STATE OF CALIFORNIA Edmund G. Brown Jr., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

December 28, 2011

Advice Letter 4286

Rasha Prince, Director
Regulatory Affairs
Southern California Gas
555 W. Fifth Street, GT14D6
Los Angeles, CA 90013-1011

Subject: Proposed Revisions to the Self-Generation Incentive Program Handbook to Implement D.11-09-015, Improvements to the Waste Heat Utilization Worksheet, Greenhouse Gas Emission Rate Testing Protocol for Electric-Only Technologies that Consume Fossil Fuels, and Guidelines to Protect Against Entities Creating Different Governance Structures to be Able to Achieve More Funding than the Capped Amount

Dear Ms. Prince:

Advice Letter 4286 is effective November 9, 2011.

Sincerely,

Edward Randolph

Edward F. Randolph, Director
Energy Division

October 10, 2011

Advice No. 22
(California Center for Sustainable Energy)

Advice No. 3245-G/3923-E
(Pacific Gas and Electric Company –U 39 M)

Advice No. 2637-E
(Southern California Edison Company – U 338-E)

Advice No. 4286
(Southern California Gas Company – U 904-G)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Proposed Revisions to the Self-Generation Incentive Program Handbook to Implement Decision (D.) 11-09-015, Improvements to the Waste Heat Utilization Worksheet, Greenhouse Gas Emission Rate Testing Protocol for Electric-Only Technologies that Consume Fossil Fuels, and Guidelines to Protect against Entities Creating Different Governance Structures to be able to Achieve More Funding than the Capped Amount

The California Center for Sustainable Energy (CCSE), on behalf of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and Southern California Gas Company (SCG), hereby submits this advice filing to propose revisions to the Self-Generation Incentive Program (SGIP) Handbook to implement California Public Utilities Commission (CPUC) D. 11-09-015,[1] propose improvements to the Waste Heat Utilization Worksheet, propose a greenhouse gas (GHG) emission rate testing protocol for electric-only technologies that consume fossil fuels, and propose guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount under the SGIP.

[1] Decision 11-09-015, *Decision Modifying the Self-Generation Incentive Program and Implementing Senate Bill 412*, September 8, 2011.

PURPOSE

Ordering Paragraph 2 of D.11-09-015 directs the Program Administrators (PAs)[2] for the SGIP, to file a Tier 2 advice letter within thirty (30) days of the effective date of the Decision to submit for approval:

- Revisions to the SGIP Handbook to implement D.11-09-015;
- Improvements to the Waste Heat Utilization Worksheet to qualify fossil fuel-based combined heat and power (CHP) projects as GHG reducing;
- A GHG emission rate testing protocol for electric-only technologies that consume fossil fuels; and
- Guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount under the SGIP.

CCSE, on behalf of the SGIP PAs, hereby submits the required advice filing in compliance with Ordering Paragraph 2 of D.11-09-015.

BACKGROUND

In 2001, the CPUC established the SGIP in D.01-03-073 to encourage the development and commercialization of new distributed generation (DG) technologies.[3] In 2009, the Legislature passed and the Governor signed Senate Bill (SB) 412 (Stats. 2009, ch. 182) which authorized the CPUC, in consultation with the California Air Resources Board (CARB), to determine what technologies should be eligible for the SGIP based on GHG emissions reductions. In addition, SB 412 extended the sunset date of the SGIP from January 1, 2012 to January 1, 2016.

To implement SB 412, the CPUC issued D.11-09-015 on September 8, 2011. In D.11-09-015, the CPUC directs the SGIP PAs to implement changes to the program identified in Attachment A to D.11-09-015. In Ordering Paragraph 2 of D.11-09-015, the CPUC orders the SGIP PAs to file a Tier 2 advice letter within thirty (30) days of the effective date of the Decision to propose revisions to the SGIP Handbook to implement D.11-09-015, improvements to the Waste Heat Utilization Worksheet, a GHG emission rate testing protocol for electric-only technologies that consume fossil fuels, and guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount under the SGIP.

PROPOSED AMENDMENTS TO THE SGIP PROGRAM HANDBOOK

This advice filing seeks to revise sections of the SGIP Program Handbook to implement D.11-09-015 and to make other necessary updates and revisions. The proposed revisions appear in the SGIP Program Handbook included in redline format in Attachment A to this filing. Additionally, the proposed revisions are summarized below:

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[2] The SGIP PAs are PG&E, SCE, SCG, and CCSE in the service territory of San Diego Gas & Electric Company (SDG&E).

[3] DG refers to generation technologies installed on the customer's side of the utility meter that provide electricity for all or a portion of that customer's onsite electric load.

A. Eligibility

Decision summary: Eligibility for participation in the SGIP will be based on GHG emissions reductions.

Handbook Modifications:
Section 1.1 – Eligible Technologies and Incentive Levels
Section 2.1 – Reservation Request-Required Attachments
Section 3.1 – Proof of Project Milestone-Required Attachments
Chapter 9 – Generator System Equipment Eligibility

B. Storage Eligibility

Decision summary: We will grant eligibility to stand-alone Advanced Energy Storage (AES). However, if a future CPUC decision in another proceeding provides any incentives to energy storage, the incentives provided to AES under the SGIP should be removed so as to prevent multiple incentives encouraging the same resource.

AES must be able to discharge its rated capacity for a minimum of two hours.

Handbook Modifications:
Section 9.1.3 – System Size for Advanced Energy Storage (AES) Projects.
Section 9.2 – Rating Criteria for System Output

C. Pressure Reduction Turbines (PRT) and Bottoming Cycle Technology Eligibility

Decision Summary: Including PRT and bottoming-cycle technologies in the SGIP will help promote these technologies as viable options for clean DG and achieve the market transformation goal articulated above.

Handbook Modifications:
Section 1.1 – Eligible Technologies and Incentive Levels
Section 9.1.4 – Generator System Equipment Eligibility-System Sizing for Pressure Reduction Turbine, Waste Heat to Power, Gas Turbine, Microturbine, Internal Combustion Engine and Fuel Cell Projects
Section 9.2 Rating Criteria for System Output

D. Biogas Eligibility

Decision Summary: Given the concerns raised regarding the ability to verify of out-of-state directed biogas, as well as the lack of local environmental benefits to California ratepayers, we will exclude it from SGIP eligibility. We will retain a separate incentive for biogas utilization for SGIP projects that use biogas from in-state sources. This eligibility applies to both onsite biogas and directed biogas produced within California.

For customers using directed biogas, a 10-year contract must be signed with 75% of the fuel coming from a renewable source (consistent with the RPS eligibility requirement).

Handbook Modifications:
Section 6 – Incentives
Section 10 – Eligible Fuels

E. System Size

Decision Summary: The minimum size requirement for wind and renewable fuel cells remains in place only as long as the Emerging Renewables Program (ERP) continues to provide incentives for these technologies. The maximum size limit for SGIP systems will be eliminated as the tiered incentive structure, which only provides incentives for the first three MW of a project's capacity, and the requirement that projects be sized to meet a customer's onsite-load, obviate the need for the maximum size limitation.

Handbook Modifications:
Section 9.1 – System Size Parameters

F. Payment Structure

Decision Summary: Replace the current upfront, capacity-based incentive mechanism with a PBI mechanism to ensure long-term performance of projects that receive SGIP incentives. Adopt a hybrid incentive structure with a 50% upfront incentive and 50% as PBI payments over a 5-year period for projects over 30kW.

Maintain the current tiered incentive structure.

PBI payments will be reduced or eliminated in years that cumulative greenhouse gas reductions do not occur.

Handbook Modifications:
Section 6.2 – Calculating the Incentive
Section 6.3 – Limitations on PBI Based on GHG Reductions
Section 6.4 – Tiered Incentives and Incentive Decline

G. Incentive Rates

Decision Summary: Renewable and waste heat capture technologies will receive an incentive of $1.25 per watt; conventional fuel-based combined heat and power (CHP) will receive an incentive of $0.50 per watt; AES will receive an incentive of $2 per watt; and fuel cells will receive an incentive of $2.25 per watt.

The biogas incentive of $2 per watt is an adder that may be used in conjunction with fuel cells or any conventional CHP technology.

Handbook Modifications:
Section 1.1 – Eligible Technologies and Incentive Levels
Section 6.1 – Incentive Rates

H. Incentive Decline

Decision Summary: 10% per year for emerging technologies and 5% per year for all other technologies, beginning January 1, 2013.

Handbook Modifications:
Section 6.4 – Tiered Incentives and Incentive Decline

I. Capacity Factor

Decision Summary: The assumed capacity factors are 10% for AES, 25% for wind, and 80% for all other distributed energy resources.

Handbook Modifications:
Section 6.2.2 – Hybrid PBI

J. 40% Manufacturer Concentration

Decision summary: No more than 40% of the annual statewide budget available on the first of a given year may be allocated to any single manufacturer's technology during that year. The initial 40% limit will cover the period from the launch of the new program through 2012 and will be calculated based on the total funding available when the program is reinstated plus any additional funds collected in 2012, if applicable.

Handbook Modifications:
Section 6.14 – Manufacturer Concentration Limit

K. Maximum Project Incentive

Decision summary: A project can receive a maximum incentive of $5 Million.

Handbook Modifications:
Section 6.5 – Total Eligible Project Cost and Maximum Incentive Amount

L. SGIP Share of Project Cost

Decision Summary: Minimum customer investment must be 40% of eligible project costs. Therefore, the SGIP portion of project cost is based on the following formula:

1 - applicable Investment Tax Credit (ITC) - 0.4

The biogas adder does not count toward the above limit for projects using DBG. Instead, the adder is applied separately to the cost of the biogas contract and shall not exceed the cost difference between the biogas contract and a similar contract for standard natural gas.

Handbook Modification:
Section 6.6 – SGIP Incentive Limit as Share of Project Cost
Section 6.7 – SGIP Incentive Limit as Share of Biogas Contract

M. Budget Allocation

Decision Summary: 75% renewable and emerging technologies, 25% non-renewable. PAs may shift funds from the non-renewable category to the renewable and emerging technologies category at their discretion if funds in the renewable and emerging technologies category are exhausted. PAs must file an advice letter to receive authorization to shift funds from the renewable and emerging technologies category to the non-renewable category.

Handbook Modification:
Section 17.1 – Budget Allocation

N. Export to Grid

Decision Summary: Customers who participate in a feed-in tariff are allowed to export 25% of their output to the grid on an annual basis.

Handbook Modifications:
Section 6.15– Export to Grid

O. Energy Efficiency Audit

Decision Summary: Mandatory for participation in SGIP unless an extensive audit has been conducted within five years of the date of the reservation request. Any measures with a payback period of two years or less shall be implemented prior to receipt of the upfront incentive payment. Exceptions may be granted by the PAs if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible.

Handbook Modifications:
Section 2.1 - Required Attachments
Section 14.2 – Energy Efficiency Requirements

P. Application Fee

Decision Summary: Equal to 1% of the amount of incentive requested

Handbook Modifications:
Section 2.1 – Reservation Request Required Attachments
Section 14.1 – Application Fee

Q. Warranty

Decision Summary: 10-year parts and service warranty required

Handbook Modification:
Section 12 – Warranty Requirements

R. Extensions

Decision Summary: We require that all projects be limited to a maximum of two extensions of six months each, after which the reservation expires automatically.

Handbook Modification:
Section 4.6 – Extending the Reservation Expiration Date

S. Pending Handbook Revisions

Handbook revisions in regards to the implementation of the hybrid-PBI payment structure and metering and monitoring protocols will be included in a second Tier 2 advice letter to be filed with 60 days of the effective date of D.11-09-015 and ARE NOT included in the version of the SGIP Handbook included as Attachment A to this filing.

PROPOSED IMPROVEMENTS TO THE WASTE HEAT UTILIZATION WORKSHEET

This advice filing seeks to make necessary improvements to the Waste Heat Utilization Worksheet to qualify fossil fuel-based CHP projects as GHG reducing. Attachment B to this filing presents the proposed revised Waste Heat Utilization Worksheet. Additionally, the proposed improvements and revisions are summarized below:

The new Waste Heat Emissions Worksheet now:

1. Incorporates Facility Electric Load
2. Calculates a Thermal Load Coincidence Factor
3. Calculates the fuel input on a higher heating value
4. Calculates the gross generated GHG in kg CO2
5. Calculates the GHG savings from heat recovery
6. Calculates the Net GHG emissions
7. Imposes the NOx emissions eligibility test
8. Imposes the GHG emissions eligibility test
9. Imposes the coincident thermal load test
10. Imposes an electrical export eligibility test

PROPOSED GHG EMISSION RATE TESTING PROTOCOL FOR ELECTRIC-ONLY TECHNOLOGIES THAT CONSUME FOSSIL FUELS

This advice filing seeks to propose a GHG emission rate testing protocol for electric-only technologies that consume fossil fuels. Attachment C to this filing presents the proposed GHG emission rate testing protocol for electric-only technologies that consume fossil fuels. Additionally, the proposed protocol is summarized below:

ASME PTC 50:
This protocol refers to the testing of electric-only fuel cells operating on fossil fuels under the 2011 SGIP. This protocol utilizes the existing ASME PTC 50-2002, which is a performance test code for fuel cells. The ASME PTC 50 calculates the energy input to the fuel cell, the electrical power output, thermal and mechanical outputs, average net power, electrical efficiency, thermal effectiveness and heat rate under certain test conditions. These results can be used to calculate the gas emission rate of the fuel cells.

PROPOSED GUIDELINES TO PROTECT AGAINST ENTITIES CREATING DIFFERENT GOVERNANCE STRUCTURES TO BE ABLE TO ACHIEVE MORE FUNDING THAN THE CAPPED AMOUNT

This advice filing seeks to propose guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount under the SGIP. Attachment D to this filing presents the proposed guidelines. Additionally, the proposed guidelines are summarized below:

In order to protect against entities creating governance structures or affiliations that would allow them to achieve more funding than the capped amount, it is required that Host Customers, Applicants, and System Owners disclose information about all other incentives and eligible tax credits available to them or any of their affiliates applicable to the project. Failure to disclose such information will be considered an infraction and is subject to the penalties indicated in Section 15 of the SGIP Handbook.

This requirement will be checked at the Reservation Request Stage and there are fields in the Reservation Request Forms where affiliations can be identified.

Handbook Modification:
Section 6.14 – Governance Structures and Affiliation with Other Entities

TIER DESIGNATION

Pursuant to General Order (GO) 96-B, Energy Industry Rule 5.2, this advice letter is submitted with a Tier 2 designation.

PROTESTS

Anyone wishing to protest this Advice Letter may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than October 31, 2011, which is twenty-one (21) days after the filing of this Advice Letter. [4] Protests should be mailed to:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Facsimile: (415) 703-2200

Copies of the protest should also be sent via e-mail to the attention of both Maria Salinas (mas@cpuc.ca.gov) and Honesto Gatchalian (jnj@cpuc.ca.gov) of the Energy Division.

[4] The twentieth day after the filing of this Advice Letter falls on Sunday, October 30, 2011. Rule 1.14 of the CPUC Rules of Practice & Procedure, provides that "[i]f the last day falls on a Saturday, Sunday, holiday or other day when the Commission offices are closed, the time limit is extended to include the first day thereafter." Thus, the time limit for protests to this Advice Letter is extended to Monday, October 31, 2011.

A copy of the protest should also be sent via e-mail, U.S. mail, and by facsimile to CCSE at the address shown below on the same date it is mailed or delivered to the Commission:

Andrew McAllister
Director of Policy & Strategy
California Center for Sustainable Energy
8690 Balboa Avenue, Suite 100
San Diego, California 92123
Facsimile: (858) 244-1178
E-mail: andrew.mcallister@energycenter.org

There are no restrictions as to who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

EFFECTIVE DATE

CCSE requests that this Advice Letter become effective on regular notice, November 9, 2011, which is thirty (30) calendar days after the date of filing.

NOTICE

CCSE is providing a copy of this Advice Letter to service list R.10-05-004.

Joseph Andrew McAllister

Andrew McAllister
Director of Policy & Strategy
California Center for Sustainable Energy

Attachments:

- Attachment A – Revised SGIP Program Handbook (Redline Version)
- Attachment B – Revised Waste Heat Utilization Worksheet
- Attachment C – Proposed GHG emission rate testing protocol for electric-only technologies that consume fossil fuels
- Attachment D – Proposed guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount

cc: Service List R.10-05-004

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Attachment A

Self-Generation Incentive Program
Handbook

October 5, 2011

Provides financial incentives for installing
clean, efficient, on-site distributed generation

Center for Sustainable Energy CALIFORNIA

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Pacific Gas and Electric Company™

SDGE
A Sempra Energy utility®

Southern California Gas Company
A Sempra Energy utility™

What's New

2011 Self-Generation Incentive Program

The 2011 Self-Generation Incentive Program (SGIP) handbook includes significant changes resulting from recent CPUC decisions.

1. Eligibility: Based on greenhouse gas (GHG) reductions.
   - Non-renewable CHP eligibility determined on project-by-project basis.
   - Electric-only technologies using fossil fuels will need certification of performance according to ASME PTC 50 protocols

2. GHG baseline: 349 kg CO2/MWh. This avoided emission factor does not account for avoided transmission and distribution losses. The actual on-site emission rate that projects must beat to be eligible for SGIP participation is 379 kg CO2/MWh. Eligibility is determined based on a cumulative 10 years performance.

3. SGIP Incentive Levels by Category

Technology Type	Incentive ($/W)
Renewable and Waste Energy Capture	
Wind Turbine	$1.25
Waste Heat to Power Technologies	$1.25
Pressure Reduction Turbine	$1.25
Conventional CHP	
Internal Combustion Engine – CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine – CHP	$0.50
Emerging technologies	
Advanced Energy Storage[1]	$2.00
Biogas[2]	$2.00
Fuel Cell – CHP or Electric Only	$2.25

4. Storage Eligibility: Stand-alone as well as paired with SGIP eligible technologies or PV.

   Advanced Energy Storage (AES) must be able to discharge its rated capacity for a minimum of 2 hours

5. Biogas Eligibility: on-site and in-state directed.
   - Directed biogas contracts must be for a minimum of ten years, and provide a minimum of 75% of the total energy input required each year.
   - On-site biogas must also provide 75% of the total energy input required each year.

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1 Stand-alone or paired with solar PV or any otherwise eligible SGIP technology.

2 Biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technologies.

6. System size: No minimum or maximum size restrictions given that project meets onsite load.
   - Wind & renewable-fueled fuel cell: 30kW minimum, smaller projects may apply to the California Energy Commission's Emerging Renewables Program.

7. Payment Structure: 50% upfront, 50% PBI based on kWh generation of on-site load.
   - Projects under 30 kW will receive the entire incentive upfront.
   - Projects will be subject to a 5% band for GHG emission rate.
   - No penalty is assessed in any year that cumulative emissions rate does not exceed 398 kg CO2/MWh.
   - PBI payments will be reduced by half in years where a project's cumulative emission rate is greater than 398 kg CO2/MWh but less than or equal to 417 kg CO2/MWh.
   - Projects that exceed an emission rate of 417 kg CO2/MWh in any given year will receive no PBI payments for the year.

8. Assumed Capacity Factors: 10% for AES, 25% for wind, and 80% for all other distributed energy resources (DER).

9. Incentive Decline: 10% per year for emerging technologies and 5% per year for all other technologies, beginning 1/1/2013.

10. Supplier Concentration: No more than 40% of the annual statewide budget available on the first of a given year may be allocated to any single manufacturer's technology during that year.   The initial 40% limit will cover the period from the launch of the new program through 2012 and will be calculated based on the total funding available when the program is reinstated plus any additional funds collected in 2012, if applicable.

11. Maximum project incentive: $5 million

12. Minimum customer investment: Must be 40% of eligible project costs. SGIP portion of project cost based on the following formula: 1-applicable Investment Tax Credit (ITC)-0.4
    - The biogas adder does not count toward above limit for projects using DBG. Instead, the adder is applied separately to the cost of the biogas contract and will not exceed the cost difference between the biogas contract and a similar contract for standard natural gas.

13. Budget Allocation: 75% renewable and emerging technologies, 25% non-renewable.

14. Program Administration Budget: The Program Administration Budget will be reduced to 7%.

15. Export to Grid: 25% maximum on an annual net basis.

16. Energy Efficiency Audit: Mandatory for participation in SGIP unless an extensive audit has been conducted within five years of the date of the reservation request. Any measures with a payback period of two years or less shall be implemented prior to receipt of the upfront incentive payment. Exceptions may be granted by the PAs if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible.

17. Application Fees: 1% of the amount of incentive requested

18. Extensions: All projects must be limited to one, six-month extension. A request for second extension will be made to the SGIP Working Group for approval.

19. Warranty: Ten-year warranty required.

Table of Contents

Program Administrator Contact Information

Potential Program Participants can obtain information and apply for incentive funding through the following Program Administrators[3]:

Pacific Gas & Electric (PG&E)

Website:	www.pge.com/sgip
Email Address:	selfgen@pge.com
Telephone:	(415) 973-6436
Fax:	(415) 973-2510
Mailing Address:	Self-Generation Incentive Program PO Box 7433 San Francisco, CA 94120
Overnight Mailing Address:	245 Market Street Mail Code N7R San Francisco, CA 94105-1797

California Center for Sustainable Energy (CCSE)

Website:	www.energycenter.org/sgip
Email Address:	sgip@energycenter.org
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Southern California Edison (SCE)

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[3] Potential eligible Projects located in the service territory of both Southern California Edison and the Southern California Gas Company can apply for incentive funding to either Program Administrator.

1 Program Overview

The Self Generation Incentive Program (SGIP) provides financial incentives for the installation of new, qualifying self-generation equipment installed to meet all or a portion of the electric energy needs of a facility and is administered by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), the Southern California Gas Company (SoCalGas) and the California Center for Sustainable Energy (CCSE)[4]. The table below is a brief summary of eligible technologies and associated incentives.

1.1 Eligible Technologies and Incentive Levels

Eligibility for participation in the SGIP will based on green house gas emission reductions. Self-generation technologies eligible for the SGIP are grouped into three incentive levels[5] as shown in Table 1-1 below.

Table 1-1 Base Incentive Levels for Eligible Technologies

Technology Type	Incentive ($/W)
Renewable and Waste Energy Recovery	
Wind Turbine	$1.25
Waste Heat to Power	$1.25
Pressure Reduction Turbine	$1.25
Non-Renewable Conventional CHP	
Internal Combustion Engine - CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine – CHP	$0.50
Emerging Technologies	
Advanced Energy Storage	$2.00
Biogas	$2.00
Fuel Cell - CHP or Electric Only	$2.25

This handbook establishes the policies and procedures of the (SGIP) for potential program participants and other interested parties. The SGIP has been approved by the California Public Utilities Commission (CPUC) and is subject to change in whole or in part at any time without prior notice. Any changes made

[4] CCSE is the Program Administer for SDG&E customers.

[5] The SGIP incentive levels were reorganized by CPUC Decision, September 9, 2011, to include Pressure Reduction Turbines, Waste Heat to Power technologies, Gas turbine, Microturbine and Internal Combustion Engine conventional fuel based CHP, stand alone Advanced Energy Storage and Biogas.

to the SGIP will be published in revisions to this Handbook and/or posted at each Program Administrator's website under "Interim Changes".[6]

1.2 Application Process

There are three application processes:

- Non-Public Entity Three Step
- Public Entity Three Step
- Two Step.

These are described by the Application Process Flowcharts in the subsection below.

SGIP funds are available on a first-come, first-served basis throughout the calendar year (January 1 through December 31). Reservations received after total funds have been committed for a calendar year will be placed on a Wait List (refer to the Wait List procedures section for further information). Reservations received before December 31 will follow the Program Rules of the year they were submitted, even if the Conditional Reservation is issued in the following year.

Incomplete or incorrect applications will result in a delay of receiving an approved reservation as well as non-placement within a queue should there be a wait-list for reservation money.

1.3 Incentive Process Flowcharts

The overall application process is illustrated in Figure 1-1 for non-Public Entities and Figure 1-2 for Public Entities.

For all residential Projects and small (<10kW) non-residential Projects, a two-step application process is available. Large (≥10kW) non-residential may opt-into the two-step application process, but all two-step requirements must be met. The small system application 2-step process is illustrated in Figure 1-3.

[6] Capitalized terms used herein are defined in Section 19 of this Handbook.

Figure 1-1 Three Step Application Process for Non-Public Entities

Applicant	Program Administrator
(1) Reservation Request Form Completed and signed Self Generation Incentive Program ***Reservation Request Form*** sent in (by mail) to the Program Administrator along with the required attachments (*see Handbook Section 4.3.2 for complete list of required attachments*)	Program Administrator logs in the ***Reservation Request Form*** Program Administrator evaluates the package for completeness and whether the proposed system appears to meet the eligibility criteria. • If no, further information requested or notification sent that the project does not qualify for further consideration, • If yes, and the Application Fee has been paid, ***Conditional Reservation Notice Letter*** will be sent
Conditional Reservation Notice Letters received. ***Proof of Project Milestone*** documents are due in 60 calendar days *(see Handbook Section 4.4.1 for complete list of required attachments)*	***Conditional Reservation Notice Letter*** Program Administrator prepares and sends a ***Conditional Reservation Notice Letter*** The letter specifies a reservation number and dollar amount for which the project has been conditionally reserved.
(2) Proof of Project Milestone ***Proof of Project Milestone*** Documents submitted (by mail) to the Program Administrator. Failure to submit these items by the date shown will automatically result in the conditional reservation being terminated.	Program Administrator logs in the Proof of Project Milestone documents and verifies whether the project has met all the necessary criteria to this step in the process. • If no, Program Administrator will send notified that the project does not qualify for further consideration, • If yes, ***Reservation Confirmation and Incentive Claim Form*** will be sent.
Reservation Confirmation and Incentive Claim Form received. Self generation system must be purchased, installed and put into operation by the Reservation Expiration Date (18-months from the date of the ***Conditional Reservation Notice Letter)*** *See Handbook Section 4.5.2 for complete list of required attachment.*	***Reservation Confirmation and Incentive Claim Form*** Program Administrator prepares and sends a ***Reservation Confirmation and Incentive Claim Form*** confirming the reservation dollar amount and reservation expiration date.
(3) Incentive Claim Form & Documents When project is completed and operational the ***Incentive Claim Form & Documents*** are submitted (by mail) with required attachments on or before the Reservation Expiration Date to the Program Administrator for processing.	Program Administrator receives completed ***Incentive Claim Form & Documents*** Upon approval of all supporting materials and completion of a successful field verification visit an incentive payment check is sent to the designated payee.

Figure 1-2 Three Step Application Process for Public Entities

Applicant	Program Administrator
(1) Reservation Request Form Completed and signed Self Generation Incentive Program ***Reservation Request Form*** sent in (by mail) to the Program Administrator along with the required attachments (*see Handbook Section 4.3.2 for complete list of required attachments)*	Program Administrator logs in the ***Reservation Request Form.*** Program Administrator evaluates the package for completeness and whether the proposed system appears to meet the eligibility criteria. • If no, further information requested or notification sent that the project does not qualify for further consideration, • If yes, and the Application Fee has been paid, ***Conditional Reservation Notice Letter*** will be sent
Conditional Reservation Notice Letters received. ***RFP or Executed Agreement*** document is due in 60 calendar days:	***Conditional Reservation Notice Letter*** Program Administrator prepares and sends a ***Conditional Reservation Notice Letter*** The letter specifies a reservation number and dollar amount for which the project has been conditionally reserved.
(2a) RFP or Executed Agreement ***RFP or Executed Agreement*** document submitted (by mail).	Program Administrator logs in and verifies the ***RFP or Executed Agreement*** Sends letter confirming receipt of document.
RFP/Agreement Confirmation Letter received. Remaining ***Proof of Project Milestone*** documents are due in 240 calendar days (*see Handbook Section 4.4.1 for complete list of required attachments)*	***RFP/Agreement Confirmation Letter*** Program Administrator prepares and sends a letter confirming receipt of the ***RFP or Executed Agreement.***
(2b) Remaining Proof of Project Milestone ***Proof of Project Milestone*** documents submitted (by mail) to the Program Administrator. Failure to submit these items by the date shown will automatically result in the conditional reservation being terminated.	Program Administrator logs in the Proof of Project Milestone documents and verifies whether the project has met all the necessary criteria to this step in the process. • If no, Program Administrator will send notified that the project does not qualify for further consideration, • If yes, ***Reservation Confirmation and Incentive Claim Form*** will be sent.
Incentive Claim Form & Documents received. Self generation system must be purchased, installed and put into operation by the Reservation Expiration Date (18 months from the date of the ***Conditional Reservation Notice Letter)*** *See Handbook Section 4.5.2 for complete list of required attachment.*	***Reservation Confrmation and Incentive Claim Form*** Program Administrator prepares and sends a ***Reservation Confirmation and Incentive Claim Form*** confirming the reservation dollar amount and reservation expiration date.
(3) Incentive Claim Form & Documents When project is completed and operational the ***Incentive Claim Form & Documents*** are submitted (by mail) with required attachments on or before the Reservation Expiration Date to the Program Administrator for processing.	Program Administrator receives completed ***Incentive Claim Form & Documents*** Upon approval of all supporting materials and completion of a successful field verification visit an incentive payment check is sent to the designated payee.

Figure 1-3 Two Step Application Process

Applicant	Program Administrator
(1) Reservation Request Form Completed and signed Self-Generation Incentive Program ***Reservation Request Form*** sent in (by mail) to the Program Administrator along with the required attachments including those for two-step applications (*see Handbook Section 4.3.2 for complete list of required attachments*):	Program Administrator logs in the ***Reservation Request Form***. Program Administrator evaluates the package for completeness and whether the proposed system appears to meet the eligibility criteria. • If <u>no</u>, further information requested or notification sent that the project does not qualify for further consideration, • If <u>yes</u>, and the Application Fee has been paid, ***Reservation Confirmation and Incentive Claim Form*** will be sent.
Reservation Confirmation and Incentive Claim Form received. Self-generation system must be purchased, installed and put into operation by the Reservation Expiration Date (<u>12-months</u> from the date of the ***Reservation Confirmation and Incentive Claim Form***). *See Handbook Section 4.5.2 for complete list of required attachment.*	***Reservation Confirmation and Incentive Claim Form*** Program Administrator prepares and sends a ***Reservation Confirmation and Incentive Claim Form*** confirming the reservation dollar amount and reservation expiration date.
(2) Incentive Claim Form & Documents When project is completed and operational the ***Incentive Claim Form & Documents*** are submitted (by mail) with required attachments on or before the Reservation Expiration Date to the Program Administrator for processing.	Program Administrator receives completed ***Incentive Claim Form & Documents***. Upon approval of all supporting materials and completion of a successful field verification visit an incentive payment check is sent to the designated payee.

2 Reservation Request

To reserve a specified incentive amount, a Reservation Request Form must be submitted with required attachments and application fee; incentive funds are not reserved until the Program Administrator receives, screens and approves these documents.

Applications that include technologies from two or more different incentive levels (Hybrid Projects) must include one Reservation Request Form for each technology in the Project. For more information on Hybrid Systems, see Sections 6.11 and 9.12.

Reservation Request Forms and instructions on completing these forms can be obtained by calling or visiting the website of the Program Administrator in your area.

2.1 Required Attachments

In addition to a completed Reservation Request Form with signatures of the Host Customer and System Owner (if not Host Customer), all applications must provide a copy of the following:

Table 2-1 Reservation Request Application Attachments

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
1. Completed Reservation Request Application and Program Contract w/ Signatures	✓	✓	✓
2. Equipment Specifications	✓	✓	✓
3. Proof of Utility Service	✓	✓	✓
4. 12-Month Electric Load Documentation	✓	✓	✓
5. Minimum Operating Efficiency Calculations (if applicable) Waste Heat Utilization Documentation OR Minimum Electric Efficiency Calculation	✓	N/A	✓
6. Proof of Power Factor Eligibility	✓	N/A	N/A

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
7. Proof of NOx Emissions Qualifications Minimum 60% System Efficiency Calculation Emissions Credits Calculation (if applicable)	✓	N/A	N/A
8. Proof of Adequate Waste Gas Fuel	✓ Waste Gas Fuel Only	N/A	N/A
9. Proof of Adequate Renewable Fuel Resource (applies to conventional CHP & fuel cells if operating on a renewable fuel)	✓	N/A	✓
10. Gas Injection Qualification	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
11. Forecasted Fuel Consumption	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
12. Directed Biogas Renewable Fuel Attestation – System Owner	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
13. Directed Biogas Renewable Fuel Attestation – Fuel Supplier	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
14. Application Fee	✓	✓	✓
15. Energy Efficiency Audit	✓	✓	✓
Additional Reservation Documents for Two-Step Applications			
16. Copy of Executed Contract or Agreement for Installation (includes warranty language documentation)	✓	✓	✓
17. Fuel Cleanup Equipment Purchase Order (nominated biogas projects exempt)	✓	N/A	✓
18. Renewable Fuel Affidavit	✓	N/A	✓

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
19. Renewable Fuel Contract	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only

1) **Reservation Request Form** – A completed and signed Reservation Request Form must be submitted with all applications. It must be completed and signed by representatives with signature authority for both the System Owner and Host Customer.

2) **Equipment Specifications** – Manufacturer equipment specifications stating rated capacity (kW) and, if necessary, fuel consumption and waste heat recovery rate, must be provide with the Reservation Request application. For Advanced Energy Storage, the manufacturer equipment specifications must include a capacity rating based on the net continuous discharge power output over a two hour period.

3) **Proof of Utility Service** – Eligibility requirements restrict participation in the SGIP to customers who are located in PG&E, SCE, SoCalGas or SDG&E service territories and physically connected to the Electric Utility transmission and distribution system. All applications must include a copy of a recent electric or gas utility bill indicating the account number, meter number, site address, and Host customer name. For new construction, the Host Customer must receive confirmation from the serving utility that their Site is within the Program Administrator's service territory.

4) **12-month Load Documentation** – To confirm that participating distributed generation systems will not exceed the Host Customer's previous 12-month peak (maximum) electrical demand, all applications must include a copy of the previous 12-months of energy consumption including maximum demand and/or kWh consumption. If the system is new or expanded construction, provide proof of projected load that will satisfy the proposed generation system including but not limited to a document that details the building systems electrical load, hours of use for the indicated building systems, and the total projected kWh consumption per year. For example:

Number of Units	Unit Description	Model	Other Description	Power Consumption per Unit (Watts)	Hours of Operation (hr/yr)	Est. energy usage per year (kWh/yr)
20	2 lamp 2ft X 4ft recessed direct/indirect fixture	32W 800 series high lumenT8	Electronic, instant start, extra efficient standard (0.88) ballast factor	55	2,080	2,288

5) **Minimum Operating Efficiency (Non-Renewable Projects)** – When applicable, applications must provide documentation satisfying the minimum operating efficiency requirement. This requirement can be met by submitting one of the following:

   a) **Waste Heat Utilization:** documentation must include a generator and thermal system description, generator electric output forecast and thermal output, generator fuel consumption forecast, thermal load magnitude forecast, and useful thermal energy forecast, to demonstrate compliance with the Program's waste heat utilization requirements (PU Code 216.6)

   b) **Minimum Electric Efficiency:** Documentation must include engineering calculations, data used and all assumptions used to demonstrate this system efficiency.

6) **Power Factor (PF) Specification (Microturbines, Internal Combustion Engines & Gas Turbines)** – When applicable, applications must include self-generating facility design specifications and/or manufacturer's specifications which show that the system will be capable of operating between 0.95 PF lagging and 0.90 PF leading.

7) **Proof of NOx Emission Qualifications (Microturbines, Internal Combustion Engines & Gas Turbines Except Waste Gas Fuel Applications)** – When applicable, applications must include documentation (see Section 9.5.2) substantiating that the generator system meets or exceeds the 60% minimum system efficiency and NOx emissions are at or below the applicable emission standard. Units that do not pass the emission standard may use emission credits.

   - **60% Minimum System Efficiency Specification** – The application must include manufacturer specifications and calculations substantiating that the minimum system efficiency of the generator is equal or greater than 60% must be included. (See Section 9.5.1 for details).

   - **Emission Credits** – If the application claims NOx emission credits for their waste heat utilization emission credit calculation documentation based on the amount of waste heat utilized over a twelve-month period must be provided. (See Section 9.5.3 for details).

8) **Proof of Adequate Waste Gas Fuel (Microturbines, Internal Combustion Engines & Gas Turbines Waste Gas Fuel Applications Only)** – When applicable, applications must include an engineering survey or study confirming that there is adequate on-site Waste Gas fuel (i.e., adequate flow rate) for continuous operation of the self-generation unit for the term of the Project's required warranty/maintenance period.

9) **Proof of Adequate Renewable Fuel (Renewable Projects)** – Applications must include an engineering survey or study confirming the Renewable Fuel (*i.e.*, adequate flow rate) and the generating system's average capacity during the term of the Project's required warranty/maintenance period.

10) **Gas Injection Qualification (Directed Biogas Renewable Fuel Projects)** Documentation that approves the Directed Biogas Renewable Fuel provider to inject the renewable fuel into the utility pipeline local to the renewable fuel source.

11) **Forecasted Fuel Consumption –** Application must include documentation of the forecasted fuel consumption of the generator over the life of project.

12) **Directed Biogas Renewable Fuel Attestation System Owner** - Attestation letter from the System Owner of its intent to notionally procure Renewable Fuel

13) **Directed Biogas Renewable Fuel Attestation Fuel Supplier** - Attestation from the fuel supplier that the fuel meets currently applicable Renewable Portfolio Standard eligibility requirements for biogas injected into a natural gas pipeline.

14) **Application Fee** – Equal to 1% of the requested incentive amount

15) **Energy Efficiency Audit** - The audit must have been performed during the past five years.

Additional Requirements for Two Step Applications

16) **Executed Contract and/or Agreement for System Installation** – All SGIP program participants must include a copy of their executed contract for purchase and installation of the system, and/or alternative System Ownership agreement (such as a Power Purchase Agreement). The contract/agreements must be legally binding and clearly spell out the scope of work, equipment, terms, total eligible system cost and warranty. All agreements must be signed by appropriate representatives (Host Customer, Installer, and/or System Owner) who are a party to the agreements and the SGIP reservation.

17) **Fuel Cleanup Equipment Purchase Order (On-site Renewable Fuel Projects)** – When applicable, application documentation must include a purchase order for Renewable Fuel cleanup equipment.

18) **Renewable Fuel Use Affidavit (On-site Renewable Fuel Projects)** – When applicable, application documentation must include a signed SGIP affidavit that they will not switch to fossil fuel for a period of five years , or the life of the equipment, whichever is shorter.

19) **Renewable Fuel Contract (Directed Biogas Renewable Fuel Projects)** – Contract between customer and renewable fuel supplier.

2.2 Submitting Reservation Request

Once the Reservation Request Form is complete and all the required attachments are secured, Applicants must submit their application package to the Program Administrator. To ensure confirmation of receipt, submit documentation to the appropriate Program Administrator by certified or overnight mail. No faxed or hand delivered applications will be accepted.

2.3 Application Screening

Once received, the Program Administrator will review the application package for completeness and determine eligibility. Applications will also be screened to ensure that the Project has not applied for incentives through other Program Administrators or other state- or government-sponsored incentive programs. While applications will be screened based on the date received, an application will not receive funding until it is deemed complete.

2.4 Incomplete Reservation Request

If an application is found to require clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 20 calendar days to respond to the requested clarification with the necessary information. If after 20 calendar days the Applicant has not submitted the requested information the application will be cancelled. Resubmitted application packages will be treated as a new application (i.e., all required documents must be resubmitted) and processed in sequence along with other new applications.

2.5 Approval of Reservation Request

Upon approval by Program Administrator of the Reservation Request package (Reservation Request Form and required attachments), the Applicant and Host Customer will receive a Conditional Reservation Notice Letter *if* funds are available.

2.6 Conditional Reservation Notice Letter

The Conditional Reservation Notice Letter confirms that a specific incentive amount is conditionally reserved for a self-generation Project. The letter will list, at a minimum, the approved incentive amount and the Proof of Project Milestone Date. All reservations are conditional until the Proof of Project Milestone documentation is submitted on or before the Proof of Project Milestone Date. The Conditional Reservation Notice Letter also will list the required information that must be submitted by the Proof of Project Milestone Date to confirm their reservation and maintain an active status.

3 Proof of Project Milestone

For three step applications:

- Non-Public Entities have 60 calendar days from the date of the Conditional Reservation Letter to satisfy all Proof of Project Milestone criteria
- Public Entities have 60 calendar days from the date of the Conditional Reservation Letter to submit a copy of the issued request for proposal (RFP or equivalent) for purchase or installation of the generating system
    - Proof of Project Milestone documentation must be submitted within 240 days of the date the Conditional Reservation Letter

Once the Applicant has successfully met Proof of Project Milestone requirements, the Program Administrator will issue an Incentive Claim Form with a Reservation Expiration Date of 18-months after the original date of Conditional Reservation.

Two Step applications do not have a Proof of Project Milestone requirement and can proceed to the next section, the Incentive Claim.

3.1 Required Attachments

All Proof of Project Milestone submittals must include the following:

Table 3-1 Proof of Project Milestone Required Materials

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
1. Copy of RFP or executed agreement for System Installation and/or Purchase for Public Entities RFP due within 60 days. All PPA materials, including an executed agreement for installation or lease due within 240 days.	✓ Public Entities only	✓ Public Entities only	✓ Public Entities only
2. Completed Proof of Project Milestone Checklist	✓	✓	✓
3. Copy of Executed Contract or Agreement for Installation (includes warranty language documentation)	✓	✓	✓
4. Copy of Executed Renewable Fuel Contract	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
5. Revised Minimum Operating Efficiency Calculations (if applicable) Waste Heat Utilization Documentation OR Minimum Electric Efficiency Calculation	✓	N/A	✓
6. Copy of Completed Air Pollution Permit Application	✓	N/A	✓ (If applicable)
7. Fuel Cleanup Equipment Purchase Order (nominated biogas projects exempt)	✓	N/A	✓
8. Renewable Fuel Affidavit	✓	N/A	✓
9. Waste Gas Fuel Affidavit	✓	N/A	✓
10. Electrical Load Documentation	✓	✓	✓

1. **Request for Proposals (RFP) Documentation for Public Entities** – Public Entities must submit a copy of Request for Proposals (RFP), Notice to Invite Bids, or similar solicitation issued for the installation, lease and/or purchase for systems proposed for the SGIP. The RFP must include sufficient project details such as the scope of work, schedule, terms, budget, and/or generating system components desired. For Public Entities not issuing an RFP, alternative documentation such as an executed letter of intent to engage with a contractor on the Host Customer letterhead, an executed contract/agreement for system installation/lease, an equipment purchase order, or alternate system ownership agreement must instead be submitted within 60 calendar days of the date the Conditional Reservation Letter.

2. **Proof of Project Milestone Checklist** – All Proof of Project Milestone submittals must be accompanied by a completed and signed checklist. It must identify both the System Owner (if different from the Host Customer), the installation contractor (including the installer's name, telephone number and contractor license number) and be completed and signed by a representative with signature authority for either the System Owner or Host Customer.

3. **Executed Contract and/or Agreement for System Installation** – All SGIP program participants must include, with their Proof of Project Milestone package, a copy of their executed contract for purchase and installation of the system, and/or alternative System Ownership agreement (such as a Power Purchase Agreement). The contract/agreements must be legally binding and clearly spell out the scope of work, terms, total eligible system price, and warranty. All agreements must be signed by appropriate representatives (Host Customer, Installer, and/or System Owner) who are a party to the agreements and the SGIP reservation.

4. **Copy of Executed Renewable Fuel Contract (Directed Biogas Renewable Fuel projects)**, The following criteria must be included in the contract:

   a. Contract should at a minimum include term (minimum of 10 years), cost, amount of renewable fuel injected on a monthly basis for the length of the contract, address of renewable fuel facility, location of pipeline injection site, name of pipeline owner, and facility address of Host Customer.

   b. The SGIP PA has the right to audit & verify Customer Generator's consumption of renewable fuel consumption upon request over the life of the contract.

   c. The Host Customer will consume the contracted renewable fuel for the sole purpose of fueling the SGIP Project.

   d. The contract includes a forecast for at least 75% of the system's anticipated fuel consumption. One possible schedule:

	Starts	Ends	MMBtu/Month	MMBtu/year
Period 1	*Date*	*date*	V	M
Period 2	*Date*	*date*	W	N
Period 3	*Date*	*date*	X	O
Period 4	*Date*	*date*	Y	P
Period 5	*Date*	*date*	Z	Q

   e. The contract must include a true-up mechanism. The supplier & customer will handle variations in actual consumption vs. the contract as follows:

      i. True-ups will occur quarterly, or as otherwise specified, based on actual consumption of the system over the preceding quarter.

      ii. Customer and Renewable Fuel supplier will agree to true up based on actual deliveries of renewable fuel. Note that the fleet of SGIP systems will have its own revenue-grade, electric NGOM and gas meters that are accessible via internet by the Program Administrator.

      iii. If less on-site fuel is consumed than renewable fuel is nominated into the pipeline, then parties can agree to a financial make-whole provision.

      iv. If more on-site fuel is consumed than Renewable Fuel is nominated into the pipeline, then parties can agree to a make whole provision, such that

Customer Generator consumes at least 75% renewable fuel, as measured annually.

5. **Revised Minimum Operating Efficiency Calculations** – When applicable, applications must provide documentation satisfying the minimum operating efficiency requirement. This requirement can be met by submitting one of the following:

   a. **Waste Heat Utilization:** documentation must include a generator and thermal system description, generator electric output forecast and thermal output, generator fuel consumption forecast, thermal load magnitude forecast, and useful thermal energy forecast, to demonstrate compliance with the Program's waste heat utilization requirements (PU Code 216.6)

   b. **Minimum Electric Efficiency:** Documentation must include engineering calculations, data used and all assumptions used to demonstrate this system efficiency.

6. **Air Permit Application (Fuel Cells, Microturbines, Internal Combustion Engines & Gas Turbines)** – Proof of Project Advancement documentation must include copies of air pollution permitting applications, such as a Permit to Construct or Operate signed and submitted to the Local Air District. Applicants, Host Customers and System Owners are solely responsible to submit air pollution permitting applications to the Local Air District as soon as the information to do so is available to prevent any delays in system permitted operation.

7. **Fuel Cleanup Equipment Purchase Order (On-site Renewable Fuel Projects)** – When applicable, application documentation must include a purchase order for Renewable Fuel cleanup equipment.

8. **Renewable Fuel Use Affidavit (Renewable Fuel Projects)** – For renewable fuel projects, application documentation must include a signed SGIP affidavit that they will not switch to fossil fuel for a period of ten years for all technologies, or the life of the equipment, whichever is shorter. The SGIP PA has the right to audit & verify Customer Generator's consumption of renewable fuel consumption upon request over the life of the contract. The Host Customer will consume the contracted renewable fuel for the sole purpose of fueling the SGIP Project.

9. **Waste Gas Fuel Use Affidavit (Waste Gas Only)** – When applicable, application documentation must include a signed SGIP affidavit that they will fuel their Project solely (100%) with Waste Gas for a period of five years for fuel cells or three years for all other technologies, or the life of the equipment, whichever is shorter.

10. **Electrical Load Documentation**: Electrical load documentation either in the form of monthly bills or an electrical load forecast must be submitted in order to determine if the project will be exporting to the grid on an annual basis.

3.2 Submitting Proof of Project Milestone

Once the Proof of Project Milestone package is complete and all the required attachments are secured, the application package must be submitted to the Program Administrator for review. Faxed or hand delivered applications are not allowed. To ensure confirmation of receipt, documentation is to be delivered to the appropriate Program Administrator by certified or overnight mail. The Program Administrator will confirm receipt of the package by notifying the reservation contacts of each party (Applicant, Host Customer, and System Owner).

3.3 Incomplete Proof of Project Milestone

If a complete Proof of Project Milestone package is not received by the Proof of Project Milestone Date, the application will be cancelled by the Program Administrator.

If submitted Proof of Project Milestone documentation is complete but requires clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 20 calendar days to respond with the necessary information. If, after 20 calendar days, the requested information has not been submitted, the application will be cancelled.

3.4 Approval of Proof of Project Milestone

Once applications have successfully demonstrated satisfaction of the Proof of Project Milestone the Program Administrator will issue a Reservation Confirmation and Incentive Claim Form. This notification will list the specific reservation dollar amount and the Reservation Expiration Date. Upon Project completion and prior to the Reservation Expiration Date, the completed Incentive Claim Form must be submitted along with all of the necessary documentation to request an incentive payment.

3.5 RFP and Proof of Project Milestone Extension

In general, no extensions to the Proof of Project Milestone Date are permitted. An extension of the due date for the RFP (or equivalent documentation) may be granted only for Public Entities up to a maximum of 60 days at the Program Administrator’s discretion. Any extension granted does not extend the Proof of Project Milestone Date or the Reservation Expiration Date. Applicants and Host Customers must demonstrate that failure to submit a satisfactory RFP (or equivalent documentation) was for reasons beyond their control. If the RFP (or equivalent documentation) submittal due date expires and no extension is granted, the Reservation will be terminated. Applicants and Host Customers may reapply for an incentive, but such re-applications will be processed in sequence along with other new applications.

4 Incentive Claim

Once the self-generation project is completed, Applicants may request payment of the incentive amount listed on their Incentive Claim Form. A generating system is considered "complete" when it is completely installed, interconnected, permitted, paid for and capable of producing electricity in the manner and in the amounts for which it was designed. The Program Administrator will disburse payment after the Program Administrator verifies the claim by field inspection that the generating system is "completed" and meets all the eligibility requirements of the SGIP. The completed Incentive Claim Form must be submitted to the Program Administrator on or before the Reservation Expiration Date, together with all required attachments described below.

4.1 Required Attachments

In addition to the completed Incentive Claim Form, the following attachments must be submitted when requesting incentive payment:

Table 4-1 Incentive Claim Required Materials

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
1) Completed Incentive Claim w/ Signatures	✓	✓	✓
2) Proof of Authorization to Interconnect	✓	✓	✓
3) Final Project Cost Breakdown Worksheet	✓	✓	✓
4) Project Cost Affidavit	✓	✓	✓
5) Final Building Permit Inspection Report	✓	✓	✓
6) Substantiation of Load (New Construction/Expanded Load Only)	✓	✓	✓
7) Substantiation of Renewable Fuel Resource	✓ On Site Renewable Fuel Only	N/A	✓ On Site Renewable Fuel Only
8) Revised Sizing Calculations (if applicable)	✓	✓	✓

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture	Fuel Cells & AES
9) Revised Minimum Operating Efficiency Calculations (if applicable) Waste Heat Utilization Documentation OR Minimum Electric Efficiency Calculation	✓	N/A	✓
10) Final Fuel Cleanup Skid Cost Documentation (on-site renewable fuel only, nominated biogas projects exempt)	✓	N/A	✓
11) Final Air Permit Documentation (if applicable) (nominated biogas projects exempt)	✓	N/A	✓
12) Supplier Renewable Fuel Documentation	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
13) Proof of Renewable Fuel Contract Commencement	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
14) Renewable Fuel Metering Specifications	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
15) Electrical Load Documentation	✓	✓	✓

1) **Incentive Claim Form** – A completed and signed Incentive Claim form must be submitted with all applications. The Incentive Claim form information must accurately represent the actual installed system size and type.

2) **Proof of Authorization to Interconnect** – A copy of the signed letter from their Electric Utility granting the Host Customer and/or System Owner permission to interconnect and operate in parallel with the local grid. For questions on the interconnection process, see Section 14.6.

3) **Final Project Cost Breakdown Worksheet** – A final Project Cost Breakdown Worksheet substantiating the claimed eligible Project cost. The Program Administrator reserves the right to withhold final incentive payment pending review and approval of Project cost and receipt of supporting documentation. For a list of total eligible Project cost, see Appendix B. The Program

Administrator reserves the right to periodically audit Host Customer's and, if different from Host Customer, the System Owner's records.

4) **Project Cost Affidavit** – A signed Project Cost Affidavit substantiating the claimed eligible Project cost.

5) **Final Building Inspection Report** – A copy of the final building inspection report demonstrating that the Project meets all codes and standards of the permitting jurisdiction. Contact your local permitting jurisdiction to learn about permitting requirements.

6) **Substantiation of Load (New Construction or Added Load Only)** – For Projects where Host Customer estimated future load was used to justify system size, applications must include documentation demonstrating that the load forecast has materialized.

7) **Substantiation of Renewable Fuel Resource** – For Projects where the Host Customer, Applicant or System Owner provided Renewable Fuel resource estimates, applications must include documentation demonstrating that the On Site Renewable Fuel resource has materialized.

8) **Revised Sizing Calculations** – When applicable, applications must include a thorough description of any changes that have occurred in the system design effecting size or incentive amount since the initial application submittal. If funding is not available, the reserved incentive cannot be increased regardless of the changes to the proposed generating system.

9) **Revised Minimum Operating Efficiency Calculations** – When applicable, applications must provide documentation satisfying the minimum operating efficiency requirement. This requirement can be met by submitting one of the following:

    a. **Waste Heat Utilization:** documentation must include a generator and thermal system description, generator electric output forecast and thermal output, generator fuel consumption forecast, thermal load magnitude forecast, and useful thermal energy forecast, to demonstrate compliance with the Program's waste heat utilization requirements (PU Code 216.6)

    b. **Minimum Electric Efficiency:** Documentation must include engineering calculations, data used and all assumptions used to demonstrate this system efficiency

10) **Fuel Cleanup Skid Cost Documentation (On-site Renewable Fuel Projects)** – When applicable for Renewable Fuel Projects, applications must include documentation substantiating the fuel cleanup skid cost.

11) **Final Air Permitting Documentation** – For those Projects that require an air permit from the local air district, the application must include a copy of the final documentation indicating compliance with all applicable air pollution regulations.

12) **Supplier Renewable Fuel Documentation (Directed Biogas Projects)** – Documentation from the supplier showing that the fuel is renewable and that it meets the quality standards to be injected into the local natural gas pipeline.

13) **Proof of Renewable Fuel Contract Commencement (Directed Biogas Projects)** – Documentation (e.g. one month fuel invoice) showing that the contract has commenced and the supplier has begun nominating the renewable fuel into the pipeline. The project will be given up to one-year from the date the Incentive Claim was received by the SGIP PA for commencement of the contract. However, no incentive will be paid until the contract has commenced.

14) **Renewable Fuel Metering Specifications** – Make, model, specifications and serial number of installed revenue grad electric NGOM and gas meters.

15) **Electrical Load Documentation** – In the case of new construction or load growth the required load will be documented.

4.2 Submitting Incentive Claim

Once the Incentive Claim Form is complete and all the required attachments are secured, the package must be submitted to the Program Administrator. To ensure confirmation of receipt, documentation shall be delivered to the appropriate Program Administrator by certified or overnight mail. No faxes or hand deliveries will be accepted.

4.3 Incomplete Incentive Claim

If a complete Incentive Claim package is not received by the Reservation Expiration Date, the application may be cancelled by the Program Administrator.

If submitted Incentive Claim documentation are complete but require clarification, the Program Administrator will request the information necessary to process that application.

4.4 Approval of Incentive Claim

Upon final approval of the incentive claim package documentation and completed field verification visit, the Program Administrator will issue the incentive in approximately 30 days. Payment will be made to the Host Customer, System Owner, or a third party (as designated), as indicated on the Incentive Claim Form, and will be mailed to the address provided.

4.5 Field Verification Visit

Upon receipt of a complete Incentive Claim Form package, the Program Administrator will conduct a field verification visit to verify that the Project system is installed as represented in the application, is operational, interconnected and conforms to the eligibility criteria of the SGIP. If the Project uses Renewable Fuel, the availability and flow rate of the Renewable Fuel will be demonstrated by Host Customer and/or System Owner. If the eligible system size depended on new construction or load growth, the required load will be confirmed at the time of Field Verification Visit. The Program Administrator also will verify system capacity rating to confirm the final incentive amount. The implementation of energy efficiency measures identified as having a less than two year payback in the Energy Efficiency Audit will also be verified at the time of the Field Verification Visit.

4.5.1 ***Failed Field Verification***

If field verification results indicate that the system is not eligible, the Program Administrator will notify the Applicant, Host Customer and System Owner the reasons for system ineligibility. The Applicant, Host Customer and System Owner will have 60 calendar days to bring the system into compliance. A subsequent inspection visit will be conducted to determine final approval. If the Applicant, Host Customer and System Owner fails to bring the system to full eligibility within the 60 days the application will be cancelled.

If the Site load or renewable fuel forecast has not yet materialized, the Applicant will be given two options; 1) Receive a onetime payment based on the Site load or fuel availability (whichever is less) demonstrated at the time of initial inspection or, 2) Wait for the Site load or fuel to materialize within 12-months from the date the Incentive Claim Forms and documents were initially received. If the Site load or fuel has not materialized within the 12-month period, the Project will be paid based on the Site load, or system operating capacity available at the end of the 12-month period. If the measures identified in the Energy Efficiency Audit with a payback period of two years or less have not been implemented the project may be cancelled. Exceptions may be granted by the PA if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible.

4.6 Extending the Reservation Expiration Date

All projects will be limited to a maximum of two, extensions of six month each, after which the reservation expires automatically. Extensions will be limited in duration and granted only for special circumstances. In addition, extensions will not be granted to projects that have not made satisfactory progress toward completion in compliance with established milestones and requirements.

4.7 Modifying the Proposed Project

The Program Administrator will expect a system to be installed as described on the Reservation Request Form and ultimately the Incentive Claim Form, but recognizes that changes may result during development of the project and/or during the installation and that substantive changes may be necessary in extraordinary circumstances.

In general changes to the project should be approved by the Program Administrator; especially those changes pertaining to: System Owner, Payee, Project location, changes in equipment type, and system Capacity.

Modifications affecting installed system capacity require that a new incentive amount be calculated as follows:

- When the newly calculated incentive is smaller than that specified in the original Reservation Request Form, the Payee will receive the smaller incentive amount.
- In general if the incentive amount increases relative to that stated in the original Reservation Request, the larger amount is granted. However, the incentive can never exceed the total project cost. Also, if adequate funds are not available, the Program Administrator cannot guarantee that the higher incentive amount will be granted.

5 Wait List Procedures

If funds are not available for a particular reservation request while a Program Administrator is still accepting new applications it will be assigned a place on a Wait List upon approval of the reservation request package (Reservation Request Form and required attachments). The Applicant and Host Customer will receive notification that their request is on a Wait List until funding is made available (through budget transfers between categories, carryover and/or project attrition), or it is withdrawn or cancelled. **A place on the Wait List is not secured until the Program Administrator receives all information and documentation required with the Reservation Request Form and the Project is determined to meet all eligibility requirements.** When applications are placed on the Wait List, the procedures below will be followed.

- Wait List position and incentive amount is based on the date all complete information is received. Applications will be given priority based on the date this information is received.
- All Wait List applications will be reviewed for completeness and eligibility. Any deficiencies must be corrected before being placed on the Wait List.
- Once all application deficiencies have been satisfactorily fixed the application will be placed on the Wait List. When the affected application has made it to the number one position in the queue and once funding becomes available within the affected level, adequate to reserve the affected application the Program Administrator will issue a Conditional Reservation. The incentive amount is based on the date all information is received (i.e. if the information was received after the incentive had been reduced, the application is subject to the lower incentive rate).

If a Wait List exists at the end of a Program Year, the Program Administrator will notify the Host Customer of any incentive or eligibility rule changes. If the Host Customer wishes to withdraw their application from the Wait List, they must promptly inform the Program Administrator.

5.1 Wait List Closure

If the Wait List hits either of the following pre-determined limits, the Wait List will be closed and new applications will no longer be accepted for a given Quarter:

- 50 Projects, Or;
- Incentive Requests resulting in more than 50% of the PA’s annual incentive budget

At the beginning of each quarter, the PAs will review any project attrition and allow new applications if funding is available[7]

The purpose of closing the Wait List is to avoid scenarios in which a prior year's Wait List takes up most, if not all, of the subsequent program year's funding.

[7] For example, if PG&E receives enough applications to warrant a Waitlist closure on February 1, PG&E will notify the Service List that they no longer receive new applications for Q1 of the given program year. If there is enough attrition to allow funding for waitlisted projects in Q2, PG&E will resume accepting applications in Q2

6 Incentives

6.1 Incentives Rates

The incentive levels for the three categories of self-generation technologies are provided below. Check the Program Administrator website for current incentive levels

Table 6-1 Incentive Levels By Category

Technology Type	Incentive ($/W)
Renewable and Waste Energy Recovery	
Wind Turbine	$1.25
Waste Heat to Power	$1.25
Pressure Reduction Turbine	$1.25
Conventional CHP	
Internal Combustion Engine - CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine – CHP	$0.50
Emerging Technologies	
Advanced Energy Storage	$2.00
Biogas	$2.00
Fuel Cell - CHP or Electric Only	$2.25

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

6.2 Calculating the Incentive

Incentives for a proposed system are calculated by multiplying the Rated Capacity of the generating system by the incentive rate of that Technology Type.

6.2.1 *Upfront Incentive for projects under 30 kW*

Projects under 30 kW in size will only receive an upfront incentive.

6.2.2 *Hybrid PBI*

For projects that are larger than 30 kW in size the SGIP will pay 50% of the incentive upfront. A performance based incentive (PBI) will cover the remaining 50%. Annual kilowatt hour based payments will be structured so that under the expected capacity factor, a project would receive the entire stream of performance payments in five years.

To calculate the basis ($/kWh) of the annual PBI payments, the following calculation is made:

$/kWh = *remaining 50% of incentive / total anticipated kWh production*

total anticipated kWh production = *nameplate capacity * capacity factor * hours per year * five years*

For a 5-year period the PBI payment will be paid annually based on recorded kWh of electricity produced over the previous 12 months and the PBI basis:

*PBI Payment = $/kWh * actual annual kWh*

Table 6-2 Assumed Capacity Factors

Technology Type	Capacity Factor
Advanced Energy Storage	10%
Wind Turbine	25%
All other Technologies	80%

Each project will have an annual production expectation established during the incentive claim phase of the project review.

Examples are included in the Appendix for calculating various incentives.

6.3 Limitations on PBI based on GHG Reductions

PBI payments will be reduced or eliminated in years that anticipated GHG reductions do not occur. Because many factors may lead to a project performing below expected levels of efficiency a 5% exceedance band above the 379 kg CO_2/MWh eligibility threshold is provided before penalties are assessed.

Therefore if:

$emission\ rate \leq 398\ \frac{kg\ CO_2}{MWh} \rightarrow$	No penalty assessed on PBI payment
$398\ \frac{kg\ CO_2}{MWh} \leq emission\ rate \leq 417\ \frac{kg\ CO_2}{MWh} \rightarrow$	PBI payment reduced by 50%
$emission\ rate > 417\ \frac{kg\ CO_2}{MWh} \rightarrow$	No PBI payment for that year

6.4 Tiered Incentives and Incentive Decline

For projects that are greater than 1 MW up to 3 MW, the incentive identified in Table 6-1 declines according to the schedule in Table 6-2.

Table 6-3 Tiered Incentive Rates

Capacity	Incentive Rate (Pct. of Base)
0 – 1 MW	100%

1 MW – 2 MW	50%
2 MW – 3 MW	25%

SGIP incentive levels will decline annually with the first reduction starting on January 1, 2013. The rate of incentive decline is provided in Table 6-4.

Table 6-4 Incentive Decline

Technology Type	Yearly Incentive Decline Rate
Renewable, Waste Energy Recovery, Conventional CHP	5%
Emerging Technologies	10%

6.5 Total Eligible Project Costs and Maximum Incentive Amount

The maximum incentive amount per project is $5 million.

No Project can receive incentive payments that exceed the Total Eligible Cost of the generating system. Submittal of Project Cost details is required to report total eligible Project Costs and to ensure that total incentives do not exceed out of pocket expenses for the System Owner (see Administrator website for Project Cost Worksheet). Total eligible Project Costs cover the generating system and its ancillary equipment. Equipment and other costs outside of the Project envelope are considered ineligible Project Costs (see Appendix for Eligible and Ineligible Project Costs), but also must be reported. For large multifaceted Projects where the generating system costs are embedded, applications must include a prorated estimate of the total eligible costs for the generating system.

6.6 SGIP Incentive Limit as Share of Project Cost

Applicants must pay a minimum of 40% of eligible project costs. To that end, the portion of project costs paid for by the SGIP will be determined as follows:

SGIP share of eligible project costs <= 1- applicable investment tax credit – 0.4

6.7 SGIP Incentive Limit as Share of Biogas Contract

Please note that the $2.00/Watt biogas adder does not apply to the SGIP share of eligible project costs for projects using directed biogas. Instead the adder is applied separately to the cost of the biogas contract and should not exceed the cost difference between the biogas contract and a similar contract for standard natural gas.

6.8 Incentives for Technologies from a California Supplier

An additional incentive of 20 percent will be provided for the installation of eligible distributed generation or Advanced Energy Storage technologies from a California Supplier. "California Supplier" means any sole proprietorship, partnership, joint venture, corporation, or other business entity that manufactures eligible distributed generation technologies in California and that meets either of the following criteria:

A) The owners or policymaking officers are domiciled in California and the permanent principal office, or place of business from which the supplier's trade is directed or managed, is located in California.

Or

B) A business or corporation, including those owned by, or under common control of, a corporation, that meets all of the following criteria continuously during the five years prior to providing eligible distributed generation technologies to an SGIP recipient:

  i) Owns and operates a manufacturing facility located in California that builds or manufactures eligible distributed generation technologies.

  ii) Is licensed by the state to conduct business within the state.

  iii) Employs California residents for work within the state.

For purposes of qualifying as a California Supplier, a distribution or sales management office or facility does not qualify as a manufacturer.

The additional incentive of 20 percent will be calculated as follows:

Adjusted Incentive ($) = Unadjusted Incentive ($) x Adjustment Factor

Where:

Adjusted Incentive ($) ≡ the increased incentive amount for the installation of eligible distributed generation or Advanced Energy Storage technologies from a California Supplier.

Unadjusted Incentive ($) ≡ the incentive amount normally calculated.

Adjustment Factor ≡ 1.20 or 20% of the Unadjusted Incentive ($)

The 20 percent adder for using a California Supplier, as defined in PUC Code 379.6(g) shall be calculated on the non-renewable incentive rate of $0.50 per watt and $2.25 per watt for fuel cells before adding the additional $2.00 per watt incentive for using biogas. The incentive for each project including the California Supplier Adder shall be capped based upon the formula proved in section 6.6.

6.8.1 *Directed Biogas Projects*

For Projects utilizing fuel that is any fraction claimed to be Directed Biogas, the 20 percent adder for using a California supplier of distributed generation resources shall be calculated on the non-renewable incentive rate, not the biogas incentive rate.

6.9 Sites with Existing Generating Capacity

For Sites with existing generating capacity previously funded by SGIP, the existing generating capacity is accounted first at the highest incentive rate, and then the proposed system capacity incentive is added on top of the existing capacity to determine which incentive capacity bin the proposed system falls. See Example #6 in Appendix A for details on calculating the incentives for systems with existing SGIP funded generating systems.

Advanced Energy Storage system capacity is not additive with the coupled self-generation capacity for purposes of calculating the tiered incentive. The incentive calculation and capacity limits are treated separately for Advanced Energy Storage and companion self-generation technologies.

6.10 Eligibility with Existing Generation

A generating system may be installed in addition to existing on-site generation if all eligibility requirements in Section 9 are met by the Project. Backup Generators are not considered “existing on-site generation”.

Non-Renewable Generating systems converted to Renewable Fuel are considered, for determining SGIP eligibility, as new generators. If all eligibility requirements in Section 9 are met, the Renewable Fuel source is local to the Project and the conversion takes place no later than 1 year from the original SGIP incentive payment. However, these conversions are only eligible to receive the additional $2.00/W biogas incentive up to 100% of the project costs. For example, a site who installed and received an incentive for a 300 kW Non-Renewable Fueled Fuel Cell is eligible for $2.00/W. The maximum eligible incentive for this project would be $600,000. Customers choosing to contractually nominate biogas for a previously installed generator will not be eligible to receive the differential between the original reservation amount and the biogas incentive.

6.11 Hybrid System Incentives

Program participants can apply for incentives for multiple types of generating technologies installed at one Site. The program defines these as “Hybrid Systems”. An example of this situation would be wind turbines and natural gas fuel cells combined at one Site. As with single technology systems, hybrid systems must meet all eligibility requirements set forth by this program. In addition, each system type must be submitted as a separate Reservation Request and will be tracked through the program as separate projects.

The total SGIP hybrid incentive is the sum of the incentive for each type of technology less other incentives. When calculating the total eligible incentive for a hybrid system, the incentives are to be calculated sequentially until the 3 MW limit is reached, with the lowest incentive rate ($/Watt) technology portion calculated first. For multiple technologies within a single Incentive Level, the incentives are calculated in the order in which they appear in Table 6-1, from top to bottom. The Appendix provides an example incentive calculation for a hybrid system that is greater than 1 MW without other incentives.

6.12 Incentives from Other Sources

Projects receiving rebates or incentives based on future performance of the Project are ineligible for SGIP participation.

Customers may not apply for SGIP incentives for the same self-generation equipment from more than one Program Administrator (e.g., PG&E and SoCalGas, SCE and CCSE).[8]

Host Customers, Applicants, and System Owners are required to disclose information about all other incentives.

For Projects receiving self-generating incentives under other programs, the SGIP incentive may be reduced, depending on the source of the other incentive, effectively allowing only part of the other program incentive in addition to the SGIP incentive.

Table 6-5 Percent of "Other Incentive" Adjustment to SGIP

Other Incentive Funding Source	Pct. Of Other Incentive Deducted from SGIP Incentive
Investor Owned Utility Ratepayer	100%
Investment Tax Credit	100%
Non-IOU Ratepayer	50%
Non-Ratepayer	0%

6.13 Governance Structures and Affiliation with Other Entities

In order to protect against entities creating governance structures or affiliations that would allow them to achieve more funding than the capped amount it is required that Host Customers, Applicants, and System Owners disclose information about all other incentives and eligible tax credits available to them or any of their affiliates applicable to the project. Failure to disclose such information will be considered an infraction and is subject to the penalties indicated in Section 15.

This requirement will be checked at the Reservation Request Stage and there are fields in the Reservation Request Forms where affiliations must be identified.

6.14 Manufacturer Concentration Limit

Any single equipment manufacturer is limited to 40% of the annual statewide SGIP budget. In other words, the SGIP shall not issue conditional reservations to a project using a technology produced by a manufacturer that has already received reservations in a given year that total 40% of the SGIP statewide

[8] Duplicative application is considered a program infraction, See section 15.1 for Program Infractions

budget at the beginning of the year. The annual statewide SGIP budget is defined as the base budget allocation plus carry-over funds from previous years.

6.15 Export to the Grid

SGIP projects that qualify for the feed-in tariff are allowed to export a percentage of their output to the grid in order to optimize system sizing.

Once on-site electric load has been met, excess generation of electricity may be exported to the grid. The amount exported to the grid is not to exceed 25% of self-generated electricity on an annual basis.

In cases where a customer is exporting electricity to the grid, the PBI payment will be calculated based on generated electricity consumed on-site as opposed to the generating system's output.

Increases or decreases in the capacity factor are applied to the on-site consumption as defined above and a new PBI payment is established.

Based on this description and the $/kWh calculated during the incentive claim step of the project, the calculation of a PBI payment is as follows:

$$\textit{New PBI} = \$/\textit{kWh} * \textit{generated electricity consumed on-site}$$

Program Administrators must be informed of arrangements made with the utility for sale of excess generation.

For verification purposes all documentation and records of exports and kWh compensation must be submitted to the Program Administrators.

7 Program Participant Criteria

The eligibility criteria for the SGIP participants govern which utility customers can participate. In order to qualify for incentives, all program eligibility criteria must be satisfied. The following sections detail these requirements.

7.1 Host Customer Eligibility

Any retail electric or gas distribution customer of PG&E, SCE, SoCalGas, or SDG&E is eligible to apply as the Host Customer and receive incentives from the SGIP. The Host Customer must be the utility customer of record at the Site where the generating equipment is or will be located. In the event the Host Customer's name is not on the utility bill, a letter of explanation is required. Said letter must address the relationship of the Host Customer to the named utility customer. Systems will be eligible for a reservation up to 12 months after receiving authorization to operate in parallel with the grid from the electric utility. Any class of customer (industrial, agricultural, commercial or residential) is eligible to be a Host Customer in the SGIP. The Host Customer's Site must be located in the service territory of, and receive retail level electric or Gas Service[9] from PG&E, SCE, SDG&E or SoCalGas at the Site. Municipal utility customers also served by SCE, PG&E, SDG&E or SoCalGas at the Site are eligible.

The Host Customer is the incentive reservation holder. The Host Customer may also be the Applicant and/or System Owner. In the event the Host Customer or System Owner withdraws from the Project and cancels the Host Customer and System Owner Agreement that is part of the Reservation Request Form, the Host Customer alone will retain sole rights to the incentive reservation and corresponding incentive reservation number. To preserve such incentive reservation and corresponding reservation number, the Host Customer must submit a new Reservation Request Form to the Program Administrator. The Host Customer thus has the right to designate the Applicant, energy services provider, and/or system installer. As the utility customer of record, the Host Customer shall be party to the SGIP Contract.

7.2 System Owner Eligibility

The System Owner is the owner of the generating equipment at the time the incentive is paid. For example, in the case when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner. The System Owner shall be designated on the Reservation Request Form, if known at that time, and on the Incentive Claim Form. If different from the Host Customer, the System Owner shall also be a party to the SGIP Contract. The Program Administrator may require documentation substantiating equipment ownership.

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[9] "…retail level electric or Gas Service…" means that the Host Customer pays for and receives distribution services, as defined by their respective utility rate schedule.

7.3 Applicant Eligibility

The Applicant is the entity that completes and submits the SGIP application and serves as the main point of communication between the SGIP Program Administrator throughout the application process. Host Customers may act as the Applicant or they may designate a third party (e.g. a party other than the Program Administrator or the utility customer) to act as the Applicant on their behalf. Applicants may be third parties such as, but not limited to, engineering firms, installation contractors, equipment distributors, Energy Service Companies (ESCO), equipment lessors, etc.

The Host Customer may elect to change the Applicant at their discretion.

7.4 RES-BCT Participants

Any local governments participating in the RES-BCT tariff (AB 2466) are eligible for incentives up to the total annual electrical load (kWh) at the Site where the generating system is located. The system's annual production capacity may not exceed the total annual electrical load at the Site where the generating system is located and the benefiting Site(s) combined. Local government sites participating in the RES-BCT tariff must comply with the 1MW cap per site.

7.5 Assignment of SGIP Application Rights & Responsibilities

The Host Customer is the exclusive reservation holder. Neither the Host Customer nor the System Owner may assign its rights or delegate its duties without prior written consent of the Program Administrator. The System Owner shall assign its rights or delegate its duties only with the prior written consent of the Host Customer, except in connection with the sale or merger of a substantial portion of its assets. Both the Host Customer and the System Owner, if different than the Host Customer, must provide assurance of Project success, if assigned, by providing any additional information requested by Program Administrator.

8 Acceptable Methods for Determining Peak Demand

8.1 Calculation of Load Based on Electric Energy (kWh) Only Data

Sites with 12-months of previous energy usage data (kWh), but without peak demand (kW) information available (e.g., customers on rate schedules without a demand component) will have an equivalent peak demand calculated using the following method –

Peak Demand (kW) = Largest Monthly Bill (kWh/month) / (Load Factor x Days/Bill X 24)

Residential: Load Factor = .45[10]

Small Commercial: Load Factor = .47[11]

Agricultural: Load Factor = .35

The resulting annual peak demand estimate should be used in section 9.1, for the technology proposed.

8.2 Calculation of Load Based on Future Growth

Applications must include an engineering estimate with appropriate substantiation of the Host Customer Site's annual peak demand forecast if the generating system size is based on future load growth, including new construction, load growth due to facility expansion or other load growth circumstances. Suggested methods of demonstrating load growth include Application for Service with corresponding equipment schedules and single line diagram; building simulation program reports such as eQUEST, EnergyPlus, EnergyPro, DOE-2, and VisualDOE; or detailed engineering calculations. The Program Administrator will verify the load growth predicted before moving forward with the Conditional Reservation Notice. Application documentation must demonstrate that sufficient load has materialized before the incentive can be paid. Additionally, the Program Administrators will verify the Site load has materialized during the field verification visit or subsequent site inspections.If the Site load forecast has not yet materialized, the Applicant will be given two options; 1) take a onetime payment based on the Site load demonstrated at the time of initial inspection or, 2) wait for the Site load to materialize within 12-months of the date the Incentive Claim Form and documents were initially received. If the Site load has not materialized within the 12-month period, the Project will be paid based on the Site load, or system operating capacity available at the end of the 12-month period whichever is less.

[10] Residential Load Factor estimated from California Investor Owned Utility domestic static load profiles.

[11] Small Commercial and agricultural Load Factors From "2002-2012 Electricity Outlook Report, CALIFORNIA, ENERGY COMMISSION, February 2002 P700-01-004F" Table III-2-1.

9 Generator System Equipment Eligibility

9.1 System Size Parameters

Only self-generation equipment installed on the Host Customer's side of the Electric Utility meter is eligible. Equipment must be sized to serve all or a portion of the electrical load at the Site.

Substantiation of system sizing is required with the initial Reservation Request application submittal.

9.1.1 *System Sizing for Wind Turbine Projects*

Wind Turbine Projects may be sized up to 200% of the Host Customer's previous 12-month annual peak demand at the proposed Site.

If the Site hosts existing generation, the combined capacity of the proposed and existing generators (excluding any back-up generators) must be no more than 200% of the Host Customer's Maximum Site Electric Load.

9.1.2 *Non-Renewable Fuel Cell Systems 5 kW or Less*

Non-Renewable Fuel Cell systems that are rated at 5 kW or less are exempt from the system sizing requirements.

9.1.3 *System Sizing for Advanced Energy Storage Projects*

Stand alone Advanced Energy Storage Projects may be sized up to the Host Customer's previous 12-month annual peak demand at the proposed Site. Advanced Energy Storage Projects coupled with generation technologies must be sized no larger than the rated capacity of the SGIP eligible technology it is operating in concert with.

Advanced Energy Storage system capacity is not additive with the companion self generation capacity for purposes of calculating the tiered incentive. The incentive calculation and capacity limits are treated separately for Advanced Energy Storage and companion self generation technologies. See incentive calculation description in Section 6.8.

9.1.4 *System Sizing for Pressure Reduction Turbine, Waste Heat to Power, Gas Turbine, Microturbine, Internal Combustion Engine and Fuel Cell Projects*

Pressure Reduction Turbine, Waste Heat to Power, Gas Turbine, Microturbine, Internal Combustion Engine and Fuel Cell Projects may be sized up to the Host Customer's previous 12-month annual peak demand at the proposed Site.

If the Site hosts existing generation, the combined capacity of the proposed and existing generators (excluding any back-up generators) must be no more than the Host Customer's Maximum Site Electric Load.

Substantiation of system sizing is required with the initial Reservation Request application submittal.

Proposed Renewable Fueled Gas Turbine, Microturbine, Internal Combustion Engine or Fuel Cell systems must include, in their Reservation Request application, an engineering survey or study confirming the on-site Renewable Fuel (i.e., adequate flow rate) and the generating system's average capacity during the term of the Project's required warranty/maintenance period.

Proposed Pressure Reduction Turbine systems must include in their Reservation Request applications an engineering survey or study confirming adequate temperature, pressure and flow within the piping system, and the generating system's average capacity during the term of the Project's required warranty/maintenance period. Proposed Waste Heat to Power systems must include in their Reservation Request applications an engineering survey or study confirming adequate waste heat production rate and temperature, and the generating system's average capacity during the term of the Project's required warranty/maintenance period.

If the renewable fuel forecast or the waste energy forecast has not yet materialized the Applicant will be given two options: 1) take a onetime payment based on the Site load, renewable fuel, or waste energy availability (whichever is less) demonstrated at the time of initial inspection or, 2) wait for the renewable fuel, or waste energy to materialize within 12-months of the date the Incentive Claim Form and documents were initially received. If the renewable fuel, or waste energy has not materialized within the 12-month period, the Project will be paid based on the Site load, or system operating capacity available at the end of the 12-month period whichever is less.

9.2 Rating Criteria for System Output

System capacity ratings are established at the time of Conditional Reservation Notification in order to determine the SGIP reservation dollar amount. If system modifications (i.e. changes in equipment make/model) are made after the Conditional Reservation Notification, the system capacity must be re-rated using currently available published component information for the changed equipment. If the number of components has increased or decreased and there is no change in the make/model of the equipment used, system components can be re-rated using the same published information used at the time of the Conditional Reservation Notification.

- For renewable technologies (except wind turbines), the generating system capacity is the operating capacity based on the average annual available Renewable Fuel flow rate, including allowable fossil fuel at ISO conditions[12].
- For non-renewable technologies, the generating system rated capacity is the net continuous power output of the packaged prime mover/generator at ISO conditions operating on a Non-Renewable fuel.

[12] Industry standard conditions to measure output – temperature at 59 degrees Fahrenheit and altitude at sea level (0 feet).

- Wind turbine rated capacity is the highest electrical output from the manufacturer's power output curve for wind speeds up to 30 mph including inverter losses.
- For Advanced Energy Storage technologies, the rated capacity must be the net continuous discharge power output (kW) over a two hour period.
- For Waste Heat to Power technologies the generating system capacity is the operating capacity based on the average annual available waste heat production rate and temperature.
- For Pressure Reduction Turbine technologies the generating system capacity is the operating capacity based upon the average annual pressure drop across the turbine and flow rate through the turbine.

Eligible technology system rated capacity must be substantiated with documentation from the manufacturer. Refer to Section 2.1 for detailed instructions on documentation requirements.

9.3 Minimum Operating Efficiency

Conventional CHP systems and Fuel Cells must meet a minimum operating efficiency requirement. These systems can satisfy this requirement by either meeting the 1) waste heat utilization, or 2) minimum electric efficiency requirements. Each of these requirements is described in detail in Sections 9.3.1 and 9.3.2 and an example is provided in Appendix A.

9.3.1 *Waste Heat Utilization*

To meet minimum waste heat utilization combined heat and power systems must meet the requirements of Public Utilities Code 216.6, which are expressed in the following equations.[13]

P.U. Code 216.6 (a) => $T / (T + E) \geq 5\%$

And,

P.U. Code 216.6 (b) => $(E + 0.5 \times T) / F \geq 42.5\%$

Where:

T ≡ The ***annual*** useful thermal output used for industrial or commercial process (net of any heat contained in condensate return and/or makeup water), heating applications (e.g., space heating, domestic hot water heating), used in a space cooling application (i.e., thermal energy used by an absorption chiller).

[13] PUC 216.6 - "Cogeneration" means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards: (a) At least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy; (b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

E ≡ The ***annual*** electric energy made available for use, produced by the generator, exclusive of any such energy used in the power production process.

F ≡ The generating system's ***annual*** Lower Heating Value (LHV) non-renewable fuel consumption.

All applications proposing combined heat and power technologies must provide documentation demonstrating an ability to meet both of the minimum waste heat utilization standards stated above, including an engineering calculation of the P.U. Code 216.6 efficiencies with documented assumptions regarding the Site's Thermal Load. An example is provided in Appendix A

Specifically, following documentation must be provided.

- **Generator & Thermal System Description**
  The application must include the performance and capacity specifications for the proposed Combined Heat and Power (CHP) system and all thermal system equipment that the CHP system interacts with or serves. This includes but is not limited to the generator system, heat recovery system, heat exchangers, absorption chillers, boilers, furnaces, etc. In addition, a thermal process diagram must be provided as part of the documentation package that shows the configuration of the generator(s), heat recovery system, pumps, heat exchangers, Thermal Load Equipment, and the working fluid flow and temperatures in/out of each piece of major equipment at design conditions.

- **Forecast of Generator Electric Output**
  The application must include a forecast of the monthly generator electric output (kWh/month) for a twelve-month period. The generator electric output forecast must be based on the operating schedule of the generator, historical or Site electric load forecast and maximum/minimum load ratings of the generating system; exclusive of any electric energy used in ancillary loads necessary for the power production process (i.e., intercooler, external fuel gas booster, etc.).

- **Forecast of Generator Thermal Output**
  The application must include a forecast of the monthly generator thermal output (Btu/month) for a twelve-month period. The generator thermal output forecast must be based on the electric output forecast of the generating system and the waste heat recovery rate specifications of the system.

- **Forecast of Generator Fuel Consumption**
  The application must include a forecast of the generating systems monthly fuel consumption (Btu/month) for a twelve-month period. The generator's fuel consumption forecast must be based on the generating system electric output forecast and the systems fuel consumption specifications.

- **Forecast of Thermal Load Magnitude**
  The application must include a monthly Thermal Load forecast (Btu/month) for a twelve-month period for the Thermal Load served by the CHP system. The forecast must be based on

engineering calculations, thermal system modeling, historical fuel billing, measured data or a combination of these methods. The Thermal Load forecast must be independent of the generator operation forecast. If historical natural gas or other fossil fuel consumption records (e.g., billing records) are used, the combustion efficiency of the natural gas or fossil fuel fired equipment that is being displaced must be included. Historical fuel consumption must be discounted to account for equipment Thermal Load that will not be displaced by the prime mover's thermal energy.

- **Forecast of Useful Thermal Output**
  The useful thermal output of the CHP system will be the lesser of the Thermal Load forecast, or the prime mover's thermal output coincident with the Thermal Load. The useful thermal output is the value used in calculating the P.U. Code 216.6 requirements.

All assumptions, backup documentation, hand calculations, models (with inputs and outputs) and custom spreadsheets used to develop the forecasts must be included in the documentation. Forecasts based solely on "professional experience" or subjective observation will be rejected. Applications must include a completed Waste Heat Utilization Worksheet, available from the Program Administrators' websites, to calculate the waste heat utilization efficiency.

9.3.2 ***Minimum Electric Efficiency***[14]

To meet the minimum electric efficiency criteria the proposed generators electrical efficiency must be equal or greater than 40%, which is expressed in the following equation.

Electrical Efficiency => E / F ≥ 40%

Where:

E ≡ The generating system's rated electric capacity as defined in Section 9.2, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh.

F ≡ The generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity.

9.3.2.1 **Minimum Operating Efficiency Worksheet**

To facilitate the PU Code 216.6 and Electrical Efficiency calculations to determine system eligibility, a Minimum Operating Efficiency Worksheet spreadsheet is available for download from the Program Administrators' websites.

There are two versions of the Minimum Operating Efficiency Worksheet; one for residential systems and a second worksheet for all other systems. "Residential systems" are Projects installed at a residential Host Customer Site. The Residential Minimum Operating Efficiency Worksheet is illustrated in Appendix A - Table A-1 and the Minimum Operating Efficiency Worksheet, for all other systems, is illustrated in Appendix A - Table A-2.

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[14] This requirement was included as an alternative requirement to meeting Public Utilities Code 216.6 in compliance with AB 2778.

9.4 Fossil Fuel Combustion Emission & Minimum System Efficiency Standards

In addition to the minimum operating efficiency requirement, microturbine, internal combustion engine and gas turbine Projects must not exceed a NOx emissions standard of 0.07 lbs/MW-hr and must meet the 60% minimum system efficiency requirement. If these Projects fail to meet the emission standard, but meet the 60% minimum system efficiency standard, then an emission credit may be determined to adjust the final emissions determination of eligibility. The following chart shows schematically the eligibility requirements, which are further detailed below.

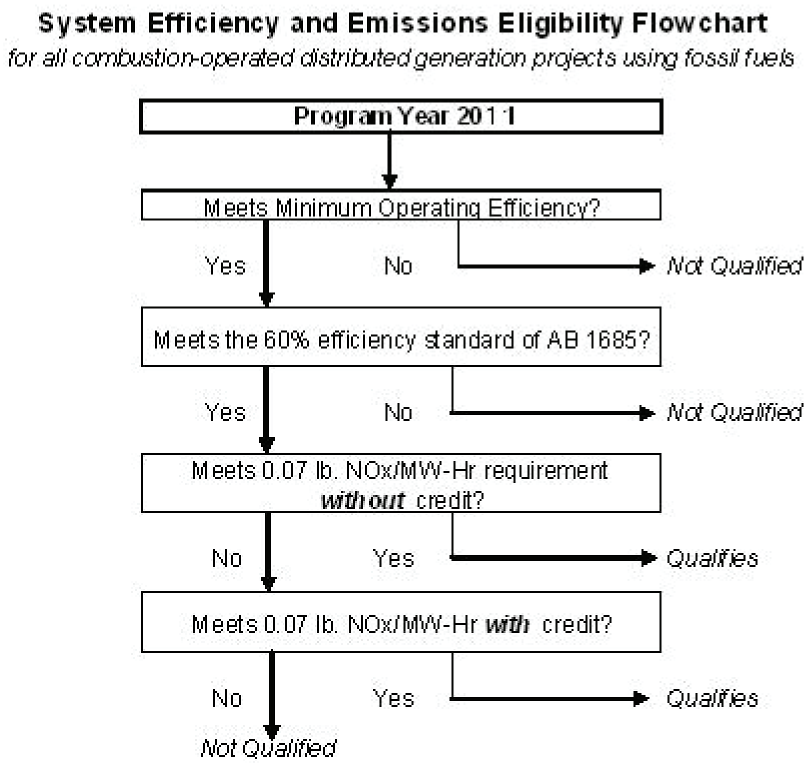

Figure 9-1 AB 1685 Eligibility Requirement Flowchart

9.4.1 *Minimum System Efficiency Standard*

Microturbine, internal combustion engine and gas turbine Projects must meet or exceed the 60% minimum system efficiency standard. The minimum system efficiency shall be measured as useful energy output divided by fuel input in higher heating value. The calculated minimum system efficiency shall be based on 100 percent load. The following formula is to be used to determine the system efficiency.

System Efficiency = (E + T) / F ≥ 60%

Where:

E ≡ The generating system's rated electric capacity as defined in Section 9.2, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh

T ≡ The generating system's waste heat recovery rate (Btu/hr) at rated capacity.

F ≡ The generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity.

9.4.2 *Fossil Fuel Combustion Emission Eligibility Requirements*

The application must include documentation demonstrating that the proposed generator will not exceed the applicable NOx emission standard (.07 lb/MWh). At the Reservation Request stage, the application must include one of the following documents to determine the NOx emissions (lb/MWh) of the proposed system.

- Manufacturer emission specifications based on factory testing using California Air Resources Board (CARB), EPA or local air district test methods[15], for the proposed generating system as configured for the Site.
- CARB distributed generation certification

Or,

- Emission engineering calculations for the proposed generating system as configured for the Site.

Conversion of emissions concentration (ppm) to production based emissions rates (lb/MWh) shall use the method found in Appendix C of this handbook.[16]

In addition, the application must include a Permit to Operate issued for the Project from the local air district or air quality authority as part of the Incentive Claim documentation.

9.4.3 *Fossil Fuel Combustion Emission Credits*

Microturbine, internal combustion engine and gas turbine Projects that do not meet the applicable NOx emission standard (.07 lb/MWh) may receive emission credits for waste heat utilization.

Credit shall be at the rate of one MWh for each 3.4 million British thermal units (Btu) of heat recovered.

The following formula is used to modify the emissions rating for a generating system by giving credit for waste heat utilization. [17]

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[15] Acceptable test methods include but not limited to CARB Test Method 100 and USEPA Test Method 7.

[16] California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix C: Procedure for Converting Emission Data to lb/MW-hr, July 2002.

[17] Emissions credit calculation is based on the California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

$Lb/MWh_{w/credit} = Lb/hr_{EmissionRate} / (MW_{Rated} + MW_{ProcessHeat}) \equiv$ System emissions with thermal credit

Where:

$Lb/hr_{EmissionRate} = Lb/MWh_{w/o\_credit} \times MW_{Rated} \equiv$ NOx emission rate at the system's rated capacity

$Lb/MWh_{w/o\_credit} \equiv$ System's verified emissions without thermal credits

$MW_{Rated} \equiv$ System's Rated Capacity as defined in Section 9.2.

$MW_{ProcessHeat} = (MMBtu/yr_{UtilizedWasteHeat} / 3.4\ MMBtu/MWh) / EFLH/yr \equiv$ Capacity credit for useful thermal energy

$MMBtu/yr_{UtilizedWasteHeat} \equiv$ Annual utilized waste heat

3.4 MMBtu/MWh ≡ Heat recovered conversion factor

EFLH/yr ≡ System's annual equivalent full load hours of operation

All assumptions, backup documentation, hand calculations, models (with inputs and outputs) and custom spreadsheets used to develop the forecasts must be included in the documentation. Forecasts based solely on "professional experience" or subjective observation will be rejected. Applications must include a completed Waste Heat/AB1685 spreadsheet, available from the Program Administrators' websites, that calculates the waste heat utilization, minimum system efficiency and emissions requirements.

Example #1: Emissions Credit for 360 kW IC Engine Generator

A 360 kW IC engine generator set is proposed to supply electric power and heat to a furniture manufacturing facility. The system utilizes an intercooler chiller that is rated at 10 kW. Its full load fuel consumption is 4.4 MMBtu/hr LHV (4.8 MMBtu/hr HHV[18]) and its full load waste heat recovery rate is 2.6 MMBtu/hr. Source testing documentation for the same generating system make/model and configuration, but from another site, indicate that the NOx emissions from this unit are 0.16 lb/MWh. The generator is fueled with a Non-Renewable fuel and is not a fuel cell. The generator electric output follows the load of the Host Customers facility, but shuts down when the load falls below 40 kW, the minimum load of the generator. The Host Customer annual peak demand is approximately 400 kW. Waste heat from the generating system is used to deliver hot water for manufacturing process, equipment cleanup and space heating. Detailed analysis of the system and Host Customer load reveals that the system will be generating 1,715,000 kWh/yr at a capacity factor of 56%. The system will produce 12,730 MMBtu/yr of recovered waste heat to serve 12,400 MMBtu/yr of thermal load, however only 8,256 MMBtu/yr of waste heat is actual useful thermal output because of non-coincident monthly load. The system consumes 21,521 MMBtu/yr LHV and 23,673 MMBtu/yr HHV of fuel. Thus -

Minimum Operating Efficiency Requirement

P.U. Code 216.6 (a)

[18] For natural gas, LHV ≈ HHV x 0.9

8,255,800,000 [Btu/yr] / {(1,715,000 [kWh/yr] x 3,413 [Btu/kWh]) + 8,255,800,000 [Btu/yr]} = 58.5% ≥ 5% ***Passes***

P.U. Code 216.6 (b)

{(1,715,000 [kWh/yr] x 3,413 [Btu/kWh]) + 0.5 x 8,255,800,000 Btu/yr} / 21,520,800,000[Btu/yr] = 46.4% ≥ 42.5% ***Passes***

AB 2778 Minimum Electric Efficiency

(360 [kW] x 3,414 [Btu/kWh]) / 4,831,200 Btu/hr = 25.4 ≥ 40% ***Fails***

Air Emissions Requirement

AB 1685 Minimum System Efficiency

{(360 [kW] x 3,414 [Btu/kWh]) + 2,598,000 [Btu/hr]} / 4,831,200 Btu/hr = 79.2 ≥ 60% ***Passes***

AB 1685 NOx Emissions w/o Waste Heat Credit

0.16 [lb/MWh] ≤ 0.07 lb/MWh NOx ***Fails***

AB 1685 NOx Emissions w/ Waste Heat Credit

{0.16 [lb/MWh] x .360 [MW]} **/** {.360 [MW] + (8,256 [MMBtu/yr] / 3.4 [MMBtu/MWh]) / 4,900 EFLH/yr} = 0.067 lb/MWh ≤ 0.07 lb/MWh NOx ***Passes***

The Minimum Operating Efficiency & Emissions worksheet,is designed to perform this calculation. Applications must include in their application a completed Minimum Operating Efficiency & Emissions worksheet, which is available from the Program Administrators' websites.

9.5 Greenhouse Gas Emission Standard

Microturbine, internal combustion engine, gas turbine and fuel cell CHP Projects as well as electric-only fuel cells operating on non-renewable fuels must not exceed a Greenhouse Gas (GHG) emissions standard of 379 kg CO_2/MW-hr. The gross GHG output is calculated by multiplying the annual fuel consumption of the generator in MMBtus by an emission factor of 53.02 kg CO_2/MMBtu[19] for the conversion of natural gas to CO_2. The GHG savings from waste heat recovery are calculated by dividing the annual waste heat recovered in MMBtus by 80% which represents a nominal boiler efficiency and then multiplying by the 53.02 kg CO_2/MMBtu emission factor. The net GHG output of the generator is calculated by subtracting the GHG savings due to waste heat recovery from the gross GHG output. The GHG emissions rate for the generator is found by dividing the net annual GHG emissions by the annual electrical output of the generator in MWh.

[19] Unspecified natural gas conversion emission factor from Appendix A of Section 95112 of the mandatory GHG reporting regulation. Title 17 of the California Code of Regulations.

9.6 Thermal Load Coincidence

In order to reduce GHG emissions and optimize system efficiency non-renewable CHP projects must not exceed the onsite thermal load with the recovered waste heat on a monthly basis. Therefore the monthly recovered waste heat divided by the monthly thermal load must be less than 1.0.

9.7 Greenhouse Gas Emission Rate Testing Protocol for Electric-Only Technologies that Consume Non-Renewable Fuels

The only eligible electric-only technologies operating on non-renewable fuels are Fuel Cells. Fuel Cells operating under these conditions will be required to be tested according to the ASME PTC 50-2002 protocol. The ASME PTC 50-2002 will be used to determine the energy input to the fuel cell, the electrical power output, thermal and mechanical outputs, average net power, electrical efficiency, thermal effectiveness and heat rate under ISO test conditions. The average net power of the fuel cell coupled with the fuel input rate (HHV) will be used to calculate the annual power generation (MWh) and fuel consumption (MMBtu) based upon an assumed capacity factor of 80%. The GHG output is calculated by multiplying the annual fuel consumption of the fuel cell in MMBtus by the emission factor of 53.02 kg CO_2/MMBtu for the conversion of natural gas to CO_2. The GHG emissions rate for the generator is found by dividing the annual GHG emissions by the annual electrical output of the generator in MWh.

9.8 Exemptions for Waste Gas Systems

Microturbine, internal combustion engine and gas turbine systems operating solely on Waste Gas are exempt from the SGIP emission requirements if the local air quality management district or air pollution control district, in issuing a Permit to Operate for the Project, provides in writing a determination that the operation of the Project will produce an onsite net air emissions benefit compared to permitted onsite emissions if the Project does not operate. Note that Waste Gas Systems, though exempt from SGIP emission requirements, still must meet the Waste Heat Utilization Requirement.

9.9 Reliability Criteria

Microturbines, internal combustion engines and gas turbines must meet both of the following reliability requirements:

1. The self-generating facility must be designed to operate in power factor mode such that the generator operates between 0.95 power factor lagging and 0.90 power factor leading. This design feature will be verified by reviewing the manufacturer's specifications at the time of application and as part of the field verification visit before incentive payment approval.
2. System Owners with facilities sized greater than 200 kW must coordinate the self-generation facility planned maintenance schedule with the Electric Utility. This allows the utility to more accurately schedule load and plan distribution system maintenance. The System Owner will only

schedule a facility's planned maintenance between October and March and, if necessary, during off-peak hours and/or weekends during the months of April to September.

9.10 Load Following Requirement for Advanced Energy Storage

To be eligible for SGIP incentives Advanced Energy Storage systems coupled with wind generation must have the ability to handle hundreds of partial discharge cycles each day. Whereas stand-alone Advanced Energy Storage systems or those coupled with other SGIP eligible generating technologies must meet the site specific requirements for on-site peak demand reduction and be capable of discharging fully at least once per day. All Advanced Energy Storage systems must have the capability to discharge over a two hour period at rated capacity.

9.11 Alternative Criteria for Generating System Eligibility – Third Party Certification

Generating systems consisting of or utilizing new technologies may be eligible for the SGIP if certification is obtained from a nationally recognized testing laboratory indicating that the technology meets the safety and/or performance requirements of a nationally recognized standard. Equipment manufacturers seeking eligibility through these criteria shall submit a written request via the PMG to the SGIP Working Group for consideration, along with the proposed standards for certification.

If a generating system consisting of or utilizing new technologies is not certified, but is in process of certification with a nationally recognized testing laboratory when the Reservation Request application is submitted and is deemed eligible by the SGIP Working Group per SGIP requirements, the Host Customer will be required to pay an Application Fee equal to 1% of the requested incentive. Once the Program Administrator issues a Conditional Reservation, the Application Fee will be forfeited if it is not withdrawn within 20 calendar days of the Conditional Reservation date by the Host Customer/System Owner or if cancelled by the Program Administrator for not satisfying the SGIP requirements.

Finally, the Host Customer or System Owner is required to obtain and submit to the Program Administrator proof of certification from a nationally recognized testing laboratory with the required Reservation Confirmation and Incentive Claim documents within 12-months of the original Reservation Expiration Date. Failure to submit proof of third party certification within the 12-month period will result in cancellation of the Project by the Program Administrator.

9.12 Hybrid Systems

A system that contains more than one type of eligible technology at one Site and behind one Electric Utility service meter is considered a "Hybrid System" and is eligible for SGIP incentives. For example, a

Wind Turbine and Fuel Cell Hybrid System installed at a single Site may receive incentives, provided each technology meets all SGIP eligibility requirements for that technology.

Hybrid projects with Advanced Energy Storage Systems are required to install metering equipment that will record the generation system output as well as the charging and discharging of the Advanced Energy Storage system. Metering system requirements are articulated in section 11 below.

9.13 Equipment and Installation Certifications

The SGIP intends to provide incentives for reliable, permanent, safe systems that are professionally installed, and comply with all applicable Federal, State and local regulations. Host Customers and System Owners are strongly encouraged to become familiar with applicable equipment certifications, design, and installation standards for the systems they are contemplating. All systems must be installed by appropriately licensed California contractors in accordance with rules and regulations adopted by the State of California Contractors' State Licensing Board. Installation contractors must have an active A, B, or C-10 license. The system installers name, telephone number and contractor license number must be submitted along with the Proof of Project Milestone documentation.

10 Eligible Fuels

Eligible fuels for eligible SGIP generating technologies are classified as renewable, non-renewable and Waste Gas. Each type of eligible fuel is described below.

10.1 Renewable Fuels

A Renewable Fuel, for the purposes of determining whether a proposed Project qualifies for renewable incentives, is a non-fossil fuel resource other than those defined as conventional in Section 2805 of the Public Utilities Code that can be categorized as one of the following: wind, gas derived from biomass, digester gas, or landfill gas. A facility utilizing a Renewable Fuel may not use more than 25 percent fossil fuel annually, as determined on a total energy input basis for the calendar year.

There are two types of Renewable Fuels allowed in the program, depending on the location of the source and how it is delivered; On-Site Renewable Fuel and Directed Biogas. A summary of the requirements for both are summarized in Table 10-1.

Table 10-1 Renewable Fuel Eligibility Requirements

Renewable Fuel Eligibility Requirements	On-Site Renewable Fuel	Directed Biogas
Meets SGIP Renewable Fuel Definition	X	X
Demonstration of availability of adequate average flow rate of Renewable Fuel.	X	X
Submission of Fuel Gas Cleanup Purchase Order	X	
Signed Affidavit Complying with SGIP Renewable Fuel Requirements	X	
Meet the currently applicable Renewable Portfolio Standard eligibility requirements for biogas injected into a natural gas pipeline.		X
Renewable Fuel Supply must be within, or Interconnected to, Utility Pipelines within California		X
Must have Installed Utility Remotely Accessible Revenue-Grade Electric NGOM & Revenue Grade Fuel Meter(s).		X
Annual Audit of Renewable Fuel Invoices		X
Notification of Change in		X

Renewable Fuel Supplier		

10.2 Proof of Adequate Renewable Fuel

Proposed Renewable Fuel systems must include, in their Reservation Request application, an engineering survey or study confirming the on-site Renewable Fuel (i.e., adequate flow rate) and the generating system's average capacity during the term of the Project's required warranty/maintenance period.

If the Site load forecast or renewable fuel forecast has not yet materialized, the Applicant will be given two options; 1) take a onetime payment based on the Site load or fuel availability (whichever is less) demonstrated at the time of initial inspection or, 2) wait for the Site load or fuel to materialize within 12-months of the date the Incentive Claim Form and documents were initially received. If the Site load or fuel has not materialized within the 12-month period, the Project will be paid based on the Site load, or system operating capacity available at the end of the 12-month period.

10.3 On-Site Renewable Fuel

For On-Site Renewable Fuel projects the following must be provided.

- Renewable fuel supplier facility must produce fuel that meets the SGIP definition of Renewable Fuels.
- Documentation demonstrating the availability of an adequate average flow rate of Renewable Fuel, for the duration of the required warranty period (10 yrs), to produce electricity at the unit's full rated capacity, or an appropriate de-rated operating capacity[20] based on the annual average available Renewable Fuel resource flow rate including allowable Non-Renewable Fuel supplement (which is no more than 25% fossil fuel as determined on a total energy input basis for the calendar year). Evidence that an adequate Renewable Fuel resource exists will be verified during the field verification visit prior to approval of the incentive. Units whose annual fuel consumption exceeds the available Renewable Fuel plus the allowable Non-Renewable Fuel supplement will have the incentive based upon on the operating capacity resulting from the average annual available Renewable Fuel flow rate, including allowable Non-Renewable fuel flow rate. Increasing an existing generator's Non-Renewable Fuel consumption to increase the available Renewable Fuel resource for a new SGIP proposed generator is not allowed.
- Submit an equipment purchase order that indicates the fuel cleanup equipment as a separate invoice item.

[20] "De-rated capacity" is the generating system average capacity based on available Renewable Fuel resource and is the capacity used to determine the incentive amount.

- Provide a signed affidavit stating that the unit will comply with the SGIP Renewable Fuel requirements. The length of this commitment shall be the same as the equipment warranty requirement discussed above for each incentive category.

10.4 Directed Biogas Renewable Fuel

Directed Biogas Renewable Fuel is obtained pursuant to a contract where biogas is nominated and delivered[21] to customers via a natural gas pipeline. Eligible Directed Biogas Renewable Fuel projects must meet all Renewable Fuel eligibility requirements in SGIP in addition to the following conditions and verification protocols:

- Renewable fuel supplier facility must produce fuel that meets the SGIP definition of Renewable Fuels.
- Renewable Portfolio Standard eligibility requirements for biogas injected into a natural gas pipeline.
- Documentation demonstrating availability of adequate average flow rate of Renewable Fuel for the duration of the required warranty period,
    - to produce electricity at the unit's full rated capacity, or an appropriate de-rated operating capacity[22] based on the annual average available Renewable Fuel resource flow rate including allowable Non-Renewable Fuel supplement
    - Evidence that an adequate Renewable Fuel resource exists will be verified during the field verification visit prior to approval of the incentive.
    - Units whose annual fuel consumption exceeds the available Renewable Fuel plus the allowable Non-Renewable Fuel supplement will have the incentive based upon on the operating capacity resulting from the average annual available Renewable Fuel flow rate, including allowable Non-Renewable fuel flow rate.
    - Increasing an existing generator's Non-Renewable Fuel consumption to increase the available Renewable Fuel resource for a new SGIP proposed generator is not allowed.
- Renewable fuel supplier facility must be located within California.
- The Host Customer and the renewable fuel supplier must install a revenue-grade fuel gas meter(s) that can be remotely monitored by the utility.
- Program Administrators will conduct an annual audit of the renewable fuel invoices for each site to ensure compliance with the requirement to procure renewable fuel for at least 75% of the

[21] There is no means of ensuring the actual molecules of renewable gas are consumed at the customer's site. Thus, the gas is not literally delivered, but notionally delivered, as the biogas may actually be utilized at any other location along the pipeline route.

~~See footnote 14.~~

generator's total fuel supply. If it is determined that Directed Biogas Renewable Fuel deliveries fell below 75% of the generator's fuel demand during any 1 year period within the warranty period a refund of a portion of the incentive will be required.

- If the Host Customer decides to change their renewable fuel supplier, or if the Customer's current renewable fuel supplier cannot meet the obligations to perform as set forth in their contract, then the Host Customer is allowed to find a new supplier within 90 days. The Program Administrator must be made aware of the situation, and the required minimum of 75% renewable fuel consumption on an annual basis, during this period of transition must be maintained. Once the Host Customer finds a new supplier, they must then enter into a new contract that provides for at least 75% of the system's anticipated consumption. The Host Customer must provide to the Program Administrator all documentation requested in the bullets above, except for metering information, unless it has changed.

10.5 Directed Biogas Renewable Fuel Audits

After the incentive is issued, SGIP requires a yearly audit process for ten years after the renewable fuel contract commences. The audit process works as follows: at the completion of each year, the Customer must provide the SGIP Program Administrator with the preceding 12 months of invoices for renewable fuel purchases. The Program Administrator will review the invoices to ensure that the Customer is satisfying the intent to procure renewable fuel to meet at least 75% of the generator's consumption. Audits can be conducted remotely, thereby reducing costs for the SGIP program.

If invoices show that nominated renewable fuel deliveries fell below 75% of the generator's fuel demand over the same period, and the generator is not malfunctioning such that it consumes more fuel than originally forecast for the nomination, then the SGIP Program Administrators will request that the Customer refund the full $2.00/Watt Biogas SGIP incentive and reserve the right to request additional costs associated with administrative and legal fees incurred by the Program Administrators.

10.6 Non-Renewable Fuels

Non-Renewable include fossil fuels and synthetic fuels.

For the SGIP, eligible fossil fuels include gasoline, natural gas and propane. Diesel fuel (including biodiesel and other fuels that can be interchanged with diesel fuel) is explicitly ineligible in the SGIP.

Synthetic fuels are fuels derived from materials that are not Renewable Fuels (see Section 10.1) or fossil fuels. Eligible synthetic fuels include, but are not limited to, the direct use or synthesis of fuels from sewage sludge, industrial waste, medical waste or hazardous waste.

10.6.1 ***Waste Gas Fuels***

Waste Gas fuels used for conventional CHP technologies and fuel cells are strictly defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

Incentives paid for Waste Gas fuel systems shall be subject to refund to the Program Administrator by the recipient if it is determined that the Project does not operate on Waste Gas for at least the required warranty period.

11 Metering Requirements

This section contains detailed information on the minimum metering and monitoring requirements for SGIP projects requesting an Advanced Energy Storage (AES) incentive. These minimum requirements were developed to increase Project Administrator knowledge of AES system performance, when coupled with an intermittent generation resource such as wind power as well as with fuel cell generation where it will serve to provide peak demand reduction.

SGIP technologies that are allowed to be coupled with an Advanced Energy Storage system must install and maintain metering and monitoring equipment at their own cost. The system owner is responsible for monitoring, maintaining and reporting the metered data to the Program Administrators on a quarterly basis for a minimum of 5 years. If the system owner chooses to contract with a Performance Monitoring and Reporting Service (PMRS), a list of qualified PMRS providers is can be found on http://www.gosolarcalifornia.ca.gov/equipment/monitors+rsp.html

All System Owners are responsible for the choice and installation of the metering hardware as well as the selection of a PMRS provider. A list of eligible meters can also be found on http://www.gosolarcalifornia.ca.gov/equipment/index.html. The System Owner is also responsible for resolving any issues relative to PMRS performance data. Please see Section 5.1.5 for further information regarding the transfer of production data.

Detailed information on these summarized metering requirements follows.

11.1 Minimum Meter Requirements

All AES systems coupled with any SGIP-eligible technology must install metering equipment capable of measuring and recording interval data on generation output and AES charging and discharging to facilitate gathering of data regarding the AES system performance. The meter must be listed with the California Energy Commission and must meet the minimum meter requirements of this section.

The California Energy Commission's list of qualifying meters can be found at http://www.gosolarcalifornia.ca.gov/equipment/index.html

11.1.1 *Meter Type*

For all AES systems the installed meter(s) may be a separate Interval Data Recording (IDR) meter(s), or if the AES technology utilizes an inverter and a rectifier for power conditioning, the meter may be internal to the AES system. The complete system must be functionally equivalent to an IDR meter, recording data no less frequently than every 15 minutes.

11.1.2 ***Meter Accuracy***

All AES systems must install a meter accurate to within ± 2% of actual system output.

11.1.3 ***Meter Measurement***

Electric meters must:

- Measure 15 minute gross energy generated (kWh) by the eligible SGIP generation system.
- Measure 15 minute gross energy for the AES system during charging and during discharge.
- Count the number of charge and discharge cycles during the 15 minute interval
- Generate a time/date stamp.

11.1.4 ***Meter Testing***

± 2% meters must be tested according to all applicable ANSI C-12 testing protocols pertaining to the monitoring of power (kW) and energy (kWh).

11.1.5 ***Meter Certification***

The accuracy rating of ±2% meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV).

11.1.6 ***Meter Memory and Storage***

All meters must have the ability to retain collected data in the event of a power outage. Meters that are reporting data remotely must have sufficient memory to retain 60 days of data if their standard reporting schedule is monthly and 7 days of data if their standard reporting schedule is daily. Meters that do not remotely report their data must retain 120 days of data. In all cases, meters must be able to retain lifetime production.

11.2 Minimum Reporting Requirements

In order to enable Program Administrators to properly evaluate the performance of AES systems installed in conjunction with eligible SGIP systems the System Owner must perform all monitoring, data collection, data retention, and reporting as specified in the corresponding sub-sections below. If the system owner chooses to contract with a PMRS the California Energy Commission's list of qualifying PMRS providers can be found at http://www.gosolarcalifornia.ca.gov/equipment/monitors+rsp.html.

11.2.1 ***Required AES Performance / Output Data***

The System Owner or PMRS must monitor, record, and report on:

- 15 minute gross energy (kWh) generated by the eligible SGIP generation system.

- 15 minute gross energy for the AES system during charging and during discharge.

- The number of charge and discharge cycles during the 15 minute interval

- A time/date stamp.

11.2.2 *Minimum Report Delivery Requirements*

The System Owner or PMRS must provide for the electronic delivery of reports to the Program Administrators on a quarterly basis.

11.2.3 *Time Granularity of Acquired Data*

The System Owner or PMRS must log all required output data points no less frequently than once every 15 minutes.

11.2.4 *Minimum Reporting Requirements*

The System Owner or PMRS must provide the following reports based on acquired, processed, and analyzed data:

16) Data as collected and summarized by hour, day, month, and year in electronic format (Excel, CSV, acceptable).
17) Data must be associated with a specific site.

11.3 Acceptable Metering Points

The metering system must meter delivered energy by having a meter at the output of the generator and a meter to measure the charge and discharge of the AES. Alternatively, one meter can be used with multiple channels that can monitor at these two points. It is acceptable to use a meter that is internal to the AES to monitor these two points as long as it meets the meter testing and certification criteria listed in sections 11.1.4 and 11.1.5.

11.4 Inspection

The meters will be inspected as part of the project inspection process.

12 Warranty Requirements

All generation systems eligible for the SGIP must have a minimum 10 year warranty. The warranty must cover all of the major components of the system that are eligible for the incentive, to protect against breakdown or degradation in electrical output of more than ten percent from their originally rated electrical output. The warranty shall cover the full cost of repair or replacement of defective components or systems, including coverage for labor costs to remove and reinstall defective components or systems.

Warranty requirements apply to all eligible technologies regardless of length of commercial availability. System Owners are required to fulfill the warranty requirements described below in the following sequence:

1. Utilize equipment warranties, which come standard with the purchase of the system.
2. If the standard equipment warranty for any major system component is of insufficient duration to meet the requirement, the customer must purchase, if one is available, an extended warranty to bridge any gap in duration, which may exist.
3. Then, and only if an application can demonstrate that a standard and/or extended warranty combination is unavailable to meet the warranty requirement – OR if the extended warranty requires the purchase of a maintenance contract – the System Owner is to enter into a maintenance contract as a substitute measure.

The System Owner must provide proof of warranty (and/or maintenance contract), and specify the warranty start and end dates within the installation contract or power purchase agreement submitted with the required Proof of Project Milestone documentation.

13 Not Eligible under the SGIP

13.1 Ineligible generating systems / equipment

- Back-Up Generators - systems intended solely for emergency or back-up generation purposes
- Any system/equipment that is capable of operating on or switching to diesel fuel, or Diesel Cycle for start-up or continuous operation
- Generating technologies not listed in Table 1-1 (Base Incentive Levels for Eligible Technologies) in Section 1.1.
- Advanced Energy Storage systems utilizing hydrogen as the storage medium are not eligible at this time
- Field demonstrations for proof-of-concept operation of experimental or non-conventional systems partially or completely paid by research and development funds
- Rebuilt, refurbished or relocated equipment

13.2 Ineligible Host Customer Loads

- Customers who have entered into contracts for Distributed Generation (DG) services (e.g. DG installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services. This does not include Power Purchase Agreements, which are allowed.
- Any portion of a Host Customer's load that is committed to Electric Utility interruptible, curtailable rate schedules, programs or any other state agency-sponsored interruptible, curtailable, or demand-response programs. For Electric Utility customers who are on an interruptible rate, only the portion of their electric load designated as firm service is eligible for the SGIP. Customers must agree to maintain the firm service level at or above capacity of the proposed generating system for the duration of the required applicable warranty period. Customers may submit a letter requesting an exemption to the firm service rule if they plan to terminate or reduce a portion of their interruptible load. Wind Projects need not abide by this portion.
- Publicly-owned or investor-owned gas, electricity distribution utilities or any Electrical Corporation (ref. Public Utility Code 218) that generates or purchases electricity or natural gas for wholesale or retail sales.

14 Other Installation Requirements & Continuing Site Access Requirements

14.1 Application Fee

In addition to the Reservation Request Package and Required Attachments, Applicants will also be required to submit an application fee.

The application fee is equal to 1% of the amount of requested incentive for SGIP projects.

Applicants may submit the application fee with the Reservation Request Application[23]. If the Application Fee is not submitted with the Reservation Request Form and required attachments, the Program Administrators will invoice the Host Customer after review of the Reservation Request Form package.

If a Conditional Reservation is granted and the $/W rebate level has been reduced (due to Commission directive, declining rebate structure, etc.), the Applicant and Host Customer will be notified and given 20 calendar days to submit in writing a request to withdraw their Reservation Request without losing their application fee.

The Host Customer will have 30 days to submit payment for the application fee in order to retain their position on the Wait list and/or activate the Reservation Request. Payment must reference the Project by facility address.

While there is no restriction of who may submit payment for the application fee, all refunded Application Fees shall only be paid to the Host Customer.

Program Administrators will only accept Application Fees in the form of a check[24].

Failure to submit payment within 30 days will result in the cancellation of the Reservation Request Application. Returned application fee checks will result in the rejection and return of the Reservation Request Application.

Scenarios in which the Application fee will be refunded to the Host Customer include, but are not limited to the following:

- Upon completion and verification of the installed SGIP Project and incentive payment.[25]
- If a Project is withdrawn from a Wait List prior to receiving a Conditional Reservation
- If upon eligibility screening, the Project does not qualify for a Conditional Reservation

[23] An application fee invoice will be included in the Reservation Request Form

[24] Cash, credit cards, money orders, promissory notes, etc. will not be accepted.

[25] Application Fees will not be altered due to project changes that may result in a different incentive.

- If a Project that has met Proof of Project Advancement and received a "Confirmed Reservation" from the Program Administrator is withdrawn due to extenuating circumstances beyond the Host Customer's control[26].

Scenarios in which the application fee will be forfeited include, but are not limited to the following:

- If a project is cancelled or withdrawn after a conditional reservation has been granted.[27]
- If a conditional reservation has been granted and the Program Administrator rejects the project for failing to meet adequate proof of project milestone or reservation expiration date requirements, the application fee will be forfeited.

All forfeited application fees will be allocated to the Program Administrator's SGIP incentive budget.

14.2 Energy Efficiency Requirements

When applicable, as part of the Reservation Request Package applicants must submit a copy of a completed Energy Efficiency Audit (EEA) performed within the past five (5) years or three (3) years if Title 24 energy efficiency compliant.

Acceptable Proof of Energy Efficiency Audits:

- Report of audit provided by the utilities, PA, or a qualified independent vendor or consultant
- Title 24 energy efficiency compliance

As a general rule the EEA must identify the following criteria:

- Energy efficiency or demand response measures that influence sizing of the project.
- Payback periods for all prescribed measures
- Feasibility or non-feasibility of EE measures

Measures identified in the EEA with a payback period of two years or less must be implemented prior to receipt of the upfront incentive payment. Verification of the implementation of the measures will be carried out by the PAs during the field verification visit. In the case of Title 24 compliance a copy of the Building Permit will be required that shows that Title 24 requirements have been met. Exceptions may be granted by the PA if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible.

[26] Subject to approval by the Program Administrator and the SGIP Working Group

[27] Application fees are specific to an application, not a Site. If the same Site reapplies to the program, they will need to submit a new application fee

In order to avoid duplication of effort, the audit requirement may be waived if the customer is currently participating in an Energy Efficiency programs approved by the PAs or the CPUC.

14.3 Eligibility of Replacement Generation

Installation of a new generating system intended to replace existing on-site generation is allowed only if the Project meets the eligibility requirements in Section 7, the Host Customer has not yet installed and received incentives on their fully allotted 3 MW incentive cap, and fits one of the following situations.

1. The replaced generating system did not receive an incentive through the California Solar Initiative, the Self-Generating Incentive Program or the Energy Commission's Emerging Renewable Program.
2. The replaced generating system did receive an incentive through the California Solar Initiative, the Self-Generating Incentive Program or the Energy Commission's Emerging Renewable Program and
    a. the existing generator has been in service for at least the applicable program's warranty period

       or

    b. the system has been in service for a period less than the applicable program's warranty period, in which case an SGIP incentive can be paid on the incremental increase above the existing generator's rated capacity (kW). For example, if an existing 100 kW fuel cell (which has received SGIP incentives but has not been in service for the required ten-year warranty period) is replaced with a 150 kW fuel cell – SGIP incentives are paid for the 50 kW increase in capacity.

In addition, the Host Customer must fully decommission and remove the replaced generator from the Site, which the Program Administrator will confirm as part of the field verification inspection.

14.4 Permanent Installation

The intent of the SGIP is to provide incentives for generation equipment installed and functioning for the duration of its useful life. Only permanently installed systems are eligible for incentives. This means that the generating system must demonstrate to the satisfaction of the Program Administrator adequate assurances of both physical and contractual permanence prior to receiving an incentive.

Physical permanence is to be demonstrated by electrical, thermal and fuel connections in accordance with industry practice for permanently installed equipment and be secured to a permanent surface (e.g. foundation). Any indication of portability, including but not limited to: temporary structures, quick disconnects, unsecured equipment, wheels, carrying handles, dolly, trailer or platform will deem the system ineligible.

Contractual permanence, **corresponding to a minimum of twice the applicable warranty period,** is to be demonstrated as follows:

- System Owner agrees to notify the Program Administrator in writing a minimum of 60 days prior to any change in either the Site location of the generation system, or change in ownership of the generation system, if the change(s) takes place within twice the applicable warranty period.
- All agreements involving the generation system receiving an incentive are to be provided to the Program Administrator for review as soon as they become available (e.g., at the Proof of Project Milestone stage, or the Incentive Claim stage at the latest). These agreements include, but not limited to system purchase and installation agreements, warranties, leases, energy or services agreements, energy savings guarantees and system performance guarantees.

14.5 Commercial Availability

Commercially available factory new generating equipment is eligible for incentives. Generating systems that utilize new technologies that are critical to its operation must have at least one year of documented commercial availability to be eligible, or meet the requirements of Section 9. “Commercially available” means that the major generating system components (e.g. the generator set, primary heat recovery system and gas cleanup equipment) are acquired through conventional procurement channels, installed and operational at a Site.

14.6 Interconnection to the Utility Distribution System

All distributed generation systems receiving incentives under the SGIP must be connected to the local Electric Utility’s distribution system. The interconnection, operation, and metering requirements for generating systems shall be in accordance with the local Electric Utility rules for customer generating facility interconnections. In order to connect a generating system to the Electric Utility distribution system, Host Customers and/or System Owners will be required to execute certain documents such as, but not limited to, an “Application to Interconnect a Generating Facility” and a “Generating Facility Interconnection Agreement” with the local Electric Utility. Written certification of interconnection and Parallel Operation to the Program Administrator prior to the Reservation Expiration Date will be required.

Applicants, Host Customers and System Owners are solely responsible to submit interconnection applications to the appropriate Electric Utility interconnection department as soon as the information to do so is available to prevent any delays in system Parallel Operation.

14.6.1 *How to Apply For Interconnection of Self Generation Systems*

For more information on electric grid and/or natural gas pipeline interconnections, please contact your local utility (investor owned utilities are listed below). It is the sole responsibility of the SGIP System

Owner and Host Customer to seek and obtain approval to interconnect the self-generation system to a utility's distribution system. System Owners and Host Customers participating in the SGIP should immediately contact the utility to seek guidance on how to apply for interconnection. Contact information is listed below.

Pacific Gas & Electric (PG&E) Website: www.pge.com/gen Phone: (415) 972-5676 (PG&E Generation Interconnection Hotline) Email: gen@pge.com
San Diego Gas and Electric San Diego Gas & Electric PO Box 129831, CP42F San Diego, CA 92123-9749 Phone: (858) 654-1278 Email: selfgensd@semprautilities.com
Southern California Edison (SCE) Southern California Edison Interconnection – Net Metering 2244 Walnut Grove Avenue, GO5 Rosemead, Ca 91770 Phone: (626)302-9680 Email: customer.generation@sce.com
Southern California Gas Company (SoCalGas) www.socalgas.com Residential Customers: (800) GAS-2200 Business Customer: (800) GAS-2000

14.7 Measurement and Evaluation (M&E) Activities

As a condition of receiving incentive payments under the SGIP, System Owners and Host Customers agree to provide full access to Site and generating system equipment in support of, as well as participate in Measurement and Evaluation (M&E) activities as required by the CPUC. M&E activities will be performed by the Program Administrator or the Program Administrator's independent third-party consultant and include but are not limited to, periodic telephone interviews, site visits, development of a M&E Monitoring Plan, installation of metering equipment, collection and transfer of data from installed system monitoring equipment, whether installed by Host Customer, System Owner, a third party, or the Program Administrator.

14.7.1 *Field M&E Visits*

During the course of the Project, the Program Administrator or the Program Administrator's independent third-party consultant will require one or more visits to the Site for M&E purposes. These site M&E visits can occur before, during or after startup of the generating system for the purposes of developing a monitoring plan, installing additional M&E instrumentation, performing equipment operations inspection and retrieving system data. These visits are separate and distinct from the field verification visits (see Section 4.5) by the Program Administrator or its consultants, which are used to determine eligibility of the installed generating system and occur during the Incentive Claim stage of the application process.

14.7.2 *Electrical Metering Requirements*

At the discretion of the Program Administrator, and in consultation with the Program Administrator's independent third-party consultant, SGIP systems may require installation of dedicated, recording, time-of-use or interval metering to measure and record electrical generation output (i.e., Net Generation Output Meter) solely for M&E purposes. Many installations will already require this type of electrical metering as a condition of interconnection with the Electric Utility grid. In the case of investor-owned electric utilities, this means compliance with their filed CPUC Rule 21, Generating Facility Interconnections. Specifications for the net generation output meter can be found on the Program Administrator's or the Electric Utility's website.

Costs for metering normally required by the Electric Utility in accordance with its tariff rules shall be paid by the customer.

14.7.3 *Other Energy Metering Requirements*

The CPUC requires that generator system installations be evaluated for compliance with SGIP requirements for efficiency, waste heat recovery, or use of renewable/non-renewable fuels. As a condition of receiving incentive payments in the SGIP, Host Customer and System Owner agree to allow the Program Administrator, or the Program Administrator's independent third-party consultant, to conduct M&E activities on completed installations. Furthermore, the Host Customer and System Owner agree to cooperate with the installation of any additional system monitoring equipment that the M&E consultant may deem necessary. All labor and material costs for instrumentation and data collection required solely for SGIP M&E purposes (and not by utility tariff) will be paid by the Program Administrator. Results of M&E activities will have no bearing on the incentive payment previously received, with the exception of Projects utilizing Renewable Fuels.

14.7.4 *M&E System Monitoring Data Transfer Requirements*

For systems with Host Customer, System Owner, third party, or Program Administrator installed monitoring equipment; the Host Customer and System Owner agree to provide system monitoring data (typically 15-minute interval data) to the SGIP M&E consultant on a quarterly basis for a period of twice the required warranty period of the generating system.

14.7.5 *Disposition of SGIP Metering Equipment*

Upon completion of the SGIP M&E metering activities at the Site, the Program Administrator will offer all M&E metering equipment to the System Owner for transference. The Program Administrator will provide an Equipment Transfer Agreement with a schedule of the SGIP M&E equipment located at the Site. The Equipment Transfer Agreement must be signed by both the System Owner and the Program Administrator. If the System Owner does not wish to accept the M&E metering equipment, the Program

Administrator or its independent third-party consultant will remove the M&E metering equipment. The Program Administrator shall pay the costs for meter removal.

14.8 Audit Rights

Program Administrator shall be allowed to periodically audit System Owner's and Host Customer's records related to the work done under this Contract, and report the results of its audit to the CPUC or its designee. System Owner and Host Customer must provide all requested Project documents to Program Administrator upon written request, and must, for 5 years following Contract termination, maintain copies of all Project documents, including, but not limited to, Contracts, invoices, purchase orders, reports, and all back-up documents, for Program Administrator's review.

14.9 Dispute Resolution

All participants shall attempt in good faith to resolve any dispute arising out of or relating to this transaction promptly by negotiations between a vice president of Program Administrator or his or her designated representative and an executive of similar authority from System Owner and/or Host Customer. Either party must give the other party, or parties, written notice of any dispute. Within thirty (30) calendar days after delivery of the notice, the executives shall meet at a mutually acceptable time and place, and shall attempt to resolve the dispute. If the matter has not been resolved within thirty (30) calendar days of the first meeting, any party may pursue other remedies, including mediation. All negotiations and any mediation conducted pursuant to this clause are confidential and shall be treated as compromise and settlement negotiations, to which Section 1152.5 of the California Evidence Code shall apply, and Section 1152.5 is incorporated herein by reference. Notwithstanding the foregoing provisions, a party may seek a preliminary injunction or other provisional judicial remedy if in its judgment such action is necessary to avoid irreparable damage or to preserve the status quo. Each party is required to continue to perform its obligations under this Contract pending final resolution of any dispute arising out of or relating to this Contract.

15 Infractions

15.1 Program Infraction

The Program Administrators will exercise their judgment in assessing program infractions, which may include gross negligence or intentional submission of inaccurate system information in an attempt to collect more incentive dollars. Program infractions may be determined at any stage of the SGIP process. If it is determined that a program infraction has been committed, a reasonable sanction shall be imposed at the discretion of the Program Administrator, and may result in a suspension from the SGIP Program for a minimum of six months

16 Program Modification

On August 21, 2003, the CPUC issued Decision 03-08-013 that instructed the SGIP Working Group to implement a more effective process for the CPUC to consider proposed new technologies or SGIP rule changes that does not rely on procedures related to petitions for modification.

The Working Group developed a process for interested parties to propose changes to the Working Group and the CPUC for careful and complete consideration in an efficient manner. This process, described in the Program Modification Guidelines (PMG), prescribes the proposal requirements, evaluation process and schedule. The latest PMG is available from any of the Program Administrators' websites.

In summary, the Program Modification Request process consists of -

1. All Program Modification Requests (PMRs) must be submitted in writing, using the current PMR format, to the SGIP Working Group for review at least 10 business days prior to the SGIP Working Group meeting or the request will roll over to the next SGIP Working Group meeting.
2. All parties desiring a program modification will be required to meet with the SGIP Working Group at the monthly SGIP Working Group meeting to determine if the Working Group would support the PMR.
3. The SGIP Working Group will first determine whether or not the proposed PMR requires a modification to a prior Commission order.
4. If the PMR is minor and non-substantive, and does not require modifications to prior Commission orders, then:
   a. The Working Group will review the PMR. If accepted, the Working Group will make the appropriate changes to the Handbook.
   b. If the Working Group needs more information, the party proposing the PMR would have the opportunity to present at the following Working Group meeting with additional information which supports its request for a program change.[28]
   c. The Working Group will make a decision to accept or deny the PMR based on the new information presented in the follow-up presentation.
   d. The proposed program change and the Working Group recommendation(s) and rationale will be captured in the Working Group meeting minutes.
   e. If the party objects to the Working Group's decision to deny the PMR, the party may write a letter to Energy Division stating why their program change should be included in SGIP. Information that supports the party's reasons to accept the program change must be included in the letter.
   f. Energy Division will then make a final decision on whether to approve the PMR.
   g. Energy Division will report its final decision at the following SGIP Working Group meeting, which will be captured in the SGIP Working Group meeting minutes.

[28] The Working Group will determine the timeframe in which the applicant should provide additional information at the following Working Group meeting.

h. If the PMR is accepted, appropriate revisions to the Handbook will be made to capture the change.

5. If the proposed change requires modification to a prior Commission order or if the PMR addresses large programmatic or substantive issues, then:

   a. The Working Group will review the PMR and make a recommendation to support or oppose the PMR in the same meeting.

   b. The proposed program change, the Working Group recommendation and rationale will be captured in the Working Group meeting minutes.

   c. Subsequent to the meeting, the Working Group will write up a summary of the discussion of the PMR at the Working Group meeting, a list of comments in support or against the PMR, as well as the Working Group's overall recommendation with rationale, which will be presented to the Applicant.

   d. The party proposing the PMR has the choice to move forward and submit a petition to modify (PTM) for Commission review regardless of the Working Group's recommendation, but the Working Group's summary must be included in the PTM.

   e. The Energy Division participates in Working Group meetings and is welcome to participate in the discussion related to the PMR as well as in generating the "list of issues". The Energy Division does not need to participate in the "recommendation" portion of the Working Group's PMR review.

   f. Once the PTM is filed with the Commission, the normal PTM process will transpire, only it will have the benefit of the idea being somewhat vetted before submittal. All parties have a chance to comment on PTMs according to the Commission's Rules of Practice and Procedure.

   g. The Commission will review and address the PTM in a decision.

17 Statewide Program Budget and Administrator Allocations

Annual incentive budgets for Program Year 2011 authorized by the CPUC for each Program Administrators are as follows:

Pacific Gas and Electric Company	$33,480,000
Southern California Edison Company	$26,040,000
California Center for Sustainable Energy	$10,230,000
Southern California Gas Company	$7,440,000

17.1 Budget Allocation

The budget is divided into two categories: the renewable and emerging technologies and non-renewable fueled projects. 75% of the project funding budget will be dedicated to the renewable and emerging technology category and 25% will be dedicated to the non-renewable category. Any carry-over funds from the previous years budget will be distributed in the same way.

AES coupled with a renewable or emerging generating technology will be funded from the renewable and emerging budget category. Stand-alone AES and AES coupled with conventional CHP technologies will be funded from the non-renewable budget category.

Although the Program Administrator may move funds from the non-renewable category to renewable and emerging technology category, the Program Administrator must seek approval from the CPUC through an advice letter prior to shifting funds from renewable and emerging technology category into the non-renewable category.

Table 17-1 Budget Allocation

Budget Category	Portion of SGIP Budget
Renewable and Emerging Technology	75%
Non-Renewable	25%

18 Program Development

The Self Generation Incentive Program is the joint work product of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), the Southern California Gas Company (SoCalGas), California Center for Sustainable Energy (CCSE), San Diego Gas & Electric (SDG&E), California Energy Commission (CEC) and the Energy Division of the California Public Utilities Commission (CPUC). The SGIP was originally designed to complement the CEC's Emerging Renewables Program (ERP)[29] by providing incentive funding to larger renewable and non-renewable self-generation units up to the first 1.0 MW in capacity.

The April 24, 2008 CPUC Decision 08-04-049 increased the incentive cap to 3.0 MW on a pilot basis contingent on available carry over budget. On December 17, 2009 by CPUC Decision 09-12-047 eliminated the requirement for available carry over funding. All projects regardless of propose capacity, will be funded from the current program year budget.

The SGIP Working Group consists of the Program Administrators and representatives from SDG&E, the California Energy Commission staff associated with the ERP, and the Energy Division of the CPUC. The CPUC tasked the Working Group with the tasks of program implementation, addressing programmatic issues and maintaining statewide program uniformity.

Incentives for solar electric systems are provided by the California Solar Initiative (CSI) program. Information regarding CSI can be found on www.gosolarcalifornia.org.

18.1 Legislation and Regulatory Background

Date	Bill Number	Description
9/6/2000	AB 970	Required the CPUC to initiate load control and distributed generation activities.
3/27/2001	Decision 01-03- 073	Required the state's investor owned utilities to work with the CPUC Energy Division, the CEC and CCSE to develop and implement a self generation incentive program.
10/12/2003	AB 1685	• Extended the SGIP through 2007 • Required that projects commencing January 1, 2005 meet a NOx emission standard • Required that projects commencing January 1, 2007 meet a more stringent NOx emission standard and a minimum system efficiency standard. • Established a NOx emission credit that can be used by combined heat and power (CHP) units to meet minimum system efficiency standard
9/22/2004	AB 1684	Exempts certain projects from NOx emission standards set forth in AB 1685 that meet waste gas fuel and permitting requirements.

[29] Wind turbines and fuel cell projects less than 30 kW should apply to the CEC's Emerging Renewable Program.

Date	Bill Number	Description
12/16/2004	Decision 04-12-045	• Modified SGIP to incorporate provisions of AB 1685 • Eliminates maximum percentage payment limits • Reduces incentive payments for several technologies • Expands opportunities for public input regarding developing a declining incentive schedule, developing an exit strategy and adopting a data release format • Required an application fee for all projects received after 1/1/2005 in order to deter against "phantom projects". This requirement was removed beginning in 2007 except in the case of new technologies that are in the process of certification.
1/12/2006	Decision 06-01-047	Established the California Solar Initiative (CSI) and ordered changes in the 2006 SGIP to accommodate the transition of solar program elements to the CSI beginning January 1, 2007.
9/29/2006	AB 2778	• Extended SGIP until January 1, 2012 • Limited eligible technologies beginning January 1, 2008 to fuel cells and wind systems that meet emissions standards required under the distributed generation certification program adopted by the State Air Resources Board • Requires that eligibility of non-renewable fuel cell projects be determined either by calculating electrical and process heat efficiency according to PU Code 216.6 or by calculating overall electrical efficiency
4/24/2008	Decision 08-04-049	Removed the 1 MW cap on incentives for 2008 and 2009 allowing projects to receive lower incentives on a tiered structure for the portion of a system over 1 MW.
9/28/2008	AB 2667	Requires an additional 20% incentive for the installation of eligible distributed generation resources from a California supplier. This additional incentive is applied only to the technology portion of the incentive; the additional incentive for renewable fuels is not included in calculating the 20%.
11/21/2008	Decision 08-11-044	• Determined that Advanced Energy Storage systems coupled with eligible SGIP technologies will receive an incentive of $2/watt of installed capacity. • Revises the process for the review of SGIP program modification requests
9/09/2009	Decision 09-09-048	Grants a petition to modify SGIP policies expanding eligibility for Level 2 incentives to include "directed biogas" projects where renewable fuel is nominated via contract.
2/25/2010	Decision 10-02-017	• Revises Decision 08-11-044 so that Advanced Energy Storage systems coupled with fuel cells must meet the site specific requirements for on-site peak demand reduction and be capable of discharging fully at least once per day in order to be eligible for the $2/watt incentive from the self-generation incentive program. • Determines that Advanced Energy Storage systems coupled with eligible technologies under the SGIP must install metering equipment capable of measuring and recording interval data on generation output and advanced energy storage system charging and discharging.

19 Definitions and Glossary

AB 970:

Assembly Bill 970, signed by Governor Davis on September 6, 2000. This legislation required the CPUC to initiate certain load control and distributed generation activities, which resulted in the SGIP.

AB 1685:

Assembly Bill 1685, signed by Governor Davis on October 12, 2003. This legislation requires the CPUC, in consultation with the Energy Commission, to administer, until January 1, 2008, a self-generation incentive program for distributed generation resources in the same form that exists on January 1, 2004, but requires that combustion-operated distributed generation Projects using fossil fuels commencing January 1, 2005, meet a NOx emission standard, and commencing January 1, 2007, meet a more stringent NOx emission standard and a minimum system efficiency standard, to be eligible for incentive rebates under the SGIP. The bill establishes a credit for combined heat and power units that the meet minimum system efficiency standard. The bill also revises the definition of an ultra-clean and low-emission distributed generation to include electric generation technologies that commence operation prior to December 31, 2008.

AB 2667:

Assembly Bill 2667, approved by the Governor September 28, 2008, requires the CPUC to provide from existing SGIP funds an additional incentive of 20% for the installation of eligible distributed generation resources from a California Supplier.

Advanced Energy Storage:

Are technologies that convert electricity into another form of energy, stored and then converted back into electricity at another time. Advanced Energy Storage systems eligible for SGIP incentives must be coupled with an eligible self generation technology, currently fuel cell and wind turbines, and be able to discharge at rated capacity for a two hour period. Advanced Energy Storage systems coupled with fuel cells must be capable of discharging fully at least once per day. Whereas as those coupled with wind turbines must have the capability of handling hundreds partial discharge cycles per day.

Applicant:

The entity, either the Host Customer, System Owner, or third party designated by the Host Customer, responsible for the development and submission of the SGIP application materials and the main point of communication between the SGIP Program Administrator for a specific SGIP Application.

Application Fee:

Is required for new technologies that are in process of certification and is 1% of the requested incentive amount, due and payable with the Reservation Request application. Once the Program Administrator issues a Conditional Reservation, the Application Fee will be forfeited if it is not withdrawn by the Host

Customer/System Owner within 20 days of the Conditional Reservation or cancelled by the Program Administrator for not satisfying the SGIP requirements.

Backup Generators:

Operate as short-term temporary replacement for electrical power during periods of Electric Utility power outages. In addition to emergency operation they ordinarily only operate for testing and maintenance. Backup generators do not produce power to be sold or otherwise supplied to the grid or provide power to loads that are simultaneously serviced by the Electric Utility grid. Backup generators only service customer loads that are isolated from the grid either by design or by manual or automatic transfer switch.

California Supplier:

Is any sole proprietorship, partnership, joint venture, corporation, or other business entity that manufactures eligible distributed generation technologies in California and that meets either of the following criteria:

A) The owners or policymaking officers are domiciled in California and the permanent principal office, or place of business from which the supplier's trade is directed or managed, is located in California.

Or

B) A business or corporation, including those owned by, or under common control of, a corporation, that meets all of the following criteria continuously during the five years prior to providing eligible distributed generation technologies to an SGIP recipient:

   i) Owns and operates a manufacturing facility located in California that builds or manufactures eligible distributed generation technologies.

   ii) Is licensed by the state to conduct business within the state.

   iii) Employs California residents for work within the state.

For purposes of qualifying as a California Supplier, a distribution or sales management office or facility does not qualify as a manufacturer.

CCSE:

California Center for Sustainable Energy

CEC:

California Energy Commission

CPUC:

California Public Utilities Commission

Directed Biogas:

A renewable fuel that is obtained pursuant to a contract where biogas is nominated and delivered to Host Customer's Project via a natural gas pipeline. There is no means of ensuring that actual molecules of renewable gas are consumed at the Host Customer's Site. Thus, the gas is not literally delivered, but notionally delivered, as the renewable fuel may actually be utilized at any other location along the pipeline route.

Electric Utility:

The Host Customer's local electric transmission and distribution service provider for their Site.

ESCO:

Energy Service Company (ESCO), a business entity that designs, builds, develops, owns, operates or any combination thereof self-generation Projects for the sake of providing energy or energy services to a Host Customer.

Fraud:

A knowing misrepresentation of the truth or concealment of a material fact to induce another to act to his or her injury.

Fuel Cell:

Power plants that produce electricity through an electrochemical reaction with a fuel source resulting in extremely low emissions and hot water or steam.

Gas Service:

The gas line from the Utility's distribution main to the serving gas meter

Host Customer:

An entity that meets all of the following criteria: 1) has legal rights to occupy the Site, 2) receives retail level electric or gas distribution service from PG&E, SCE, SoCalGas or SDG&E, 3) is the utility customer of record at the Site 4) is connected to the electric grid, and 5) is the recipient of the net electricity generated from the self-generation equipment.

Interim Changes:

Changes by the Program Administrators to the SGIP instituting legislative, regulatory, clarifying or corrective rules that are posted on their SGIP websites.

Investor Owned Utility:

For purposes of the SGIP, this refers to Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and Southern California Gas Company.

ISO:

International Standards Organization

Non-Renewable Fuel:

Includes fossil fuels and synthetic fuels not generated from a renewable resource.

Parallel Operation:

The simultaneous operation of a self-generator with power delivered or received by the Electrical Utility while interconnected to the grid. Parallel Operation includes only those generators that are interconnected with the Electric Utility distribution system for more than 60 cycles.

PG&E:

Pacific Gas and Electric Company

Power Purchase Agreements:

An agreement for the sale of electricity from one party to another, where the electricity is generated and consumed on the Host Customer Site. Agreements that entail the export and sale of electricity from the Host Customer Site do not constitute Host Customer's use of the generated electricity and therefore are ineligible for the SGIP.

Program Year:

January 1 through December 31.

Proof of Project Milestone Date:

The Proof of Project Milestone Date is the date when required information to demonstrate that their Project is moving forward is due.

Project:

For purposes of the SGIP, the "Project" is the installation and operation of the proposed eligible self-generation technology (ies), as described by the submitted Reservation Request documentation.

Project Completion Date:

For purposes of the SGIP, the Project completion date will be determined when the Host Customer receives permission, from the Electric Utility, to operate in parallel.

Public Entity:

Includes the United States, the state and any county, city, public corporation, or public district of the state, and any department, entity, agency, or authority of any thereof.[30]

Renewable Fuel:

A Renewable Fuel is a non-fossil fuel resource other than those defined as conventional in Section 2805 of the Public Utilities Code that can be categorized as one of the following: solar, wind, gas derived from biomass, digester gas, or landfill gas. A facility utilizing a Renewable Fuel may not use more than 25 percent fossil fuel annually, as determined on a total energy input basis for the calendar year.

Reservation Expiration Date:

The Reservation Expiration Date is the date the Incentive Reservation expires and all required documentation must be provided by.

SCE:

Southern California Edison

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[30] Source: CALIFORNIA CODES - PUBLIC CONTRACT CODE, SECTION 21611

SDG&E:

San Diego Gas and Electric

Single Business Enterprise:

For purposes of defining a Site, a Single Business Enterprise is a business that has a unique taxpayer or employer identification number. Two or more businesses with the same taxpayer or employer identification number, as a group, are a Single Business Enterprise.

Site:

A Single Business Enterprise or home located on an integral parcel or parcels of land undivided by a public road or thoroughfare regardless of the number of meters serving that Site; or if divided by a public road or thoroughfare, served by a single Electric Utility meter. Separate business enterprises or homes on a single parcel of land undivided by a highway, public road, thoroughfare or railroad would be considered for purposes of the SGIP as separate Sites.

SoCalGas:

Southern California Gas Company

System Owner:

The owner of the generating system at the time the incentive is paid. For example, in the case when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner.

Thermal Load:

Host Customer heating process(es) including but not limited to industrial process heating, space heating, domestic hot water heating and/or heat input to an absorption chiller used for space cooling or refrigeration.

Thermal Load Equipment:

Thermal end-use equipment such as but not limited to absorption chillers (indirect or direct fired), boilers, water heaters, space heaters, furnaces, dryers, secondary heat exchangers, thermal storage tanks or vessels including pumps, cooling towers, and piping or any other ancillary equipment.

Waste Gas:

Natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

Appendix A - System Calculation Examples

Efficiency Calculations

Example #1: 5 kW Residential Fuel Cell CHP System

A 5 kW fuel cell operating on natural gas is proposed to provide electricity and heat to a residential Host Customer. The fuel cell is sized to operate at an annual average 90% capacity factor. The residential Host Customer's Thermal Load consists of pool heating, domestic hot water and space heating. The Applicant used the Residential Minimum Operating Efficiency Worksheet (see Table A-1) and entered the following information –

- Rated Net Generating Capacity – The rated kW capacity of the proposed generating system
- Ancillary Generating System Loads – The rated kW size of all ancillary loads necessary for generator operation.
- Fuel Consumption Rate (LHV) – The lower heating value fuel consumption at rated capacity (Btu/hr).
- Fuel Consumption Rate (HHV) – The higher heating value fuel consumption at rated capacity (Btu/hr).
- Waste Heat Recovery Rate – The amount of recoverable heat from the generating system (Btu/hr)
- Zip Code of Residence – The zip code location of the Host Customer.
- Dwelling Living Area – The living area of the home (sq ft)
- Residential Space Heating – Check box indicating that recovered waste heat will be used for space heating.
    - Residential Type – Single family, town home or apartments
    - Vintage – When was the period the home was constructed.
- Pool Heating – Check box indicating that recovered waste heat will be used for pool heating.
    - Energy smart pools net load data entered into "Pool Heating" worksheets
- Domestic Hot Water - Check box indicating that recovered waste heat will be used for domestic hot water heating.
    - Household Size – The number of people living in the home.
- Generator Equipment Full Load Hours per Month

The fuel cell exceeds the PU Code 216.6. (a) and (b) requirements, therefore it meets the minimum operating efficiency requirement for the program. It is exempt from the NOx emissions eligibility and passes the GHG emissions eligibility. The thermal coincidence factor is less than 1.0 for every month of the year indicating that it is utilizing waste heat recovery effectively and since it is qualified for the feed-in-tariff the export factor indicates that it is exporting less than the program export limit which is 25% more than the site electrical load.

Table A-1 Residential Minimum Operating Efficiency Worksheet

Applicant:	ESCO	Date:	January 1, 2011
Host Customer:	Residential Customer	Application No.:	XX-XXX

Instructions: This spreadsheet determines if a proposed generating system meets the Minimum Operating Efficiency eligibility requirement of the Self-Generation Incentive Program for **Residential customers**. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	5	kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	0	kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	42,844	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **lower heating value** of fuel.
Fuel Consumption Rate (HHV) =	47,511	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **higher heating value** of fuel.
Waste Heat Recovery Rate =	22,000	Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074	lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable		Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels strictly defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.
Fuel Cell ?	☑ Yes		Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes		Is the proposed generator qualified for the Feed-in Tariff?

Zip Code of Residence =	94027	**Weather Zone =**	5	**Electric Utility =**	PG&E
Dwelling Living Area =	7,800 sqft	**City =**	ATHERTON	**Gas Utility =**	PG&E

Applicable Thermal Loads
Check the residential thermal load(s) to be included

Residential Space Heating	☑	**Residential Type =**	Single Family	**Vintage =**	1992-present	**Vintage # =**	5
Pool Heating	☑	Enter Energy Smart Pools Net Load Data into "Pool Heating" Worksheet					
Domestic Hot Water	☑	**Household Size =**	2 Persons				

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	744	100%	3,720	3,164	16,368,000	85,387,670	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Feb	672	672	100%	3,360	3,209	14,784,000	70,323,418	0.2	14,784,000	28,791,168	31,927,392	1,693	980	713
Mar	744	744	100%	3,720	5,000	16,368,000	68,659,955	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Apr	720	720	100%	3,600	4,520	15,840,000	66,924,136	0.2	15,840,000	30,847,680	34,207,920	1,814	1,050	764
May	744	744	100%	3,720	3,721	16,368,000	53,428,187	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Jun	720	720	100%	3,600	3,599	15,840,000	38,922,630	0.4	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Jul	744	744	100%	3,720	2,808	16,368,000	23,576,485	0.7	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Aug	744	744	100%	3,720	2,852	16,368,000	27,700,472	0.6	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Sep	720	720	100%	3,600	2,764	15,840,000	33,771,321	0.5	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Oct	744	744	100%	3,720	2,540	16,368,000	51,170,604	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Nov	720	720	100%	3,600	2,852	15,840,000	67,552,174	0.2	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Dec	744	350	47%	1,750	3,120	7,700,000	84,297,602	0.1	7,700,000	14,995,400	16,628,850	882	510	371
Annual Total	8,760	8,366	96%	41,830	40,149	184,052,000	671,714,655		184,052,000	358,432,904	397,477,026	21,074	12,198	8,876

Minimum Operating Efficiency Eligibility = PASS

P.U. Code 216.6 (a) =	56.3% ≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part 292
P.U. Code 216.6 (b) =	65.5% ≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part 292
Minimum Electric Efficiency =	35.9% ≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6

NOx Emissions Eligibility = EXEMPT

AB 1685 Total Efficiency =	82.2% ≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits	0.074 ≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/ CHP Credits =	0.032 ≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D:

GHG Emissions Eligibility = PASS

GHG Emissions (kg CO2/MWh) =	212 < 379	TRUE	CPUC Decision 11-09-015

Coincidence of Thermal Load = PASS

Max Thermal Load Coincidence	0.69 ≤ 1.0	TRUE	CPUC Decision 11-09-015

Electrical Export Eligible = PASS

Electrical Export Factor=	1.04 ≤1.25	TRUE	CPUC Decision 11-09-015

	Enter **Net Total Monthly Pool Load (10^6 BTU's)** from Energy Smart Pools Base Analysis											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Load	73	61	59	59	46	33	19	23	29	45	60	74
Provide hardcopy of Energy Smart Pools Executive and Engineer Reports												

Example #2: Efficiency Calculations for 255 kW IC Engine CHP System

Three 85 kW internal combustion engines operating on natural gas are proposed to provide electricity and heat to a hospital. The internal combustion engines are sized such that they will operate at close to full load most of the year. Their output will be reduced in July and August so that the recovered waste heat does not exceed the thermal load.. The hospital's Thermal Load consists primarily of domestic hot water and space heating. The Minimum Operating Efficiency Worksheet used for this application is similar to the residential version, but the Thermal Load and Electrical Load per Month must be calculated and justified separately and entered manually for each month. The internal combustion engines exceed the PU Code 216.6. (a) and (b) requirements, therefore they meet the minimum operating efficiency requirement for the program. They also pass the NOx emissions eligibility with CHP credits and pass the GHG emissions eligibility. Their thermal coincidence factor is less than 1.0 for every month of the year indicating that they are utilizing waste heat recovery effectively and since they are qualified for the feed-in-tariff the export factor indicates that they are exporting less than the program export limit which is 25% more than the site electrical load.

Table A-2 Minimum Operating Efficiency Worksheet

Applicant:	ESCO	Date:	January 1, 2011
Host Customer:	Commercial Customer	Application No.:	XX-XXXX

Instructions: This spreadsheet calculates the operating system efficiency, system efficiency and emissions eligibility of generation systems applying to the Self-Generating Incentive Program for incentives. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, baseline emissions, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	255 kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	5 kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	2,967,000 Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **lower heating value** of fuel.
Fuel Consumption Rate (HHV) =	3,263,700 Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **higher heating value** of fuel.
Waste Heat Recovery Rate =	1,470,000 Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074 lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable	Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels strictly defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.
Fuel Cell ?	☐ Yes	Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes	Is the proposed generator qualified for the Feed-in Tariff?

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	710	95%	177,500	354,000	1,043,700,000	1,290,024,000	0.81	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Feb	672	640	95%	160,000	264,000	940,800,000	1,128,312,000	0.83	940,800,000	1,898,880,000	2,088,768,000	110,746	62,352	48,395
Mar	744	710	95%	177,500	347,000	1,043,700,000	1,117,080,000	0.93	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Apr	720	710	99%	177,500	353,000	1,043,700,000	1,068,048,000	0.98	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
May	744	690	93%	172,500	360,000	1,014,300,000	1,026,864,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jun	720	690	96%	172,500	400,000	1,014,300,000	1,024,992,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jul	744	655	88%	163,750	425,000	962,850,000	972,792,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Aug	744	655	88%	163,750	421,000	962,850,000	974,016,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Sep	720	690	96%	172,500	385,000	1,014,300,000	1,197,936,000	0.85	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Oct	744	710	95%	177,500	321,000	1,043,700,000	1,259,280,000	0.83	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Nov	720	700	97%	175,000	309,000	1,029,000,000	1,281,024,000	0.80	1,029,000,000	2,076,900,000	2,284,590,000	121,129	68,197	52,932
Dec	744	710	95%	177,500	310,000	1,043,700,000	1,312,056,000	0.80	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Annual Total	8,760	8,270	94%	2,067,500	4,249,000	12,156,900,000	13,652,424,000		12,156,900,000	24,537,090,000	26,990,799,000	1,431,052	805,699	625,354

Minimum Operating Efficiency Eligibility = PASS

P.U. Code 216.6 (a) =	63.3% ≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part 292
P.U. Code 216.6 (b) =	53.5% ≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part 292
Minimum Electric Efficiency =	26.7% ≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6

NOx Emissions Eligibility = PASS

AB 1685 Total Efficiency =	71.7% ≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits =	0.074 ≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/ CHP Credits =	0.027 ≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

GHG Emissions Eligibility = PASS

GHG Emissions (kg CO2/MWh) =	302 < 379	TRUE	CPUC Decision 11-09-015

Coincidence of Thermal Load = PASS

Max Thermal Load Coincidence Factor=	0.99 ≤ 1.0	TRUE	CPUC Decision 11-09-015

Electrical Export Eligible = PASS

Electrical Export Factor=	0.49 ≤1.25	TRUE	CPUC Decision 11-09-015

Incentive Calculations

Example #3: Single System Wind Turbine Technology

A Host Customer proposes to install an 800 kW wind turbine to provide a portion of their facilities' peak (maximum) electric demand. There are no other incentives included. The incentive for this technology is $1.25/Watt (or $1,250/kW) and the Project cost is $800,000 ($1,000/kW). Multiplying the incentive by the capacity of the generation results in an incentive of $1,000,000. Assuming a 30% investment tax credit (and based upon the formula provided in section 6.6) the incentive is limited to 30% of the project cost which is $240,000. $120,000 of the incentive would be received upfront and the remaining $120,000 would be paid based on expected kWh generation over five years, calculated as nameplate capacity x capacity factor x hours per year x five years.

Table A-3 Example of PBI Payment for an 800 kW Wind Turbine Operating at 25% Capacity Factor.

Year	Capacity (kW)	Capacity Factor	Hrs/Yr	kWh	Total kWh	PBI	Total PBI
1	800	25%	8760	1,752,000	1,752,000	$24,000	$24,000
2	800	25%	8760	1,752,000	3,504,000	$24,000	$48,000
3	800	25%	8760	1,752,000	5,256,000	$24,000	$72,000
4	800	25%	8760	1,752,000	7,008,000	$24,000	$96,000
5	800	25%	8760	1,752,000	8,760,000	$24,000	$120,000

($120,000 performance payment)/8,760,00 kWh = 1.37 cents/kWh PBI

Because the wind turbine operated as expected, it receives the full and final PBI payment at the end of year five. If the turbine were to operate better than expected, it would receive the same $120,000 payment in a shorter time frame. Similarly if it generated fewer kWh than predicted by year five, it would not receive the full payment.

Table A-4 Example of PBI Payment for an 800 kW Wind Turbine with a Declining Capacity Factor

Year	Capacity (kW)	Capacity Factor	Hrs/Yr	kWh	Total kWh	PBI	Total PBI
1	800	25%	8760	1,752,000	1,752,000	$24,000	$24,000
2	800	25%	8760	1,752,000	3,504,000	$24,000	$48,000
3	800	25%	8760	1,752,000	5,256,000	$24,000	$72,000
4	800	20%	8760	1,401,600	6,657,600	$19,200	$91,200
5	800	20%	8760	1,401,600	8,059,200	$19,200	$110,400

In the example shown in Table A-4 above, the capacity factor begins to decline in year four. This results in fewer kWh generated, and a correspondingly lower PBI for that year. Because the wind turbine did not maintain an average 25% capacity factor during the five years of PBI eligibility, this project would not receive the full SGIP incentive.

Example #4: Incentive Calculation for System Receiving Incentives from Other Programs

A Host Customer is installing a 1.0 MW fuel cell, operating on Renewable Fuel, which is estimated to cost $10 million ($10/Watt). The Project received a previous rebate of 20% of the Project costs ($2 million) from an IOU Ratepayer funded program. The SGIP incentive for this technology is $4.25/watt. Because the other incentive is IOU ratepayer funded, the SGIP incentive is adjusted. Given a 30% investment tax credit (and based upon the formula in section 6.6) the SGIP incentive cannot exceed 30% of the eligible project cost. In addition, out-of-pocket expense of the System Owner must not be less than zero. The out-of-pocket expense of the system is the total eligible Project cost less any incentives including SGIP. Under the SGIP, this Project would be eligible for an incentive of $2.5 million as follows:

Maximum SGIP Incentive based on System Size = 1,000,000 W x $4.25 / W = $4,250,000

Adjusted SGIP Incentive = $4,250,000 – 1.0 x $2,000,000 = $2,250,000

Project Cost Cap on SGIP Incentive = $10,000,000 x 30% = $3,000,000

Total Incentive = $2,250,000 + $2,000,000 = $4,250,000

Since the total Incentive ($4,250,000) is lower than the total eligible Project cost of $10 million and the SGIP Incentive is lower than the Project Cost Cap the SGIP incentive is $2,250,000.

Example #5: Incentive Calculation for Systems with Output Capacity above 1 MW and Receiving Incentives from Other Programs

A customer is installing a 2.2 MW fuel cell, operating on natural gas, which is estimated to cost $13 million. The incentives for this technology are $2.25/watt for the first 1.0 MW, 50% of $2.25/watt for the capacity greater than 1.0 MW up to 2.0 MW and 25% of $2.25/Watt for the capacity greater than 2.0 MW up to 3.0 MW. The Project also received a $1 million rebate from a Federal taxpayer funded program. Given a 30% investment tax credit (and based upon the formula in section 6.6) the SGIP incentive cannot exceed 30% of the eligible project cost. Under the SGIP, the incentive would be calculated as follows:

Maximum SGIP Incentive = 1,000,000 Watt x $2.25/Watt + 1,000,000 Watt x 50% x $2.25/Watt + 200,000 Watt x 25% x $2.25/Watt = $3,487,500

Adjusted SGIP Incentive = $3,487,500 – 0.0 x $1,000,000 = $3,487,500

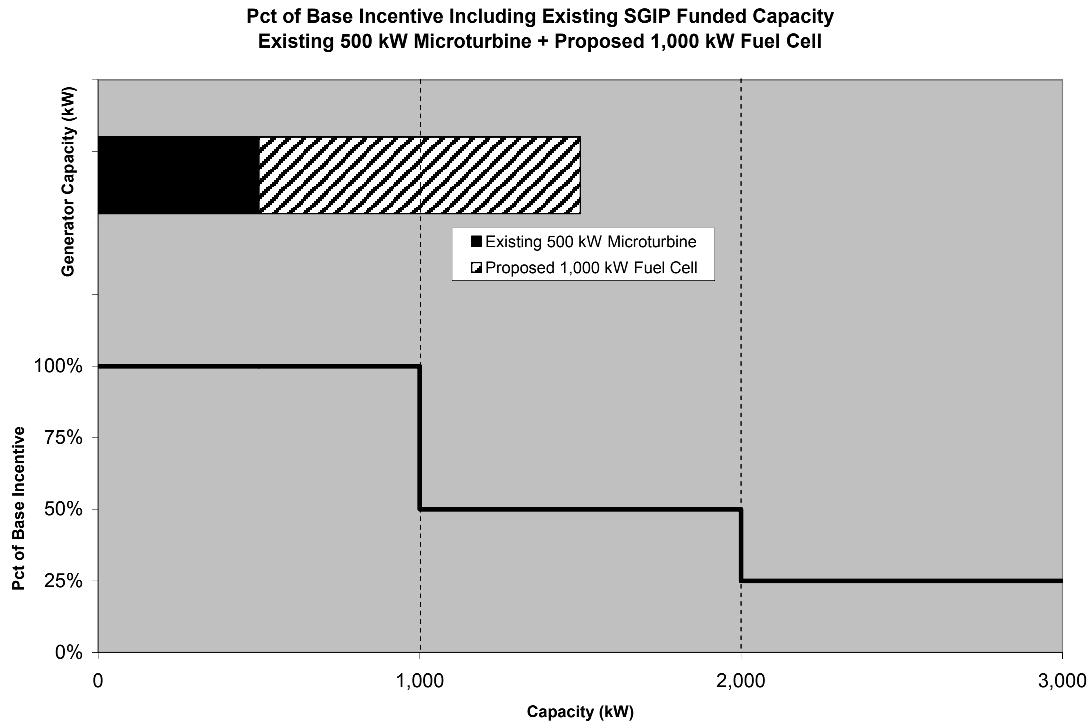
Project Cost Cap on SGIP Incentive = $13,000,000 x 30% = $3,900,000

Total Incentive = $3,487,500 + $1,000,000 = $4,487,500

Since total incentive of $4,487,500 is lower than the total eligible Project cost of $13 million and the SGIP Incentive is lower than the Project Cost Cap the SGIP incentive is $3,487,500.

Example #6: Incentive Calculation for System Added to Site with Existing SGIP Funded Capacity

A customer is installing a 1 MW fuel cell, operating on natural gas, which is estimated to cost $6 million. Under the SGIP, any existing generating capacity previously funded by SGIP is accounted for at that *highest incentive as illustrated in the following chart. Because the customer Site has an existing 500 kW microturbine cogenerator, the proposed system receives 500 kW at $2.25/Watt and the remaining 500 kW at $1.125/Watt. Given a 30% investment tax credit (and based upon the formula in section 6.6) the SGIP incentive cannot exceed 30% of the eligible project cost.*



s

The incentive would be calculated as follows:

> *Existing SGIP Funded Capacity = 500,000 Watt*
>
> *Proposed Capacity = 1,000,000 Watt*

Project Cost Cap on SGIP Incentive = $6,000,000 x 30% = $1,800,000 Maximum SGIP Incentive = 500,000 Watt x $2.25/Watt + 500,000 Watt x 50% x $2.25/Watt = $1,687,500Since total incentive of $1,687,500 is lower than the total eligible Project cost of $6 million and lower than the project cost cap of $1,800,000 the SGIP incentive is $1,687,500.

Example #7: Incentive Calculation for Advanced Energy Storage System

A customer proposes to install a 1 MW Advanced Energy Storage system and a natural gas fueled 1 MW fuel cell cogenerator. The total project cost is $7 million. Given a 30% investment tax credit (and based upon the formula in section 6.6) the SGIP incentive cannot exceed 30% of the eligible project cost. Since the Advanced Energy Storage capacity is not additive with the companion fuel cell, the Advanced Energy Storage system receives $2.00/Watt for 1,000 kW of capacity and the fuel cell receives $2.25/Watt for 1,000 kW of capacity.

The incentive would be calculated as follows:

Advanced Energy Storage = 1,000,000 Watt

Fuel Cell = 1,000,000 Watt

Project Cost Cap on SGIP Incentive = $7,000,000 x 30% = $2,100,000

Maximum SGIP Incentive = 1,000,000 Watt x $2.00/Watt + 1,000,000 Watt x $2.25/Watt = $4,250,000

Since total incentive of $4,250,000 is higher than the Project cost cap the SGIP incentive is $2,100,000.

Example #8: Hybrid System Incentive Calculation

	Wind Turbine	**Non-Renewable Fuel Cell**	**Hybrid System Total**
1. Incentive Rate ($/Watt)	$1.25/W Wind Turbine (A)	$2.25/W Fuel Cell (B)	
2. Technology Capacity (kW)	800 kW (C)	300kW (D)	1,100 kW (E) C + D
3. Incented Capacity (kW)	800 kW (F) F = C	200 kW (G) = 1,000 - F + 100 kW (H) H = E - 1,000	1,100 kW (I) F + G + H
4. Potential SGIP hybrid Incentive	$1,000,000 (J) J = A x F $1.25/W x 800,000 W	$450,000 (K) K = B x G $2.25/W x 200,000 W $112,500 (L) L = B x 50% x H $2.25/W x 50% x 100,000 W	**$1,562,500** J + K + L
5. Eligible Project Cost	$800,000	$1,650,000	**$2,450,000**
6. Project Cost Cap on SGIP Incentive (given 30% ITC)	$240,000	$495,000	**$735,000**
7. Maximum SGIP Incentive	$240,000	$495,000	**$735,000**

Example #9: Export to Grid

The following example demonstrates the SGIP incentive payments for a system that exports to the grid:

A 1.3 MW CHP system is designed to meet heat demand and is producing more electrical output than needed on site.

- At an 80% assumed capacity factor, the CHP system would generate 9.1 GWh/year
  *(1.3 MW * 80% * 8760 = ~9.1 GWh/ year)*
- In the previous year, the facility only consumed 7 GWh, or ~3/4 of the expected output.
  (7 GWh / 9.1 GWh = ~3/4)
- Because the facility's electrical load is ~3/4 of the expected output, it would receive an SGIP incentive for ~3/4 of the system capacity which in this example is ~1 MW.
  *(~3/4 * 1.3MW = 1 MW)*
- The total incentive would be $500,000
  *(1 MW * $.50/W = $500,000)*
- $250,000 (50% of the total incentive) would be paid up-front.
- The remaining $250,000 is spread over the next five years with an expected on-site load of 7 GWh per year, resulting in a PBI payment of 0.7 cents per kWh
  ($250,000 / 5 years / 7 GWh = ~0.7c per kWh)

Now assume that the actual capacity factor is 90% instead of 80%.

- At a capacity factor of 90%, total generation is ~10.2 GWh
  *(1.3 MW * 90% * 8760 = ~10.2 GWh/ year)*
- On-site consumption remains constant at 7 GWh and the project still only receives an incentive for 1 MW
- The 90% capacity factor increases incentivized on-site generation to 7.9 GWh.
  *(1MW * 90% * 8760 = ~7.9 GWh)*
- Due to the increase in generation, the project would receive an accelerated PBI payment of $55,300
  *(0.7c per kWh * 7.9 GWh = $55,300)*
- The project would receive the accelerated PBI payment even though 0.9 GWh of this amount attributed to "on-site" capacity was exported.
  (7.9 GWh – 7 GWh = 0.9 GWh)
- In this example, a total of 3.2 GWh would be exported
  (10.2 GWh – 7 GWh = 3.2 GWh)
- 0.9 GWh of this total would be compensated under both the PBI and FIT tariff.

Appendix B - Description of Total ELIGIBLE PROJECT COSTS

The following costs may be included in total eligible Project cost:

1. Self-generation equipment capital cost
2. Engineering and design costs
3. Construction and installation costs. For Projects in which the generation equipment is part of a larger Project, only the construction and installation costs directly associated with the installation of the energy generating equipment are eligible.
4. Engineering feasibility study costs
5. Interconnection costs, including:
    a. Electric grid interconnection application fees
    b. Metering costs associated with interconnection
6. Environmental and building permitting costs
7. Warranty and/or maintenance contract costs associated with eligible Project cost equipment (See 2.6.2 for full explanation of eligible costs)
8. Gas line installation costs, limited to the following:
    a. Costs associated with installing a natural gas line on the customer's Site that connects the serving gas meter or customer's natural gas infrastructure to the distributed generation unit(s).[31]
    b. Customer's cost for an additional (second) Gas Service to serve the distributed generation unit if this represents a lower cost than tying to the existing meter or Gas Service.
    c. Customer's cost for any evaluation, planning, design, and engineering costs related to enhancing/replacing the existing Gas Service specifically required to serve the distributed generation unit.
9. Sales tax and use tax
10. Generating system measurement, monitoring and data acquisition equipment.
11. Air emission control equipment capital cost

[31] In many cases, the Utility requires a separate, Utility owned gas meter, dedicated to the generator to qualify for a generation gas rate schedule. In that case, costs associated with installing a separate gas meter that are in excess of those covered under the applicable gas rules may be included as an Eligible Project Cost.

12. Primary heat recovery equipment, i.e. heat recovery equipment directly connected to the generation system whose sole purpose is to collect the waste heat produced by the power plant. For example, a heat exchanger or heat recovery boiler (a.k.a., heat recovery steam generator, or HRSG) used to capture heat from a gas turbine is an eligible cost
13. Heat recovery piping and controls necessary to interconnect the generating equipment to either the Primary Heat Recovery Equipment or the heat recovery piping and controls within the space primarily occupied by the generator partitioned by a fence or wall, whichever cost is less. If there is no identifiable Primary Heat Recovery Equipment and no identifiable space primarily occupied by the generator, eligible heat recovery piping and control costs shall be limited to the generator skid.
14. Level 2 Projects (except wind turbines) may claim the cost associated with securing a bond to certify use of Renewable Fuel, described in the SGIP Contract, as eligible costs.
15. For Level 2 technologies (except wind turbines), the cost of equipment to remove moisture and other undesirable constituents from Renewable Fuels that would damage the generation equipment. Such equipment includes but is not limited to “gas skids”, dryers/moisture removal and siloxane removal towers.
16. Cost of capital included in the system price by the vendor, contractor or subcontractor (the entity that sells the system) is eligible if paid by the System Owner.

Appendix C - Conversion of Emissions PPM to Lb/MWH

Procedure for Converting Emission Data to lb/MW-hr

Engines

Engine emission standards are typically expressed in terms of ppmv or in grams/brake horsepower-hour. Given below are factors to convert from ppm to grams/brake horsepower-hour and from grams/brakehorsepower-hour to pound/megawatt hour.

The resulting answers will be approximate values since various default assumptions were used to develop natural gas default factors. The efficiency of the engine has the greatest affect on the concentration (ppmvd) to mass emission rate conversion (g/bhp-hr), which can vary from 20 to 40 percent. In the calculations below, the efficiency is proportional to the engine brake specific fuel consumption.

PPM to GM/Bhp-hr

Concentration in exhaust by volume (dry) (ppmvd) = $\frac{\text{volume of pollutant (Vp)}}{\text{volume of exhaust (Ve)}} \times 10^6$

Vp = emission factor (g/bhp-hr) x horsepower x (1/molecular weight) x molar volume x conversion factors

Ve = F-factor for exhaust volume x excess air correction x engine brake specific fuel consumption x horsepower x conversion factors

These factors can be reduced to: ppmvd = (gm/Bhp-hr) * factor

Reciprocating Engines, natural gas fueled

Pollutant	Factor
NOx	57-59
VOC	163-170
CO	93-97

Values taken from California Air Pollution Control Officers Association (CAPCOA) report: Portable Equipment Rule Piston IC Engine Technical Reference Document, 1995.

Source: California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix C: Procedure for Converting Emission Data to lb/MW-hr, July 2002.

Lean-burn Engines, natural gas fueled

Pollutant	Factor
NOx	80
VOC	212
CO	123

Factors provided from Waukesha

<u>GM/Bhp-hr to Lb/MW-hr</u>

Gm/Bhp-hr x 3.07 = lb/MW-hr

- Includes 95% factor for generator efficiency
- Conversion factors for grams to pounds and brake horsepower to watts

Gas Turbines

lb/MW-hr = (emission rate [lb/MMBtu]) x (3.413 [MMBtu/MWh]) / (efficiency)

2.5 ppmvd = 0.0093 lb/MMBtu for NOx
2 ppmvd = 0.0027 lb/MMBtu for VOC
5 ppmvd = 0.013 lb/MMBtu for CO

efficiency for central station power plant is 50%

INDEX

Attachment B

Self-Generation Incentive Program
Waste Heat, Minimum System Efficiency Emissions Spreadsheet

Applicant:		Date:	
Host Customer:		Application No.:	

Instructions:

This spreadsheet calculates the operating system efficiency, system efficiency and emissions eligibility of generation systems applying to the Self-Generating Incentive Program for incentives. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fue consumption, waste heat recovery rate, baseline emissions, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGII Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	255 kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	5 kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	2,967,000 Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **lower heating value** of fuel.
Fuel Consumption Rate (HHV) =	3,263,700 Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **higher heating value** of fuel.
Waste Heat Recovery Rate =	1,470,000 Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074 lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable	Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels strictly defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.
Fuel Cell ?	☐ Yes	Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes	Is the proposed generator qualified for the Feed-in Tariff?

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	710	95%	177,500	300,000	1,043,700,000	1,290,024,000	0.81	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Feb	672	640	95%	160,000	300,000	940,800,000	1,128,312,000	0.83	940,800,000	1,898,880,000	2,088,768,000	110,746	62,352	48,395
Mar	744	710	95%	177,500	300,000	1,043,700,000	1,117,080,000	0.93	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Apr	720	710	99%	177,500	300,000	1,043,700,000	1,068,048,000	0.98	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
May	744	690	93%	172,500	300,000	1,014,300,000	1,026,864,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jun	720	690	96%	172,500	300,000	1,014,300,000	1,024,992,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jul	744	655	88%	163,750	300,000	962,850,000	972,792,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Aug	744	655	88%	163,750	300,000	962,850,000	974,016,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Sep	720	690	96%	172,500	300,000	1,014,300,000	1,197,936,000	0.85	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Oct	744	710	95%	177,500	300,000	1,043,700,000	1,259,280,000	0.83	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Nov	720	700	97%	175,000	300,000	1,029,000,000	1,281,024,000	0.80	1,029,000,000	2,076,900,000	2,284,590,000	121,129	68,197	52,932
Dec	744	710	95%	177,500	300,000	1,043,700,000	1,312,056,000	0.80	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Annual Total	8,760	8,270	94%	2,067,500	3,600,000	12,156,900,000	13,652,424,000		12,156,900,000	24,537,090,000	26,990,799,000	1,431,052	805,699	625,354

Minimum Operating Efficiency Eligibility = PASS

P.U. Code 216.6 (a) =	63.3% ≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part 292
P.U. Code 216.6 (b) =	53.5% ≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part 292
Minimum Electric Efficiency =	26.7% ≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6

NOx Emissions Eligibility = PASS

AB 1685 Total Efficiency =	71.7% ≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits =	0.074 ≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/ CHP Credits =	0.027 ≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

GHG Emissions Eligibility = PASS

GHG Emissions (kg CO2/MWh) =	302 < 379	TRUE	CPUC Decision 11-09-015

Coincidence of Thermal Load = PASS

Max Thermal Load Coincidence Factor=	0.99 ≤ 1.0	TRUE	CPUC Decision 11-09-015

Electrical Export Eligible = PASS

Electrical Export Factor=	0.57 ≤1.25	TRUE	CPUC Decision 11-09-015

Self-Generation Incentive Program
Minimum Operating Efficiency Spreadsheet

Applicant:	ESCO	Date:	January 1, 2011
Host Customer:	Residential Customer	Application No.:	XX-XXX

Instructions:

This spreadsheet determines if a proposed generating system meets the Minimum Operating Efficiency eligilbility requirement of the Self-Generation Incentive Program for **Residential customers**. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	5	kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	0	kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	42,844	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **lower heating value** of fuel.
Fuel Consumption Rate (HHV) =	47,511	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on **higher heating value** of fuel.
Waste Heat Recovery Rate =	22,000	Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074	lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable		Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels strictly defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.
Fuel Cell ?	☑ Yes		Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes		Is the proposed generator qualified for the Feed-in Tariff?

Zip Code of Residence = 94027 **Weather Zone =** 5 **Electric Utility =** PG&E

Dwelling Living Area = 7,800 sqft **City =** ATHERTON **Gas Utility =** PG&E

Applicable Thermal Loads

Check the residential thermal load(s) to be included

Residential Space Heating ☐ **Residential Type =** Single Family **Vintage =** 1992-present **Vintage # =** 5

Pool Heating ☑ Enter Energy Smart Pools Net Load Data into "Pool Heating" Worksheet

Domestic Hot Water ☐ **Household Size =** 2 Persons

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	744	100%	3,720	3,164	16,368,000	73,000,000	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Feb	672	672	100%	3,360	3,209	14,784,000	61,000,000	0.2	14,784,000	28,791,168	31,927,392	1,693	980	713
Mar	744	744	100%	3,720	5,000	16,368,000	59,000,000	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Apr	720	720	100%	3,600	4,520	15,840,000	59,000,000	0.3	15,840,000	30,847,680	34,207,920	1,814	1,050	764
May	744	744	100%	3,720	3,721	16,368,000	46,000,000	0.4	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Jun	720	720	100%	3,600	3,599	15,840,000	33,000,000	0.5	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Jul	744	744	100%	3,720	2,808	16,368,000	19,000,000	0.9	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Aug	744	744	100%	3,720	2,852	16,368,000	23,000,000	0.7	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Sep	720	720	100%	3,600	2,764	15,840,000	29,000,000	0.5	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Oct	744	744	100%	3,720	2,540	16,368,000	45,000,000	0.4	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Nov	720	720	100%	3,600	2,852	15,840,000	60,000,000	0.3	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Dec	744	350	47%	1,750	3,120	7,700,000	74,000,000	0.1	7,700,000	14,995,400	16,628,850	882	510	371
Annual Total	8,760	8,366	96%	41,830	40,149	184,052,000	581,000,000		184,052,000	358,432,904	397,477,026	21,074	12,198	8,876

Minimum Operating Efficiency Eligibility =	**PASS**		
P.U. Code 216.6 (a) =	56.3% ≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part 292
P.U. Code 216.6 (b) =	65.5% ≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part 292
Minimum Electric Efficiency =	35.9% ≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions Eligibility =	**EXEMPT**		
AB 1685 Total Efficiency =	82.2% ≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits =	0.074 ≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/ CHP Credits =	0.032 ≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits,
GHG Emissions Eligibility =	**PASS**		
GHG Emissions (kg CO2/MWh) =	212 < 379	TRUE	CPUC Decision 11-09-015
Coincidence of Thermal Load =	**PASS**		
Max Thermal Load Coincidence	0.86 ≤ 1.0	TRUE	CPUC Decision 11-09-015
Electrical Export Eligible =	**PASS**		
Electrical Export Factor=	1.04 ≤1.25	TRUE	CPUC Decision 11-09-015

Attachment C

Greenhouse Gas Emission Rate Testing Protocol for Electric-Only Technologies that Consume Fossil Fuels

This protocol refers to the testing of electric only fuel cells operating on fossil fuels under the 2011 Self Generation Incentive Program as required by CPUC Decision 11-09-015. This protocol utilizes the existing ASME PTC 50-2002, which is a performance test code for fuel cells. The ASME PTC 50 calculates the energy input to the fuel cell, the electrical power output, thermal and mechanical outputs, average net power, electrical efficiency, thermal effectiveness and heat rate under certain test conditions. These results can be used to calculate the gas emission rate of the fuel cells.

A summary of the test procedures and methods is as follows:

Before starting test, fuel cell shall run in steady-state conditions for an agreed-upon period of time. Test shall not run for less than one hour, and interval between readings shall not be less than 1 min. For participation in the SGIP it is required that the fuel cell generating system be tested under ISO conditions.

Primary Variables:

1. Class 1 have relative sensitivity coeff. Of 0.2 or greater. These require measurement instruments with higher accuracy and greater redundancy than Class 2
    a. Ex: Input fuel flow, fuel heating value, gross power output, aux/ parasitic power consumed by fuel cell system
2. Class 2 have relative sensitivity coeff of less than 0.2
    a. Ex: fuel cell system output voltage, output current, output frequency

INSTRUMENTS AND METHODS OF MEASUREMENT

Determination of Outputs:

1. Water or Heat Transfer Fluid Flow
2. Water or Heat Transfer Fluid Temperature
3. “Other Measurements”
    a. Water pressures
    b. Static Pressure
4. Electrical Output Measurements (true RMS required to account for harmonic distortion)

Determination of Fuel Input:

1. Fuel Types Considered

2. Consistent Gaseous or Liquid Fuels- heating values must vary less than 1%
3. Consistency of Fuel Flow- difference between max and min fuel flow should be less than 2%
4. Determination of Fuel Heating Value- can be measured by an on-line chromatograph or by taking a minimum of three samples per test and analyzing each for heating value.
5. Determination of Liquid Fuel Specific Gravity- each fuel sample taken shall have specific gravity evaluated at three temperatures covering the range of temps during the testing.
6. Measurement of Liquid Fuel Flow-
7. Measurement of Gaseous Fuel Flow- must meet uncertainty requirement of the code (with less than 2% total uncertainty (at 95% confidence))
8. Calculation of Fuel Input
9. Sampling- automatic sampling should be done in accordance with ASTM D 5287

Computation of RESULTS

Computation of Inputs

1. State of Input Fuel
2. State of Input Oxidant
3. Computation of Input Energy
    a. Fuel Chemical Energy Input
    b. Fuel Pressure Energy Input
    c. Fuel Thermal Energy Input
    d. Secondary Thermal Energy Input
    e. Oxidant Pressure Energy Input
    f. Oxidant Thermal Energy Input
    g. Auxiliary Electrical Input
    h. Shaft Work Input
    i. Total Energy Into System

Computation of Electrical Power Output

1. Averaging of Test Data
2. Real Power
3. Electrical Total Energy
4. Net Electrical Energy

Computation of Thermal and Mechanical Outputs

1. Computation of Thermal Energy Captured
2. Computation of Shaft work out of System

Computation of Average Net Power

Computation of Efficiencies

1. Computation of Electrical Efficiencies
2. Computation of Thermal Effectiveness
3. Computation of Heat Rate
4. Computation of Fuel Chargeable to Power Heat Rate

A post-test uncertainty analysis is required. Expected to give results with less than 2% total uncertainty (at 95% confidence).

The average net power of the fuel cell coupled with the fuel input rate (HHV) will be used to calculate the annual power generation (MWh) and fuel consumption (MMBtu) based upon an assumed capacity factor of 80%. The GHG output is calculated by multiplying the annual fuel consumption of the fuel cell in MMBtus by an emission factor of 53.02 kg CO_2/MMBtu[1] for the conversion of natural gas to CO_2. The GHG emissions rate for the generator is found by dividing the annual GHG emissions by the annual electrical output of the generator in MWh.

[1] Unspecified natural gas conversion emission factor from Appendix A of Section 95112 of the mandatory GHG reporting regulation. Title 17 of the California Code of Regulations.

Attachment D

Governance Structures and Affiliations with other Entities

In order to protect against entities creating governance structures or affiliations that would allow them to achieve more funding than the capped amount it is required that Host Customers, Applicants, and System Owners disclose information about all other incentives and eligible tax credits available to them or any of their affiliates applicable to the project. Failure to disclose such information will be considered an infraction and is subject to the penalties indicated in Section 15.

This requirement will be checked at the Reservation Request Stage and there are fields in the Reservation Request Forms where affiliations must be identified.