# SELF-GENERATION INCENTIVE PROGRAM

# 2020 BIOGAS GENERATION MARKET ASSESSMENT AND COST-EFFECTIVENESS REPORT

Submitted to:
California Public Utilities Commission
and
Pacific Gas and Electric Company
SGIP Working Group

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# TABLE OF CONTENTS

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# LIST OF FIGURES

# LIST OF TABLES

# 1 EXECUTIVE SUMMARY

California's Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs. The SGIP is funded by California's ratepayers and managed by program administrators (PAs) representing California's large investor owned utilities (IOUs). The Program Administrators are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas and Electric (SDG&E). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

This study is not an evaluation of onsite generation within the SGIP (a separate impact evaluation of the 2018-2019 SGIP will be completed later in 2020). Rather, this study seeks to increase understanding of the current market conditions for onsite generation, specifically biogas[1] fueled onsite generation, and the key drivers associated with the cost-effectiveness of the onsite generation over time. This is a forward looking, *not retrospective analysis* of the potential cost-effectiveness of onsite generation under a range of assumptions and scenarios. This project was completed, in part, as a sensitivity analysis of the SGIP program benefits and costs to changes in program design and participant technology characteristics including fuel choice and flared versus vented baselines. The purpose of this analysis is to test how various changes can impact the cost-effectiveness tests performed on the SGIP. The results can be considered indicative of ways to improve the program but are not actual evaluations of the program.

Program evaluation and market assessments have been a regular part of the SGIP environment since the program's inception in 2001. In 2019 the evaluation team authored the *2019 SGIP Energy Storage Market Assessment and Cost-effectiveness Report* which was a study similar to this biogas generation study but focused on both behind-the-meter (BTM) storage and in-front-of-the-meter (IFOM) utility scale storage in California. These studies aim to provide information and analyses to help the CPUC, California policy makers, PAs, and stakeholders better understand the costs, benefits, and market conditions for the primary SGIP technologies. Some of the research questions addressed pertain directly to legislative requirements set out in Senate Bill 700, while others are associated with ongoing CPUC proceedings on program budgets, goals, and requirements. This study is focused primarily on biogas fueled generation as the program in 2020 transitioned to requiring 100 percent renewable fuel for all SGIP funded onsite

[1] Note that this report uses the term biogas to include any methane produced by a biological source used to power an engine to be consistent with SGIP handbook and program documents. The exception is when quoting directly. In other sources, biomethane and Renewable Natural Gas (RNG) are often also used to describe biogas that has been refined and upgraded to be injected into natural gas pipelines and be chemically interchangeable with natural gas.

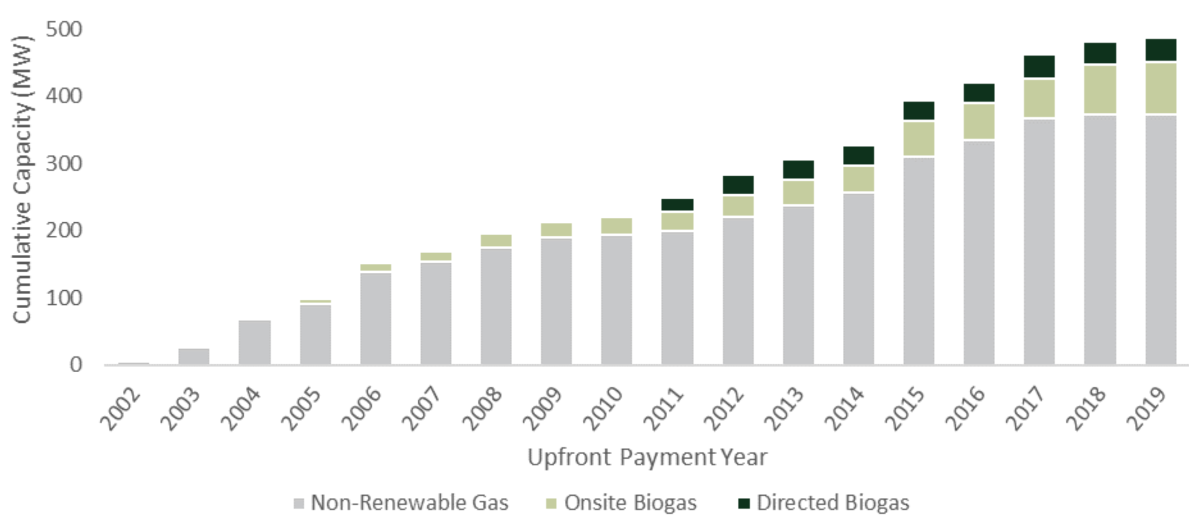
generation projects. This report focuses on assessing two related aspects of SGIP funded biogas generation (more details can be found in Section 2):

- The market drivers and barriers to biogas generation and how other policies and programs impact the market
- The cost-effectiveness of biogas fueled generation under several different scenarios

## 1.1 ONSITE GENERATION WITHIN THE SELF-GENERATION INCENTIVE PROGRAM

The SGIP offers incentives for four primary onsite generation technologies that can be fueled by biogas: microturbines, internal combustion engines, gas turbines and fuel cells (electric-only and CHP). By the end of 2019, the SGIP had provided incentives for 923 onsite generation projects representing 488 MW of rebated capacity. Growth in SGIP onsite generation capacity (in MW) by upfront payment year is summarized in Figure 1-1. This figure also provides the breakdown of generation projects by fuel type (onsite biogas, directed biogas, or non-renewable natural gas).

**FIGURE 1-1: GROWTH IN SGIP GENERATION REBATED CAPACITY BY UPFRONT PAYMENT YEAR AND FUEL TYPE**



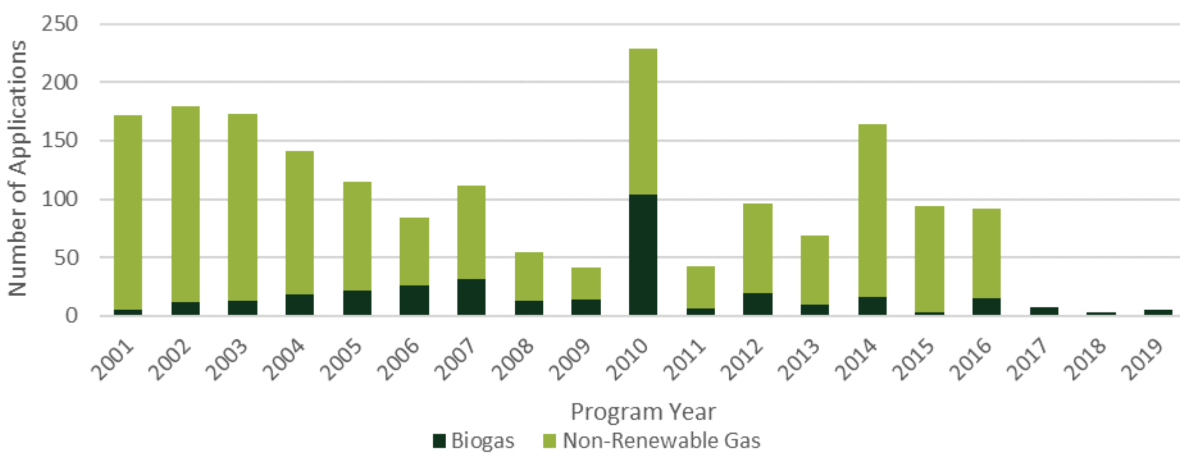

Beginning in 2017, the SGIP required that all onsite generation projects be fueled in part by a renewable fuel. The renewable fuel requirement increased annually until 2020 when it became 100 percent (Table 1-1).

**TABLE 1-1: SGIP MINIMUM RENEWABLE FUEL BLENDING REQUIREMENT FOR ONSITE GENERATION**

| Application Year | SGIP Renewable Fuel Requirement |
|---|---|
| 2016 and prior | 0% |
| 2017 | 10% |
| 2018 | 25% |
| 2019 | 50% |
| 2020 | 100% |

Figure 1-2 shows the distribution of SGIP onsite generation applications from program year 2001 through 2019 by fuel type (Non-renewable gas or biogas – either onsite or directed). Application volume fluctuated from program year to year but has dropped off significantly since 2017 when the renewable fuel requirement was put into place. No onsite generation applications have been submitted to date in 2020.

**FIGURE 1-2: SGIP ONSITE GENERATION APPLICATIONS BY FUEL TYPE, PROGRAM YEARS 2001-2019**



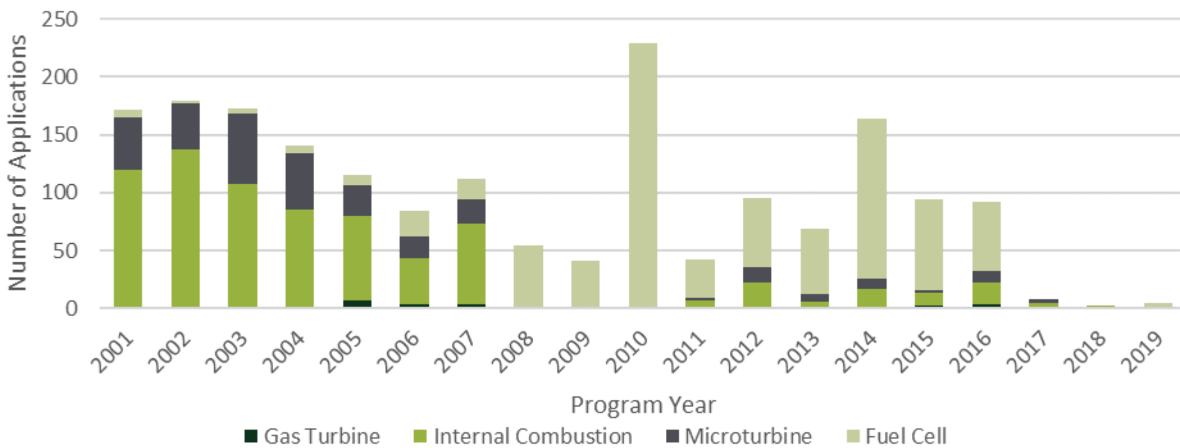

It is important to note that in 2020, CPUC Decision (D.) 20-01-021 resulted in two significant changes to the program's implementation. The first change put a temporary pause on accepting program applications for "renewable generation technologies using collect/use/destroy (aka Wastewater Treatment Plants (WWTP) and Landfills (LF)) as the biomethane baseline[2]." This pause is in effect until the "Commission provides further direction." The second change was an increase in the incentive for onsite generation, from \$0.60/W with an additional \$0.60/W biogas adder to \$2.00/W with a \$2.50/W resiliency adder. While the cost-effectiveness results provided in this report are reflective of the higher 2020 incentive levels, at this time, per the SGIP PAs, this change has not been instituted in practice and is awaiting a

[2] Or what would have happened to the methane in the absence of the generator. Most facilities are required to destroy methane by burning it, or flaring. Dairies and smaller landfills and wastewater treatment plants are not required to flare or destroy methane and so would have vented (or released) this methane to the atmosphere.

database update that is scheduled for October 2020. As a result, the lack of 2020 participation should not be associated with the higher incentives.

Figure 1-2 and Figure 1-3 show the distribution of SGIP onsite generation applications from program year 2001 through 2019 of the projects using biogas and non-renewable gas and type of onsite generation technology, respectively. Internal combustion engines and microturbines dominated the program until 2008 at which point fuel cells became the dominant technology. Fuel cell applications have fallen in recent years; according to fuel cell project developers interviewed that fall is closely tied to the SGIP program requirements surrounding the use of a renewable fuel and the sourcing of that fuel from inside the Western Electric Coordinating Council[3] (WECC).

**FIGURE 1-3: SGIP ONSITE GENERATION APPLICATIONS BY TECHNOLOGY, PROGRAM YEARS 2001 - 2019**




## 1.2 BIOGAS MARKET ASSESSMENT FINDINGS

The market assessment portion of this study addresses questions about drivers and barriers for onsite and directed biogas generation adoption. It is intended to help policy makers, program administrators, and stakeholders understand the alternative biogas dispositions available to California biogas producers and the rationale behind their decision making. It also provides a glimpse into SGIP participants' experiences with the onsite generation component of the SGIP and their onsite generation equipment. The market research relies on interviews and surveys with 19 utility and regulatory staff, 6 industry

3 Western Electricity Coordinating Council is a "not-for-profit organization that works to effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection's Bulk Power System." (www.wecc.org)

experts, 5 project developers, and 47 customers (made up of both SGIP participants and nonparticipants) to identify the key drivers and barriers to onsite generation market adoption.

With respect to adoption drivers, we investigate several potential influences on onsite biogas generation adoption including bill savings, backup power/resiliency, biofuel self-consumption, and perceptions of GHG and grid benefits. Interviews with customers identified key barriers to onsite generation adoption including economic barriers such as upfront equipment purchase costs, ongoing O&M and fuel procurement costs, and programmatic barriers. Below we present high level findings from the market assessment element of this study based directly from the sample of stakeholders that were either interviewed or surveyed. Findings and analyses based on these surveys are presented in Section 6.

***Key factors driving adoption of onsite biogas generation.*** The primary benefits reported by project developers and participating customers fell into two main categories: economic and environmental. Saving money on their electric bills, lowering demand charges, and reducing GHG emissions were top rated factors for customers' decisions to install onsite generation at their facilities. Marketing messages used by project developers emphasize the advantages conferred by onsite generation projects related to their economic and environmental benefits. Marketing messages are framed in terms of helping customers to meet their corporate goals in these areas.

***Perceived barriers to onsite biogas generation.*** Barriers to onsite generation fall into one of two categories: **economic** or **programmatic.** Primary **e**conomic barriers include:

- **Biogas is an expensive fuel,** with the price to customers for pipeline or directed biogas significantly more than natural gas. Currently directed biogas prices average $13-23/MMBtu[4] versus approximately $3/MMBtu for natural gas. High biogas costs within California result from expensive clean-up costs and high gas pipeline interconnection costs (reported by industry to be higher than in other states). SGIP also requires biogas be sourced within the WECC and benefit a California air basin, hence other lower-cost sources are ineligible. Other research has found similar cost differentials: "Total gas monitoring/cleaning and interconnection costs in California are estimated to be between $1.5 and $3.5 million per site, depending on facility size and location. Interconnection cost estimates for other states are considerably lower, between $75,000 and

[4] Supporting letter by ENERGY VISION 138 East 13th Street New York, NY 10003 for Reply Comments of Southern California Gas Company (U904g) to Assigned Commissioner's Ruling Seeking Comments on Implementation of Senate Bill 700 and Other Program Modifications in CPUC Rulemaking 12-11-005 (Filed November 8, 2012)

$500,000."[5] However, recent changes allowing landfills to provide directed biogas to the gas distribution grid reduce this differential.

- **Some biogas producers have other lucrative markets** steering them away from biogas generation, specifically low carbon fuel standard (LCFS) credits combined with Federal Renewable Fuel Standards (RFS) for transportation applications, or for generation applications other incentives such as the BioMAT.
- **Biogas generation equipment is expensive to operate.** Operations and maintenance (O&M) of the generator and cleanup/emissions control equipment can represent significant costs. Estimates of these costs vary, but in some scenarios, technologies can consume a substantial portion of the cost of offsetting grid generated electricity. For example, a 400 kW fuel cell is expected to require O&M costing $0.05/kWh for the generator and an additional $0.05/kWh for O&M of the cleanup system, which has a substantial impact when offsetting grid electricity at ~$0.16/kWh. Details on sources for these estimates and other costs can be found in Section 7.
- **Combustion technologies are challenging to permit in California.** Stationary engines in California must meet stringent emissions standards to ensure air quality. Meeting these increasingly strict standards, such as AQMD's 1110-2, have driven many existing combustion generators to shut down rather than upgrade cleanup and emission control equipment.

Programmatic barriers relate to program restrictions that impede biogas generation, either through program rules or perceptions by project developers of a barrier. Key programmatic barriers include:

- Program requirements which began on January 1, 2017 required **SGIP projects be fueled in part by biogas. The percentage of biogas required increased annually, and beginning in 2020, projects had to be fueled by 100 percent biogas** (as discussed in D. 20-01-021). Previously, generators were able to use a combination of natural gas and biogas, and were able to procure biogas from both in-state or out of state resources. Prior to 2017, projects that used biogas also received a "biogas adder" incentive—however once the biogas requirement became mandatory, this adder was no longer paid out on the required portion of biogas used, making the requirements to participate in the program more costly, and therefore decrease the value of paid-incentives.
- Project developers' perception that the **SGIP has become less reliable as a funding source**, particularly for larger projects. This was attributed to a combination of factors including reduction of generation incentives and transitioning funds to storage technologies, the lottery approach adopted by the program in 2015, and the caps on project size and incentive level.

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[5] Russell, Pye, Dana Lowell, and Brian Jones. 2017. Renewable Natural Gas: The RNG Opportunity for Natural Gas Utilities. M.J. Bradley & Associates. http://www.mjbradley. com/reports/renewable-natural-gas-rng-opportunity-natural-gas-utilities

- **Lack of program marketing for promotion of biogas generation** by the SGIP PAs has hindered project development, according to project developers and nonparticipating customers. The program's redirected focus to energy storage has contributed to this perception. However, the higher incentives that were recently authorized had not been implemented by the time of the surveys so these perceptions may change.

## 1.3 COST-EFFECTIVENESS FINDINGS

We analyzed biogas fueled generation using the five Standard Practice Manual (SPM) tests: Participant Cost Test (PCT), Total Resource Cost Test (TRC), Societal Total Resource Cost Test (STRC), Program Administrator Cost Test (PA), and Ratepayer Impact Test (RIM). The reported findings focus largely on the PCT and TRC cost tests to provide a better understanding of the benefits and costs observed by potential customers and society, while also providing information on the other SPM test values.

Figure 1-4 and Figure 1-5 illustrate the TRC and the PCT benefit cost ratios for the directed and onsite fueled technologies on a flared and vented baseline. These are sorted by each simulation's TRC in 2020 and fall into cleanly delineated groupings by flared vs. vented baselines and directed vs. onsite biogas. **Error! Reference source not found.** shows the minimum and maximum for each grouping. These figures show that no directed biogas technologies with a flared baseline have a TRC greater than one in 2020 while all onsite fueled technologies with a vented baseline have estimated TRC ratios of more than one. The results presented in Figure 1-4 illustrate the benefit of higher methane avoided cost benefits and the cost of higher priced directed biogas on the TRC benefit cost ratio. Technologies installed in 2030[6] are found to have higher TRC ratios, with those using a vented baseline showing a larger increase in their TRC ratio between 2020 and 2030. The larger increase in the TRC for technologies with a vented baseline is due to rapid growth in California's avoided GHG valuation.

6 Cost-effectiveness estimates use a forecast of avoided costs, bill savings and increases, and measure costs through the life of the measure. For measures installed in the future, the forecast of the inputs begins at the scenario's year of installation through the measure expected useful life. These forecasts use the values in the 2020 Avoided Costs Calculator, future rates have an assumed growth rate and the analysis assumed forecasted declines in fuel cell costs based on observed growth rates and progress ratios while other technologies are assumed to have constant real costs. See Section 8 for more details.

**FIGURE 1-4: TRC BENEFIT COST RATIOS IN 2020 AND 2030**

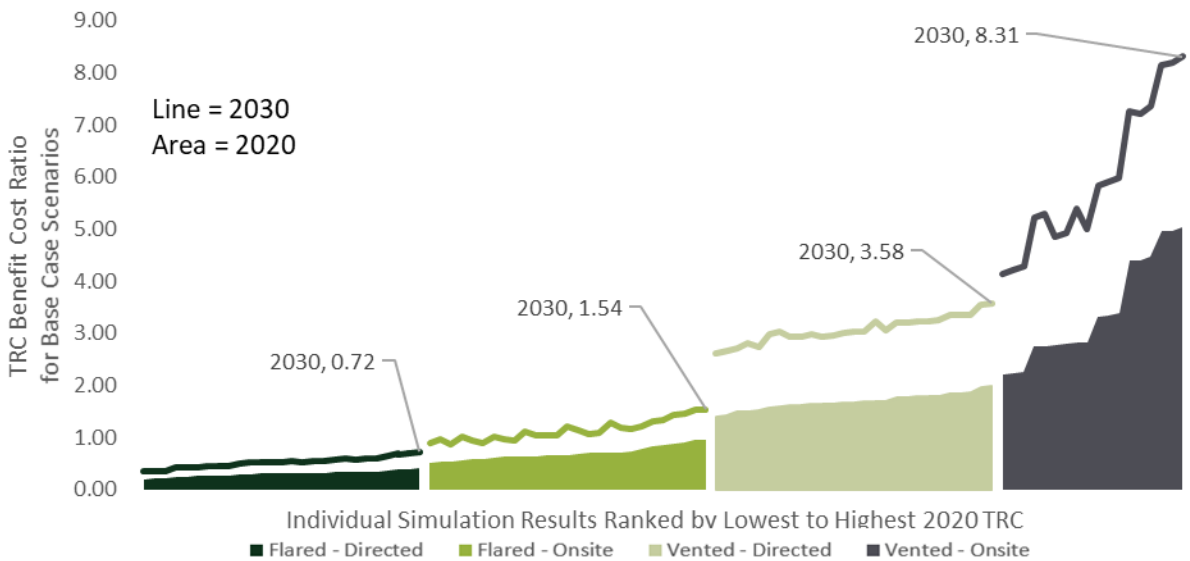
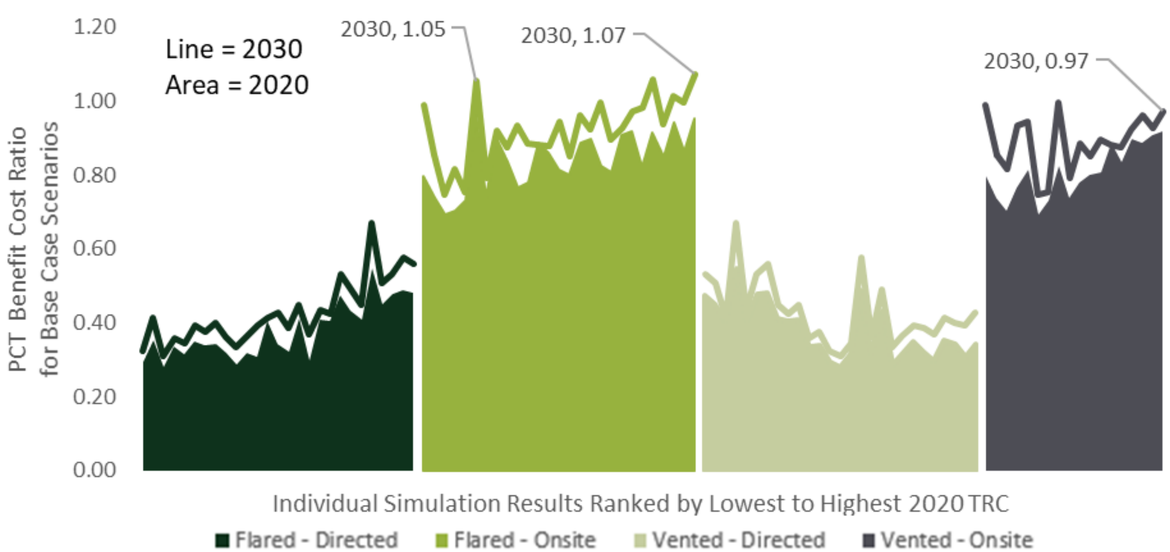



Figure 1-5 illustrates the PCT benefit cost ratio for the same technologies and scenarios whose TRC estimates are presented in Figure 1-4. The PCT estimates indicate that no technologies pass the PCT in 2020. The high cost of directed biogas to fuel the technologies negatively impacts the PCT. A handful of on-site biogas technologies have a PCT benefit cost ratio greater than one in 2030 as the increasing utility rates and bill savings contribute to technologies fueled by onsite biogas passing the PCT.

**FIGURE 1-5: PCT BENEFIT COST RATIO IN 2020 AND 2030**



The PCT benefit cost ratio is not impacted by the flared and vented baseline status of the technology. The current SGIP program and regulatory environment does not provide participant customers a way to monetize the large GHG reduction value associated with installing a biogas fueled technology on a vented baseline (e.g., at a dairy). Table 1-2 presents the lowest and highest ratios in Figure 1-4 and Figure 1-5 by base case group (directed vs. onsite and flared vs. vented).

**TABLE 1-2: LOWEST AND HIGHEST TRC RATIOS BY GROUP AND ASSOCIATED PCT RATIOS**

| Technology | 2020 TRC | 2030 TRC | 2020 PCT | 2030 PCT | Base Case Group |
|---|---|---|---|---|---|
| Microturbines | 0.20 | 0.34 | 0.29 | 0.32 | Flared - Directed |
| Fuel Cell Elec (Large) | 0.40 | 0.72 | 0.48 | 0.56 | |
| Fuel Cell Elec (Small) | 0.52 | 0.89 | 0.80 | 0.99 | Flared - Onsite |
| Gas Turbine (Large) | 0.96 | 1.54 | 0.95 | 1.07 | |
| Fuel Cell Elec (Small) | 1.40 | 2.62 | 0.47 | 0.53 | Vented - Directed |
| Gas Turbine (Small) | 1.95 | 3.58 | 0.34 | 0.43 | |
| Fuel Cell Elec (Small) | 2.20 | 4.15 | 0.80 | 0.99 | Vented - Onsite |
| IC Engine (Large) | 5.04 | 8.31 | 0.92 | 0.97 | |

The cost-effectiveness analysis implemented several scenarios in addition to the base case analyses presented above. Some of these scenarios have higher costs associated with including the cost of a digester while others add the SGIP resiliency incentive and additional funding for onsite biogas that is available from other sources. Layering additional incentives improves the PCT ratio, in some cases well above one, making some technologies cost effective from the participant's perspective. It is not clear how many participants or developers are fully informed on all the incentives that are available to help increase the participant's benefits from onsite biogas generation.

## 1.4 FUTURE OUTLOOK AND CONSIDERATIONS

The California market for biogas fueled generation is significantly impacted by multiple levels of government policies and programs. The SGIP is but one part of these policies and programs—many of these are complementary, but some are competing. SGIP and other policy makers should keep these factors in mind and, if possible, coordinate across agencies to help California and the SGIP reach policy and program goals. Based on the findings in this study, several interventions could help drive towards SGIP and other state goals to reduce emissions, reduce peak demand, and transform the energy market. Some of these interventions or changes are specific to the SGIP and others would require coordination across agencies. Below we list some possible interventions and indicate which would require broader coordination beyond SGIP.

- **Interagency cooperation and coordination.** The number of California and federal government programs available for the beneficial use of biogas is numerous. Some of these programs are complimentary while others are mutually exclusive. Ensuring the interagency programs are not in conflict with one another and that dissension does not exist amongst program rules is important to alleviate customer confusion and increase biogas program participation. This interagency collaboration would require coordination far outside of the SGIP.
- **Improve economics** for onsite generation projects. These improvements could come in several different forms, including increasing SGIP incentives. For directed biogas, this could further include expanding directed biogas procurement outside of WECC, and reevaluating siloxane requirements. However, allowing procurement outside of WECC would make verification more challenging and would limit in-state benefits. Many of these paths are outside the control of the SGIP and will require cross-cutting collaboration across multiple levels of public agencies.
- **Consider Raising Some Incentive Levels and Re-Evaluating Structures.** No base case scenario is estimated to have a participant cost test (PCT) ratio above one. Generators with a vented baseline (which consume methane that would otherwise be released to the atmosphere) lead to high GHG reductions and have a significantly higher TRC ratios than their PCT ratios. Higher incentives could improve the participant economics for scenarios associated with significant GHG benefits and TRC ratios above one.
- **Coordinate Layering of Incentives.** Layering of additional incentives can lead to PCT ratios above one but requires well-located facilities and savvy developers or participants. Improved marketing and outreach could improve developers' knowledge of all the various incentives that are available to improve the customer's economics and likelihood of adoption. SGIP incentives could be modified when other incentives are available to make better use of public funds, but such coordination with other programs could be challenging for both administrators and participants.
- **Directed Biogas has Benefits but may Require Additional Attention.** Most generation using directed biogas with a vented baseline is expected to exceed a TRC benefit cost ratio of 1 in 2030. Directed biogas with a flared baseline could approach a TRC ratio of 1 with cost reductions. These benefits all assume that directed biogas is used for the life of the generator. To maximize the benefits from directed biogas, the source of generation and longevity of fueling contracts needs to be ensured.
- **Simplify program participation requirements.** Participants' relatively low reported satisfaction level with program requirements (average level reported was 3.2 on a scale of one to five) and developers' confusion with program rules and cross-program eligibility both point to the need for clearer program rules and requirements in order to increase participation in biogas programs. Any simplifications need to be balanced with enough safeguards to ensure progress towards program goals.

# 2 INTRODUCTION AND STUDY OBJECTIVES

Established legislatively in 2001 to help address peak electricity problems facing California, the Self-Generation Incentive Program (SGIP) represents one of the longest-lived and broadest-based distributed energy resource (DER) incentive programs in the country. Since its inception, the SGIP has provided incentives to a wide variety of DER technologies including fuel cells, combined heat and power (CHP), solar photovoltaics (PV), wind turbines, and advanced energy storage (AES) systems.

This section identifies the study objectives, summarizes potential drivers and barriers for onsite generation in California, and presents the overall approach to fulfilling the study objectives.

## 2.1 STUDY OBJECTIVES

The scope and timing of SGIP measurement and evaluation (M&E) activities is driven by the CPUC SGIP M&E plan.[7] The 2020 SGIP Energy Biogas Market Assessment and Cost-effectiveness Report intends to inform CPUC decisions implementing SB 700. Below we present a list of key research questions addressed by this report. These questions were developed in consultation with the CPUC and the SGIP PAs.

### 2.1.1 Key Research Questions

Below we present a list of key research questions to be addressed by the 2020 Biogas Generation Cost-Effectiveness/Market Characterization Study. These questions were developed in consultation with the CPUC and the SGIP Working Group.[8]

- What evidence do we have that behind-the-meter (BTM) biogas generation is cost effective or will achieve cost-effectiveness in the next ten years given current SGIP incentive rates? How does the CE vary for onsite versus directed biogas?
- Biogas generation costs:

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7 Available here as of November 16, 2020: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIPMeasEvalPlanFINAL.PDF

8 The SGIP program administrators (PAs) are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCal Gas), and the Center for Sustainable Energy (CSE) who administers the SGIP for customers of San Diego Gas and Electric (SDG&E).

  - How much does BTM generation cost, and how have these costs changed over time?
  - How do the costs of BTM generation compare between onsite biogas and directed biogas? How does this vary by market segment (dairy, landfill, wastewater treatment plant, other)?
  - How are biogas generation costs likely to change over the next ten years and how will these changes affect biogas generation cost-effectiveness?
- What value does BTM biogas generation currently provide to ratepayers (i.e., total resource cost test)?
  - How do the benefits of BTM biogas generation compare between onsite biogas and directed biogas? How do the benefits compare for a flared versus a vented baseline?
  - How do the benefits of BTM biogas generation differ by point of view (customer, society, and ratepayer)?
- Drivers and barriers to biogas generation adoption:
  - What are the main drivers and motivations for customers to install biogas generation? How do they vary for onsite vs directed biogas projects?
  - What are the perceived benefits after installing biogas generation? To what extent are customers realizing the benefits they expected?
  - What are the main barriers for biogas generation adoption? How do they vary for onsite vs directed biogas projects?
  - What is the Impact of CARB and AQMD on both existing and/or potential installation of generators?
  - How does the availability of Low Carbon Fuel Standard (LCFS) credits for the transportation sector affect the availability of directed biogas (or pipeline biomethane) for BTM generation? Is the availability of LCFS credits for transportation competing with biogas availability for BTM generation? How does this vary by carbon intensity of the biogas source?
  - Clarification of information in previous impact evaluation regarding vented and flared credits for GHG's vs. the grid.
- What is the expected permanency of biogas as a fuel source vs a transition back to natural gas? What is the life expectancy of biogas systems?
- To what extent are customers installing biogas generation without the SGIP incentive (including customers outside California)?
- What would encourage increased adoption of biogas generation (onsite and directed)?

## 2.2 RESEARCH METHODOLOGY

This section provides a high-level summary of the approach used to answer the study's research questions. We pursued two separate but related research activities: market research and cost-effectiveness analysis.

- The **market research** addresses questions about drivers and barriers for biogas generation adoption. It will also help policy makers, program administrators, and stakeholders understand key trends in the biogas market and learn about SGIP participants' experiences with the program and their onsite generation equipment.
- The **cost-effectiveness** analysis addresses questions related to the costs and benefits associated biogas generation. By evaluating cost-effectiveness for prototypical applications, we can understand to what extent incentives are needed to promote adoption of biogas generation, and how assumptions about cost-trends influence the technology's cost-effectiveness going forward.

After conducting the cost-effectiveness and market research activities, we combine the findings and provide a comprehensive assessment of the biogas onsite generation market. Below we provide brief summaries of the market research and cost-effectiveness approaches. Additional details are provided in Section 4 (Market Research Approach) and Section 6 (Cost-Effectiveness Approach).

### 2.2.1 Summary of Market Research Approach

For this study we define market actors into five broad categories:

- **Utility and regulatory staff** who are responsible for administering, regulating and developing policies and procedures for the programs that affect the biogas market in California.
- **Industry experts** who have deep knowledge and insights regarding the current state of the biogas market in California and nationally. Many are also actively involved with advocacy organizations at the forefront of assessing the barriers and benefits of a variety of biogas end uses in the areas of transportation and generation. Several are in leadership positions for specific industries that are best-suited for biogas production and biogas generation.
- Onsite generation **project developers** who market, install, finance and, in some cases, operate onsite generation equipment for the host customer.[9] In certain cases, a developer may also be a manufacturer.

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9 The SGIP may have other definitions of a developer for program eligibility and budget purposes. Here we define developers for research purposes only.

- **Participating Host customers** who have installed onsite generation systems (biogas or natural gas fueled) and receive an incentive from the SGIP.
- **Nonparticipating Host customers** who either installed onsite generation systems (biogas or natural gas fueled) outside of the SGIP or produced biogas onsite but have not installed onsite generation.

The market research relies on interviews and phone/web surveys with utility and regulatory staff, biogas industry experts, onsite generation project developers (who in some cases are also the generation technology manufacturers), and SGIP onsite generation participant and nonparticipant customers to identify the key drivers and barriers to onsite biogas generation adoption. When thinking about drivers we consider what the primary motivations are for customers to install onsite generation in terms of desired outcomes (e.g., bill savings, backup power/reliability, biogas self-consumption, grid benefits (civic duty), or other financial benefits in the form of NEM or LCFS credits generated by selling electricity back to the grid).

Interviews with host customers also identify key barriers to onsite generation adoption. We investigate the major barriers to both onsite electricity generation (e.g., upfront cost, technology uncertainty, space constraints, etc.), as well as alternative uses onsite biogas producers have available to them that may provide greater benefits. We also investigate what steps may be needed to mitigate, compensate for, or remove these barriers.

Section 5 provides additional details on the data sources and methods used for the market characterization.

### 2.2.2 Summary of Cost-Effectiveness Approach

The cost-effectiveness analysis leverages the SGIP cost-effectiveness (SGIPce) model first developed in 2011 to evaluate the cost-effectiveness of all SGIP eligible technologies. It was updated in 2015 to reflect changes in technology costs and eligible technologies. For this research we updated SGIPce again with a focus on renewable technology costs and operations and maintenance costs.

SGIPce is a highly flexible economic model that quantifies the various cash flows associated with the purchase and operation of DERs including PV, CHP, fuel cells, and energy storage. The model calculates the bill impacts of technologies throughout their lifetime and the associated acquisition and operations costs including financing, insurance, fueling, maintenance, and tax costs (or credits). Looking from the grid’s perspective, SGIPce quantifies the changes in the utility’s marginal operating costs and considers incentive payments and program administration costs. The model quantifies the present value of all cost and benefit streams for the life of the technology and for new technologies installed ten years into the future accounting for changes in retail rates, technology capital and operating costs, and changes in utility marginal costs.

The cost-effectiveness analysis is based on the average capacity factor observed for installed technologies. The energy production for modeled technologies is analyzed as baseload production where the technology produces energy at the assumed capacity factor every hour of every day. Section 6 provides a comprehensive overview of the cost-effectiveness methodology, including details on all the inputs and calculations. Below we provide a brief listing of key model components:

- **Retail rates.** We selected the most appropriate, forward looking retail rates available from PG&E, SCE, and SDG&E. The selected rates differ by technology size as larger technologies are assumed to be installed at customer sites with larger loads and retail rates appropriate for the customer's size.
- **Technology characteristics.** We defined the characteristics of the renewable generation systems installed at each customer location, including technology types (Fuel Cells, Gas Turbine, Internal Combustion Engines, and Microturbines), system size (kW), efficiency, and average observed capacity factor.
- **Technology costs.** We researched technology, O&M, biogas cleaning, and digester costs to determine average capital costs and ongoing maintenance costs. Different fuel types were modeled with different cost components. Scenarios were modeled differently, including with and without digesters and with and without non-SGIP incentives.
- **Utility avoided costs.** We used the 2020 CPUC avoided cost calculator to develop representative marginal costs for PG&E, SCE, and SDG&E. All avoided costs components were accounted for, including generation energy and capacity, ancillary services, transmission and distribution (T&D) capacity, environment, and renewable portfolio standard (RPS) costs. The environmental or emissions avoided costs were also used to value the reduction in methane emissions for technologies installed with a vented baseline.
- **SGIP assumptions.** We defined the incentive levels offered by SGIP and the implied program administration costs to closely match recent program actuals at the outset of the analysis. Incentives are then reduced over time. Scenarios with higher SGIP incentives for resiliency benefits that match program actuals were also modeled.
- **Global assumptions.** We updated marginal tax rates/credits, discount rates, and other financing assumptions.

We use SGIPce to calculate the cost-effectiveness of various renewable generation technologies using the cost-effectiveness tests established in the Standard Practice Manual.[10] Specifically, we use the participant

[10] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

test, the ratepayer impact measure test, the total resource cost test, the societal total resource cost test, and the program administrator cost test. We evaluate cost-effectiveness using 2020 as a base year and for each year ten years into the future (through 2030). A cost-effectiveness value for 2030 represents the present value of all costs and benefits of a renewable generation system installed in 2030. Additional details on the modeling approach and assumptions are provided in Section 7.

### 2.2.3 Report Contents

This report is organized into the following sections:

- Section 1 is the executive summary
- Section 2 provides an introduction, lays out the objectives of this study, and provides relevant background on the SGIP and other elements
- Section 3 provides an overview of biogas programs and options in California
- Section 4 describes the research methods and data sources used for the market characterization component of this study
- Section 5 presents the findings from the market characterization analysis
- Section 6 describes the research methods and data sources used for the cost-effectiveness component of this study
- Section 7 presents the findings from the cost-effectiveness analysis
- Section 8 summarizes all evaluation findings and provides overarching takeaways
- Appendix A presents an overview of the questions included in the in-depth interview guides used for the interviews with utility and regulatory staff, biogas industry experts, and project developer.
- Appendix B presents the web/phone survey instrument for the SGIP participant and nonparticipant surveys
- Appendix C includes the results from all cost-effectiveness tests calculated in this study.

# 3 PROGRAM HISTORY

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) 9702 (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 provides financial incentives for the installation of distributed generation (DG) and AES technologies that meet all or a portion of a customer's electricity needs. The SGIP is funded by California's ratepayers and managed by program administrators (PAs) representing California's major investor owned utilities (IOUs). The PAs are Pacific Gas & 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 & Electric (SDG&E). The CPUC provides oversight and guidance on the SGIP.

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

By 2007, growing concerns with potential air quality impacts prompted changes to the eligibility of technologies under the SGIP. Approval of AB 2778 (Lieber) 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 (Kehoe, October 11, 2009) refocused the SGIP toward GHG emission reductions and led to a re-examination of technology eligibility by the CPUC. As a result of that re-examination, the list of technologies eligible for the SGIP expanded to again include CHP, pressure reduction turbines, energy storage paired with renewables, 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. Eligibility requirements for onsite generation projects also changed during 2011 when CPUC Decision D. 11-09-015 required that all directed biogas be procured from within the WECC. This change was implemented due to "concerns raised regarding the ability to verify out-of-state directed biogas, as well as the lack of local environmental benefits to California ratepayers".

In addition to the changes described above, D. 16-06-055 formalized the program's goals:

1. **Environmental:** The reduction of GHGs, the reduction of criteria air pollutants, and the limitation of other environmental impacts such as water usage.
2. **Grid Support:** Reduce or shift peak demand, improve efficiency and reliability of the distribution and transmission system, lower grid infrastructure costs, provide ancillary services, and ensure customer reliability of DERs.
3. **Market Transformation:** To create lasting change that increases the adoption and penetration of DER technologies through strategic intervention in defined markets.

Most recently, SB 700 (Wiener, September 27, 2018) authorized the continuation of SGIP through 2025. In the course of implementing SB 700, the CPUC has expressed its intention to consider other program modifications including: Overall collection levels for years 2020-2024, funding allocations among technology and customer sectors, and incentive levels for each technology.[11] Finally, on August 1st, 2019, the CPUC issued its decision approving greenhouse gas emissions reduction requirements for the SGIP storage budget.[12] This decision modified the SGIP to ensure that eligible SGIP energy storage systems reduce GHGs. The decision requires SGIP PAs to provide a digitally accessible GHG signal that provides marginal GHG emissions factors to project developers.

Most recently, beginning in 2017, the SGIP required that onsite generation projects be fueled in part by a renewable fuel. The renewable fuel requirement increased annually until 2020 when the program required onsite generation to be fueled by 100 percent renewable fuel (Table 3-1).

**TABLE 3-1: SGIP MINIMUM RENEWABLE FUEL BLENDING REQUIREMENT FOR ONSITE GENERATION**

| Application Year | SGIP Renewable Fuel Requirement |
|---|---|
| 2016 and prior | 0% |
| 2017 | 10% |
| 2018 | 25% |
| 2019 | 50% |
| 2020 | 100% |

11 https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB700

12 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K988/309988017.PDF

## 3.1 SGIP BIOGAS GENERATION POPULATION ACTIVITY AND TRENDS

By the end of 2019, the SGIP had provided incentives for 925 onsite generation projects representing 485 MW of rebated capacity. Figure 3-1, shows the distribution of onsite generation fuel types for the incentivized SGIP projects and installed rebated capacity since program inception. As this figure shows, the majority of the SGIP incentivized projects are fueled by non-renewable gas (81 percent projects and 77 percent of capacity), while 19 percent (171 projects) of projects and 23 percent (114 MW) of capacity are fueled by either directed or onsite biogas. To date, a greater percentage of renewably fueled SGIP projects and rebated capacity have been fueled with onsite biogas (62 percent of projects and 68 percent of capacity) rather than directed biogas.

**FIGURE 3-1: COMPLETED GAS GENERATION PROJECT COUNT AND CAPACITY BY GAS TYPE, 2001 – 2019**

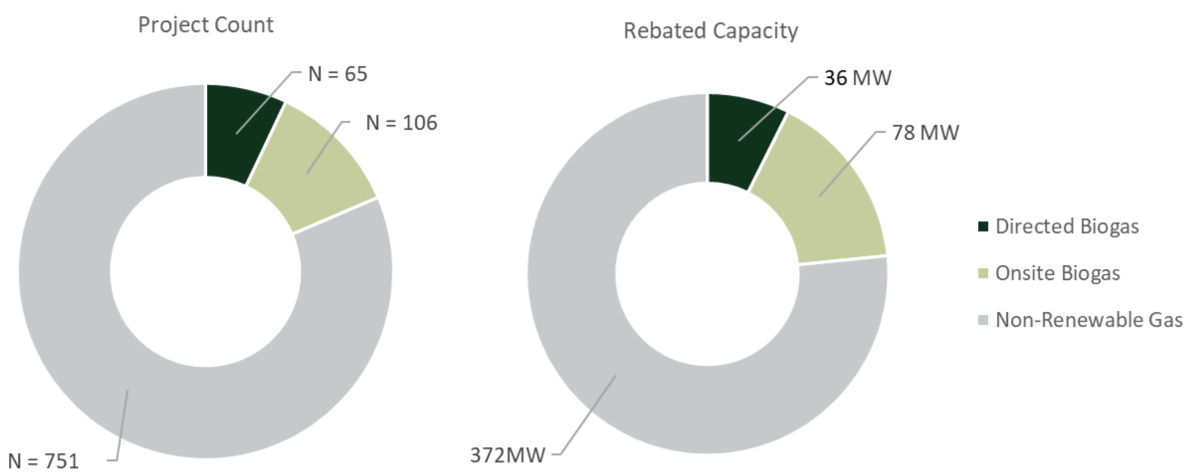



Figure 3-2 below shows cumulative SGIP incentivized onsite generation capacity by fuel type (onsite RNG, directed RNG, NG) since the program's inception by upfront payment year.[13] As this figures show, non-renewably fueled projects dominated the program's installed capacity early on but starting around 2011 biogas projects began to come online play a more substantial role in the program.

[13] Throughout this report we present SGIP program statistics as a function of program year or upfront payment year. The program year represents the calendar year the application was submitted. The upfront payment year is the calendar year during which the incentive was paid. The program year indicates what program rules were applicable during the SGIP application, whereas the upfront payment year is a proxy for when the system was interconnected and operational. The upfront payment year is often one or more years after the application program year.

**FIGURE 3-2: GROWTH IN SGIP GENERATION REBATED CAPACITY BY UPFRONT PAYMENT YEAR AND FUEL TYPE**

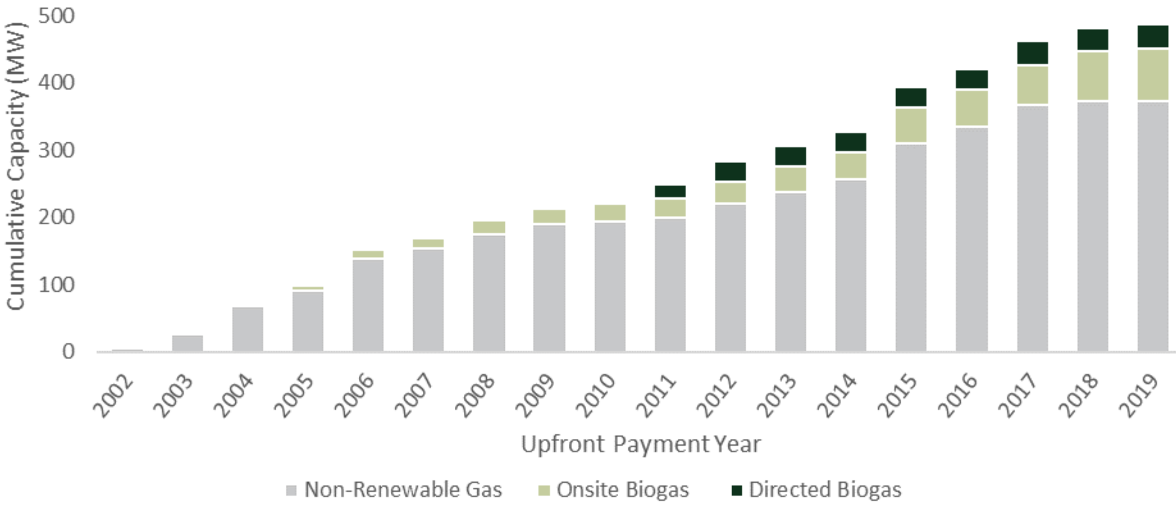
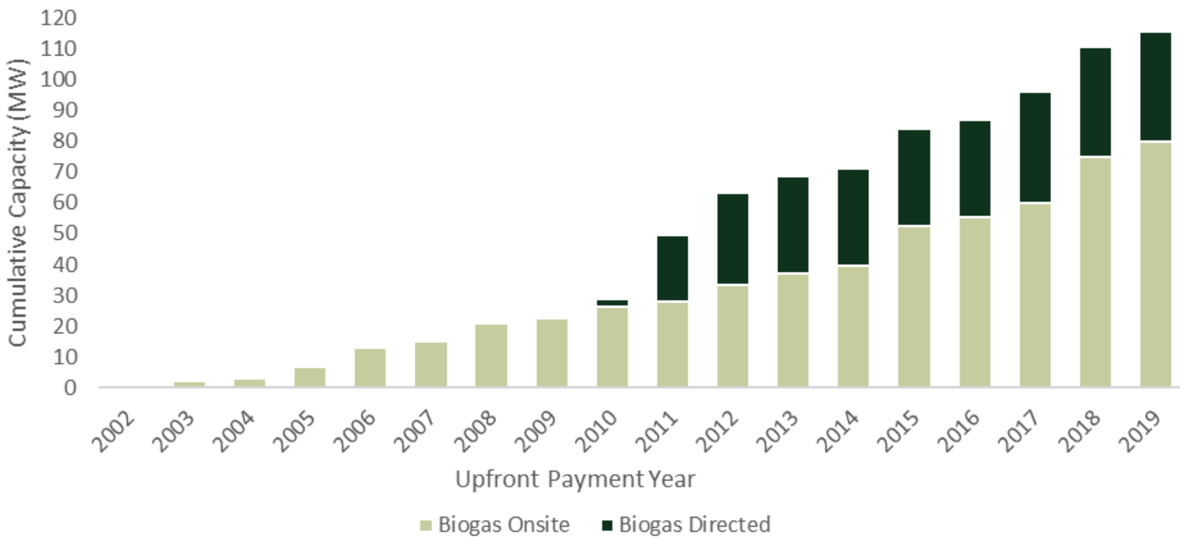


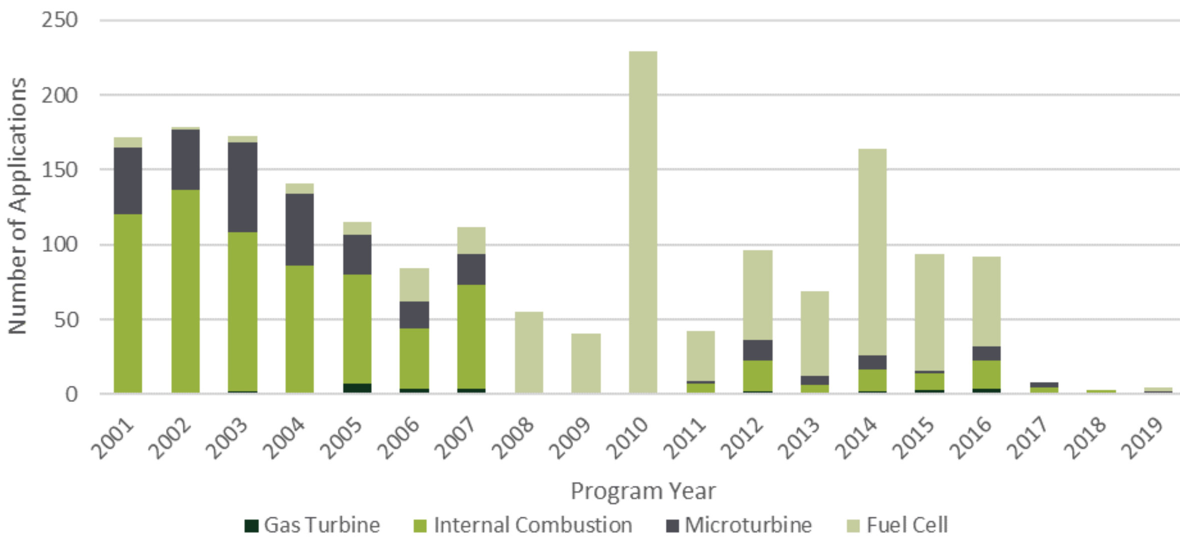

Figure 3-3 isolates the growth in SGIP capacity for just biogas fueled projects. As this figure shows, the first SGIP biogas fueled applications to receive a program incentive were paid in 2002. Eight years later, in 2010, the first directed biogas projects received incentive payments. Since 2013, only 4.2 MW of SGIP directed biogas capacity has been installed, all of which was added in 2017. Onsite SGIP biogas capacity has consistently increased year over year. Between 2010 and 2019, the SGIP added an average of 5.7 MW of onsite biogas capacity a year, with the largest increases in 2015 (12.6 MW) and 2018 (14.7 MW).

**FIGURE 3-3: GROWTH IN SGIP BIOGAS FUELED GENERATION REBATED CAPACITY BY UPFRONT PAYMENT YEAR AND BIOGAS SOURCE**



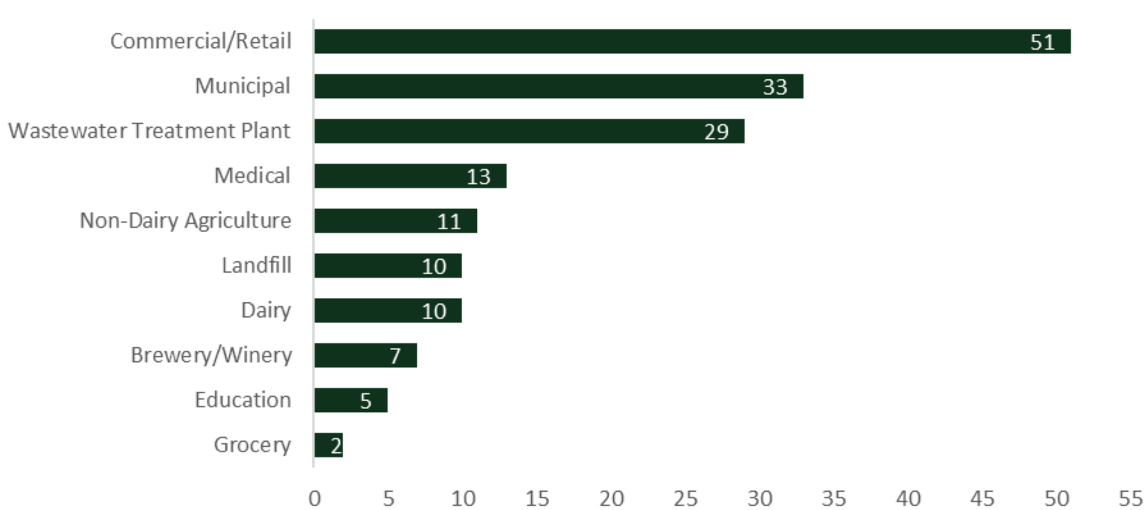

Despite what appears to be a steady increase in installed onsite generation capacity in the figures above, there has been significant volatility in the number of onsite generation applications submitted to the SGIP program annually. Figure 3-4 below shows the distribution of onsite generation applications by technology that have applied to the program since its inception. Prior to 2008 the majority of program applications submitted were for microturbines and internal combustion engines, however there was a significant shift in 2008 to electric-only and CHP fuel cells. The large spike in fuel cell applications in 2010 was related to one developer being well positioned to offer directed biogas fuel cell projects using out of state gas, however that increase was short lived after the CPUC instituted a ruling (D. 11-09-015) in 2011 which required program biogas to be procured from within the WECC. Additional fuel cell applications were submitted between 2011 and 2016, although the volume varied drastically from year to year, and then in 2017 program applications across all technologies fell off entirely. Only 9 applications have been submitted to the program since the beginning of 2017. In 2017 the SGIP program began phasing in a new program requirement for onsite generation requiring a portion of the fuel used to power the generation equipment to be renewable natural gas which came more costly after 2016 when the LCFS program began and gave RNG producers an alternative (and in many cases very lucrative) option for utilizing the biogas they produced onsite. Interviews with project developers reported discontinuing their program SGIP applications around that time due to this new program requirement.

**FIGURE 3-4: SGIP ONSITE GENERATION APPLICATIONS BY TECHNOLOGY, PROGRAM YEARS 2001 - 2019**




In total, the SGIP has provided incentives for 171 biogas projects. Figure 3-5, presents these projects by customer type as identified through the SGIP tracking data. The largest share of biogas generation participants are commercial and retail entities making up roughly 30 percent (51) of the projects. Municipalities and wastewater treatment plants are the next most prevalent biogas generation participants representing 19 percent (33) and 17 percent (29) of these projects, respectively.

**FIGURE 3-5: COMPLETED BIOGAS GENERATION PROJECT COUNT BY CUSTOMER TYPE, 2001 – 2019**



# 4 BIOGAS IN CALIFORNIA

Biogas is methane and other gases formed when organic material is decomposed anaerobically (in the absence of oxygen). The organic matter can come from a variety of sources such as dairies, wastewater treatment plants and landfills. When this biogas is refined to pipeline quality it is often called biomethane. This section presents an overview of the primary sources of biogas in California and the various incentives that are driving this market.

## 4.1 MARKET CHARACTERISTICS

There are roughly three primary sources of biogas within California:

- **Dairies** that collect manure and process it through a digester. Note that this only captures methane from the anaerobic decompositions of manure and not cow flatulence or burps. Larger dairies usually store manure for many days to allow the manure to break down and then be used as fertilizer later. The manure is typically stored wet in ponds or dry in piles or barns. Most of the manure is isolated from the air so the manure breaks down anaerobically and produces methane that is released into the atmosphere.
- Larger **Wastewater Treatment Plants** that use anaerobic digesters to break down organic wastes and produce methane. Most of these plants are required to destroy the methane produced, usually through combustion or flaring.
- **Landfills** that are essentially large anerobic digesters that isolate organic materials, which break down over time isolated from the air. They produce methane that is then collected via pipes to be destroyed by flaring or can be cleaned and used to power onsite electrical generation equipment or injected as RNG into a gas pipeline. California requires most landfills to collect this methane and destroy it; usually by flaring or burning.

Other sources of biogas include Municipal Solid Waste digesters that process green waste (food scraps, yard clippings, etc.) from municipal sources and breweries or other food processing facilities that use anaerobic digesters to reduce their amount of waste and, if desired, produce biogas for heating or generation. However, these sources currently appear to provide significantly less biogas than the three bulleted sources identified above and to date less than 10 percent of onsite biogas SGIP sites fall outside these categories. In general, bigger is better economically due to economies of scale for projects to collect and refine biogas to create usable fuel.

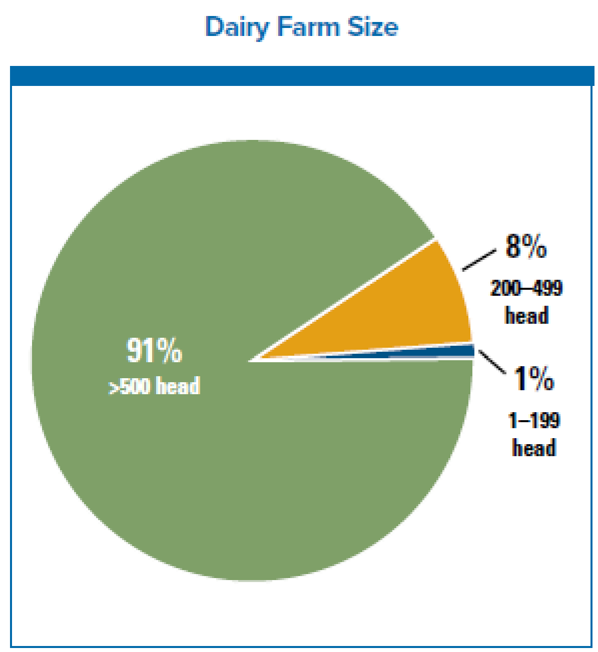
### 4.1.1 Dairies

The US Environmental Protection Agency (EPA) tracks methane sources including landfills and estimates the availability of methane from dairies as part of its efforts to track sources of GHG's. The EPA estimates that there are 799 dairy farms in California that are candidates for anaerobic digesters.[14] This estimate is based on the EPA's determination that the addition of a digester is potentially economically viable for dairies with 500 or more cows. However, other industry experts estimate that 1,500 or more cows are needed to provide the economies of scale to make anaerobic digesters economically viable

**FIGURE 4-1: EPA DATA FOR DAIRIES IN CALIFORNIA**

| Market Opportunities to Generate Electricity with Anaerobic Digestion (2007) | |
|---|---|
| Total number of dairy operations | 2,165 |
| Total number of mature dairy cows (000 head) | 1,841 |
| Number of feasible dairy cow operations[1] | 889 |
| Number of mature dairy cows at feasible operations (000 head) | 1,352 |
| Methane emission reduction potential (000 tons/year) | 341 |
| Methane production potential (billion ft$^3$/year) | 27.9 |
| Electricity generation potential (000 MWh/yr) | 2,375 |

[1] Anaerobic digestion was considered feasible at all existing operations with flushed or scraped freestall barns and drylots with at least 500 dairy cows.




The EPA tracks known digesters as part of the AgSTAR: Biogas Recovery in the Agriculture Sector program.[15] As of March 2020, 38 agricultural digesters were known to be operating at dairies in California. A significant number of additional digesters are under construction with assistance from the California Department of Food & Agriculture's (CDFA) Dairy Digester and Development Program (DDRDP) that provides grants for up to half the cost of the digester up to $3 million. This program has allocated grants to 108 digesters in California, with many still under construction.

14 US EPA, Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities, June 2018, EPA-430-R-18-006

15 https://www.epa.gov/agstar

### 4.1.2 Wastewater Treatment Plants (WWTP)

Based on data from the California Association of Sanitation Agencies, there are 242 wastewater treatment plants in California. Of these, 154 are known to have a digester installed to help process waste and produce methane, and they are designed, on average, to process 23 million gallons of wastewater per day. Of these plants, 42 have a digester in place but only flare that gas to destroy it and the other 112 are believed to make beneficial use of the gas. There are an additional 85 WWTP that do not use digesters. Currently, these tend to be smaller, with an average design flow of only 1.5 million gallons of wastewater processed per day.

### 4.1.3 Landfills

In addition to dairies, the US EPA also tracks landfills as potential sources of methane as part of the Landfill Methane Outreach Program.[16] Within that system, the EPA has record of 405 landfills in California.[17] Of these, 265 have a methane collection system in place, but only 15 of them are listed as using the methane for generation or pipeline injection, while the rest flare the collected methane. The EPA has identified 137 landfills in California that do not have a methane collection system in place, but these tend to be much smaller with an average of approximately 383,000 tons of waste in place. The average size of landfills with methane collection systems in place is around 19 million tons of waste.

### 4.1.4 California Biogas Summary and Standard Practices

Table 4-1 summarizes the primary sources of biogas within California that are available for potential biogas generation projects. This table also shows what the standard practice or 'baseline' process is for each source. As stated above, larger dairies collect manure in ponds/lagoons or stack it in piles in barns. The manure decomposes anaerobically and releases (or vents) methane to the atmosphere. Dairies do not usually have a digester in place unless they are creating biogas to fuel generation or for transportation.[18] Larger wastewater treatment plants often have digesters installed onsite to process the solid waste byproduct produced during the initial water treatment process. Many of these use the resulting biogas for onsite electricity generation, pipeline injection, or other 'beneficial use' instead of flaring. Larger landfills collect biogas produced by waste decomposition and most are required to flare the biogas to destroy the methane rather than venting it. A handful of landfills upgrade the biogas and use the fuel beneficially.

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16 https://www.epa.gov/lmop/about-landfill-methane-outreach-program

17 https://www.epa.gov/lmop/project-and-landfill-data-state

18 Based on discussions with dairy digester developers.

**TABLE 4-1: BIOGAS SOURCE MARKET SIZES IN CALIFORNIA**

| Source | Number in California | Standard Practice | Number known to be Producing and Collecting Biogas | Number Known to be using Biomethane for Generation or Pipeline Injection |
|---|---|---|---|---|
| Dairies (> 500 Cows) | 799 | Collect and Store Manure – methane vents to atmosphere | 38* | 38 |
| Wastewater Treatment Plants | 242 | Most use digester and many then generate | 154 | 112 |
| Landfills | 405 | Collect gas and flare | 265 | 15 |

*Approximately 100 more are currently in development.

## 4.2 BIOGAS MANAGEMENT AND USES

Most wastewater treatment plants and landfills are required to collect and flare (or combust) biogas to destroy the methane and create $CO_2$ and water. Dairies do not typically collect methane unless they are using it for beneficial uses. These beneficial uses include pipeline injection or onsite electricity generation.

### 4.2.1 Pipeline Injection

An increasing number of sites are upgrading biogas and injecting this gas into the natural gas distribution system. To do so, the directed biogas (or biomethane[19]) must meet natural gas pipeline standards for both heat content and low quantities of impurities. This requires removing $CO_2$ to increase heat content and potentially expensive filtering and treatment to remove compounds that are likely problematic such as hydrogen sulfide ($H_2S$), ammonia ($NH_3$) and siloxanes. Hydrogen sulfide and ammonia can rapidly increase corrosion of the steel in the pipeline and other components. "Siloxanes are manmade by-products created as a result of a variety of combustion processes. They are difficult and expensive to measure due to the complex and varying gas matrices. Siloxanes in biogas can convert to SiO2 when the gas is combusted. This produces a layer of what is essentially glass inside the combustion elements."[20] This accumulation of SiO2 will eventually force the equipment to be shut down for expensive and time-consuming maintenance

19 The term biomethane is often used to identify biogas that has been cleaned up to pipeline quality. However, SGIP has consistently used the term biogas for all forms of biogas or biomethane, so in this report we use the term biogas predominantly to be consistent with SGIP documents.

20 https://www.ohiolumex.com/siloxanes-in-biogas?adgroupid=68698513406&keyword=siloxane%20landfill%20gas&adgroupid=68698513406&keyword=siloxane%20landfill%20gas&gclid=CjwKCAjwkdL6BRAREiwA-kiczEXTF7WbrF96KKLoqIUEvXtXckhgY78pCxuHQjc1a3ElzbMBcHyvQBoCswAQAvD_BwE

and repairs. They can also extinguish pilot lights in equipment and therefore can result in significant safety hazards. The current limit for siloxanes in directed biogas for pipeline injection in California is 0.1 $mg/m^3$.

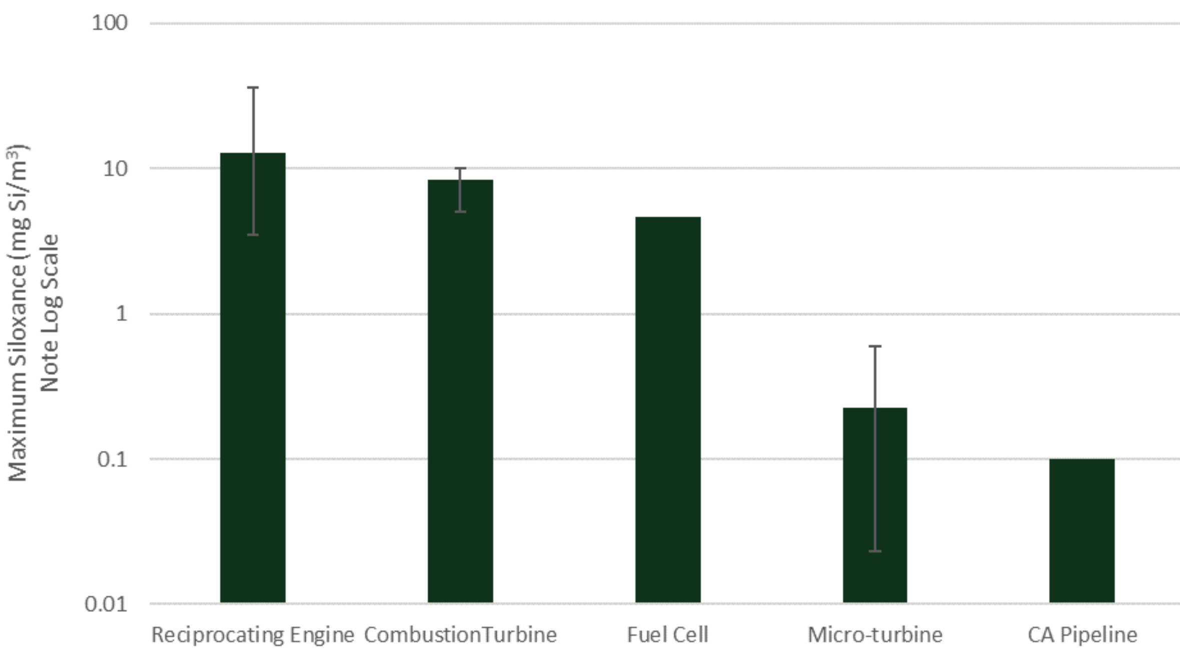
In addition to purification, biogas also needs to be pressurized to be at a sufficient pressure to be injected into the gas pipeline. This gas then becomes functionally identical to the Compressed Natural Gas (CNG) that flows through California's pipelines for use in customers businesses and homes. The upgrading, cleanup, and pressurization equipment, plus the connection to the pipeline, can be very expensive with costs ranging well into the millions of dollars. This equipment also requires regular operations and maintenance, and the pressurization equipment can require significant amounts of electricity to operate. Some industry experts estimate that O&M alone for these processes can be as much as $20 per MMBtu. These costs result in directed biogas being substantially more expensive than natural gas.

Once injected into the natural gas distribution network, the directed biogas co-mingles with fossil based natural gas, where it is then used by the utility, or provides a source of directed biogas. The producers of directed biogas are paid by selling credits or through long term contracts. The directed biogas is then used to offset an equivalent amount of natural gas by the purchasers of these credits or the buyer of the contracted directed biogas . One application of directed biogas (or pipeline biomethane) for SGIP projects; directed biogas is biogas delivered through a natural gas pipeline system and used at a distant customer's site. Within the SGIP, this is considered a renewable fuel. This gas can also be used for transportation and receive credits via California's Low Carbon Fuel Standard and the federal Renewable Fuel Standard.

### 4.2.2 Electricity Generation

Biogas can also be used to generate electricity, either onsite or through directed biogas where the generator operator agrees to buy directed biogas from a producer. For onsite generation, the biogas still needs to be processed to remove many of the impurities as for pipeline injection, but often the requirements for use in combustion are not as stringent as for injection into a pipeline. Figure 4-2 shows the published acceptable range (shown as error bars) of siloxanes for different uses and the current California specification for pipeline injection of 0.1 $mg/m^3$. Note that most engines have requirements that are significantly less stringent than the California pipeline standard. Some reciprocating (or internal combustion) engines can tolerate nearly 1,000x more siloxanes (10 -100 $mg/m^3$) than are allowed in California pipelines. Some microturbines, however, require fuel with a lower siloxane (0.01-0.1 $mg/m^3$) content than California pipelines. The California Siloxane requirement on biogas is not a SGIP specific barrier but does impact the availability of directed biogas from in-state sources as it is more restrictive than most generators require.

**FIGURE 4-2: SILOXANE REQUIREMENTS FOR DIFFERENT ENGINES AND CALIFORNIA PIPELINES**[21]




## 4.3 POLICY INTERVENTIONS

Multiple federal and state programs are in place to incent the beneficial use of biomethane. These have many forms such as grants, tax breaks, credits, and other incentives. These include:

- Transportation Incentive Programs – California's Low Carbon Fuel Standard (LCFS) and the federal Renewable Fuel Standard (RFS) are market-based programs with the goal of reducing the carbon intensity of transportation fuels.
- Generation Incentive Programs – In addition to the SGIP, California's BioMAT program provides a feed-in-tariff for biogas generation. RECs and NEM also offer opportunities for compensation for the production of renewably-generated electricity that is fed into the grid.
- California Department of Food and Agriculture Digester (CDFA) – The CDFA provides grants to help offset the cost of anaerobic digester installation at dairies to facilitate the production of biogas for beneficial use.

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21 Taken directly from "California Council on Science & Technology, Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications: An Independent Review of Scientific and Technical Information".

- Federal Tax Credits (ITC) – the federal government offers tax credits on eligible renewable energy generating systems, including fuel cells and microturbines.
- Pipeline Interconnection Incentives - Assembly Bill 1900 directed an incentive program to be offered to aid biogas pipeline interconnection costs.

Table 4- presents more details on biogas programs and whether they can be used by SGIP participants or not.

**TABLE 4-2: ALTERNATIVE/COMPLIMENTARY BIOGAS PROGRAMS**

| Program | Compatible with SGIP Participation | Financial Incentive/Credit |
|---|---|---|
| LCFS | N | LCFS Credit at $200/MT: $6.75-$74.88/MMBtu based on CI of biogas |
| RFS | N | RINS Credits range from $5-$15/credit, 11.7 RINs/MMBtu of RNG gas |
| BioMAT | N | Feed-in-tariff: $127.72-$199.72/MWh to sell electricity directly to utility |
| RECs | Y | RECs are sold as a commodity into the marketplace. 1 REC = 1 MWh of renewable-generated energy |
| NEM | Y | Compensation for renewable electricity exported back to the utility, based on retail rate net of nonbypassable charges |
| CDFA DDRDP | Y | Grants for up to half of the cost of AD installation ($2M/project max) |
| ITC | Y | 26 percent tax credit based on the FMV of installed fuel cells or microturbines |
| Interconnection Assistance | N | Grants for up to half of interconnection costs for dairies ($3M/project max, $5M for clusters) |

### 4.3.1 Transportation Incentive Programs

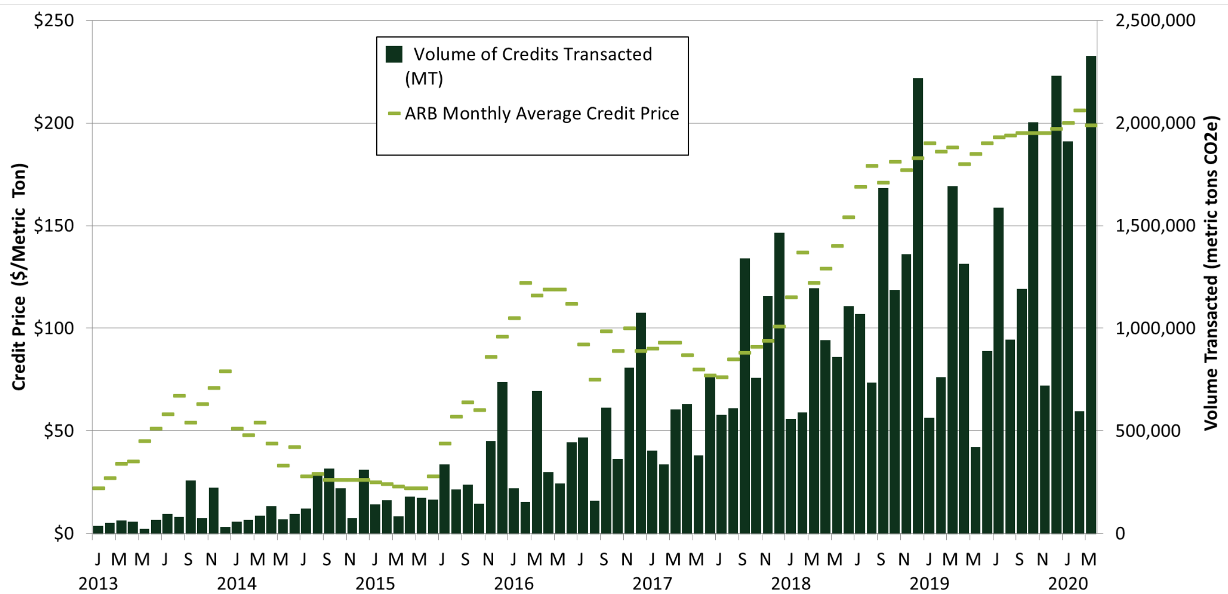
#### California's Low Carbon Fuel Standard (LCFS)

California's Low Carbon Fuel Standard (LCFS) began implementation on January 1, 2011 with the goal of reducing California's greenhouse gas (GHG) emissions and other pollutants. "The LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce GHG emissions and decrease petroleum dependence in the transportation sector. The LCFS standards are expressed in terms of the "carbon intensity" (CI) of gasoline and diesel fuel and their respective substitutes."[22] This program established a market-based program that allows carbon-intensive fuel producers like refineries to buy credits from lower carbon sources such as biogas. The carbon intensity can vary substantially by source, with dairies providing some of the greatest carbon reduction due to a very high carbon equivalent baseline. Credits are based on the tons of carbon

[22] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about

removed by use of a lower carbon fuel. Figure 4-3 shows the historical trend in credits. The price in the 2019 and early 2020 has averaged close to $200 per Metric Ton of carbon removed.

**FIGURE 4-3: LCFS HISTORICAL CREDIT PRICING**




"The Low Carbon Fuel Standard (LCFS) assigns a carbon intensity (CI) value to each fuel according to the source and also sets a target of average carbon intensity for the transportation sector as a whole. Fuels with a carbon intensity above the target generate deficits by the amount of the difference between the fuel's CI and the target CI. Fuels with carbon intensity below the target generate credits based on the difference between the fuel's CI and the target CI. Credits are then sold to firms that have accumulated deficits, and the market clears when the credit price equates the number of generated credits to deficits. In such a market, for a given credit price, credits can be thought of as a subsidy on low-carbon fuel and deficits can be thought of as a tax on high-carbon fuel. Since the credit is dependent on the degree to which a fuel falls below the target, the effective subsidy per unit of RNG differs depending on whether the RNG was sourced from dairy gas, landfill gas, municipal solid waste, or digestion in a wastewater treatment plant. In the table below are the carbon intensities of the four sources of RNG, as well as fossil natural gas, diesel, and the 2020 CI target for reference."[23] Table 4-3 shows the carbon intensities and prices by source.

[23] Quoted from Jaffe et al, Final Draft Report on The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute Contract No. 13-307 Prepared for the California Air Resources Board and the California Environmental Protection Agency

**TABLE 4-3: LCFS CARBON INTENSITIES AND PRICES**

| Fuel Type | Specific Source | $CO_2e$/MT | $gCO_2e$/MMBtu | LCFS Credit Benefit to RNG ($/MMBtu) at $200/MT |
|---|---|---|---|---|
| Diesel | Diesel | 102.01 | 107,709 | |
| Target | 2020 Target | 91.81 | 96,939 | |
| CNG | CA CNG via pipeline | 78.37 | 82,749 | |
| CNG | Landfill gas | 46.42 | 49,013 | $6.75 |
| CNG | Dairy Digester Biogas to CNG | -276.24 | -291,674 | $74.88 |
| CNG | MSW Digester Gas to CNG | -22.93 | -24,211 | $21.39 |
| CNG | WWTP AD to CNG | 19.34 | 20,421 | $12.47 |

## Renewable Fuel Standard (RFS)

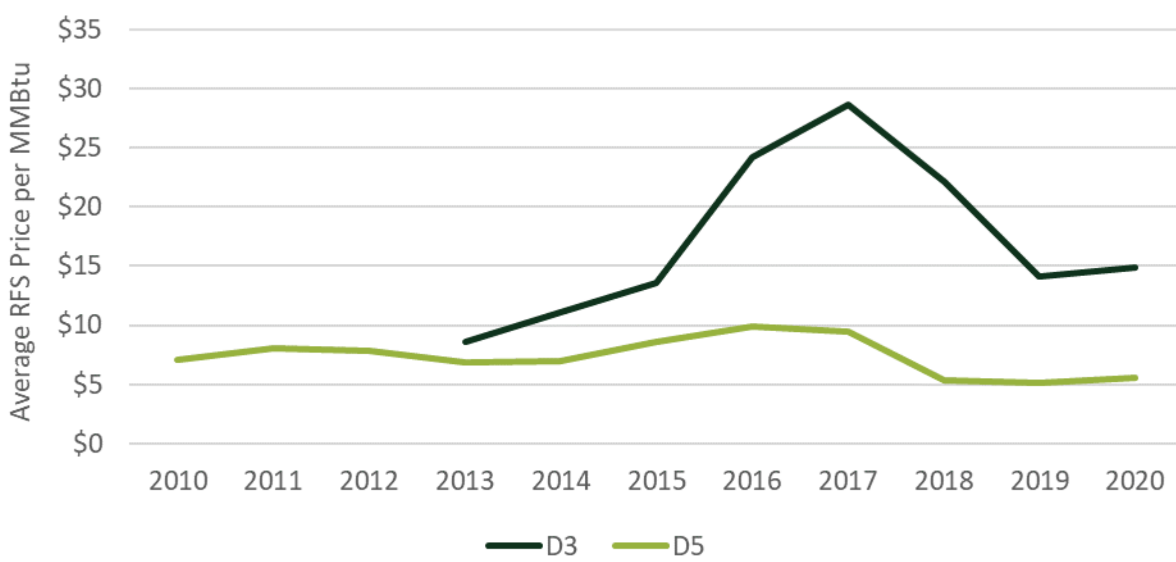
In addition to the LCFS, biogas producers can also participate in the federal Renewable Fuel Standard (RFS). The same fuel can sell credits in both markets simultaneously to ‘stack’ benefits. “The Renewable Fuel Standard (RFS) program was created under the Energy Policy Act of 2005 (EPAct), which amended the Clean Air Act (CAA). The Energy Independence and Security Act of 2007 (EISA) further amended the CAA by expanding the RFS program. EPA implements the program in consultation with U.S. Department of Agriculture and the Department of Energy. The RFS program is a national policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel. The four renewable fuel categories under the RFS are:

- Biomass-based diesel
- Cellulosic biofuel
- Advanced biofuel
- Total renewable fuel”[24]

This program can provide additive incentives to California’s LCFS based on the fuel category. Almost all potential sources of biogas covered in this report (Dairy Digesters, WWTP, LFG and MSW) qualify as cellulosic biofuel, or d-code D5. The volume of desired fuel by source is set by the EPA annually as part of a rulemaking process. Credits are traded as Renewable Identification Numbers (RIN). A RIN is a credit equivalent to a gallon of fuel ethanol, and there are 11.7 RINs per MMBtu of natural gas.

[24] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

**FIGURE 4-4: FEDERAL RIN PRICES OVER TIME**




## Program Compliance Basics

"Obligated parties under the RFS program are refiners or importers of gasoline or diesel fuel. Compliance is achieved by blending renewable fuels into transportation fuel, or by obtaining credits (called "Renewable Identification Numbers", or RINs) to meet an EPA-specified Renewable Volume Obligation (RVO).

EPA calculates and establishes RVOs every year through rulemaking, based on the CAA volume requirements and projections of gasoline and diesel production for the coming year. The standards are converted into a percentage and obligated parties must demonstrate compliance annually.

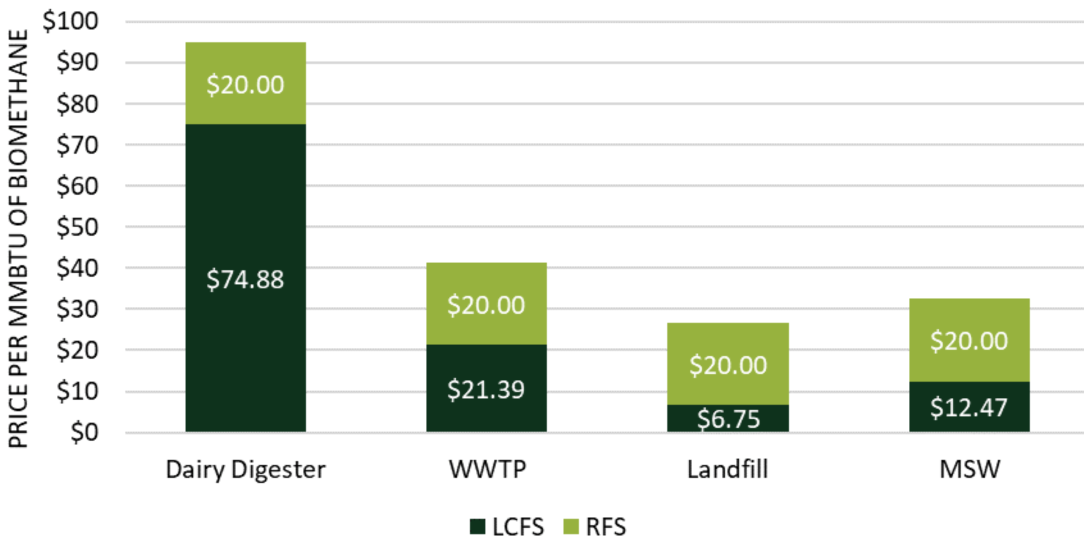
Each fuel type is assigned a "D-code" – a code that identifies the renewable fuel type – based on the feedstock used, fuel type produced, energy inputs and GHG reduction thresholds, among other requirements. The four categories of renewable fuel have the following assigned D-codes:

- **Cellulosic biofuel** is assigned a D-code of 3 (e.g., cellulosic biofuel) or D-code of 7 (cellulosic diesel)
- **Biomass-based diesel** is assigned a D-code of 4
- **Advanced biofuel** is assigned a D-code of 5
- **Renewable fuel** (non-advanced/conventional biofuel) is assigned a D-code of 6 (grandfathered fuels are also assigned a D-code of 6)

"Renewable identification numbers" or RINs are the credits that obligated parties use to demonstrate compliance with the standard. Obligated parties must obtain sufficient RINs for each category to demonstrate compliance with the annual standard."

These credits do not vary based on carbon intensity as LCFS credits do. On a $/MMBtu basis, RFS credits can be substantially larger (for landfills) or smaller (for dairies) than LCFS. Figure 4-5 shows the average value of transportation credits per MMBtu of biogas.

**FIGURE 4-5: AVERAGE PRICES OF TRANSPORTATION CREDITS**




The high prices for LCFS credits from dairies are a significant driver in increasing biomethane production from that sector.

### 4.3.2 Incentives for Electrical Generation from Biogas

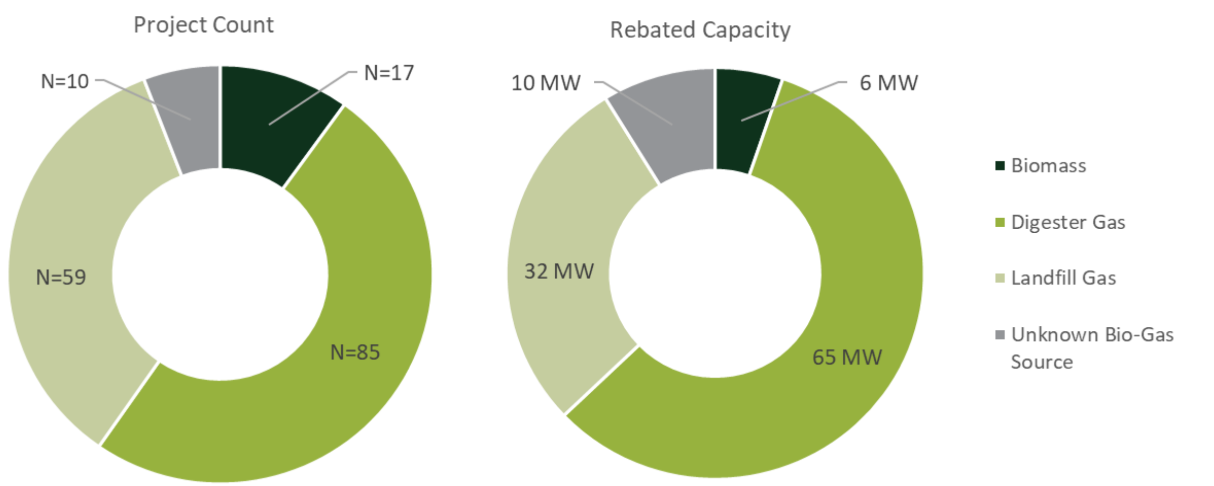
In addition to market-based credits for offsetting transportation fuel, several programs exist to incent biogas fueled generation.

#### Self-Generation Incentive Program (SGIP)

As discussed in Section 2 of this report, since the inception of the SGIP in 2001 it has provided financial incentives for the installation of distributed generation (DG) technologies. Up until 2017 the onsite generation could be fueled by either natural gas or renewable biogas, however starting in 2017 the program began requiring a portion of the fuel to come from a renewable source, and beginning in 2020, 100 percent of the fuel had to be renewable biogas. The SGIP incentives are split 50/50 between an upfront payment and a five-year Performance Based Incentive (PBI). The PBI is based on the expected output of the onsite generation equipment when operating at an 80 percent capacity factor for those 5 years for non-renewable natural gas fueled projects.

Figure 4-6, shows the breakdown of completed SGIP biogas fueled projects by biogas fuel with regards to project count and rebated capacity since the program's inception. Overall, the most prevalent type of biogas for SGIP projects is digester gas, which makes up roughly half of completed biogas projects and 57 percent of rebated capacity (consisting of 85 projects and 65 MW of capacity). Landfill gas makes up roughly a third of SGIP biogas in terms of completed projects and capacity. The biomass gas represents the smallest share of SGIP biogas projects, which consist of 17 projects and 6 MW of capacity. The biogas source for ten projects, representing 10 MW of capacity could not be determined from the program tracking data, primarily due to the age of the projects.

**FIGURE 4-6: COMPLETED GAS GENERATION PROJECT COUNT AND CAPACITY BY BIOGAS TYPE, 2001 – 2019**




## Net Energy Metering (NEM)

California's Net Energy Metering (NEM) policies, beginning in 1995 with the original NEM tariff or "NEM 1.0," have encouraged the adoption of customer-sited renewable resources like solar photovoltaic (PV) systems, fuel cells, renewable and biogas fueled generation, and distributed wind. NEM tariffs incentivize the installation of customer-sited renewable resources by compensating NEM customers for energy that is produced and exported to the grid.

California's NEM policies are one of a handful of tools available from the California Public Utilities Commission (CPUC) to encourage the adoption of customer-sited renewable resources. California Senate

Bill (SB) 656 (Alquist, 1995) required every electric utility in the state, whether or not the entity is subject to the jurisdiction of the CPUC, to develop a standard contract or tariff providing for NEM. SB 656 allowed NEM customers to be compensated for the electricity generated by an eligible customer-sited renewable resource and fed back to the utility over an entire billing period. SB 656 required California utilities to make this NEM tariff available to eligible customers on a first-come, first-served basis until the time that the total rated generating capacity in each utility's service area equaled 0.1 percent of the utility's peak electricity demand forecast for 1996.[25]

On February 5, 2016, the CPUC issued Decision (D.) 16-01-044, which created the NEM successor tariff, known as "NEM 2.0."[26] The current NEM 2.0 program went into effect in SDG&E's service territory on June 29, 2016, in PG&E's service territory on December 15, 2016, and in SCE's service territory on July 1, 2017. The program provides customer-generators full retail rate credits for energy exported to the grid and requires them to pay charges intended to align NEM customer costs more closely with non-NEM customer costs. Customer-generators taking service under NEM 2.0 must pay a one-time interconnection fee, pay non-bypassable charges, and transfer to a time-of-use (TOU) rate.[27]

### Bioenergy Market Adjusting Tariff (BIOMAT)

California provides the Bioenergy Market Adjusting Tariff (BioMAT) to incent biogas fueled electricity generation. This program was created by SB 1122 and follows up to a similar feed-in-tariff. "The BioMAT is a feed-in tariff program for small bioenergy renewable generators less than 5 MW in size. The BioMAT program offers up to 250 MW to eligible projects through a fixed-price standard contract to export electricity to California's three large investor owned utilities (IOUs). Electricity generated as part of the BioMAT program counts towards the utilities' RPS targets and the utilities own and REC credits for the energy produced. Small-scale bioenergy projects can be procured in three categories:

- **Category 1:** Biogas from wastewater treatment, municipal organic waste diversion, food processing, and co-digestion - **110 MW**
- **Category 2:** Dairy and other agricultural bioenergy - **90 MW**
- **Category 3:** Bioenergy using byproducts of sustainable forest management (including fuels from high hazard zones effective February 1, 2017) - **50 MW**"[28]

25 California Senate Bill 656, Alquist. February 22, 1995. http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

26 CPUC Decision Adopting Successor to Net Energy Metering Tariff. February 5, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

27 Additional information on the NEM bill calculation methodology, including the treatment of Net Surplus Compensation (NSC) and annual true-up statements, is included in Section 4.

28 https://www.cpuc.ca.gov/SB_1122/

This program provides a feed-in-tariff of $127.72/MWh to $199.72/MWh to sell electricity directly to the utility. "The program is modeled largely after the existing Renewable Market Adjusting Tariff ("ReMAT"), which implements SB 32 for all renewable generators. Available contract price will start at $127.72/MWh in Period 1 (February 2016) and the Power Purchase Agreement (PPA) can have 10, 15, or 20-year terms. Once the PPA is executed, the Contract Price is fixed over the Delivery Term. Available prices have the potential to adjust every 2 months and are set according to market acceptance and market depth on a statewide (all IOU) basis."[29]

Table 4-4 shows the different categories and capacities in the BioMAT program. Also shown are the current Power Purchase Agreement (PPA) prices being offered.

**TABLE 4-4: BIOMAT CAPACITY AND STATUS**

| Utility | Category | Program Capacity (MW) | Remaining Capacity (MW) | PPA Price per MWh |
|---|---|---|---|---|
| PG&E[30] | 1 – Waste | 30.5 | 28.047 | $127.72 |
| | 2 – Dairy and Ag | 33.5 | 12.436 | $187.72 (Dairy)<br>$183.72 (Other Ag) |
| | 3 - Forestry | 47 | 36.120 | $199.72 |
| SCE | 1 – Waste | 55.5 | TBD* | $127.72 |
| | 2 – Dairy and Ag | 56.5 | TBD* | $187.72 (Dairy)<br>$183.72 (Other Ag) |
| | 3 - Forestry | 2.5 | 2.5 | $199.72 |
| SDG&E | 1 – Waste | 24.0 | 21 | $127.72 |
| | 2 – Dairy and Ag | 0.0 | N/A | N/A |
| | 3 - Forestry | 0.5 | 0.5 | $199.72 |

* The Verdant team is still working to determine these values.

Participants in the BioMAT program are NOT eligible for SGIP or NEM. Generators that received an SGIP incentive must wait ten years to participate in the BioMAT program.

## Renewable Energy Credits (RECs)

Utility customers generating energy from biogas or other renewable sources may be eligible to create Renewable Energy Credits (RECs). Each REC represents 1 MWh of renewably generated electricity and may be traded on REC markets to aid in compliance with state or other Renewable Portfolio Standards

[29] https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/BioMAT/BioMAT_JointIOUWebinar_FINAL.pdf

[30] https://pgebiomat.accionpower.com/biomat/home.asp; accessed September 6, 2020

(RPS). “A REC confers to its holder a claim on the renewable attributes of one unit of energy generated from a renewable resource. A REC consists of the renewable and environmental attributes associated with the production of electricity from a renewable source. RECs are "created" by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy.”[31] The creation and trading of RECs must be verified via a third party.

RECs can be used to support voluntary (like green tariffs) or compulsory (RPS) green energy programs. Utility green tariff programs allow customers to switch to new tariff rates to procure renewable energy via the utility. The value of RECs vary significantly by state and can be volatile given fluctuations in renewable energy supply, demand and evolving legislative or regulatory goals. Community Choice Aggregator (CCA) green power programs are driving an increase in the market in California for RECs. [32] “California’s REC market is tracked by the Western Renewable Energy Generation Information System (WREGIS), which tracks renewable energy generation and creates WREGIS certificates for every REC generated. The WREGIS certificates (or RECs) are used to demonstrate compliance with state RPS policies. WREGIS serves 14 states and two Canadian provinces.”[33] For reference, in mid-June 2019, the price SCE paid for RECs was $0.018 per kWh, which is significantly lower than the prices paid by LCFS and Biomat. [34]

If participating in BioMAT, these credits are owned by the utility. If generating outside of BioMAT, these credits accrue to the owner of the generation.

## 4.4 CALIFORNIA DEPARTMENT OF FOOD AND AGRICULTURE (CDFA) DAIRY DIGESTER RESEARCH AND DEVELOPMENT PROGRAM (DDRDP)

The California Department of Food and Agriculture (CDFA) Dairy Digester Research and Development Program (DDRDP) is funded by the Greenhouse Gas Reduction Fund (GGRF). The DDRDP is a competitive grant program that provides funds to assist in the installation of anaerobic digesters at dairies to produce biogas for beneficial use. The program provides grants for up to half of the project cost with a maximum of $2 million per project.[35] Table 4-5 shows the scoring criteria CDFA uses to evaluate grant

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31 CPUC Distributed Generation and Renewable Energy Credits (RECs) https://www.cpuc.ca.gov/General.aspx?id=5913

32 Status and Trends in the U.S. Voluntary Green Power Market (2017 Data), NREL, https://www.nrel.gov/docs/fy19osti/72204.pdf

33 https://www.srectrade.com/markets/rps/srec/california

34 https://www.sce.com/regulatory/tariff-books/rates-pricing-choices/renewable-energy-credit, accessed September 13, 2020

35 http://www.cdfa.ca.gov/oefi/ddrdp/docs/2020_DDRDP_FAQ.pdf. Accessed September 6, 2020.

applications. Note that the most valuable scoring criteria is estimated greenhouse gas reductions. Other factors such as project viability and community impact are also evaluated.

### TABLE 4-5: CDFA DDRDP SCORING CRITERIA FOR PROJECT SELECTION

| Criteria | Points |
|---|---|
| Digester Project Plan and Long-term Viability | 20 |
| Budget Work Sheet and Financials | 10 |
| Estimated Greenhouse Gas Emissions Reduction | 35 |
| Project Readiness | 10 |
| Environmental Performance | 15 |
| Community Impact | 10 |
| **Total** | **100** |

As of September 2020, the program has provided a total of $183.4 million to 108 dairy digesters since 2014. Applications for 2020 are currently being reviewed by CDFA.

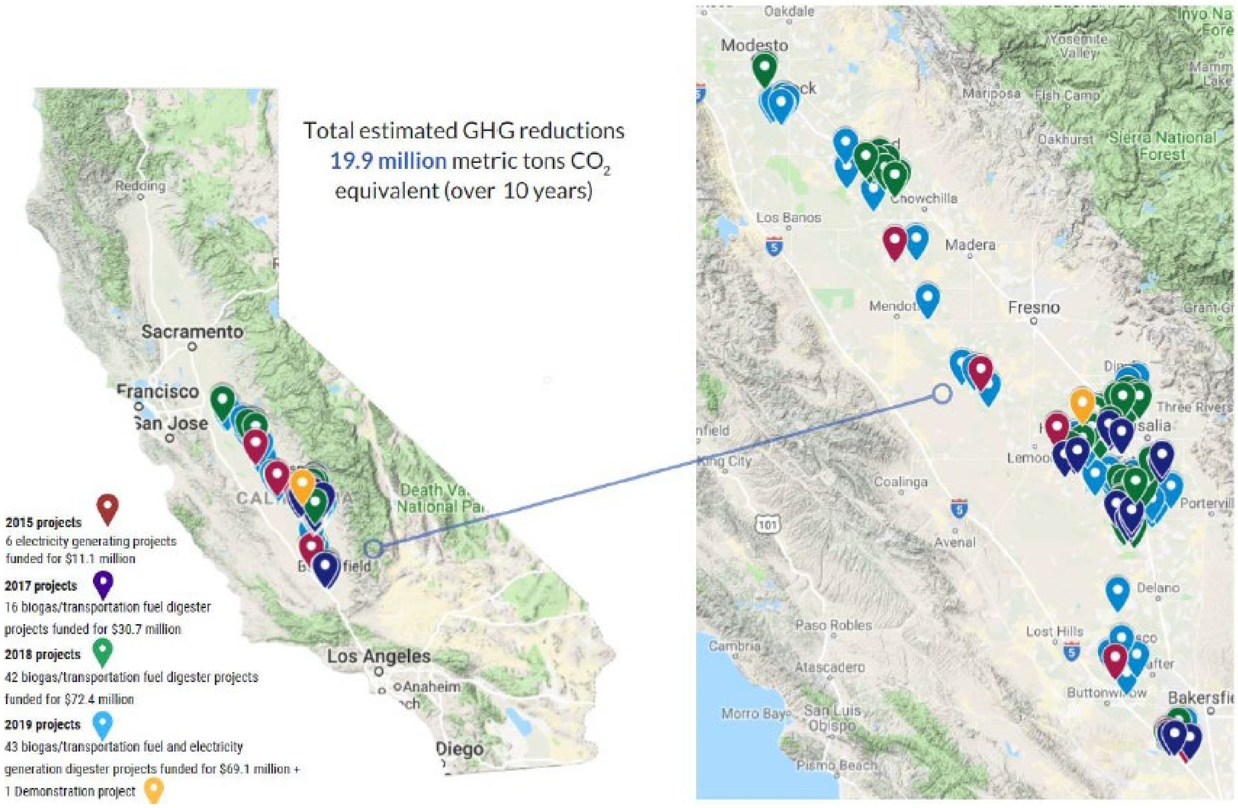
### TABLE 4-6: CDFA DDRDP PROJECTS

| Year | Number of Projects | Use(s) | Total Funding |
|---|---|---|---|
| 2015 | 6 | Electricity Generation | $11.1 million |
| 2017 | 16 | Biogas for Transportation Fuel | $30.7 million |
| 2018 | 42 | Biogas for Transportation Fuel | $72.4 million |
| 2019 | 43 | Biogas for Transportation Fuel* | $69.1 million + 1 demonstration project |
| 2020 | TBD | TBD | TBD |

*Two projects in 2019 plan to use fuel cells to generate electricity onsite and sell this electricity for EV charging to receive LCFS credits without injecting into a pipeline.

As shown in Table 4-6, the majority of digesters installed with assistance from the DDRDP produce biogas for transportation, and therefore participate in both the state LCFS and federal RFS markets. Two recent projects plan to generate electricity with a fuel cell that is used to provide electricity for electric vehicle charging. This allows these two projects to still participate in the LCFS, but the prices for these credits are substantially less, since the electric grid is the baseline instead of the large negative carbon offset given to dairies. That effectively lowers the LCFS credit by 2/3, but by selling electricity instead of gas, these projects do not need to compress the gas to pipeline pressures and do not need to connect to a natural gas pipeline. These same projects could have chosen to participate in the SGIP or BioMAT programs instead but chose to participate in the market-based LCFS. Figure 4-7 shows more information on the DDRDP projects.

**FIGURE 4-7: GEOGRAPHICAL DISTRIBUTION OF CDFA FUNDED DAIRY DIGESTERS IN CALIFORNIA[36]**




## 4.5 UNITED STATES DEPARTMENT OF AGRICULTURE (USDA) RURAL ENERGY FOR AMERICA PROGRAM (REAP)

The United States Department of Agriculture provides grants and loans for renewable energy systems in rural areas through the Rural Energy for America Program (REAP). The grants can cover 25 percent of total eligible project costs up to a maximum of $500,000.[37] These are restricted to rural small business or farms so these grants are unlikely to be used by landfills or waste water treatment plants, which are usually owned by municipalities or corporations. These grants require a separate application process that can be somewhat cumbersome but can aid in making use of biogas from some dairies for generation.

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36 Report of Funded Projects (2015 – 2019), Dairy Digester Research and Development Program, California Department of Food and Agriculture 2020 Report to the Joint Legislative Audit Committee.

37 https://www.rd.usda.gov/sites/default/files/fact-sheet/508_RD_FS_RBS_REAP_RE.pdf

## 4.6 THE FEDERAL INVESTMENT TAX CREDIT (ITC)

The investment tax credit (ITC) provides a credit on federal taxes for any entity installing renewable fueled generation. This credit is based on a percentage of the fair market value of the installed equipment and will decrease incrementally in subsequent years per federal law and being eliminated in 2022. To take advantage of this credit, the owner must have federal tax liability. The ITC effectively reduces the installed cost for the PTC and TRC and therefore has significant impacts on cost results until it expires in 2022.

## 4.7 PIPELINE INTERCONNECTION ASSISTANCE FOR BIOGAS

Assembly Bill (AB) 1900, which was enacted into law in Chapter 602 of the Statutes of 2012 established the law to create an incentive program to aid biogas projects with interconnecting to the natural gas distribution network. That bill, among other things, requires the California Public Utilities Commission to adopt standards that specify the concentrations of constituents of concern that are found in biogas, and to adopt monitoring, testing, reporting, and recordkeeping protocols, to ensure the protection of human health and to ensure the integrity and safety of the pipelines and pipeline facilities. Additionally, on December 18, 2017, the California Public Utilities Commission (CPUC) issued Decision (D.) 17-12-004 which establishes the necessary framework to direct natural gas corporations ("Utility" or "Utilities") to implement not less than five dairy biogas Pilot Projects to demonstrate interconnection to the common carrier pipeline system and allow for rate recovery of reasonable infrastructure costs pursuant to Senate Bill (SB) 1383.

"The State of California provides financial reimbursements to offset biogas developer pipeline interconnection costs. Under Assembly Bill 2313, these reimbursements can be up to 50 percent of the interconnection costs or $3 million per project, whichever is lower. If a project involves a cluster of dairy farms, the reimbursements can be up to 50 percent of the interconnections costs or $5 million, whichever is lower. Reimbursements for biogas interconnection costs are implemented by the California Public Utilities Commission (CPUC) decisions and policies and carried out by regulated investor owned gas utilities."[38]

## 4.8 SUMMARY OF INCENTIVES

As discussed in this chapter, the state of California and the federal government provide several incentives to promote the beneficial use of biogas. Some of these programs are complimentary and allow

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38 https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables/biomethane-faq.page?ctx=large-business

participants to 'stack' incentives while others are mutually exclusive. Table 4-7 summarizes which programs can be used together and which cannot.

**TABLE 4-7: INCENTIVE CAPABILITY CROSS REFERENCE**

| Program | LCFS | RFS | SGIP - Onsite | SGIP - Directed | NEM | BioMAT | RECs | ITC | CDFA DDRDP | USDA REAP | Interconnection Assistance |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **LCFS** | | Y | N | N | N | N | N | Y | Y | N | Y |
| **RFS** | Y | | N | N | N | N | N | Y | Y | N | Y |
| **SGIP - Onsite** | N | N | | N | Y | N | Y | Y | N | NY | N |
| **SGIP - Directed** | N | N | N | | Y | N | Y | Y | Y* | Y | Y* |
| **NEM** | N | N | Y | Y | | N | Y | Y | N* | Y | N* |
| **BioMAT** | N | N | N | N | N | | N | Y | Y* | Y | Y* |
| **RECs** | N | N | Y | Y | Y | Y | | Y | Y | Y | Y |
| **ITC** | Y | Y | Y | Y | Y | Y | Y | | Y | Y | Y |
| **CDFA DDRDP** | Y | Y | Y | Y | Y | Y | Y | Y | | Y | Y |
| **USDA REAP** | N | N | Y | Y | Y | Y | Y | Y | Y | | N |
| **Interconnection Assistance** | Y | Y | N | Y | Y* | Y* | Y | Y* | Y* | N | |

*Only applicable for selling/buying directed biogas through the gas network

In general, the beneficial use options for producers of biogas generally fall into either selling biogas through the gas distribution network for use elsewhere (and getting LCFS/RFS credits or selling for use by the utility or a directed biogas generator) or for onsite generation (with assistance from SGIP/NEM or the BioMAT program).

# 5 MARKET RESEARCH DATA AND METHODS

This section summarizes the research activities and sources of data used in the market research component of this study. The primary data sources used in this evaluation included:

**Pre-existing data sources:**

- The SGIP Statewide Project Database[39] managed by the PAs – this dataset was used to create the sample frame for the developer in-depth interviews and SGIP participant (biogas and natural gas) and cancelled applicant web surveys (Section 4.1)

**Data from research activities:**

- In-depth interviews (IDIs) with utility and regulatory staff, biogas industry experts, onsite generation equipment manufacturers, and project developers by Verdant Associates professional evaluation staff (Section 4.2)
- Web and phone surveys completed by SGIP biogas and natural gas fueled onsite generation participants (Section 4.3)
- Web and phone surveys completed by SGIP nonparticipants, including customers who had applied to SGIP and later cancelled their application or customers who have not applied to the SGIP but are prime candidates for onsite biogas generation projects due to the production of biogas at their facility (Section 4.3)

The research activities outlined above enabled the evaluation team to gain a deep understanding of the biogas generation market in California, and key factors that affect it, including the numerous and often competing options for using their biogas. The IDIs with regulatory and utility staff focused on the current programs affecting the market, the effect of LCFS credits on the market, the main barriers that impede biogas generation adoption in California, and actions to address these barriers. The IDIs with biogas industry experts centered on the current state of the biogas market at the national and California-specific levels, the specific actions their organizations are taking to promote biogas use, the effect of LCFS and RIN credits and CDFA grants on the market for biogas generation projects, and more broadly, key barriers to biogas generation and directed biogas and how to address them. The IDIs with project developers addressed their primary customers or market targets, the business/economic proposition that they make

[39] Accessed June 17, 2020.

to their prospective clients, and the key drivers, barriers, and trends they perceive in the biogas onsite generation market.

The telephone and web surveys conducted as part of this study focused on customers' level of SGIP and onsite biogas generation awareness, familiarity, and experience. The data collection also explored the factors influencing customers' decisions to install onsite biogas generation (both barriers and drivers), the role SGIP versus other biogas related programs play in their decision-making, and their experiences to-date with both the SGIP and onsite generation projects.

## 5.1 SGIP STATEWIDE PROJECT DATABASE

A copy of the SGIP statewide project database was downloaded from www.selfgenca.com on June 17, 2020. All completed SGIP nonresidential onsite generation applications submitted in program years 2001 through June 2020 are included in the database for this evaluation. The breakout of submitted SGIP onsite generation projects by generation fuel type (natural gas or biogas) and by PA is shown in Table 5-1 below.

**TABLE 5-1: SGIP COMPLETED NATURAL GAS OR BIOGAS PROJECTS BY PA AND APPLICATION STATUS**

| Application Status | PA | # Natural Gas Projects | # Biogas Projects | # Total Projects |
|---|---|---|---|---|
| Completed or Currently Active | PG&E | 339 | 92 | 431 |
| | SCE | 167 | 46 | 213 |
| | SCG | 176 | 23 | 199 |
| | CSE | 78 | 18 | 96 |
| **Completed/Active Total** | | **760** | **179** | **939** |
| Cancelled[40] | PG&E | 211 | 44 | 255 |
| | SCE | 155 | 46 | 201 |
| | SCG | 170 | 16 | 186 |
| | CSE | 34 | 31 | 65 |
| **Cancelled Total** | | **570** | **137** | **707** |
| **SGIP Onsite Generation Total** | | **1,330** | **316** | **1,646** |

Of the 922 completed or active onsite generation projects shown above, 930 (99 percent) were completed during or before PY 2016.[41] Just 9 completed or active projects (1 percent) submitted their applications in 2017, 2018 or 2019. No applications have been submitted to the SGIP in 2020 for onsite generation equipment. This sharp drop-off in onsite generation projects during the last four years coincided with the

40 Including withdrawn applications.

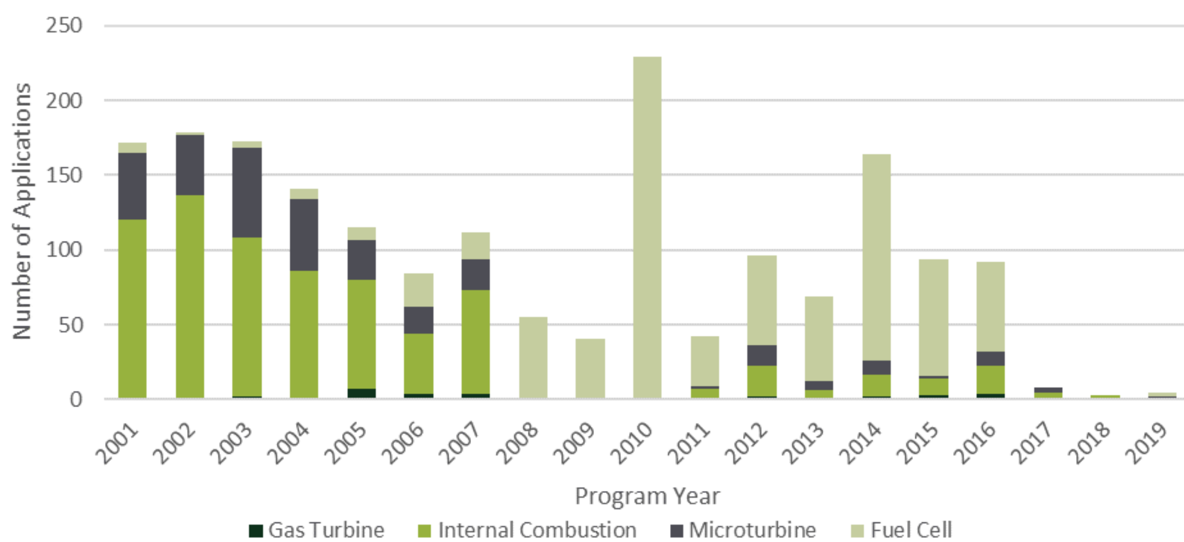
41 The program year variable corresponds to the year portion of the Date Received (aka application date) variable in the SGIP database.

gradual increase by the SGIP program of the proportion of WECC-sourced renewable fuel that was required to qualify for a program incentive. As Table 5-2 shows, the program went from having no renewable fuel requirement prior to 2017 to having a 100 percent renewable fuel requirement by 2020. This significant decline in onsite generation projects during these years is a primary focus of this evaluation. Figure 5-1 below, shows the yearly distribution of SGIP onsite generation applications by generation technology since program inception.

**TABLE 5-2: SGIP MINIMUM RENEWABLE FUEL BLENDING REQUIREMENT FOR ONSITE GENERATION**

| Application Year | SGIP Renewable Fuel Requirement |
|---|---|
| 2016 and prior | 0% |
| 2017 | 10% |
| 2018 | 25% |
| 2019 | 50% |
| 2020 | 100% |

**FIGURE 5-1: DISTRIBUTION OF ONSITE GENERATION APPLICATIONS BY TECHNOLOGY, 2001-2019**




## 5.2 IN-DEPTH INTERVIEWS

A key activity during this market assessment was the completion of numerous in-depth interviews with California utility and regulatory agency staff, biogas industry experts and onsite generation project developers. In total, 16 in-depth interviews with 30 individuals representing 16 of the most important biogas organizations within California and the U.S. were conducted across all these three categories. The purpose of these in-depth interviews was to learn about the market landscape for biogas-fueled projects (onsite generation as well as other potential biogas end uses such as transportation fuel) and to discuss the potential drivers, barriers, and alternatives to biogas generation projects. The interviews addressed both high-level areas such as the state of the California market for biogas generation (past, present and future), and more detailed information about the operation of various biogas programs (SGIP, BioMAT, LCFS, RPS, Fuel Cell NEM, etc.) and the costs and credits associated with participation in these programs. Key areas of focus were current factors affecting the market for onsite generation, future market trends for onsite generation, and the effect of the SGIP program on the sales and operation of onsite generation equipment. Appendix A presents a summary of the questions included in the interview guides used for these in-depth interviews. Figure 5-2 below summarizes the in-depth interviews completed across the four targeted populations.

**TABLE 5-3: IN-DEPTH INTERVIEWS COMPLETED AND FOCUS OF INTERVIEW**

| Population | Organization | Interviews | Individuals | Interview Focus |
|---|---|---|---|---|
| California Regulatory Staff | CPUC - Energy Division | 1 | 1 | • Agency's current perspective on biogas market<br>• Current programs affecting the biogas generation market<br>• Effect of LCFS credits on the market for biogas generation projects<br>• Main barriers that impede SGIP biogas generation adoption and possible remedies<br>• Roles that the regulators can play to address barriers to biogas generation |
| | CPUC - Biogas | 1 | 4 | |
| | CARB | 1 | 2 | |
| Utility Staff | PG&E | 2 | 4 | • Utility's perspective on best use of biogas<br>• Current perspective on biogas market and future direction<br>• Approach to promoting biogas market<br>• Information on completed and cancelled projects<br>• Main barriers that impede biogas generation adoption and ways to address them<br>• Actions that the CPUC and utilities can take to address barriers |
| | SoCalGas | 1 | 8 | |
| Biogas Industry Experts | BioEnergy Assoc of California | 1 | 1 | • Your organization's approach to promoting the biogas market, including biogas generation<br>• Current outlook on state and national biogas markets<br>• The effect of LCFS, RIN and CDFA credits on the market for biogas generation projects<br>• Main barriers that impede SGIP biogas generation adoption and possible remedies<br>• Approaches by other states to address barriers<br>• Experience in California with cleanup and pipeline interconnection costs<br>• Actions that regulators, utilities and others can take to address barriers |
| | CA Association of Sanitation Agencies | 1 | 1 | |
| | American Biogas Council | 1 | 1 | |
| | Environmental Defense Fund | 1 | 1 | |

| Population | Organization | Interviews | Individuals | Interview Focus |
|---|---|---|---|---|
| | State End User Expert* | 1 | 1 | |
| | Dekany Consulting | 1 | 1 | |
| | Waste Management Inc | 1 | 1 | |
| Onsite Generation Project Developers | Developer #1 | 1 | 1 | • Your company's activities to promote the biogas market<br>• Sales and marketing messages.<br>• Barriers to biogas generation and directed biogas, and how to address them<br>• Effect of LCFS credits on biogas market.<br>• Information on completed biogas generation projects – cost-effectiveness<br>• Experience in California with cleanup and interconnection costs<br>Motivations for customers to pursue biogas generation, directed biogas and business as usual |
| Onsite Generation Project Developers | Developer #2 | 1 | 1 | • Your company's activities to promote the biogas market<br>• Sales and marketing messages.<br>• Barriers to biogas generation and directed biogas, and how to address them<br>• Effect of LCFS credits on biogas market.<br>• Information on completed biogas generation projects – cost-effectiveness<br>• Experience in California with cleanup and interconnection costs<br>• Motivations for customers to pursue biogas generation, directed biogas and business as usual<br>• |
| | Developer #3 | 1 | 2 | |
| | Developer #4 | 1 | 1 | |
| **Total** | **16** | **30** | | |
| | | | | |

* This Industry Expert is an employee at a CA public agency and preferred not to be identified.

### 5.2.1 In-Depth Interviews Sample Design

The sample frame for the biogas in-depth interviews was derived based on a combination of discussions with key stakeholders, internet research, and feedback from early interviews with industry experts. The industry expert interviews, consisted of representatives of leading biogas and industry-specific advocacy groups that could provide perspectives on the biogas market both in California and across the U.S., insights from one or more of the primary onsite biogas producing industries (dairy, wastewater treatment and landfill), were knowledgeable about programs outside of SGIP (LCFS, RPS, BioMAT, Fuel Cell NEM, etc.), and who could speak knowledgeably to California's GHG goals/targets. The project developers interviewed had biogas project experiences that spanned the full range of onsite generation fuel types (onsite biogas, directed biogas, and natural gas) and industries (dairy, wastewater treatment, landfill, other). Each of the firms selected represented the largest biogas generation project developers for their designated market segment(s) in California (both inside and outside the SGIP) and/or across the U.S. Collectively, those interviewed represent the most important sources of biogas market intelligence and insight both within and outside of California.

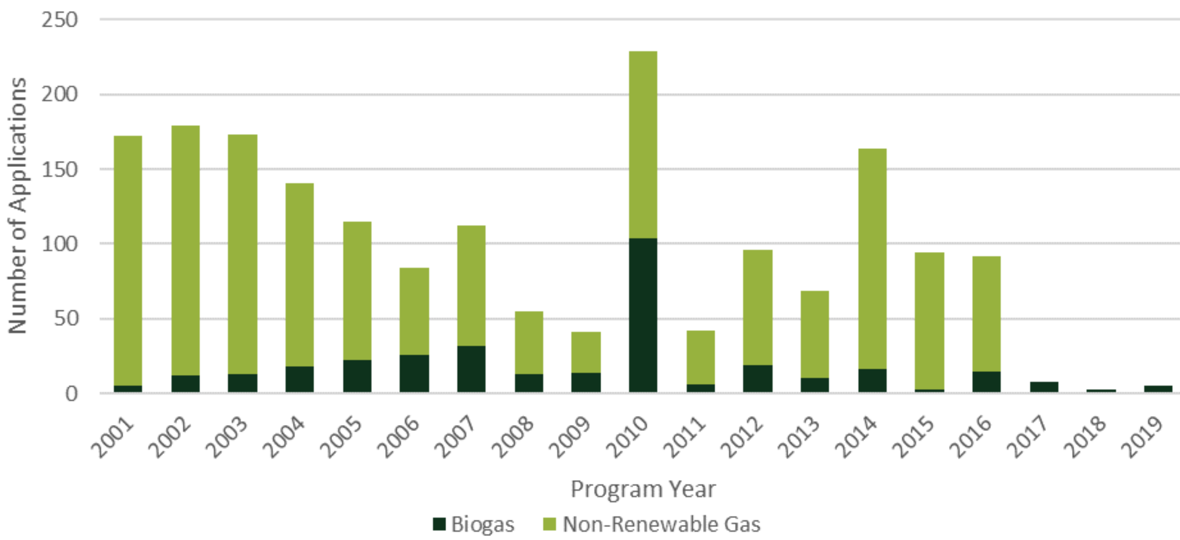
## 5.3 CUSTOMER TELEPHONE AND WEB SURVEYS

The second primary data collection activity conducted as part of this study was a series of telephone or web surveys conducted with a wide spectrum of California nonresidential customers. These customers were segmented into the following four groups for surveying purposes:

- **SGIP biogas onsite generation participants** received an SGIP incentive for installing onsite generation at their facility powered by either onsite or directed biogas. These customers are referred to as *Biogas SGIP Participants* throughout the later sections of this report.
- **SGIP natural gas onsite generation participants** received an SGIP incentive for installing onsite generation at their facility powered by natural gas. These customers are referred to as *NonBiogas SGIP Participants* throughout the later sections of this report.
- **SGIP cancelled onsite generation applicants** submitted an application to the SGIP for an onsite generation project that was subsequently cancelled. The submitted applications could have been for a generation project fueled with biogas or natural gas. These customers are referred to as *SGIP Cancelled Applicants* throughout the later sections of this report.
- **SGIP nonparticipants** have not submitted an application to the SGIP for an onsite generation project, but are one of the primary business types that are capable of producing biogas onsite at their facility and thus maybe potential candidates for future SGIP biogas fueled onsite generation projects. It is possible that these nonparticipants already have onsite generation installed at their facility but did not receive an SGIP incentive for this project. These customers are referred to as *SGIP Nonparticipants* throughout the later sections of this report.

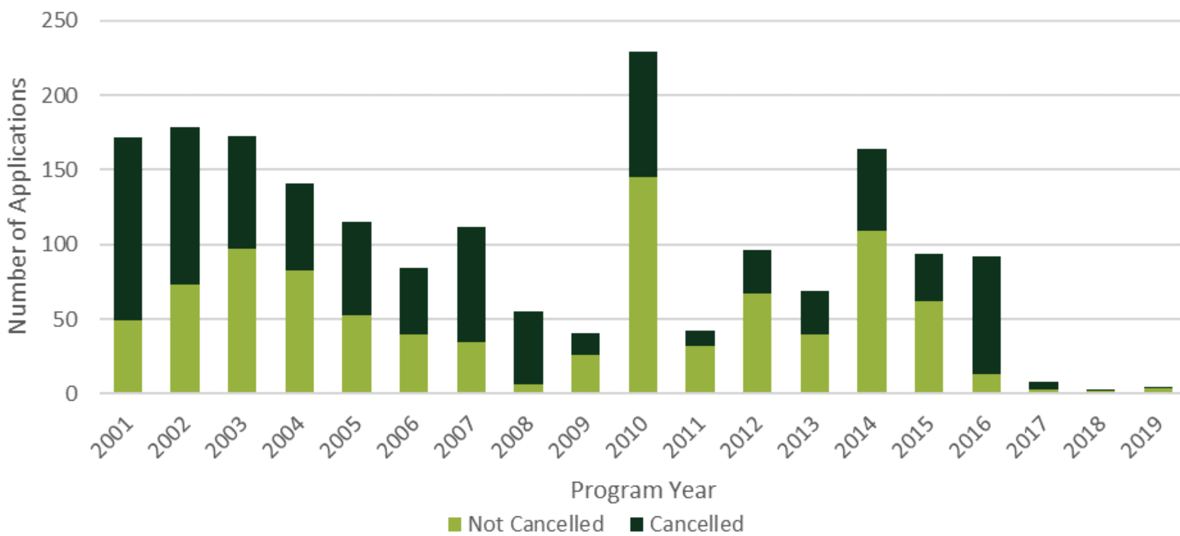
Survey questions for the **Biogas and NonBiogas SGIP participants** covered topics relating to how they first learned about onsite generation and the SGIP, the current status of the generation equipment installed at their facility, their experience and satisfaction with the SGIP and generation equipment, and the key decision influences that led their organization to purchase and install onsite generation equipment. As shown in Figure 5-2, the majority of SGIP onsite generation applications submitted since the program began in 2001 have been for Nonbiogas (natural gas) fueled projects. While these organizations did not intend to fuel these projects with biogas, respondent questions focused on if they are still using natural gas as the primary fuel for this equipment, whether they are capable of producing any biogas onsite, and the likelihood of installing additional onsite generation equipment in the future.

FIGURE 5-2: DISTRIBUTION OF ONSITE GENERATION APPLICATIONS BY FUEL TYPE, PROGRAM YEARS 2001-2019




As shown in Figure 5-3 below, a large percentage of onsite generation applications submitted to the SGIP each year are cancelled. To better understand the dynamics that led to these cancellations and determine whether the onsite generation project was eventually completed outside of the program, or is likely to be completed at a later date, the evaluation team included **SGIP cancelled applicants** in the data collection effort. Similar to the SGIP participant survey, these cancelled applicants were also asked questions about how they first learned about onsite generation and the SGIP, their experience and satisfaction with the SGIP, and the key decision influences that led their organization to consider installing onsite generation equipment.

FIGURE 5-3: DISTRIBUTION OF ONSITE GENERATION APPLICATIONS BY PROGRAM STATUS, PROGRAM YEARS 2001-2019




The evaluation effort also included phone surveys with California nonresidential customers who had not submitted an application to the SGIP (**SGIP nonparticipants**) but could potentially be a good fit for the program. These customers' primary business activity results in the production of biogas that could be used to renewably fuel onsite generation equipment. Developing an onsite generation project that uses onsite biogas could lead to their applying for an SGIP onsite generation incentive in the future. These customers fell into one of three primary business categories: Dairies, Wastewater Treatment Plants (WWTP), or Landfills.

The SGIP nonparticipant surveys were conducted by telephone as there was no email address available for these customers. Contact information was also limited for these customers, so in many cases it was necessary for a professional interviewer to call the primary phone number for the organization and describe the SGIP research to the person who answered in order to find the appropriate person to survey.

The questions asked of SGIP nonparticipants included their awareness and familiarity with onsite generation equipment and the SGIP program, their perceptions of the primary barriers and benefits to installing onsite generation equipment at their facility, the presence of an anaerobic digester at their site and their likelihood to install onsite generation in the future.

All of the customer telephone and web surveys focused primarily on quantitative, scalar questions, with some selected follow-up open-ended questions. A survey invitation with a web link was emailed to all customers in the participant population. Following the initial round of completed surveys, a reminder email was sent to those in the sample that had not yet responded. Appendix B presents the full survey instrument used for the customer web surveys.

### 5.3.1 Customer Telephone and Web Survey Sample Design

The sample design for the customer telephone and web survey was devised so that data could be collected from customers who had installed or who had potential for future installation of onsite generation equipment. For sampling purposes, and to account for those who had submitted multiple applications to the SGIP for an onsite generation incentive, SGIP participants and cancelled applicants were aggregated based on customer name.[42]

The sample frame for the nonparticipant survey was constructed from three primary databases that were based on secondary research and supplemented with sector-specific internet research. The resulting database was cross-checked with the SGIP program tracking database to ensure each organization had not previously submitted an application for an onsite generation equipment incentive. These are the same databases described in Section 3, and by sector included:

- Dairies: EPA's Agstar Livestock Anerobic Digester database
- WWTP: Based on data from the California Association of Sanitation Agencies
- Landfills: EPA's Landfill Methane Outreach Program (LMOP) Database

Table 5-4 summarizes the targeted customer sample population and the number of completed surveys for each customer type. As this table shows, biogas SGIP participants were the most responsive with 36 percent of the sample population completing a survey, while nonparticipating dairies were the least responsive. In total we reached out to 55 dairies, of which four were SGIP participants with successfully completed projects three had applied for SGIP but subsequently cancelled applications, and another 48 were SGIP nonparticipants. Unfortunately, only four of these 55 dairies responded to the survey. This is likely related to the nature of the farming profession as an "in the field profession" rather than a desk job—so reaching these customers is notoriously difficult. The table below also shows the rate of email "bounce-backs"[43] for SGIP participants and cancelled applications was high. This was not unexpected, as participation in the SGIP program has been low the past few years, and so a large portion of the sample frame was five or more years old and thus, many of the contacts may no longer be in the same job or with the same organization. Through internet research, we were able to track down some individuals who had

42 For example, applications across all locations of large retailers were aggregated to a single host customer.

43 Bounce-backs can be an automated email indicating than the email address is no longer valid or can be an autoreply that that the individual is no longer at the company. If a new/forwarding email was provided we updated our sample and reached out to the new contact.

changed jobs and agreed to either complete the survey or pass along contact information for another person within the organization who could respond to the survey.

#### TABLE 5-4: TELEPHONE AND WEB SAMPLE DESIGN AND COMPLETED SURVEYS

| Customer Type | Sample Population | # Completes | Percent | SGIP Projects Represented | Bounce-backs/ Nonrespondents | Percent |
|---|---|---|---|---|---|---|
| Biogas SGIP Participants | 28 | 10 | 36% | 10 | 5 | 18% |
| NonBiogas SGIP Participants | 78 | 10 | 13% | 13 | 21 | 27% |
| SGIP Cancelled Applicants | 19 | 3 | 16% | 3 | 3 | 16% |
| SGIP Nonparticipants: Dairy | 48 | 3 | 6% | n/a | 45 | 94% |
| SGIP Nonparticipants: WWTP | 235 | 17 | 7% | n/a | 43 | 18% |
| SGIP Nonparticipants: Landfill | 297 | 4 | 1% | n/a | 16 | 5% |
| **Total** | **705** | **47** | **7%** | **26** | **133** | **19%** |

Table 5-5 provides a distribution of the primary business types represented in the population of completed surveys. As this table shows the majority of respondents were either WWTP, municipal facilities, dairies or landfills.

#### TABLE 5-5: PRIMARY BUSINESS TYPES COMPLETED SURVEYS

| Business Type | Biogas Participants | NonBiogas Participants | Cancelled Applicants | NonParticipants | Total |
|---|---|---|---|---|---|
| Brewery | | 2 | | | 2 |
| Commercial | | 2 | | | 2 |
| Dairy | 1 | | | 3 | 4 |
| Energy | | 1 | | | 1 |
| Entertainment | | 1 | | | 1 |
| Municipal | 4 | 2 | 1 | | 7 |
| NonDairyAg | 1 | | | | 1 |
| Tech | 1 | 1 | | | 2 |
| Uniform Cleaning | | | 1 | | 1 |
| WWTP | 2 | | 1 | 18 | 21 |
| Medical | | 1 | | | 1 |
| Landfill | | | | 4 | 4 |

To increase the response rate for this surveying effort, Verdant staff followed up on all automatic reply emails received to identify another contact at the organization who would be able to answer the survey questions. A second email was also sent a week after the first email to all participants who had not yet responded to the web survey. This email reminded them of the survey and the date the survey would be closed. While the achieved sample distribution did not mirror the surveyed sample population distribution as close as desired, the customer survey responses were not weighted due to the small number of total responses. The survey results provide a qualitative picture of the market based on the customers who responded to the survey but should not be viewed with any type of statistical precision.

# 6 MARKET RESEARCH RESULTS

This section presents findings from the primary data collected through telephone and web surveys of participating and nonparticipating customers and in-depth interviews of utility and regulatory agency staff, industry experts and project developers during this evaluation. Results are organized thematically by:

- *Perceived Benefits of Onsite Biogas Generation Systems*, i.e., what factors motivate customers to install onsite generation equipment and utilize directed or onsite biogas to fuel the generation equipment and to what extent are customers realizing the benefits they expected based on perceived performance.
- *Perceived Barriers to Onsite Biogas Generation Adoption*, i.e., what factors impede customers from onsite generation using either biogas produced onsite or purchased (directed) biogas from an outside entity.
- *Effect of SGIP on Onsite Biogas Generation Market,* i.e., how has the SGIP influenced the market for onsite generation to date (both directed, onsite, and NG fueled systems).
- *Actions to Address Barriers to Onsite Biogas Generation Adoption,* i.e., what remedies are available to regulators and program administrators to address factors that impede installation and/or use of biogas in onsite generation.

Results from the analysis of data collected via in-depth interviews (IDIs) with utility and regulatory staff, industry experts and project developers[44] and participant and nonparticipant telephone and web surveys are presented below as they pertain to each section.

## 6.1 PERCEIVED BENEFITS OF ONSITE BIOGAS GENERATION

The motivations for purchasing and installing onsite generation are discussed in this section. Findings from developer interviews and customer surveys are consistent regarding the rationale for installing onsite generation, in general. Interviews with project developers and industry experts were used to assess what these market actors see as the key benefits resulting from installing biogas generation onsite at a

[44] For purposes of this study, a Project Developer is the entity who handles a substantial amount of the project's development and implementation activities. In many cases, the Project Developer and Manufacturer are the same entity.

customer's facility and how these differ for onsite versus directed biogas projects. The primary benefits reported were economic and environmental.

**Economic and other benefits, such as the ones shown in Figure 5-1, historically have driven onsite biogas generation installations at Wastewater Treatment Plants and Landfills.** According to one industry expert:

> *"Anaerobic Digesters have been an integral part of Wastewater Treatment Plants for decades. Historically they have provided 40 to 60 percent of power needs, and done this for decades, both in California and across the U.S. Most treatment plants of any size have Anaerobic Digesters and are putting biogas to productive use. They flare (unused biogas) as little as possible."*

**Economic benefits are also among the highest-ranked factors reported by SGIP participants for installing onsite biogas generation, along with environmental benefits.** Surveyed customers (biogas and natural gas fueled SGIP participants, as well as nonparticipants who installed onsite generation outside of the program) were asked to rate the importance of several factors in their decision to install onsite generation at their facility, using a 1-to-5 scale of importance where 1 means not at all important and 5 means extremely important. The 1-to-5 scale was used throughout the survey. As shown in Figure 6-1 below, the highest scored factors reported by SGIP participants were to save money on their electric bill (4.7 out of 5), to reduce demand charges (4.7) and to reduce their organizations GHG emissions (4.4). Both SGIP participants and nonparticipants rated reliability (*to provide backup/emergency power to our facility*) fairly low (average rating 2.9 out of 5).

**FIGURE 6-1: AVERAGE REPORTED ONSITE GENERATION DECISION INFLUENCE IMPORTANCE RATINGS**

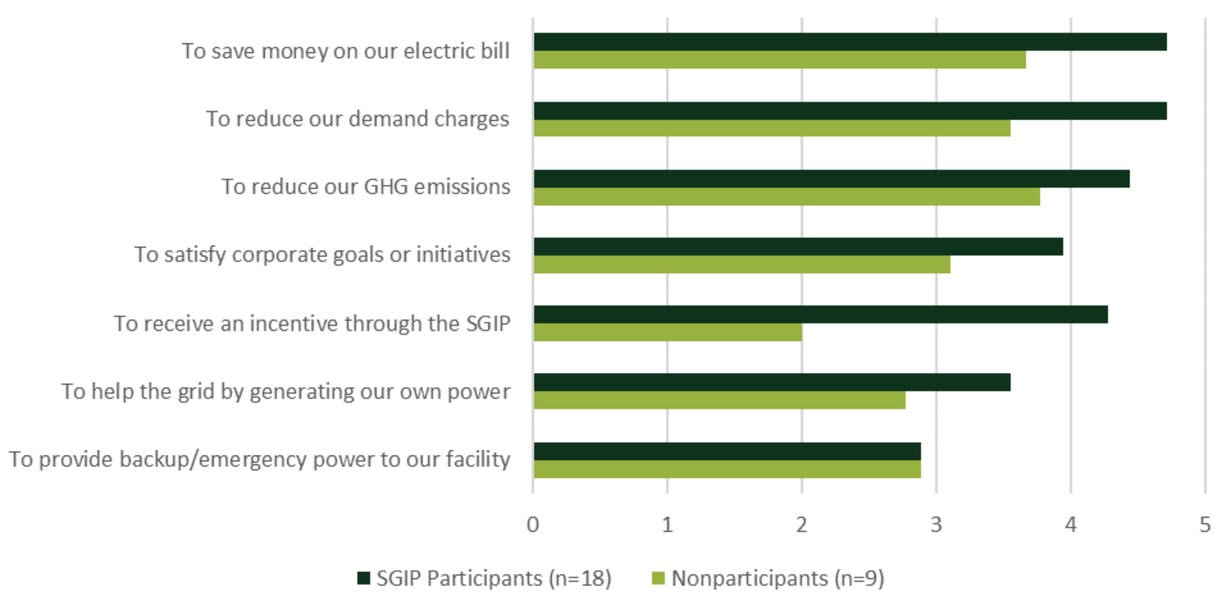


Table 4-7 below shows the average ratings for each of the respondent types. It is interesting to note that the Biogas and Nonbiogas participants scored all the elements similarly except for factors such as the SGIP incentive and the availability of backup/emergency power afforded by the onsite biogas generation. The SGIP incentive was rated higher by Biogas participants, likely due to their appreciation for the role the incentive plays in offsetting the increased cost of the fuel procurement (biogas costs for directed biogas or anerobic digester/cleanup costs for onsite biogas). It is interesting to note that providing backup power to the facility is less important for Biogas participants than Nonbiogas participants. The majority of Biogas participants that responded to the survey utilized onsite biogas, as opposed to directed biogas, in their projects and thus the scores shown below are reflective primarily of onsite biogas projects. Due to the high cost of directed biogas in California relative to the cost of purchased biogas from out-of-state (as described further in Section 5.2.1 below), directed biogas projects are less likely to be driven by economic reasons until RNG prices come down or incentives go up.

**TABLE 6-1: AVERAGE CUSTOMER ONSITE GENERATION INFLUENCE RATINGS BY RESPONDENT TYPE**

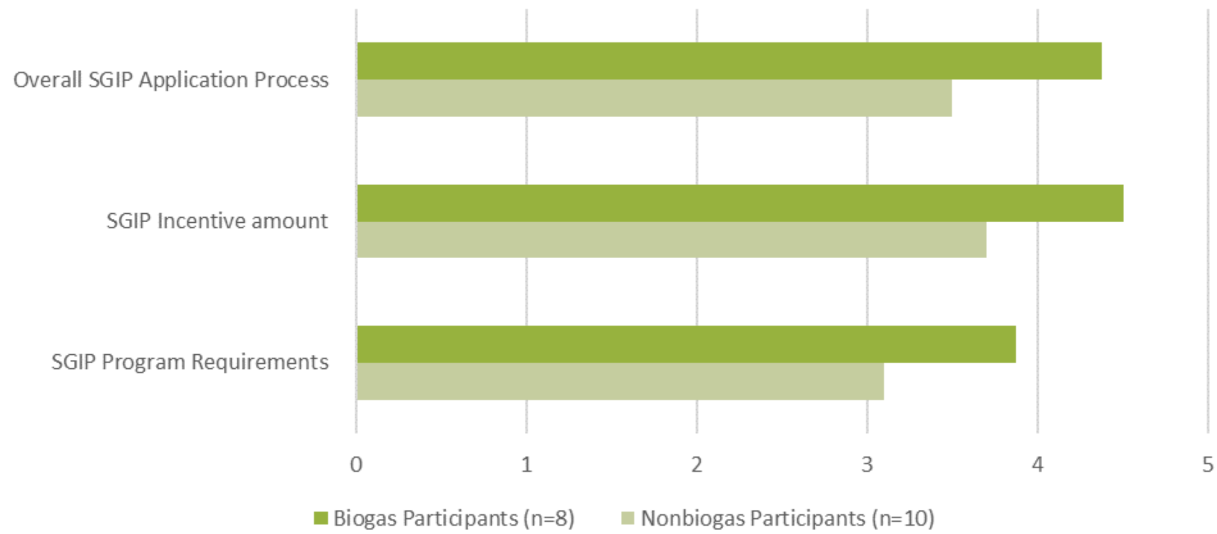
| Onsite Generation Decision Influence | Biogas Participants (n=8) | NonBiogas Participants (n=10) | Nonparticipants (n=9) |
|---|---|---|---|
| To save money on our electric bill | 4.6 | 4.8 | 3.7 |
| To reduce our demand charges | 4.6 | 4.8 | 3.6 |
| To reduce our GHG emissions | 4.4 | 4.5 | 3.8 |
| To satisfy corporate goals or initiatives | 4.0 | 3.9 | 3.1 |
| To receive an incentive through the SGIP | 4.6 | 4.0 | 2.0 |
| To help the grid by generating our own power | 3.3 | 3.8 | 2.8 |
| To provide backup/emergency power to our facility | 2.4 | 3.3 | 2.9 |

Survey respondents who produced onsite biogas were asked how their organization decides on what to do with this biogas. They cited mostly economic factors, several of which related to energy production: *"Profitability", "Use what [we] have onsite – it is free or very inexpensive fuel", "Prior to cogen it was used to heat the AD and onsite buildings, but energy production was the goal", "We use the power to offset PG&E purchased electricity primarily. Then the additional we [produce] is sold back to the grid with a PPA."*

Related, participating customer surveys validate that participants are well satisfied with the SGIP incentive and other aspects of the SGIP program. SGIP onsite generation participants were queried regarding their satisfaction with several SGIP elements, including the SGIP application process, the SGIP incentive, and the SGIP program requirements. They were asked to rate each of these elements on a 1 to 5 satisfaction scale with 5 being "extremely satisfied" and 1 being "not at all satisfied". The average reported satisfaction ratings are shown below in Figure 6-2. It is interesting to note that while overall satisfaction for all elements was moderate across participants, Biogas participants are more satisfied than Nonbiogas participants across all areas. While biogas participants were very satisfied with the incentive amount (4.5

on a scale of 1 to 5) and SGIP application process (4.4 out of 5), they were less satisfied with SGIP program requirements (3.9 out of 5).

**FIGURE 6-2: SGIP ONSITE GENERATION PARTICIPANTS SATISFACTION WITH VARIOUS SGIP ELEMENTS**




**Marketing messages used by project developers emphasize the advantages conferred by these projects related to economic, environmental and reliability benefits.** Marketing messages are framed in terms of helping customers to meet their corporate goals in these areas. The higher incentives recently authorized for SGIP including the resiliency adder may shift this some, although these incentives had not yet been implemented at the time of the surveys. One developer noted that compared to natural gas generation, biogas is very nuanced since it applies to only a small subset of customers (i.e., dairies, landfills and WWTPs).

## 6.2 PERCEIVED BARRIERS TO ONSITE BIOGAS GENERATION ADOPTION

Another consideration for onsite generation adoption is the presence of barriers in the market, such as up-front cost, lack of awareness, program requirements, and other factors. This section summarizes concerns expressed by industry experts, project developers and nonparticipating SGIP customers in this area. Barriers to onsite generation fall into one of two categories: They are either **economic** or they are **programmatic.**

### 6.2.1 Economic Barriers

The primary barriers to biogas generation adoption through SGIP are economic in nature. The main sources include:

First, **biogas purchased within California is an expensive fuel compared with biogas procured from out-of-state** and natural gas in general. Currently directed biogas prices average $13 - 23 per MMBtu versus approximately $3 per MMBtu for Natural Gas. High biogas costs within California are reported by industry to be from a combination of expensive clean-up costs, and extremely high gas pipeline interconnection costs (reportedly many times more expensive in California than in other U.S. states). However, these additional costs have only been reported by industry contents and not verified with hard data due to the often-confidential nature of project cost data. Related, the biogas for SGIP generation must be sourced within WECC and benefit one of California's air basins, meaning other lower-cost sources are ineligible. Industry experts and project developers commented extensively on this:

> *"Another rule – the biogas has to be sourced within WECC meaning basically it must be within California. Consequently, it's going to be much more expensive."*
>
> *"Pipeline standards in California are really hard to meet and very expensive – in some cases there are duplicative clean up processes. Also, interconnection is very expensive in California. The cost is 10 times more than other states – we need to figure out why and how costs can be lowered. Michigan is many times less expensive than California. Interconnection and pipeline standards are huge barriers."*
>
> *"Biogas is expensive – SGIP incentives don't make a dent."*
>
> *"Gas interconnection costs are awful in California. There are 2 reasons for that. California is ten times more expensive than anywhere else. Also, gas quality standards address a couple of constituents in the gas, oxygen is one of them. They are more strict in California, more than they need to be. For oxygen (siloxane), the real level is 0.4, while the California level is 0.2. In Parris, a waste management company project – the first one in California – the 0.2 standard cost an extra $2,000,000 for them. For the rest of the country, it is a few hundred thousand dollars. It is ridiculously expensive in California, which is probably why it's more attractive to locate outside of California."*
>
> *"Everyone is trying to avoid the California interconnection standards."*
>
> *"The cost of (directed) biogas in California has gone up exponentially due to the LCFS and Federal RFS. Directed biogas is far too expensive to make projects pencil out. It is a minimum of a 5x premium. Companies are only doing these projects to meet renewable targets but 95% have renewables covered in solar and so will only do this for resiliency and power quality."*

Some project developers also noted that biogas in California is becoming increasingly hard (or more expensive) to find and that "the low hanging fruit has already been tapped".

Second, **biogas producers have other lucrative options** steering them away from biogas generation, specifically LCFS credits for transportation applications and other incentives such as the BioMAT feed-in tariff and the RIN incentives from the federal Renewable Fuel Standards program. Further, LCFS incentives are directed toward transportation rather than power generation, invalidating their use for biogas generation. A table summarizing the alternative/complementary programs is provided below. Industry experts and project developers' comments on these other programs included the following:

> *"You run the numbers and look for highest return. Through BioMAT, you can get 12 to 18 cents/kWh. SGIP can get about 6 cents/kWh. If you supplement with brown gas, you can get another 3 cents. If you generate LCFS credits and wheel the power, you can get about 70 cents/kWh. That's the calculation."*
>
> *"LCFS (credits) drive any gas towards transportation."*
>
> *"The LCSF program is a no brainer for large dairies. For small/medium dairies, capital costs are high, and it doesn't scale down well. It works particularly for dairies near gas pipeline, power line. And the economics are favorable generally for 3000 milk cow equivalents and larger. You could do 2,000 and down maybe below if a farm were right next to the pipeline."*

**TABLE 6-2: ALTERNATIVE/COMPLIMENTARY BIOGAS PROGRAMS**

| Program | Compatible with SGIP Participation | Financial Incentive/Credit |
|---|---|---|
| LCFS | N | LCFS Credit at $200/MT: $6.75-$74.88/MMBtu based on CI of biogas |
| RFS | N | RINS Credits range from $5-$15/credit, 11.7 RINs/MMBtu of RNG gas |
| BioMAT | N | Feed-in-tariff: $127.72-$199.72/MWh to sell electricity directly to utility |
| RECs | Y | RECs are sold as a commodity into the marketplace. 1 REC = 1 MWh of renewable-generated energy |
| NEM | Y | Compensation for renewable electricity exported back to the utility, based on retail rate net of nonbypassable charges |
| CDFA DDRDP | Y | Grants for up to half of the cost of AD installation ($2M/project max) |
| ITC | Y | 26 percent tax credit based on the FMV of installed fuel cells or microturbines |
| Interconnection Assistance | N | Grants for up to half of interconnection costs for dairies ($3M/project max, $5M for clusters) |

Surveyed customers were asked about their awareness of and participation in these alternative biogas programs. Awareness of the LCFS and RFS transportation incentive programs were moderate (49 percent were aware of LCFS and 38 percent were aware of RFS), however none reported receiving any of these credits. Survey respondents who had some type of onsite generation installed were also asked similar questions regarding electrical generation programs (NEM, BioMAT and RECs) and as shown in Table 6-3 below, respondents had fairly high levels of awareness of NEM and RECs, and lower levels of awareness of BioMAT. The higher levels of participation in NEM were primarily tied to excess solar generation produced onsite as opposed to excess electricity from their onsite generation equipment.

#### TABLE 6-3: KNOWLEDGE AND PARTICIPATION IN OTHER ONSITE ELECTRICAL GENERATION PROGRAMS

| Does your organization participate in … | NEM | | BioMAT | | REC | |
|---|---|---|---|---|---|---|
| | # | % | # | % | # | % |
| Yes, we participate in program | 9 | 39% | 1 | 4% | 6 | 26% |
| No, we know about program but do not participate | 6 | 26% | 7 | 30% | 10 | 43% |
| We do not know about the program | 5 | 22% | 12 | 52% | 6 | 26% |
| Don't know | 3 | 13% | 3 | 13% | 1 | 4% |

Respondents were asked what actions their organization would take if NEM, BioMAT or RECs were no longer available. As the table below shows, a number of respondents reported they would use more of it onsite or would look into battery storage to capture the excess. Again, here it is important to note that much of the surplus being fed into NEM is likely from solar and not onsite generation equipment.

#### TABLE 6-4: RESPONDENTS ACTIONS ABSENT NEM, BIOMAT OR RECS

| NEM | BioMAT | RECs | Customer Responses |
|---|---|---|---|
| Y | Y* | Y | "Shut it down? **Switch to all RCNG (Renewable Compressed Natural Gas)**" |
| Y | N | N | *"We would likely try to better match our production with onsite demand to minimize export to the grid"*<br>*"The only energy we send back under NEM is excess solar. We would likely still send it back to the grid, but not get paid for it. We might consider adding more energy storage. Our natural gas generators are not allowed to export, and we do not generate excess energy with anything other than solar"*<br>*"Look into storage"*<br>*"**Continue to use it to feed our facilities** and still categorize it as renewable"* |
| Y | N | Y | *"**Use it onsite**"*<br>*"In theory, fuel cells don't produce excess electricity. They are well matched to building energy consumption. They consume all the electricity in the buildings. We would buy RECs from the market if we weren't able to generate them"* |
| N | N | Y | *"**Use it and not export as much**"*<br>*"No impact to our operations"* |

* We are aware that a customer cannot participate in NEM and BioMAT, however this was the response provided by the respondent and thus we are providing it here.

In response to a question regarding the role these other electrical credits/programs play in their organizations decision regarding what to do with the electricity generated onsite, respondents stated that these other programs do influence their decision making. For example:

*"NEM Credits and RECs influence the County's decision regarding investments in renewable and clean energy projects; on site generation reduces the need for REC purchases."*

*"They help [us] to comply with internal policy that generation be 100% renewable."*

*"That's what they base the justification of the cost effectiveness on."*

*"We are considering conversion of our biogas to biomethane, which could allow us to export power from our microturbines. NEM could then have an effect on use of this resource."*

Third, **biogas generation equipment is expensive to operate**: operations and maintenance of the generator and cleanup/emissions control equipment can represent significant costs. Estimates of these costs vary significantly, but our research puts generator O&M in the range of $0.015-$0.054/kWh and cleanup/emissions O&M in the $0.04-$0.05/kWh range, these costs can consume a substantial portion of the cost of offsetting grid generated electricity at ~$0.16/kWh. One industry expert commented:

*"Electricity [from IC engine] involves just maintaining the engine – engines are a lot cheaper than Renewable Natural Gas equipment, from a capital cost and O&M cost perspective."*

Fourth, **combustion technologies are very challenging to permit** in California. Stationary engines in California must meet stringent emissions standards to ensure air quality. Meeting these increasingly strict standards such as AQMD's 1110-2 have driven many existing combustion generators to shut down rather than upgrade cleanup and emission control equipment. Additionally, only fuel cells that meet an emerging CARB GHG standard for efficiency can participate in the NEM program. Therefore, combustion technologies (not fuel cells, PV or wind) are not allowed to be compensated for any excess generation fed back into the grid as part of NEM. Project developers noted:

*"You can generate, but if it's in the South Coast or the Bay Area, controlling air emissions requires a significant investment in pre-treatment and after-treatment. It's cost prohibitive – and only in California."*

*"AQMD requirements – how big a barrier? Nearly all dairies are in the San Joaquin District or the Sacramento District. They are tough but not impossible. You can put advanced catalysts on engines. It costs more but is not a killer. We are worried they will come out with rules (in the future) that we can't meet."*

Finally, many dairies face the added expense of installing an anerobic digester in order to harvest the biogas from manure.

- Across all customer survey respondents, 58 percent of likely biogas producers had an anaerobic digester (AD) installed onsite – meaning that 42 percent do not have an AD and would need to incur this cost before considering installing onsite biogas generation.

- The installation cost of an AD is significant. Most customer survey respondents with anerobic digesters installed (10 of 16 respondents) reported that it cost more than $4 million to install the AD at their facility. The average cost reported was around $5.5 million, and there was one report of a digester costing as much as $20 million. Half of these responses were wastewater plants and their cost on average was more than $7 million. The remaining half were a mix of dairies, breweries, and municipal facilities and cost on average $3.2 million. The two dairies reported their AD cost approximately $2 million. Costs for digesters at wastewater treatment plants tend to be higher due to the larger volumes at these facilities compared to other facilities such as dairies. The $2 million costs reported by the two dairies is consistent with dairies in the 3,000 cow size range based on cost estimates in Section 7.
- Just three respondents recalled receiving a grant to help offset the cost of the digester. Grant sources included the CDFA program and the State Revolving Loan Fund. Two of the three respondents provided estimates of the percentage of the digester cost that was covered by the grants (30 percent and 45 percent, respectively).
- The cost to operate the digester varied widely across those who responded. Half of the respondents reported the annual cost was in the hundreds of thousands of dollars annually, one reported it was as high as $1.5 million annually, and three reported it was in the tens of thousands. However, it is important to note that the majority of respondents were unsure how much it cost to operate (15 out of 23 respondents).
- Three-fourths of those with digesters reported that they are fueled with biogas or a combination of biogas and natural gas. Of these, 48 percent are biogas only.
- Among those who do not have a digester, 24 percent (4 of 17 respondents) reported their organization had considered installing one. Reasons for not doing so included that they did not perceive a need for it, ADs are too expensive, they have space constraints and/or a lack of feedstock, the nearest gas line is too far away, an AD would not work with the way their system is configured, the dairy is too small or is a pasture based dairy, and they landfill their solids.

### 6.2.2 Programmatic Barriers

Programmatic barriers relate to program restrictions that impede biogas generation, either through program rules or requirements, or as a result of perceptions by project developers of a barrier. There are three sources of programmatic barriers.

First, a program requirement was imposed on **January 1, 2020** requiring that **SGIP projects be fueled by 100 percent biogas** as discussed in D. 20-01-021**.** Previously, generators were able to use a combination of natural gas and biogas and were able to procure biogas from in-state or out of state. One industry expert commented:

*"The emphasis on in-state projects may limit the market too severely. There is lots of this emphasis across the legislation."*

Second is project developers' perception that the **SGIP program has become less reliable as a funding source,** particularly for larger projects**.** This was attributed to a combination of factors including the lottery approach adopted by the program in 2015, and the caps on project size and incentive level. Comments included the following:

*"SGIP capped at 5 MW nameplate capacity under new rules… SGIP may pay for cost of technology but not the cost of the biofuel. Also, SGIP maxes out at $5 million/project – makes it harder to justify (larger) projects."*

*"Around 2015, the SGIP program became less reliable with the lottery (approach)."*

Further, a few project developers reported they had submitted applications for projects that were not "fully baked" since if you missed getting your application in you could have to wait for another year to submit again. We heard a similar theme from a nonparticipant survey respondent who reported they their organization had considered applying for an SGIP incentive however did not as they had heard the *"[SGIP] funds were mostly distributed already*". This is one of the reasons the SGIP has seen the cancellation rate for these technologies at close to 40 percent since program inception.

Additionally, **there has been no participation in the program in 2020 to date** as (D.) 20-01-021 also directed the SGIP PAs to "pause acceptance of incentive applications for renewable generation technologies using collect/use/destroy (aka WWTP and LFs) as the biomethane baseline until this Commission provides further direction" (i.e. after the workshop on renewable generation technologies in the 2$^{nd}$ or 3$^{rd}$ quarters of 2020).

Third, **the lack of program marketing for promotion of biogas generation** by the SGIP PAs has hindered the development of projects. For example, both project developers and customers were unaware of recently approved significant increases in incentive levels for biogas generation projects which have not yet been implemented by the PAs. The program's redirected focus to energy storage has contributed to this perception. Some utility staff also acknowledged a general lack of promotion of biogas projects through SGIP. Among the comments provided were:

*"Utility outreach – not much."*

*"…we're not focusing on biogas. There are just a few projects in the program, and it has not received a lot of attention."*

*"Pre-COVID, we used to have quarterly meetings. Was when storage became really big. You could meet the program administrators face-to-face and get updates. I don't know what happened to them. I would love it if those meetings came back, even if it's just a virtual thing."*

*"The SGIP program has been well received and heavily used by WWTP. It's not a pivot point for project decisions, but a consideration when they are looking to upgrade power generation. It's very welcomed and very used. They have been concerned about shift of the SGIP program toward storage as opposed to generation…"*

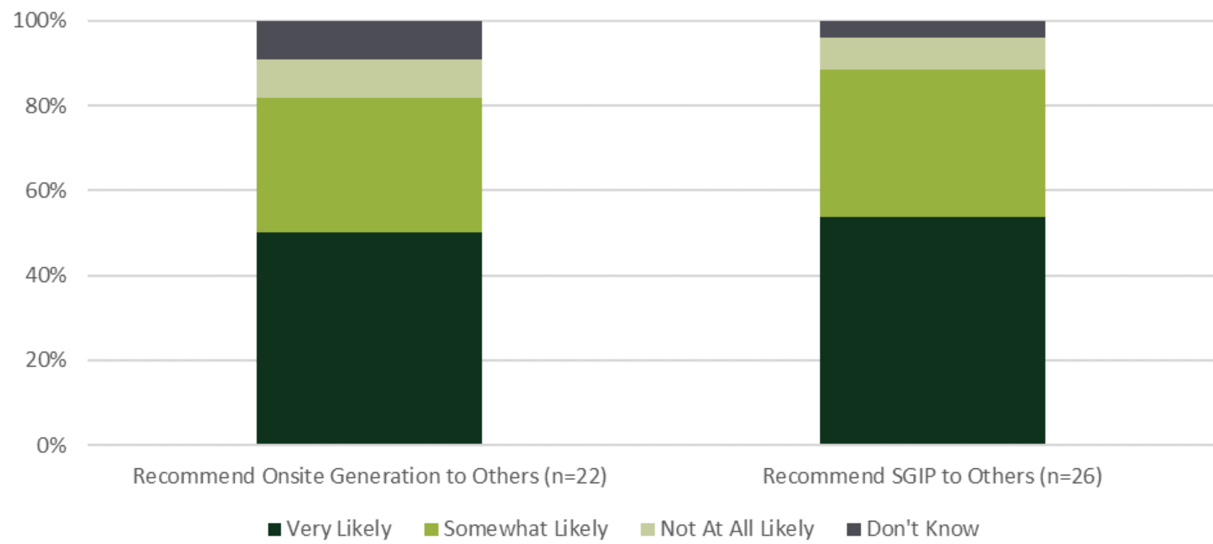
The lack of program marketing has resulted in low awareness of the SGIP program among nonparticipating customers who appear to be strong candidates for onsite biogas generation. All of the SGIP participants who responded to the survey reported they were aware of the SGIP program,[45] however less than 30 percent of nonparticipants reported being aware of the program. It is important to note that the nonparticipants interviewed for this study were all organizations that have the potential to produce biogas onsite to fuel onsite generation equipment (dairies, WWTP and landfills) and thus, this low level of awareness about the program is an indication that more can be done to ensure these customers, who could be good candidates for onsite biogas generation, are informed about the program.

**Those who are aware of the program are fairly knowledgeable about it.** A sizeable majority, 95 percent, of participants reported that they were very or somewhat familiar with the program (27 percent and 68 percent, respectively). However only about half of the nonparticipants who knew about the program reported feeling knowledgeable about the program. Again, these non-participating customers who may have a higher potential for onsite biogas generation do not appear to have adequate information about the SGIP and program incentives that are available. Two-thirds of those who were aware of the program reported they first became aware of the program more than five years ago and the other one-third reported becoming aware between one and five years ago. No respondents reported learning about the SGIP within the last year, which aligns with distributors concerns regarding the focus of the program shifting nearly entirely to storage in the last few years. This is another likely contributing factor to the significant reduction in program participation in the last five years. While SGIP program awareness is not recent, the majority reported they became aware of the program through their utility (38 percent) or a project developer, contractor or consultant (34 percent). When asked what technologies they were aware could be incentivized through the SGIP, fuel cells were the most common response (reported by 79 percent of those who were aware of the SGIP), followed by internal combustion engines (76 percent), microturbines (69 percent), advanced energy storage (62 percent), and gas turbines (52 percent).

[45] This question was asked of participants since in some cases five or more years have passed since their participation in the program and we wanted to make sure the individual being surveyed had adequate program knowledge.

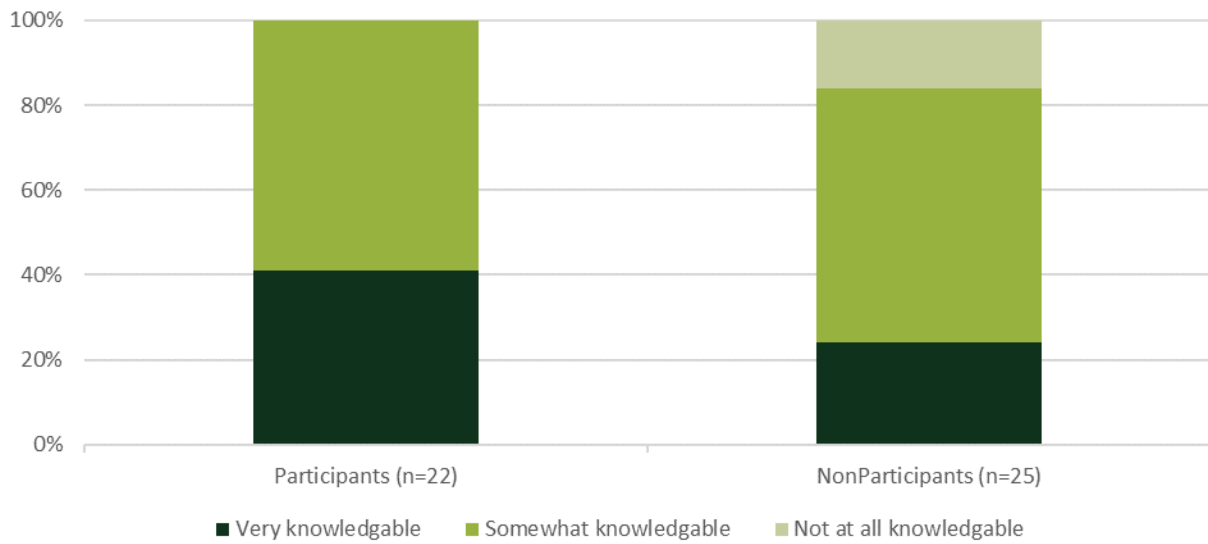
Despite this lack of program awareness, **SGIP participants' experiences with the program and with their onsite generation have been favorable** and most would recommend onsite generation to others based on this. As shown in Figure 6-3 below, participating customers' experiences with onsite generation equipment installed through the SGIP are positive and thus, the majority of respondents (82 percent) say they would be very or somewhat likely to recommend installing onsite generation to others. Similarly, 91 percent of SGIP participants reported being very or somewhat likely to recommend the SGIP to others.

**FIGURE 6-3: SGIP PARTICIPANTS LIKELIHOOD OF RECOMMENDING ONSITE GENERATION OR THE SGIP TO OTHERS**




**Awareness of onsite generation systems is often from sources outside of the SGIP program.** All of the SGIP participants interviewed reported they were very or somewhat knowledgeable about onsite generation systems. These systems are often more complicated to install and operate than a typical solar or storage project and so organizations that install them typically need someone on staff that is knowledgeable about their operation. Most respondents first learned about onsite generation on the job (at their current or previous employer, 35 percent), through word of mouth (19 percent), through online or other research (14 percent), or  a project developer or other vendor (12 percent). One WWTP respondent whose organization has not participated in SGIP and does not have onsite generation currently installed reported that they had conducted a biogas utilization study, but did not install any generation equipment because of economic issues: a "*30 year ROI [is] too long*".

**FIGURE 6-4: RESPONDENTS KNOWLEDGE LEVEL ABOUT ELECTRIC ONSITE GENERATION SYSTEMS**




## 6.3 EFFECT OF SGIP ON ONSITE BIOGAS GENERATION MARKET

The impact the SGIP has had on customers decisions regarding the purchase and installation of onsite generation equipment are discussed in this section. Findings from developer interviews and customer surveys both illustrate how the past SGIP incentives offered were often critical to the financial viability of an onsite generation project and the increased SGIP incentive levels (per CPUC D. 20-01-021) will likely increase the feasibility of some future projects that were not viable at prior incentive levels.

After hearing about the increased SGIP incentive levels, some project developers speculated that projects that previously were not feasible financially under the old incentive levels could become viable. Among their comments:

> *“With an SGIP grant (at the new incentive level), I can imagine someone with a project in the 1,500 cow range becoming (economically) viable. With the $4.50 resiliency adder, there are probably some small/medium dairies to apply this to.”*
>
> *“Increasing the incentive amount is huge. You also need to increase the desire for dairies to inject biogas into the pipeline…There are some sweet incentives there for biogas for transportation through the LCFS. That doesn’t increase (biogas) supply into the pipeline though.”*

Surveyed SGIP participants were asked to describe in their own words the role the SGIP played in their organization’s decision to install onsite generation at their facility. Nearly all responses provided indicated the SGIP had played a very large role financially in their decision to install onsite generation and that without the SGIP incentive, the project may not have been financially viable. It is important to note that these surveyed participants included both biogas- and non-biogas-fueled onsite generation participants and included biogas participants who participated in the program prior to the addition of the WECC-sourced fuel requirement, which has increased the cost of procuring RNG according to project developers. As a result, the financial role played by the program in these prior years may not be representative of the role more recently given the increased WECC-sourcing requirement. Examples of participants' responses included:

> *"SGIP was instrumental in our decision. The project would not have been financially viable without the incentive provided by SGIP."*
>
> *"The SGIP incentive component was a driver in determining the economic viability of making the significant investment to install a Microturbine Cogeneration system."*
>
> *"The [SGIP] funds offset construction costs and lowered the kWh price in the PPA enough to make the project feasible."*
>
> *"SGIP rebates reduced the payback time which made construction more attractive and easier to finance."*
>
> *"[SGIP] project financial incentives that resulted in lower Power Purchase Agreement (PPA) rates to the County. Fuel Cell investor was able to use SGIP to lessen the project cost."*
>
> *"The incentive provided under SGIP was a significant factor in the decision to construct a cogeneration facility, and helped expedite the project due to the milestones set up to get the project constructed and operational."*
>
> *"SGIP made the project financially very attractive."*

SGIP participants were also asked what their organization would have done if the SGIP incentive was not available to offset a portion of the cost of their onsite generation equipment. Over one-third (37 percent) responded that their organization would likely have still installed the onsite generation equipment without the incentive. The remaining 63 percent of respondents were divided evenly between reporting that the onsite generation equipment would not have been installed, that they would have had to reevaluate the project feasibility, and that they were unsure as to what would have occurred.

### Installation of Onsite Generation Equipment Outside of SGIP

As part of the surveying effort, 24 nonparticipating dairies, WWTP, or landfills were interviewed to learn more about their awareness and experience with onsite generation equipment. Of these 24 respondents, 14 reported their organization had installed one or more onsite generation technologies at their facility, of whom 64 percent reported an internal combustion engine had been installed and one respondent reported a gas turbine had been installed.[46] The majority of this equipment (90 percent) was installed in 2010 or earlier, with only one respondent reporting a more recent installation within the last 4 years. All but two of those with internal combustion engines reported they were still installed and operational. Financial incentives or grants were only reported to have been received for the installation of solar. One respondent reported they had considered applying for an SGIP incentive however did not as the "[*SGIP] funds were mostly distributed already*". Sixty percent of those surveyed who did not currently have onsite generation installed at their facility reported they had considered installing onsite generation, but did not as it was either too expensive or they did not see a need for it.

The customer survey sample also included organizations who had submitted an SGIP application in the past but later cancelled or withdrew the application. These organizations were included to better understand their experience with the program, why their application was not completed and whether the onsite generation equipment was installed outside of the program. Three cancelled applicants responded to the survey and two reported their organization had installed the onsite biogas generation equipment at their facility (one was fueled with onsite biogas and one with natural gas) while one had not. The primary reason given for why these SGIP applications did not more forward were financial:

> *"At the time that the SGIP application was withdrawn, it became apparent that the design/build process advocated by our consultant at the time was not going to result in a project cost that would allow the project to move forward."*
>
> *"The payback that the contractor projected at the onset of the project was not aligned with the actual payback. The cost for gas was much higher, the engine was sized for peak demand and the payback predicated on selling energy back to the utility at the same rate the utility charges. It took a lot of digging, on my part, to discover that the energy we produce, beyond what we use, will be credited at less than 15 percent of what we pay for it."*

### Future Plans for Onsite Generation

To assess the future outlook for onsite generation from the end user's perspective, survey respondents were asked to rate their organization's likelihood of installing onsite generation at their facility in the future. As shown in Figure 6-5, more than half of both SGIP participants and nonparticipants reported being very or somewhat likely to install onsite generation in the future. Participants are slightly less likely to install onsite generation in the future than nonparticipants, since a high percentage of them already have onsite generation installed that is currently operable.

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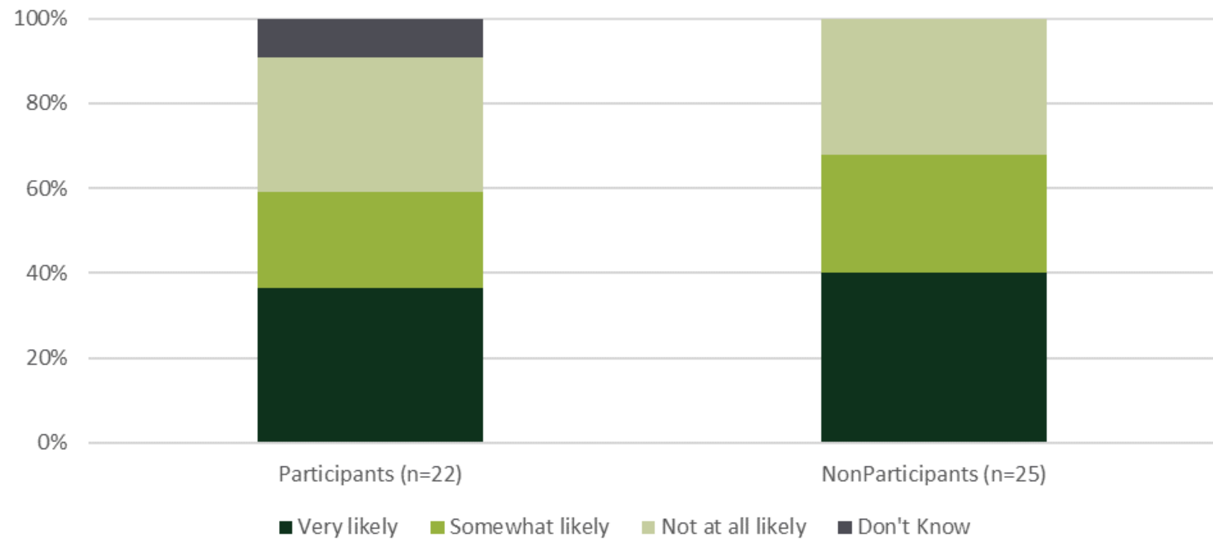
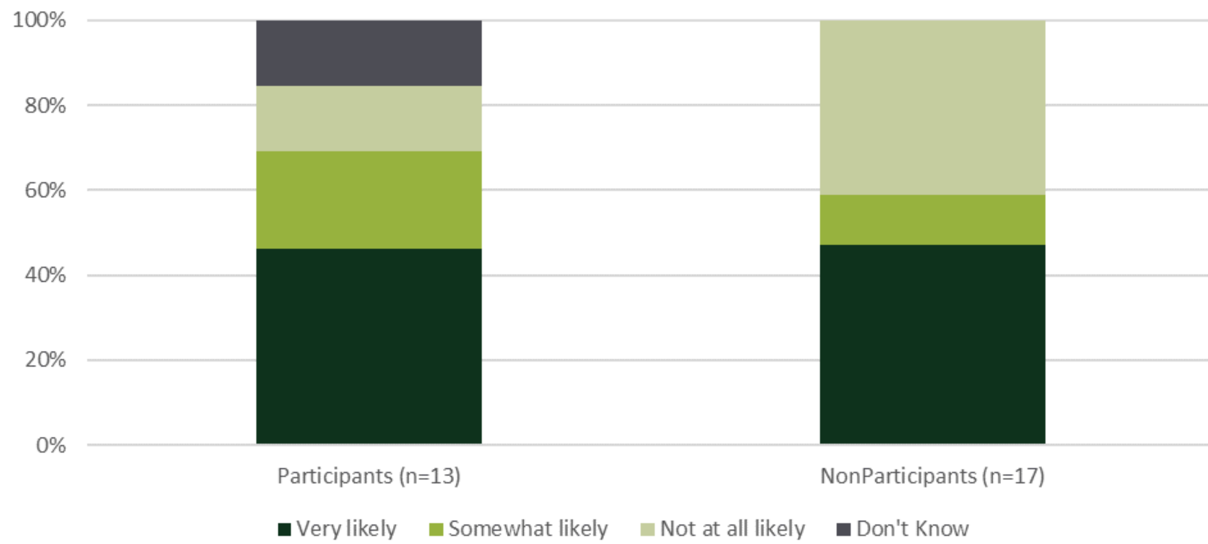
46 Fifty percent reported solar had been installed onsite at their facility.

**FIGURE 6-5: RESPONDENTS LIKELIHOOD TO INSTALL ONSITE GENERATION IN THE FUTURE**




When asked about the likely timing for this future generation, the majority (60 percent of respondents) estimated it would occur in the next one to five years. The remaining respondents were evenly split between estimating it would occur sooner (within the next year) or in a later timeframe (more than five years from now). Respondents who reported they were likely to install onsite generation were asked whether they were likely to fuel this future onsite generation with biogas, and as shown in Figure 6-6 below, less than fifty percent stated they are very likely to do so.

#### FIGURE 6-6: RESPONDENTS LIKELIHOOD TO FUEL ONSITE GENERATION WITH BIOGAS




It is interesting to note that of those who said they were likely to fuel with biogas, more than 20 percent of non-participating landfills and wastewater treatment plants reported they would be unlikely to apply for an SGIP incentive for this biogas fueled onsite generation. This may indicate a lack of knowledge of the program or belief that the program participation requirements are too onerous and not worth it the effort it takes to participate for the incentive being offered.

Respondents who reported they were unlikely to install onsite generation in the future were asked why this was the case. Responses were primarily related to costs, permitting, or the lack of onsite (or additional onsite) fuel to power the generation equipment.

> ***Financial:*** *"ROI is too low", "Not cost effective and our sustainability goals require us to not use fossil fuels", "Cost"*
>
> ***Permitting:*** *"California Air Resources Board doesn't want any internal combustion engines", "The technology is too new, the SCAQMD requirements are too stringent and hard to achieve and the expense to maintain the plant is too high"*
>
> ***Fueling:*** *"I don't have enough biogas to add more", "Gas limitations", "Not enough digester gas production to maximize existing production capacity"*

## 6.4 ACTIONS TO ADDRESS BARRIERS TO ONSITE BIOGAS GENERATION ADOPTION

During the interviews with project developers and surveys with participating and nonparticipating customers a number of actions were identified, including some SGIP specific actions, which respondents believed could help to alleviate some of the barriers faced to onsite generation. These actions included:

- **Improved economics** for onsite generation projects. These improvements could come in a number of different forms, including:
  - *Increased SGIP incentives* – while Decision. 20-01-021 called for an increase in onsite generation program incentives, those increases have yet to be put into place (per SGIP website and communication with program PA). These forthcoming increases were discussed with projected developers and the market appears very receptive to these increased incentives and optimistic for how they could improve the financials of some potential projects. A clear and complete description of the eligibility rule to qualify for the resiliency adder will be required to determine the ultimate reach of these revised incentive levels.
  - *Expanding RNG procurement outside of WECC* – while many interviewed parties understood the rational for the WECC procurement requirement, feedback was provided that with the new Green-e® certification expected near the end of 2020[47] the environmental attributes of renewable fuels (outside the WECC) may be more feasible to ensure. Another respondent took issue with the fact that LCFS allows biogas to be sourced from outside of the WECC and thus it was in essence not "a level playing field".
  - *Reevaluate Siloxane requirements* – one of the reasons industry experts reported the cost of directed biogas was so high was the added biogas cleaning expense to fulfill California's siloxane requirements, which according to some industry experts can be as much as 10x higher than in some other states. The low siloxane limit of 0.1 mg Si/m$^3$ for pipeline biogas is a California regulation and not a SGIP requirement.
- **Simpler program participation requirements.** SGIP program participants rated their satisfaction with the program requirements lower than both the application process and the incentive amount (the average satisfaction rating for the program requirements was a 3.2 out of 5). Developers felt that the program rules and eligibility with participation in other programs was confusing, "*the language is confusing as to eligibility".* One respondent stated that for their biogas project to move forward they would need *"Net metering incentives that are easily understood and well supported."* All of this points to simpler program rules and requirements being beneficial to increase program participation.

[47] https://www.green-e.org/renewable-fuels

- **Increase SGIP onsite generation outreach and support.** Program participants and developers commented on the SGIP significant shift to AES in the last few years and the resulting reduction in the program's marketing and outreach regarding onsite generation technologies. Numerous developers were unaware of the higher incentives for onsite generation equipment that were approved in January 2020 (they have yet to be put into place at the time of this report) and one SGIP applicant, who later cancelled his organizations application, said that when he called to ask a question about his onsite generation application he talked to at least seven utility staff who asked him if he was referring to an application for AES. He said it was as if the program implementers were not even aware the program continued to incentivize onsite generation equipment.
- **Interagency cooperation and coordination.** The number of California and federal government programs out there to promote the beneficial use of biogas is numerous. Some of these programs are complimentary and allow participants to 'stack' incentives while others are mutually exclusive. Ensuring the interagency programs are not in conflict with one another and there is not dissension amongst the program rules is important to alleviate customer confusion and increase program participation across all biogas programs available. This interagency collaboration would require coordination far outside of the SGIP.

# 7 COST-EFFECTIVENESS APPROACH

This section summarizes the sources of data and methodologies used in the cost-effectiveness component of this study. The discussion of the cost-effectiveness approach is divided into the following sub-sections:

- Overview of approach
- Discussion of cost-effectiveness tests
- Key inputs

## 7.1 OVERVIEW OF APPROACH

This project was completed as a sensitivity analysis of Self-Generation Incentive Program (SGIP) benefits and costs. The purpose of this analysis is to test how various changes can impact the cost-effectiveness tests performed on renewable fuel technologies incentivized through SGIP. The results can be considered indicative of ways to improve the program but are not actual evaluations of the program. The analysis can help determine whether specific elements of an incentive program should be continued in their current form or be altered in some way to achieve desired outcomes. More broadly, this cost-effectiveness analysis allows insights into the effects of rate structures, incentive levels, and other policies on costs and benefits of renewable fuel technologies being implemented by the SGIP. The results of this analysis can inform future program design as to possible tools that could improve cost-effectiveness results from the perspective of participants, the utility, society, and ratepayers.

In 2009, the CPUC adopted an evaluation framework and methodology for assessing cost-effectiveness of distributed generation (DG) technologies.[48] The DG cost-effectiveness methodology is derived from the Standard Practice Manual (SPM) first published in the 1980s and used for several decades in evaluating energy efficiency technologies and programs.[49] The 2009 CPUC decision on DG cost-effectiveness provides specific guidance on the tests to be used, the costs and benefits to be included in each test, and the avoided cost inputs to be used when calculating program costs and benefits.

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[48] CPUC, "Decision Adopting Cost-Benefit Methodology for Distributed Generation," Decision (D.) 09-08-026, August 20, 2009.

[49] CPUC, California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, October 2001: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

This analysis considered the cost-effectiveness of renewable fuel generation technologies using five distinct tests:

- **The Participant Cost Test (PCT)** is the measure of the quantifiable benefits and costs to the customer due to participation in the program.
- **The Ratepayer Impact Measure (RIM) Test** measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.
- **The Total Resource Cost (TRC) Test** measures the net costs of a program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.
  - **The Societal TRC (STRC)** is a variant of the TRC test that uses a lower societal discount rate.
- **The Program Administrator (PA) Cost Test** measures the net costs of a program as a resource option based on the costs incurred by the PA (including incentive costs) and excluding any net costs incurred by the participants.

The May 2019 CPUC cost-effectiveness Decision (D.) 19-05-019 designated the TRC test as the primary cost-effectiveness test and adopted modified versions of the TRC, PA, and RIM tests for all distributed energy resources starting July 2019.[50] The cost-effectiveness analysis undertaken for renewable fuel generation technologies is consistent with D. 19-05-019, highlighting the TRC and presenting results from the five distinct tests (TRC, STRC, PA, RIM and PCT).

The five cost-effectiveness tests listed above are applied to a variety of use cases involving renewable fuel generation technologies that have been rebated through SGIP. The following technologies and sizes are included in the evaluation:

- Fuel Cell 1,400 kW, 800 kW, 400 kW, and 200 kW
- Gas Turbine 11,350 kW and 3,600 kW
- Internal Combustion Engine 1,500 kW and 500 kW
- Microturbine 200 kW

In January 2020, the CPUC SGIP Revisions Pursuant to Senate Bill 700 Decision (D. 20-01-021) asked the PA to pause acceptance of incentive applications for renewable generation technologies that do not have

[50] CPUC, Decision 19-05-019, Decision Adopting Cost Effectiveness Analysis Framework Policies for all Distributed Energy Resources, May 2019. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF

a vented baseline.[51] This cost-effectiveness evaluation, however, develops estimates of the five SPM cost-effectiveness tests for the above technologies with flared and vented baselines, using both onsite and directed biogas assumptions.[52] This study provides the Commission and interested stakeholders with information on the costs and benefits to reflect the technologies, baselines, and fuel sources that were available to be incentivized through the SGIP in 2019. The results from this evaluation provide data to help inform future SGIP technology and incentive options. Scenarios are presented describing the cost-effectiveness of the various technologies for combinations of the following cases:

- With and without a resiliency adder
- Vented baseline assuming directed and onsite biogas
- Flared baseline assuming directed and onsite biogas
- Onsite vented baseline with and without inclusion of the digester cost
- Onsite vented baseline with the digester cost and a California Department of Farms Association Grant
- Onsite vented baseline with the digester cost and a US Department of Agriculture Grant
- Onsite and directed, vented and flared baselines with Renewable Energy Credits
- Flared baseline for directed and onsite biogas with observed capacity factor and a 0.8 capacity factor

The following subsections describe the key inputs to the cost-effectiveness tests in more detail.

## 7.2 KEY INPUTS

This subsection provides additional details on the following aspects of the cost-effectiveness analysis:

- Technology characteristics
- Customer retail rates
- Customer incentives and tax credits
- Utility avoided costs
- Program administrator costs

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51 CPUC, Decision 20-01-021, Self-Generation Incentive Program Revisions, Pursuant to Senate Bill 700 and Other Program Changes, January 2020. https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=325979689

52 The onsite biogas with vented baseline cost-effectiveness evaluation only includes the fuel cell and ICE technologies.

### 7.2.1 Renewable Generation Technology Characteristics

Table 7-1 lists the technologies, the sizing used in the modeling, the system's potential gas consumption if the system were running at full capacity (a capacity factor of 1.0), the average capacity factor observed for these systems in SGIP[53] and the system's efficiency. The sizing (kW) assigned to each technology is based on technology sizing found in the SGIP program. Many of the technologies have a "large" and "small" technology size. These are not intended to imply that these sizes represent all of the technology sizes rebated by the program. Instead, the larger size represents a prototypical large sized system for the technology while the smaller sized system is a representative system for smaller installations of the technology. Using this approach, the cost-effectiveness model provides estimates of the SPM tests based on the range of system sizes. Combined heat and power could add some additional savings due to offsetting heating load but SGIP does not require heat recover for renewably fueled generation and historically we have observed very few SGIP biogas sites recovering heat for facility use.

**TABLE 7-1: TECHNOLOGY DESCRIPTION**

| Technology[54] | Size (kW) | MMBtu/h Consumption | Capacity Factor | Efficiency |
|---|---|---|---|---|
| Fuel Cell – CHP (FC) | 1,400 | 9.00 | 0.74 | 0.39 |
| Fuel Cell - CHP (FC) | 400 | 2.57 | 0.74 | 0.39 |
| Fuel Cell – All Electric (FCE) | 800 | 4.85 | 0.87 | 0.49 |
| Fuel Cell – All Electric (FCE) | 200 | 1.21 | 0.87 | 0.49 |
| Gas Turbine (GT) | 11,350 | 99.72 | 0.82 | 0.32 |
| Gas Turbine (GT) | 3,600 | 31.63 | 0.82 | 0.32 |
| Internal Combustion Engine (ICE) | 1,500 | 9.46 | 0.50 | 0.27 |
| Internal Combustion Engine (ICE) | 500 | 3.15 | 0.50 | 0.27 |
| Microturbines (MT) | 200 | 1.88 | 0.58 | 0.21 |

<u>Energy Consumption</u>

The MMBTU/h presented in Table 7-1 lists the amount of input energy required to fuel the generation technology at the listed capacity factor. Large systems will need more input energy than smaller systems,

[53] Scenarios were implemented using the average observed capacity factor and using a capacity factor of 0.80.

[54] Fuel Cell – CHP have the ability to use heat for other purposes. Fuel Cell – All Electric (or

all else held constant. In addition, systems with a higher efficiency will need less input energy than same sized systems with a lower efficiency rating.

#### Capacity Factor

The system's capacity factor refers to the amount of power produced annually by the generator relative to the maximum amount of energy that could be produced from the generation technology. For example, a generation technology rated at 400 kW could theoretically produce 3,504,000 kWh = 400*8,760 if operated at 100 percent capacity factor all year. If that same technology is operated at a 74 percent capacity the annual energy production is 2,592,960 kWh. SGIP's performance-based incentives (PBI) are calculated during system planning based on a minimum capacity factor of 80 percent. If a system's metered performance is less than 80 percent, the incentive received by the participant customer is reduced.[55] Given the average observed capacity factors listed in Table 7-1, it is not unusual for SGIP technologies to operate at less than an 80 percent capacity factor. Two cost-effectiveness scenarios are implemented assuming a capacity factor of 80 percent to illustrate the impact of capacity factor on cost-effectiveness.

#### Technology Efficiency

The efficiency of the generation technology refers to the efficacy with which a generator produces power. Electrical efficiency is measured as the amount of electricity generated per amount of fuel or energy consumed by the generator. The electrical efficiency used for this evaluation assumes the generation technologies are not operating as a CHP facility.

#### Technology Fuel and Flared versus Vented Baseline

The cost-effectiveness of the generation technologies is analyzed under multiple renewable fuels and a flared versus vented baseline (see Table 7-2). For this analysis, all fuels are renewable, either directed or onsite biogas. All technologies will be analyzed using directed biogas with both a flared and a vented baseline line. For onsite biogas, all technologies will be analyzed using a flared baseline but only fuel cells and internal combustion engines will be analyzed for onsite biogas with a vented baseline.

The directed biogas is purchased from a biogas distributor for an increased cost relative to natural gas. The directed biogas can be purchased from a source that is required to flare or burn their methane to reduce its GHG impacts on the environment or from a source that is allowed to vent the methane. If the directed biogas is purchased from a source that is required to flare their methane, using the biogas in the generation technology to produce electricity will result in avoided GHGs associated with the participating

55 Beginning in 2011, SGIP technologies fueled by natural gas were assumed to have a 0.80 annual capacity factor to achieve necessary GHG reductions. All of the generation technologies modeled in this evaluation are fueled by renewable natural gas and are not required to have a 0.80 annual capacity factor.

customer reducing their purchase of electricity from the utility grid. The value of this reduction in GHGs is accounted for in the electricity avoided costs that contribute to the cost-effectiveness benefits in the TRC, PA, and RIM tests. If the directed biogas is purchased from a source that is allowed to vent their methane, capturing the methane to develop biogas that will be used in electricity generation results in two sources of GHG reductions. Like the directed biogas from a flared source, the production of electricity reduces the participant customer's purchase of electricity from the grid and GHGs that are associated with the utility provided electricity. The directed biogas from a vented source also reduces GHGs associated with the venting of methane into the atmosphere. The right most column in Table 7-2, lists this second type of CO2 equivalent reduction associated with using biogas that is allowed to be vented, to produce electricity. This additional source of GHG reduction is valued in the cost-effectiveness tests at the total GHG Adder value listed in the 2020 Avoided Cost Calculator. The additional value of GHG reduction from vented directed biogas is added to the benefits described above in the TRC, PA, and RIM tests.

Onsite biogas is associated with many business types including, but not limited to, wastewater treatment plants, landfills, and dairies. Wastewater treatment plants and landfills operate under regulations requiring them to capture and flare or capture and use their methane. Dairies are currently allowed to vent their methane. The onsite biogas used in generation technology at businesses that are required to capture and flare or use their methane are modeled in the cost-effectiveness evaluation as a flared baseline. As described above, generation technologies with a flared baseline are associated with GHG reductions linked to the reduced use of utility electricity. The generation technologies at businesses with a vent baseline, however, reduced GHGs due to both their reduced use of utility electricity and their capture and use of methane.

### TABLE 7-2: TECHNOLOGY SCENARIOS INCLUDING FUEL TYPES, FLARED VERSUS VENTED BASELINE AND GHG IMPACTS

| Technology | Directed Biogas, Flared & Vented Baseline | Onsite Biogas, Flared Baseline | Onsite Biogas, Vented Baseline | GHG Additional Reduction: Vented Baseline Relative to Flared (CO2e lbs/MWh) |
|---|---|---|---|---|
| Fuel Cell | Yes | Yes | Yes | 6,531 |
| Fuel Cell – All Electric | Yes | Yes | Yes | 5,198 |
| Gas Turbine | Yes | Yes | No | N/A |
| Internal Combustion Engine | Yes | Yes | Yes | 9,434 |
| Microturbines | Yes | Yes | No | N/A |

### 7.2.2 Installed System Costs

This subsection presents the installed system capital costs and sources, the next subsection presents the operational and maintenance (O&M) costs and sources. The installed system costs for generation technologies fueled by distributed and onsite biogas can vary significantly depending on the complexity of the installation and the need to add a variety of additional technologies. A system fueled by directed biogas may only incur the cost of the generation technology. While a system fueled by onsite biogas may face a myriad of other costs including the expense to buy a digester to make the biogas, and technology to clean up the biogas. Table 7-3 lists the cost attributes used in the cost-effectiveness model for the year 2020. For components such as system costs, some technologies are assumed to experience expanded demand and technological progress leading to reductions in costs over time while other components are assumed to grow at the rate of inflation. The system costs were estimated based on a literature review. A cost per kW value was calculated based on these recent sources for each technology.

**TABLE 7-3: TECHNOLOGY COST COMPONENTS**

| Technology & Size (kW) | Installed System Cost ($/kW)[56] | Biogas Cleanup Cost ($/kW)[57] | Digester Cost ($/kW)[58] |
|---|---|---|---|
| Fuel Cell– 1,400 | $4,218 | $717 | $3,032 |
| Fuel Cell– 400 | $4,613 | $999 | $4,370 |
| Fuel Cell – All Electric – 800 | $4,390 | $796 | $3,289 |
| Fuel Cell – All Electric – 200 | $4,848 | $1,148 | $6,099 |
| Gas Turbine – 11,359 | $2,708 | $519 | -- |
| Gas Turbine – 3,600 | $2,852 | $703 | -- |
| Internal Combustion Engine – 1,500 | $2,496 | $694 | $2,948 |
| Internal Combustion Engine – 500 | $2,845 | $928 | $3,947 |
| Microturbines – 200 | $3,366 | $1,589 | -- |

Technologies using directed biogas, with both a vented and flared baseline only pay the system costs. Systems using onsite biogas that are not dairies are paying the system cost and the biogas cleanup cost. Systems installed at dairies are modeled as paying the system costs and the biogas cost as the base case.

56 Installed system costs are based on a combination of two sources:

- Distributed Generation, Battery Storage, and Combined Heat and Power Characteristics and Costs in the Buildings and Industrial Sectors, US Energy Information Administration. May 2020.
- A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California. CEC-500-2019-030. ICF. March 2019.

57 Biogas Cleanup Costs are based on a curve fit to flow rate ($199{,}310*(\text{MMBtu/h})^{0.7359}$) to data from these sources:

- Personal Communication between Staff and Industry
- Frazier, Hamilton, and Ndegwa. Anaerobic Digestion: Biogas Utilization and Cleanup. Oklahoma State University. February 2017. https://extension.okstate.edu/fact-sheets/anaerobic-digestion-biogas-utilization-and-cleanup.html
- Encina Wastewater Authority Energy & Emissions Strategic Plan Final Report, Kennedy/Jenks Consultants, April 2011.
- Final Report for AQMD Contract #: 13432 Conduct a Nationwide Survey of Biogas Cleanup Technologies and Costs, by Gas Technology Institute
- Las Gallinas Valley Sanitation District - Biogas Utilization Technologies Evaluation, Final Technical Memorandum, April 2014, CH2MHILL.

58 Digester Installed Cost (including construction) and collection to the point of cleanup are estimated as a function of the number of cows, and therefore the amount of biogas produced per day. These estimates are based on a model developed for covered lagoons based on EPA AgStar digester data as published in this paper and adjusted for inflation:

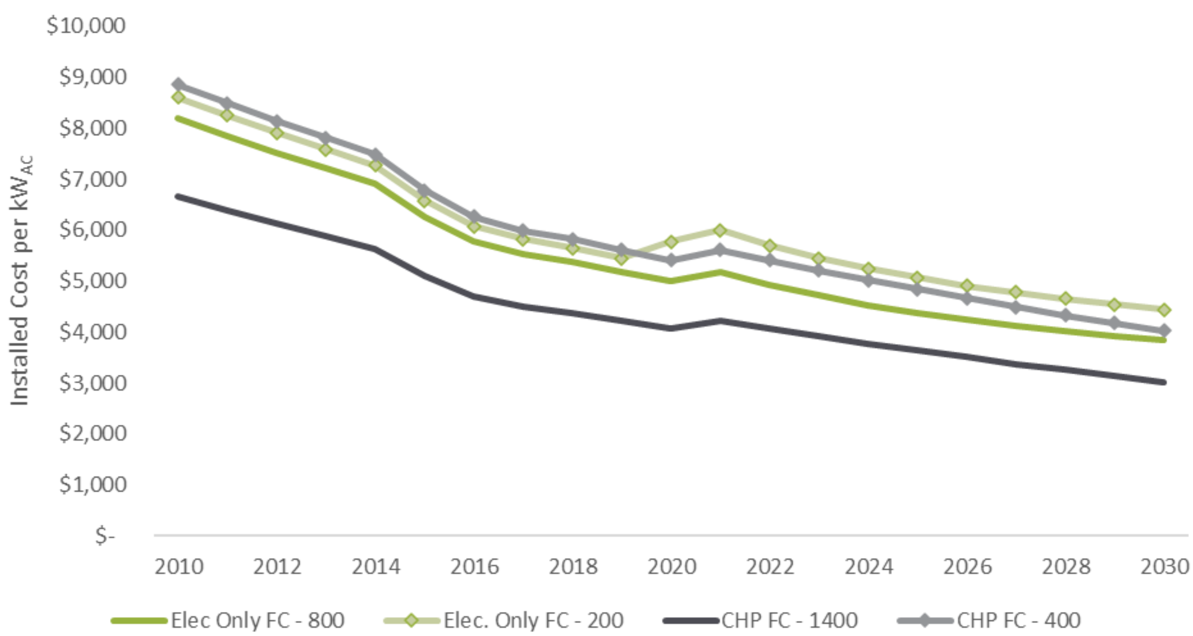
- Lauer et. Al, Making money from waste: The economic viability of producing biogas and biomethane in the Idaho dairy industry, Applied Energy, 1995.

Scenarios were also run with dairies paying for a digester. A 1,400 kW Fuel Cell installed at a dairy is modeled as costing $4,935/kW in scenarios where the farm is assumed to already have a digester and $7,967/kW in scenarios where a digester must be added. This compares to a 1,400 kW fuel cell operating on directed biogas where the total cost would be $4,218/kW.

The technology costs listed in Table 7-3 also illustrate economies of scale. All technologies other than microturbines were modeled for a large and a small kW size. For each technology, the larger system size has a lower system cost per kW than the smaller sized system. The biogas cleanup and digester costs also show economies of scale.

Costs for most technologies have remained relatively flat over time given that combustion generation technologies are relatively mature. Fuel cells, however, are still a somewhat nascent technology that is evolving and advancing over time. Figure 7-1 shows these costs over time.

**FIGURE 7-1: INSTALLED FUEL CELL COSTS OVER TIME (WITH CLEANUP, 2020$)**




## 7.2.3 Operations and Maintenance Costs

Like installed costs, operations and maintenance (O&M) costs vary with equipment type and size. We used published literature to estimate these costs and Table 7-4 lists the O&M cost attributes used in the cost-effectiveness model for the year 2020. Sources for these costs are listed in the footnotes below.

**TABLE 7-4: O&M COSTS**

| Technology & Size (kW) | System O&M Cost ($/kWh)[59] | Biogas O&M Clean Cost ($/kWh) [60] | Digester O&M ($/kWh)[61] |
|---|---|---|---|
| Fuel Cell –1,400 | $0.031 | $0.05 | $0.012 |
| Fuel Cell –400 | $0.050 | $0.05 | $0.017 |
| Fuel Cell – All Electric – 800 | $0.039 | $0.05 | $0.011 |
| Fuel Cell – All Electric – 200 | $0.064 | $0.05 | $0.016 |
| Gas Turbine – 11,359 | $0.019 | $0.04 | -- |
| Gas Turbine – 3,600 | $0.015 | $0.04 | -- |
| Internal Combustion Engine – 1,500 | $0.020 | $0.04 | $0.017 |
| Internal Combustion Engine – 500 | $0.024 | $0.04 | $0.023 |
| Microturbines – 200 | $0.022 | $0.04 | -- |

## 7.3 RETAIL RATES AND DIRECTED BIOGAS ADDITIONAL COST

Each generation technology was modeled in each of the IOU service territories as producing electricity that would replace electricity valued at an IOU specific commercial TOU rate. The rates chosen were based on the size of the customer typically owning a given technology and technology size. The electricity rates used to value electricity production are listed in Table 7-5.

59 Equipment O&M Costs were estimated using a regression fit through multiple sources based on installed capacity and then allocated by kWh.

- Distributed Generation, Battery Storage, and Combined Heat and Power Characteristics and Costs in the Buildings and Industrial Sectors, US Energy Information Administration. May 2020.
- A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California. CEC-500-2019-030. ICF. March 2019.
- Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California FINAL TECHNICAL REPORT to the State of California Air Resources Board Contract # 14-456, Kaffka et all (UC Davis)

60 Cleanup Costs are based on the average of multiple sources:

- Encina Wastewater Authority Energy & Emissions Strategic Plan Final Report, 2011, Kennedy/Jenkins Engineers/Scientists.
- La Gallinas Valley Sanitation District - Biogas Utilization Technologies Evaluation CH2M Hill April 2014.
- Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California FINAL TECHNICAL REPORT to the State of California Air Resources Board Contract # 14-456, Kaffka et all (UC Davis)

61 Linear curve fit of 186.63*Cows$^{0.7153}$ derived from Kaffka et all (UC Davis), Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California FINAL TECHNICAL REPORT to the State of California Air Resources Board Contract # 14-456

**TABLE 7-5: LIST OF PARTICIPANT CUSTOMER ELECTRICITY RATES USED TO VALUE ELECTRICITY PRODUCTION**

| Technology & Size | PG&E | SCE | SDG&E |
|---|---|---|---|
| Fuel Cell –1,400 | B20TOU | TOU-8 | A6-TOU |
| Fuel Cell –400 | B10TOU | TOU-8 | A6-TOU |
| Fuel Cell – All Electric – 800 | B19TOU | TOU-8 | A6-TOU |
| Fuel Cell – All Electric – 200 | B10TOU | TOU-GS-3 | AL-TOU |
| Gas Turbine – 11,359 | B20TOU | TOU-8 | A6-TOU |
| Gas Turbine – 3,600 | B20TOU | TOU-8 | A6-TOU |
| Internal Combustion Engine – 1,500 | B20TOU | TOU-8 | A6-TOU |
| Internal Combustion Engine – 500 | B19TOU | TOU-8 | A6-TOU |
| Microturbines – 200 | B10TOU | TOU-GS-3 | AL-TOU |

The participant customers using directed biogas to fuel their technologies are modeled as customers that purchase gas on the wholesale market. These customers pay the utilities a transportation cost based on the volume of gas that they use to fuel their technology. The directed biogas customers also pay a biogas adder of $1.75/therm,[62] to compensate the directed biogas supplier for the increased cost of biogas relative to natural gas. Other scenarios with lower directed biogas costs are presented in 8.2.3

### 7.3.1 Incentives and Tax Credits

All renewable natural gas technologies are assigned a base SGIP incentive rate of $2/W. This base incentive amount is applied to technologies less than 1000 kW. For renewable natural gas technologies sized between 1000 kW up to 2000 kW, the incentive rate is modified to $1.5/W while technologies sized 2000 kW and larger are eligible for $1/W incentives up to a maximum incentive of $5,000,000. SGIP customers are paid 50 percent of the incentive upfront and the remaining 50 percent over five years based on the capacity factor of the renewable natural gas technology. We model the incentive based on the average capacity factor observed from metered data. The modeled capacity factors were listed previously in Table 7-1. The cost-effectiveness analysis also includes a scenario where technologies are modeled with an 80 percent capacity factor which impacts the level of energy production, bill and avoided cost savings, and incentives. An 80 percent capacity factor receives the maximum SGIP rebate for a given technology.

The cost-effectiveness analysis also implemented scenarios with incentives increased to include a resiliency adder. Decision 20-01-021 instituted a resiliency adder of $2.5/W for renewable generation

[62] Based on the range of $12-$23/MMBtu quoted by reply comments of Southern California Gas Company (U904G) To Assigned Commissioner's Ruling Seeking Comments on Implementation of Senate Bill 700 and Other Program Modifications and supported by letter from Energy Vision.

natural gas technologies incentivized in SGIP.[63] Combining the resiliency adder with the base $2/W SGIP incentive results in an incentive of $4.5/W for renewable generation projects implemented for resiliency purposes. The cost-effectiveness analysis includes scenarios with the combined resiliency incentive, estimating the SPM cost-effectiveness test with the higher incentive level to illustrate the impact of this increase on the five SPM tests.

The California Department of Food and Agriculture (CDFA) makes grants available to implement dairy digesters. The Budget Act of 2017-18 requires the CDFA to award grants to dairies that are implementing digesters that results in the long-term reduction in methane emissions. Scenarios were implemented in the cost-effectiveness evaluation that assume the participant dairy receives a CDFA grant that reduces the cost of the dairy digester by 50 percent.

The United States Department of Agriculture (USDA) Rural Energy for America Program (REAP) can provide additional incentives for renewable generation. This program provides grants to cover 25 percent of biomass fueled generation in rural areas with populations of less than 50,000 residents. The maximum grant amount is $500,000.

The Federal Investment Tax Credit (ITC) is available nonresidential customers renewable natural gas electricity production technologies. The value of the ITC, however, is dependent on the technology type. Fuel cell technologies (both CHP and all electric) are eligible for a 26 percent ITC in 2020, declining to 22 percent in 2021 and 2022, and zero for technologies installed after 2022. All other technologies are eligible for a 10 percent ITC in 2020 and 2021 and with zero thereafter. Participant customers also benefit from the California state 5-year Modified Accelerated Cost Recovery System (MACRS) and the federal 100 percent bonus depreciation system.

## 7.4 AVOIDED COSTS

Renewable natural gas fueled generation technologies are modeled as producing electricity that reduces the customer usage of power supplied from the grid. For all the SPM tests other than the PCT, the electricity production is valued using the CPUC 2020 ACC. The ACC produces an avoided cost shape for each climate zone. For the cost-effectiveness evaluation we chose two climate zones from each utility, one to represent the coastal avoided costs and one to represent the inland. For PG&E coastal, we used the avoided costs from 3A and zone 13 for inland. For SCE we used 6 for coastal and 15 for the inland avoided costs. For SDG&E we used the avoided costs from 7 for coastal and 10 for inland.[64]

63 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF

64 In the 2020 ACC there is very little to no difference in the avoided costs by climate zone within a utility.

To assess the utility value of additional GHG reduction associated with technologies installed on a vented baseline, the GHG adder from the ACC was applied to the CO2e reduction associated with the reduction in methane emissions.

## 7.5 PROGRAM ADMINISTRATOR COSTS

PAs bear the cost of designing and managing the SGIP. These administrative costs are applied in the PA, RIM, TRC, and STRC tests. We assign them on a $/kW basis using the installed capacities of the renewable natural gas technologies. CPUC ruling (D. 11-11-005) PG&E and SCE were found to have excess administrative budget while the Consortium for Sustainable Energy (CSE), the PA for SDG&E's SGIP, was found to need additional resources. The ruling stated that CSE needed additional funds because it lacks the large institutional resources to leverage for administration of SGIP. For PG&E and SCE the model uses an administrative cost of 7 percent of the incentive, while technologies installed in SDG&E's territory have an administrative cost of 10 percent of the incentive.[65] Administration costs are modeled to increase with inflation at 2 percent per year.

## 7.6 FINANCING, DISCOUNT RATES, AND TAXES

Below we present several key inputs and global assumptions applicable throughout our modeling:

- The Federal marginal tax rate is 21 percent
- The California state tax rate is 8.84 percent
- All technologies are financed with debt/equity:
    - Customers finance with 60 percent equity and have a debt interest rate of 6 percent
- The participant discount rate is 8 percent, utility discount rate is 7.5 percent, and the societal discount rate is 3 percent
- The inflation rate 2 percent

[65] Based on CPUC ruling (D. 20-01-021, January 16th, 2020). This decision notes that PA budgets are listed as 7 percent. CSE receives a ten percent budget to cover the large amount of residential applications that it receives.

# 8 COST-EFFECTIVENESS RESULTS

This section summarizes the results from the cost-effectiveness component of this study. A detailed discussion of the cost-effectiveness methodology and key assumptions was presented in Section 6. The cost-effectiveness results presented in this section represent the findings from 279 distinct simulations based on combinations of customer renewable generation technologies, fuel source, methane baseline, total installation costs, and incentive levels. At times throughout this section, we present findings averaged across a group of simulations to present overall cost-effectiveness trends. Other times, we highlight individual simulation results to explore the influence of specific cost and benefit components. By selecting individual simulation results, we are not implying that these findings are representative of the cost-effectiveness of all other renewable generation technologies. Instead, we select specific simulations for in-depth analysis as they allow us to highlight aspects of cost-effectiveness that we deem relevant or important.

Below we summarize the key parameters that make up the simulation results presented in this section. The analysis included 16 scenarios across the different input parameters where four of the scenarios represent the base case (see Table 8-1 below). Please refer to Section 6 for additional details on each parameter.

- Two fuel sources combined with two methane baselines leading to four "base case" estimates of cost-effectiveness for most technologies. The four base cases include onsite biogas with a flared and a vented baseline and directed biogas with a flared and a vented baseline.
  - The onsite biogas with a vented baseline represented renewable generation technologies installed at a dairy. The onsite biogas with a flared baseline represents renewable generation technologies installed at locations where regulations require the methane source to flare their methane, wastewater treatment and landfills are examples of organizations required to flare their methane.
- Two SGIP incentive levels. The base incentive level and a higher incentive level representing the base SGIP and the resiliency adder SGIP incentive.
- Measure costs that differ by fuel source and the participant customer's need for a digester.
  - The measure costs for technologies fueled by directed biogas are modeled using only technology specific costs.
  - The measure costs for technologies fueled by onsite biogas include the technology measure cost and onsite biogas cleanup costs.
  - Scenarios for technologies fueled by onsite biogas at dairies are implemented with the measure cost including the cost of a digester.

  - An additional scenario is executed where the dairy receives a grant from the California Department of Food and Agriculture (CDFA) for half of the digester cost.
  - Scenarios where the dairy receives a grant from both the CDFA and the United States Department of Agriculture (USDA) for the digester cost.
- The cost-effectiveness analysis is modeled using observed technology specific average capacity factor and an assumed 80 percent capacity factor.
- Three scenarios were modeled where the technologies receive Renewable Energy Credits or RECs.

The table below itemizes the different scenarios included in the cost-effectiveness analysis. The base case scenarios represent the cost-effectiveness of the technologies using different fuel sources and a vented versus flared baseline. The extra scenarios incorporate additional costs and benefits.

**TABLE 8-1: COST EFFECTIVENESS SCENARIOS**

| Fuel Type | Incentive with Resiliency Adder | Capacity Factor | Dairy or Vented Baseline | Digester Cost Included | CDFA Grant | UDSA Grant | Recs | Directed Biogas Cost per therm | Base Case |
|---|---|---|---|---|---|---|---|---|---|
| Onsite biogas (OSB) | | Actual | | | | | | $1.75 | X |
| Directed Biogas (DBG) | | Actual | | | | | | $1.75 | X |
| OSB | | Actual | X | | | | | $1.75 | X |
| DBG | | Actual | X | | | | | $1.75 | X |
| OSB | X | Actual | | | | | | $1.75 | |
| DBG | X | Actual | | | | | | $1.75 | |
| OSB | X | Actual | X | | | | | $1.75 | |
| OSB | X | Actual | X | X | | | | $1.75 | |
| OSB | | Actual | X | X | | | | $1.75 | |
| OSB | | Actual | X | X | X | | | $1.75 | |
| OSB | | 0.80 | | | | | | $1.75 | |
| DBG | | 0.80 | | | | | | $1.75 | |
| OSB | | Actual | X | X | X | X | | $1.75 | |
| OSB | X | Actual | X | X | X | X | X | $1.75 | |
| OSB | X | Actual | | | | | X | $1.75 | |
| DBG | X | Actual | | | | | X | $1.75 | |
| DBG | | Actual | | | | | | $1.20 | |
| DBG | | Actual | | | | | | $0.70 | |

In this section we focus on the results that we believe are most relevant and illustrative of the impact that various factors can have on the cost-effectiveness of renewable fueled generation technology. Appendix C lists the results of all cost-effectiveness tests performed.

## 8.1 RENEWABLE FUELED GENERATION COST-EFFECTIVENESS

The benefits for the total resource cost (TRC), societal total resource cost (STRC), program administrator (PA), and ratepayer impact test (RIM) are largely composed of avoided cost savings while the participant cost test (PCT) benefits are largely bill savings. For technologies fueled by directed biogas and onsite biogas with a flared baseline, the avoided costs are principally those associated with the participant customer producing electricity and foregoing the use of electricity supplied by the utility. For technologies fueled by onsite biogas with a vented baseline, or onsite biogas at a dairy, the avoided cost are the avoided cost savings associated with electricity production onsite and the reduction in GHGs associated with the reduction in methane. Methane is a powerful greenhouse gas with high $CO_2$ equivalence, resulting in the reduction in methane associated with the vented baseline having a very high GHG avoided cost benefit. Table 4-1 shows the vented and flared baselines for biogas by facility type used in this analysis; please see section 3 for more information.

#### TABLE 8-2: ONSITE BIOGAS BASELINES

| Baseline | Facility Type |
|---|---|
| Vented | Dairies |
| Flared | Wastewater Treatment Plants, Landfills |

Figure 8-1 illustrates the electricity production avoided cost benefits, the methane reduction GHG avoided cost benefits associated with two of the technologies analyzed that use a vented baseline, and one of the commercial electricity rates used in the analysis. The avoided costs of grid electricity include the GHG benefits associated with using less utility provided electricity. The GHG intensity, or tons of $CO_2$ per MWh of electricity supplied, associated with grid electricity is approximately 0.4 tons per MWh in the 2020 avoided cost calculator. The reduction in methane associated with producing electricity from a vented baseline with either an internal combustion engine or an all-electric fuel cell, is substantially higher, ranging from over 2 to over 4 tons of CO2 equivalents per MWh. The large quantity of GHG reduction associated with a vented baseline is reflected in the high GHG avoided cost benefits for internal combustion engines and fuel cells in Figure 8-1. Internal combustion engines are less efficient than fuel cells (see Table 6.1) in their production of electricity. The lower efficiency of internal combustion engines implies that if the technologies were the same size with the same capacity factor, the internal combustion engine would require more biogas to produce the same quantity of electricity. While the internal combustion engine consumes more biogas, it leads to more methane reduction per MWh of electricity produced and higher GHG benefits. The high GHG benefits associated with a vented baseline will be clearly illustrated in cost-effectiveness discussions below.

**FIGURE 8-1: AVOIDED ELECTRICITY BENEFITS AND AVOIDED GREEN HOUSE GAS BENEFITS FOR INTERNAL COMBUSTION ENGINES AND FUEL CELLS**

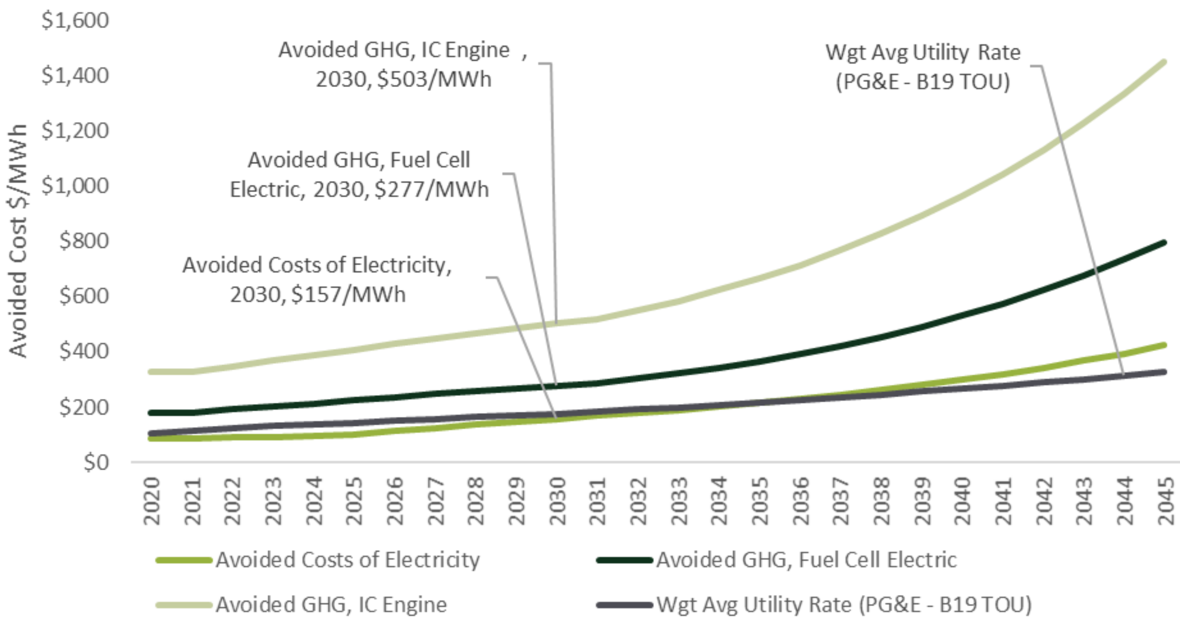
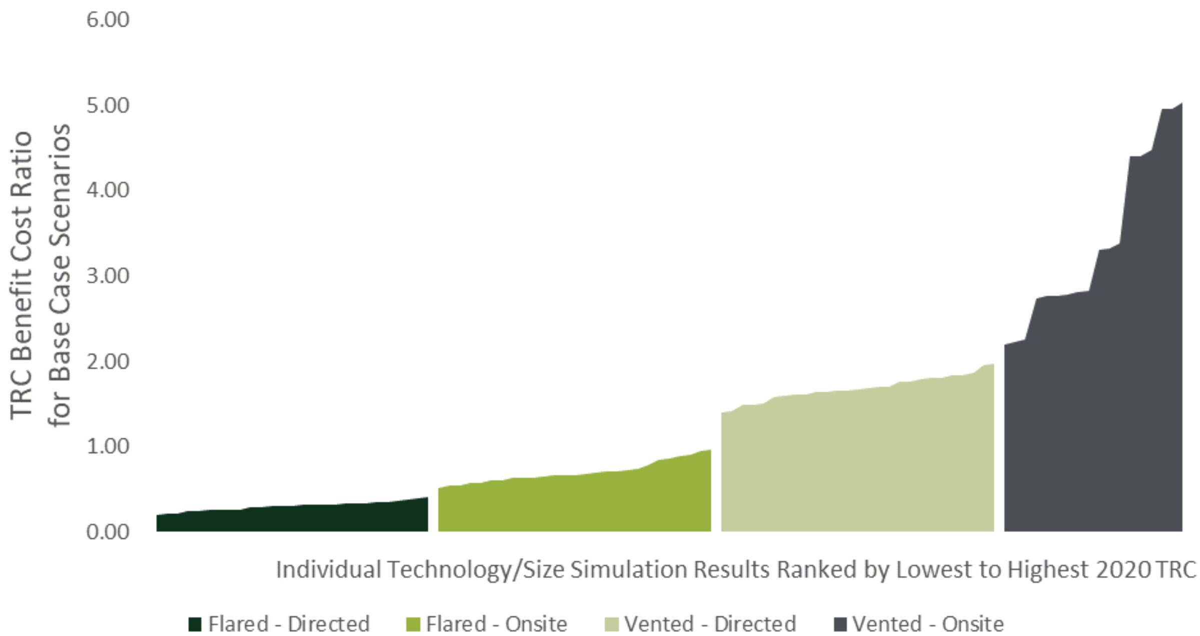



Figure 8-1 also illustrates the modeled time path of PG&E's B19 TOU rate. The rate initially is higher than the avoided costs of electricity, but the electricity avoided costs grow more rapidly than the modeled time path of the utility rate that is assumed to grow at approximately 4 percent. The utility rate is used to model customer bill savings, the primary benefit in the PCT benefit cost ratio. The slow growth of utility rates relative to avoided electricity and GHG benefits implies that the TRC is likely to grow more rapidly than the PCT. Much of the rapid growth in the avoided electricity benefits is due to rapidly rising avoided GHG benefits.

### 8.1.1 Total Resource Cost Test: Base Case

**Error! Reference source not found.** presents the results of the total resource cost (TRC) for technologies using renewable fuel under the base case in 2020. We define the base case as technologies fueled by directed (DBG) and onsite (OSB) biogas where the baseline is either flared or vented and the simulations use an average actual capacity factor, the base SGIP incentive (no resiliency adder), and the measure costs do not include the cost of a new digester, additional grants, or RECs. Recall the TRC represents the cost-effectiveness from the joint perspective of the participant customer and the utility. The TRC benefits are the avoided cost value of the electricity produced and the GHG reduction while the costs are the program administrator non-incentive costs and the participant customer measure and increased fuel cost.

**FIGURE 8-2: TRC BY DIRECTED AND ONSITE BIOGAS AND VENTED AND FLARED BASELINE – 2020**




* Each grouping represents all technologies modeled for each combination of baseline type and fuel type.

The TRC test values presented in **Error! Reference source not found.** are ordered from lowest TRC benefit cost ratio to highest. the TRC from lowest to highest directly aligns with fueling source and GHG baseline, with technologies using DBG on a flared baseline having the lowest TRC values, followed by OBG with a flared baseline, DBG with a vented baseline and the highest TRC ratios are for OSB technologies with a vented baseline. The average TRC ratio for the base case DBG flared baseline is 0.31 (dark green in **Error! Reference source not found.**) and the OSB with a flared baseline is 0.70 where the DBG TRC ratio values range from 0.20 to 0.40 and the OSB values range from 0.52 to 0.96. The technologies with a vented baseline have a substantially higher TRC ratio than those with a flared baseline. The average TRC ratio for DBG technologies with a vented baseline is 1.68 with a range from 1.40 to 1.98 and the average for the OSB fueled technologies is 3.42 with a range from 2.20 to 5.04.

The pattern observed where the flared baseline TRC ratio is less than the vented and the DBG is less than the OSG is directly related to the benefits and costs in the TRC. The benefits in the TRC are the avoided cost benefits associated with the technology's electricity production (reduction in grid electricity) and the additional value of the GHG reduction of methane under the vented baseline.[66] The DBG and OSB fueled

66 Generation technologies installed with a flared baseline do not lead to additional GHG reductions relative to the flaring of the GHGs.

technologies are modeled to produce the same quantity of electricity and have the same avoided cost benefits for a given baseline, utility, technology and size combination.[67] The capture and use of methane for the vented baseline, however, leads to substantial GHG reductions relative to the flared baseline and these GHG reductions are valued in the avoided costs using the total GHG adder value in the ACC. The substantially higher value of the TRC benefits under the vented baseline relative to the flared baseline is due to the vented baseline's higher GHG savings.

The costs of the TRC include, but are not limited to, the measure and fueling costs incurred by the participant customer. For the base case simulations, the OSB fueled technology measure costs include both the technology cost and the fuel cleanup costs while the DBG fueled technology measure costs are limited to the technology costs. For the DBG fueled technologies, however, the participant customer must purchase biogas to fuel the generator while the technologies fueled by OSB use a fuel source that is freely available onsite (after fuel cleanup costs). The cost of purchasing DBG is substantially higher than the OSB fuel cleanup costs, leading to higher TRC costs for DBG and contributing to their lower TRC ratio values relative to OSB.

### Technology Level TRC

**Error! Reference source not found.** Table 8-3 presents the TRC ratio values averaged across IOUs for the four base case scenarios by technology and technology size for 2020. Figure 8-3 and Figure 8-4 present the average base case TRC ratio results by technology for 2020 and 2030, respectively. The data presented in the table and graphs reinforce the findings illustrated in **Error! Reference source not found.**, that technologies with a vented baseline have larger GHG reductions and avoided cost savings (increasing the TRC ratio) while DBG fuel costs reduce the value of the TRC ratio relative to OSB. Comparing TRC ratio values in 2020 across technologies, large all electric fuel cells have a TRC ratio of 0.39 for the DBG with a flared baseline scenario, the highest TRC ratio for this scenario. The large, all electric fuel cell has the highest TRC for this scenario because it has a higher efficiency, requiring less of the relatively expensive directed biogas for a given amount of electricity production. The high efficiency of the all-electric fuel cell, however, contributes to fuel cells having a lower TRC ratio relative to other technologies when operating on a vented baseline (2.77 versus 4.98 for large internal combustion engines (ICE)). Somewhat paradoxically, consuming less fuel for a given amount of electricity produced also reduces the relative amount of methane consumed for a given amount of electricity production. In comparison, the ICEs are relatively inefficient at producing electricity, increasing their relative reduction in methane on a vented baseline.

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[67] For OSB fueled technologies with a vented baseline, gas turbines and microturbines are not modeled. These technologies are not observed in the SGIP for OSB with a vented baseline.

**TABLE 8-3: AVERAGE TRC RATIO BY TECHNOLOGY AND BASE CASE SCENARIO**

| | DBG, Flared | OSB, Flared | DBG, Vented | OSB, Vented |
|---|---|---|---|---|
| Gas Turbine (Large) | 0.31 | 0.89 | 1.86 | |
| Gas Turbine (Small) | 0.31 | 0.91 | 1.86 | |
| Fuel Cell (Large) | 0.34 | 0.68 | 1.67 | 3.34 |
| Fuel Cell (Small) | 0.32 | 0.58 | 1.54 | 2.80 |
| Fuel Cell Elec (Large) | 0.39 | 0.67 | 1.62 | 2.77 |
| Fuel Cell Elec (Small) | 0.35 | 0.54 | 1.44 | 2.23 |
| Microturbine (all Sizes) | 0.21 | 0.63 | 1.73 | |
| Internal Combustion Engine (Small) | 0.26 | 0.67 | 1.70 | 4.43 |
| Internal Combustion Engine (Large) | 0.26 | 0.74 | 1.75 | 4.98 |

Comparing the TRC estimates for technologies installed in 2020 and 2030, the average TRC for a gas turbine fueled by OSB on a flared baseline increases from 0.90 in 2020 to 1.44 in 2030, an increase of 59 percent. The average TRC for the OSB gas turbine with a flared baseline is higher than for the other technologies modeled using this fuel source and baseline due to this technology being installed and modeled as operating at a higher average capacity factor (See Table 7-1), leading to more avoided electricity benefits and the technology has a lower measure cost ($/kWh) than fuel cells and microturbines (See Table 7-3).

Comparing the 2020 and 2030 TRC estimates for technologies using OSB and a vented baseline, the TRC ratio for ICE increased from 4.70 to 7.75 an increase of 65 percent and fuel cells increased from 2.78 to 5.09, an 83 percent increase. Fuel cells have a higher percentage increase than ICE because the cost of fuel cells is projected to decline as the technology becomes more mature while ICE is an established technology, and the price of this technology is projected to remain unchanged.

The data in the table above and the two figures below show that all modeled technologies with a vented baseline (both DBG and OSB) pass the TRC test in 2020 and 2030. The vented baseline contributes to large avoided electricity and GHG benefits relative to the TRC costs (participant and utility costs). No technologies modeled with a flared baseline are estimated to pass the TRC test in 2020, with estimated TRC ratios ranging from 0.91 for OSB gas turbines on a flared baseline to 0.21 for DBG microturbines. The substantial increase in avoided costs causes the estimated 2030 TRC ratio to exceed one for flared baseline internal combustion engines, gas turbines, and fuel cells fueled by OSB. The technologies fueled by DBG on a flared baseline are not estimated to pass the TRC test within the time frame of this analysis. The high cost of DBG constrains the value of the TRC ratio even with increasing avoided cost values.

**FIGURE 8-3: AVERAGE TRC BY DIRECTED AND ONSITE BIOGAS, VENTED AND FLARED BASELINE, AND TECHNOLOGY, 2020**

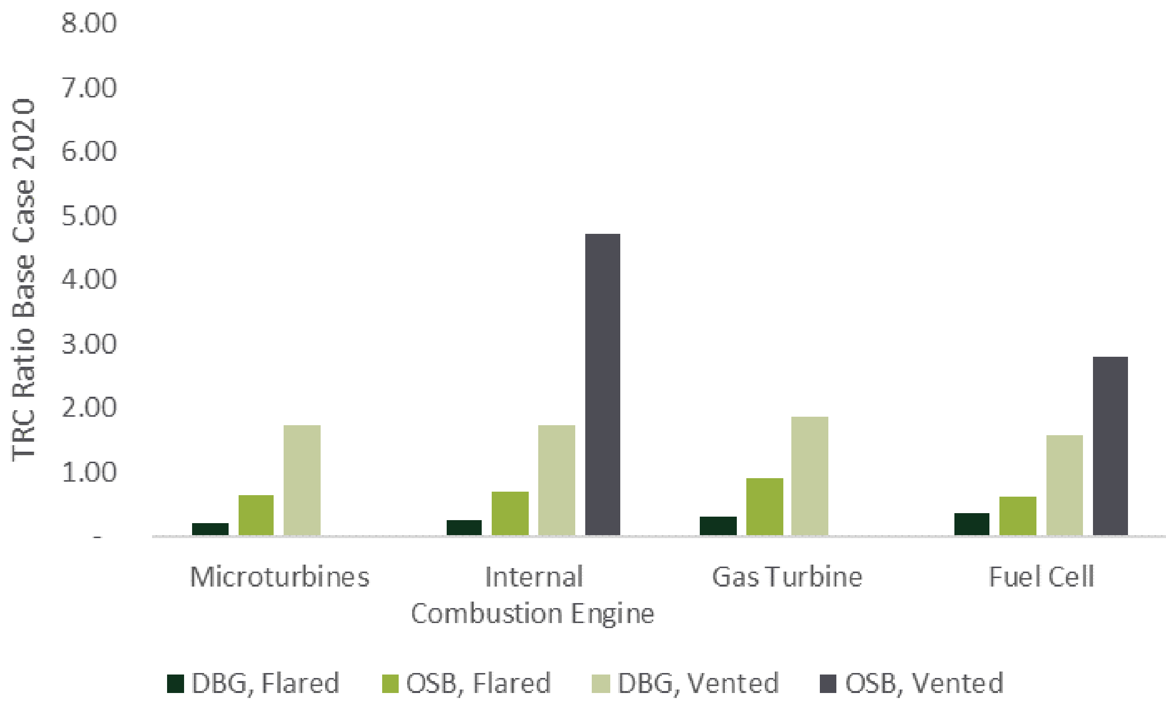
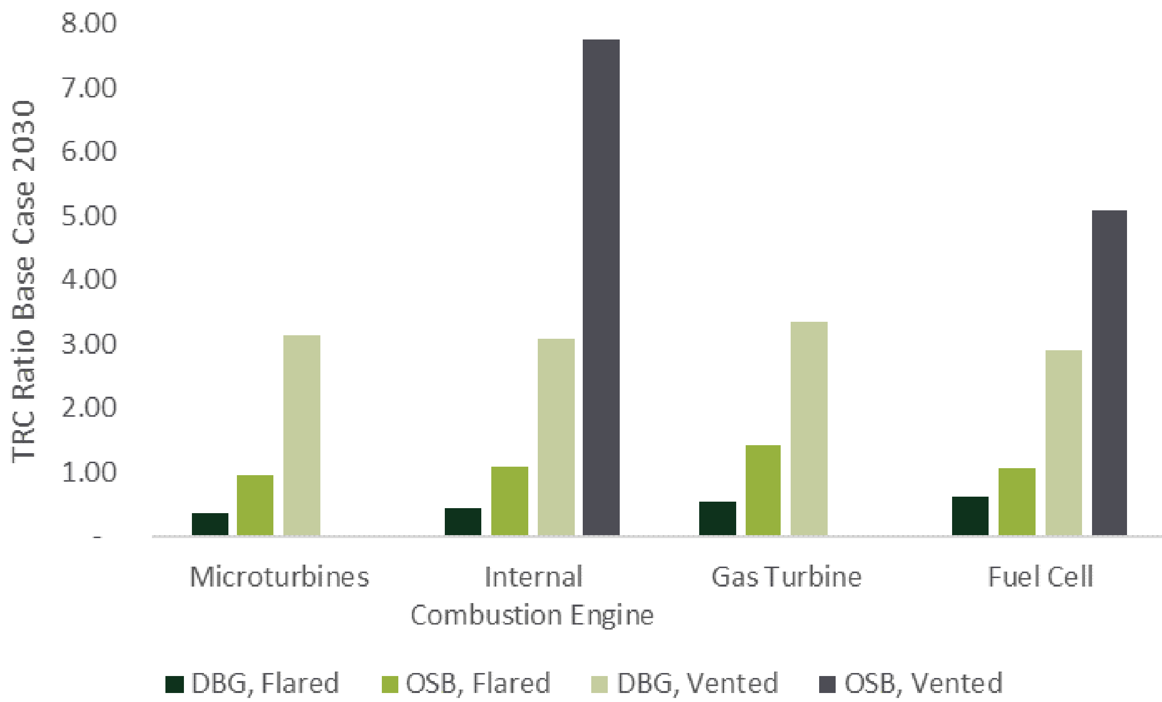


**FIGURE 8-4: AVERAGE TRC BY DIRECTED AND ONSITE BIOGAS, VENTED AND FLARED BASELINE, AND TECHNOLOGY, 2030**

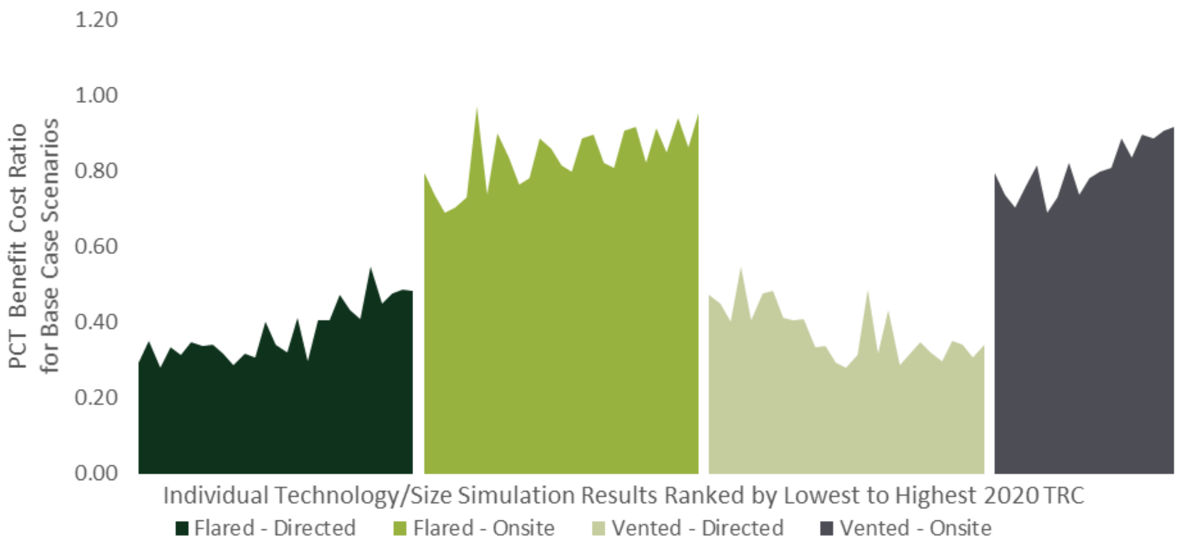



## 8.1.2 Participant Cost Test: Base Case

Figure 8-5 present the results of the participant cost test (PCT) for technologies using renewable fuel under the base case in 2020. The PCT evaluates the cost-effectiveness of renewable fuel generation technologies from the participant customer's point of view. The PCT benefits are the bill savings associated with the electricity produced by the technologies, rebates, reductions in taxes, and the investment tax credit (ITC). The change in the customers total tax liability may be a benefit or a cost in the PCT. If the installation of the technology leads to a reduction in taxes, the reduction is treated as a benefit whereas an increase in taxes, is an increase in costs. The PCT costs include the measure costs, the increase in fuel costs to run the generator, and increases in taxes.

The technology specific PCT ratio values are listed in the same order as the TRC technology specific ratio values were listed previously in **Error! Reference source not found.** (ordered from lowest TRC ratio to highest). The PCT and TRC graphs, however, show both similarities and substantial differences when comparing the cost-effectiveness of these technologies. Both the PCT ratio and the TRC ratio find that technologies fueled by DBG have lower test values than the same technology configuration fueled by OSB. In both the PCT and the TRC the increased cost of fueling the technology is a cost in the test, contributing to lower cost-effectiveness values for the PCT and the TRC. The vented versus flared baseline, however, have substantially different impacts on the PCT than the TRC. The baseline of methane capture, venting versus flaring, does not impact the value of the bill savings, incentive received, or tax implications for the participant customer and therefore does not impact the PCT benefits. The larger GHG reduction associated with the vented compared to the flared baseline does not increase the value of the cost-effectiveness test to the participant unlike what was found in the TRC test.

**FIGURE 8-5: PCT BY DIRECTED AND ONSITE BIOGAS AND VENTED AND FLARED BASELINE**




The average PCT for the base case DBG flared and vented baseline is 0.38 (dark and lightest green in Figure 8-5) and the OSB with a flared or vented baseline is 0.82 where the DBG PCT values range from 0.28 to 0.55 and the OSB values range from 0.69 to 0.97. Note that no technology has a PCT above 1 in the base case scenarios. The PCT value is not dependent on the vented versus flared baseline, the value of the PCT ratio for DBG using a flared or vented baseline is equivalent for a given technology installed in a specific IOU territory. OSB technologies with PCT ratios greater than one includes microturbines and gas turbines. These technologies generally have a lower cost ($/kWh) in 2020 than fuel cells, the technology with the lowest average PCT in 2020.

## Technology Level PCT

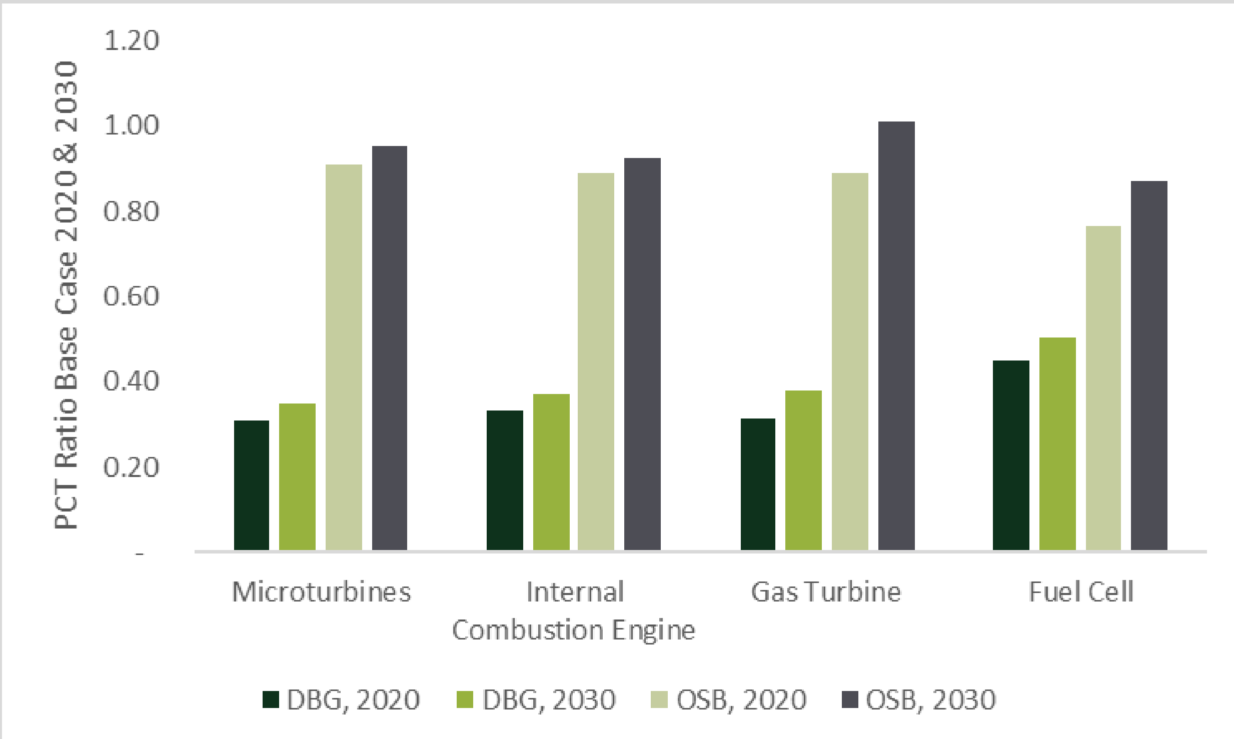
Figure 8-6 and Table 8-4 show the average base case PCT ratio results by technology for 2020 and 2030 installations. The results are not presented for the vented versus flared baseline because the PCT values are not dependent on GHG savings. Figure 8-6 and Table 8-4 reinforce the findings illustrated in Figure

8-5, technologies fueled by DBG have substantially lower PCT ratios than those fueled by OSB. Comparing the PCT estimates for technologies installed in 2020 and 2030, the modeled PCT values increase less over the ten-year time period than the TRC presented in Figure 8-3 and Figure 8-4. Increases in the PCT are largely dependent on increases in the value of bill savings or increases in utility rates and declining measure costs while increases in the TRC are rely on increases in avoided costs and declining measure costs. The model inputs have utility inputs increase much slower than the forecasted increase in avoided costs.

#### TABLE 8-4: AVERAGE PCT RATIO BY TECHNOLOGY, DISTRIBUTED VERSUS ONSITE BIOGAS AND 2020, 2030

| | DBG, 2020 | OSB, 2020 | DBG, 2030 | OSB, 2030 |
|---|---|---|---|---|
| Gas Turbine (Large) | 0.30 | 0.84 | 0.37 | 0.97 |
| Gas Turbine (Small) | 0.33 | 0.94 | 0.39 | 1.05 |
| Fuel Cell (Large) | 0.42 | 0.80 | 0.45 | 0.88 |
| Fuel Cell (Small) | 0.41 | 0.72 | 0.43 | 0.76 |
| Fuel Cell Elec (Large) | 0.48 | 0.80 | 0.56 | 0.96 |
| Fuel Cell Elec (Small) | 0.49 | 0.75 | 0.57 | 0.89 |
| Microturbine (all Sizes) | 0.31 | 0.91 | 0.35 | 0.95 |
| Internal Combustion Engine (Small) | 0.34 | 0.87 | 0.38 | 0.89 |
| Internal Combustion Engine (Large) | 0.33 | 0.90 | 0.37 | 0.95 |

**FIGURE 8-6: AVERAGE PCT BY DIRECTED AND ONSITE BIOGAS, VENTED AND FLARED BASELINE, AND TECHNOLOGY, 2020 & 2030**




### 8.1.3 Base Case Benefit Cost Ratios Over Time

Figure 8-7 presents the benefit cost ratios for OSB fuel cells (400 kW) with a vented baseline in SDG&E's territory for technologies installed in 2020 through 2030. The figure includes the PCT, TRC, Societal TRC and the RIM test.[68] In 2020 the TRC for the 400 kW OSB fuel cell with a vented baseline ranged from 2.77 in PG&E's service territory, 2.79 for SDG&E and 2.83 in SCE's territory. The STRC is 3.05 for SDG&E in 2020, slightly higher than the TRC due to the lower societal discount rate. The PCT ratio for this technology in SDG&E's territory is 0.73 and the RIM benefit cost ratio is 3.45. The high avoided cost values, including the value of the methane reductions associated with the vented baseline, contribute to high TRC, STRC, RIM and PA benefit cost ratios relative to the PCT ratio.

Figure 8-7 illustrates the rapid increase in the benefit cost test ratios for ratios that have the avoided costs as a benefit relative to the PCT which has the participant customer bill savings as a benefit. The avoided

68 The PA ratio is very large due to the high avoided costs and the relatively low PA costs. In 2020 the PA test ratio is 73. To more clearly see the values for the other benefit cost tests the PA ratio has been left off the graph.

costs are derived from the 2020 ACC. The 2020 ACC includes a substantial increase in the value of reduction in GHGs. The increasing GHG values impact the TRC, STRC, RIM, and PA benefit cost ratios both through the reduced use of electricity sourced from the grid and the additional reduction in methane associated with the vented baseline.

**FIGURE 8-7: BENEFIT COST RATIOS FOR OSB FUEL CELLS (400 KW) WITH VENTED BASELINE 2020-2030**

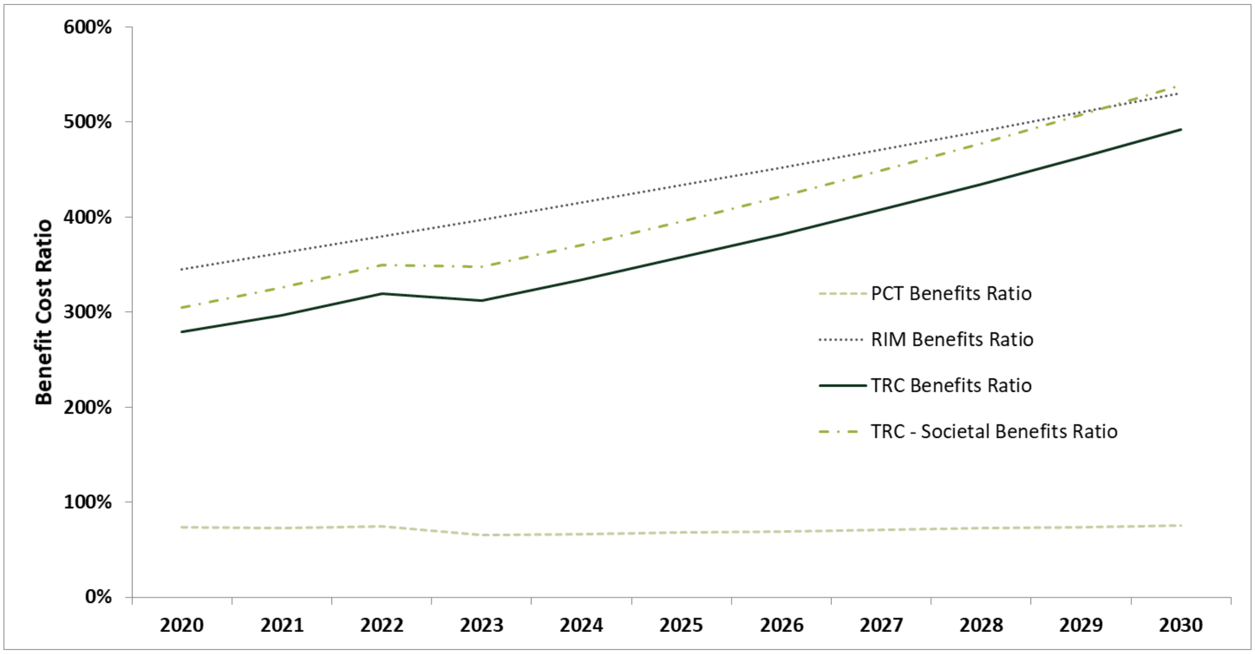
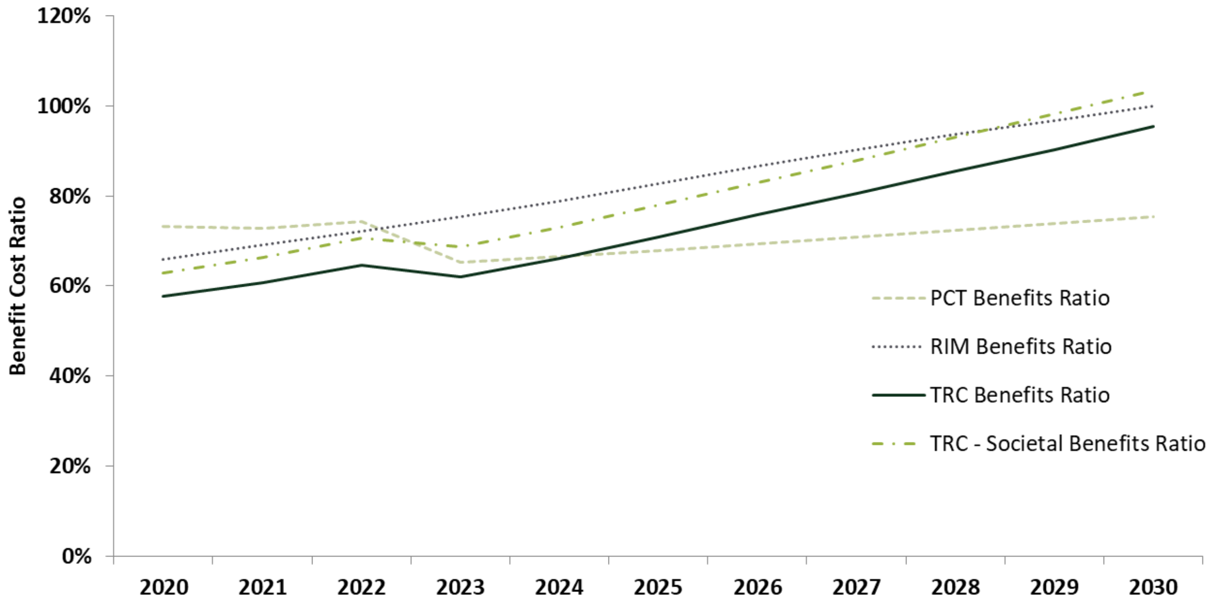



Figure 8-8 presents the benefit cost ratios for the OSB fuel cell (400 kW) with a flared baseline in SDG&E's service territory. When comparing Figure 8-7 and Figure 8-8, the PCT ratio has the same values in the two figures because the flared versus vented baseline does not impact the value of the participant benefits. The TRC, STRC, and RIM values illustrated in these two graphs, however, differ substantially. In 2020 the TRC ratio in SDG&E's territory is 0.58, the STRC is 0.63 and the RIM is 0.66. These values are substantially lower than their values for the same technology simulated under a vented baseline (where all three of these benefit cost values exceeded 2.0). In Figure 8-8, the trajectory of the benefit cost ratios clearly illustrate that the ITC for this technology expires in 2022, leading to a dip in the 2023 PCT and a flattening of the slope of the other three cost tests. The steeper slope of the TRC, STRC, and RIM ratios when compared to the PCT reinforces the more rapid increase in the avoided costs relative to the assumed increase in customer rates.

FIGURE 8-8: BENEFIT COST RATIOS FOR OSB FUEL CELLS (400 KW) WITH A FLARED BASELINE 2020-2030




### 8.1.4 Base Case Benefit Cost Ratios Components

Figure 8-9 illustrates the different components of the benefit cost ratios for the OSB fuel cell with a vented baseline that was illustrated over time in Figure 8-7. The disaggregation of the different benefit and cost components helps to illustrate the importance of the avoided methane valuation for the TRC, STRC, PA, and RIM test. For the results presented in Figure 8-9, the avoided emissions value accounts for 80 percent of the TRC benefits in 2020 with the avoided cost benefits associated with reduced grid electricity usage accounting for nearly all of the remaining TRC benefits.

The disaggregated cost and benefit components also illustrate the importance of the operations and maintenance costs (O&M) when analyzing the cost for the PCT and TRC/STRC ratios. The generation technologies analyzed for this evaluation are associated with substantial operations and maintenance costs which include fuel clean-up costs, maintenance, and insurance costs. The cost components for the OSB fuel cell, however, do not include fueling costs.

**FIGURE 8-9: BENEFIT COST RATIO ATTRIBUTES FOR OSB FUEL CELLS (400 KW) WITH VENTED BASELINE 2020**

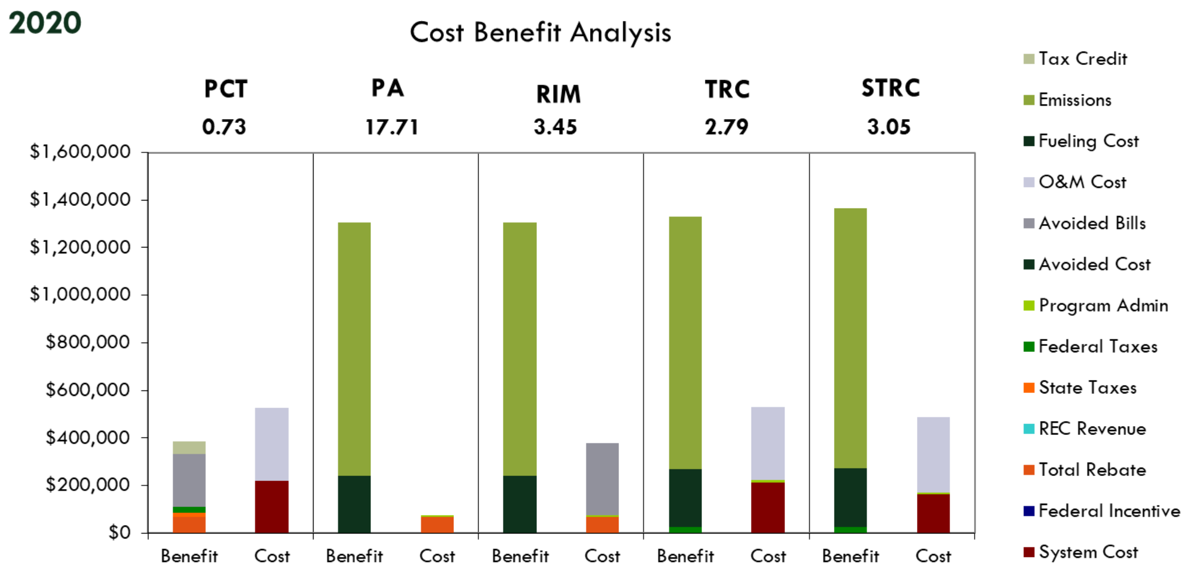
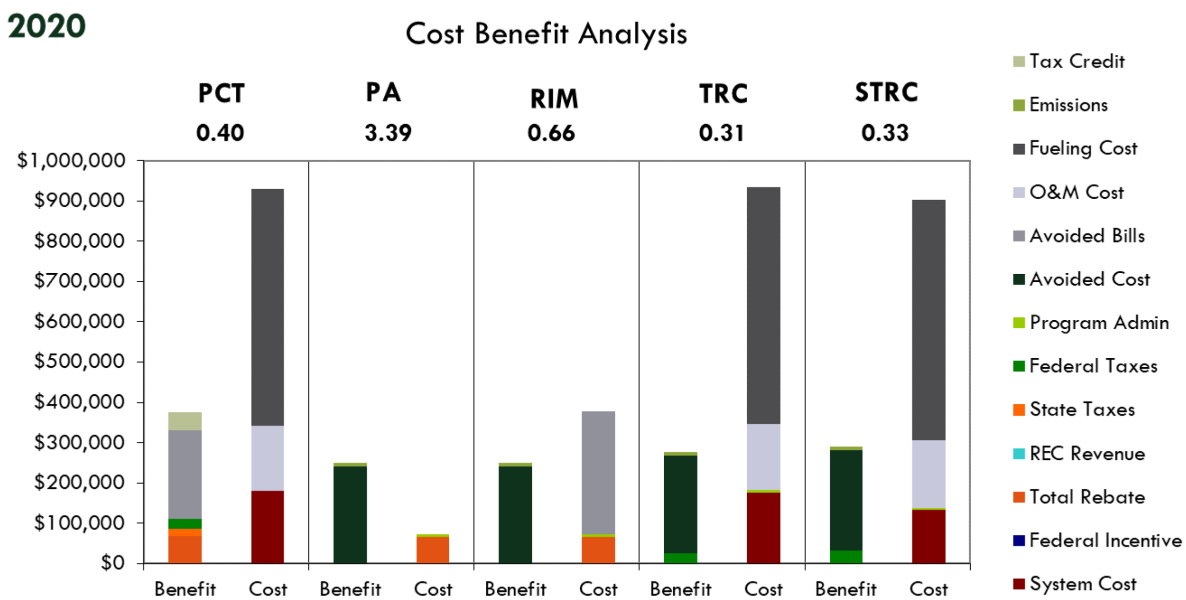



Figure 8-10 illustrates the benefit and cost components for a DBG fuel cell with a flared baseline in SDG&E's territory. The results in Figure 8-9 and Figure 8-10 differ by the fuel source, OSB versus DBG, and baseline, vented versus baseline. The cost test components in Figure 8-10 have fueling costs for the PCT, TRC, and STRC, while the PA, RIM, TRC and STRC do not have the large environmental benefits that are observable in Figure 8-9.

**FIGURE 8-10: BENEFIT COST RATIO ATTRIBUTES FOR DBG FUEL CELLS (400 KW) WITH FLARED BASELINE 2020**




Comparing the PCT ratios in Figure 8-9 and Figure 8-10, the OSB Fuel cell with a vented baseline has a PCT of 0.73 while the DBG flared baseline value is 0.40. The DBG simulation has a lower PCT due to the high fueling costs (the dark gray segment in the costs). The high fueling costs contribute to lower cost-effectiveness and higher federal and state tax refunds relative to the OSB analysis, that are counted as benefits in the PCT ratio.

The fueling costs included in Figure 8-10 illustrate the high costs associated with participant customers purchasing DBG. The simulations are modeled with the customer purchasing DBG on the wholesale market, so these costs do not enter the RIM or the PA benefit cost tests. The high fueling costs are included as customer costs in the TRC and the STRC benefit cost tests. The OSB and vented fuel cell in Figure 8-9 has a TRC ratio of 2.79 while the DBG flared TRC ratio is 0.31. The DBG flared fuel cell has high fuel costs and low emission benefits relative to the OSB vented fuel cell. These two differences largely account for the substantial difference in their benefit cost ratios.

## 8.2 SCENARIOS THAT IMPACT COST-EFFECTIVENESS

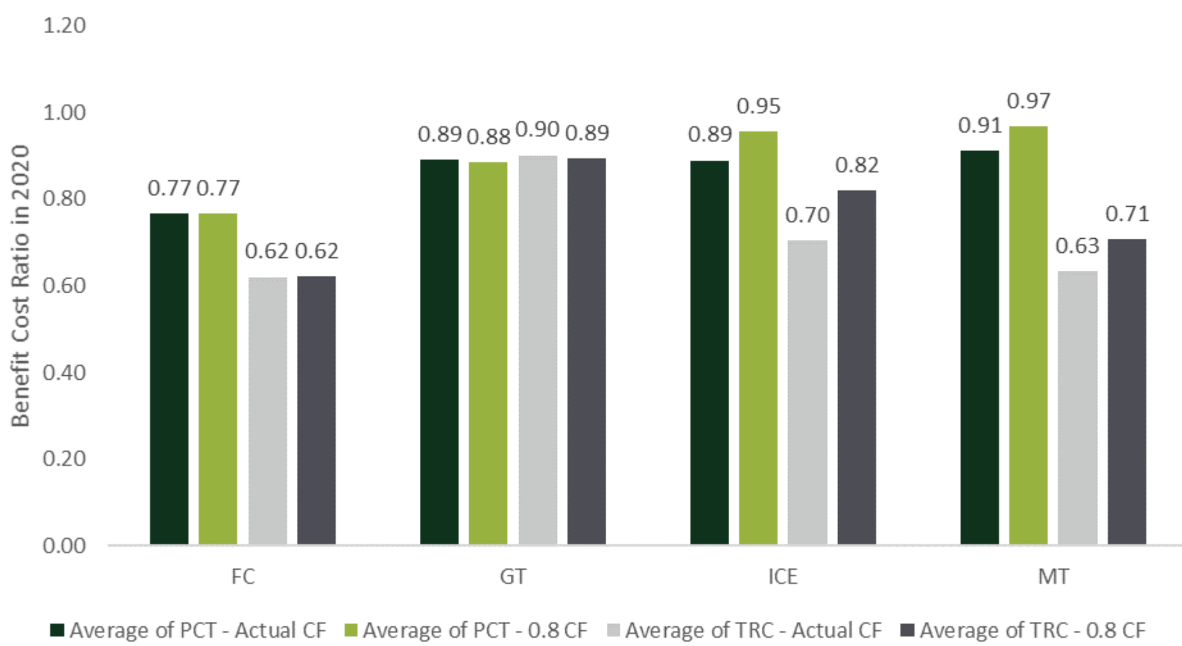
In addition, the base case analyses, we also investigated scenarios that impact benefit cost ratios such as actual vs. expected (0.8) capacity factors, the inclusion of digester costs, and the use of RECs and grants to help mitigate those costs, and finally the effect of the resiliency adder on participant cost test ratios.

### 8.2.1 Capacity Factor Scenarios

The base case capacity factors that we used in the analysis were based on the observed annual generation of the operational SGIP fleet to date. Known decommissioned sites were excluded from that analysis. However, SGIP PBI payments are calculated assuming a capacity factor of 0.8, or that the generator runs at full power 80 percent of the time or at 80 percent power all the time. When non-renewable generation was last allowed in SGIP, the 0.8 capacity factor was a program requirement but with the move to all renewable generation, this requirement no longer applies. Table 6-1 shows the capacity factors that were observed in the past and used in the base case analysis

Fuel cells and gas turbines have historically shown higher capacity factors to serve ‘baseload’ whereas engines and microturbines have sometimes been used for more ‘load following’ applications so have shown less generation on an annual basis. Figure 8-11 shows how the benefit cost ratio impacts the participant and total resource cost tests for onsite generation with a flared baseline.

**FIGURE 8-11: IMPACT OF CAPACITY FACTOR ON BENEFIT COST RATIOS (ONSITE, FLARED)**

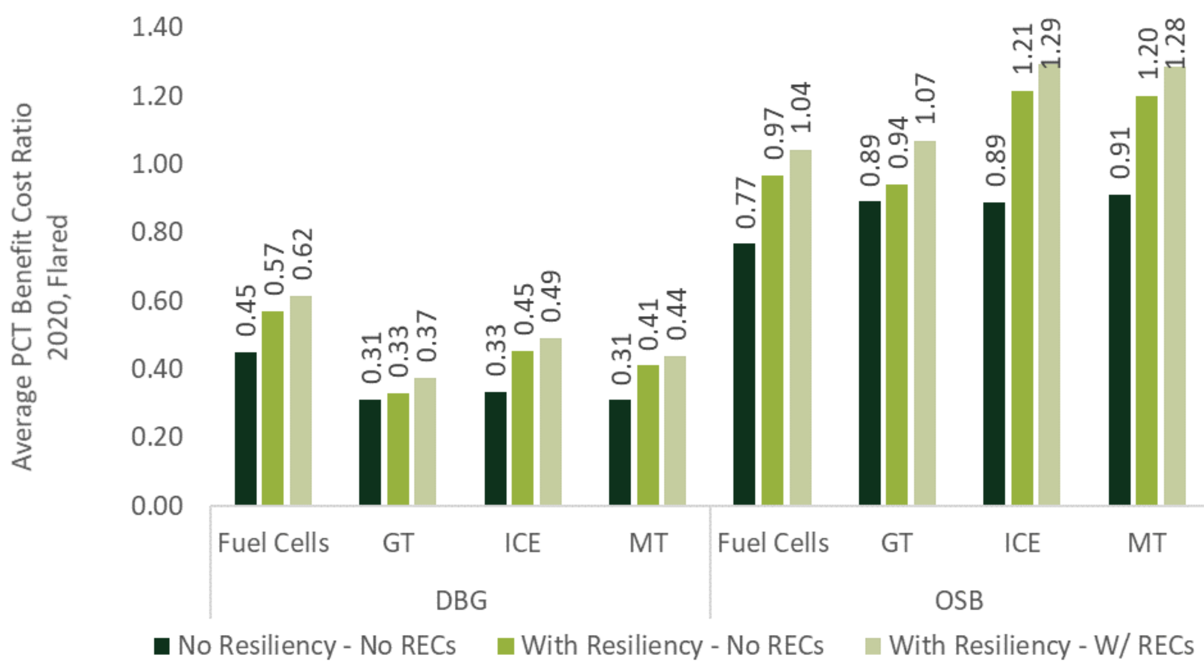



Engines and microturbines show an increase in both the PCT and TRC ratios when comparing the actual (0.50 and 0.58 respectively) and 0.8 capacity factors as more electricity is generated every year so more electricity and cost from the grid is avoided. Gas turbines exhibit a small decrease in both tests given that the 0.8 capacity factor is lower than the 0.87 we observed and used in the base case analyses.

## 8.2.2 Resiliency Adder and RECs

Decision 20-01-021 directed the SGIP to provide additional incentives of $2.50/watt for "customers subject to two or more discrete PSPS events and defines additional customers as having critical resiliency needs." The current SPM does not provide a means to quantify resiliency benefits, so analyzing systems with the resiliency adder was modeled as an increase in the SGIP incentives. Note that the higher incentive raises the average onsite biogas fuel cell PCT benefit cost ratio to approximately 1.0 in 2020 and raises the PCT ratio for internal combustion engines and microturbines to approximately 1.20. These findings support the conclusion that increasing the SGIP incentive to the level of the SGIP + resiliency incentive may be sufficient to spur additional uptake. As previously noted, flared and vented results for the participant test are identical since the participants currently receive no direct benefit from the additional carbon reductions of technologies on a vented baseline. Figure 8-12 shows how the PCT ratio changes with addition of the resiliency adder and the combination of the resiliency adder and the benefits of RECs to the participant.

**FIGURE 8-12: RESILIENCE ADDER AND UTILIZATION OF RECS IMPACT ON PARTICIPANT COST TESTS**




Renewable Energy Credits (RECs) can provide additional revenues to owners of renewable generation. Not all generators take advantage of these credits, however. The combination of the resiliency adder and RECs raises the average PCT above 1 for all technology groups using onsite biogas. This indicates that customers or developers that are fortunate enough to be able to locate generators in areas that can enhance resiliency, make use of onsite biogas and additionally layer RECs have cost-effective options for installing generation. The impact on the TRC is virtually zero given that incentives do not have a significant impact on that test and the impact or RECs are minimal.

### 8.2.3 Directed Biogas Cost Scenarios

The PCT and TRC cost-effectiveness ratios for directed biogas, that are presented above, are lower than those for the same technology, baseline, and incentive configuration using onsite biogas due to the cost of acquiring the directed biogas. The analysis above uses $1.75 per therm (or $17.5/MMBtu) as the cost of directed biogas, the midrange of price estimates from SoCalGas ($1.20/therm to $2.30/therm).[62 above] A recent study using production costs found that landfills should be able to produce directed biogas (or pipeline biogas) in the range of $0.70/therm to $1.90/therm.[69] Landfills currently provide over 90 percent of the biogas in the LCFS so are significant source of biogas or directed biogas with a flared baseline. Figure 8-13 presents the 2020 and 2030 TRC Benefit Cost Ratios by technology for alternative price scenarios of directed biogas. The lower cost directed biogas scenarios at $0.70 therm ($7/MMBtu) and $1.20/therm ($12/MMBtu) exhibit higher TRC ratios and some technologies approach a TRC ratio of 1 by 2030 at the lowest cost of directed biogas. Note that technology types are abbreviated in Figure 8-13; FCE are Fuel Cell Electric, FC are Fuel Cells, GT are Gas Turbines, ICE are Internal Combustion Engines, and MT are Microtubines.

[69] Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment; An American Gas Foundation Study Prepared by ICF, December 2019

**FIGURE 8-13: THE IMPACT OF LOWER COST DIRECTED BIOGAS TRC BENEFIT COST RATIOS**

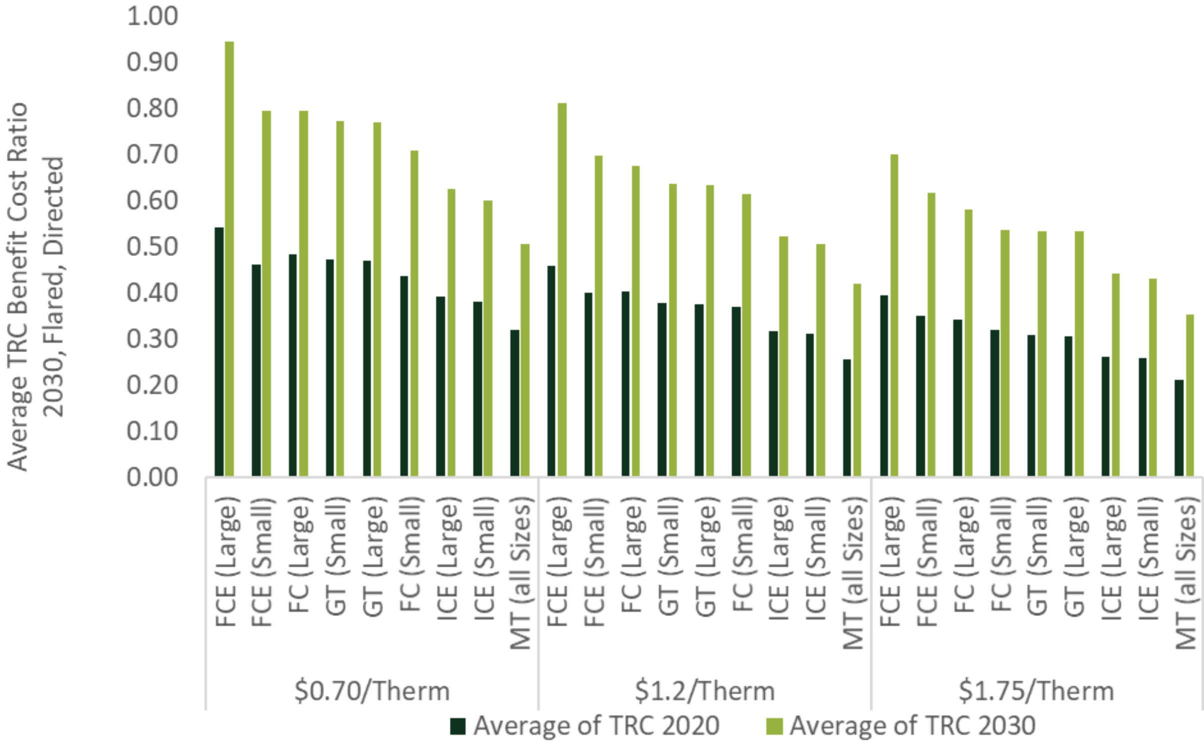
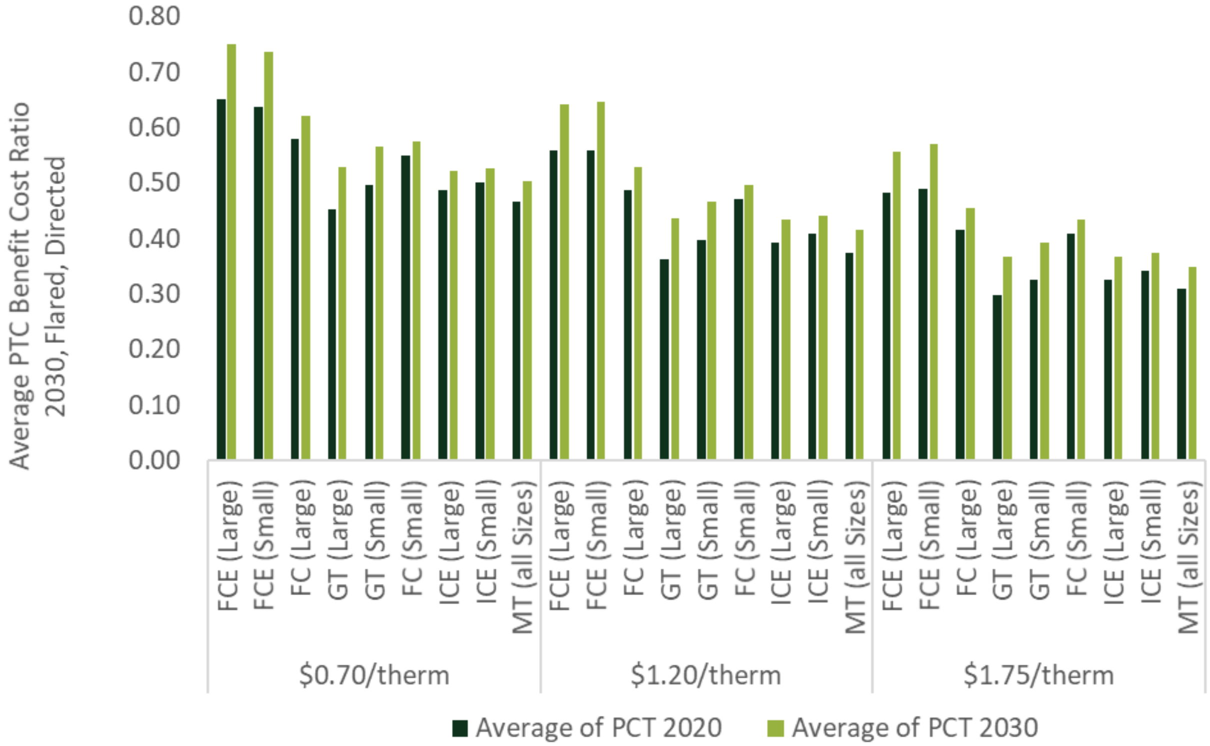



Figure 8-14 shows how lower directed biogas prices also raise the participant cost tests. Lower prices for directed biogas improve the participant cost tests, but with existing base case incentives, the lower directed biogas prices are not a sufficient reduction in participant costs for the PCT ratio to reach 1.

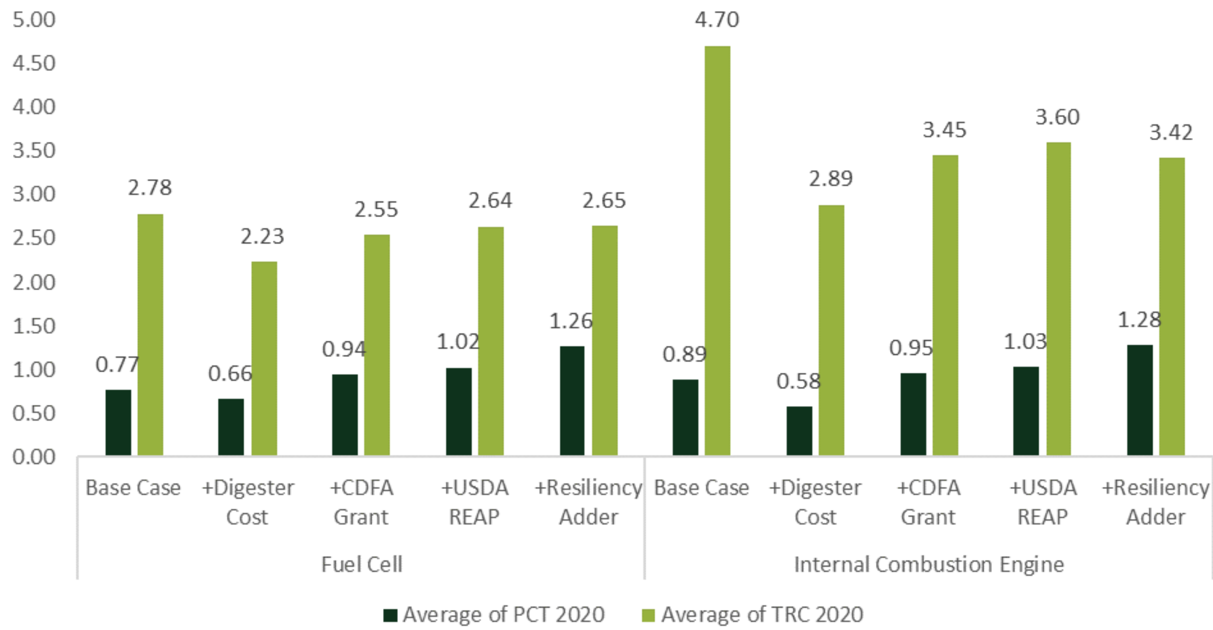
**FIGURE 8-14: THE IMPACT OF LOWER COST DIRECTED BIOGAS ON PARTICIPANT BENEFIT COST RATIOS**




## 8.2.4 Digester Cost and Incentives Scenarios

Anaerobic digesters are expensive, so few dairies install them unless the dairy is using biogas for generation or upgrading and injecting biogas to a pipeline. The SGIP, however, does not allow participants to include the cost of the digester in system costs. Therefore, the scenarios presented above do not include the cost of the digester cost that would likely need to be purchased of technologies fueled by onsite biogas with a vented baseline. Dairies have the option of applying for a CDFA grant to offset up to half of the cost of the digester and any associated biogas cleanup costs. Additionally, the USDA's Rural Energy for America Program (REAP) can provide incentives for renewable generation. We implemented scenarios that included the cost of the digester and the cost of the digester combined with incentives from the CDFA and USDA REAP grant programs. The resulting PCT and TRC averages are shown in Figure 8-15.

**FIGURE 8-15: DIGESTER COST AND GRANT IMPACTS FOR ONSITE BIOGAS, VENTED**




Inclusion of the digester cost increases costs to both the participant and society, so inclusion of that costs lowers both the PCT and TRC benefit cost ratios. Addition of the CDFA grant funds has a net reduction in this cost, increasing these benefit cost ratios compared to results that include the digester cost. However, even with inclusion of the CDFA and grant, the average PCT ratio (at $2.00/watt) is still below one. Combined with the high value that LCFS credits assign to vented baselines (dairies), this indicates the existing base incentive may not be sufficient to drive significant adoption. However, in those (potentially rare) cases where participants can make use of the USDA and/or the resiliency adder the PCT ratio can rise above one.

## 8.3 COST-EFFECTIVENESS FINDINGS

The cost-effectiveness of biogas fueled SGIP systems vary significantly based on scenario. Here we summarize high level cost-effectiveness findings.

Throughout this section, we presented cost-effectiveness findings for multiple technologies. However, industry has reported that current California rules for permitting of combustion generation make installation of any new stationary generator that burns fuel challenging. Flares to destroy methane are also subject to increasingly stringent emissions standards. Fuel cells generate electricity without combustion and are therefore cleaner and easier to permit than other technologies and it is possible that only fuel cells will be realistically able to participate in SGIP due to permitting challenges. Increased agency collaboration (e.g., CPUC and AQMD) to equitably value different emissions reductions could help align policies and incentives to increase the beneficial use of biogas.

Vented baselines (i.e., dairies) show significantly higher TRC benefit cost ratios than flared baselines. This is consistent with earlier analyses, but as California moves towards a cleaner grid and increases the cost of carbon to society, these differences increase. Despite the high value to society, SGIP systems with a vented baseline cannot currently monetize the increased benefit of destroying methane at a value like LCFS participants can. The wide difference between the TRC and PCT benefit cost ratios indicates that increasing the incentives available to dairies, or any other biogas generators that can be shown to destroy methane that would have otherwise been released to the atmosphere, would be beneficial to both participants and society.

Although SGIP biogas generators with a flared baseline in 2020 do not exhibit TRC benefit cost ratios above 1, most onsite systems with a flared baseline are estimated to exceed a TRC benefit cost ratio of 1 by 2030. This indicates that incentivizing these systems in the future will provide a cost-effective benefit to society.

Directed biogas is challenged to be cost effective due to the high cost of the biogas in California, which is approximately six times the cost of natural gas. The high fueling costs lower the benefit cost ratios and lead to the TRC and PCT not forecast to exceed 1 in the next 10 years for directed biogas generation with flared baselines, assuming a $1.75/therm cost for directed biogas. Lower cost directed biogas that could be available from landfills or other large sources substantially improves TRC ratios but is still not quite expected to exceed a TRC of 1 by 2030. However, future changes in policies, biogas availability, or dramatic improvements in generation technology could change that outcome.

Directed biogas systems fueled from a vented baseline, like those at dairies. already show TRC ratios well above 1 in 2020. However, sourcing this gas economically can be very challenging due in part to the high value of LCFS credits that dairies can receive. The gas from these sources needs to continue to be used throughout the generator’s life to meet those estimates. Additionally, the LCFS program allows producers across the nation to participate in the LCFS, unlike SGIP that requires directed biogas producers to be in the Western Electricity Coordinating Council (WECC). Given the relative success of the LCFS in connecting dairies to the gas distribution network, focusing on onsite generation from dairies that are far from gas pipelines or otherwise are difficult to connect to a gas pipeline may be a reasonable area to focus on for SGIP backed generation.

# APPENDIX A IN-DEPTH INTERVIEW GUIDE SUMMARY

This section presents a summary of the questions included in the in-depth interview guides used for this study. Each of the guides were individually tailored for the specific person being interviewed. The tables shown below provide an overview of the types of questions included for each of the types of respondents interviewed, California regulatory and IOU staff, biogas industry experts, onsite generation project developers.

## A.1 CALIFORNIA REGULATOR AND IOU STAFF

A summary of the questions asked to California state regulators and IOU staff members are included in the table below.

### TABLE A-1: CALIFORNIA REGULATORY AND IOU STAFF INTERVIEW GUIDE SUMMARY

| Respondent | Question Battery |
|---|---|
| All | What is your role within your organization and how long have you been in this role? |
| | |
| CPUC | What is the CPUC's regulatory perspective on biogas? |
| | Is there anyone at the CPUC overseeing at a high level the intersection of the CA biogas programs that currently exist? (LCFS, BIOMat, SGIP, RPS credits). Is there a strategy direction for the future of biogas? |
| | What is the CPUC's direction with respect to RNG being injected into the pipeline? Is your focus on CA sourced RNG into pipeline? |
| | Can you provide us information or status update on RNG projects you focus on: The Opt-in RNG Tariff? Biomethane pilots? The Biomethane Interconnection Incentive Program? |
| | What part of SB 1440 is your focus? |
| | What are primary Barriers faced by biogas producers in CA with respect to interconnection? |
| | What value does BTM biogas generation currently provide to ratepayers (i.e., in terms of the total resource cost test)? And how does that value for BTM biogas generation compare with the value to ratepayers for LCFS transportation biogas [that is fed directly into the gas distribution system]? |
| | What are the main barriers that impede BTM biogas generation adoption in CA? a. What strategies are available to mitigate, compensate for, or remove these barriers? And what role can the CPUC play to implement them? |
| | |
| CARB | What is CARB's long-term vision for biogas? |
| | Is the use for **transportation fuel** an interim step in the electrification of the transportation sector? If so, what is the timing of that transition to electrification?? |
| | Will LCFS include the landfill and wastewater treatment gas in the future or just lower CI fuels from dairies? |
| | Does CARB's vision include the use of biogas as a replacement for end use natural gas or for electricity generation? |
| | Are there any air quality-related motivations for customers to pursue biogas generation vs business as usual? |

| Respondent | Question Battery |
|---|---|
| | What has been the effect of LCFS credits on the biogas market? |
| | What role does CARB see for current and **future Renewable Natural Gas** as a replacement for natural gas in buildings (where electrification is not feasible in the short or mid-timeframe) or for electricity generation? |
| | We understand emission rules make it difficult to install **onsite generation**. What is CARBs position on biomethane generation to be used onsite or fed back into the electric grid? |
| | How were the Carbon Intensities (CI) derived and how much of dairies' CI level is related to the baseline relative to landfills or wastewater treatment plant requirements to destroy/control methane via burning? |
| | How does **CARB coordinate** with other agencies regarding the use of biofuels? CPUC, CEC, Department of Ag, AQMD |
| | |
| | |
| IOUs | Review SGIP Project Info – confirm details. For Cancelled projects, completed projects. |
| | For Cancelled projects, can you tell me about what happened with each project during that time frame? Did they plan to use the electricity they generated on site or feed it into the grid? Why was it cancelled? What were primary motivations to participate? What were barriers to participate? How much of the costs were expected to be covered by the program? |
| | What are the primary barriers faced by customers? |
| | What has the 100% biogas requirement done to customers considering SGIP? |
| | Have the increased incentives (from $$1.20 to $4.50 with resiliency adder helped?) |
| | What is your company's approach to promoting biogas generation projects through SGIP? |

## A.2 BIOGAS INDUSTRY EXPERTS

A summary of the questions asked to biogas industry experts are included in the table below.

### TABLE A-2: BIOGAS INDUSTRY EXPERTS INTERVIEW GUIDE SUMMARY

| Topic | Question Battery |
|---|---|
| **BACKGROUND** | What is your role within your organization and how long have you been in this role? |
| **BIOGAS PROJECTS HISTORY** | Are most of your customers' projects biogas generation? Are customers developing pipeline (directed) biogas projects? What are the factors that lead them to consider generation vs. pipeline projects? |
| | Are most generation projects sized to meet internal load or are they oversized to sell excess power back to the grid? |
| | What has the overall trend been with respect to biogas project development in recent years vs. prior? (contrast generation vs. pipeline/directed) Have you seen any increase/decrease in projects? What do you attribute that to? |
| **COST INFORMATION/ECONOMICS** | Are there any reports or published sources that detail the capital and operating costs for [CUSTOMER TYPE] that you can share with us on this topic? |
| | How are these projects financed? What are typical paybacks/ROI? |

| Topic | Question Battery |
|---|---|
| | Are the LCFS credits sufficient to drive interest in biogas projects? |
| **BARRIERS** | What do you see as the major barriers to biogas generation adoption? What strategies are available to address these barriers? What actions can regulatory agencies such as the CPUC, CARB, or the CEC take to help reduce these barriers? |
| | We understand that the pipeline interconnection and gas cleanup costs in California are around 10 times higher those for other places in the U.S. We've also heard that gas quality standards are stricter in CA than they need to be. For Oxygen – a reasonable (real) level is 0.4, while for California, the level is 0.2. How has this affected [CUSTOMER TYPE] interest in Directed biogas? |
| | Are the current incentives through the SGIP and other programs, and the Low Carbon Fuel Standards (LCFS) incentives sufficient to motivate end-users to develop projects? Why or why not? |
| | How would you characterize the current state of the [CUSTOMER TYPE] market for biogas in California vs. the rest of the U.S.? Maturity, scope and scale, number and types of interconnections and uses? |
| **CLOSING** | Are there any other specific organizations that you'd recommend we interview for this study? |
| | |

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## A.3 ONSITE GENERATION PROJECT DEVELOPERS

A summary of the questions asked to onsite generation project developers are included in the table below.

**TABLE A-3: ONSITE GENERATION PROJECT DEVELOPER INTERVIEW GUIDE SUMMARY**

| Topic | Question Battery |
|---|---|
| **BACKGROUND** | What is your role within your organization and how long have you been in this role? |
| **CURRENT MARKET STATE** | What is the current state of the California market for biogas generation, in terms of the market maturity, scope and scale, number of installations? |
| **CUSTOMER MOTIVATIONS** | What are the main motivations for customers to pursue biogas generation, directed biogas and business as usual? |
| **MARKETING APPROACH** | What is your firm's marketing approach for biogas generation, directed biogas projects? |
| **BARRIERS** | What do you see as the major barriers to biogas generation adoption? What strategies are available to address these barriers? What actions can regulatory agencies such as the CPUC, CARB, or the CEC take to help reduce these barriers? |
| | We understand that the pipeline interconnection and gas cleanup costs in California are around 10 times higher those for other places in the U.S. We've also heard that gas quality standards are stricter in CA than they need to be. For Oxygen – a reasonable (real) level is 0.4, while for California, the level is 0.2. How has this affected [CUSTOMER TYPE] interest in Directed biogas? |
| **LCFS CREDTS** | Are the LCFS credits sufficient to drive interest in biogas projects? |
| **SGIP ACTIVITY & INCENTIVES** | Discussion of [ORGANIZATION'S] SGIP projects - cancelled projects, completed projects |
| | Are the current incentives through the SGIP and other programs, and the Low Carbon Fuel Standards (LCFS) incentives sufficient to motivate end-users to develop projects? Why or why not? |
| **CLOSING** | Are there any other specific organizations that you'd recommend we interview for this study? |

# APPENDIX B CUSTOMER TELEPHONE/WEB SURVEY INSTRUMENT

This section includes the survey instrument that was administered to all of the customer segments surveyed. Skips were used to ensure that the correct questions batteries were asked of each of the four surveyed populations (Biogas SGIP participants, NonBiogas SGIP participants, SGIP cancelled applicants, SGIP nonparticipants).

## B.1 SURVEY INPUT VARIABLES

The following variables were used as inputs to the customer telephone/web survey.

### TABLE B-4: SURVEY INPUT VARIABLES

| Variable Name | Description |
|---|---|
| Contact1 | Customer Name |
| Email | Customer email address |
| SGIP_Flag | If contact was in SGIP database SGIP_Flag = 1 |
| ProjectDeveloper | Project Developer or Applicant |
| BusType | Business type description (Dairy, WWTP, Landfill, MSW, Hospital, Farm, Brewery, Other, etc) |
| Cancelled | 1 = Cancelled SGIP project, 0 = No Cancelled SGIP project |
| SGIP_Gen | SGIP Generation Equipment (fuel cell, microturbine, gas turbine, internal combustion engine, none) |
| FuelType | Biogas Type (Onsite, Directed, Natural Gas, Unknown) |
| Web | 1 if data will be preloaded for Web surveys, 0 if surveys will be conducted by phone |

## B.2 SURVEY INSTRUMENT

Thank you for agreeing to complete this survey. We have a few questions for you on your awareness and attitudes regarding Biogas (also referred to as “Renewable Natural Gas” or RNG) and associated Biogas Generation systems.

### INTRODUCTION

**Intro1.** For this survey we are looking to connect with the individual at your organization who is familiar with [if SGIP_flag = 1 then “onsite electric generation”, else “biogas management”] at your facility. Are you this person?

1 Yes

2 No, there is someone else at my organization who would be better to speak with
3 No, we outsource this role to an outside entity
99 Don’t Know

**Intro2. [If Intro1 = 2 or 3]** Could you please provide us with the contact information for this individual.
1 First and Last Name [RECORD]
2 Phone [RECORD]
3 Email [RECORD]
4 [If Intro1 = 3] Organization [RECORD]

**[IF Intro1 = 2 or 3 or 99 then Thank and Terminate – “This survey requires we collect data from an individual familiar with the** [if SGIP_flag = 1 then “onsite electric generation”, else “biogas management”] **at your facility. We have no further questions for you. Thank you for your time”]**

**[IF Intro1= 1, THEN ASK Q1a]**
**Q1a.** According to our records your organization’s Business Type is <*BusType*>. Is that correct?
1 Yes
2 No
99 Don’t Know

**Q1b. [IF Q1a = 2]** Please describe your organization’s primary business activity?
1 Airport
2 Automotive
3 Brewery
4 Commercial
5 Dairy
6 Data Center
7 Education
8 Energy
9 Entertainment
10 Farm
11 Financial
12 Food Processing/Agriculture
13 Hotel/Motel
14 Landfill
15 Medical
16 Military
17 Municipal Solid Waste
18 Municipal
19 Real Estate
20 Technology
21 Uniforms

22 Wastewater Treatment
23 Other [RECORD]
99 Don't Know

Fix Bustype based on Q1b response
If Q1b = 3 then BusTYpe = "Brewery"
If Q1b = 5 then BusTYpe = "Dairy"
If Q1b = 10 then BusTYpe = "Farm"
If Q1b = 12 then BusTYpe = "NonDairyAg"
If Q1b = 14 then BusTYpe = "Landfill"
If Q1b = 16 then BusTYpe = "Military"
If Q1b = 17 then BusTYpe = "MSW"
If Q1b = 18 then BusTYpe = "Municipal"
If Q1b = 22 then BusTYpe = "WWTP"

### ONSITE GENERATION KNOWLEDGE LEVEL

**Q2a.** How knowledgeable are you about onsite electric generation systems, such as fuel cells, microturbines, gas turbines, or internal combustion engines?

1 Very knowledgeable
2 Somewhat knowledgeable
3 Not at all knowledgeable
99 Don't Know

**Q2b. [IF Q2a = 1,2]** How did you first learn about onsite generation systems?

1 **[If SGIP_flag = 1]** Through < ProjectDeveloper >
2 Online research
3 Through my utility
4 Through SGIP materials
5 Word of mouth
6 Other [RECORD]
99 Don't Know

### SGIP AWARENESS AND FAMILIARITY

**Q3.** Have you heard of the Self-Generation Incentive Program, often referred to as SGIP, that is administered by California's investor-owned utilities?

1 Yes, I have heard of the Self-Generation Incentive Program (SGIP)
2 No, I have not heard of the Self-Generation Incentive Program (SGIP)
99 Don't Know

**[If Q3 = Yes then SGIP_Aware = 1, else SGIP_Aware = 0]**

**[If SGIP_Aware = 1 Ask Q4, else skip to Q10)**

**Q4.** How familiar are you with the Self-Generation Incentive Program?

1 Very familiar
2 Somewhat familiar
3 Not very familiar
4 Not at all familiar
99 Don't Know

**Q5.** When did you first become aware of the SGIP?

1 Within the last year
2 More than 1 year ago but less than 5 years ago
3 More than 5 years ago
99 Don't Know

**Q6.** How did you first become aware of the SGIP?

1 Through my utility
2 Through a Project Developer or contractor
3 Through online research/SGIP website
4 Word of mouth
5 Other [RECORD]
99 Don't Know

**Q7.** Which of the following technologies were you aware could receive incentives through the SGIP? (Select Multiple, but not a choice and Don't Know)

1 Advanced Energy Storage (AES) (e.g. batteries)
2 Fuel Cells
3 Microturbines
4 Internal Combustion Engines
5 Gas Turbine
6 Other [RECORD]
99 Don't Know

### CURRENT ANAEROBIC DIGESTER EQUIPMENT STATUS

**Q10. [If BusType in ("Brewery" "Dairy" "Farm" "NonDairyAg" "Landfill" "Military" "MSW" "Municipal" "WWTP")]** Does your organization have an anaerobic digester installed onsite at your facility?

1 Yes
2 No
99 Don't Know

**Q11. [If Q10 = 1]** Did your organization receive any grants to help offset a portion of the cost of the anerobic digester?

1 Yes
2 No
99 Don’t Know

**Q12. [If Q11 = 1]** Who provided the grant?

1 California Department of Food and Agriculture (CDFA)
2 Other [RECORD]
99 Don’t Know

**Q12a. [if Q11 = 1]** Approximately what percent of the cost of the anaerobic digester did the grant cover?

1 [RECORD] percent of anaerobic digester
99 Don’t know

**Q13. [If Q11 = 1]** Is the anerobic digester currently operational?

1 Yes
2 No
99 Don’t Know

**Q14. [If Q13 = 2]** Why is it no longer operational?

1 No longer have anything to digest
2 Shut down business
3 Too costly to operate/economics didn’t make sense
4 Permitting issues
5 Other [RECORD]
99 Don’t Know

**Q15. [If Q10 = 1]** What was the approximate cost to install your anaerobic digester?

1 Approximate Cost to Install [RECORD $$]
99 Don’t Know

**Q15a. [If Q15 = 99]** Would you estimate it cost ….

1 Less than $500,000
2 $500,000 to $1,000,000
3 $1,000,001 to $2,000,000
4 $2,000,001 to $3,000,000
5 $3,000,001 to $4,000,000

6 More than $4,000,000
99 Don't Know

**Q16. [If Q10 = 1]** What is the approximate annual cost to operate your anaerobic digester?

1 Approximate Cost to Operate [RECORD $$]
99 Don't Know

**Q17. [If Q10 = 1]** What power source is used to provide heat to your anaerobic digester?

1 Natural Gas
2 Biogas
3 A combination of natural gas and biogas
4 Other [RECORD]
5 None
99 Don't Know

**Q18. [If Q10 = 2]** Has your organization ever considered installing an anerobic digester?

1 Yes
2 No
99 Don't Know

**Q19. [If Q10 = 2]** What are the main reasons your organization has not installed an anerobic digester? (Select Multiple)

1 Lack of awareness
2 Too expensive
3 Anaerobic digestion is done offsite
4 Permitting and/or regulations issues
5 Didn't need it
6 Other Reason [RECORD]
99 Don't Know

### CURRENT ONSITE GENERATION EQUIPMENT STATUS

**[If SGIP_Flag = 0 ask Q20, else skip to Q25]**

**Q20.** Please select any onsite generation technologies your organization has installed at your facility. (Select multiple)

1 Fuel Cell
2 Gas Turbine
3 Microturbine

4 Internal Combustion Engine
5 Solar
6 Wind
7 None
99 Don’t Know

**Q90. [Q20 in 1-4]** When was this onsite generation equipment installed?

1 In 2016 or later
2 Between 2011 and 2015
3 In 2010 or prior
99 Don’t Know

**Q91. [Q20 in 1-4]** Is the onsite generation equipment still installed and operational?

1 Installed and operational
2 Installed but not operational
3 No longer installed
99 Don’t Know

**Q20a. [if Q20 in 1-4]** What is the total installed capacity (in kW) of the onsite generation installed at your facility?

1 [RECORD] kW
99 Don’t Know

**Q20b. [if Q20 in 1-6]** Did your organization receive any grants or incentives to offset a portion of the cost of the onsite generation equipment?

1 Yes
2 No
99 Don’t Know

**Q20c. [if Q20b = 1]** Who provided the grant or incentive?

1 [RECORD]
99 Don’t Know

**Q20d. [If Q20b = 2 and SGIP_aware = 1]** Did your organization consider applying for an SGIP incentive for the onsite generation equipment?

1 Yes
2 No

99 Don’t Know

**Q20e. [If Q20d = 1]** Why? **[If Q20d = 2]** Why not?

1 [RECORD]
99 Don’t Know

**Q20f. [if Q20b = 1]** Approximately what percent of the generation equipment did the grant or funding cover?

1 [RECORD] percent covered
99 Don’t know

**Q21. [If Q20 = 7]** Please select any onsite generation technologies your organization has <u>considered</u> installing at your facility? (Select Multiple)

1 Fuel Cell
2 Gas Turbine
3 Microturbine
4 Internal Combustion Engine
5 Solar
6 Wind
7 None
99 Don’t Know

**Q22. [If Q21 in 1-6]** What was the primary reason this onsite generation wasn’t installed at your facility?

1 [RECORD]
99 Don’t Know

**Q23. [If Q20=7]** Were any of the following items reasons why onsite generation equipment was not installed? (Select multiple)

1 Lack of awareness
2 Too expensive
3 Too complicated/time consuming
4 Regulations too cumbersome
5 Didn’t need it
6 Energy bill savings not sufficient
7 Other Reason [RECORD]
99 Don’t Know

**[If SGIP_Flag = 1 and SGIP_Gen ne “none” Ask Q25, else skip to Q30]**

**Q25.** According to our records, your organization installed a *{SGIP_Gen}* onsite at one of your facilities that received an incentive from the SGIP program. Is that correct?

1 Yes
2 No
99 Don't Know

**Q26. [Q25 = 1]** Is the *{SGIP_Gen}* still installed and operational?

1 Installed and operational
2 Installed but not operational
3 No longer installed
99 Don't Know

**Q27. [Q25 = 1]** Please describe in your own words the role the SGIP program played in your organization's decision to install a *{SGIP_Gen}*?

1 [RECORD]
99 Don't Know

**Q28. [Q25 = 1]** What would your organization have likely done if the SGIP incentive was not available to offset a portion of the cost of the *{SGIP_Gen}?*

1 Installed the {SGIP_Gen} without the incentive
2 Installed a different type of onsite generation
3 Would not have installed the {SGIP_Gen} or any other type of onsite generation
4 Other [RECORD]
99 Don't Know

**Q29. [Q25 = 2]** Is a *{SGIP_Gen}* installed at your organization's facility?

1 Yes
2 No
99 Don't Know

**[If SGIP_Flag = 1 and Cancelled=1 ask Q30, else skip to Q35]**

**Q30.** According to our records, your organization submitted an application to the SGIP for an incentive to cover a portion of the cost of a *{SGIP_Gen}* that was cancelled or withdrawn. Is this correct?

1 Yes

2 No
99 Don't Know

**Q31. [Q30 = 1]** At what stage of the project was the application cancelled?

1 Planning Phase
2 Permitting Phase
3 Construction Phase
4 Other [RECORD]
99 Don't Know

**Q32. [Q30 = 1]** Did this onsite generation project move forward without the SGIP incentive?

1 Yes
2 No
99 Don't Know

**Q33. [Q30 = 1]** What was the main reason the SGIP application was cancelled or withdrawn?

1 [RECORD]
99 Don't Know

**Q34. [Q30 = 1 and Q32 =2]** Please explain why you would or would not consider installing onsite generation at your facility in the future?

1 [RECORD]
99 Don't Know

**Q35. [If Q20 in 1-4, or Q26 = 1 or 2, or Q32 = 1 or Q29 = 1]** What type of fuel is currently (or was previously) used to power the onsite generation equipment installed at your facility? (Select multiple)

1 Onsite biogas
2 Purchased Natural Gas
3 Purchased or Directed Renewable Natural Gas (Biogas)
4 Diesel
5 Other [RECORD]
99 Don't Know

### CURRENT BIOGAS GENERATION USE AND DRIVERS (ONSITE PARTS AND NONPARTS)

**Q36. [If Q35 ne 1]** Does your organization currently produce biogas, or a gas that could be turned into biogas, at your facility?

| | |
|---|---|
| 1 | Yes |
| 2 | No |
| 99 | Don't Know |

**Q37. [If Q36 = 1 or Q35 = 1]** Please select all of the uses for the biogas produced at your facility? (Select multiple)

| | |
|---|---|
| 1 | Vent the gas |
| 2 | Flare the gas |
| 3 | Turn it into biomethane for onsite pipeline injection |
| 4 | Transport it to another facility where it is processed and injected into the pipeline |
| 5 | Use it to generate electricity for use by our organization |
| 6 | Use it to generate electricity that is exported to the electric grid |
| 7 | Turn it into CNG to fuel company vehicles onsite |
| 8 | Turn it into CNG for sale to others |
| 9 | Use it to heat an anerobic digester |
| 10 | Other [RECORD] |
| 99 | Don't Know |

**Q38. [If Q37 in 1-10]** Approximately what percentage of the biogas produced is used for each of these uses? (show table with answers selected in Q37)

| | |
|---|---|
| 1 | [RECORD] % |
| 99 | Don't Know |

**Q39. [If Q37 in 1-10]** How did you decide which biogas use was most appropriate for your operation?

| | |
|---|---|
| 1 | [RECORD] |
| 99 | Don't Know |

**Pipeline injection:**

**Q40a. [If Q37 = 3 or 4]** Approximately how much RNG does your organization inject into the pipeline annually?

| | |
|---|---|
| 1 | [RECORD] MMBTU/year |

99 Don’t Know

**Q40b. [If Q37 = 3]** Did you need to extend the pipeline to a point of interconnection onsite at your facility?

1 Had pipeline connection onsite already
2 Pipeline extension needed
99 Don’t Know

**Q40c. [If Q40b = 2]** What was the approximate cost of the pipeline extension?

1 [RECORD Cost in $]
99 Don’t Know

**Q40d. [If Q40b in 1 or 2]** What was the approximate cost of interconnection?

1 [RECORD Cost in $]
99 Don’t Know

**Q40e. [If Q37 =4 and Q37 ne 3]** Why doesn’t your facility inject the RNG directly into the pipeline from your site?

1 [RECORD]
99 Don’t Know

**Ask of all**

**Q41a.** Are you aware of California’s Low Carbon Fuel Standard, frequently referred to as the LCFS?

1 Yes
2 No
99 Don’t Know

**Q41b.** Are you aware of the Federal Renewable Fuel Standard (RFS) program?

1 Yes
2 No
99 Don’t Know

**Q41c. [(If Q41a = 1 or Q41b = 1) and Q37 = 3 or 4]** Does your organization receive LCFS or RFS credits for the biogas you inject into the pipeline?

1 Yes – LCFS

2 Yes – RFS
3 Yes – LCFS and RFS
4 No
99 Don't Know

**Q41d. [If Q41c in 1, 2, 3]** If LCFS or RFS credits were no longer available what would your organization likely do with the share of biogas currently being injected into the pipeline? (Select multiple)

1 Continue to inject it into the pipeline
2 Use it to fuel onsite generation equipment
3 Use it to fuel company vehicles
4 Unsure
5 Other [RECORD]
99 Don't Know

**Q41e. [If Q41c in 1, 2, 3]** Please describe the role LCFS or RFS credits play in your organization's decision regarding what to do with the biogas you produce onsite?

1 [RECORD]
99 Don't Know

**Q41f. [Q37 = 3 or 4]** Does your organization have a long-term contract with a gas utility to buy the RNG your organization produces onsite?

1 Yes
2 No
99 Don't Know

**Electricity Generation (onsite or directed):**

**Q42a. [If Q37 = 5 or 6 or Q35 = 1,2,3]** Approximately how much electricity does your organization generate onsite annually?

1 [RECORD] kWh/year
99 Don't Know

**Q42b. [If Q37 = 6 or Q35 = 1, 2, 3]** Does your organization receive NEM credits for generating electricity and delivering it to the grid?

1 Yes, we receive NEM credits
2 No, we are aware of NEM credits, but we do not receive any
3 No, we are not aware of NEM credits

99 Don't Know

**Q42c. [If Q37 = 6 or Q35 = 1,2,3]** Does your organization participate in the BIOMAT program?

1 Yes, we participate in the BIOMAT program
2 No, we are aware of the BIOMAT program, but we do not participate
3 No, we are not aware of the BIOMAT program
99 Don't Know

**Q42d. [If Q37 = 6 or Q35 = 1, 2, 3]** Does your organization receive Renewable Energy Certificates (RECs) for generating electricity and delivering it to the grid?

1 Yes, we receive Renewable Energy Certificates (RECs)
2 No, we are aware of Renewable Energy Certificates (RECs) but we do not receive any
3 No, we are not aware of Renewable Energy Certificates (RECs)
99 Don't Know

**Q42e. [If Q42b = 1 or Q42c = 1 or Q42d = 1]** If [IF Q42b = 1 read "NEM credits", IF Q42c = 1 "the BIOMAT program", If Q42d = 1 "Renewable Energy Certificates (RECs)"] were no longer available what would you organization do with the electricity generated onsite at your facility?

1 [RECORD]
99 Don't Know

**Q42f. [If Q42b = 1 or Q42c = 1 or Q42d = 1]** Please describe the role [IF Q42b = 1 read "NEM credits", IF Q42c = 1 "the BIOMAT program", If Q42d = 1 "Renewable Energy Certificates (RECs)"] play in your organization's decision regarding what to do with the electricity you generate onsite at your facility?

1 [RECORD]
99 Don't Know

**Onsite vehicle fueling:**

**Q43. [If Q37 = 7 or 8 or Q35 = 1]** Approximately how much CNG (in gasoline gallon equivalents) does your organization produce annually to be used as vehicle fuel?

1 [RECORD] gge/year
2 None
99 Don't Know

**Q44. [If Q37 = 2 or Q35 = 1]** Are you required by law to flare any unused biogas at your facility?

1 Yes

2 No
99 Don't Know

## CURRENT BIOGAS USE AND DRIVERS– (DIRECTED PARTS AND NONPARTS

**Q45. [If Q35 = 3 or FuelType = "Directed]** What is the primary reason your organization uses directed biogas to generate electricity onsite at your facility?

1 [RECORD]
99 Don't Know

**Q46. [If Q37 = 5,6 or If Q20 in 1-4 or q26 = 1 or 2 or Q32 = 1]** On a scale of 1 to 5, where 5 is very important and 1 is not at all important, please rate the importance of the following factors in your decision to install onsite generation?

1 To save money on our electric bill
2 To reduce our demand charges
3 To receive an incentive through the SGIP
4 To help the grid by generating our own power
5 To reduce our GHG emissions
6 To satisfy corporate goals or initiatives
7 To provide backup/emergency power to our facility

**Q47. [If Q35 = 1 or 3 or q37 = 5 or 6]** How likely are you to transition from using biogas to fuel your onsite generation to natural gas in the future?

1 Very Likely
2 Somewhat Likely
3 Not at all likely
99 Don't know

**Q48. [If Q47 = 1,2,3]** Why do you say that?

1 [RECORD]
99 Don't know

## LIKELIHOOD OF FUTURE GENERATION INSTALLATION IN FACILITY

**Q50.** How likely are you to consider installing (**[If Q37 = 5,6 or If Q20 in 1-4 or q26 = 1 or 2 or Q32 = 1 or Q29 = 1]** then "additional") onsite generation at your facility in the future?

2 Very Likely
3 Somewhat Likely
4 Not at all likely
99 Don't know

**Q51. [IF Q50 = 1,2]** When do you anticipate you would install this onsite generation?

1 Within the next year
2 More than one year from now but within the next 5 years
3 More than 5 years from now
99 Don't Know

**Q52. [IF Q50 = 3]** What are the main reasons you are unlikely to install (**[If Q37 = 5,6 or If Q20 in 1-4 or q26 = 1 or 2 or Q32 = 1 or Q29 = 1]** then "additional") onsite generation at your facility?

1 [Record Answer]
99 Don't Know

**Q53. [IF Q50 = 3]** Please rate on a scale of 1 to 5, where 5 is very significant and 1 is not at all significant, how significant the following reasons are in your decision not to install (**[If Q37 = 5,6 or If Q20 in 1-4 or q26 = 1 or 2 or Q32 = 1 or Q29 = 1]** then "additional") onsite generation at your facility? [ROTATE LIST]

1 Cost of onsite generation
2 Cost of biogas cleanup
3 Safety concerns
4 Regulatory Compliance Difficulties
5 Other [RECORD]

**Q54. [IF Q50 = 1,2]** How likely is your organization to fuel future your onsite generation projects with biogas?

1 Very Likely
2 Somewhat Likely
3 Not at all Likely
99 Don't Know

**Q55. [If Q54 = 1 or 2]** How likely is your organization to apply for an SGIP incentive for this biogas generation project?

1 Very Likely
2 Somewhat Likely
3 Not at all Likely
99 Don't Know

### SATISFACTION WITH THE SGIP

**Q60.** [IF Q4 = 1,2 or SGIP_Flag = 1] Using a 1 to 5 scale, where 1 is not at all satisfied and 5 is extremely satisfied, please rate your satisfaction with the following SGIP elements:

Q60a. Overall SGIP Application Process [RECORD 1 TO 5 RATING, or checkbox for "N/A"]
Q60b. SGIP Incentive amount [RECORD 1 TO 5 RATING, or checkbox for "N/A"]
Q60c. SGIP Program Requirements [RECORD 1 TO 5 RATING, or checkbox for "N/A"]

**Q61.** Based on your experience, how likely are you to recommend installing onsite generation to others?

4 Very Likely
5 Somewhat Likely
6 Not at all Likely
99 Don't Know

**Q62.** [IF Q4 = 1,2 or SGIP_Flag = 1] Based on your experience, how likely are you to recommend the SGIP to others?

1 Very Likely
2 Somewhat Likely
3 Not at all Likely
99 Don't Know

## CUSTOMER FIRMOGRAPHICS

**NonRes1a. [If Bustype = "Dairy"]** Approximately how many total cows are at your dairy?

1 [RECORD Cows]
99 Don't Know

**NonRes1b. [If Bustype = "Dairy"]** Approximately how many <u>milking</u> cows are at your dairy?

1 [RECORD Milking Cows]
99 Don't Know

**NonRes1c. [If Bustype = WWTP"]** On average, approximately how many gallons of water does your facility process per day?

1 [RECORD gallons]
99 Don't Know

**NonRes1d. [If BusType = "MSW"]** On average, approximately how many tons of waste does your facility process per day?

1 [RECORD tons of waste]
99 Don't Know

**NonRes1e. [If BusType = "Landfill"]** On average, approximately how many tons of waste are in place at your facility?

1 [RECORD tons of waste]
99 Don't Know

**NonRes3.** Does your organization have any goals regarding sustainability, GHG reductions, or climate change? (Select all that apply)

1 Yes – we have sustainability goals
2 Yes – we have GHG reduction goals
3 Yes – we have climate change goals
4 Yes – we have other environmental goals
5 No
99 Don't know

**[If NonRes3 = 4 then ask NonRes4]**
**NonRes4.** Please describe your organizations other environmental goals.

2 [RECORD]

**NonRes5.** Which of the following best describes the location of your organization with respect to wildfire risk?

1 My organization is in an area with high wildfire risk
2 My organization is in an area with moderate wildfire risk
3 My organization is in an area with low wildfire risk
99 Don't know

**[IF NonRes5 in 1 or 2 ASK NonRes6]**
**NonRes6.** Has your organization ever been affected by your utility using preventative fire outages on days with high fire risk?

1 Yes, my organization has lost power due to my utility using preventative fire outages.
2 No, my organization has not lost power due to my utility using preventative fire outages.
99 Don't know

**Closing.** Is there anything further that the previous questions have not addressed but that you would like us to know about your organization's thoughts or experiences with either onsite electricity generation, biogas production in California, or the Self-Generation Incentive Program?

1 [RECORD]
99 Nothing further

**END OF SURVEY.** Those are all the questions we have for you. On behalf of the California Public Utilities Commission, thank you very much for your time today.

# APPENDIX C COST-EFFECTIVENESS RESULTS

This Appendix presents the results of all scenarios for the four benefit cost ratios in 2020, 2026, and 2030 by technology and scenario. Scenarios are listed in Table C-1 and results are listed in Table C-2

- TRC - Total Resource Cost Benefit Cost Ratio
- PCT – Participant Cost Test Benefit Cost Ratio
- PA – Program Administrator Benefit Cost Ratio
- RIM – Ratepayer Impact Benefit Cost Ratio

**TABLE C-1: SCENARIO DECRIPTIONS AND CROSS REFERENCE**

| Scenario | Fuel Type | Resiliency Adder | Capacity Factor | Dairy/ Vented Baseline | Digester Costs | CDFA Grant | USDA Grant | RECS | Technologies | DBG Price | Base case |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | OSB | No | Actual | Flared | N/A | N/A | N/A | No | All | N/A | Base Case |
| 2 | DBG | No | Actual | Flared | N/A | N/A | N/A | No | All | $1.75 | Base Case |
| 3 | DBG | No | Actual | Vented | N/A | N/A | N/A | No | All | $1.75 | Base Case |
| 4 | OSB | Yes | Actual | Flared | N/A | N/A | N/A | No | All | N/A | Scenario |
| 5 | DBG | Yes | Actual | Flared | N/A | N/A | N/A | No | All | $1.75 | Scenario |
| 6 | OSB | Yes | Actual | Vented | No Digester Cost | No CDFA Grant | No | No | FC & ICE | N/A | Scenario |
| 7 | OSB | Yes | Actual | Vented | With Digester Cost | No CDFA Grant | No | No | FC & ICE | N/A | Scenario |
| 8 | OSB | No | Actual | Vented | With Digester Cost | No CDFA Grant | No | No | FC & ICE | N/A | Scenario |
| 9 | OSB | No | Actual | Vented | With Digester Cost | With CDFA Grant | No | No | FC & ICE | N/A | Scenario |
| 10 | OSB | No | 0.8 | Flared | N/A | N/A | N/A | No | All | N/A | Scenario |
| 11 | DBG | No | 0.8 | Flared | N/A | N/A | N/A | No | All | $1.75 | Scenario |
| 12 | OSB | No | Actual | Vented | No Digester Cost | No CDFA Grant | No | No | FC & ICE | N/A | Base Case |
| 13 | OSB | No | Actual | Vented | With Digester Cost | With CDFA Grant | Yes | No | FC & ICE | N/A | Scenario |
| 14 | OSB | Yes | Actual | Vented | With Digester Cost | With CDFA Grant | Yes | Yes | FC & ICE | N/A | Scenario |
| 15 | OSB | Yes | Actual | Flared | N/A | N/A | N/A | Yes | All | N/A | Scenario |
| 16 | DBG | Yes | Actual | Flared | N/A | N/A | N/A | Yes | All | $1.75 | Scenario |
| 17 | DBG | No | Actual | Flared | N/A | N/A | N/A | No | All | $1.20 | Scenario |
| 18 | DBG | No | Actual | Flared | N/A | N/A | N/A | No | All | $0.70 | Scenario |

### TABLE C-2: BENEFIT COST RATIOS BY TECHNOLOGY AND SCENARIO

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario1 | PG&E | OSB | Gas Turbine (Large) | 84% | 109% | 132% | 82% | 91% | 98% | 2609% | 3900% | 5111% | 76% | 88% | 98% |
| Scenario1 | SCE | OSB | Gas Turbine (Large) | 94% | 127% | 152% | 86% | 93% | 100% | 2941% | 4547% | 5906% | 81% | 100% | 112% |
| Scenario1 | SDG&E | OSB | Gas Turbine (Large) | 89% | 120% | 145% | 85% | 88% | 94% | 2693% | 4163% | 5437% | 78% | 100% | 113% |
| Scenario1 | PG&E | OSB | Gas Turbine (Small) | 86% | 111% | 133% | 91% | 99% | 106% | 830% | 1240% | 1626% | 71% | 84% | 94% |
| Scenario1 | SCE | OSB | Gas Turbine (Small) | 96% | 128% | 154% | 95% | 101% | 107% | 935% | 1446% | 1878% | 77% | 96% | 107% |
| Scenario1 | SDG&E | OSB | Gas Turbine (Small) | 91% | 121% | 146% | 94% | 96% | 101% | 857% | 1324% | 1729% | 73% | 95% | 108% |
| Scenario1 | PG&E | OSB | Fuel Cell CHP (Large) | 65% | 82% | 104% | 78% | 79% | 88% | 439% | 656% | 858% | 68% | 80% | 91% |
| Scenario1 | SCE | OSB | Fuel Cell CHP (Large) | 72% | 95% | 120% | 81% | 81% | 90% | 494% | 762% | 989% | 73% | 92% | 103% |
| Scenario1 | SDG&E | OSB | Fuel Cell CHP (Large) | 68% | 90% | 114% | 80% | 78% | 85% | 452% | 697% | 909% | 69% | 90% | 104% |
| Scenario1 | PG&E | OSB | Fuel Cell CHP (Small) | 55% | 70% | 88% | 69% | 68% | 75% | 329% | 492% | 643% | 68% | 82% | 93% |
| Scenario1 | SCE | OSB | Fuel Cell CHP (Small) | 61% | 80% | 101% | 74% | 72% | 79% | 370% | 572% | 742% | 69% | 88% | 100% |
| Scenario1 | SDG&E | OSB | Fuel Cell CHP (Small) | 58% | 76% | 95% | 73% | 69% | 75% | 339% | 523% | 682% | 66% | 87% | 100% |
| Scenario1 | PG&E | OSB | Fuel Cell Elec (Large) | 64% | 87% | 112% | 77% | 83% | 94% | 365% | 546% | 714% | 69% | 83% | 94% |
| Scenario1 | SCE | OSB | Fuel Cell Elec (Large) | 71% | 100% | 129% | 82% | 88% | 99% | 411% | 634% | 822% | 71% | 90% | 101% |
| Scenario1 | SDG&E | OSB | Fuel Cell Elec (Large) | 67% | 95% | 122% | 81% | 85% | 95% | 377% | 581% | 758% | 67% | 88% | 102% |
| Scenario1 | PG&E | OSB | Fuel Cell Elec (Small) | 52% | 70% | 89% | 80% | 87% | 99% | 365% | 546% | 714% | 51% | 61% | 69% |
| Scenario1 | SCE | OSB | Fuel Cell Elec (Small) | 57% | 80% | 103% | 70% | 73% | 81% | 411% | 634% | 822% | 68% | 86% | 98% |
| Scenario1 | SDG&E | OSB | Fuel Cell Elec (Small) | 54% | 76% | 97% | 74% | 77% | 86% | 377% | 581% | 758% | 60% | 77% | 88% |
| Scenario1 | PG&E | OSB | Microturbine (all Sizes) | 60% | 75% | 90% | 97% | 101% | 105% | 275% | 411% | 538% | 48% | 57% | 65% |
| Scenario1 | SCE | OSB | Microturbine (all Sizes) | 67% | 87% | 103% | 86% | 85% | 88% | 310% | 479% | 622% | 63% | 81% | 93% |
| Scenario1 | SDG&E | OSB | Microturbine (all Sizes) | 63% | 82% | 98% | 90% | 89% | 92% | 282% | 437% | 570% | 56% | 72% | 83% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario1 | PG&E | OSB | Internal Combustion Engine (Small) | 63% | 79% | 95% | 84% | 84% | 87% | 248% | 371% | 486% | 62% | 76% | 87% |
| Scenario1 | SCE | OSB | Internal Combustion Engine (Small) | 71% | 92% | 109% | 90% | 89% | 92% | 280% | 433% | 562% | 64% | 83% | 94% |
| Scenario1 | SDG&E | OSB | Internal Combustion Engine (Small) | 66% | 86% | 103% | 89% | 86% | 88% | 255% | 394% | 514% | 61% | 81% | 94% |
| Scenario1 | PG&E | OSB | Internal Combustion Engine (Large) | 70% | 89% | 106% | 89% | 92% | 96% | 331% | 494% | 648% | 63% | 76% | 86% |
| Scenario1 | SCE | OSB | Internal Combustion Engine (Large) | 78% | 103% | 122% | 92% | 93% | 97% | 373% | 576% | 749% | 68% | 87% | 99% |
| Scenario1 | SDG&E | OSB | Internal Combustion Engine (Large) | 74% | 96% | 116% | 91% | 90% | 93% | 339% | 525% | 685% | 65% | 85% | 98% |
| Scenario2 | PG&E | DBG | Gas Turbine (Large) | 31% | 42% | 53% | 31% | 35% | 39% | 991% | 1351% | 1663% | 77% | 88% | 98% |
| Scenario2 | SCE | DBG | Gas Turbine (Large) | 32% | 45% | 56% | 30% | 33% | 37% | 409% | 536% | 630% | 85% | 100% | 110% |
| Scenario2 | SDG&E | DBG | Gas Turbine (Large) | 29% | 41% | 51% | 29% | 31% | 34% | 308% | 393% | 458% | 84% | 100% | 110% |
| Scenario2 | PG&E | DBG | Gas Turbine (Small) | 31% | 43% | 53% | 34% | 38% | 43% | 563% | 792% | 996% | 73% | 84% | 94% |
| Scenario2 | SCE | DBG | Gas Turbine (Small) | 32% | 44% | 55% | 32% | 35% | 39% | 283% | 369% | 433% | 82% | 97% | 106% |
| Scenario2 | SDG&E | DBG | Gas Turbine (Small) | 30% | 42% | 52% | 32% | 34% | 36% | 263% | 340% | 400% | 80% | 96% | 106% |
| Scenario2 | PG&E | DBG | Fuel Cell CHP (Large) | 34% | 46% | 58% | 43% | 44% | 49% | 372% | 536% | 683% | 69% | 81% | 91% |
| Scenario2 | SCE | DBG | Fuel Cell CHP (Large) | 35% | 48% | 60% | 41% | 41% | 45% | 256% | 345% | 413% | 78% | 93% | 103% |
| Scenario2 | SDG&E | DBG | Fuel Cell CHP (Large) | 33% | 45% | 57% | 41% | 39% | 43% | 238% | 318% | 381% | 75% | 92% | 103% |
| Scenario2 | PG&E | DBG | Fuel Cell CHP (Small) | 32% | 42% | 53% | 41% | 41% | 45% | 294% | 425% | 544% | 69% | 82% | 93% |
| Scenario2 | SCE | DBG | Fuel Cell CHP (Small) | 33% | 44% | 55% | 41% | 40% | 44% | 227% | 307% | 369% | 75% | 90% | 100% |
| Scenario2 | SDG&E | DBG | Fuel Cell CHP (Small) | 31% | 42% | 53% | 40% | 38% | 41% | 211% | 284% | 342% | 72% | 89% | 100% |
| Scenario2 | PG&E | DBG | Fuel Cell Elec (Large) | 40% | 54% | 70% | 49% | 51% | 58% | 328% | 477% | 612% | 70% | 83% | 94% |
| Scenario2 | SCE | DBG | Fuel Cell Elec (Large) | 40% | 57% | 72% | 48% | 50% | 56% | 255% | 351% | 426% | 75% | 91% | 101% |
| Scenario2 | SDG&E | DBG | Fuel Cell Elec (Large) | 38% | 54% | 69% | 48% | 48% | 53% | 237% | 324% | 393% | 72% | 90% | 101% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario2 | PG&E | DBG | Fuel Cell Elec (Small) | 35% | 47% | 61% | 55% | 59% | 67% | 328% | 477% | 612% | 52% | 62% | 69% |
| Scenario2 | SCE | DBG | Fuel Cell Elec (Small) | 36% | 51% | 64% | 45% | 46% | 51% | 255% | 351% | 426% | 72% | 88% | 98% |
| Scenario2 | SDG&E | DBG | Fuel Cell Elec (Small) | 34% | 48% | 61% | 47% | 48% | 53% | 237% | 324% | 393% | 65% | 80% | 90% |
| Scenario2 | PG&E | DBG | Microturbine (all Sizes) | 21% | 29% | 35% | 35% | 38% | 42% | 235% | 334% | 423% | 50% | 59% | 67% |
| Scenario2 | SCE | DBG | Microturbine (all Sizes) | 21% | 30% | 36% | 28% | 29% | 31% | 175% | 225% | 263% | 73% | 86% | 95% |
| Scenario2 | SDG&E | DBG | Microturbine (all Sizes) | 20% | 28% | 34% | 29% | 30% | 32% | 164% | 210% | 245% | 67% | 79% | 87% |
| Scenario2 | PG&E | DBG | Internal Combustion Engine (Small) | 26% | 35% | 43% | 35% | 37% | 39% | 223% | 321% | 410% | 64% | 77% | 88% |
| Scenario2 | SCE | DBG | Internal Combustion Engine (Small) | 26% | 36% | 44% | 34% | 35% | 37% | 179% | 238% | 282% | 72% | 86% | 96% |
| Scenario2 | SDG&E | DBG | Internal Combustion Engine (Small) | 25% | 34% | 42% | 34% | 34% | 36% | 168% | 220% | 262% | 70% | 85% | 95% |
| Scenario2 | PG&E | DBG | Internal Combustion Engine (Large) | 27% | 36% | 44% | 34% | 37% | 40% | 282% | 402% | 512% | 65% | 77% | 87% |
| Scenario2 | SCE | DBG | Internal Combustion Engine (Large) | 27% | 37% | 45% | 32% | 34% | 36% | 202% | 265% | 313% | 76% | 90% | 99% |
| Scenario2 | SDG&E | DBG | Internal Combustion Engine (Large) | 25% | 35% | 43% | 32% | 32% | 34% | 188% | 245% | 290% | 74% | 89% | 99% |
| Scenario3 | PG&E | DBG | Gas Turbine (Large) | 195% | 278% | 354% | 31% | 35% | 39% | 6083% | 9311% | 12350% | 478% | 573% | 652% |
| Scenario3 | SCE | DBG | Gas Turbine (Large) | 184% | 263% | 334% | 30% | 33% | 37% | 1962% | 2981% | 3925% | 411% | 517% | 597% |
| Scenario3 | SDG&E | DBG | Gas Turbine (Large) | 177% | 252% | 319% | 29% | 31% | 34% | 1418% | 2140% | 2811% | 389% | 506% | 594% |
| Scenario3 | PG&E | DBG | Gas Turbine (Small) | 198% | 281% | 358% | 34% | 38% | 43% | 3469% | 5310% | 7044% | 451% | 548% | 627% |
| Scenario3 | SCE | DBG | Gas Turbine (Small) | 180% | 257% | 326% | 32% | 35% | 39% | 1278% | 1932% | 2536% | 374% | 477% | 555% |
| Scenario3 | SDG&E | DBG | Gas Turbine (Small) | 179% | 254% | 322% | 32% | 34% | 36% | 1212% | 1829% | 2403% | 371% | 487% | 574% |
| Scenario3 | PG&E | DBG | Fuel Cell CHP (Large) | 176% | 248% | 322% | 43% | 44% | 49% | 1949% | 2977% | 3943% | 361% | 443% | 510% |
| Scenario3 | SCE | DBG | Fuel Cell CHP (Large) | 164% | 231% | 298% | 41% | 41% | 45% | 1030% | 1556% | 2041% | 314% | 401% | 467% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario3 | SDG&E | DBG | Fuel Cell CHP (Large) | 162% | 228% | 294% | 41% | 39% | 43% | 979% | 1476% | 1937% | 311% | 409% | 482% |
| Scenario3 | PG&E | DBG | Fuel Cell CHP (Small) | 161% | 227% | 293% | 41% | 41% | 45% | 1539% | 2351% | 3114% | 362% | 449% | 519% |
| Scenario3 | SCE | DBG | Fuel Cell CHP (Small) | 151% | 213% | 274% | 41% | 40% | 44% | 911% | 1376% | 1804% | 302% | 388% | 454% |
| Scenario3 | SDG&E | DBG | Fuel Cell CHP (Small) | 149% | 210% | 270% | 40% | 38% | 41% | 866% | 1307% | 1715% | 299% | 395% | 467% |
| Scenario3 | PG&E | DBG | Fuel Cell Elec (Large) | 170% | 246% | 323% | 49% | 51% | 58% | 1454% | 2215% | 2929% | 311% | 383% | 441% |
| Scenario3 | SCE | DBG | Fuel Cell Elec (Large) | 160% | 232% | 302% | 48% | 50% | 56% | 903% | 1364% | 1786% | 267% | 340% | 395% |
| Scenario3 | SDG&E | DBG | Fuel Cell Elec (Large) | 158% | 229% | 297% | 48% | 48% | 53% | 859% | 1295% | 1697% | 264% | 346% | 407% |
| Scenario3 | PG&E | DBG | Fuel Cell Elec (Small) | 149% | 215% | 281% | 55% | 59% | 67% | 1454% | 2215% | 2929% | 231% | 282% | 324% |
| Scenario3 | SCE | DBG | Fuel Cell Elec (Small) | 142% | 205% | 266% | 45% | 46% | 51% | 903% | 1364% | 1786% | 257% | 329% | 384% |
| Scenario3 | SDG&E | DBG | Fuel Cell Elec (Small) | 140% | 202% | 262% | 47% | 48% | 53% | 859% | 1295% | 1697% | 238% | 308% | 359% |
| Scenario3 | PG&E | DBG | Microturbine (all Sizes) | 184% | 263% | 335% | 35% | 38% | 42% | 2027% | 3114% | 4138% | 434% | 542% | 629% |
| Scenario3 | SCE | DBG | Microturbine (all Sizes) | 167% | 238% | 303% | 28% | 29% | 31% | 993% | 1501% | 1975% | 417% | 550% | 657% |
| Scenario3 | SDG&E | DBG | Microturbine (all Sizes) | 166% | 236% | 300% | 29% | 30% | 32% | 946% | 1428% | 1879% | 390% | 519% | 618% |
| Scenario3 | PG&E | DBG | Internal Combustion Engine (Small) | 180% | 255% | 324% | 35% | 37% | 39% | 1576% | 2416% | 3208% | 455% | 574% | 670% |
| Scenario3 | SCE | DBG | Internal Combustion Engine (Small) | 165% | 234% | 297% | 34% | 35% | 37% | 893% | 1350% | 1774% | 362% | 474% | 561% |
| Scenario3 | SDG&E | DBG | Internal Combustion Engine (Small) | 164% | 232% | 293% | 34% | 34% | 36% | 850% | 1283% | 1686% | 358% | 480% | 574% |
| Scenario3 | PG&E | DBG | Internal Combustion Engine (Large) | 186% | 264% | 336% | 34% | 37% | 40% | 1987% | 3046% | 4043% | 460% | 573% | 665% |
| Scenario3 | SCE | DBG | Internal Combustion Engine (Large) | 170% | 242% | 307% | 32% | 34% | 36% | 1003% | 1516% | 1992% | 379% | 493% | 581% |
| Scenario3 | SDG&E | DBG | Internal Combustion Engine (Large) | 168% | 239% | 303% | 32% | 32% | 34% | 953% | 1439% | 1891% | 375% | 500% | 596% |
| Scenario4 | PG&E | OSB | Gas Turbine (Large) | 84% | 109% | 132% | 85% | 93% | 100% | 1569% | 2345% | 3073% | 74% | 87% | 97% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario4 | SCE | OSB | Gas Turbine (Large) | 95% | 127% | 152% | 89% | 95% | 102% | 1768% | 2734% | 3551% | 80% | 99% | 110% |
| Scenario4 | SDG&E | OSB | Gas Turbine (Large) | 89% | 120% | 144% | 87% | 91% | 96% | 1619% | 2503% | 3269% | 77% | 98% | 111% |
| Scenario4 | PG&E | OSB | Gas Turbine (Small) | 86% | 111% | 133% | 99% | 106% | 112% | 498% | 745% | 976% | 68% | 80% | 91% |
| Scenario4 | SCE | OSB | Gas Turbine (Small) | 97% | 129% | 154% | 103% | 108% | 114% | 562% | 868% | 1128% | 73% | 92% | 103% |
| Scenario4 | SDG&E | OSB | Gas Turbine (Small) | 91% | 121% | 145% | 102% | 104% | 108% | 514% | 795% | 1038% | 70% | 90% | 104% |
| Scenario4 | PG&E | OSB | Fuel Cell CHP (Large) | 66% | 83% | 105% | 97% | 98% | 107% | 195% | 291% | 381% | 57% | 70% | 80% |
| Scenario4 | SCE | OSB | Fuel Cell CHP (Large) | 73% | 96% | 120% | 99% | 100% | 108% | 219% | 339% | 439% | 61% | 80% | 91% |
| Scenario4 | SDG&E | OSB | Fuel Cell CHP (Large) | 69% | 90% | 114% | 99% | 96% | 103% | 201% | 310% | 404% | 58% | 78% | 91% |
| Scenario4 | PG&E | OSB | Fuel Cell CHP (Small) | 57% | 71% | 89% | 90% | 89% | 95% | 146% | 219% | 286% | 54% | 68% | 79% |
| Scenario4 | SCE | OSB | Fuel Cell CHP (Small) | 63% | 82% | 101% | 95% | 93% | 100% | 165% | 254% | 330% | 56% | 74% | 86% |
| Scenario4 | SDG&E | OSB | Fuel Cell CHP (Small) | 59% | 77% | 96% | 94% | 90% | 96% | 151% | 232% | 303% | 53% | 72% | 85% |
| Scenario4 | PG&E | OSB | Fuel Cell Elec (Large) | 65% | 88% | 113% | 99% | 106% | 117% | 162% | 242% | 317% | 56% | 70% | 81% |
| Scenario4 | SCE | OSB | Fuel Cell Elec (Large) | 73% | 101% | 129% | 105% | 112% | 123% | 183% | 282% | 365% | 58% | 76% | 88% |
| Scenario4 | SDG&E | OSB | Fuel Cell Elec (Large) | 68% | 95% | 122% | 104% | 108% | 118% | 167% | 258% | 337% | 55% | 74% | 87% |
| Scenario4 | PG&E | OSB | Fuel Cell Elec (Small) | 53% | 71% | 90% | 98% | 106% | 118% | 162% | 242% | 317% | 43% | 53% | 61% |
| Scenario4 | SCE | OSB | Fuel Cell Elec (Small) | 59% | 81% | 103% | 89% | 92% | 100% | 183% | 282% | 365% | 56% | 74% | 85% |
| Scenario4 | SDG&E | OSB | Fuel Cell Elec (Small) | 56% | 77% | 98% | 92% | 95% | 104% | 167% | 258% | 337% | 50% | 66% | 77% |
| Scenario4 | PG&E | OSB | Microturbine (all Sizes) | 62% | 77% | 91% | 126% | 127% | 130% | 122% | 182% | 239% | 39% | 49% | 57% |
| Scenario4 | SCE | OSB | Microturbine (all Sizes) | 69% | 88% | 104% | 115% | 112% | 113% | 138% | 213% | 277% | 50% | 67% | 78% |
| Scenario4 | SDG&E | OSB | Microturbine (all Sizes) | 65% | 83% | 98% | 119% | 116% | 117% | 125% | 194% | 253% | 45% | 60% | 70% |
| Scenario4 | PG&E | OSB | Internal Combustion Engine (Small) | 66% | 81% | 96% | 118% | 116% | 116% | 110% | 165% | 216% | 47% | 60% | 71% |
| Scenario4 | SCE | OSB | Internal Combustion Engine (Small) | 73% | 93% | 110% | 124% | 121% | 121% | 124% | 192% | 250% | 50% | 67% | 78% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario4 | SDG&E | OSB | Internal Combustion Engine (Small) | 68% | 87% | 103% | 123% | 118% | 117% | 113% | 175% | 228% | 47% | 64% | 76% |
| Scenario5 | PG&E | DBG | Gas Turbine (Large) | 31% | 42% | 53% | 32% | 36% | 40% | 796% | 1164% | 1509% | 76% | 87% | 97% |
| Scenario5 | SCE | DBG | Gas Turbine (Large) | 32% | 45% | 56% | 31% | 34% | 38% | 378% | 539% | 675% | 84% | 99% | 109% |
| Scenario5 | SDG&E | DBG | Gas Turbine (Large) | 29% | 41% | 51% | 29% | 31% | 34% | 290% | 400% | 496% | 82% | 98% | 109% |
| Scenario5 | PG&E | DBG | Gas Turbine (Small) | 32% | 43% | 54% | 37% | 41% | 45% | 394% | 577% | 748% | 69% | 81% | 91% |
| Scenario5 | SCE | DBG | Gas Turbine (Small) | 32% | 45% | 55% | 35% | 38% | 41% | 245% | 342% | 423% | 79% | 93% | 103% |
| Scenario5 | SDG&E | DBG | Gas Turbine (Small) | 30% | 42% | 52% | 34% | 36% | 39% | 228% | 316% | 391% | 77% | 92% | 103% |
| Scenario5 | PG&E | DBG | Fuel Cell CHP (Large) | 35% | 46% | 59% | 54% | 54% | 59% | 186% | 272% | 353% | 58% | 71% | 81% |
| Scenario5 | SCE | DBG | Fuel Cell CHP (Large) | 36% | 49% | 61% | 51% | 50% | 54% | 171% | 242% | 301% | 68% | 82% | 93% |
| Scenario5 | SDG&E | DBG | Fuel Cell CHP (Large) | 34% | 46% | 57% | 50% | 48% | 52% | 159% | 224% | 279% | 65% | 81% | 92% |
| Scenario5 | PG&E | DBG | Fuel Cell CHP (Small) | 33% | 43% | 54% | 54% | 53% | 57% | 143% | 209% | 272% | 55% | 68% | 79% |
| Scenario5 | SCE | DBG | Fuel Cell CHP (Small) | 34% | 45% | 56% | 53% | 51% | 55% | 143% | 202% | 252% | 63% | 77% | 87% |
| Scenario5 | SDG&E | DBG | Fuel Cell CHP (Small) | 32% | 43% | 53% | 52% | 50% | 53% | 133% | 187% | 233% | 60% | 76% | 86% |
| Scenario5 | PG&E | DBG | Fuel Cell Elec (Large) | 41% | 55% | 70% | 63% | 66% | 72% | 158% | 233% | 302% | 57% | 70% | 81% |
| Scenario5 | SCE | DBG | Fuel Cell Elec (Large) | 42% | 58% | 73% | 62% | 64% | 69% | 157% | 225% | 283% | 63% | 79% | 89% |
| Scenario5 | SDG&E | DBG | Fuel Cell Elec (Large) | 39% | 55% | 69% | 61% | 62% | 66% | 146% | 208% | 262% | 61% | 77% | 88% |
| Scenario5 | PG&E | DBG | Fuel Cell Elec (Small) | 36% | 48% | 61% | 68% | 72% | 80% | 158% | 233% | 302% | 45% | 54% | 62% |
| Scenario5 | SCE | DBG | Fuel Cell Elec (Small) | 37% | 51% | 65% | 57% | 58% | 62% | 157% | 225% | 283% | 61% | 76% | 87% |
| Scenario5 | SDG&E | DBG | Fuel Cell Elec (Small) | 35% | 49% | 61% | 59% | 60% | 65% | 146% | 208% | 262% | 56% | 70% | 79% |
| Scenario5 | PG&E | DBG | Microturbine (all Sizes) | 23% | 30% | 36% | 46% | 48% | 51% | 119% | 173% | 223% | 42% | 51% | 58% |
| Scenario5 | SCE | DBG | Microturbine (all Sizes) | 23% | 30% | 37% | 38% | 38% | 40% | 121% | 162% | 197% | 62% | 74% | 82% |
| Scenario5 | SDG&E | DBG | Microturbine (all Sizes) | 21% | 29% | 35% | 39% | 39% | 41% | 114% | 151% | 184% | 57% | 68% | 76% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario5 | PG&E | DBG | Internal Combustion Engine (Small) | 28% | 36% | 44% | 50% | 51% | 53% | 110% | 160% | 206% | 50% | 62% | 72% |
| Scenario5 | SCE | DBG | Internal Combustion Engine (Small) | 28% | 37% | 45% | 47% | 47% | 49% | 116% | 159% | 195% | 59% | 72% | 81% |
| Scenario5 | SDG&E | DBG | Internal Combustion Engine (Small) | 26% | 35% | 43% | 47% | 46% | 48% | 108% | 148% | 181% | 57% | 71% | 80% |
| Scenario5 | PG&E | DBG | Internal Combustion Engine (Large) | 28% | 37% | 45% | 45% | 47% | 50% | 144% | 209% | 271% | 53% | 65% | 75% |
| Scenario5 | SCE | DBG | Internal Combustion Engine (Large) | 28% | 38% | 46% | 42% | 43% | 45% | 138% | 190% | 234% | 65% | 78% | 87% |
| Scenario5 | SDG&E | DBG | Internal Combustion Engine (Large) | 26% | 36% | 44% | 42% | 42% | 43% | 130% | 176% | 217% | 63% | 77% | 87% |
| Scenario6 | PG&E | OSB | Fuel Cell CHP (Large) | 328% | 446% | 577% | 97% | 98% | 107% | 1071% | 1642% | 2178% | 311% | 393% | 459% |
| Scenario6 | SCE | OSB | Fuel Cell CHP (Large) | 335% | 459% | 592% | 99% | 100% | 108% | 1095% | 1689% | 2236% | 306% | 397% | 466% |
| Scenario6 | SDG&E | OSB | Fuel Cell CHP (Large) | 328% | 450% | 582% | 99% | 96% | 103% | 1049% | 1617% | 2143% | 304% | 406% | 482% |
| Scenario6 | PG&E | OSB | Fuel Cell CHP (Small) | 275% | 374% | 481% | 90% | 89% | 95% | 803% | 1232% | 1634% | 296% | 381% | 449% |
| Scenario6 | SCE | OSB | Fuel Cell CHP (Small) | 281% | 384% | 494% | 95% | 93% | 100% | 822% | 1267% | 1678% | 280% | 368% | 435% |
| Scenario6 | SDG&E | OSB | Fuel Cell CHP (Small) | 275% | 376% | 485% | 94% | 90% | 96% | 787% | 1213% | 1608% | 277% | 375% | 448% |
| Scenario6 | PG&E | OSB | Fuel Cell Elec (Large) | 272% | 392% | 516% | 99% | 106% | 117% | 745% | 1139% | 1509% | 257% | 328% | 385% |
| Scenario6 | SCE | OSB | Fuel Cell Elec (Large) | 279% | 405% | 532% | 105% | 112% | 123% | 765% | 1179% | 1557% | 244% | 318% | 374% |
| Scenario6 | SDG&E | OSB | Fuel Cell Elec (Large) | 273% | 396% | 521% | 104% | 108% | 118% | 733% | 1128% | 1493% | 241% | 324% | 386% |
| Scenario6 | PG&E | OSB | Fuel Cell Elec (Small) | 219% | 314% | 411% | 98% | 106% | 118% | 745% | 1139% | 1509% | 199% | 251% | 293% |
| Scenario6 | SCE | OSB | Fuel Cell Elec (Small) | 225% | 325% | 424% | 89% | 92% | 100% | 765% | 1179% | 1557% | 235% | 308% | 364% |
| Scenario6 | SDG&E | OSB | Fuel Cell Elec (Small) | 220% | 318% | 416% | 92% | 95% | 104% | 733% | 1128% | 1493% | 218% | 289% | 341% |
| Scenario6 | PG&E | OSB | Internal Combustion Engine (Small) | 431% | 576% | 708% | 118% | 116% | 116% | 837% | 1288% | 1713% | 360% | 473% | 565% |
| Scenario6 | SCE | OSB | Internal Combustion Engine (Small) | 438% | 588% | 722% | 124% | 121% | 121% | 851% | 1315% | 1746% | 342% | 457% | 546% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario6 | SDG&E | OSB | Internal Combustion Engine (Small) | 427% | 574% | 706% | 123% | 118% | 117% | 814% | 1257% | 1671% | 337% | 463% | 560% |
| Scenario6 | PG&E | OSB | Internal Combustion Engine (Large) | 486% | 652% | 801% | 117% | 118% | 120% | 1130% | 1738% | 2312% | 389% | 499% | 590% |
| Scenario6 | SCE | OSB | Internal Combustion Engine (Large) | 494% | 666% | 817% | 120% | 119% | 121% | 1148% | 1775% | 2357% | 381% | 502% | 594% |
| Scenario6 | SDG&E | OSB | Internal Combustion Engine (Large) | 483% | 651% | 801% | 119% | 116% | 117% | 1098% | 1697% | 2256% | 378% | 511% | 613% |
| Scenario7 | PG&E | OSB | Fuel Cell CHP (Large) | 268% | 362% | 475% | 83% | 79% | 88% | 1071% | 1642% | 2178% | 311% | 393% | 459% |
| Scenario7 | SCE | OSB | Fuel Cell CHP (Large) | 274% | 372% | 488% | 85% | 81% | 89% | 1095% | 1689% | 2236% | 306% | 397% | 466% |
| Scenario7 | SDG&E | OSB | Fuel Cell CHP (Large) | 269% | 365% | 480% | 84% | 78% | 85% | 1049% | 1617% | 2143% | 304% | 406% | 482% |
| Scenario7 | PG&E | OSB | Fuel Cell CHP (Small) | 217% | 292% | 383% | 75% | 69% | 76% | 803% | 1232% | 1634% | 296% | 381% | 449% |
| Scenario7 | SCE | OSB | Fuel Cell CHP (Small) | 222% | 300% | 393% | 79% | 73% | 79% | 822% | 1267% | 1678% | 280% | 368% | 435% |
| Scenario7 | SDG&E | OSB | Fuel Cell CHP (Small) | 218% | 294% | 387% | 78% | 70% | 76% | 787% | 1213% | 1608% | 277% | 375% | 448% |
| Scenario7 | PG&E | OSB | Fuel Cell Elec (Large) | 226% | 331% | 448% | 85% | 89% | 101% | 745% | 1139% | 1509% | 257% | 328% | 385% |
| Scenario7 | SCE | OSB | Fuel Cell Elec (Large) | 232% | 342% | 462% | 90% | 94% | 107% | 765% | 1179% | 1557% | 244% | 318% | 374% |
| Scenario7 | SDG&E | OSB | Fuel Cell Elec (Large) | 227% | 334% | 453% | 89% | 91% | 102% | 733% | 1128% | 1493% | 241% | 324% | 386% |
| Scenario7 | PG&E | OSB | Fuel Cell Elec (Small) | 169% | 247% | 336% | 79% | 83% | 96% | 745% | 1139% | 1509% | 199% | 251% | 293% |
| Scenario7 | SCE | OSB | Fuel Cell Elec (Small) | 174% | 255% | 347% | 73% | 72% | 82% | 765% | 1179% | 1557% | 235% | 308% | 364% |
| Scenario7 | SDG&E | OSB | Fuel Cell Elec (Small) | 170% | 250% | 341% | 75% | 75% | 85% | 733% | 1128% | 1493% | 218% | 289% | 341% |
| Scenario7 | PG&E | OSB | Internal Combustion Engine (Small) | 258% | 341% | 418% | 73% | 68% | 68% | 837% | 1288% | 1713% | 360% | 473% | 565% |
| Scenario7 | SCE | OSB | Internal Combustion Engine (Small) | 262% | 348% | 426% | 76% | 71% | 71% | 851% | 1315% | 1746% | 342% | 457% | 546% |
| Scenario7 | SDG&E | OSB | Internal Combustion Engine (Small) | 257% | 342% | 419% | 76% | 69% | 69% | 814% | 1257% | 1671% | 337% | 463% | 560% |
| Scenario7 | PG&E | OSB | Internal Combustion Engine (Large) | 311% | 412% | 505% | 77% | 74% | 76% | 1130% | 1738% | 2312% | 389% | 499% | 590% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario7 | SCE | OSB | Internal Combustion Engine (Large) | 316% | 420% | 515% | 79% | 75% | 76% | 1148% | 1775% | 2357% | 381% | 502% | 594% |
| Scenario7 | SDG&E | OSB | Internal Combustion Engine (Large) | 310% | 413% | 507% | 78% | 73% | 73% | 1098% | 1697% | 2256% | 378% | 511% | 613% |
| Scenario8 | PG&E | OSB | Fuel Cell CHP (Large) | 269% | 364% | 479% | 68% | 64% | 73% | 2410% | 3695% | 4902% | 371% | 453% | 520% |
| Scenario8 | SCE | OSB | Fuel Cell CHP (Large) | 275% | 375% | 492% | 70% | 66% | 74% | 2465% | 3801% | 5033% | 363% | 457% | 527% |
| Scenario8 | SDG&E | OSB | Fuel Cell CHP (Large) | 271% | 369% | 486% | 69% | 63% | 70% | 2360% | 3640% | 4824% | 362% | 472% | 551% |
| Scenario8 | PG&E | OSB | Fuel Cell CHP (Small) | 218% | 293% | 386% | 60% | 53% | 59% | 1808% | 2772% | 3678% | 372% | 459% | 530% |
| Scenario8 | SCE | OSB | Fuel Cell CHP (Small) | 223% | 302% | 396% | 63% | 56% | 63% | 1849% | 2852% | 3776% | 346% | 440% | 509% |
| Scenario8 | SDG&E | OSB | Fuel Cell CHP (Small) | 219% | 298% | 391% | 63% | 54% | 60% | 1771% | 2731% | 3620% | 345% | 452% | 530% |
| Scenario8 | PG&E | OSB | Fuel Cell Elec (Large) | 227% | 333% | 453% | 67% | 70% | 81% | 1677% | 2565% | 3397% | 318% | 390% | 448% |
| Scenario8 | SCE | OSB | Fuel Cell Elec (Large) | 233% | 345% | 467% | 72% | 74% | 86% | 1723% | 2653% | 3505% | 296% | 375% | 432% |
| Scenario8 | SDG&E | OSB | Fuel Cell Elec (Large) | 230% | 339% | 460% | 71% | 71% | 82% | 1649% | 2540% | 3361% | 295% | 385% | 450% |
| Scenario8 | PG&E | OSB | Fuel Cell Elec (Small) | 169% | 248% | 338% | 66% | 68% | 81% | 1677% | 2565% | 3397% | 234% | 286% | 328% |
| Scenario8 | SCE | OSB | Fuel Cell Elec (Small) | 174% | 256% | 349% | 60% | 57% | 67% | 1723% | 2653% | 3505% | 283% | 361% | 419% |
| Scenario8 | SDG&E | OSB | Fuel Cell Elec (Small) | 171% | 252% | 344% | 62% | 60% | 70% | 1649% | 2540% | 3361% | 261% | 337% | 390% |
| Scenario8 | PG&E | OSB | Internal Combustion Engine (Small) | 260% | 344% | 422% | 53% | 50% | 52% | 1884% | 2899% | 3855% | 474% | 594% | 691% |
| Scenario8 | SCE | OSB | Internal Combustion Engine (Small) | 265% | 351% | 430% | 56% | 53% | 54% | 1915% | 2960% | 3931% | 440% | 566% | 661% |
| Scenario8 | SDG&E | OSB | Internal Combustion Engine (Small) | 261% | 347% | 425% | 56% | 51% | 52% | 1831% | 2830% | 3761% | 438% | 581% | 687% |
| Scenario8 | PG&E | OSB | Internal Combustion Engine (Large) | 313% | 415% | 510% | 59% | 58% | 60% | 2511% | 3864% | 5138% | 479% | 593% | 686% |
| Scenario8 | SCE | OSB | Internal Combustion Engine (Large) | 319% | 424% | 520% | 61% | 59% | 61% | 2553% | 3946% | 5239% | 467% | 594% | 690% |
| Scenario8 | SDG&E | OSB | Internal Combustion Engine (Large) | 315% | 419% | 514% | 61% | 57% | 58% | 2441% | 3772% | 5014% | 466% | 613% | 720% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario9 | PG&E | OSB | Fuel Cell CHP (Large) | 297% | 402% | 524% | 88% | 87% | 96% | 2410% | 3695% | 4902% | 371% | 453% | 520% |
| Scenario9 | SCE | OSB | Fuel Cell CHP (Large) | 304% | 413% | 538% | 91% | 89% | 97% | 2465% | 3801% | 5033% | 363% | 457% | 527% |
| Scenario9 | SDG&E | OSB | Fuel Cell CHP (Large) | 299% | 407% | 531% | 90% | 86% | 93% | 2360% | 3640% | 4824% | 362% | 472% | 551% |
| Scenario9 | PG&E | OSB | Fuel Cell CHP (Small) | 254% | 342% | 444% | 91% | 88% | 94% | 1808% | 2772% | 3678% | 372% | 459% | 530% |
| Scenario9 | SCE | OSB | Fuel Cell CHP (Small) | 260% | 352% | 455% | 95% | 91% | 98% | 1849% | 2852% | 3776% | 346% | 440% | 509% |
| Scenario9 | SDG&E | OSB | Fuel Cell CHP (Small) | 256% | 347% | 449% | 94% | 89% | 95% | 1771% | 2731% | 3620% | 345% | 452% | 530% |
| Scenario9 | PG&E | OSB | Fuel Cell Elec (Large) | 257% | 371% | 495% | 93% | 99% | 111% | 1677% | 2565% | 3397% | 318% | 390% | 448% |
| Scenario9 | SCE | OSB | Fuel Cell Elec (Large) | 264% | 384% | 510% | 98% | 104% | 116% | 1723% | 2653% | 3505% | 296% | 375% | 432% |
| Scenario9 | SDG&E | OSB | Fuel Cell Elec (Large) | 259% | 377% | 502% | 98% | 101% | 112% | 1649% | 2540% | 3361% | 295% | 385% | 450% |
| Scenario9 | PG&E | OSB | Fuel Cell Elec (Small) | 200% | 288% | 382% | 101% | 108% | 121% | 1677% | 2565% | 3397% | 234% | 286% | 328% |
| Scenario9 | SCE | OSB | Fuel Cell Elec (Small) | 205% | 297% | 394% | 93% | 96% | 105% | 1723% | 2653% | 3505% | 283% | 361% | 419% |
| Scenario9 | SDG&E | OSB | Fuel Cell Elec (Small) | 202% | 292% | 389% | 96% | 99% | 109% | 1649% | 2540% | 3361% | 261% | 337% | 390% |
| Scenario9 | PG&E | OSB | Internal Combustion Engine (Small) | 325% | 430% | 527% | 98% | 94% | 94% | 1884% | 2899% | 3855% | 474% | 594% | 691% |
| Scenario9 | SCE | OSB | Internal Combustion Engine (Small) | 330% | 439% | 537% | 103% | 98% | 98% | 1915% | 2960% | 3931% | 440% | 566% | 661% |
| Scenario9 | SDG&E | OSB | Internal Combustion Engine (Small) | 325% | 433% | 530% | 102% | 96% | 95% | 1831% | 2830% | 3761% | 438% | 581% | 687% |
| Scenario9 | PG&E | OSB | Internal Combustion Engine (Large) | 360% | 479% | 587% | 88% | 86% | 88% | 2511% | 3864% | 5138% | 479% | 593% | 686% |
| Scenario9 | SCE | OSB | Internal Combustion Engine (Large) | 366% | 489% | 598% | 90% | 87% | 89% | 2553% | 3946% | 5239% | 467% | 594% | 690% |
| Scenario9 | SDG&E | OSB | Internal Combustion Engine (Large) | 361% | 483% | 592% | 90% | 85% | 85% | 2441% | 3772% | 5014% | 466% | 613% | 720% |
| Scenario10 | PG&E | OSB | Gas Turbine (Large) | 83% | 108% | 131% | 82% | 90% | 97% | 2563% | 3832% | 5021% | 76% | 88% | 98% |
| Scenario10 | SCE | OSB | Gas Turbine (Large) | 94% | 126% | 151% | 85% | 92% | 99% | 2889% | 4467% | 5802% | 81% | 100% | 112% |
| Scenario10 | SDG&E | OSB | Gas Turbine (Large) | 88% | 119% | 143% | 84% | 88% | 93% | 2645% | 4088% | 5340% | 78% | 100% | 113% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario10 | PG&E | OSB | Gas Turbine (Small) | 85% | 109% | 132% | 91% | 98% | 105% | 815% | 1219% | 1597% | 71% | 84% | 94% |
| Scenario10 | SCE | OSB | Gas Turbine (Small) | 95% | 127% | 152% | 95% | 100% | 106% | 919% | 1420% | 1845% | 77% | 96% | 107% |
| Scenario10 | SDG&E | OSB | Gas Turbine (Small) | 90% | 120% | 144% | 93% | 96% | 100% | 841% | 1300% | 1698% | 73% | 95% | 108% |
| Scenario10 | PG&E | OSB | Fuel Cell CHP (Large) | 66% | 85% | 107% | 79% | 81% | 90% | 463% | 691% | 904% | 68% | 81% | 92% |
| Scenario10 | SCE | OSB | Fuel Cell CHP (Large) | 74% | 98% | 123% | 82% | 82% | 91% | 520% | 803% | 1042% | 73% | 92% | 104% |
| Scenario10 | SDG&E | OSB | Fuel Cell CHP (Large) | 70% | 92% | 117% | 81% | 79% | 87% | 477% | 735% | 959% | 70% | 91% | 104% |
| Scenario10 | PG&E | OSB | Fuel Cell CHP (Small) | 56% | 71% | 90% | 69% | 69% | 75% | 347% | 518% | 678% | 68% | 82% | 93% |
| Scenario10 | SCE | OSB | Fuel Cell CHP (Small) | 62% | 82% | 103% | 74% | 73% | 80% | 390% | 602% | 782% | 70% | 89% | 101% |
| Scenario10 | SDG&E | OSB | Fuel Cell CHP (Small) | 59% | 78% | 98% | 74% | 70% | 76% | 358% | 552% | 720% | 67% | 87% | 101% |
| Scenario10 | PG&E | OSB | Fuel Cell Elec (Large) | 62% | 85% | 110% | 76% | 82% | 93% | 348% | 519% | 679% | 69% | 82% | 94% |
| Scenario10 | SCE | OSB | Fuel Cell Elec (Large) | 70% | 98% | 127% | 82% | 87% | 99% | 391% | 603% | 782% | 70% | 89% | 101% |
| Scenario10 | SDG&E | OSB | Fuel Cell Elec (Large) | 66% | 93% | 120% | 81% | 84% | 94% | 358% | 552% | 720% | 67% | 88% | 101% |
| Scenario10 | PG&E | OSB | Fuel Cell Elec (Small) | 51% | 68% | 88% | 79% | 86% | 98% | 348% | 519% | 679% | 51% | 60% | 69% |
| Scenario10 | SCE | OSB | Fuel Cell Elec (Small) | 56% | 79% | 101% | 70% | 72% | 81% | 391% | 603% | 782% | 67% | 86% | 98% |
| Scenario10 | SDG&E | OSB | Fuel Cell Elec (Small) | 53% | 74% | 96% | 73% | 76% | 85% | 358% | 552% | 720% | 59% | 77% | 88% |
| Scenario10 | PG&E | OSB | Microturbine (all Sizes) | 67% | 85% | 102% | 104% | 110% | 116% | 338% | 505% | 662% | 49% | 59% | 67% |
| Scenario10 | SCE | OSB | Microturbine (all Sizes) | 75% | 98% | 117% | 91% | 92% | 95% | 381% | 589% | 766% | 65% | 84% | 96% |
| Scenario10 | SDG&E | OSB | Microturbine (all Sizes) | 70% | 92% | 111% | 96% | 96% | 100% | 349% | 539% | 705% | 58% | 75% | 86% |
| Scenario10 | PG&E | OSB | Internal Combustion Engine (Small) | 74% | 94% | 113% | 89% | 92% | 97% | 339% | 507% | 664% | 67% | 80% | 92% |
| Scenario10 | SCE | OSB | Internal Combustion Engine (Small) | 82% | 109% | 130% | 96% | 99% | 103% | 382% | 591% | 768% | 68% | 87% | 99% |
| Scenario10 | SDG&E | OSB | Internal Combustion Engine (Small) | 78% | 103% | 123% | 95% | 95% | 98% | 350% | 541% | 706% | 65% | 86% | 99% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario10 | PG&E | OSB | Internal Combustion Engine (Large) | 81% | 105% | 126% | 96% | 102% | 108% | 452% | 675% | 885% | 67% | 79% | 90% |
| Scenario10 | SCE | OSB | Internal Combustion Engine (Large) | 91% | 122% | 145% | 100% | 104% | 109% | 509% | 788% | 1023% | 72% | 90% | 102% |
| Scenario10 | SDG&E | OSB | Internal Combustion Engine (Large) | 86% | 114% | 137% | 98% | 100% | 104% | 466% | 721% | 942% | 68% | 89% | 102% |
| Scenario11 | PG&E | DBG | Gas Turbine (Large) | 31% | 42% | 52% | 31% | 35% | 39% | 975% | 1426% | 1849% | 77% | 88% | 98% |
| Scenario11 | SCE | DBG | Gas Turbine (Large) | 32% | 45% | 56% | 30% | 33% | 37% | 404% | 576% | 721% | 85% | 100% | 110% |
| Scenario11 | SDG&E | DBG | Gas Turbine (Large) | 29% | 41% | 51% | 29% | 31% | 33% | 305% | 421% | 521% | 84% | 100% | 110% |
| Scenario11 | PG&E | DBG | Gas Turbine (Small) | 31% | 43% | 53% | 34% | 38% | 43% | 554% | 809% | 1049% | 73% | 84% | 94% |
| Scenario11 | SCE | DBG | Gas Turbine (Small) | 32% | 44% | 55% | 32% | 35% | 39% | 279% | 389% | 482% | 82% | 96% | 106% |
| Scenario11 | SDG&E | DBG | Gas Turbine (Small) | 30% | 42% | 52% | 32% | 33% | 36% | 260% | 359% | 445% | 80% | 96% | 106% |
| Scenario11 | PG&E | DBG | Fuel Cell CHP (Large) | 35% | 46% | 58% | 43% | 44% | 49% | 387% | 568% | 736% | 69% | 82% | 92% |
| Scenario11 | SCE | DBG | Fuel Cell CHP (Large) | 35% | 48% | 61% | 41% | 41% | 45% | 260% | 368% | 459% | 78% | 93% | 103% |
| Scenario11 | SDG&E | DBG | Fuel Cell CHP (Large) | 33% | 46% | 58% | 40% | 39% | 43% | 242% | 339% | 423% | 76% | 93% | 104% |
| Scenario11 | PG&E | DBG | Fuel Cell CHP (Small) | 32% | 42% | 54% | 41% | 41% | 45% | 306% | 449% | 583% | 70% | 83% | 94% |
| Scenario11 | SCE | DBG | Fuel Cell CHP (Small) | 33% | 45% | 56% | 40% | 40% | 44% | 231% | 326% | 407% | 75% | 91% | 101% |
| Scenario11 | SDG&E | DBG | Fuel Cell CHP (Small) | 31% | 42% | 53% | 40% | 38% | 41% | 215% | 301% | 376% | 73% | 89% | 101% |
| Scenario11 | PG&E | DBG | Fuel Cell Elec (Large) | 39% | 53% | 69% | 49% | 51% | 58% | 314% | 462% | 600% | 70% | 83% | 94% |
| Scenario11 | SCE | DBG | Fuel Cell Elec (Large) | 40% | 56% | 72% | 49% | 50% | 56% | 248% | 355% | 446% | 74% | 90% | 101% |
| Scenario11 | SDG&E | DBG | Fuel Cell Elec (Large) | 38% | 53% | 68% | 48% | 48% | 53% | 230% | 327% | 412% | 72% | 89% | 101% |
| Scenario11 | PG&E | DBG | Fuel Cell Elec (Small) | 35% | 47% | 60% | 55% | 59% | 67% | 314% | 462% | 600% | 52% | 61% | 69% |
| Scenario11 | SCE | DBG | Fuel Cell Elec (Small) | 36% | 50% | 63% | 45% | 46% | 51% | 248% | 355% | 446% | 72% | 87% | 98% |
| Scenario11 | SDG&E | DBG | Fuel Cell Elec (Small) | 34% | 47% | 60% | 48% | 48% | 53% | 230% | 327% | 412% | 65% | 79% | 89% |
| Scenario11 | PG&E | DBG | Microturbine (all Sizes) | 22% | 29% | 37% | 34% | 38% | 42% | 274% | 396% | 511% | 52% | 61% | 68% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario11 | SCE | DBG | Microturbine (all Sizes) | 22% | 30% | 37% | 27% | 28% | 31% | 186% | 250% | 304% | 75% | 88% | 97% |
| Scenario11 | SDG&E | DBG | Microturbine (all Sizes) | 21% | 29% | 35% | 28% | 30% | 32% | 175% | 233% | 283% | 69% | 81% | 89% |
| Scenario11 | PG&E | DBG | Internal Combustion Engine (Small) | 27% | 37% | 45% | 33% | 36% | 39% | 286% | 417% | 540% | 69% | 81% | 92% |
| Scenario11 | SCE | DBG | Internal Combustion Engine (Small) | 27% | 38% | 47% | 32% | 34% | 37% | 202% | 278% | 342% | 76% | 90% | 99% |
| Scenario11 | SDG&E | DBG | Internal Combustion Engine (Small) | 26% | 36% | 44% | 32% | 33% | 35% | 190% | 258% | 317% | 74% | 89% | 99% |
| Scenario11 | PG&E | DBG | Internal Combustion Engine (Large) | 27% | 37% | 47% | 33% | 36% | 40% | 356% | 518% | 670% | 68% | 80% | 90% |
| Scenario11 | SCE | DBG | Internal Combustion Engine (Large) | 28% | 39% | 48% | 31% | 33% | 36% | 223% | 306% | 376% | 79% | 93% | 102% |
| Scenario11 | SDG&E | DBG | Internal Combustion Engine (Large) | 26% | 36% | 45% | 30% | 32% | 34% | 208% | 283% | 348% | 77% | 92% | 102% |
| Scenario12 | PG&E | OSB | Fuel Cell CHP (Large) | 331% | 451% | 583% | 78% | 79% | 88% | 2410% | 3695% | 4902% | 371% | 453% | 520% |
| Scenario12 | SCE | OSB | Fuel Cell CHP (Large) | 338% | 464% | 599% | 81% | 81% | 90% | 2465% | 3801% | 5033% | 363% | 457% | 527% |
| Scenario12 | SDG&E | OSB | Fuel Cell CHP (Large) | 333% | 457% | 591% | 80% | 78% | 85% | 2360% | 3640% | 4824% | 362% | 472% | 551% |
| Scenario12 | PG&E | OSB | Fuel Cell CHP (Small) | 277% | 377% | 487% | 69% | 68% | 75% | 1808% | 2772% | 3678% | 372% | 459% | 530% |
| Scenario12 | SCE | OSB | Fuel Cell CHP (Small) | 283% | 388% | 499% | 74% | 72% | 79% | 1849% | 2852% | 3776% | 346% | 440% | 509% |
| Scenario12 | SDG&E | OSB | Fuel Cell CHP (Small) | 279% | 382% | 492% | 73% | 69% | 75% | 1771% | 2731% | 3620% | 345% | 452% | 530% |
| Scenario12 | PG&E | OSB | Fuel Cell Elec (Large) | 274% | 396% | 522% | 77% | 83% | 94% | 1677% | 2565% | 3397% | 318% | 390% | 448% |
| Scenario12 | SCE | OSB | Fuel Cell Elec (Large) | 281% | 409% | 539% | 82% | 88% | 99% | 1723% | 2653% | 3505% | 296% | 375% | 432% |
| Scenario12 | SDG&E | OSB | Fuel Cell Elec (Large) | 276% | 402% | 530% | 81% | 85% | 95% | 1649% | 2540% | 3361% | 295% | 385% | 450% |
| Scenario12 | PG&E | OSB | Fuel Cell Elec (Small) | 220% | 317% | 415% | 80% | 87% | 99% | 1677% | 2565% | 3397% | 234% | 286% | 328% |
| Scenario12 | SCE | OSB | Fuel Cell Elec (Small) | 226% | 327% | 428% | 70% | 73% | 81% | 1723% | 2653% | 3505% | 283% | 361% | 419% |
| Scenario12 | SDG&E | OSB | Fuel Cell Elec (Small) | 222% | 322% | 422% | 74% | 77% | 86% | 1649% | 2540% | 3361% | 261% | 337% | 390% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario12 | PG&E | OSB | Internal Combustion Engine (Small) | 440% | 588% | 722% | 84% | 84% | 87% | 1884% | 2899% | 3855% | 474% | 594% | 691% |
| Scenario12 | SCE | OSB | Internal Combustion Engine (Small) | 447% | 600% | 737% | 90% | 89% | 92% | 1915% | 2960% | 3931% | 440% | 566% | 661% |
| Scenario12 | SDG&E | OSB | Internal Combustion Engine (Small) | 440% | 591% | 726% | 89% | 86% | 88% | 1831% | 2830% | 3761% | 438% | 581% | 687% |
| Scenario12 | PG&E | OSB | Internal Combustion Engine (Large) | 495% | 664% | 815% | 89% | 92% | 96% | 2511% | 3864% | 5138% | 479% | 593% | 686% |
| Scenario12 | SCE | OSB | Internal Combustion Engine (Large) | 504% | 678% | 831% | 92% | 93% | 97% | 2553% | 3946% | 5239% | 467% | 594% | 690% |
| Scenario12 | SDG&E | OSB | Internal Combustion Engine (Large) | 496% | 668% | 821% | 91% | 90% | 93% | 2441% | 3772% | 5014% | 466% | 613% | 720% |
| Scenario13 | SCE | OSB | Fuel Cell CHP (Large) | 309% | 420% | 545% | 93% | 92% | 100% | 2465% | 3801% | 5033% | 363% | 457% | 527% |
| Scenario13 | SDG&E | OSB | Fuel Cell CHP (Large) | 305% | 414% | 538% | 93% | 89% | 96% | 2360% | 3640% | 4824% | 362% | 472% | 551% |
| Scenario13 | PG&E | OSB | Fuel Cell CHP (Small) | 269% | 360% | 464% | 99% | 97% | 103% | 1808% | 2772% | 3678% | 372% | 459% | 530% |
| Scenario13 | SCE | OSB | Fuel Cell CHP (Small) | 275% | 370% | 476% | 104% | 101% | 107% | 1849% | 2852% | 3776% | 346% | 440% | 509% |
| Scenario13 | SDG&E | OSB | Fuel Cell CHP (Small) | 271% | 365% | 469% | 103% | 98% | 104% | 1771% | 2731% | 3620% | 345% | 452% | 530% |
| Scenario13 | PG&E | OSB | Fuel Cell Elec (Large) | 264% | 380% | 504% | 97% | 104% | 115% | 1677% | 2565% | 3397% | 318% | 390% | 448% |
| Scenario13 | SCE | OSB | Fuel Cell Elec (Large) | 271% | 393% | 520% | 103% | 109% | 121% | 1723% | 2653% | 3505% | 296% | 375% | 432% |
| Scenario13 | SDG&E | OSB | Fuel Cell Elec (Large) | 267% | 386% | 512% | 102% | 106% | 116% | 1649% | 2540% | 3361% | 295% | 385% | 450% |
| Scenario13 | PG&E | OSB | Fuel Cell Elec (Small) | 221% | 288% | 343% | 115% | 115% | 115% | 1677% | 2565% | 3397% | 234% | 286% | 328% |
| Scenario13 | SCE | OSB | Fuel Cell Elec (Small) | 226% | 298% | 354% | 107% | 103% | 101% | 1723% | 2653% | 3505% | 283% | 361% | 419% |
| Scenario13 | SDG&E | OSB | Fuel Cell Elec (Small) | 223% | 293% | 349% | 110% | 106% | 104% | 1649% | 2540% | 3361% | 261% | 337% | 390% |
| Scenario13 | PG&E | OSB | Internal Combustion Engine (Small) | 347% | 458% | 559% | 110% | 106% | 105% | 1884% | 2899% | 3855% | 474% | 594% | 691% |
| Scenario13 | SCE | OSB | Internal Combustion Engine (Small) | 353% | 467% | 570% | 115% | 110% | 109% | 1915% | 2960% | 3931% | 440% | 566% | 661% |
| Scenario13 | SDG&E | OSB | Internal Combustion Engine (Small) | 348% | 461% | 563% | 114% | 107% | 106% | 1831% | 2830% | 3761% | 438% | 581% | 687% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario13 | PG&E | OSB | Internal Combustion Engine (Large) | 369% | 490% | 600% | 92% | 90% | 92% | 2511% | 3864% | 5138% | 479% | 593% | 686% |
| Scenario13 | SCE | OSB | Internal Combustion Engine (Large) | 375% | 500% | 611% | 94% | 91% | 93% | 2553% | 3946% | 5239% | 467% | 594% | 690% |
| Scenario13 | SDG&E | OSB | Internal Combustion Engine (Large) | 370% | 494% | 604% | 94% | 89% | 89% | 2441% | 3772% | 5014% | 466% | 613% | 720% |
| Scenario14 | PG&E | OSB | Fuel Cell CHP (Large) | 300% | 405% | 527% | 115% | 114% | 122% | 1071% | 1642% | 2178% | 311% | 393% | 459% |
| Scenario14 | SCE | OSB | Fuel Cell CHP (Large) | 307% | 416% | 540% | 117% | 116% | 124% | 1095% | 1689% | 2236% | 306% | 397% | 466% |
| Scenario14 | SDG&E | OSB | Fuel Cell CHP (Large) | 301% | 409% | 531% | 116% | 113% | 119% | 1049% | 1617% | 2143% | 304% | 406% | 482% |
| Scenario14 | PG&E | OSB | Fuel Cell CHP (Small) | 267% | 357% | 450% | 125% | 122% | 125% | 803% | 1232% | 1634% | 296% | 381% | 449% |
| Scenario14 | SCE | OSB | Fuel Cell CHP (Small) | 273% | 367% | 462% | 129% | 126% | 129% | 822% | 1267% | 1678% | 280% | 368% | 435% |
| Scenario14 | SDG&E | OSB | Fuel Cell CHP (Small) | 267% | 360% | 454% | 128% | 124% | 126% | 787% | 1213% | 1608% | 277% | 375% | 448% |
| Scenario14 | PG&E | OSB | Fuel Cell Elec (Large) | 262% | 365% | 435% | 126% | 130% | 127% | 745% | 1139% | 1509% | 257% | 328% | 385% |
| Scenario14 | SCE | OSB | Fuel Cell Elec (Large) | 269% | 377% | 449% | 131% | 135% | 132% | 765% | 1179% | 1557% | 244% | 318% | 374% |
| Scenario14 | SDG&E | OSB | Fuel Cell Elec (Large) | 263% | 369% | 440% | 130% | 132% | 128% | 733% | 1128% | 1493% | 241% | 324% | 386% |
| Scenario14 | PG&E | OSB | Fuel Cell Elec (Small) | 220% | 254% | 305% | 138% | 121% | 120% | 745% | 1139% | 1509% | 199% | 251% | 293% |
| Scenario14 | SCE | OSB | Fuel Cell Elec (Small) | 225% | 262% | 315% | 129% | 111% | 108% | 765% | 1179% | 1557% | 235% | 308% | 364% |
| Scenario14 | SDG&E | OSB | Fuel Cell Elec (Small) | 221% | 257% | 309% | 133% | 113% | 111% | 733% | 1128% | 1493% | 218% | 289% | 341% |
| Scenario14 | PG&E | OSB | Internal Combustion Engine (Small) | 316% | 451% | 551% | 132% | 135% | 132% | 837% | 1288% | 1713% | 360% | 473% | 565% |
| Scenario14 | SCE | OSB | Internal Combustion Engine (Small) | 321% | 460% | 562% | 136% | 139% | 136% | 851% | 1315% | 1746% | 342% | 457% | 546% |
| Scenario14 | SDG&E | OSB | Internal Combustion Engine (Small) | 315% | 451% | 551% | 135% | 136% | 133% | 814% | 1257% | 1671% | 337% | 463% | 560% |
| Scenario14 | PG&E | OSB | Internal Combustion Engine (Large) | 365% | 484% | 593% | 120% | 116% | 115% | 1130% | 1738% | 2312% | 389% | 499% | 590% |
| Scenario14 | SCE | OSB | Internal Combustion Engine (Large) | 371% | 494% | 604% | 122% | 117% | 116% | 1148% | 1775% | 2357% | 381% | 502% | 594% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario14 | SDG&E | OSB | Internal Combustion Engine (Large) | 364% | 485% | 594% | 121% | 114% | 113% | 1098% | 1697% | 2256% | 378% | 511% | 613% |
| Scenario15 | PG&E | OSB | Gas Turbine (Large) | 84% | 109% | 132% | 97% | 105% | 111% | 1569% | 2345% | 3073% | 74% | 87% | 97% |
| Scenario15 | SCE | OSB | Gas Turbine (Large) | 95% | 127% | 152% | 101% | 107% | 112% | 1768% | 2734% | 3551% | 80% | 99% | 110% |
| Scenario15 | SDG&E | OSB | Gas Turbine (Large) | 89% | 120% | 144% | 100% | 102% | 107% | 1619% | 2503% | 3269% | 77% | 98% | 111% |
| Scenario15 | PG&E | OSB | Gas Turbine (Small) | 86% | 111% | 133% | 112% | 118% | 123% | 498% | 745% | 976% | 68% | 80% | 91% |
| Scenario15 | SCE | OSB | Gas Turbine (Small) | 97% | 129% | 154% | 116% | 120% | 125% | 562% | 868% | 1128% | 73% | 92% | 103% |
| Scenario15 | SDG&E | OSB | Gas Turbine (Small) | 91% | 121% | 145% | 114% | 115% | 119% | 514% | 795% | 1038% | 70% | 90% | 104% |
| Scenario15 | PG&E | OSB | Fuel Cell CHP (Large) | 66% | 83% | 105% | 105% | 106% | 115% | 195% | 291% | 381% | 57% | 70% | 80% |
| Scenario15 | SCE | OSB | Fuel Cell CHP (Large) | 73% | 96% | 120% | 108% | 108% | 116% | 219% | 339% | 439% | 61% | 80% | 91% |
| Scenario15 | SDG&E | OSB | Fuel Cell CHP (Large) | 69% | 90% | 114% | 107% | 105% | 111% | 201% | 310% | 404% | 58% | 78% | 91% |
| Scenario15 | PG&E | OSB | Fuel Cell CHP (Small) | 57% | 71% | 89% | 97% | 96% | 102% | 146% | 219% | 286% | 54% | 68% | 79% |
| Scenario15 | SCE | OSB | Fuel Cell CHP (Small) | 63% | 82% | 101% | 102% | 100% | 106% | 165% | 254% | 330% | 56% | 74% | 86% |
| Scenario15 | SDG&E | OSB | Fuel Cell CHP (Small) | 59% | 77% | 96% | 101% | 97% | 102% | 151% | 232% | 303% | 53% | 72% | 85% |
| Scenario15 | PG&E | OSB | Fuel Cell Elec (Large) | 65% | 88% | 113% | 107% | 115% | 126% | 162% | 242% | 317% | 56% | 70% | 81% |
| Scenario15 | SCE | OSB | Fuel Cell Elec (Large) | 73% | 101% | 129% | 113% | 120% | 132% | 183% | 282% | 365% | 58% | 76% | 88% |
| Scenario15 | SDG&E | OSB | Fuel Cell Elec (Large) | 68% | 95% | 122% | 112% | 117% | 127% | 167% | 258% | 337% | 55% | 74% | 87% |
| Scenario15 | PG&E | OSB | Fuel Cell Elec (Small) | 53% | 71% | 90% | 104% | 113% | 124% | 162% | 242% | 317% | 43% | 53% | 61% |
| Scenario15 | SCE | OSB | Fuel Cell Elec (Small) | 59% | 81% | 103% | 95% | 99% | 107% | 183% | 282% | 365% | 56% | 74% | 85% |
| Scenario15 | SDG&E | OSB | Fuel Cell Elec (Small) | 56% | 77% | 98% | 99% | 102% | 111% | 167% | 258% | 337% | 50% | 66% | 77% |
| Scenario15 | PG&E | OSB | Microturbine (all Sizes) | 62% | 77% | 91% | 134% | 135% | 137% | 122% | 182% | 239% | 39% | 49% | 57% |
| Scenario15 | SCE | OSB | Microturbine (all Sizes) | 69% | 88% | 104% | 123% | 119% | 120% | 138% | 213% | 277% | 50% | 67% | 78% |
| Scenario15 | SDG&E | OSB | Microturbine (all Sizes) | 65% | 83% | 98% | 127% | 123% | 124% | 125% | 194% | 253% | 45% | 60% | 70% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario15 | PG&E | OSB | Internal Combustion Engine (Small) | 66% | 81% | 96% | 126% | 124% | 124% | 110% | 165% | 216% | 47% | 60% | 71% |
| Scenario15 | SCE | OSB | Internal Combustion Engine (Small) | 73% | 93% | 110% | 132% | 129% | 129% | 124% | 192% | 250% | 50% | 67% | 78% |
| Scenario15 | SDG&E | OSB | Internal Combustion Engine (Small) | 68% | 87% | 103% | 132% | 126% | 125% | 113% | 175% | 228% | 47% | 64% | 76% |
| Scenario15 | PG&E | OSB | Internal Combustion Engine (Large) | 72% | 90% | 107% | 127% | 127% | 128% | 149% | 222% | 291% | 51% | 64% | 74% |
| Scenario15 | SCE | OSB | Internal Combustion Engine (Large) | 80% | 104% | 123% | 130% | 128% | 130% | 168% | 259% | 337% | 56% | 73% | 85% |
| Scenario15 | SDG&E | OSB | Internal Combustion Engine (Large) | 75% | 97% | 116% | 129% | 125% | 125% | 153% | 236% | 308% | 53% | 71% | 84% |
| Scenario16 | PG&E | DBG | Gas Turbine (Large) | 31% | 42% | 53% | 36% | 40% | 44% | 796% | 1164% | 1509% | 76% | 87% | 97% |
| Scenario16 | SCE | DBG | Gas Turbine (Large) | 32% | 45% | 56% | 35% | 38% | 42% | 378% | 539% | 675% | 84% | 99% | 109% |
| Scenario16 | SDG&E | DBG | Gas Turbine (Large) | 29% | 41% | 51% | 34% | 35% | 38% | 290% | 400% | 496% | 82% | 98% | 109% |
| Scenario16 | PG&E | DBG | Gas Turbine (Small) | 32% | 43% | 54% | 42% | 46% | 50% | 394% | 577% | 748% | 69% | 81% | 91% |
| Scenario16 | SCE | DBG | Gas Turbine (Small) | 32% | 45% | 55% | 39% | 42% | 45% | 245% | 342% | 423% | 79% | 93% | 103% |
| Scenario16 | SDG&E | DBG | Gas Turbine (Small) | 30% | 42% | 52% | 39% | 40% | 43% | 228% | 316% | 391% | 77% | 92% | 103% |
| Scenario16 | PG&E | DBG | Fuel Cell CHP (Large) | 35% | 46% | 59% | 59% | 59% | 64% | 186% | 272% | 353% | 58% | 71% | 81% |
| Scenario16 | SCE | DBG | Fuel Cell CHP (Large) | 36% | 49% | 61% | 55% | 54% | 58% | 171% | 242% | 301% | 68% | 82% | 93% |
| Scenario16 | SDG&E | DBG | Fuel Cell CHP (Large) | 34% | 46% | 57% | 55% | 53% | 56% | 159% | 224% | 279% | 65% | 81% | 92% |
| Scenario16 | PG&E | DBG | Fuel Cell CHP (Small) | 33% | 43% | 54% | 58% | 58% | 61% | 143% | 209% | 272% | 55% | 68% | 79% |
| Scenario16 | SCE | DBG | Fuel Cell CHP (Small) | 34% | 45% | 56% | 57% | 55% | 59% | 143% | 202% | 252% | 63% | 77% | 87% |
| Scenario16 | SDG&E | DBG | Fuel Cell CHP (Small) | 32% | 43% | 53% | 56% | 54% | 56% | 133% | 187% | 233% | 60% | 76% | 86% |
| Scenario16 | PG&E | DBG | Fuel Cell Elec (Large) | 41% | 55% | 70% | 69% | 72% | 78% | 158% | 233% | 302% | 57% | 70% | 81% |
| Scenario16 | SCE | DBG | Fuel Cell Elec (Large) | 42% | 58% | 73% | 67% | 69% | 74% | 157% | 225% | 283% | 63% | 79% | 89% |
| Scenario16 | SDG&E | DBG | Fuel Cell Elec (Large) | 39% | 55% | 69% | 66% | 67% | 71% | 146% | 208% | 262% | 61% | 77% | 88% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario16 | PG&E | DBG | Fuel Cell Elec (Small) | 36% | 48% | 61% | 72% | 77% | 84% | 158% | 233% | 302% | 45% | 54% | 62% |
| Scenario16 | SCE | DBG | Fuel Cell Elec (Small) | 37% | 51% | 65% | 61% | 62% | 67% | 157% | 225% | 283% | 61% | 76% | 87% |
| Scenario16 | SDG&E | DBG | Fuel Cell Elec (Small) | 35% | 49% | 61% | 64% | 64% | 69% | 146% | 208% | 262% | 56% | 70% | 79% |
| Scenario16 | PG&E | DBG | Microturbine (all Sizes) | 23% | 30% | 36% | 49% | 51% | 54% | 119% | 173% | 223% | 42% | 51% | 58% |
| Scenario16 | SCE | DBG | Microturbine (all Sizes) | 23% | 30% | 37% | 41% | 41% | 42% | 121% | 162% | 197% | 62% | 74% | 82% |
| Scenario16 | SDG&E | DBG | Microturbine (all Sizes) | 21% | 29% | 35% | 42% | 42% | 44% | 114% | 151% | 184% | 57% | 68% | 76% |
| Scenario16 | PG&E | DBG | Internal Combustion Engine (Small) | 28% | 36% | 44% | 53% | 54% | 56% | 110% | 160% | 206% | 50% | 62% | 72% |
| Scenario16 | SCE | DBG | Internal Combustion Engine (Small) | 28% | 37% | 45% | 51% | 51% | 52% | 116% | 159% | 195% | 59% | 72% | 81% |
| Scenario16 | SDG&E | DBG | Internal Combustion Engine (Small) | 26% | 35% | 43% | 50% | 49% | 51% | 108% | 148% | 181% | 57% | 71% | 80% |
| Scenario16 | PG&E | DBG | Internal Combustion Engine (Large) | 28% | 37% | 45% | 49% | 51% | 53% | 144% | 209% | 271% | 53% | 65% | 75% |
| Scenario16 | SCE | DBG | Internal Combustion Engine (Large) | 28% | 38% | 46% | 45% | 46% | 48% | 138% | 190% | 234% | 65% | 78% | 87% |
| Scenario16 | SDG&E | DBG | Internal Combustion Engine (Large) | 26% | 36% | 44% | 45% | 45% | 46% | 130% | 176% | 217% | 63% | 77% | 87% |
| Scenario17 | PG&E | DBG | Gas Turbine (Large) | 38% | 51% | 63% | 38% | 43% | 48% | 982% | 1435% | 1861% | 77% | 88% | 98% |
| Scenario17 | SCE | DBG | Gas Turbine (Large) | 39% | 54% | 66% | 36% | 40% | 44% | 405% | 577% | 723% | 85% | 100% | 110% |
| Scenario17 | SDG&E | DBG | Gas Turbine (Large) | 35% | 49% | 60% | 34% | 36% | 40% | 305% | 421% | 522% | 84% | 100% | 110% |
| Scenario17 | PG&E | DBG | Gas Turbine (Small) | 39% | 52% | 65% | 42% | 47% | 52% | 560% | 819% | 1061% | 73% | 84% | 94% |
| Scenario17 | SCE | DBG | Gas Turbine (Small) | 38% | 53% | 65% | 39% | 42% | 46% | 281% | 391% | 484% | 82% | 96% | 106% |
| Scenario17 | SDG&E | DBG | Gas Turbine (Small) | 36% | 50% | 61% | 38% | 40% | 43% | 261% | 360% | 446% | 80% | 96% | 107% |
| Scenario17 | PG&E | DBG | Fuel Cell CHP (Large) | 41% | 54% | 68% | 51% | 52% | 58% | 371% | 545% | 706% | 69% | 81% | 91% |
| Scenario17 | SCE | DBG | Fuel Cell CHP (Large) | 41% | 55% | 69% | 48% | 47% | 52% | 255% | 360% | 450% | 78% | 93% | 103% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario17 | SDG&E | DBG | Fuel Cell CHP (Large) | 39% | 52% | 66% | 47% | 45% | 49% | 237% | 332% | 415% | 75% | 92% | 103% |
| Scenario17 | PG&E | DBG | Fuel Cell CHP (Small) | 38% | 49% | 61% | 48% | 47% | 52% | 293% | 430% | 558% | 69% | 82% | 93% |
| Scenario17 | SCE | DBG | Fuel Cell CHP (Small) | 38% | 51% | 63% | 47% | 46% | 50% | 225% | 319% | 398% | 75% | 90% | 100% |
| Scenario17 | SDG&E | DBG | Fuel Cell CHP (Small) | 36% | 48% | 60% | 47% | 44% | 47% | 210% | 294% | 367% | 72% | 89% | 100% |
| Scenario17 | PG&E | DBG | Fuel Cell Elec (Large) | 47% | 63% | 81% | 57% | 60% | 68% | 328% | 482% | 627% | 70% | 83% | 94% |
| Scenario17 | SCE | DBG | Fuel Cell Elec (Large) | 47% | 66% | 83% | 56% | 58% | 64% | 254% | 364% | 458% | 75% | 91% | 101% |
| Scenario17 | SDG&E | DBG | Fuel Cell Elec (Large) | 44% | 62% | 79% | 55% | 55% | 61% | 236% | 336% | 422% | 73% | 90% | 101% |
| Scenario17 | PG&E | DBG | Fuel Cell Elec (Small) | 40% | 54% | 69% | 63% | 68% | 77% | 328% | 482% | 627% | 52% | 62% | 69% |
| Scenario17 | SCE | DBG | Fuel Cell Elec (Small) | 41% | 57% | 72% | 51% | 52% | 57% | 254% | 364% | 458% | 72% | 88% | 98% |
| Scenario17 | SDG&E | DBG | Fuel Cell Elec (Small) | 39% | 54% | 68% | 54% | 54% | 60% | 236% | 336% | 422% | 65% | 80% | 89% |
| Scenario17 | SCE | DBG | Microturbine (all Sizes) | 26% | 35% | 43% | 34% | 34% | 37% | 174% | 233% | 284% | 73% | 86% | 94% |
| Scenario17 | SDG&E | DBG | Microturbine (all Sizes) | 24% | 33% | 40% | 35% | 36% | 38% | 163% | 217% | 264% | 67% | 79% | 87% |
| Scenario17 | PG&E | DBG | Internal Combustion Engine (Small) | 32% | 42% | 51% | 43% | 44% | 47% | 223% | 325% | 420% | 64% | 77% | 88% |
| Scenario17 | SCE | DBG | Internal Combustion Engine (Small) | 31% | 42% | 52% | 40% | 41% | 44% | 179% | 246% | 302% | 73% | 86% | 96% |
| Scenario17 | SDG&E | DBG | Internal Combustion Engine (Small) | 30% | 40% | 49% | 40% | 40% | 42% | 167% | 227% | 280% | 70% | 85% | 95% |
| Scenario17 | PG&E | DBG | Internal Combustion Engine (Large) | 33% | 43% | 53% | 42% | 44% | 48% | 281% | 409% | 530% | 65% | 77% | 87% |
| Scenario17 | SCE | DBG | Internal Combustion Engine (Large) | 32% | 44% | 53% | 38% | 40% | 42% | 201% | 276% | 339% | 76% | 90% | 99% |
| Scenario17 | SDG&E | DBG | Internal Combustion Engine (Large) | 30% | 41% | 50% | 38% | 38% | 40% | 187% | 255% | 314% | 74% | 89% | 99% |
| Scenario18 | PG&E | DBG | Gas Turbine (Large) | 49% | 64% | 78% | 48% | 53% | 59% | 982% | 1435% | 1861% | 77% | 88% | 98% |
| Scenario18 | SCE | DBG | Gas Turbine (Large) | 48% | 66% | 80% | 45% | 48% | 53% | 405% | 577% | 723% | 85% | 100% | 110% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario18 | SDG&E | DBG | Gas Turbine (Large) | 44% | 59% | 72% | 42% | 44% | 47% | 305% | 421% | 522% | 84% | 100% | 110% |
| Scenario18 | PG&E | DBG | Gas Turbine (Small) | 50% | 65% | 80% | 54% | 59% | 64% | 560% | 819% | 1061% | 73% | 84% | 94% |
| Scenario18 | SCE | DBG | Gas Turbine (Small) | 47% | 64% | 78% | 48% | 51% | 55% | 281% | 391% | 484% | 82% | 96% | 106% |
| Scenario18 | SDG&E | DBG | Gas Turbine (Small) | 45% | 61% | 74% | 47% | 48% | 51% | 261% | 360% | 446% | 80% | 96% | 107% |
| Scenario18 | PG&E | DBG | Fuel Cell CHP (Large) | 50% | 64% | 81% | 62% | 62% | 69% | 371% | 545% | 706% | 69% | 81% | 91% |
| Scenario18 | SCE | DBG | Fuel Cell CHP (Large) | 49% | 65% | 81% | 56% | 55% | 61% | 255% | 360% | 450% | 78% | 93% | 103% |
| Scenario18 | SDG&E | DBG | Fuel Cell CHP (Large) | 46% | 61% | 77% | 56% | 53% | 57% | 237% | 332% | 415% | 75% | 92% | 103% |
| Scenario18 | PG&E | DBG | Fuel Cell CHP (Small) | 45% | 57% | 72% | 57% | 56% | 61% | 293% | 430% | 558% | 69% | 82% | 93% |
| Scenario18 | SCE | DBG | Fuel Cell CHP (Small) | 44% | 59% | 73% | 54% | 53% | 57% | 225% | 319% | 398% | 75% | 90% | 100% |
| Scenario18 | SDG&E | DBG | Fuel Cell CHP (Small) | 42% | 55% | 69% | 54% | 51% | 54% | 210% | 294% | 367% | 72% | 89% | 100% |
| Scenario18 | PG&E | DBG | Fuel Cell Elec (Large) | 56% | 75% | 96% | 67% | 71% | 80% | 328% | 482% | 627% | 70% | 83% | 94% |
| Scenario18 | SCE | DBG | Fuel Cell Elec (Large) | 55% | 76% | 97% | 65% | 67% | 74% | 254% | 364% | 458% | 75% | 91% | 101% |
| Scenario18 | SDG&E | DBG | Fuel Cell Elec (Large) | 52% | 72% | 91% | 64% | 64% | 71% | 236% | 336% | 422% | 73% | 90% | 101% |
| Scenario18 | PG&E | DBG | Fuel Cell Elec (Small) | 47% | 62% | 80% | 72% | 79% | 88% | 328% | 482% | 627% | 52% | 62% | 69% |
| Scenario18 | SCE | DBG | Fuel Cell Elec (Small) | 47% | 65% | 82% | 58% | 59% | 65% | 254% | 364% | 458% | 72% | 88% | 98% |
| Scenario18 | SDG&E | DBG | Fuel Cell Elec (Small) | 45% | 61% | 77% | 61% | 62% | 68% | 236% | 336% | 422% | 65% | 80% | 89% |
| Scenario18 | PG&E | DBG | Microturbine (all Sizes) | 34% | 43% | 52% | 55% | 58% | 62% | 234% | 339% | 438% | 50% | 59% | 67% |
| Scenario18 | SCE | DBG | Microturbine (all Sizes) | 32% | 42% | 51% | 41% | 42% | 44% | 174% | 233% | 284% | 73% | 86% | 94% |
| Scenario18 | SDG&E | DBG | Microturbine (all Sizes) | 30% | 40% | 48% | 44% | 43% | 46% | 163% | 217% | 264% | 67% | 79% | 87% |
| Scenario18 | PG&E | DBG | Internal Combustion Engine (Small) | 40% | 51% | 62% | 53% | 54% | 57% | 223% | 325% | 420% | 64% | 77% | 88% |
| Scenario18 | SCE | DBG | Internal Combustion Engine (Small) | 38% | 51% | 61% | 49% | 49% | 52% | 179% | 246% | 302% | 73% | 86% | 96% |

| Scenarios Sheet Lookup | Utility | Fuel Type | Tech Detail | TRC 2020 | TRC 2026 | TRC 2030 | PCT 2020 | PCT 2026 | PCT 2030 | PA 2020 | PA 2026 | PA 2030 | RIM 2020 | RIM 2026 | RIM 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario18 | SDG&E | DBG | Internal Combustion Engine (Small) | 36% | 48% | 58% | 49% | 47% | 49% | 167% | 227% | 280% | 70% | 85% | 95% |
| Scenario18 | PG&E | DBG | Internal Combustion Engine (Large) | 41% | 53% | 65% | 53% | 55% | 58% | 281% | 409% | 530% | 65% | 77% | 87% |
| Scenario18 | SCE | DBG | Internal Combustion Engine (Large) | 39% | 52% | 63% | 47% | 48% | 51% | 201% | 276% | 339% | 76% | 90% | 99% |
| Scenario18 | SDG&E | DBG | Internal Combustion Engine (Large) | 37% | 49% | 60% | 46% | 46% | 48% | 187% | 255% | 314% | 74% | 89% | 99% |