent 12% of the directed biogas population.

Non-Renewable” while those with existing directed biogas contracts are listed as “Directed Biogas Contracts – Renewable”.

FIGURE 5-2: GREENHOUSE GAS IMPACTS BY ENERGY SOURCE AND CALENDAR YEAR



5.2 NON-RENEWABLE GENERATION PROJECT IMPACTS

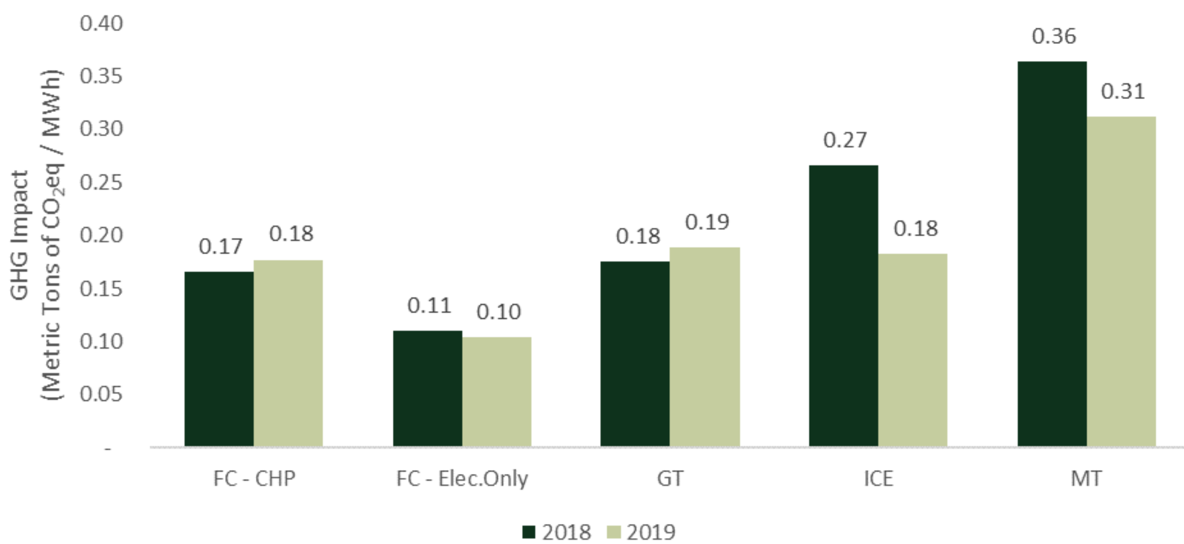
SGIP non-renewable generation projects include fuel cells (CHP and electric-only), gas turbines, IC engines, and microturbines. These projects are powered by natural gas and used to generate electricity to serve a customer’s load. These projects produce emissions that are proportional to the amount of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

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

5.2.1 Non-renewable Generation Project Greenhouse Gas Impacts

The GHG impact rates of non-renewable SGIP generation projects are shown below in Figure 5-3. All non-renewable technologies were found to increase the amount of GHG emissions over their assumed baseline. Microturbines were found to have the highest impact rates on a metric ton of CO_2eq per MWh generated basis than other technologies, at 0.36 and 0.31 for 2018 and 2019 respectively. IC engines in 2018 also saw high rates of 0.27 metric tons of CO_2eq per MWh generated but dropped significantly in 2019. Fuel cells, specifically all-electric fuel cells, provide the lowest emissions on metric tons of CO_2eq per MWh.

FIGURE 5-3: NON-RENEWABLE GREENHOUSE GAS IMPACT RATE BY TECHNOLOGY TYPE AND CALENDAR YEAR



While the impact rates displayed above in Figure 5-3, and below in Table 5-1 and Table 5-2 show that at a technology level, non-renewable fueled microturbines emit the highest GHG emissions per MWh, they are also responsible for the lowest total annual energy generation of the combustion technologies, making up only about 3 percent of the annual generation.

Table 5-1 and Table 5-2 show the impact rates of the individual contributors to the GHG impact calculations. All non-renewable technologies have a higher emissions rate than the electrical power plants that they avoid (A > B). Even when accounting for the heating and cooling services avoided, the emissions impact (F) is still higher, relative to the conventional energy services baseline. Electric-only fuel cells do not recover useful heat but have the lowest emissions impact (F) relative to the electrical power plants they avoid.

TABLE 5-1: NON-RENEWABLE GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE (2018)

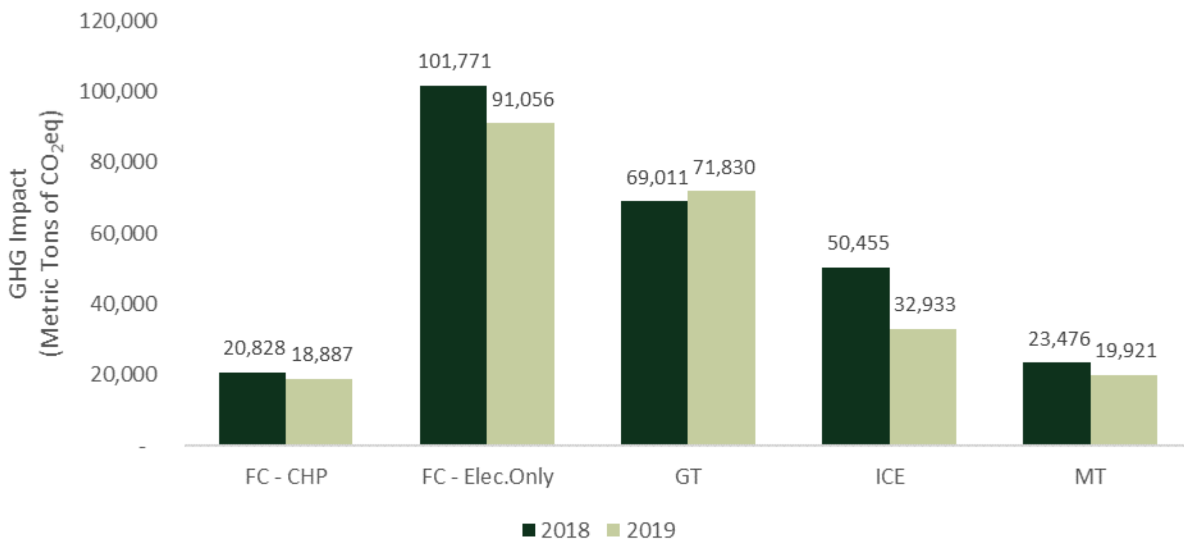
Technology Type	Metric Tons of CO_2 per MWh						Annual Energy Generation [MWh]
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Cooling Services (D)	Total Avoided Emissions (E = B+C+D)	Emissions Impact (F = A-E)	
FC-CHP	0.46	0.24	0.05	0.00	0.29	0.17	125,718
FC-Elec.	0.36	0.25	-	-	0.25	0.11	926,951
GT	0.56	0.24	0.14	0.01	0.39	0.18	392,969
ICE	0.62	0.25	0.09	0.01	0.35	0.27	190,137
MT	0.72	0.25	0.11	0.01	0.36	0.36	64,605

TABLE 5-2: NON-RENEWABLE GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE (2019)

Technology Type	Metric Tons of CO_2 per MWh						Annual Energy Generation [MWh]
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Cooling Services (D)	Total Avoided Emissions (E = B+C+D)	Emissions Impact (F = A-E)	
FC-CHP	0.48	0.26	0.04	0.00	0.30	0.18	106,668
FC-Elec.	0.36	0.26	-	-	0.26	0.10	874,906
GT	0.56	0.26	0.11	0.01	0.37	0.19	380,969
ICE	0.54	0.26	0.09	0.01	0.35	0.18	180,789
MT	0.68	0.26	0.11	0.01	0.37	0.31	63,885

The overall impacts can be found by multiplying the annual electric generation by the impact rates for each technology, as shown below in Figure 5-4. Although microturbines demonstrated the highest emissions rates, their lower contribution to annual generation meant that the impacts of their GHG emissions were not as high as other technologies. Non-renewable electric-only fuel cells demonstrated the largest increase in GHG emissions across all technologies, increasing the GHG impact by 91 to 102 thousand metric tons of CO_2 in 2018 and 2019.

FIGURE 5-4: NON-RENEWABLE GREENHOUSE GAS IMPACT BY TECHNOLOGY TYPE



5.3 RENEWABLE BIOGAS PROJECT IMPACTS

SGIP renewable biogas projects include CHP fuel cells, electric-only fuel cells, microturbines, and internal combustion engines. About 16 percent of the total SGIP rebated capacity is fueled, at least partially, by renewable biogas. Sources of biogas include landfills, wastewater treatment plants (WWTP), dairies, and food processing facilities. Analysis of the emission impacts associated with renewable biogas SGIP projects is more complex than for non-renewable projects. This complexity is due in part to the additional baseline component associated with biogas collection and treatment in the absence of the SGIP project installation. Also, some projects generate only electricity while others are CHP projects that use waste heat to meet site heating and cooling loads. Consequently, renewable biogas projects can directly impact emissions the same way that non-renewable projects can, but they also include emission impacts caused by the treatment of the biogas in the absence of the program.

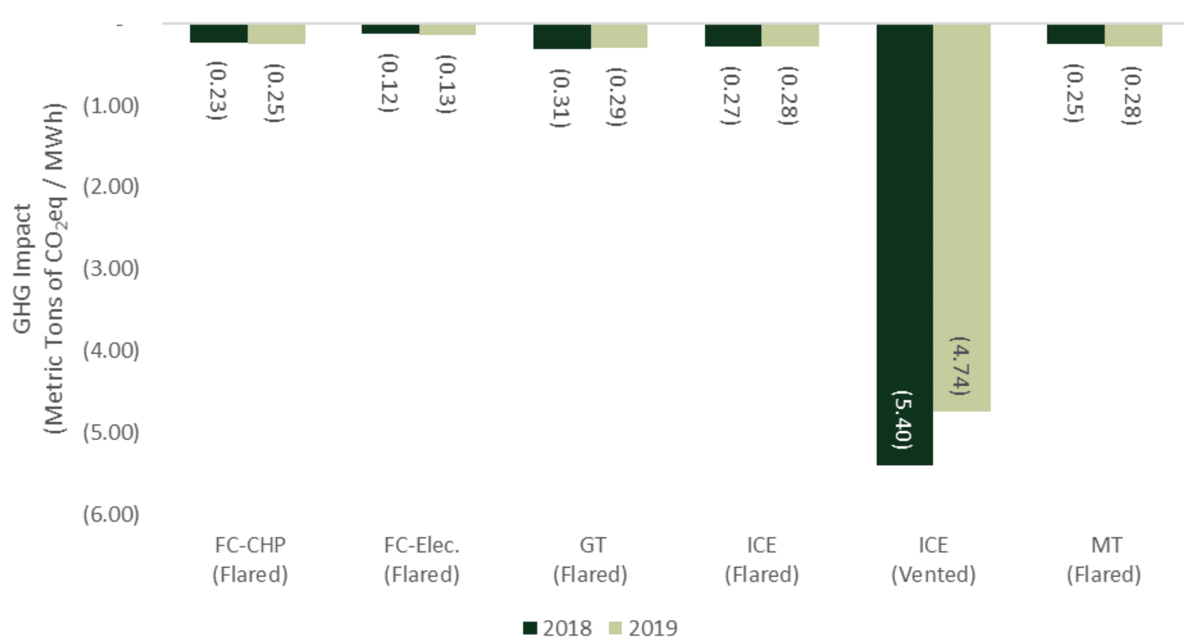
Renewable biogas SGIP projects capture and use biogas that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained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

5.3.1 Renewable Biogas Project Greenhouse Gas Impacts

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of metric tons of CO_2 equivalent (CO_2eq) so that direct comparisons can be made across technologies and energy sources. On a per mass unit basis, the global warming potential of CH_4 is 25 times that of CO_2. The biogas baseline estimates of vented emissions (CH_4 emissions from renewable SGIP facilities) are converted to CO_2eq by multiplying the metric tons of CH_4 by 25. In this section, CO_2eq emissions are reported if projects with a biogas venting baseline are included, otherwise; CO_2 emissions are reported.

The annual GHG performance of renewable biogas SGIP projects is summarized below in Figure 5-5 by technology type and biogas baseline. CHP fuel cells, electric-only fuel cells, IC engines, and microturbines are all deployed in locations that would have otherwise flared biogas. Internal combustion engines were the only technology deployed at locations, such as dairies, which would have otherwise vented biogas.

FIGURE 5-5: RENEWABLE BIOGAS GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY AND BIOGAS BASELINE TYPE (2018 AND 2019)



All renewable biogas technologies reduced GHG emissions regardless of the biogas baseline type. Technologies with flaring biogas achieved reductions between 0.13 and 0.31 metric tons of CO_2 per MWh. Internal combustion engines with vented biogas baselines achieved GHG reductions that were an over of magnitude greater, between 4.7 and 5.4 metric tons of CO_2eq per MWh. The individual components contributing to renewable emissions impacts for each technology and biogas baseline are listed in Table 5-3 and Table 5-4 for 2018 and 2019 respectively.

TABLE 5-3: RENEWABLE GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE (2018)

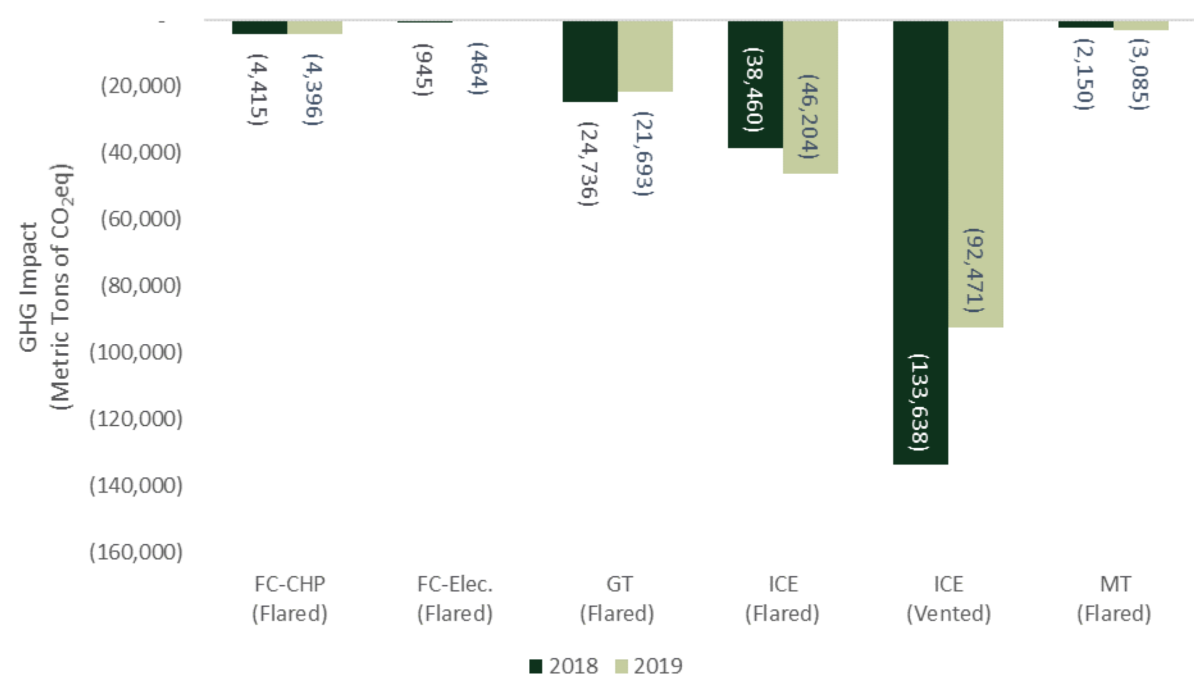
Technology Type	Metric Tons of CO_2eq per MWh						Annual Energy Generation [MWh]
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Biogas Treatment (D)	Total Avoided Emissions (E = B+C+D)	Emissions Impact (F = A-E)	
FC-CHP (Flared)	0.46	0.23	0.08	0.38	0.69	(0.23)	19,566
FC-Elec. (Flared)	0.36	0.25	-	0.22	0.48	(0.12)	8,012
GT (Flared)	0.56	0.20	0.21	0.46	0.87	(0.31)	79,103
ICE (Flared)	0.62	0.26	0.13	0.51	0.89	(0.27)	140,128
ICE (Vented)	0.62	0.27	0.14	5.60	6.02	(5.40)	24,751
MT (Flared)	0.72	0.25	0.13	0.59	0.97	(0.25)	8,773

TABLE 5-4: RENEWABLE GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE (2019)

Technology Type	Metric Tons of CO_2eq per MWh						Annual Energy Generation [MWh]
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Biogas Treatment (D)	Total Avoided Emissions (E = B+C+D)	Emissions Impact (F = A-E)	
FC-CHP (Flared)	0.48	0.25	0.09	0.40	0.73	(0.25)	17,465
FC-Elec. (Flared)	0.36	0.27	-	0.22	0.50	(0.13)	3,467
GT (Flared)	0.56	0.23	0.16	0.46	0.85	(0.29)	74,832
ICE (Flared)	0.54	0.26	0.11	0.44	0.82	(0.28)	165,049
ICE (Vented)	0.54	0.26	0.14	4.88	5.28	(4.74)	19,500
MT (Flared)	0.68	0.26	0.15	0.56	0.96	(0.28)	10,881

The total CO_2eq impact of renewable biogas projects is shown in Figure 5-6. Over thirty percent of the total 2018 and 2019 GHG impact for renewable CHP fuel cells came from directed biogas projects. All renewable electric-only fuel cell GHG impacts were from directed biogas projects.

FIGURE 5-6: RENEWABLE BIOGAS GREENHOUSE GAS IMPACT BY TECHNOLOGY AND BIOGAS BASELINE TYPE (2018 AND 2019)



5.4 WASTE GAS, WIND, AND PRESSURE REDUCTION TURBINE PROJECT IMPACTS

Wind and pressure reduction turbine projects (PRT) do not consume any type of fuel and do not recover waste heat. Their emissions reduction rates (both for CO_2 and criteria pollutants) are equal to the emissions rate of the grid, as described in Appendix C. As discussed in Section 2, there is a single Microturbine that utilizes waste gas to generate electricity. While this is not a renewable fuel type, we characterized this as "Other" to demonstrate the impact of using this fuel type. The individual components contributing to waste gas, wind, and PRT GHG emissions are shown below in Table 5-5 and Table 5-6.

TABLE 5-5: WIND AND PRESSURE REDUCTION TURBINE GREENHOUSE GAS IMPACTS (2016)

Technology Type	Metric Tons of CO_2 per MWh				Annual Energy Impact [MWh]
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Total Avoided Emissions (C=B)	Emissions Impact (D = A-C)	
MT	0.72	0.23	0.23	0.49	6,361
PRT	-	0.24	0.24	(0.24)	11,939
WD	-	0.26	0.26	(0.26)	77,511

TABLE 5-6: WIND AND PRESSURE REDUCTION TURBINE GREENHOUSE GAS IMPACTS (2017)

Technology Type	Metric Tons of CO2 per MWh				Annual Energy Impact [MWh]
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Total Avoided Emissions (C=B)	Emissions Impact (D = A-C)	
MT	0.68	0.25	0.25	0.42	9,447
PRT	-	0.27	0.27	(0.27)	10,713
WD	-	0.27	0.27	(0.27)	84,043

5.5 ENERGY STORAGE PROJECT IMPACTS

This section summarizes the environmental impacts associated with energy storage systems. We examine how the behavior of the systems led to an overall increase or decrease in GHG emissions throughout 2018 and 2019. The GHG considered in this analysis is CO_2, as this is the primary contributor to GHG emissions that are potentially affected by the operation of SGIP storage systems.

Fifteen-minute GHG impacts were calculated for each SGIP energy storage system as the difference between the grid power plant emissions for observed system operations and the emissions for the baseline conditions. Baseline emissions are those that would have occurred in the absence of the storage system. Facility loads are identical for baseline and SGIP conditions. What varies is the timing and quantity of grid power plant electricity required to maintain a balance between facility loads and electrical supply in response to storage charging and discharging.

Energy storage technologies are not perfectly efficient. Consequently, the amount of energy they discharge over any given period is always less than the amount of energy required to charge the system. In other words, over a year, these technologies will increase the energy consumption of a customer's home or facility relative to the baseline condition without the storage system.

The 15-minute energy impact of each system is equal to the charge or discharge that occurred during that interval. The energy impact during each 15-minute interval is then multiplied by the marginal emission rate for that interval (kilograms CO_2 / kWh) to arrive at a 15-minute emission impact. Emissions generally increase during storage charge and decrease during storage discharge. A system's annual GHG impact is the sum of the 15-minute emissions.

For energy storage systems to reduce emissions, the emissions *avoided* during storage discharge must be greater than the emission increases during storage charging. Since energy storage technologies inherently consume more energy during charging relative to energy discharged, the marginal emissions rate must be lower during charging hours relative to discharge hours. In other words, SGIP storage systems must charge during “cleaner” grid hours and discharge during “dirtier” grid hours to achieve GHG reductions.

Greenhouse gas impacts for nonresidential systems are positive in 2018 and 2019, reflecting increased emissions. The magnitude and the sign of greenhouse gas impacts are dependent on the timing of storage charging and discharging. The residential sector, however, contributed to a decrease in GHG emissions throughout 2018 and 2019. This was largely an effect of charging systems from on-site PV generation in morning hours when marginal emissions were lower than afternoon and evening hours. Systems were either trying to maintain zero net loads during these higher marginal emission hours or responding to TOU price signals. The GHG impacts for each year are presented below in Table 5-7.

TABLE 5-7: GREENHOUSE GAS IMPACTS (2018 AND 2019)

Customer Sector	2018		2019	
	N	Population Impact (MT CO_2)	N	Population Impact (MT CO_2)
Nonresidential	539	1,517	813	1,358
Residential	3,242	-69	7,647	-799
Total	**3,781**	**1,448**	**8,460**	**559**

In 2019, residential systems decreased GHG emissions by 8.1 kilograms for each kWh of capacity and nonresidential systems increased emissions by roughly 3.9 kilograms for each kWh of capacity. In the 2018 evaluation, we found residential systems decreased emissions by roughly 3.6 kg/kWh and nonresidential systems increased emissions by roughly 16 kg/kWh. Both sectors realized a significant improvement from the 2018 evaluation, even though the nonresidential systems still increased net emissions overall.

APPENDIX A PROGRAM STATISTICS

This appendix provides detailed Self-Generation Incentive Program (SGIP) statistics beyond the tables and figures included in Section 2.

A.1 PROGRAM STATISTICS

At the end of 2019, the SGIP had paid incentives to 9,860 projects representing 718 MW of rebated capacity. Table A-1 shows this counts and rebated capacities of all completed projects by program administrator (PA). PG&E made up 39% of all completed rebated capacity installed through the SGIP, followed by SCE at 28%, SCG and 21%, and CSE at 13%.

TABLE A-8: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR

Program Administrator	Project Count	Rebated Capacity [MW]	Percent of Rebated Capacity
CSE	2,084	92	13%
PG&E	3,755	278	39%
SCE	3,371	198	28%
SCG	650	150	21%
Total	**9,860**	**718**	**100%**

The variety of technology types receiving incentives are shown below in Table A-2.

TABLE A-9: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY TECHNOLOGY TYPE

Technology Type	Project Count	Average Capacity [kW]	Total Rebated Capacity [MW]	Percent of Rebated Capacity
Energy Storage	8,895	21	187	26%
Fuel Cell - CHP	127	340	43	6%
Fuel Cell - Electric Only	321	409	131	18%
Gas Turbine	15	4,625	69	10%
Internal Combustion Engine	300	684	205	29%
Microturbine	160	239	38	5%
Pressure Reduction Turbine	9	429	4	1%
Wind	32	1,233	39	5%
Waste Heat to Power	1	125	<1	<1%
Total	**9,860**	**73**	**718**	**100%**

One focus in this evaluation has been to separate out the differences between those projects taking a performance-based incentive (PBI) payment and those without. The breakout of project counts and rebated capacities of completed projects by technology and incentive payment mechanism are shown below in Table A-3.

TABLE A-10: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY PBI VS. NON-PBI

Technology Type	PBI		Non-PBI	
	Rebated Capacity [MW]	Count of Projects	Rebated Capacity [MW]	Count of Projects
ES	130	460	57	8,435
FC-CHP	9	10	34	117
FC-Elec.	90	231	41	90
GT	39	6	30	9
ICE	49	44	156	256
MT	13	17	26	143
PRT	4	9	-	-
WD	26	14	14	18
WHP	<1	1	-	-
Total	**360**	**792**	**358**	**9,068**

SGIP projects are fueled by a variety of renewable and non-renewable energy sources. The majority of SGIP projects are powered by non-renewable fuels such as natural gas. On-site biogas projects typically use biogas derived from landfills or anaerobic digestion processes that convert biological matter to a renewable fuel source. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert wastes from these facilities to biogas. Directed biogas projects purchase biogas fuel that is produced at a location other than the project site. The 'Other' energy source group includes energy storage, wind turbine, waste heat to power, and pressure reduction turbine projects. These are displayed in Table A-4.

TABLE A-11: COMPLETED PROJECT COUNT AND REBATED CAPACITY BY TECHNOLOGY TYPE AND ENERGY SOURCE

Technology Type	Energy Source	Total Rebated Capacity [MW]	Count of Projects	Percent of Rebated Capacity
ES	Other	187	8,895	26%
FC-CHP	Non-Renewable	22	104	3%
	On-site Biogas	14	17	2%
	Directed Biogas	7	6	1%
FC-Elec.	Non-Renewable	107	263	15%
	Directed Biogas	25	58	3%
GT	Non-Renewable	58	14	8%
	On-site Biogas	11	1	2%
ICE	Non-Renewable	160	245	22%
	On-site Biogas	46	55	6%
MT	Non-Renewable	29	126	4%
	On-site Biogas	7	32	1%
	Other	2	2	0%
PRT	Other	4	9	1%
WD	Other	39	32	5%
WHP	Other	0	1	0%
Total		**718**	**9,860**	**100%**

Combined heat and power (CHP) projects can recover useful heat to serve heating loads such as process hot water or cooling loads by use of an absorption chiller. The useful heat end use has important implications for natural gas distribution impacts and consequently greenhouse gas emissions impacts. Table A-5 summarizes the useful heat end uses observed in the SGIP.

TABLE A-12: PROJECT COUNTS AND REBATED CAPACITIES FOR PROJECTS WITH USEFUL HEAT RECOVERY BY USEFUL HEAT END USE (2019)

Useful Heat End Use	Project Count	Rebated Capacity [MW]	Percent of Rebated Capacity
Cooling Only	32	36	14%
Heating Only	223	162	61%
Heating and Cooling	64	67	25%
Total	**319**	**265**	**100%**

* Technologies excluded from total capacity include energy storage, pressure reduction turbines, wind turbines, and other generation technologies exempt from heat recovery requirements.

By the end of 2019, the SGIP paid or reserved $980 million in incentives. Eligible costs reported by applicants surpassed $3.5 billion. Table A-6 shows the breakdown of incentives paid by the SGIP and costs reported by applicants for each technology type. The leverage ratio, calculated as the ratio of SGIP participant investment to SGIP incentives, is one financial measure of the SGIP's effectiveness in accelerating development of markets for distributed energy resources.

TABLE A-13: INCENTIVES PAID, REPORTED COSTS, AND LEVERAGE RATIO BY TECHNOLOGY TYPE

Technology Type	Rebated Capacity [MW]	SGIP Incentive [Nominal $MM]	Eligible Costs [Nominal $MM]	Leverage Ratio
ES	187	$233	$510	1.18
FC-CHP	43	$126	$329	1.62
FC-Elec.	131	$381	$1,509	2.96
GT	69	$15	$322	20.59
ICE	205	$149	$566	2.79
MT	38	$33	$143	3.40
PRT	4	$3	$20	4.85
WD	39	$40	$146	2.67
Total	**718**	**$980**	**$3,546**	**2.62**

SGIP projects are electrically interconnected to load serving entities that are either investor owned (IOU) or municipal utilities. Table A-7 shows each PA's rebated capacity by electric utility type and technology type. Over 70 percent of rebated capacity was interconnected to investor owned electric utilities.

TABLE A-14: REBATED CAPACITIES OF SGIP PROJECTS BY ELECTRIC UTILITY TYPE, PROGRAM ADMINISTRATOR, AND TECHNOLOGY TYPE

Program Administrator	Electric Utility Type	AES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
CSE	IOU	9	10	11	18	13	2	1	1	-	65
	Municipal	27	-	<1	-	-	-	-	-	-	27
PG&E	IOU	21	13	62	15	85	16	1	19	<1	234
	Municipal	32	-	2	-	7	-	-	3	-	45
SCE	IOU	19	7	33	-	43	9	1	17	-	129
	Municipal	69	-	-	-	-	-	-	-	-	69
SCG	IOU	1	6	1	20	54	7	-	-	-	91
	Municipal	9	6	22	15	3	3	-	-	-	59
Total		**187**	**43**	**131**	**69**	**205**	**38**	**4**	**39**	**<1**	**718**

A.2 PROGRAM STATISTICS TRENDS

The date a project is operational is used to determine when a project's normal operations and begins to accrue impacts. Table A-8 and Table A-9 display the project counts and capacities by technology type and upfront payment year. Table A-8 shows the annual counts and capacities while Table A-9 shows cumulative counts and capacities.

TABLE A-15: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND YEAR OF OPERATION

Year of Operation	Metric	ES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
2001	Count	-	-	-	-	2	1	-	-	-	**3**
	Capacity [MW]	-	-	-	-	1	<1	-	-	-	**1**
2002	Count	-	1	-	-	19	14	-	-	-	**34**
	Capacity [MW]	-	<1	-	-	12	2	-	-	-	**14**
2003	Count	-	-	-	-	53	27	-	-	-	**80**
	Capacity [MW]	-	-	-	-	41	4	-	-	-	**45**
2004	Count	-	1	-	1	51	22	-	1	-	**76**
	Capacity [MW]	-	<1	-	1	29	3	-	1	-	**35**
2005	Count	-	4	-	3	48	26	-	1	-	**82**
	Capacity [MW]	-	3	-	7	25	5	-	<1	-	**40**
2006	Count	-	7	-	1	26	25	-	-	-	**59**
	Capacity [MW]	-	4	-	5	16	4	-	-	-	**29**
2007	Count	-	4	-	1	25	12	-	-	-	**42**
	Capacity [MW]	-	2	-	5	16	2	-	-	-	**24**
2008	Count	-	3	1	2	8	8	-	-	-	**22**
	Capacity [MW]	-	2	<1	8	7	2	-	-	-	**20**
2009	Count	-	3	1	-	8	3	-	3	-	**18**
	Capacity [MW]	-	2	<1	-	2	2	-	1	-	**7**
2010	Count	-	27	14	-	12	2	-	3	-	**58**
	Capacity [MW]	-	2	7	-	6	<1	-	2	-	**17**
2011	Count	1	52	43	1	4	1	-	4	-	**106**
	Capacity [MW]	1	5	17	4	2	<1	-	5	-	**35**
2012	Count	2	10	41	-	-	3	-	7	-	**63**
	Capacity [MW]	1	11	23	-	-	1	-	14	-	**50**
2013	Count	13	4	35	1	2	2	1	2	-	**60**
	Capacity [MW]	1	3	16	5	5	1	1	2	-	**34**
2014	Count	47	3	16	1	7	4	-	1	-	**79**
	Capacity [MW]	2	0	11	11	6	4	-	1	-	**35**
2015	Count	281	4	69	1	14	-	1	3	-	**373**
	Capacity [MW]	17	4	26	4	14	-	1	4	-	**80**
2016	Count	370	2	56	1	4	2	3	-	-	**438**
	Capacity [MW]	27	2	15	4	5	2	1	-	-	**56**
2017	Count	113	2	44	-	11	6	3	4	1	**184**
	Capacity [MW]	19	2	16	-	12	5	1	4	<1	**59**
2018	Count	2,984	-	1	2	5	2	1	2	-	**2,997**
	Capacity [MW]	44	-	<1	15	6	<1	<1	4	-	**69**
2019	Count	5,084	-	-	-	1	-	-	1	-	**5,086**
	Capacity [MW]	76	-	-	-	<1	-	-	2	-	**78**
Total	**Count**	**8,895**	**127**	**321**	**15**	**300**	**160**	**9**	**32**	**1**	**9,860**
	Capacity [MW]	**187**	**43**	**131**	**69**	**205**	**38**	**4**	**40**	**<1**	**718**

TABLE A-16: CUMULATIVE PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND UPFRONT PAYMENT YEAR

Year of Operation	Metric	ES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
2001	Count	-	-	-	-	2	1	-	-	-	**3**
	Capacity [MW]	-	-	-	-	1	<1	-	-	-	**1**
2002	Count	-	1	-	-	21	15	-	-	-	**37**
	Capacity [MW]	-	<1	-	-	12	2	-	-	-	**15**
2003	Count	-	1	-	-	74	42	-	-	-	**117**
	Capacity [MW]	-	<1	-	-	54	6	-	-	-	**60**
2004	Count	-	2	-	1	125	64	-	1	-	**193**
	Capacity [MW]	-	1	-	1	83	9	-	1	-	**95**
2005	Count	-	6	-	4	173	90	-	2	-	**275**
	Capacity [MW]	-	4	-	9	108	14	-	2	-	**136**
2006	Count	-	13	-	5	199	115	-	2	-	**334**
	Capacity [MW]	-	8	-	13	124	18	-	2	-	**164**
2007	Count	-	17	-	6	224	127	-	2	-	**376**
	Capacity [MW]	-	10	-	18	139	20	-	2	-	**189**
2008	Count	-	20	1	8	232	135	-	2	-	**398**
	Capacity [MW]	-	12	<1	26	146	22	-	2	-	**208**
2009	Count	-	23	2	8	240	138	-	5	-	**416**
	Capacity [MW]	-	14	1	26	148	24	-	3	-	**215**
2010	Count	-	50	16	8	252	140	-	8	-	**474**
	Capacity [MW]	-	16	7	26	155	24	-	5	-	**232**
2011	Count	1	102	59	9	256	141	-	12	-	**580**
	Capacity [MW]	1	21	25	30	157	25	-	9	-	**267**
2012	Count	3	112	100	9	256	144	-	19	-	**643**
	Capacity [MW]	2	32	57	30	157	26	-	23	-	**317**
2013	Count	16	116	135	10	258	146	1	21	-	**703**
	Capacity [MW]	3	35	64	35	162	27	1	25	-	**350**
2014	Count	63	119	151	11	265	150	1	22	-	**782**
	Capacity [MW]	5	35	74	46	168	32	1	26	-	**385**
2015	Count	344	123	220	12	279	150	2	25	-	**1,155**
	Capacity [MW]	21	39	100	50	182	32	2	30	-	**456**
2016	Count	714	125	276	13	283	152	5	25	-	**1,593**
	Capacity [MW]	48	41	115	55	187	33	3	30	-	**512**
2017	Count	827	127	320	13	294	158	8	29	1	**1,777**
	Capacity [MW]	67	43	131	55	199	38	4	34	<1	**571**
2018	Count	3,811	127	321	15	299	160	9	31	1	**4,774**
	Capacity [MW]	111	43	131	69	205	38	4	38	<1	**640**
2019	Count	8,895	127	321	15	300	160	9	32	1	**9,860**
	Capacity [MW]	187	43	131	69	205	38	4	38	<1	**718**

A project's program year is used to determine what program rules and policies are applicable to it. Table A-10 and Table A-11 list project counts and rebated capacities by program year and technology type for projects paid on or before December 31st, 2019. Table A-10 shows the annual counts and capacities while Table A-11 shows the cumulative counts and capacities.

TABLE A-17: PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND PROGRAM YEAR

Program Year	Metric	AES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
PY01	Count	-	1	-	-	27	21	-	-	-	49
	Capacity [MW]	-	<1	-	-	15	3	-	-	-	18
PY02	Count	-	1	-	1	54	17	-	-	-	73
	Capacity [MW]	-	1	-	1	37	3	-	-	-	41
PY03	Count	-	2	-	1	54	40	-	2	-	99
	Capacity [MW]	-	1	-	1	38	5	-	2	-	46
PY04	Count	-	3	-	1	49	30	-	-	-	83
	Capacity [MW]	-	2	-	1	25	6	-	-	-	34
PY05	Count	-	6	-	2	31	14	-	-	-	53
	Capacity [MW]	-	4	-	9	22	3	-	-	-	38
PY06	Count	-	7	-	3	17	13	-	-	-	40
	Capacity [MW]	-	5	-	13	11	4	-	-	-	33
PY07	Count	-	2	1	1	24	7	-	2	-	37
	Capacity [MW]	-	1	<1	4	10	2	-	1	-	18
PY08	Count	-	6	-	-	-	-	-	1	-	7
	Capacity [MW]	-	1	-	-	-	-	-	0	-	1
PY09	Count	1	18	8	-	-	-	-	3	-	30
	Capacity [MW]	1	7	3	-	-	-	-	2	-	13
PY10	Count	1	65	80	-	-	-	-	7	-	153
	Capacity [MW]	1	13	38	-	-	-	-	9	-	60
PY11	Count	26	3	20	-	5	1	-	5	-	60
	Capacity [MW]	3	1	13	-	5	1	-	11	-	33
PY12	Count	216	7	39	3	13	8	2	3	-	291
	Capacity [MW]	8	1	17	20	21	5	2	4	-	79
PY13	Count	112	2	32	1	3	2	-	2	1	155
	Capacity [MW]	7	2	19	4	2	2	-	1	<1	37
PY14	Count	415	2	87	1	13	4	4	1	-	527
	Capacity [MW]	41	3	25	4	8	2	1	1	-	84
PY15	Count	123	2	50	1	6	2	3	2	-	189
	Capacity [MW]	29	2	15	11	10	1	1	4	-	73
PY16	Count	61	-	4	-	3	1	-	-	-	69
	Capacity [MW]	8	-	2	-	2	2	-	-	-	14
PY17	Count	2,405	-	-	-	1	-	-	4	-	2,410
	Capacity [MW]	55	-	-	-	1	-	-	4	-	61
PY18	Count	4,680	-	-	-	-	-	-	-	-	4,680
	Capacity [MW]	30	-	-	-	-	-	-	-	-	30
PY19	Count	855	-	-	-	-	-	-	-	-	855
	Capacity [MW]	5	-	-	-	-	-	-	-	-	5
Total	**Count**	**8,895**	**127**	**321**	**15**	**300**	**160**	**9**	**32**	**1**	**9,860**
	Capacity [MW]	**187**	**43**	**131**	**69**	**205**	**38**	**4**	**39**	**<1**	**718**

TABLE A-18: CUMULATIVE PROJECT COUNTS AND REBATED CAPACITY BY TECHNOLOGY TYPE AND PROGRAM YEAR

Program Year	Metric	AES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
PY01	Count	-	1	-	-	27	21	-	-	-	**49**
	Capacity [MW]	-	<1	-	-	15	3	-	-	-	**18**
PY02	Count	-	2	-	1	81	38	-	-	-	**122**
	Capacity [MW]	-	1	-	1	51	6	-	-	-	**59**
PY03	Count	-	4	-	2	135	78	-	2	-	**221**
	Capacity [MW]	-	2	-	3	89	11	-	2	-	**105**
PY04	Count	-	7	-	3	184	108	-	2	-	**304**
	Capacity [MW]	-	4	-	4	113	16	-	2	-	**139**
PY05	Count	-	13	-	5	215	122	-	2	-	**357**
	Capacity [MW]	-	8	-	13	136	19	-	2	-	**177**
PY06	Count	-	20	-	8	232	135	-	2	-	**397**
	Capacity [MW]	-	13	-	26	147	24	-	2	-	**210**
PY07	Count	-	22	1	9	256	142	-	4	-	**434**
	Capacity [MW]	-	13	<1	30	156	26	-	3	-	**229**
PY08	Count	-	28	1	9	256	142	-	5	-	**441**
	Capacity [MW]	-	14	<1	30	156	26	-	3	-	**230**
PY09	Count	1	46	9	9	256	142	-	8	-	**471**
	Capacity [MW]	1	21	3	30	156	26	-	5	-	**242**
PY10	Count	2	111	89	9	256	142	-	15	-	**624**
	Capacity [MW]	2	34	41	30	156	26	-	14	-	**302**
PY11	Count	28	114	109	9	261	143	-	20	-	**684**
	Capacity [MW]	4	35	53	30	162	26	-	25	-	**336**
PY12	Count	244	121	148	12	274	151	2	23	-	**975**
	Capacity [MW]	12	36	71	50	182	32	2	29	-	**415**
PY13	Count	356	123	180	13	277	153	2	25	1	**1,130**
	Capacity [MW]	19	38	90	55	184	33	2	30	<1	**452**
PY14	Count	771	125	267	14	290	157	6	26	1	**1,657**
	Capacity [MW]	60	41	115	58	192	36	3	31	<1	**536**
PY15	Count	894	127	317	15	296	159	9	28	1	**1,846**
	Capacity [MW]	89	43	129	69	202	37	4	35	<1	**609**
PY16	Count	955	127	321	15	299	160	9	28	1	**1,915**
	Capacity [MW]	97	43	131	69	204	38	4	35	<1	**622**
PY17	Count	3,360	127	321	15	300	160	9	32	1	**4,325**
	Capacity [MW]	152	43	131	69	205	38	4	39	<1	**683**
PY18	Count	8,040	127	321	15	300	160	9	32	1	**9,005**
	Capacity [MW]	182	43	131	69	205	38	4	39	<1	**713**
PY19	Count	8,895	127	321	15	300	160	9	32	1	**9,860**
	Capacity [MW]	187	43	131	69	205	38	4	39	<1	**718**

Table A-12 lists the total incentives, eligible costs, and leverage ratio by technology type and program year.

TABLE A-19: PROJECT INCENTIVES, COSTS, AND LEVERAGE RATIO BY TECHNOLOGY TYPE AND PROGRAM YEAR

Program Year	Metric	ES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
PY01	Incentive	-	$0.50	-	-	$9.04	$2.22	-	-	-	$11.76
	Cost	-	$3.60	-	-	$30.71	$8.14	-	-	-	$42.45
	Leverage	-	6.20	-	-	2.40	2.67	-	-	-	2.61
PY02	Incentive	-	$1.50	-	$0.81	$20.67	$2.33	-	-	-	$25.31
	Cost	-	$4.26	-	$3.73	$81.12	$8.41	-	-	-	$97.53
	Leverage	-	1.84	-	3.61	2.92	2.61	-	-	-	2.85
PY03	Incentive	-	$3.38	-	$1.00	$21.54	$4.78	-	$2.63	-	$33.33
	Cost	-	$7.28	-	$4.69	$81.33	$17.41	-	$5.38	-	$116.09
	Leverage	-	1.16	-	3.69	2.78	2.64	-	1.04	-	2.48
PY04	Incentive	-	$5.58	-	$1.00	$16.86	$5.07	-	-	-	$28.51
	Cost	-	$16.97	-	$7.18	$61.53	$17.50	-	-	-	$103.19
	Leverage	-	2.04	-	6.18	2.65	2.45	-	-	-	2.62
PY05	Incentive	-	$7.89	-	$1.05	$12.13	$2.85	-	-	-	$23.92
	Cost	-	$22.46	-	$13.30	$53.58	$11.62	-	-	-	$100.96
	Leverage	-	1.85	-	11.64	3.42	3.08	-	-	-	3.22
PY06	Incentive	-	$19.46	-	$1.80	$6.96	$3.28	-	-	-	$31.50
	Cost	-	$37.43	-	$29.57	$29.78	$14.08	-	-	-	$110.86
	Leverage	-	0.92	-	15.43	3.28	3.29	-	-	-	2.52
PY07	Incentive	-	$2.00	$1.00	$0.60	$6.61	$2.02	-	$1.84	-	$14.07
	Cost	-	$4.47	$3.85	$1.38	$34.30	$7.88	-	$6.35	-	$58.24
	Leverage	-	1.24	2.85	1.30	4.19	2.90	-	2.46	-	3.14
PY08	Incentive	-	$2.78	-	-	-	-	-	$0.26	-	$3.03
	Cost	-	$5.98	-	-	-	-	-	$0.35	-	$6.33

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Program Year	Metric	ES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
	Leverage	-	1.16	-	-	-	-	-	0.34	-	1.09
PY09	Incentive	$2.00	$23.54	$11.50	-	-	-	-	$2.41	-	$39.45
	Cost	$6.49	$62.49	$30.51	-	-	-	-	$5.14	-	$104.62
	Leverage	2.25	1.65	1.65	-	-	-	-	1.14	-	1.65
PY10	Incentive	$1.20	$40.65	$159.79	-	-	-	-	$9.75	-	$211.39
	Cost	$5.17	$93.47	$390.09	-	-	-	-	$33.46	-	$522.19
	Leverage	3.30	1.30	1.44	-	-	-	-	2.43	-	1.47
PY11	Incentive	$3.93	$1.81	$34.71	-	$11.42	$0.44	-	$9.47	-	$61.78
	Cost	$6.77	$7.18	$158.96	-	$25.80	$2.83	-	$40.36	-	$241.90
	Leverage	0.72	2.96	3.58	-	1.26	5.50	-	3.26	-	2.92
PY12	Incentive	$16.50	$3.09	$46.58	$3.17	$23.30	$4.80	$1.31	$3.75	-	$102.51
	Cost	$29.30	$14.18	$204.74	$67.38	$59.39	$29.79	$4.70	$17.07	-	$426.56
	Leverage	0.78	3.58	3.40	20.27	1.55	5.21	2.58	3.55	-	3.16
PY13	Incentive	$12.51	$3.86	$46.14	$1.01	$0.72	$2.48	$-	$1.44	$0.18	$68.33
	Cost	$22.99	$17.12	$238.75	$20.73	$6.80	$7.79	$-	$5.57	$0.48	$320.23
	Leverage	0.84	3.44	4.17	19.57	8.45	2.14	-	2.87	1.70	3.69
PY14	Incentive	$73.83	$6.34	$48.69	$0.97	$12.63	$1.03	$1.24	$1.36	-	$146.08
	Cost	$139.94	$18.80	$283.27	$45.63	$45.42	$7.42	$9.51	$5.60	-	$555.59
	Leverage	0.90	1.97	4.82	45.95	2.60	6.22	6.67	3.13	-	2.80
PY15	Incentive	$46.96	$3.30	$29.06	$3.48	$2.74	$0.63	$0.88	$3.55	-	$90.61
	Cost	$99.66	$13.12	$177.25	$128.00	$31.48	$4.37	$5.90	$12.39	-	$472.18
	Leverage	1.12	2.97	5.10	35.74	10.50	5.96	5.67	2.49	-	4.21
PY16	Incentive	$10.44	-	$3.20	-	$3.43	$0.65	-	-	-	$17.72
	Cost	$23.31	-	$21.75	-	$20.63	$5.95	-	-	-	$71.64
	Leverage	1.23	-	5.81	-	5.01	8.12	-	-	-	3.04
PY17	Incentive	$43.51	-	-	-	$1.32	-	-	$3.45	-	$48.28

Program Year	Metric	ES	FC-CHP	FC-Elec.	GT	ICE	MT	PRT	WD	WHP	All Proj.
	Cost	$114.13	-	-	-	$4.53	-	-	$14.62	-	$133.28
	Leverage	1.62	-	-	-	2.44	-	-	3.23	-	1.76
PY18	Incentive	$19.61	-	-	-	-	-	-	-	-	$19.61
	Cost	$51.13	-	-	-	-	-	-	-	-	$51.13
	Leverage	1.61	-	-	-	-	-	-	-	-	1.61
PY19	Incentive	$3.00	-	-	-	-	-	-	-	-	$3.00
	Cost	$11.15	-	-	-	-	-	-	-	-	$11.15
	Leverage	2.72	-	-	-	-	-	-	-	-	2.72
Total	**Incentive**	**$233.50**	**$125.67**	**$380.67**	**$14.89**	**$149.37**	**$32.57**	**$3.44**	**$39.91**	**$0.18**	**$980.19**
	Cost	**$510.04**	**$328.82**	**$1,509.18**	**$321.60**	**$566.41**	**$143.20**	**$20.11**	**$146.27**	**$0.48**	**$3,546.11**
	Leverage	**1.18**	**1.62**	**2.96**	**20.59**	**2.79**	**3.40**	**4.85**	**2.67**	**1.70**	**2.62**

APPENDIX B ENERGY IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix provides additional detail about the metered data and the ratio estimation methodology used to quantify the energy impacts of the Self-Generation Incentive Program (SGIP) in this evaluation report. This appendix also includes generation project energy and peak demand impacts detail not shown in Section 4. The focus of this section is estimation of impacts from generation projects, however we also discuss the ratio estimation process for energy storage projects. The following key topics are discussed in this appendix:

- Estimation Methodology (Emphasis on Generation Projects)
  - Data Processing and Validation
  - Operational Status Research (OSR)
  - Ratio Estimation
- Energy Impacts
- Coincident Demand Impacts

B.1 ESTIMATION METHODOLOGY

Estimation of SGIP impacts relies on large datasets of metered electrical, fuel consumption and heat recovery. We use these data to estimate electrical generation, fuel consumption and heat recovery where we have no metered data that passes quality control validation. We multiply sums of metered impacts taken for a particular type of system over a particular period by of time by the ratio of sums of capacities without valid data to those with valid metered data. The impact estimate then is the sum of the metered and the estimated impact.

B.1.1 Data Processing and Validation

Electrical Net Generation Output (ENGO) Data

Metered ENGO data provide information on the amount of electricity generated by SGIP projects net of ancillary loads such as pumps and compressors. These data are typically kWh recorded at 15-minute intervals but sometimes are at hourly or longer intervals or are average kW over the interval.

These ENGO data are collected from a variety of sources, including meters installed in prior evaluation years under the direction of the PAs, and meters installed by project hosts, applicants, electric utilities, and third parties. Because many different meters are in use among the many different providers, these ENGO data arrive in a wide variety of data formats. Some formats require extensive processing to be associated with the correct project and put into a format common to all projects.

During processing to the common format, all ENGO data pass through a rigorous quality control review. Only data that pass the review are accepted for use in this evaluation. Key factors in the review are system capacity, unit count, and technology. Some technologies can generate farther above nameplate capacity for longer periods than other technologies. Some technologies can generate at lower capacity factor for longer periods than other technologies. In addition, some fuel cells may consume substantial electricity during standby.

Fuel Consumption Data

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

Fuel consumption data used in this impacts evaluation are obtained mostly in units of standard cubic feet or therms from natural gas metering systems installed on SGIP projects by natural gas distribution companies, SGIP participants, or by third parties. Verdant reviews fuel consumption data and documents their bases prior to processing the data into a common data format and unit of MBtu LHV.

During processing of fuel consumption data, they are merged with ENGO data for quality control reviews. The fuel data are examined for reasonableness of electrical conversion efficiency for the technology over the course of multiple hours or days. In cases where validity checks fail, data providers are contacted to further refine the basis of data, otherwise data are ignored as unrepresentative. In some cases, it is determined the data are for a host customer’s entire facility rather than from metering dedicated to the SGIP project.

Some fuel consumption data arrive already merged with ENGO data, but most fuel consumption data arrive in various formats and intervals much greater than one hour (e.g., in daily or monthly intervals). These longer interval data enable calculation of monthly and annual efficiencies but are not used to estimate performance for shorter intervals.

Useful Heat Recovery Data

Useful heat recovery is the thermal energy captured by heat recovery equipment and used to satisfy heating and/or cooling loads at the SGIP project site. Useful heat recovery data are used to assess overall efficiencies of SGIP projects and to estimate avoided baseline natural gas use. This avoided use is used in calculation of GHG emission impact estimates where it reduces net emissions.

Heat recovery data are collected from metering systems installed in prior evaluation years as well as metering systems installed by applicants, hosts, and third parties. Because many different meters are in use among the many different providers, these heat data arrive in a wide variety of data formats. Some formats require extensive processing to be associated with the correct project and put into a format common to all projects. Heat data may arrive in units of Btu or as flow with associated high and low temperatures. In the latter case, heat exchanger and fluid properties are identified in calculation of useful recovered MBtu.

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

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

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

Operational Status Research

Using a short phone survey, we collected categorical operating status data on systems for which no metered data are available and that are not already known to be permanently retired. Completed surveys allow classification of system-months as offline or online. For offline system-months, we estimated impacts using a zero-ratio estimator. For online system months, we estimated impacts using a ratio estimator developed from similar systems whose metered data indicate they were online that same month. Some surveys identify systems as being permanently retired or decommissioned. We identify a best estimate of retirement date in the survey and estimate impacts from that date forward using a zero-ratio estimator.

Operational status research is conducted only with contacts familiar with the operational status of the unmetered system. The operating status survey identifies most recently known system contacts that may include system, hosts, applicants, or former data providers. Contact information from PA system lists, inspection reports, or site visit summaries are used. When these contacts are out of date, contact information may be sought from internet sources.

Ratio Estimation

Non-AES Project Approach

An overview of the ratio estimation methodology was included in Section 3. The strata included in the ratio analysis for electricity generation values were presented in Table 3-1, and are also listed below:

1. Operational status
2. Warranty status (under corresponding handbook)
3. Technology type
4. Program incentive structure (PBI versus Non-PBI)
5. Capacity size category
6. Fuel type
7. PA

The ratio estimation methodology works well when metered data are available in each stratum. Often, lack of metered data for certain strata necessitated use of more general strata. For these estimates the criteria of matching project characteristics is relaxed. The relaxation begins with the removal of the lowest order strata characteristic from the strata definition. If fewer than five projects have metered data after strata relaxation, the strata definition is further relaxed, and the next lowest order is characteristic is removed. The relaxation cycle continues until at least five projects with data are included in the strata. All estimates include the same technology type and, in most cases, technology type and warranty status.

Energy Storage Projects Sample to Population Scaling Methodology

To scale sample data results up to the population level, the following calculation was performed to determine the weight of each individual system within the sample.

$$w_i^a = C_i^a \times \frac{\sum_{j=1}^{N_a} C_j^a}{\sum_{k=1}^{n_a} C_k^a} \qquad \textbf{EQUATION B-1}$$

Where:

w_i^a = weight of system 'i' in sample with technology type 'a'
C_x^a = capacity (in kW) of system 'x' with technology type 'a'
N_a = number of systems in population with technology type 'a'
n_a = number of systems in sample with technology type 'a'

The capacity of the system we are weighing is multiplied by the total size (in kW) of all systems within the population with the same technology type. This result is then divided by the total size (in kW) of all systems within the sample of the same technology type. This is known as kW weighting.

The population mean was then estimated as:

$$\bar{X} = \frac{\sum_{i=1}^{n} w_i x_i}{\sum_{i=1}^{n} w_i} \qquad \textbf{EQUATION B-2}$$

With standard deviation:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n} w_i (x_i - \bar{X})^2}{\sum_{i=1}^{n} w_i}} \qquad \textbf{EQUATION B-3}$$

Where:

x_i = impact for system 'i'
w_i = weight of system 'i'
n = number of systems in sample

B.2 ENERGY IMPACTS

The following tables summarize the program energy impacts for 2018 and 2019. Some figures include earlier years to demonstrate trends over time. Table B-1 displays the annual electrical energy impact and associated annual capacity factor by technology type for 2018 and 2019, while Table B-2 shows the same information by technology type and energy source.

TABLE B-20: ANNUAL ELECTRICAL GENERATION AND CAPACITY FACTOR BY YEAR AND TECHNOLOGY TYPE

Technology Type	Annual Electricity Generation [GWh]		Annual Capacity Factor	
	2018	2019	2018	2019
FC-CHP	145	124	0.39	0.33
FC-Elec.	935	878	0.81	0.76
GT	472	456	0.78	0.75
ICE	355	365	0.20	0.20
MT	80	84	0.24	0.25
PRT	12	11	0.35	0.32
WD	78	84	0.22	0.24
Total	**2,077**	**2,003**		

TABLE B-21: ANNUAL ELECTRICAL GENERATION AND CAPACITY FACTOR BY YEAR AND TECHNOLOGY TYPE

Technology Type	Energy Source	Annual Electricity Generation [GWh]		Annual Capacity Factor	
		2018	2019	2018	2019
FC-CHP	Non-Renewable	91	71	0.46	0.36
	On-site Biogas	20	17	0.17	0.15
	Directed Biogas	35	35	0.58	0.58
FC-Elec.	Non-Renewable	761	726	0.82	0.78
	Directed Biogas	174	152	0.80	0.71
GT	Non-Renewable	393	381	0.77	0.75
	On-site Biogas	79	75	0.81	0.76
ICE	Non-Renewable	190	181	0.14	0.13
	On-site Biogas	165	185	0.41	0.46
MT	Non-Renewable	65	64	0.25	0.25
	On-site Biogas	9	11	0.14	0.17
	Other	6	9	0.33	0.50
PRT	Other	12	11	0.35	0.32
WD	Other	78	84	0.22	0.24

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TABLE B-22: ANNUAL ELECTRICAL GENERATION BY TECHNOLOGY, YEAR, ENERGY SOURCE, AND PROGRAM ADMINISTRATOR

Technology Type	Energy Source	CSE		PG&E		SCE		SCG		Total	
		2018	2019	2018	2019	2018	2019	2018	2019	2018	2019
FC-CHP	Non-Renewable	20	18	45	32	9	8	18	14	91	71
	On-site Biogas	2	1	-	-	8	6	9	10	20	17
	Directed Biogas	33	33	-	-	2	2	-	-	35	35
	All	55	52	45	32	19	17	27	24	145	124
FC-Elec.	Non-Renewable	66	63	367	353	190	177	137	132	761	726
	Directed Biogas	11	10	84	72	47	41	32	29	174	152
	All	77	73	451	425	237	219	169	161	935	878
GT	Non-Renewable	126	119	105	101	-	-	162	161	393	381
	On-site Biogas	-	-	-	-	-	-	79	75	79	75
	All	126	119	105	101	-	-	241	236	472	456
ICE	Non-Renewable	2	2	101	97	19	32	68	50	190	181
	On-site Biogas	9	10	110	109	43	54	4	11	165	185
	All	11	12	211	206	62	86	72	61	355	365
MT	Non-Renewable	0	0	34	32	6	6	25	26	65	64
	On-site Biogas	1	1	4	4	3	5	1	1	9	11
	Other	-	-	1	3	6	7	-	-	6	9
	All	1	1	39	39	14	17	26	27	80	84
PRT	Other	5	4	3	4	5	3	-	-	12	11
	All	5	4	3	4	5	3	-	-	12	11
WD	Other	4	4	40	44	34	36	-	-	78	84
	All	4	4	40	44	34	36	-	-	78	84
Non-Renewable		214	202	652	614	224	223	410	384	1,500	1,423
On-site Biogas		11	13	114	114	54	65	93	96	272	288
Directed Biogas		44	43	84	72	49	43	32	29	209	188
Other		9	8	43	50	44	46	-	-	96	104
Total		**279**	**265**	**893**	**850**	**370**	**378**	**535**	**509**	**2,077**	**2,003**

B.3 DEMAND IMPACTS

Plots of IOU peak hour generation from 2003 to 2019 follow for PG&E, SCE, and SDG&E. Totals and subtotals by PBI versus non-PBI, energy source and technology type, appear in the figures below.

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FIGURE B-7: PG&E PEAK HOUR GENERATION BY CALENDAR YEAR

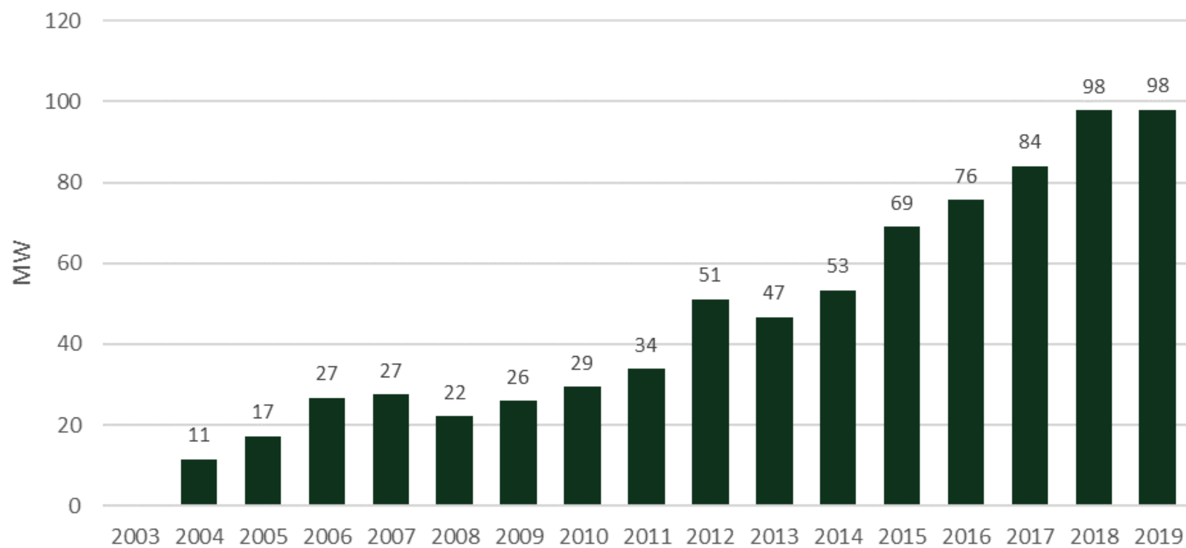


FIGURE B-8: PG&E PEAK HOUR GENERATION BY PBI VERSUS NON-PBI

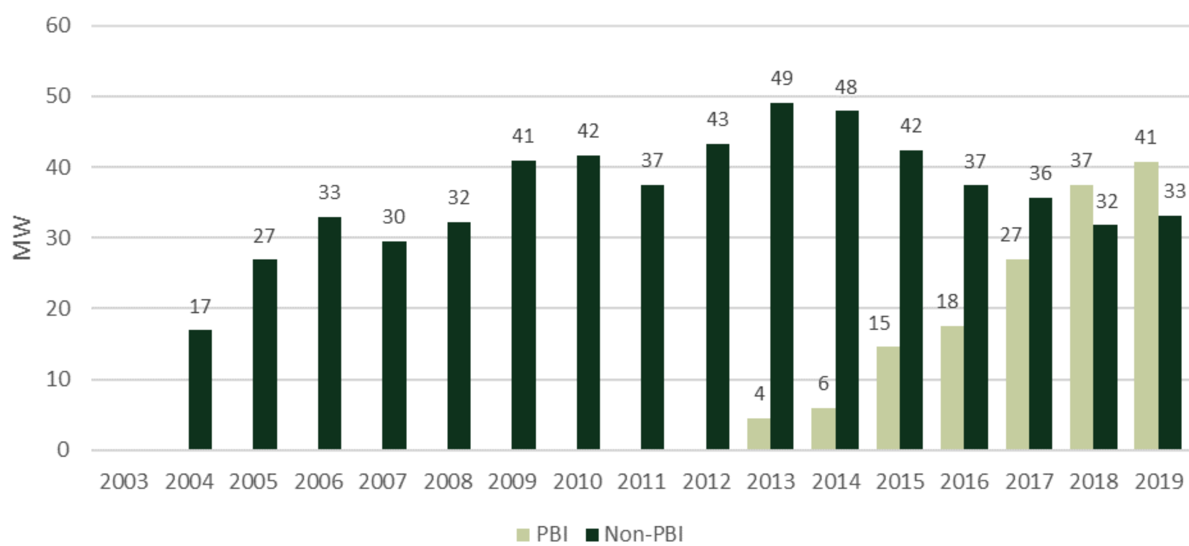


FIGURE B-9: PG&E PEAK HOUR GENERATION BY ENERGY SOURCE

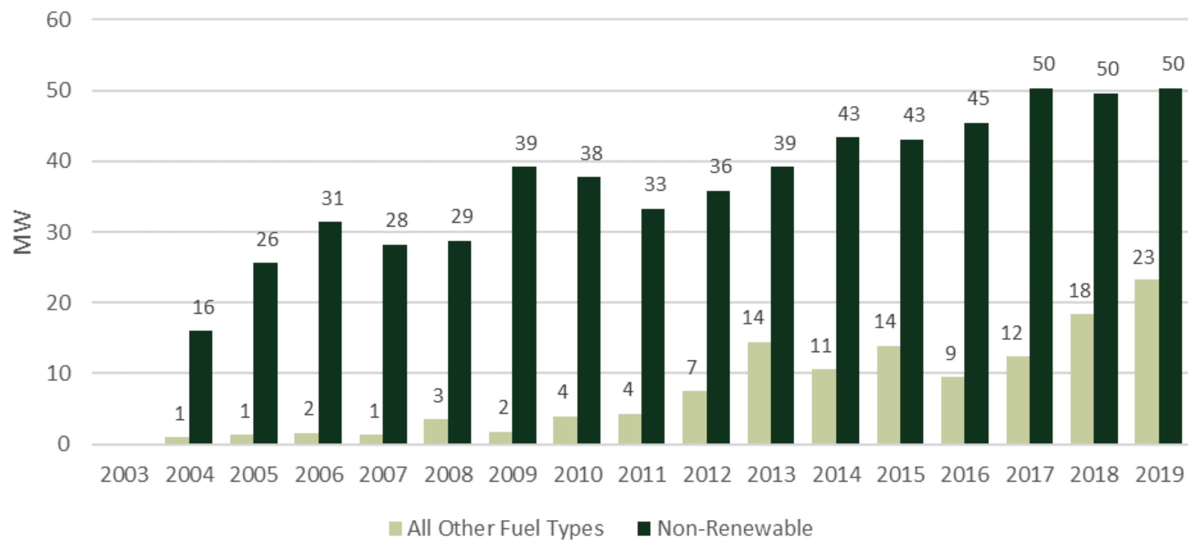


FIGURE B-10: PG&E PEAK HOUR GENERATION BY TECHNOLOGY

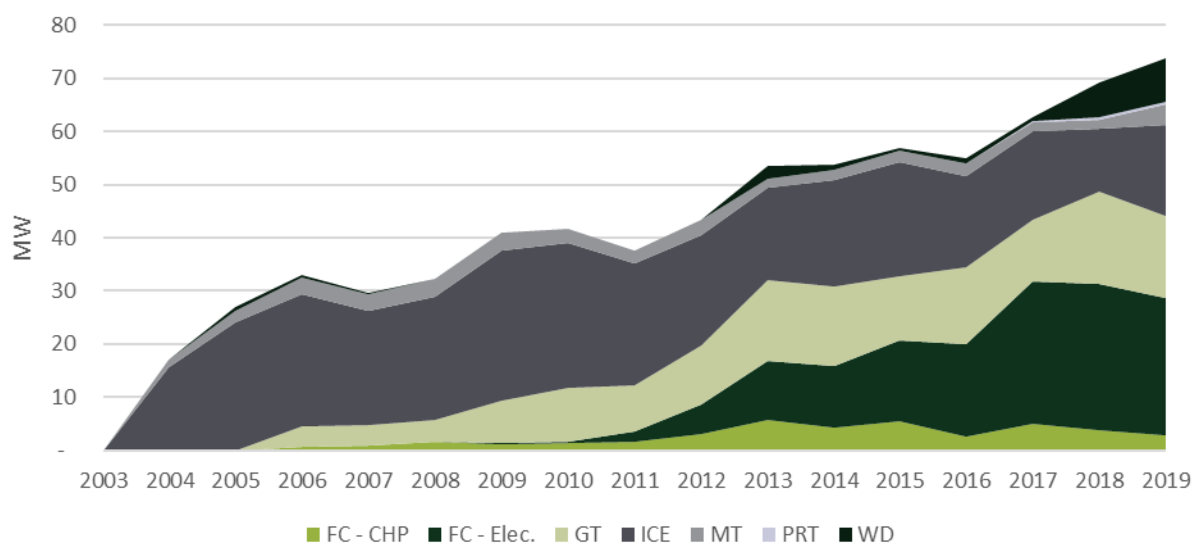


FIGURE B-11: SCE PEAK HOUR GENERATION BY CALENDAR YEAR

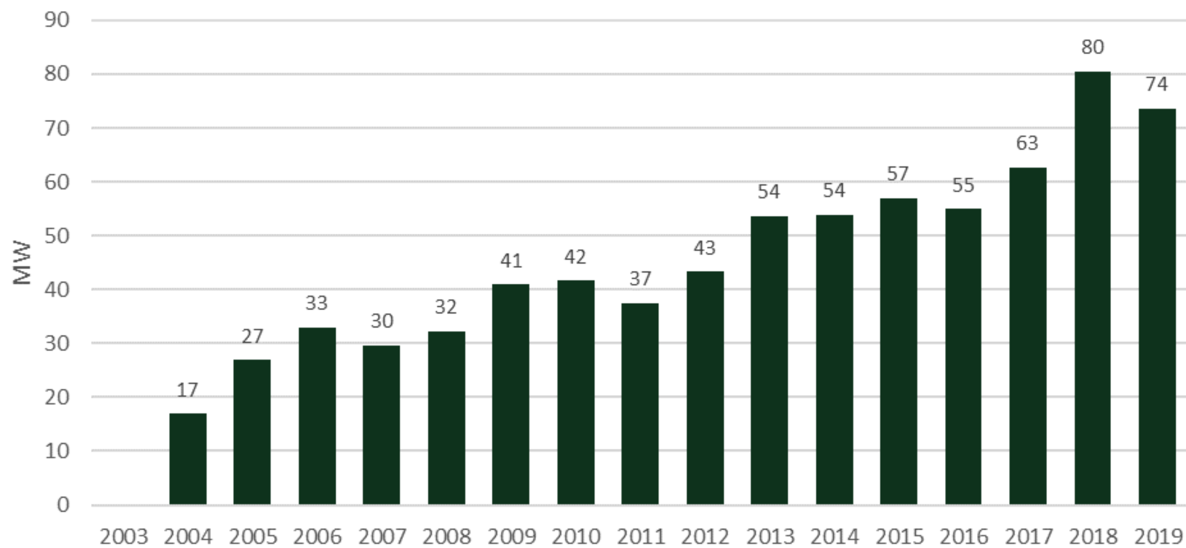


FIGURE B-12: SCE PEAK HOUR GENERATION BY PBI VERSUS NON-PBI

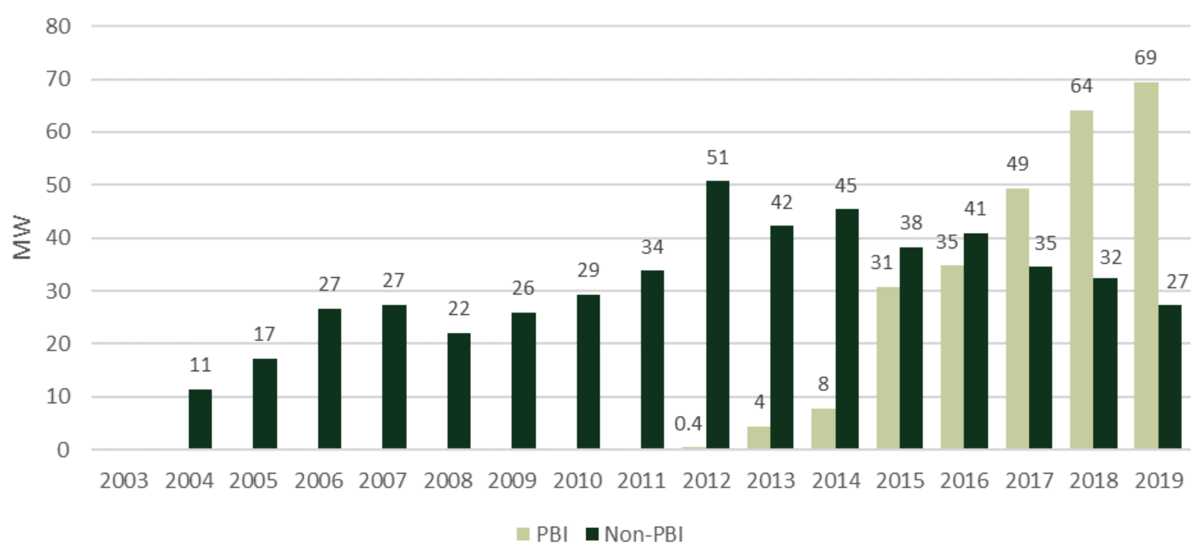


FIGURE B-13: SCE PEAK HOUR GENERATION BY ENERGY SOURCE

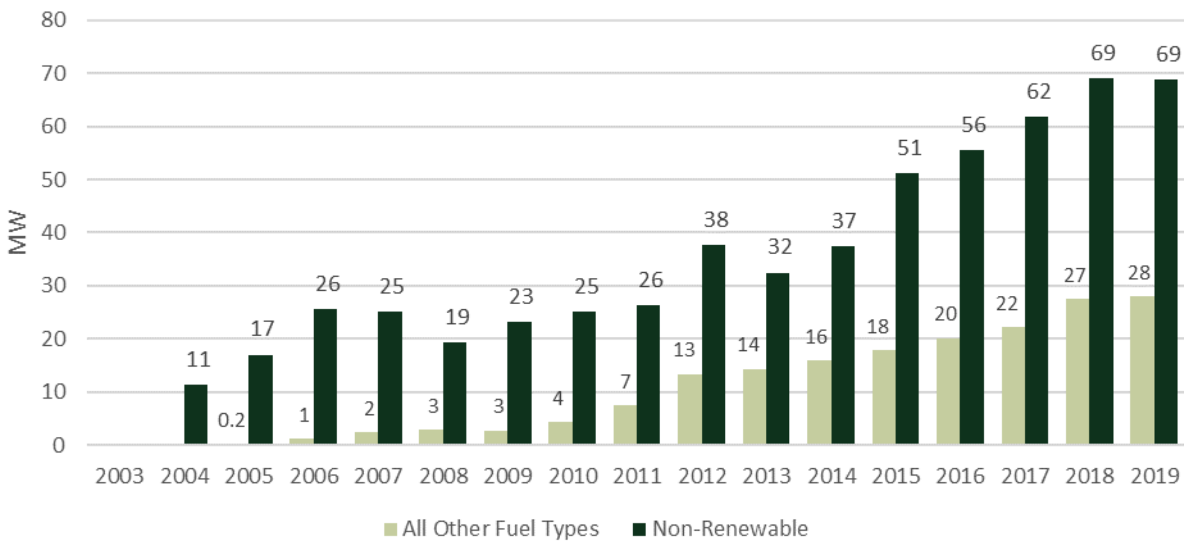


FIGURE B-14: SCE PEAK HOUR GENERATION BY TECHNOLOGY

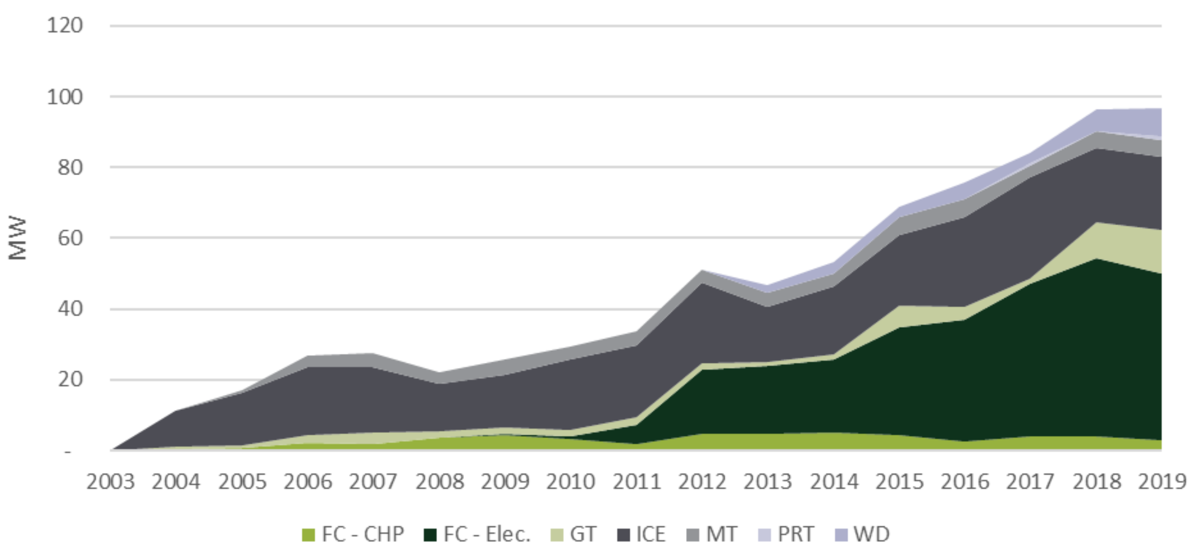


FIGURE B-15: SDG&E PEAK HOUR GENERATION BY CALENDAR YEAR

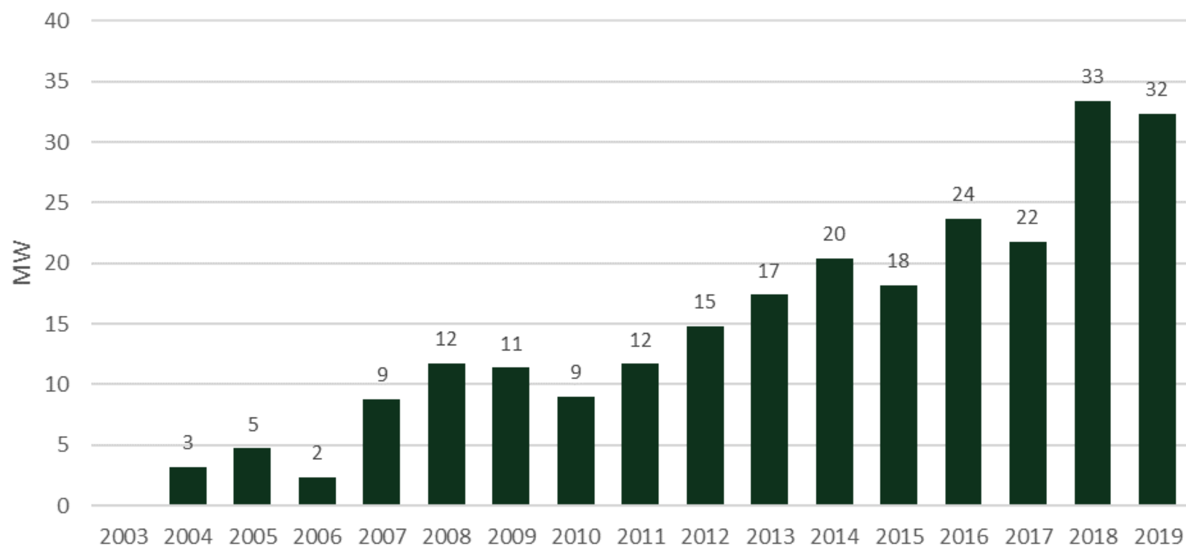


FIGURE B-16: SDG&E PEAK HOUR GENERATION BY PBI VERSUS NON-PBI

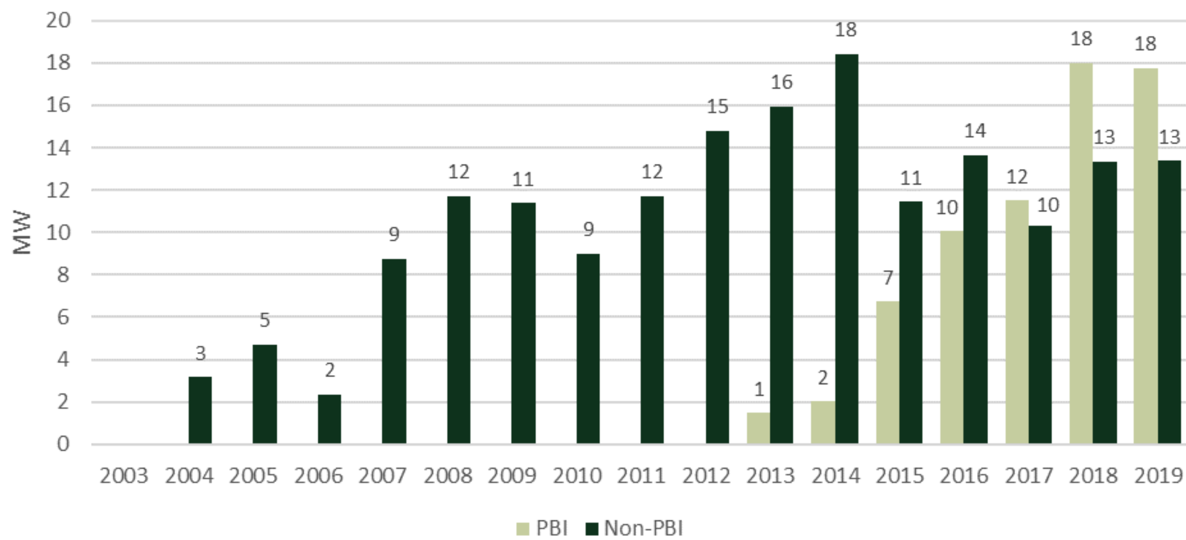


FIGURE B-17: SDG&E PEAK HOUR GENERATION BY ENERGY SOURCE

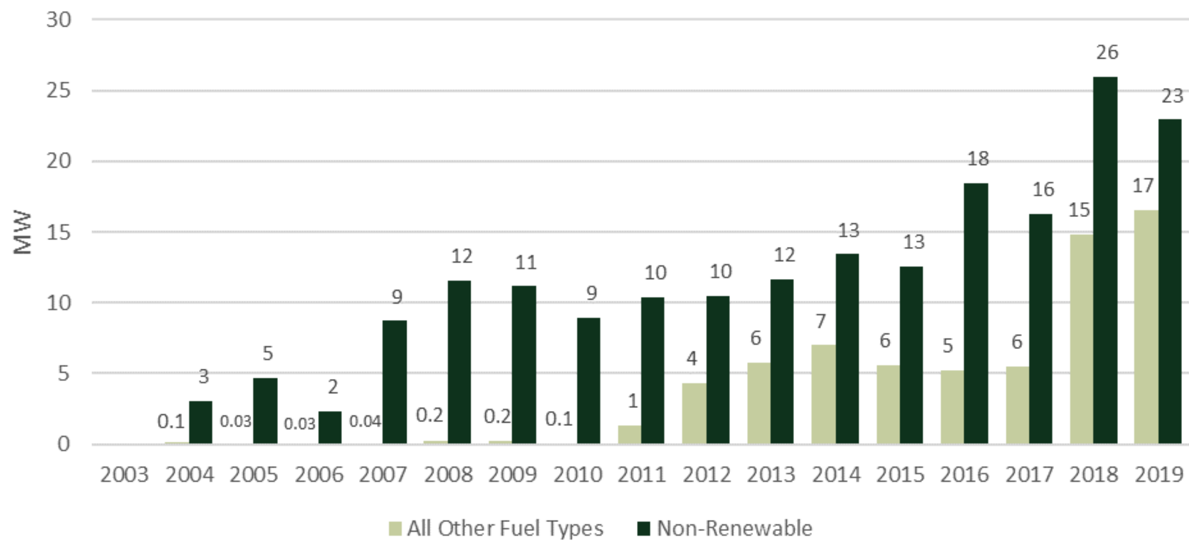
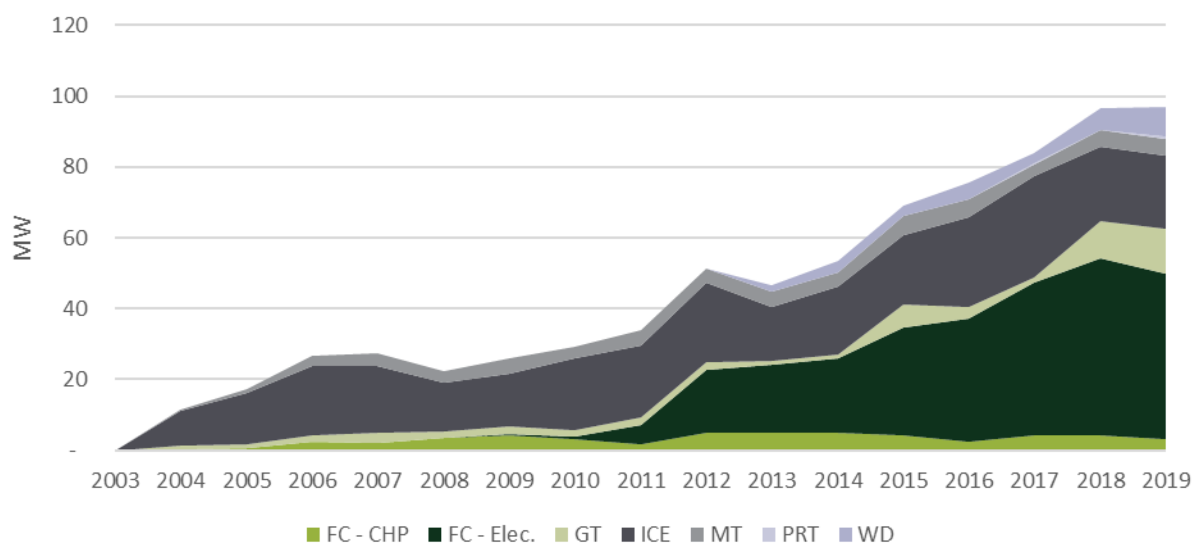


FIGURE B-18: SDG&E PEAK HOUR GENERATION BY TECHNOLOGY



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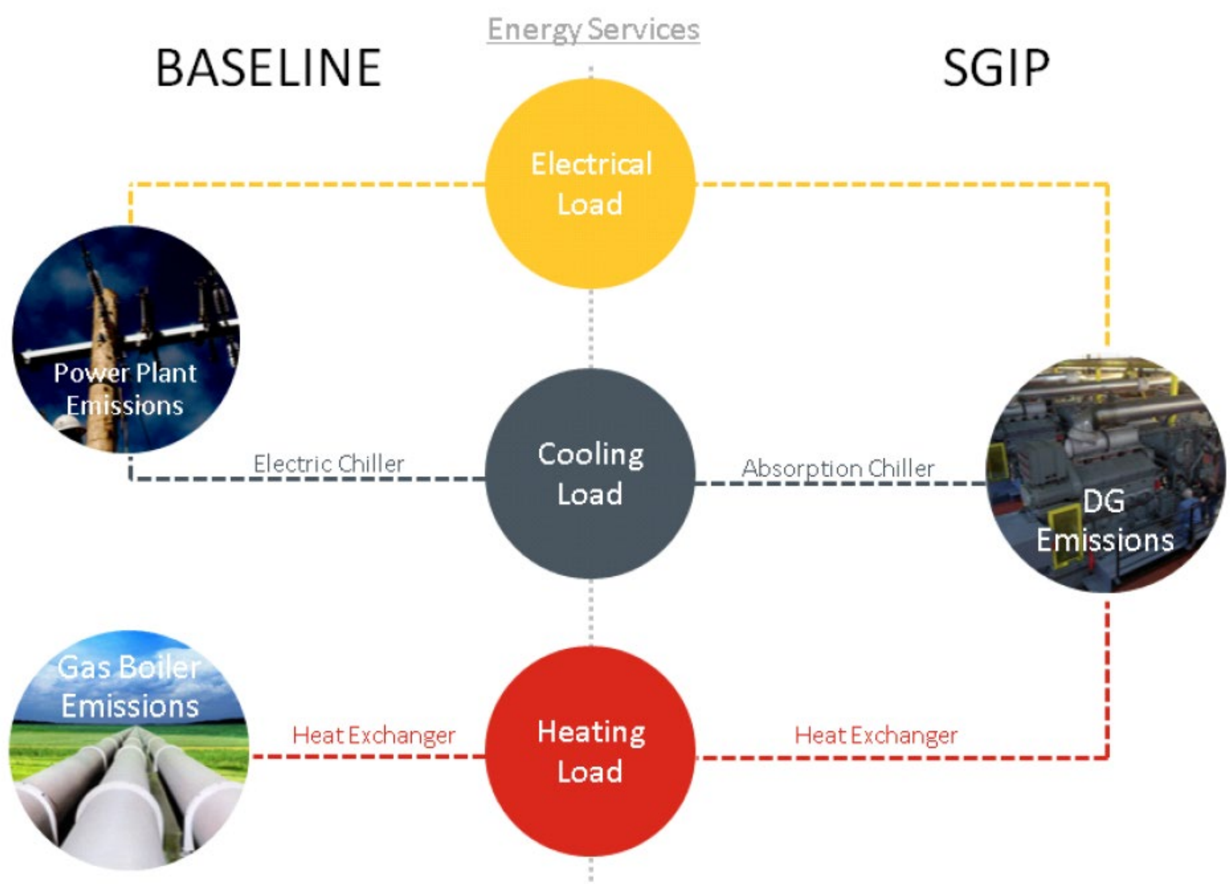
APPENDIX C GREENHOUSE GAS IMPACTS ESTIMATION METHODOLOGY AND RESULTS

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

C.1 OVERVIEW

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

FIGURE C-19: GREENHOUSE GAS IMPACTS SUMMARY SCHEMATIC



Hourly GHG impacts are calculated for each SGIP generation project as the difference between the GHG emissions produced by the rebated distributed generation (DG) project and baseline GHG emissions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP project. SGIP projects displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases.

SGIP projects powered by biogas may reduce emissions of CH_4 in cases where venting of the biogas directly to the atmosphere would have occurred in the absence of the SGIP project.

SGIP Project CO_2 Emissions (sgipGHG)

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

Electric Power Plant CO_2 Emissions (basePpENGO)

When in operation, power generated by all SGIP projects directly displaces electricity that in the absence of the SGIP would have been generated by a central station power plant to satisfy the site's electrical loads.[44] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The avoided CO_2 emissions for these baseline conventional power plants are estimated on an hour-by-hour basis over all 8,760 hours of the year.[45] The estimates of electric power plant CO_2 marginal emissions were accessed from WattTime.[46]

WattTime developed the CO_2 marginal emissions estimates utilizing the following methodology, consistent with the approach used in the CPUC Avoided Cost Calculator (ACC).[47]

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

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

46 WattTime developed real-time and forecasted marginal GHG emissions data for SGIP. https://sgipsignal.com/.

47 More information about the avoided cost calculator, along with a link to the 2020 ACC can be found on the CPUC website: https://www.cpuc.ca.gov/general.aspx?id=5267

$$Heat\ Rate\ \left[\frac{Btu}{kWh}\right] = \frac{(MP-VOM)}{GasPrice+Gas\ Delivery\ Cost+(EF\times CO_2Cost)}$$ **EQUATION C-4**

$$Marginal\ Emissions\ Rate\ \left[\frac{\$}{kWh}\right] = Heat\ Rate\ \times EF$$ **EQUATION C-5**

Where:

MP	=	Market price of electricity (including cap and trade costs) [$/MWh]
VOM	=	Variable O&M cost for a natural gas plant [$/MWh]
Gas Price	=	Cost of natural gas delivered to an electric generator [$/MMBtu]
Gas Delivery Cost	=	Cost to deliver gas to the power plant [$/MMBtu]
EF	=	Emissions factor for tons of CO_2 per MMBtu of natural gas [metric ton CO_2/MMBtu]
CO_2Cost	=	Cost of carbon in the Cap & Trade program [$/metric ton CO_2]

TABLE C-23: VALUES AND SOURCES FOR MARGINAL EMISSIONS CALCULATIONS

Input	Value	Source
MP	Average: $35.28 / MWh	CAISO OASIS for each DLAP
VOM	$2.4 / MWh	2019 ACC (workbook DA_RT HR Shapes_06.11.2019.xlsx)
Gas Price	Average: $3.34 / MMBtu	Data purchased from GTI
Gas Delivery Cost*	PGE: $1.219 / MMBtu So. Cal: $1.363 / MMBtu	2019 ACC
EF	0.0531 metric tons of CO_2 / MMBtu	2019 ACC
CO_2Cost	Average: $15.31 / metric ton of CO_2	CAISO OASIS Gas Allowance Price

* PG&E delivery cost are developed using both the PG&E Local Transmission cost and the PG&E Backbone from the 2019 ACC. The breakout between the two is referenced from the PGE 2020 General Rate Case document[48] which specifies a weight of 27.6% for the backbone cost and 72.4% for the local transmission cost.

While the approach to calculating marginal emissions has stayed consistent over the last few years, the inputs have differed since the previous evaluation cycle. In particular, one large difference has to do with the increase in gas delivery costs since 2016. The 2018 ACC referenced gas delivery costs from the 2015 CPUC Renewable Portfolio Standard (RPS) calculator.[49] In August 2016, PG&E's gas delivery local transmission costs increased almost 70% from January 2016. This increase in the gas delivery cost, which is in the denominator of the heat rate calculation, has been a large driver in decreasing the overall heat rate, and subsequently, the marginal emissions estimates used in this evaluation.

48 Pacific Gas and Electric Company 2020 General Rate Case Phase II, Prepared Testimony, Cost of Service. November 22, 2019.

49 More details about the RPS calculator can be found on the CPUC website at https://www.cpuc.ca.gov/RPS_Calculator/.

CO_2 Emissions Associated with Heating Services (baseBlr)

Recovered useful heat may displace natural gas that would have been used in the absence of the SGIP to fuel boilers to satisfy site heating loads. This displaces accompanying CO_2 emissions from the boiler's combustion process.[50]

CO_2 Emissions Associated with Cooling Services (basePpChiller)

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

CO_2 Emissions from Biogas Treatment (baseBio)

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

GHG impacts expressed in terms of CO_2 equivalent (CO_2eq)[51] were calculated by date and time (hereafter referred to as "hour") as:

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

EQUATION C-6

Where:

$\Delta GHG_{i,h}$ = the GHG impact for SGIP project *i* for hour *h* [Metric Tons CO_2eq per hour]

Negative GHG impacts (ΔGHG) indicate reduction in GHG emissions. Not all SGIP projects include all of the above variables. Inclusion is determined by the SGIP DG technology and fuel types and is discussed further in Sections C.2 and C.3. Section C.2 describes GHG emissions from SGIP projects (sgipGHG), as well as

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

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

heating and cooling services associated with combined heat and power (CHP) projects. In Section C.3, baseline GHG emissions are described in detail.

C.2 SGIP PROJECT GHG EMISSIONS (SGIPGHG)

The technology-specific emissions rates were calculated to account for CO_2 emissions from SGIP projects. SGIP projects that consume natural gas or renewable biogas emit CO_2. When multiplied by the energy generated by these projects, the results represent hourly CO_2 emissions in pounds, converted to metric tons.

SGIP emission rates SGIP projects that use natural gas fuel were calculated as:

$$sgipGHG_{i,h} = Btu \times \frac{1 ft^3 CH_4}{935\ Btu} \times \frac{1 lbmole\ CH_4}{379\ ft^3} \times \frac{1 lbmole\ CO_2}{1 lbmole\ CH_4} \times \frac{44 lbs\ CO_2}{1 lbmole\ CO_2}) \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}$$

EQUATION C-7

SGIP emission rates SGIP projects that use renewable biogas fuel were calculated as:

$$sgipGHG_{i,h} = engohr_{i,h} \times \frac{3412\ Btu}{kWh} \times \left(\frac{1}{EFF_T}\right) \times \frac{1 lbmole\ CH_4}{379\ ft^3} \times \frac{1 lbmole\ CO_2}{1 lbmole\ CH_4} \times \frac{44 lbs\ CO_2}{1 lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}$$

EQUATION C-8

Where:

$sgipGHG_{i,h}$	=	the CO_2 emitted by SGIP project i during project h [Metric ton/hr]
$engohr_{i,h}$	=	electrical output of SGIP project i during project h from metered data collected from SGIP projects net of any parasitic losses [kWh]
EFF_T	=	the measured electrical efficiency of technology T (see Table C-2). [Dimensionless fractional efficiency]

TABLE C-24: ELECTRICAL EFFICIENCY BY TECHNOLOGY TYPE USED FOR GHG EMISSIONS CALCULATION

Technology Type (T)	2018 Electrical Efficiency (EFF_T)	2019 Electrical Efficiency (EFF_T)
Fuel Cell – CHP	0.418	0.399
Fuel Cell – Elec.	0.537	0.530
Gas Turbine	0.342	0.344
Internal Combustion Engine	0.312	0.358
Microturbine	0.266	0.283

* Based on the lower heating value (LHV) metered data collected from SGIP projects

C.3 BASELINE GHG EMISSIONS

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

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

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

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

Electric Power Plant CO_2 Emissions Rate

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

- The emissions of CO_2 from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and
- The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

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

$baseCO2EF_{r,h}$	=	the CO_2 emission rate for utility *r* for hour *h*. This value is from WattTime [Metric tons / kWh]

Electric Power Plant Operations Corresponding to Electric Chiller Operation

An absorption chiller may be used to convert heat recovered from SGIP CHP projects into chilled water to serve buildings or process cooling loads. Since absorption chillers replace the use of electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions associated with these cogeneration facilities. The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$chlrElec_{i,h} = Chilller_i \times heathr_{i,h} \times COP \ \times effElecChlr \times \left(\frac{1tonhrCooling}{12Mbtu}\right)$$

EQUATION C-9

Where:

$chlrElec_{i,h}$	=	the electricity of a power plant that would be needed to provide baseline electric chiller for SGIP CHP project *i* for hour *h* [kWh]
$Chiller_i$	=	an allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspections report. See Table C-3.
$heathr_{i,h}$	=	the quantity of useful heat recovered for SGIP CHP project *i* for hour *h* from metering or ratio analysis [MBtu]
COP	=	0.6 – assumed efficiency of the absorption chiller using heat from SGIP CHP project [$Mbtu_{out}/Mbtu_{in}$]
effElecChlr	=	0.634 - assumed efficiency of the baseline new standard efficiency electric chiller [kWh/tonhr·Cooling]

TABLE C-25: ASSIGNEMENT OF CHILLER ALLOCATION FACTOR

Project Design	$Chiller_i$
Heating and Cooling	0.5
Cooling Only	1
Heating Only	0

Baseline GHG Emissions from Power Plant Operations

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

$$basePpChiller_{i,h} = baseCO_2EF_{i,h} \times chlrElec_{i,h}$$ **EQUATION C-10**

$$basePpEngo_{i,h} = baseCO_2EF_{i,h} \times engohr_{i,h}$$ **EQUATION C-11**

Where:

$basePpChiller_{i,h}$ = the baseline power plant GHG emissions avoided due to SGIP CHP project *i* delivery of cooling services for hour *h* [Metric Ton CO_2/hr]

$basePpEngo_{i,h}$ = the baseline power plant GHG emissions avoided due to SGIP CHP project *i* electricity generation for hour *h* [Metric Ton CO_2/hr]

Boiler GHG Emissions (baseBlr)

A heat exchanger is typically used to transfer useful heat recovered from SGIP CHP projects to building heating loads. The equation below represents the process by which heating services provided by SGIP CHP projects are calculated. This equation reflects the ability to use recovered useful heat in lieu of natural gas and, therefore, help reduce CO_2 emissions, and were calculated based upon hourly useful heat recovery values for the SGIP CHP project as follows:

$$baseBlr_{i,h} = Boiler_i \times heathr_{i,h} \times effHx \times \frac{1}{effBlr} \times \frac{1 ft^3 CH_4}{935\ Btu} \times \frac{1{,}000\ Btu}{1\ Mbtu} \times \frac{1\ lbmoleCO_2}{1 lbmoleCH_4} \times \frac{44\ lbs\ CO_2}{1 lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}$$

EQUATION C-12

Where:

$baseBlr_{i,h}$ = the CO_2 emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h* [Metric tons CO_2/hr]

effBlr = 0.8 - assumed efficiency of the baseline natural boiler, based on previous cost effectiveness evaluations [$Mbtu_{out}/Mbtu_{in}$]

$Boiler_i$	=	an allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspections report. See Table C-4.
$heathr_{i,h}$	=	the quantity of useful heat recovered for SGIP CHP project *i* for hour *h* from metering or ratio analysis [MBtu]
effHX	=	0.9 – assumed efficiency of the SGIP CHP project's primary heat exchanger

TABLE C-26: ASSIGNEMENT OF BOILER ALLOCATION FACTOR

Project Design	$Boiler_i$
Heating and Cooling	0.5
Cooling Only	0
Heating Only	1

Biogas GHG Emissions (baseBio)

Distributed generation projects powered by renewable biogas carry an additional GHG reduction benefit. The baseline treatment of biogas is an influential determinant of GHG impacts for renewable-fueled SGIP projects. Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared).

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

For dairy digesters the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2,000 dairies in California, conventional manure management practice for flush dairies[52] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO_2 and CH_4. These lagoons are typically uncovered, so all CH_4 generated in the lagoon escapes into the atmosphere. Currently, there are no statewide requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for volatile organic compounds. This information and the site contacts support a biogas venting baseline for dairies.

For other digesters, including WWTPs and food processing facilities, the baseline is not quite as straightforward. There are approximately 250 WWTPs in California, and the larger facilities (i.e., those that could generate 1 MW or more of electricity) tend to install energy recovery systems; therefore, the baseline assumption for these facilities in past SGIP impact evaluations was flaring. However, in some previous SGIP impact evaluations, it was assumed that most of the remaining WWTPs do not recover energy and flare the gas on an infrequent basis. Consequently, for smaller facilities (i.e., those with capacity less than 150 kW), venting of the biogas (CH_4) was used in PY07 and PY08 SGIP impact evaluations as the baseline. However, all renewable-fueled distributed generation WWTPs and food processing facilities participating in the SGIP that were contacted in 2009 said that they flare biogas and cited local air and water regulations as the reason. Therefore, flaring was used as the biogas baseline for the PY09-PY19 impact evaluation reports.

Defining the biogas baseline for landfill gas recovery operations presented a challenge in past SGIP impact evaluations. A study conducted by the California Energy Commission in 2002[53] showed that landfills with biogas capacities less than 500 kW would tend to vent rather than flare their landfill gas by a margin of more than three to one. In addition, landfills with over 2.5 million metric tons of waste are required to collect and either flare or use their gas. Installation verification inspection reports and renewable-fueled DG landfill site contacts verified that they would have flared their CH_4 in the absence of the SGIP. Therefore, the biogas baseline assumed for landfill facilities is flaring of the $CH_{4.}$

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include "directed biogas" projects. Deemed renewable fuel use projects, directed biogas projects are eligible for higher incentives under the SGIP. Directed biogas projects purchase biogas fuel

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

53 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

that is produced at another location. The procured biogas is processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased gas is not likely to be delivered and used at the SGIP renewable fuel use project, directed biogas projects are treated in the SGIP as renewable fuel use projects.

For directed biogas projects where the biogas is injected into the pipeline outside of California, information on the renewable fuel baseline was not available.[54] To establish a directed biogas baseline the following assumptions were made:

- The renewable fuel baseline for all directed biogas projects is flaring biogas,[55]
- Seventy-five percent of the energy consumed by directed biogas SGIP projects on an energy basis (the minimum amount of biogas required to be procured by a directed biogas project) is assumed to have been injected at the biogas source, and
- Biogas is assumed to be consumed for a period of five years after the upfront payment date for PY10 and earlier projects, and 10 years after the upfront payment date for PY11 and later projects.

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

GHG Emissions of Flared Biogas

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

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

- Facilities using digester gas (with the exception of dairies),

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

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

- Landfill gas facilities, and
- Projects fueled by directed biogas.

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

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

EQUATION C-13

GHG Emissions of Vented Biogas

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

$$baseBio_{vent_{i,h}} = \frac{3412\ Btu}{kWh} \times \frac{1}{EFF_T} \times \frac{1ft^3CH_4}{935\ Btu} \times \frac{1lbmoleCH_4}{379\ ft^3CH_4} \times \frac{16lbsCH_4}{lbmoleCH_4} \times engohr_{i,h} \times \frac{1\ metric\ ton}{2{,}205\ lbs} \times \frac{21\ metric\ tons\ CO_2}{1\ metric\ ton\ CH_4}$$

EQUATION C-14

Where:

$baseBio_{i,h}$	=	the CO_2 emissions of the baseline methane emissions for SGIP CHP project *i* for hour *h* [Metric tons CO_2/hr]
EFF_T	=	electrical efficiency of technology T (See Table C-2).

C.4 SUMMARY OF GHG IMPACT RESULTS

TABLE C-27: GHG IMPACTS BY TECHNOLOGY TYPE AND ENERGY SOURCE [METRIC TONS CO_2eq]

Technology Type	Energy Source	2018 GHG Impact	2019 GHG Impact	Overall GHG Impact
Fuel Cell – CHP	Non-Renewable	13,060	10,947	24,007
	Onsite Biogas – Flared	-4,415	-4,396	-8,811
	Directed Biogas Contracts - Non-Renewable	7,768	7,940	15,708
Fuel Cell – Electric Only	Non-Renewable	83,721	75,689	159,410
	Directed Biogas Contracts - Non-Renewable	18,049	15,367	33,417
	Directed Biogas Contracts - Renewable	-945	-464	-1,409
Gas Turbine	Non-Renewable	69,011	71,830	140,841
	Onsite Biogas – Flared	-24,736	-21,693	-46,429
Internal Combustion Engine	Non-Renewable	50,455	32,933	83,388
	Onsite Biogas – Flared	-38,460	-46,204	-84,664
	Onsite Biogas – Vented	-133,638	-92,471	-226,110
Microturbine	Non-Renewable	23,476	19,921	43,397
	Onsite Biogas – Flared	-2,150	-3,085	-5,235
	Other	2,080	2,467	4,547
Pressure Reduction Turbine	Other	-2,879	-2,868	-5,747
Wind	Other	-19,775	-22,361	-42,136

TABLE C-28: GHG IMPACTS BY PROGRAM ADMINISTRATOR AND TECHNOLOGY TYPE [METRIC TONS CO_2eq]

PA	Technology Type	2018 GHG Impact	2019 GHG Impact	Overall GHG Impact
CSE	Fuel Cell – CHP	9,807	9,654	19,461
	Fuel Cell – Electric Only	9,078	7,612	16,690
	Gas Turbine	28,662	26,857	55,519
	Internal Combustion Engine	(1,883)	(2,863)	(4,746)
	Microturbine	(27)	(139)	(166)
	Pressure Reduction Turbine	(1,088)	(942)	(2,031)
	Wind	(962)	(1,058)	(2,020)
	CSE Total	**43,587**	**39,120**	**82,707**
PG&E	Fuel Cell – CHP	5,018	4,204	9,222
	Fuel Cell – Electric Only	37,060	37,590	74,650
	Gas Turbine	9,469	13,122	22,591
	Internal Combustion Engine	(113,257)	(87,869)	(201,126)
	Microturbine	9,138	7,346	16,484
	Pressure Reduction Turbine	(755)	(1,143)	(1,898)
	Wind	(11,005)	(12,120)	(23,126)
	PG&E Total	**(64,332)**	**(38,870)**	**(103,202)**
SCE	Fuel Cell – CHP	(99)	145	45
	Fuel Cell – Electric Only	30,956	25,179	56,135
	Gas Turbine	-	-	-
	Internal Combustion Engine	(26,685)	(24,042)	(50,728)
	Microturbine	3,297	2,161	5,458
	Pressure Reduction Turbine	(1,037)	(782)	(1,819)
	Wind	(7,808)	(9,183)	(16,991)
	SCE Total	**(1,377)**	**(6,523)**	**(7,899)**
SCG	Fuel Cell – CHP	1,687	487	2,174
	Fuel Cell – Electric Only	23,732	20,211	43,943
	Gas Turbine	6,144	10,157	16,302
	Internal Combustion Engine	20,182	9,032	29,214
	Microturbine	10,999	9,935	20,934
	Pressure Reduction Turbine	-	-	-
	Wind	-	-	-
	SCG Total	**62,745**	**49,822**	**112,567**
Energy Storage (Non-Res.)		1,517	1,358	2,875
Energy Storage (Res.)		(69)	(799)	(867)
Program Total		**42,072**	**44,109**	**86,181**

* Energy storage emissions were not evaluated at the PA level

APPENDIX D SOURCES OF UNCERTAINTY AND RESULTS

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

D.1 OVERVIEW OF ENERGY IMPACTS UNCERTAINTY

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

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

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

For this impacts evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impacts estimates uncertainty. The term MCS refers to “the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[56]

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

D.2 OVERVIEW OF GREENHOUSE GAS IMPACTS UNCERTAINTY

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

D.2.1 Baseline Central Station Power Plant GHG Emissions

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

D.2.2 Baseline Biogas Project GHG Emissions

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

56 Webster's dictionary.

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

TABLE D-29: METHANE DISPOSITION BASELINE ASSUMPTIONS FOR BIOGAS PROJECTS

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

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

D.3 SOURCES OF DATA FOR UNCERTAINTY ANALYSIS

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

D.3.1 SGIP Project Information

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

D.3.2 Metered Data for SGIP Projects

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

- 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.

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

D.3.3 Manufacturer's Technical Specifications

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

D.4 UNCERTAINTY ANALYSIS ANALYTICAL METHODOLOGY

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

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

D.4.1 Ask Question

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

- Program Total Annual Electrical Energy Impacts and,
- Program Total Coincident Peak Electrical Demand Impacts.

D.4.2 Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility, accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the projects came online during 2019 and, therefore, contributed to energy impacts for only a portion of the year. Some of the projects for which metered data are available have gaps that required estimation of impacts for a portion of hours during 2018 and 2019. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of the monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came online during 2019, and, therefore, contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the project is metered. However, for many of the SGIP projects, metered data are available for a portion – but not all – of 2018 and 2019. This complicates any analysis that requires classification of projects as either "metered" or "not metered."

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

- Each data archive (e.g., electricity) for each month for each project is classified as being either "metered" (at least 90% of any given month's reported impacts are based on metered data) or "unmetered" (less than 90% of any given month's reported impacts are based on metered data) for MCS purposes.
- An operations status of "Normal" or "Unknown" was assigned to each month for each unmetered system based on the Operational Status Research (OSR) of participants.[57]

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

D.4.3 Generate Sample Data

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

If metered data are available for the project, then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the project, the actual values are created using distributions that reflect performance variability assumptions. A total of 1,000 simulation runs were used to generate sample data.

Metered Data Available – Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table D-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 D-30: SUMMARY OF RANDOM MEASUREMENT ERROR VARIABLES

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

Metered Data Unavailable – Generating Sample Data from Performance Distributions

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

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

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

TABLE D-31: PERFORMANCE DISTRIBUTIONS DEVELOPED FOR THE 2018 AND 2019 CAISO PEAK HOUR MCS ANALYSIS

Technology Type	Energy Source	PA
Fuel Cell – Combined Heat and Power	Non-renewable, Renewable	All
Fuel Cell – Electric only	All	
Gas Turbine	All	
Internal Combustion Engine	Non-renewable, Renewable	
Microturbine	Non-renewable, Renewable	
Pressure Reduction Turbine	All	
Wind	All	

Performance Distributions for CAISO Peak Hour MCS

Performance distributions used to generate sample data for annual peak demand impacts are shown in Figure D-1 through Figure D-20.

FIGURE D-20: MCS DISTRIBUTION – 2018 CHP FUEL CELL (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

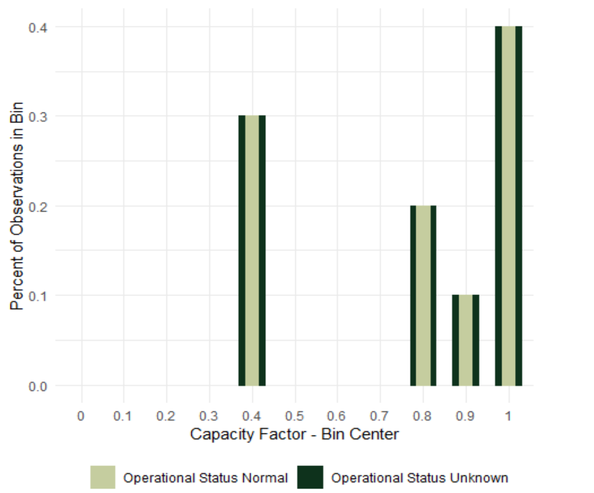

FIGURE D-21: MCS DISTRIBUTION – 2018 CHP FUEL CELL (RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

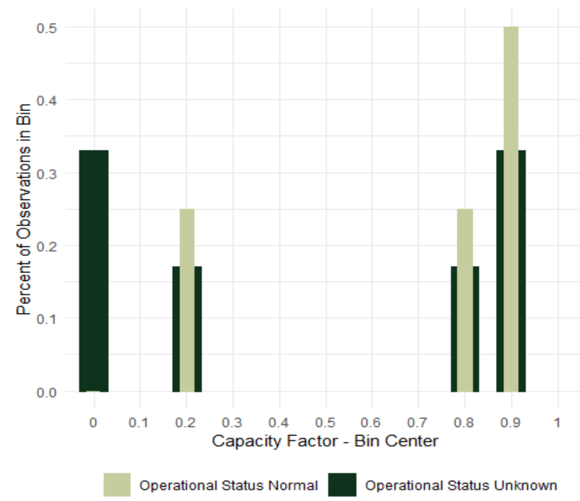

FIGURE D-22: MCS DISTRIBUTION – 2018 ELECTRIC-ONLY FUEL CELL (ALL FUEL) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

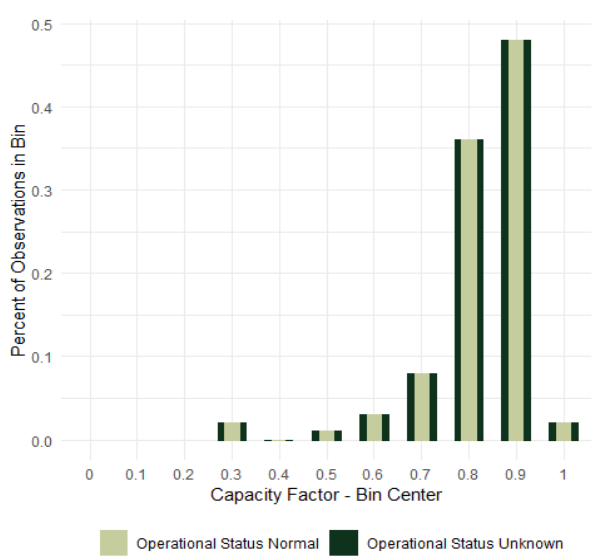

FIGURE D-23: MCS DISTRIBUTION – 2018 GAS TURBINE (ALL FUEL) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

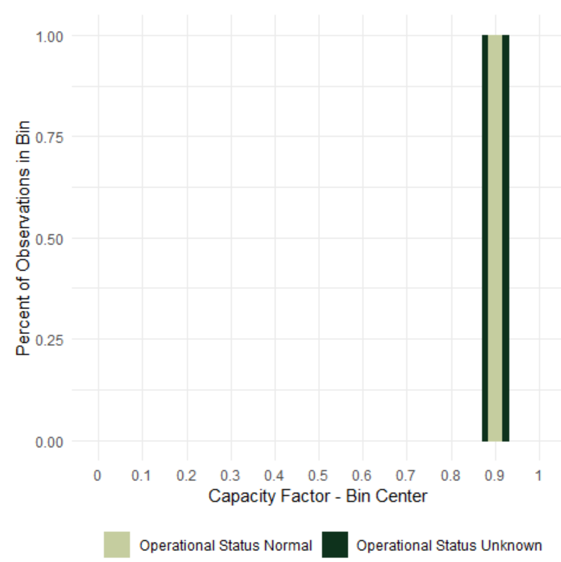

FIGURE D-24: MCS DISTRIBUTION – 2018 INTERNAL COMBUSTION ENGINE (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

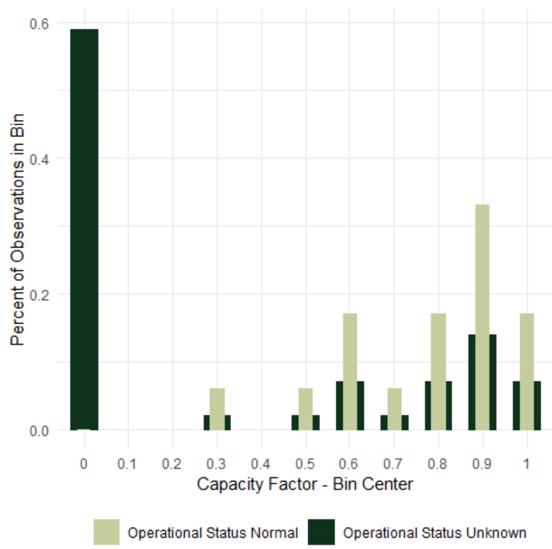

FIGURE D-25: MCS DISTRIBUTION – 2018 INTERNAL COMBUSTION ENGINE (RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

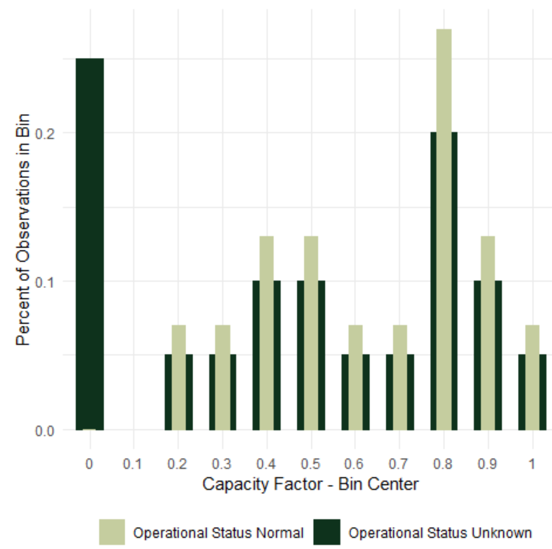

FIGURE D-26: MCS DISTRIBUTION – 2018 MICROTURBINE (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

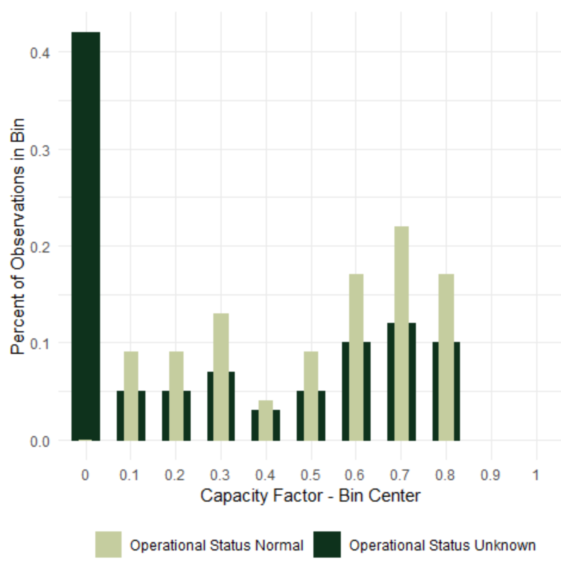

FIGURE D-27: MCS DISTRIBUTION – 2018 MICROTURBINE (RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

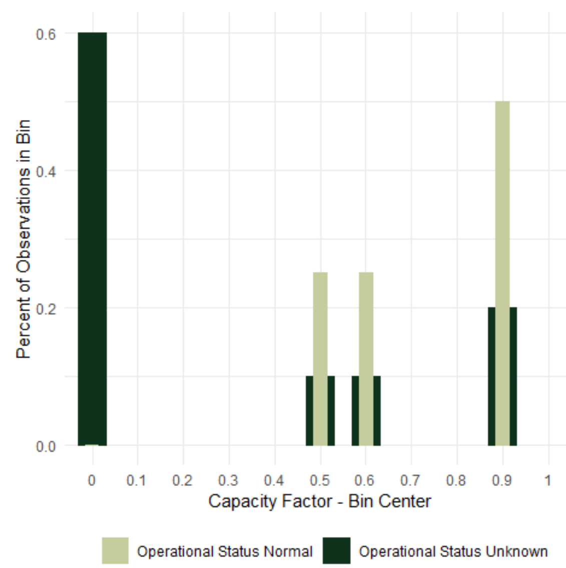

FIGURE D-28: MCS DISTRIBUTION – 2018 PRESSURE REDUCTION TURBINE PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

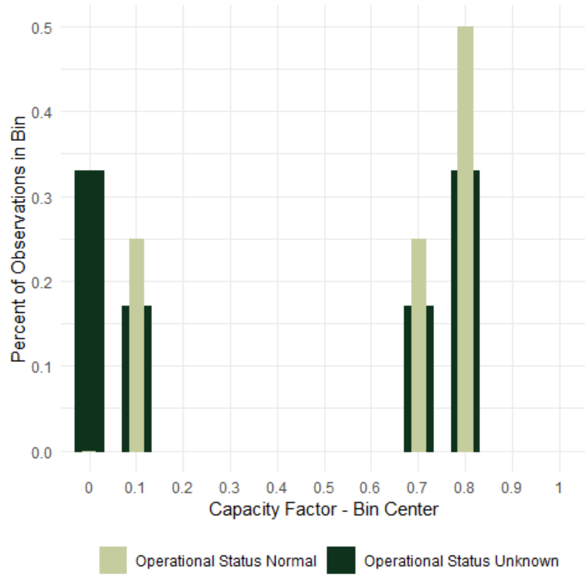

FIGURE D-29: MCS DISTRIBUTION – 2018 WIND TURBINE PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

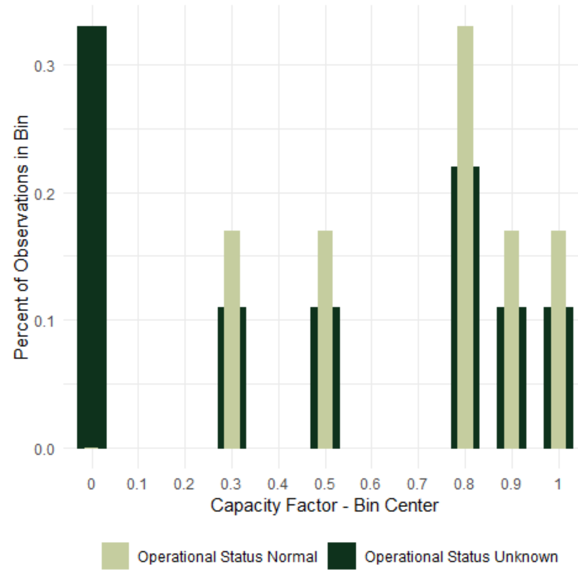

FIGURE D-30: MCS DISTRIBUTION – 2019 CHP FUEL CELL (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

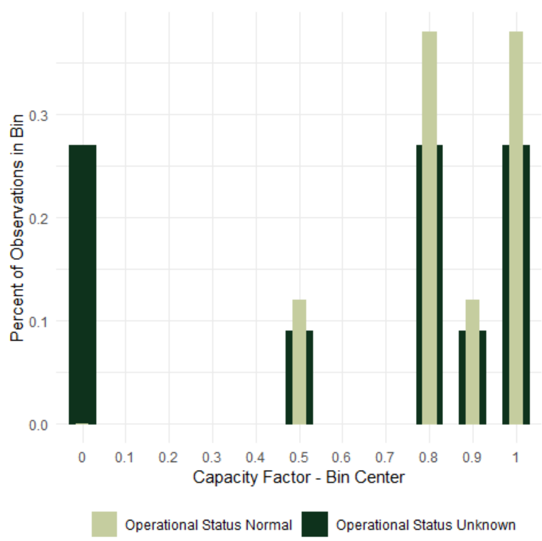

FIGURE D-31: MCS DISTRIBUTION – 2019 CHP FUEL CELL (RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

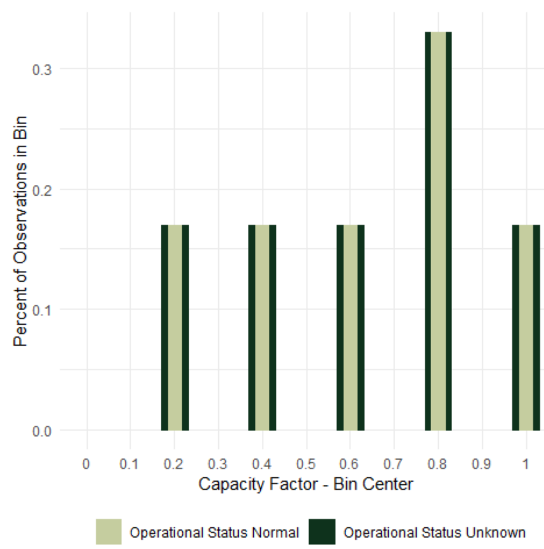

FIGURE D-32: MCS DISTRIBUTION – 2019 ELECTRIC-ONLY FUEL CELL (ALL FUEL) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

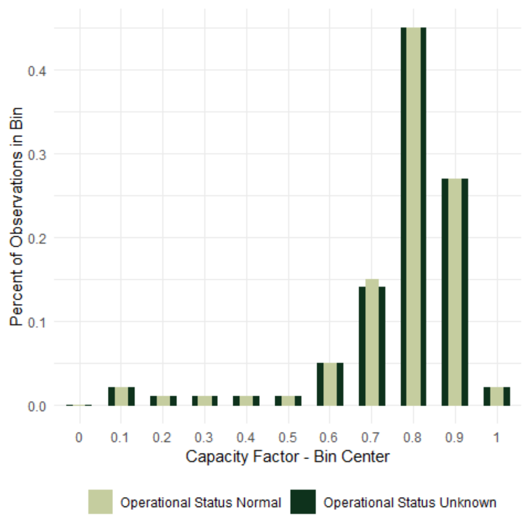

FIGURE D-33: MCS DISTRIBUTION – 2019 GAS TURBINE (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

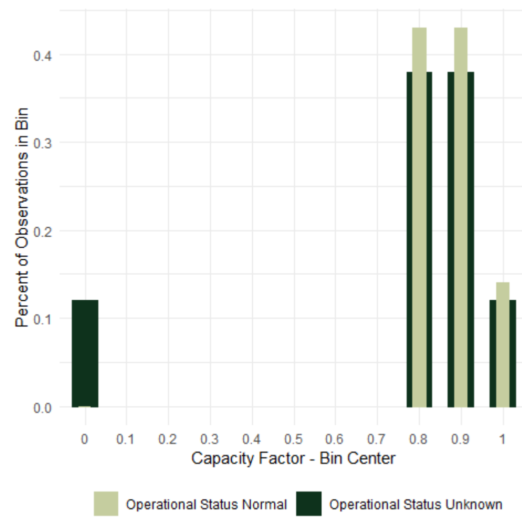

FIGURE D-34: MCS DISTRIBUTION – 2019 INTERNAL COMBUSTION ENGINE (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

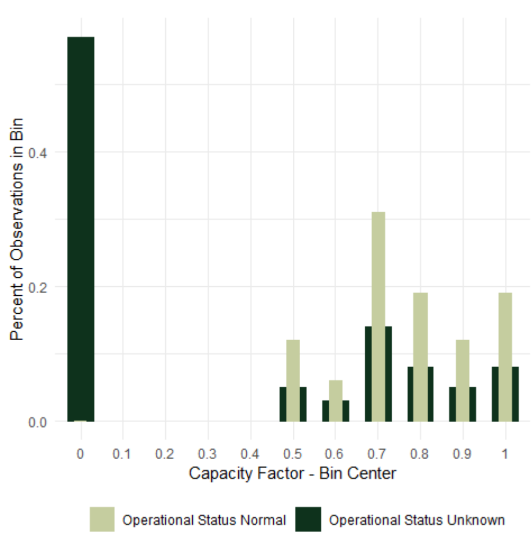

FIGURE D-35: MCS DISTRIBUTION – 2019 INTERNAL COMBUSTION ENGINE (RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

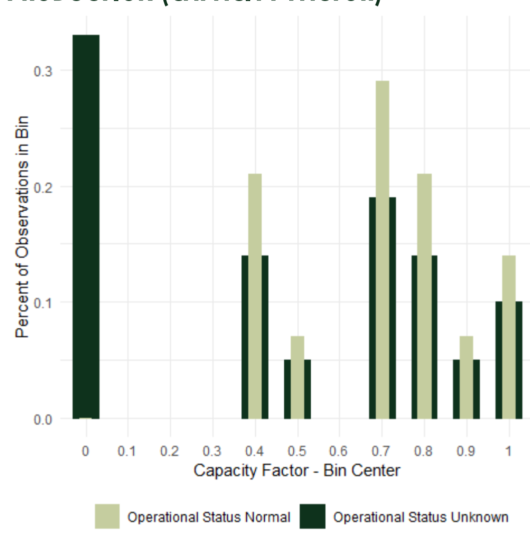

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FIGURE D-36: MCS DISTRIBUTION – 2019 MICROTURBINE (NON-RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

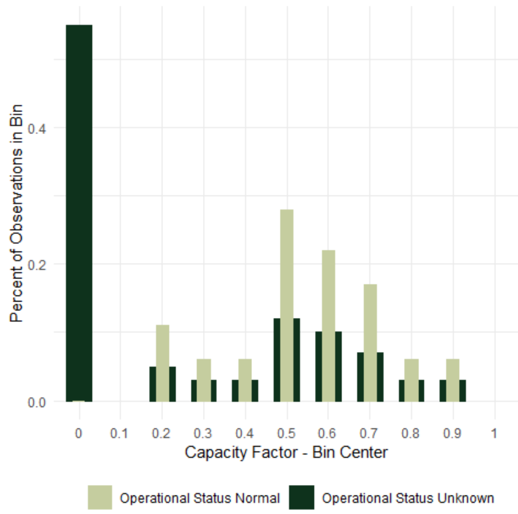


FIGURE D-37: MCS DISTRIBUTION – 2019 MICROTURBINE (RENEWABLE) PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

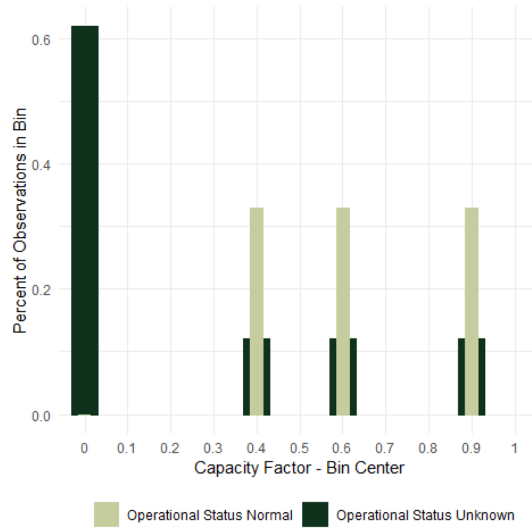


FIGURE D-38: MCS DISTRIBUTION – 2019 PRESSURE REDUCTION TURBINE PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

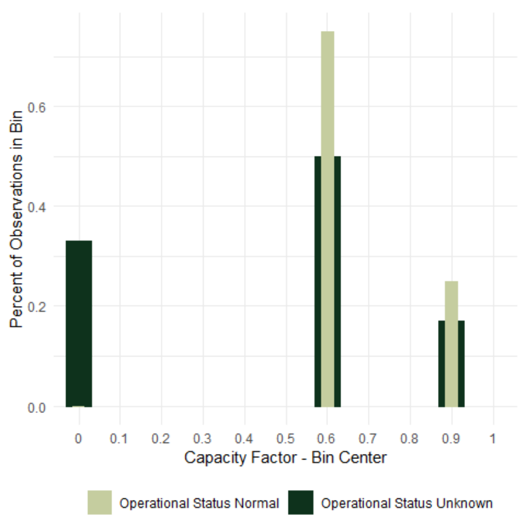


FIGURE D-39: MCS DISTRIBUTION – 2019 WIND TURBINE PEAK DEMAND PRODUCTION (CAPACITY FACTOR)

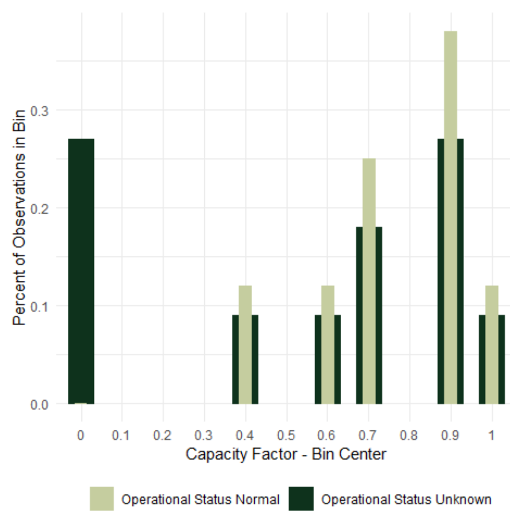


Table D-4 shows the groups used to estimate the uncertainty in the yearly energy production.

TABLE D-32: PERFORMANCE DISTRIBUTIONS DEVELOPED FOR THE 2018 AND 2019 ANNUAL ENERGY PRODUCTIONS MCS ANALYSIS

Technology Type	Energy Source	PA
Fuel Cell – Combined Heat and Power	All	All
Fuel Cell – Electric only	All	
Gas Turbine	All	
Internal Combustion Engine	Non-renewable, Renewable	
Microturbine	Non-renewable, Renewable	
Pressure Reduction Turbine	All	
Wind	All	

Performance Distributions for Energy Impacts

Performance distributions used to generate sample data for 2018 and 2019 annual energy impacts are shown in Table D-21 through Figure D-38.

FIGURE D-40: MCS DISTRIBUTION – 2018 INTERNAL COMBUSTION ENGINE (NON-RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

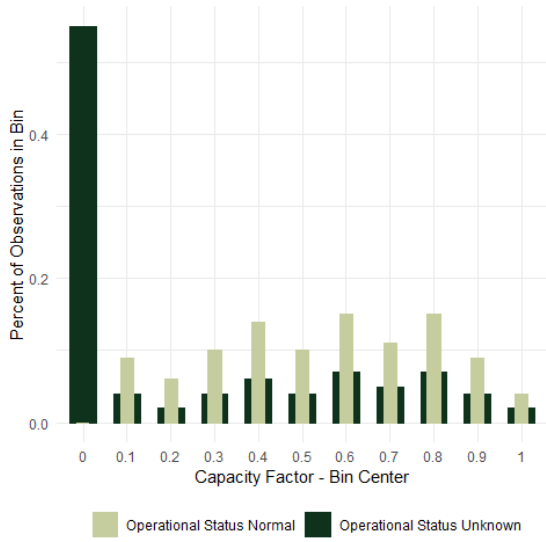


FIGURE D-41: MCS DISTRIBUTION – 2018 INTERNAL COMBUSTION ENGINE (RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

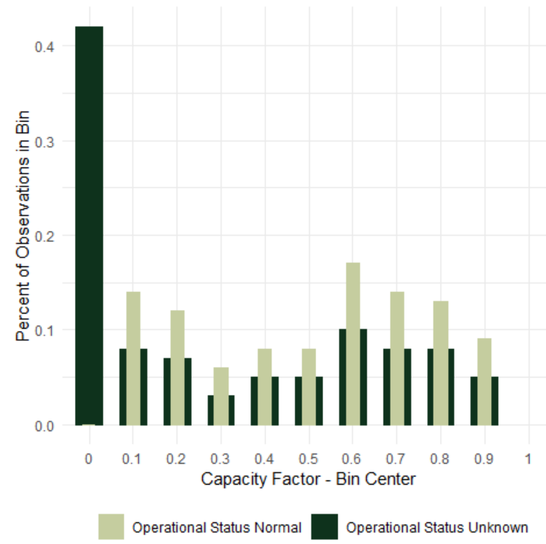


FIGURE D-42: MCS DISTRIBUTION – 2018 MICROTURBINE (NON-RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

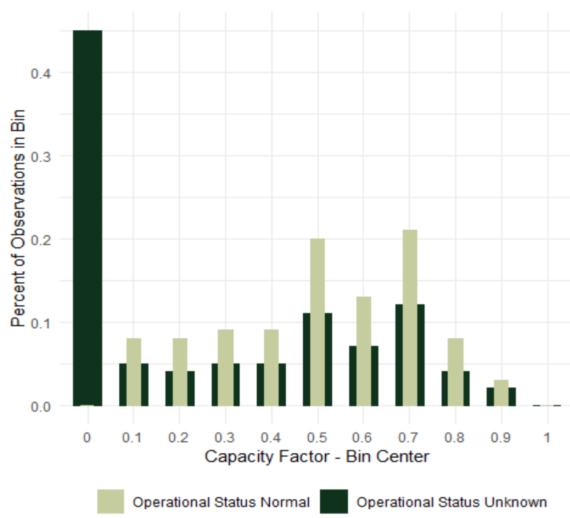


FIGURE D-43: MCS DISTRIBUTION – 2018 MICROTURBINE (RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

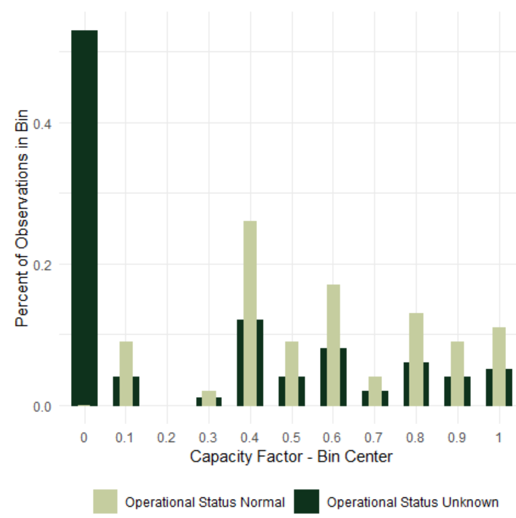


FIGURE D-44: MCS DISTRIBUTION – 2018 CHP FUEL CELL (ALL FUEL) ENERGY PRODUCTION (CAPACITY FACTOR)

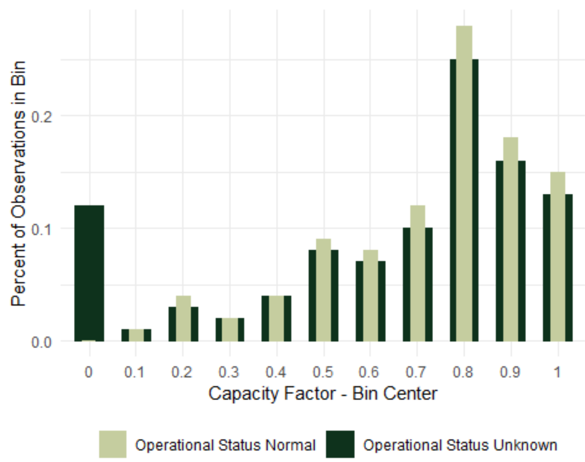


FIGURE D-45: MCS DISTRIBUTION – 2018 ELECTRIC-ONLY FUEL CELL (ALL FUEL) ENERGY PRODUCTION (CAPACITY FACTOR)

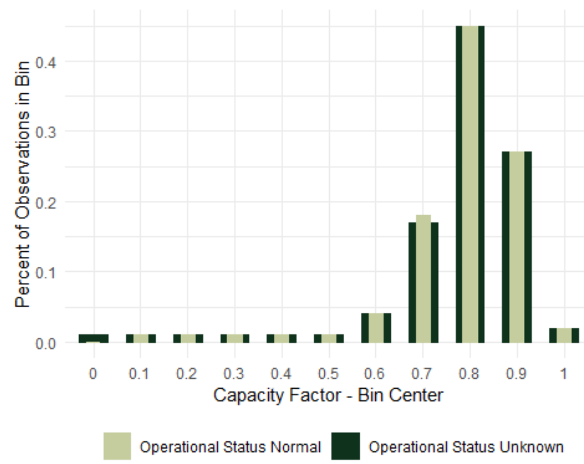


FIGURE D-46: MCS DISTRIBUTION – 2018 GAS TURBINE (ALL) ENERGY PRODUCTION (CAPACITY FACTOR)

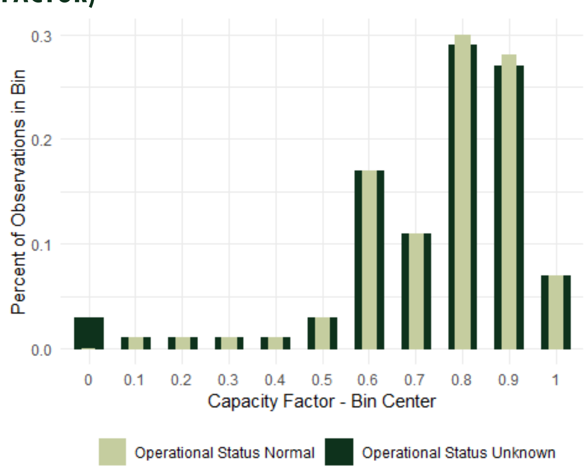


FIGURE D-47: MCS DISTRIBUTION – 2018 PRESSURE REDUCTION TURBINE ENERGY PRODUCTION (CAPACITY FACTOR)

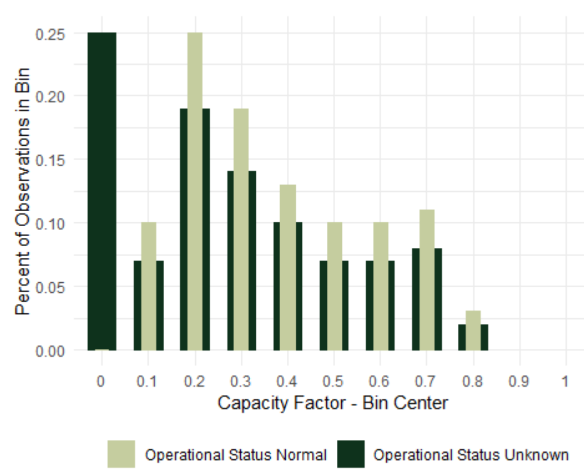


FIGURE D-48: MCS DISTRIBUTION – 2018 WIND TURBINE ENERGY PRODUCTION (CAPACITY FACTOR)

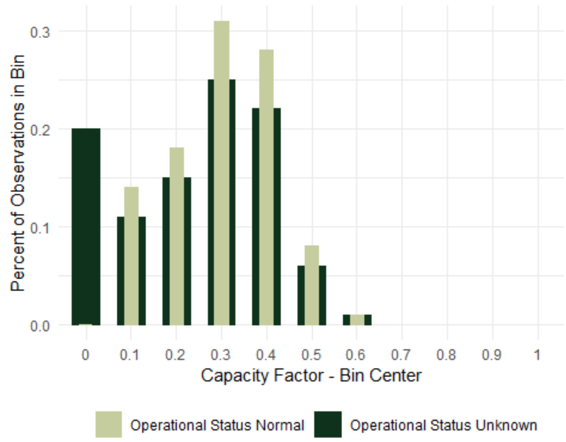


FIGURE D-49: MCS DISTRIBUTION – 2019 INTERNAL COMBUSTION ENGINE (NON-RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

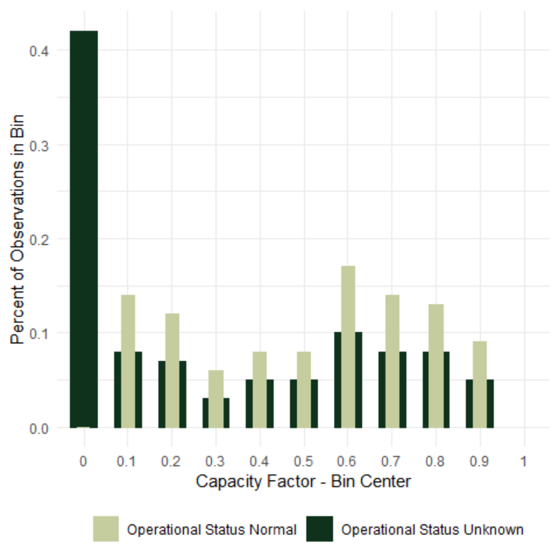


FIGURE D-50: MCS DISTRIBUTION – 2019 INTERNAL COMBUSTION ENGINE (RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

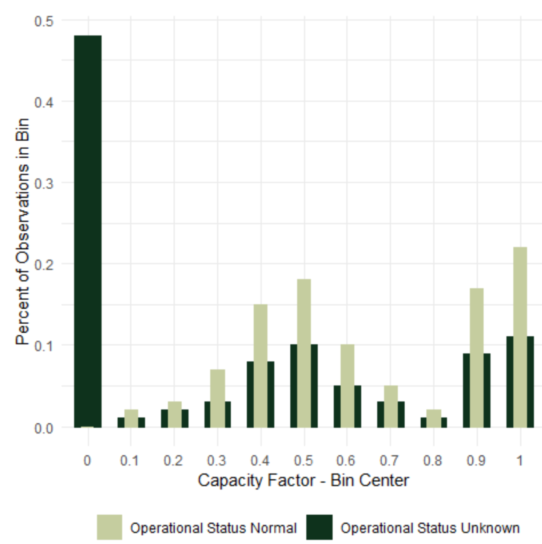


FIGURE D-51: MCS DISTRIBUTION – 2019 MICROTURBINE (NON-RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

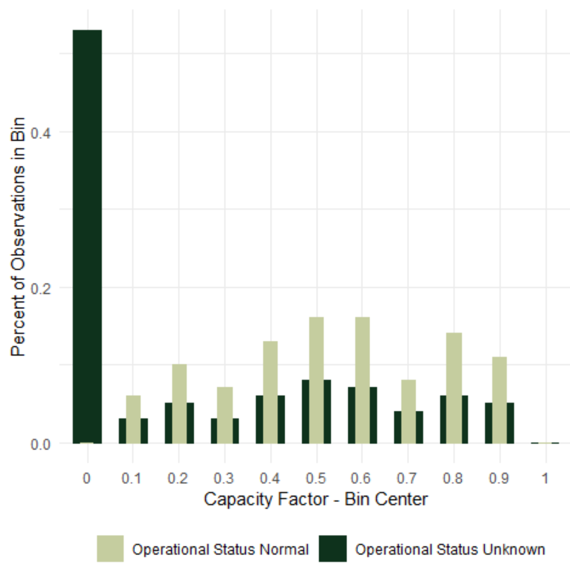


FIGURE D-52: MCS DISTRIBUTION – 2019 MICROTURBINE (RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

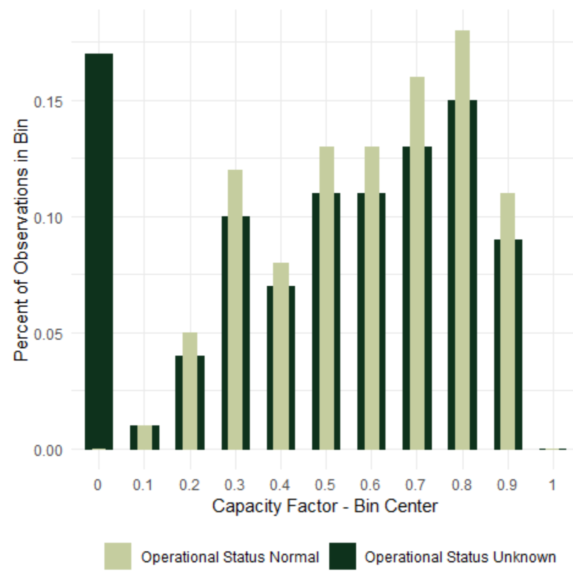


FIGURE D-53: MCS DISTRIBUTION – 2019 CHP FUEL CELL (ALL FUEL) ENERGY PRODUCTION (CAPACITY FACTOR)

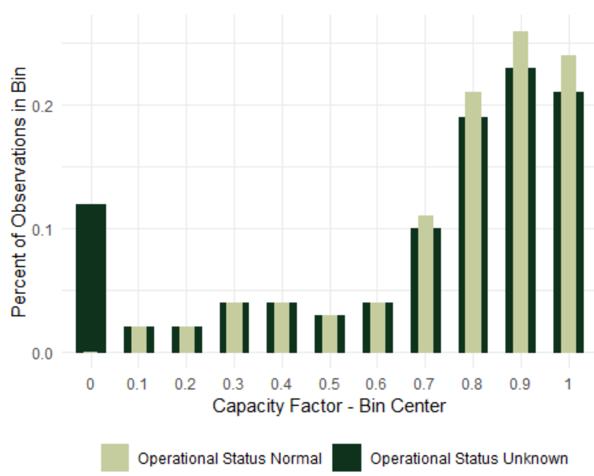


FIGURE D-54: MCS DISTRIBUTION – 2019 ELECTRIC-ONLY FUEL CELL (ALL FUEL) ENERGY PRODUCTION (CAPACITY FACTOR)

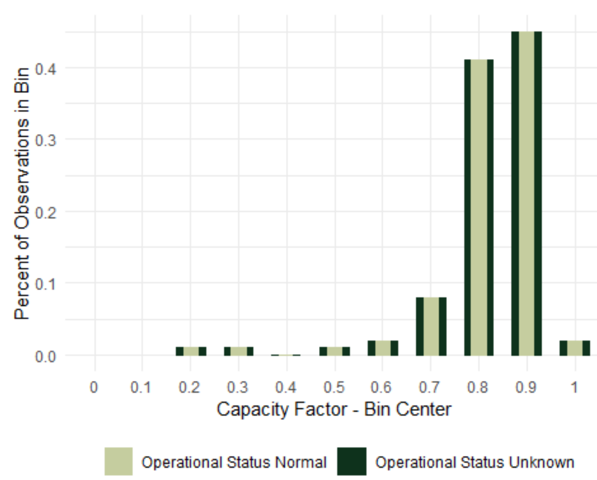


FIGURE D-55: MCS DISTRIBUTION – 2019 GAS TURBINE (NON-RENEWABLE) ENERGY PRODUCTION (CAPACITY FACTOR)

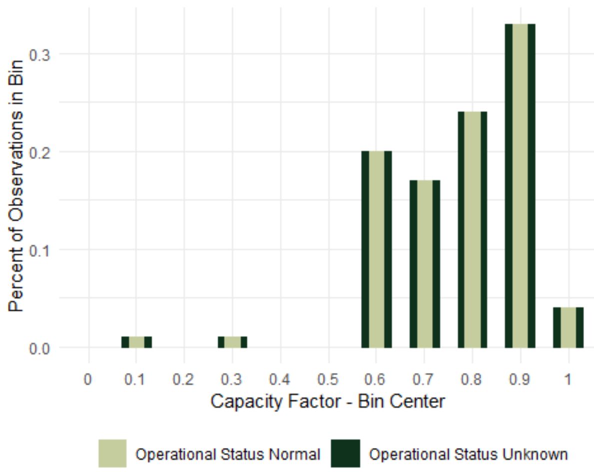


FIGURE D-56: MCS DISTRIBUTION – 2019 PRESSURE REDUCTION TURBINE ENERGY PRODUCTION (CAPACITY FACTOR)

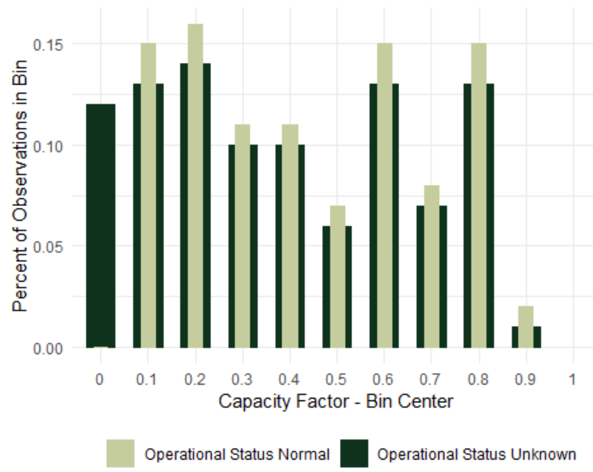
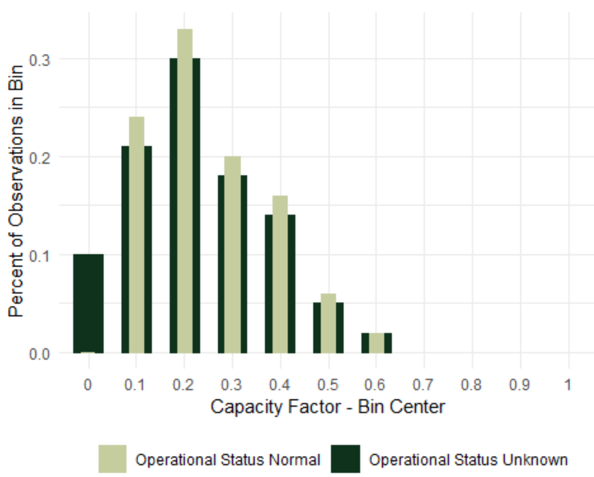


FIGURE D-57: MCS DISTRIBUTION – 2019 WIND TURBINE ENERGY PRODUCTION (CAPACITY FACTOR)



D.4.5 Bias

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

Planned Data Collection Disproportionally Favors Dissimilar Groups

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

Actual Data Collection Allocations Deviate from Planned Data Collection Allocations

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

Treatment of Bias

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

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

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

D.4.6 Calculate the Quantities of Interest for Each Sample

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

- Program Total Annual Electrical Energy Impacts, and
- Program Total Coincident Peak Electrical Demand Impacts.

D.5 ANALYZE ACCUMULATED QUANTITIES OF INTEREST

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

D.6 2018 RESULTS

This section presents the confidence levels for the energy and peak demand impacts results and the precision and confidence intervals associated with those confidence levels during 2018. In cases where an accuracy level of 90 percent confidence and 10 percent precision (i.e., 90/10) was achieved, the 90 percent confidence interval and resulting precision are reported. If 90/10 was not achieved, but the resulting precision at a 70 percent confidence is more precise than 30 percent, the 80 percent confidence interval and resulting precisions are reported. If the precision results at a 70 percent confidence is less precise than 30 percent, the confidence and precision are reported at a 70 percent confidence level. It should also be noted that decommissioned projects are not included in the rollup of uncertainty results, however, they are included in the distributions used for estimated sites as described earlier in this Appendix. Results are shown for metered, estimated, and combined impacts.

TABLE D-33: UNCERTAINTY ANALYSIS RESULTS FOR ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2018)

Technology Type/Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**80%**	**18.5%**	**0.564 to 0.819**
Estimated	90%	10.0%	0.702 to 0.858
Metered	80%	75.5%	0.112 to 0.805
Fuel Cell – Electric Only	**90%**	**1.3%**	**0.813 to 0.834**
Estimated	90%	1.7%	0.809 to 0.837
Metered	90%	1.1%	0.815 to 0.832
Gas Turbine	**70%**	**100.0%**	**0 to 0.796**
Estimated	90%	5.9%	0.725 to 0.817
Metered	70%	100.0%	0 to 0.796
Internal Combustion Engine	**70%**	**82.4%**	**0.057 to 0.591**
Estimated	80%	10.0%	0.515 to 0.629
Metered	70%	100.0%	0 to 0.441
Microturbine	**70%**	**68.5%**	**0.125 to 0.667**
Estimated	80%	18.9%	0.475 to 0.697
Metered	70%	62.6%	0.11 to 0.478
Pressure Reduction Turbine	**70%**	**33.0%**	**0.233 to 0.464**
Estimated	80%	27.9%	0.32 to 0.568
Metered	70%	33.0%	0.233 to 0.462
Wind	**80%**	**27.5%**	**0.212 to 0.373**
Estimated	90%	9.0%	0.231 to 0.277
Metered	80%	27.6%	0.212 to 0.373

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TABLE D-34: UNCERTAINTY ANALYSIS RESULTS FOR ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2018)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**18.5%**	**0.564 to 0.821**
Estimated		90%	9.6%	0.706 to 0.855
Metered		80%	17.7%	0.564 to 0.806
Fuel Cell – Combined Heat and Power	Renewable	**70%**	**75.4%**	**0.112 to 0.803**
Estimated		80%	8.0%	0.72 to 0.845
Metered		70%	75.4%	0.112 to 0.802
Fuel Cell – Electric Only	All Fuel	**90%**	**1.3%**	**0.813 to 0.834**
Estimated		90%	1.7%	0.809 to 0.837
Metered		90%	1.1%	0.815 to 0.832
Gas Turbine	Non-Renewable	**70%**	**100.0%**	**0 to 0.796**
Estimated		90%	5.9%	0.725 to 0.817
Metered		70%	100.0%	0 to 0.796
Internal Combustion Engine	Non-Renewable	**70%**	**71.9%**	**0.09 to 0.548**
Estimated		80%	6.2%	0.503 to 0.57
Metered		70%	71.4%	0.057 to 0.341
Internal Combustion Engine	Renewable	**70%**	**100.0%**	**0 to 0.615**
Estimated		80%	8.2%	0.545 to 0.643
Metered		70%	100.0%	0 to 0.55
Microturbine	Non-Renewable	**80%**	**66.1%**	**0.11 to 0.539**
Estimated		80%	9.2%	0.462 to 0.556
Metered		70%	61.7%	0.11 to 0.463
Microturbine	Renewable	**70%**	**72.1%**	**0.125 to 0.77**
Estimated		80%	11.8%	0.577 to 0.731
Metered		70%	77.6%	0.097 to 0.771
Pressure Reduction Turbine	No Fuel	**70%**	**33.0%**	**0.233 to 0.464**
Estimated		80%	27.9%	0.32 to 0.568
Metered		70%	33.0%	0.233 to 0.462
Wind	No Fuel	**80%**	**27.5%**	**0.212 to 0.373**
Estimated		90%	9.0%	0.231 to 0.277
Metered		80%	27.6%	0.212 to 0.373

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TABLE D-35: UNCERTAINTY ANALYSIS RESULTS FOR CSE - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2018)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	90%	8.0%	0.719 to 0.845
Estimated	80%	8.0%	0.719 to 0.845
Metered	90%	0.3%	0.802 to 0.806
Fuel Cell – Electric Only	**90%**	**1.8%**	**0.809 to 0.838**
Estimated	90%	2.3%	0.804 to 0.842
Metered	90%	0.0%	0.832 to 0.832
Gas Turbine	**90%**	**0.1%**	**0.796 to 0.797**
Estimated	--	--	--
Metered	90%	0.1%	0.796 to 0.797
Internal Combustion Engine	**70%**	**100.0%**	**0 to 0.603**
Estimated	80%	14.0%	0.48 to 0.637
Metered	70%	100.0%	0 to 0.057
Microturbine	**80%**	**23.6%**	**0.416 to 0.674**
Estimated	80%	21.1%	0.471 to 0.723
Metered	90%	7.1%	0.415 to 0.478
Pressure Reduction Turbine	**80%**	**26.5%**	**0.33 to 0.568**
Estimated	70%	33.7%	0.298 to 0.601
Metered	90%	0.1%	0.424 to 0.425
Wind	**90%**	**0.2%**	**0.372 to 0.374**
Estimated	--	--	--
Metered	90%	0.2%	0.372 to 0.374

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TABLE D-36: UNCERTAINTY ANALYSIS RESULTS FOR PG&E - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2018)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**90%**	**5.7%**	**0.737 to 0.826**
Estimated	90%	7.2%	0.723 to 0.836
Metered	90%	0.1%	0.804 to 0.805
Fuel Cell – Electric Only	**90%**	**0.8%**	**0.815 to 0.829**
Estimated	90%	1.0%	0.814 to 0.83
Metered	90%	0.0%	0.815 to 0.815
Gas Turbine	**70%**	**100.0%**	**0 to 0.792**
Estimated	90%	6.5%	0.72 to 0.821
Metered	--	--	--
Internal Combustion Engine	**80%**	**27.6%**	**0.341 to 0.601**
Estimated	90%	9.8%	0.516 to 0.628
Metered	80%	23.4%	0.341 to 0.55
Microturbine	**70%**	**73.8%**	**0.097 to 0.645**
Estimated	80%	17.6%	0.486 to 0.693
Metered	70%	65.4%	0.097 to 0.463
Pressure Reduction Turbine	**90%**	**0.2%**	**0.233 to 0.234**
Estimated	--	--	--
Metered	90%	0.2%	0.233 to 0.234
Wind	**80%**	**11.0%**	**0.212 to 0.264**
Estimated	90%	8.5%	0.232 to 0.275
Metered	90%	0.1%	0.212 to 0.212

TABLE D-37: UNCERTAINTY ANALYSIS RESULTS FOR SCE - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2018)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**70%**	**75.7%**	**0.112 to 0.812**
Estimated	80%	8.3%	0.716 to 0.846
Metered	70%	66.8%	0.112 to 0.564
Fuel Cell – Electric Only	**90%**	**1.1%**	**0.814 to 0.833**
Estimated	90%	1.4%	0.812 to 0.835
Metered	90%	0.0%	0.832 to 0.833
Gas Turbine	--	--	--
Estimated	--	--	--
Metered	--	--	--
Internal Combustion Engine	**70%**	**73.5%**	**0.09 to 0.587**
Estimated	80%	9.8%	0.517 to 0.629
Metered	70%	66.2%	0.09 to 0.441
Microturbine	**70%**	**70.8%**	**0.11 to 0.642**
Estimated	80%	19.7%	0.47 to 0.701
Metered	90%	6.5%	0.11 to 0.125
Pressure Reduction Turbine	**80%**	**8.7%**	**0.401 to 0.477**
Estimated	80%	13.7%	0.381 to 0.502
Metered	90%	0.1%	0.462 to 0.463
Wind	**80%**	**10.1%**	**0.218 to 0.267**
Estimated	90%	9.4%	0.231 to 0.279
Metered	90%	0.1%	0.218 to 0.218

TABLE D-38: UNCERTAINTY ANALYSIS RESULTS FOR SCG - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2018)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**80%**	**10.1%**	**0.661 to 0.81**
Estimated	90%	9.0%	0.711 to 0.852
Metered	90%	6.0%	0.661 to 0.745
Fuel Cell – Electric Only	**90%**	**1.4%**	**0.811 to 0.835**
Estimated	90%	1.9%	0.807 to 0.838
Metered	90%	0.0%	0.815 to 0.815
Gas Turbine	**90%**	**4.2%**	**0.738 to 0.802**
Estimated	90%	4.9%	0.735 to 0.811
Metered	90%	0.1%	0.738 to 0.739
Internal Combustion Engine	**70%**	**100.0%**	**0 to 0.581**
Estimated	80%	9.9%	0.519 to 0.633
Metered	70%	100.0%	0 to 0.221
Microturbine	**70%**	**35.8%**	**0.365 to 0.772**
Estimated	90%	8.7%	0.464 to 0.552
Metered	70%	35.8%	0.365 to 0.772
Pressure Reduction Turbine	**-**	**-**	**-**
Estimated	-	-	-
Metered	-	-	-
Wind	**-**	**-**	**-**
Estimated	-	-	-
Metered	-	-	-

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TABLE D-39: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT BY TECHNOLOGY TYPE AND BASIS (2018)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**70%**	**43.7%**	**0.344 to 0.879**
Estimated	70%	34.9%	0.45 to 0.933
Metered	70%	41.2%	0.342 to 0.823
Fuel Cell – Electric Only	**90%**	**4.1%**	**0.791 to 0.858**
Estimated	90%	5.6%	0.774 to 0.867
Metered	90%	1.1%	0.814 to 0.831
Gas Turbine	**90%**	**2.0%**	**0.878 to 0.915**
Estimated	90%	0.0%	0.9 to 0.9
Metered	90%	2.1%	0.877 to 0.915
Internal Combustion Engine	**70%**	**100.0%**	**0 to 0.558**
Estimated	70%	50.7%	0.223 to 0.681
Metered	70%	100.0%	0 to 0.433
Microturbine	**70%**	**84.2%**	**0.048 to 0.558**
Estimated	70%	99.3%	0.002 to 0.568
Metered	70%	66.8%	0.107 to 0.538
Pressure Reduction Turbine	**70%**	**53.5%**	**0.134 to 0.441**
Estimated	70%	53.0%	0.19 to 0.62
Metered	70%	53.4%	0.134 to 0.44
Wind	**80%**	**28.1%**	**0.348 to 0.62**
Estimated	70%	30.1%	0.349 to 0.65
Metered	80%	17.9%	0.348 to 0.5

TABLE D-40: UNCERTAINTY ANALYSIS RESULTS FOR CSE - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2018)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**18.4%**	**0.631 to 0.915**
Estimated		80%	27.2%	0.55 to 0.962
Metered		90%	0.4%	0.815 to 0.823
Fuel Cell – Combined Heat and Power	Renewable	**80%**	**78.9%**	**0.1 to 0.85**
Estimated		70%	78.9%	0.1 to 0.85
Metered		90%	0.4%	0.342 to 0.345
Fuel Cell – Electric Only	All Fuel	**90%**	**5.5%**	**0.777 to 0.868**
Estimated		90%	7.9%	0.749 to 0.877
Metered		90%	0.1%	0.821 to 0.823
Gas Turbine	Non-Renewable	**90%**	**0.2%**	**0.911 to 0.916**
Estimated		--	--	--
Metered		90%	0.2%	0.911 to 0.916
Internal Combustion Engine	Non-Renewable	**70%**	**100.0%**	**0 to 0.6**
Estimated		70%	100.0%	0 to 0.9
Metered		90%	0.4%	0.402 to 0.405
Internal Combustion Engine	Renewable	**70%**	**100.0%**	**0 to 0.65**
Estimated		70%	46.2%	0.271 to 0.737
Metered		--	--	--
Microturbine	Non-Renewable	**70%**	**62.4%**	**0.112 to 0.483**
Estimated		70%	62.4%	0.112 to 0.483
Metered		--	--	--
Microturbine	Renewable	**70%**	**100.0%**	**0 to 0.6**
Estimated		70%	100.0%	0 to 0.9
Metered		90%	0.4%	0.533 to 0.538
Pressure Reduction Turbine	No Fuel	**90%**	**0.5%**	**0.42 to 0.424**
Estimated		--	--	--
Metered		90%	0.5%	0.42 to 0.424
Wind	No Fuel	**90%**	**0.4%**	**0.348 to 0.351**
Estimated		--	--	--
Metered		90%	0.4%	0.348 to 0.351

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TABLE D-41: UNCERTAINTY ANALYSIS RESULTS FOR PG&E - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2018)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**15.2%**	**0.655 to 0.889**
Estimated		80%	21.8%	0.6 to 0.934
Metered		90%	0.2%	0.754 to 0.757
Fuel Cell – Combined Heat and Power	Renewable	--	--	--
Estimated		--	--	--
Metered		--	--	--
Fuel Cell – Electric Only	All Fuel	**90%**	**2.4%**	**0.805 to 0.844**
Estimated		90%	3.0%	0.798 to 0.849
Metered		90%	0.1%	0.83 to 0.831
Gas Turbine	Non-Renewable	**90%**	**0.0%**	**0.9 to 0.9**
Estimated		90%	0.0%	0.9 to 0.9
Metered		--	--	--
Internal Combustion Engine	Non-Renewable	**80%**	**18.4%**	**0.362 to 0.525**
Estimated		80%	26.5%	0.333 to 0.573
Metered		90%	0.2%	0.423 to 0.425
Internal Combustion Engine	Renewable	**80%**	**23.2%**	**0.399 to 0.64**
Estimated		80%	33.3%	0.344 to 0.687
Metered		90%	0.2%	0.555 to 0.558
Microturbine	Non-Renewable	**80%**	**22.0%**	**0.337 to 0.527**
Estimated		80%	31.3%	0.294 to 0.562
Metered		90%	0.3%	0.524 to 0.527
Microturbine	Renewable	**70%**	**80.2%**	**0.048 to 0.435**
Estimated		70%	85.4%	0.046 to 0.586
Metered		90%	0.4%	0.048 to 0.048
Pressure Reduction Turbine	No Fuel	**90%**	**0.3%**	**0.133 to 0.134**
Estimated		--	--	--
Metered		90%	0.3%	0.133 to 0.134
Wind	No Fuel	**80%**	**25.8%**	**0.352 to 0.597**
Estimated		70%	32.7%	0.317 to 0.625
Metered		90%	0.2%	0.498 to 0.5

TABLE D-42: UNCERTAINTY ANALYSIS RESULTS FOR SCE - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2018)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**70%**	**42.9%**	**0.4 to 1**
Estimated		70%	42.9%	0.4 to 1
Metered		90%	0.4%	0.588 to 0.592
Fuel Cell – Combined Heat and Power	Renewable	**70%**	**83.4%**	**0.078 to 0.856**
Estimated		80%	31.7%	0.467 to 0.9
Metered		90%	0.4%	0.077 to 0.078
Fuel Cell – Electric Only	All Fuel	**90%**	**3.6%**	**0.794 to 0.854**
Estimated		90%	4.7%	0.783 to 0.86
Metered		90%	0.1%	0.826 to 0.827
Gas Turbine	Non-Renewable	**--**	**--**	**--**
Estimated		--	--	--
Metered		--	--	--
Internal Combustion Engine	Non-Renewable	**70%**	**55.6%**	**0.126 to 0.44**
Estimated		70%	33.1%	0.252 to 0.502
Metered		90%	0.3%	0.125 to 0.126
Internal Combustion Engine	Renewable	**70%**	**31.6%**	**0.337 to 0.648**
Estimated		70%	54.1%	0.218 to 0.732
Metered		90%	0.2%	0.432 to 0.434
Microturbine	Non-Renewable	**70%**	**60.6%**	**0.107 to 0.436**
Estimated		70%	73.7%	0.084 to 0.555
Metered		90%	0.3%	0.107 to 0.108
Microturbine	Renewable	**70%**	**100.0%**	**0 to 0.408**
Estimated		70%	100.0%	0 to 0.611
Metered		90%	0.4%	0.14 to 0.141
Pressure Reduction Turbine	No Fuel	**70%**	**40.1%**	**0.244 to 0.571**
Estimated		70%	53.0%	0.19 to 0.62
Metered		90%	0.4%	0.438 to 0.442
Wind	No Fuel	**80%**	**33.5%**	**0.347 to 0.696**
Estimated		80%	33.5%	0.347 to 0.696
Metered		--	--	--

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TABLE D-43: UNCERTAINTY ANALYSIS RESULTS FOR SCG - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2018)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**27.2%**	**0.543 to 0.95**
Estimated		80%	25.0%	0.6 to 1
Metered		90%	0.4%	0.543 to 0.547
Fuel Cell – Combined Heat and Power	Renewable	**90%**	**0.4%**	**0.872 to 0.88**
Estimated		-	-	-
Metered		90%	0.4%	0.872 to 0.88
Fuel Cell – Electric Only	All Fuel	**90%**	**4.7%**	**0.785 to 0.862**
Estimated		90%	6.4%	0.764 to 0.869
Metered		90%	0.1%	0.813 to 0.815
Gas Turbine	Non-Renewable	**90%**	**1.3%**	**0.877 to 0.9**
Estimated		90%	0.0%	0.9 to 0.9
Metered		90%	0.3%	0.877 to 0.882
Internal Combustion Engine	Non-Renewable	**80%**	**30.6%**	**0.258 to 0.485**
Estimated		80%	26.9%	0.303 to 0.526
Metered		90%	0.2%	0.258 to 0.259
Internal Combustion Engine	Renewable	**70%**	**100.0%**	**0 to 0.685**
Estimated		70%	68.0%	0.152 to 0.8
Metered		-	-	-
Microturbine	Non-Renewable	**80%**	**28.4%**	**0.246 to 0.441**
Estimated		70%	35.0%	0.223 to 0.464
Metered		90%	0.2%	0.359 to 0.36
Microturbine	Renewable	**90%**	**0.4%**	**0.942 to 0.951**
Estimated		-	-	-
Metered		90%	0.4%	0.942 to 0.951
Pressure Reduction Turbine	No Fuel	**-**	**-**	**-**
Estimated		-	-	-
Metered		-	-	-
Wind	No Fuel	**-**	**-**	**-**
Estimated		-	-	-
Metered		-	-	-

D.7 2019 RESULTS

This section presents the confidence levels for the energy and peak demand impacts results and the precision and confidence intervals associated with those confidence levels during 2019. The confidence and precision reporting follows the same logic as described for the 2018 results above. Results are shown for metered, estimated, and combined impacts.

TABLE D-44: UNCERTAINTY ANALYSIS RESULTS FOR ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2019)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**80%**	**26.7%**	**0.464 to 0.803**
Estimated	80%	8.0%	0.678 to 0.795
Metered	80%	80.8%	0.085 to 0.803
Fuel Cell – Electric Only	**90%**	**4.3%**	**0.765 to 0.834**
Estimated	90%	2.2%	0.76 to 0.795
Metered	90%	3.3%	0.78 to 0.834
Gas Turbine	**80%**	**6.7%**	**0.713 to 0.815**
Estimated	80%	13.6%	0.698 to 0.917
Metered	90%	0.7%	0.746 to 0.757
Internal Combustion Engine	**70%**	**81.9%**	**0.062 to 0.62**
Estimated	80%	11.0%	0.527 to 0.657
Metered	70%	100.0%	0 to 0.478
Microturbine	**70%**	**56.4%**	**0.168 to 0.601**
Estimated	80%	14.1%	0.473 to 0.628
Metered	70%	78.3%	0.067 to 0.554
Pressure Reduction Turbine	**80%**	**28.0%**	**0.242 to 0.43**
Estimated	80%	33.5%	0.25 to 0.502
Metered	80%	18.1%	0.242 to 0.348
Wind	**80%**	**20.7%**	**0.281 to 0.427**
Estimated	80%	10.0%	0.274 to 0.335
Metered	80%	20.7%	0.281 to 0.428

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TABLE D-45: UNCERTAINTY ANALYSIS RESULTS FOR ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2019)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**25.0%**	**0.465 to 0.775**
Estimated		80%	8.1%	0.676 to 0.796
Metered		80%	21.1%	0.464 to 0.713
Fuel Cell – Combined Heat and Power	Renewable	**70%**	**80.8%**	**0.085 to 0.804**
Estimated		80%	7.8%	0.68 to 0.795
Metered		70%	80.9%	0.085 to 0.804
Fuel Cell – Electric Only	All Fuel	**90%**	**4.3%**	**0.765 to 0.834**
Estimated		90%	2.2%	0.76 to 0.795
Metered		90%	3.3%	0.78 to 0.834
Gas Turbine	Non-Renewable	**80%**	**6.7%**	**0.713 to 0.815**
Estimated		80%	13.6%	0.698 to 0.917
Metered		90%	0.7%	0.746 to 0.757
Internal Combustion Engine	Non-Renewable	**70%**	**59.0%**	**0.144 to 0.56**
Estimated		80%	6.6%	0.512 to 0.583
Metered		70%	64.9%	0.062 to 0.291
Internal Combustion Engine	Renewable	**70%**	**100.0%**	**0 to 0.644**
Estimated		90%	9.6%	0.564 to 0.684
Metered		70%	100.0%	0 to 0.598
Microturbine	Non-Renewable	**70%**	**51.6%**	**0.168 to 0.527**
Estimated		80%	9.0%	0.462 to 0.553
Metered		70%	73.3%	0.067 to 0.438
Microturbine	Renewable	**70%**	**62.1%**	**0.167 to 0.716**
Estimated		80%	11.2%	0.524 to 0.656
Metered		70%	87.4%	0.053 to 0.783
Pressure Reduction Turbine	No Fuel	**80%**	**28.0%**	**0.242 to 0.43**
Estimated		80%	33.5%	0.25 to 0.502
Metered		80%	18.1%	0.242 to 0.348
Wind	No Fuel	**80%**	**20.7%**	**0.281 to 0.427**
Estimated		80%	10.0%	0.274 to 0.335
Metered		80%	20.7%	0.281 to 0.428

TABLE D-46: UNCERTAINTY ANALYSIS RESULTS FOR CSE - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2019)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**90%**	**9.8%**	**0.664 to 0.809**
Estimated	80%	9.8%	0.664 to 0.809
Metered	90%	6.1%	0.712 to 0.804
Fuel Cell – Electric Only	**90%**	**4.7%**	**0.759 to 0.834**
Estimated	90%	3.2%	0.752 to 0.801
Metered	90%	0.0%	0.833 to 0.834
Gas Turbine	**80%**	**20.0%**	**0.612 to 0.917**
Estimated	80%	20.0%	0.612 to 0.917
Metered	90%	0.1%	0.746 to 0.747
Internal Combustion Engine	**70%**	**100.0%**	**0 to 0.632**
Estimated	80%	16.0%	0.485 to 0.669
Metered	70%	100.0%	0 to 0.062
Microturbine	**70%**	**54.7%**	**0.169 to 0.576**
Estimated	80%	16.3%	0.467 to 0.649
Metered	70%	53.3%	0.168 to 0.554
Pressure Reduction Turbine	**80%**	**33.5%**	**0.25 to 0.501**
Estimated	70%	46.0%	0.202 to 0.547
Metered	90%	0.2%	0.328 to 0.329
Wind	**80%**	**24.2%**	**0.261 to 0.428**
Estimated	80%	20.3%	0.241 to 0.363
Metered	90%	0.2%	0.427 to 0.428

TABLE D-47: UNCERTAINTY ANALYSIS RESULTS FOR PG&E - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2019)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**80%**	**16.6%**	**0.546 to 0.763**
Estimated	90%	6.5%	0.688 to 0.783
Metered	90%	0.1%	0.546 to 0.547
Fuel Cell – Electric Only	**90%**	**1.4%**	**0.77 to 0.792**
Estimated	90%	1.3%	0.768 to 0.787
Metered	90%	0.0%	0.792 to 0.792
Gas Turbine	**90%**	**7.8%**	**0.703 to 0.822**
Estimated	90%	7.8%	0.703 to 0.822
Metered	--	--	--
Internal Combustion Engine	**70%**	**36.1%**	**0.291 to 0.619**
Estimated	80%	9.7%	0.533 to 0.648
Metered	80%	24.4%	0.29 to 0.478
Microturbine	**70%**	**83.4%**	**0.053 to 0.581**
Estimated	80%	12.9%	0.485 to 0.629
Metered	70%	78.5%	0.053 to 0.438
Pressure Reduction Turbine	**90%**	**0.1%**	**0.347 to 0.348**
Estimated	--	--	--
Metered	90%	0.1%	0.347 to 0.348
Wind	**90%**	**5.4%**	**0.286 to 0.318**
Estimated	90%	7.1%	0.281 to 0.324
Metered	90%	0.0%	0.29 to 0.29

TABLE D-48: UNCERTAINTY ANALYSIS RESULTS FOR SCE - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2019)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**70%**	**79.9%**	**0.085 to 0.764**
Estimated	80%	7.8%	0.679 to 0.794
Metered	70%	69.1%	0.085 to 0.465
Fuel Cell – Electric Only	**90%**	**1.4%**	**0.766 to 0.788**
Estimated	90%	1.9%	0.762 to 0.791
Metered	90%	0.0%	0.785 to 0.785
Gas Turbine	**--**	**--**	**--**
Estimated	--	--	--
Metered	--	--	--
Internal Combustion Engine	**70%**	**54.4%**	**0.181 to 0.614**
Estimated	80%	10.5%	0.529 to 0.653
Metered	70%	53.5%	0.181 to 0.598
Microturbine	**70%**	**79.2%**	**0.067 to 0.581**
Estimated	80%	13.8%	0.475 to 0.627
Metered	70%	42.7%	0.067 to 0.168
Pressure Reduction Turbine	**80%**	**26.3%**	**0.242 to 0.414**
Estimated	80%	14.6%	0.324 to 0.434
Metered	90%	0.1%	0.241 to 0.242
Wind	**90%**	**6.1%**	**0.281 to 0.317**
Estimated	90%	7.2%	0.279 to 0.322
Metered	90%	0.2%	0.281 to 0.282

TABLE D-49: UNCERTAINTY ANALYSIS RESULTS FOR SCG - ANNUAL ENERGY IMPACT RESULTS BY TECHNOLOGY TYPE AND BASIS (2019)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**80%**	**12.9%**	**0.611 to 0.792**
Estimated	90%	9.5%	0.666 to 0.807
Metered	80%	12.9%	0.611 to 0.792
Fuel Cell – Electric Only	**90%**	**1.7%**	**0.765 to 0.791**
Estimated	90%	2.1%	0.761 to 0.793
Metered	90%	0.0%	0.78 to 0.781
Gas Turbine	**90%**	**5.4%**	**0.721 to 0.803**
Estimated	90%	7.0%	0.709 to 0.816
Metered	90%	0.1%	0.756 to 0.757
Internal Combustion Engine	**70%**	**100.0%**	**0 to 0.617**
Estimated	80%	10.4%	0.533 to 0.657
Metered	70%	100.0%	0 to 0.144
Microturbine	**70%**	**36.1%**	**0.368 to 0.783**
Estimated	80%	9.6%	0.461 to 0.558
Metered	70%	36.1%	0.368 to 0.784
Pressure Reduction Turbine	**--**	**--**	**--**
Estimated	--	--	--
Metered	--	--	--
Wind	**--**	**--**	**--**
Estimated	--	--	--
Metered	--	--	--

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TABLE D-50: UNCERTAINTY ANALYSIS RESULTS FOR PEAK DEMAND IMPACT BY TECHNOLOGY TYPE AND BASIS (2019)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	**70%**	**43.7%**	**0.344 to 0.879**
Estimated	70%	34.9%	0.45 to 0.933
Metered	70%	41.2%	0.342 to 0.823
Fuel Cell – Electric Only	**90%**	**4.1%**	**0.791 to 0.858**
Estimated	90%	5.6%	0.774 to 0.867
Metered	90%	1.1%	0.814 to 0.831
Gas Turbine	**90%**	**2.0%**	**0.878 to 0.915**
Estimated	90%	0.0%	0.9 to 0.9
Metered	90%	2.1%	0.877 to 0.915
Internal Combustion Engine	**70%**	**100.0%**	**0 to 0.558**
Estimated	70%	50.7%	0.223 to 0.681
Metered	70%	100.0%	0 to 0.433
Microturbine	**70%**	**84.2%**	**0.048 to 0.558**
Estimated	70%	99.3%	0.002 to 0.568
Metered	70%	66.8%	0.107 to 0.538
Pressure Reduction Turbine	**70%**	**53.5%**	**0.134 to 0.441**
Estimated	70%	53.0%	0.19 to 0.62
Metered	70%	53.4%	0.134 to 0.44
Wind	**80%**	**28.1%**	**0.348 to 0.62**
Estimated	70%	30.1%	0.349 to 0.65
Metered	80%	17.9%	0.348 to 0.5

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TABLE D-51: UNCERTAINTY ANALYSIS RESULTS FOR CSE - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2019)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**100.0%**	**0 to 1**
Estimated		70%	100.0%	0 to 1
Metered		90%	0.3%	0.776 to 0.781
Fuel Cell – Combined Heat and Power	Renewable	**70%**	**36.3%**	**0.4 to 0.857**
Estimated		70%	66.7%	0.2 to 1
Metered		90%	0.3%	0.852 to 0.857
Fuel Cell – Electric Only	All Fuel	**90%**	**8.5%**	**0.705 to 0.835**
Estimated		80%	8.4%	0.705 to 0.834
Metered		90%	0.1%	0.833 to 0.835
Gas Turbine	Non-Renewable	**90%**	**0.3%**	**0.664 to 0.667**
Estimated		--	--	--
Metered		90%	0.3%	0.664 to 0.667
Internal Combustion Engine	Non-Renewable	**70%**	**100.0%**	**0 to 0.7**
Estimated		70%	100.0%	0 to 0.8
Metered		90%	0.4%	0.355 to 0.358
Internal Combustion Engine	Renewable	**70%**	**100.0%**	**0 to 0.681**
Estimated		70%	46.5%	0.281 to 0.771
Metered		--	--	--
Microturbine	Non-Renewable	**70%**	**51.5%**	**0.114 to 0.357**
Estimated		70%	100.0%	0 to 0.471
Metered		90%	0.4%	0.235 to 0.237
Microturbine	Renewable	**70%**	**100.0%**	**0 to 0.564**
Estimated		70%	100.0%	0 to 0.6
Metered		90%	0.4%	0.559 to 0.564
Pressure Reduction Turbine	No Fuel	**90%**	**0.4%**	**0.34 to 0.343**
Estimated		--	--	--
Metered		90%	0.4%	0.34 to 0.343
Wind	No Fuel	**70%**	**100.0%**	**0 to 0.9**
Estimated		70%	100.0%	0 to 0.9
Metered		--	--	--

TABLE D-52: UNCERTAINTY ANALYSIS RESULTS FOR PG&E - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2019)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**30.5%**	**0.426 to 0.8**
Estimated		70%	36.7%	0.391 to 0.844
Metered		90%	0.3%	0.437 to 0.439
Fuel Cell – Combined Heat and Power	Renewable	**--**	**--**	**--**
Estimated		--	--	--
Metered		--	--	--
Fuel Cell – Electric Only	All Fuel	**90%**	**3.7%**	**0.746 to 0.804**
Estimated		90%	4.8%	0.735 to 0.81
Metered		90%	0.1%	0.798 to 0.8
Gas Turbine	Non-Renewable	**80%**	**58.9%**	**0.235 to 0.909**
Estimated		80%	58.9%	0.235 to 0.909
Metered		--	--	--
Internal Combustion Engine	Non-Renewable	**80%**	**17.4%**	**0.351 to 0.499**
Estimated		80%	25.4%	0.32 to 0.538
Metered		90%	0.3%	0.411 to 0.413
Internal Combustion Engine	Renewable	**80%**	**32.5%**	**0.327 to 0.641**
Estimated		70%	38.1%	0.299 to 0.667
Metered		90%	0.3%	0.404 to 0.406
Microturbine	Non-Renewable	**80%**	**22.3%**	**0.328 to 0.516**
Estimated		80%	33.4%	0.289 to 0.578
Metered		90%	0.3%	0.486 to 0.488
Microturbine	Renewable	**70%**	**100.0%**	**0 to 0.31**
Estimated		70%	85.1%	0.033 to 0.407
Metered		90%	0.4%	0 to 0
Pressure Reduction Turbine	No Fuel	**90%**	**0.4%**	**0.651 to 0.656**
Estimated		--	--	--
Metered		90%	0.4%	0.651 to 0.656
Wind	No Fuel	**80%**	**25.4%**	**0.441 to 0.742**
Estimated		80%	32.1%	0.376 to 0.731
Metered		90%	0.2%	0.739 to 0.742

TABLE D-53: UNCERTAINTY ANALYSIS RESULTS FOR SCE - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2019)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**80%**	**33.3%**	**0.5 to 1**
Estimated		80%	33.3%	0.5 to 1
Metered		--	--	--
Fuel Cell – Combined Heat and Power	Renewable	**70%**	**59.0%**	**0.186 to 0.72**
Estimated		80%	32.3%	0.42 to 0.82
Metered		90%	0.5%	0.185 to 0.187
Fuel Cell – Electric Only	All Fuel	**90%**	**5.3%**	**0.731 to 0.812**
Estimated		90%	6.6%	0.717 to 0.819
Metered		90%	0.1%	0.774 to 0.775
Gas Turbine	Non-Renewable	**--**	**--**	**--**
Estimated		--	--	--
Metered		--	--	--
Internal Combustion Engine	Non-Renewable	**80%**	**29.3%**	**0.259 to 0.474**
Estimated		80%	31.7%	0.273 to 0.527
Metered		90%	0.2%	0.259 to 0.26
Internal Combustion Engine	Renewable	**80%**	**43.2%**	**0.268 to 0.676**
Estimated		70%	50.5%	0.235 to 0.716
Metered		90%	0.3%	0.574 to 0.577
Microturbine	Non-Renewable	**70%**	**87.9%**	**0.022 to 0.348**
Estimated		70%	89.2%	0.027 to 0.472
Metered		90%	0.4%	0.022 to 0.022
Microturbine	Renewable	**70%**	**56.7%**	**0.097 to 0.351**
Estimated		70%	100.0%	0 to 0.463
Metered		90%	0.4%	0.203 to 0.205
Pressure Reduction Turbine	No Fuel	**80%**	**41.1%**	**0.25 to 0.6**
Estimated		70%	46.5%	0.25 to 0.685
Metered		90%	0.4%	0.385 to 0.389
Wind	No Fuel	**80%**	**22.2%**	**0.465 to 0.731**
Estimated		80%	32.2%	0.402 to 0.785
Metered		90%	0.4%	0.586 to 0.591

TABLE D-54: UNCERTAINTY ANALYSIS RESULTS FOR SCG - PEAK DEMAND IMPACT BY TECHNOLOGY TYPE, ENERGY SOURCE, AND BASIS (2019)

Technology Type / Basis	Energy Source	Confidence Level	Precision	Confidence Interval
Fuel Cell – Combined Heat and Power	Non-Renewable	**70%**	**30.8%**	**0.45 to 0.85**
Estimated		70%	38.5%	0.4 to 0.9
Metered		90%	0.3%	0.641 to 0.646
Fuel Cell – Combined Heat and Power	Renewable	**90%**	**0.4%**	**0.827 to 0.835**
Estimated		--	--	--
Metered		90%	0.4%	0.827 to 0.835
Fuel Cell – Electric Only	All Fuel	**90%**	**5.9%**	**0.726 to 0.817**
Estimated		90%	7.8%	0.707 to 0.826
Metered		90%	0.1%	0.767 to 0.769
Gas Turbine	Non-Renewable	**80%**	**27.5%**	**0.511 to 0.9**
Estimated		70%	32.4%	0.46 to 0.902
Metered		90%	0.2%	0.868 to 0.872
Internal Combustion Engine	Non-Renewable	**70%**	**40.7%**	**0.183 to 0.433**
Estimated		80%	25.6%	0.291 to 0.491
Metered		90%	0.2%	0.182 to 0.183
Internal Combustion Engine	Renewable	**70%**	**52.8%**	**0.229 to 0.744**
Estimated		70%	52.8%	0.229 to 0.744
Metered		--	--	--
Microturbine	Non-Renewable	**80%**	**29.9%**	**0.225 to 0.418**
Estimated		70%	35.1%	0.209 to 0.435
Metered		90%	0.2%	0.355 to 0.357
Microturbine	Renewable	**90%**	**0.4%**	**0.883 to 0.891**
Estimated		--	--	--
Metered		90%	0.4%	0.883 to 0.891
Pressure Reduction Turbine	No Fuel	**--**	**--**	**--**
Estimated		--	--	--
Metered		--	--	--
Wind	No Fuel	--	--	--
Estimated		--	--	--
Metered		--	--	--