STATE OF CALIFORNIA

Edmund G. Brown Jr., *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

March 22, 2012

Advice Letter 3253-G/3940-E

Brian K. Cherry
Vice President,
Regulation and Rates
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
Email: PGETariffs@pge.com

Subject: Staff's Disposition of Advice Letter 3253-G/3940-E, a Supplemental Filing which proposed revisions to the Self-Generation Incentive Program Handbook to implement Decision (D.) 11-09-015: Implementation of the Hybrid-Performance-Based Incentive Payment Structure; Metering and Monitoring Protocols; Other Amendments

Dear Mr. Cherry:

Energy Division has determined that Advice Letter 3253-G/3940-E is in compliance with decision (D.)11-09-015. Energy Division approves the supplemental advice letter filed on February 17, 2012, with an effective date of March 22, 2012.

On November 7, 2011, Pacific Gas and Electric Company (PG&E), on behalf of the Self-Generation Incentive Program (SGIP) Program Administrators (PAs),[1] filed an Advice Letter 3253-G/3940-E, et seq. (AL). This AL 3253-G/3940-E proposed revisions to the Self-Generation Incentive Program Handbook to implement modifications to the SGIP pursuant to D. 11-09-015. On February 17, 2012, PG&E on behalf of the SGIP PAs filed a supplement to PG&E's Advice Letter 3253-G/3940-E, et seq (Supplemental AL) that proposed additional revisions to the SGIP Handbook including: new requirements to implement the hybrid performance-based incentive structure; metering and monitoring protocols; and other amendments. On February 27, 2012, the California Energy Storage Alliance (CESA) and the California Clean DG Coalition (CCDC) filed protests. CESA requested an extension to the protest deadline to file additional comments, which was granted by the Energy Division. On March 12th, 2012, CESA filed a second protest letter.

On March 19th, the SGIP PAs filed a reply to the protests requesting that Energy Division reject the issues raised by CESA and CCDC.

Attachment 1 contains a discussion of how Energy Division determined the supplemental advice letter complies with the decision and addresses the protests from CESA and CCDC.

Sincerely,

Edward Randolph

Edward F. Randolph, Director

Energy Division

[1] The SGIP PAs are PG&E, Southern California Edison Company, Southern California Gas Company and the California Center for Sustainable Energy in San Diego Gas & Electric Territory.

Cc:
Andrew Yip, Pacific Gas and Electric Company
Caitlin Henig, Pacific Gas and Electric Company
Billy Gamboa, The California Center for Sustainable Energy
Jana Kopyciok, The California Center for Sustainable Energy
Jim Stevenson, Southern California Edison Company
Rosalinda Magana, Southern California Gas Company

Attachment 1

Protest 1. Site-specific metering and monitoring protocols

CCDC proposes that cost barriers to SGIP participation for small (less than 300kW) CHP units need to be better addressed.[2] In the Supplemental AL, the SGIP PAs stated that CHP units 300 kW and smaller may use on-board electrical, thermal, and fuel metering systems to mini minimize costs. In their reply to CCDC's protest, the PA removed the requirement for EDI 867 data formatting for performance data providers (PDP), which will reduce the cost of PDP data transfer.

Energy Division finds that the changes included in the Supplemental AL and in the SGIP PAs reply will help reduce barriers for small CHP, and does not see the need for additional changes at this time. As a result, the Energy Division rejects Protest 1.

Protest 2. Energy Division is Required to Prepare a Resolution for the Commission's Consideration

CESA contends in their protest that, pursuant to Rule 7.6.2 of General Order 96-B, Energy Division is required to dispose of this AL via a Commission resolution. In their reply, the SGIP PAs state that CESA is incorrect in their interpretation of Rule 7.6.2, and that these advice letters are subject to Energy Division disposition, as provided in Rule 7.6.1.

Energy Division agrees with the SGIP PAs contention that a resolution is not required to dispose of this supplemental AL based on Rule 7.6.1 which states,

> "Industry Division disposition is appropriate where statutes or Commission orders have required the action proposed in the advice letter, or have authorized the action with sufficient specificity, that the Industry Division need only determine as a technical matter whether the proposed action is within the scope of what has already been authorized by statutes or Commission orders…. An advice letter will be subject to Industry Division disposition even though its subject matter is technically complex, so long as a technically qualified person could determine objectively whether the proposed action has been authorized by the statutes or Commission orders cited in the advice letter."

The supplemental AL was required by D.11-09-015, which specifically ordered the PAs to make revisions to the SGIP Handbook necessary to implement the modifications to SGIP. As mentioned above, D.11-09-015 explicitly orders the SGIP PAs to file advice letters to revise the handbook to implement the modifications to SGIP including metering and monitoring protocols and GHG emissions testing protocols for electric-only technologies that consume fossil fuels.[3] The Supplemental AL establishes rules for metering and monitoring SGIP systems, as well as a establishing a protocol to ensure that advanced energy storage systems meet the GHG requirements for SGIP. Therefore, the proposed actions in the Supplemental AL are authorized in a Commission decision and, per Rule 7.6.1, it is within Energy Division's authority to dispose of this AL via a disposition letter. As such, Energy Division rejects Protest 2.

Protest 3a. Greenhouse gas Exemption for Energy Storage

[2] CCDC Protest, p. 2.
[3] D.11-09-015, Ordering Paragraphs (OP) 2 and 3.

CESA requests that advanced energy storage (AES) systems be made temporarily exempt from the GHG emissions requirements set forth in D. 11-09-015. In their reply, the SGIP PAs state that exempting AES systems from a GHG requirement would be in violation of Senate Bill (SB) 412 (Kehoe, 2009).

This protest is outside of the scope of the Supplemental AL. Further, Energy Division agrees that this protest also runs in opposition to D. 11-09-015 and SB 412. SB 412 specifically states that Commission to determine what technologies should be eligible for the SGIP based on GHG emissions reductions. Based on this provision, Energy Division believes the Commission does not have the statutory authority to exempt AES systems for GHG emissions requirements within SGIP. Therefore, Energy Division rejects Protest 3a.

Protest 3b. Reduced Round Trip Efficiency Methodology

In the supplemental AL, the SGIP PAs propose a round-trip efficiency (RTE) requirement of 67.9% for all AES systems. In their protest, CESA proposes a new methodology for establishing GHG compliance of AES technologies by comparing average emissions for off-peak charging and marginal avoided emissions for on-peak discharge, which could result in a RTE requirement as low as 45%.

In their reply, the SGIP PAs note that 2011 saw more AES applications than any other technology type (a total of 147), all of which meet the 67.9% RTE. The SGIP PAs further state that they are open to adopting CESA's recommendations to analyze additional data to determine if changes to the RTE need to made in the future.

The RTE requirement of 67.9% was first introduced in an Energy Division staff proposal that proposed modifications to the SGIP, where it was vetted by parties. The RTE requirement is in line with D. 11-09-015's direction that the SGIP PAs to establish a "GHG emission rate testing protocol for electric only technologies which use natural gas".[4] Energy Division hereby rejects Protest 3b, but fully supports the SGIP PAs further analyzing data as it becomes available in the future to determine if revisions to the RTE requirement are necessary.

Protest 3c. Greenhouse Gas Exemption for Energy Storage Coupled with Renewable Generation

CESA requests that AES systems charged predominantly from renewables will reduce GHG emissions and should be granted a categorical exemption from demonstrating GHG reductions. Specifically, CESA recommends using a 75% baseline wherein eligibility is granted if an AES system uses 25 percent or less of its total energy input from non-renewable sources. In their reply, the SGIP PAs note that before such a methodology can be implemented, metering costs, configurations, and verification protocols must be established.

Energy Division agrees with the SGIP PAs that to grant this request now would be premature. Energy Division hereby rejects Protest 3c, but fully supports the SGIP PAs recommendation to continue working with CESA and other industry representatives to establish these protocols in the future.

[4] D.11-09-015, OP 2.

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulation and Rates

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-6520

February 17, 2012

Advice No. 3253-G-A/3940 –E-A
(Pacific Gas and Electric Company – U 39 M)

Advice No. 24-A
(California Center for Sustainable Energy)

Advice No. 2651-E-A
(Southern California Edison Company – U 338 E)

Advice No. 4292-A
(Southern California Gas Company – U 904 G)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: **Supplemental Filing: Proposed Revisions to the Self-Generation Incentive Program Handbook to Implement Decision (D.) 11-09-015: Implementation of the Hybrid-Performance-Based Incentive Payment Structure; Metering and Monitoring Protocols; Other Amendments**

Pacific Gas and Electric Company ("PG&E"), on behalf of the Self-Generation Incentive Program ("SGIP") Program Administrators[1] ("PAs"), hereby submits this supplement to PG&E's Advice Letter 3253-G/3940-E, et seq. ("Advice Letter").

Purpose

Ordering Paragraph 3 of D.11-09-015 directed the PAs for the SGIP, to file a Tier 2 advice letter within sixty (60) days of the effective date of the Decision to submit for approval:

- Implementation of the hybrid-Performance-Based Incentive payment structure; and
- Metering and monitoring protocols.

PG&E, on behalf of the SGIP PAs, hereby submits this supplement to the required advice filing in compliance with Ordering Paragraph 3 of D.11-09-015.

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[1] The SGIP PAs are PG&E, Southern California Edison Company ("SCE"), Southern California Gas Company ("SCG"), and the California Center for Sustainable Energy ("CCSE") in the service territory of San Diego Gas & Electric Company ("SDG&E").

This supplemental advice filing supplements and does not replace, in part or in its entirety, PG&E Advice 3253-G/3940-E, et seq., filed on November 7, 2011.

Background

On November 7, 2011, PG&E, on behalf of the SGIP PAs, timely filed Advice 3253-G/3940-E, et seq., to propose revisions to the SGIP Handbook as part of implementing D.11-09-015. Specifically, the SGIP PAs proposed revisions to implement the hybrid-Performance-Based Incentive ("PBI") payment structure, the metering and monitoring protocols, and other amendments, in accordance with D.11-09-015.

On November 28, 2011, seven parties filed Protests to Advice Letter 3253-G/3940-E, et seq.[2] On December 1, 2011, PG&E, on behalf of the SGIP PAs, requested to extend the due date to submit their Reply to the Protests because of the large number of Protests that were submitted and the complexity of the issues addressed. The request was granted on December 5, 2011.

On December 19, 2011, PG&E, on behalf of the SGIP PAs, filed a Reply to the Protests. In that Reply, the PAs identified certain clarifications that the PAs agreed should be included in the SGIP Handbook and stated that PG&E would file an amended Advice Letter in order to clarify certain proposed sections of the SGIP Handbook.

Proposed Amendments to the SGIP Program Handbook

This supplemental advice filing seeks to revise previously proposed sections of the SGIP Handbook to implement D.11-09-015 and to make other necessary updates and revisions. The proposed revisions are supplemental to the green-line document filed on November 7, 2011. The revisions that appear in the SGIP Handbook for this supplemental advice filing are in blue-line format in Attachment A to this filing. The proposed revisions are summarized below:

A. Proposed Amendments to Revisions Proposed in Advice 3253-G/3940-E, Et Seq.

In order to amend the revisions proposed in Advice Letter 3253-G/3940-E, et seq., the SGIP PAs propose that clarifying language be added to the following proposed sections of the SGIP Handbook:

- **Section 2.1: Reservation Request Required Attachments.** Clarifying language about metering and monitoring plans has been added in items 17 (Preliminary Monitoring Plan) and 22 (Proposed Monitoring Plan).

- **Section 4.1**: **Incentive Claim Required Attachments**. Clarifying language about metering and monitoring plans has been added in item 17 (Final Monitoring Schematic).

[2] On December 16, 2011, Bloom Energy withdrew their protest to the Advice Letter.

- **Section 11.2: Minimum Electrical Meter Requirements**. Clarifying language about data security, meter type, meter data access, meter memory and storage and communication transfer protocols has been added.

- **Section 11.3**: **Minimum Thermal Metering Requirements.** Clarifying language about size-differentiated metering, data security, meter type, meter data access, meter memory and storage, communication transfer protocols and acceptable thermal metering points has been added.

- **Section 11.4**: **Minimum Fuel Metering Requirements**. Clarifying language about size-differentiated metering, data requirements, data security, meter type, meter data access, meter memory and storage, communication transfer protocols and acceptable fuel metering points has been added.

- **Section 19.2.2**: Data Reporting, Security and Confidentiality. Clarifying language about meter communication and data collection has been added.

- **Section 19.3.3: Application to Provide PDP Services.** The requirement to be listed as an approved PMRS provider was deleted.

B. Other Clarifications

The SGIP PAs propose that clarifying language be added to the following proposed sections of the SGIP Handbook:

- Section 9.1: System Size Parameters

- Section 9.6: Greenhouse Gas Emission Standard for AES Projects

Tier Designation

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

Protests

In an effort to launch the 2012 SGIP as soon as possible, PG&E requests that the protest period for this filing be shortened to ten (10) days.

Anyone wishing to protest this supplemental 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 **February 27, 2012**, which is ten (10) days after the filing of this Advice Letter. Protests should be mailed to:

CPUC Energy Division
Attention: Tariff Unit, 4th Floor
505 Van Ness Avenue
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: mas@cpuc.ca.gov and jnj@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

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

Brian K.Cherry
Vice President, Regulation and Rates
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-6520
E-mail: PGETariffs@pge.com

Effective Date

In an effort to launch the 2012 SGIP as soon as possible, PG&E requests that this Advice Letter become effective on **March 8, 2012**, which is twenty (20) calendar days after the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this Advice Letter is being sent electronically and via U.S. mail to parties shown on the attached list and the service lists for R.10-05-004. Address changes to the GO 96-B service list and electronic approvals should be directed to e-mail PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian Cherry/ewe

Vice President – Regulation and Rates

cc: Service List R.10-05-004

Attachments

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 M)**

Utility type:

☑ ELC ☑GAS

☐ PLC ☐ HEAT ☐ WATER

Contact Person: Linda Tom-Martinez

Phone #: (415) 973-4612

E-mail: lmt1@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas

PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #:**PG&E 3253-G-A/3940-E-A, CCSE 24-A, SCE 2651-E-A, SCG 4292-A** **Tier: 2**

Subject of AL: **Supplemental Filing: Proposed Revisions to the Self-Generation Incentive Program Handbook to Implement Decision (D.) 11-09-015: Implementation of the Hybrid-Performance-Based Incentive Payment Structure; Metering and Monitoring Protocols; Other Amendments**

Keywords (choose from CPUC listing):

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.11-09-015

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for:

Confidential information will be made available to those who have executed a nondisclosure agreement: ☐ Yes ☐ No

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: ______________________________

Resolution Required? ☐Yes ☑No

Requested effective date: **March 8, 2012** No. of tariff sheets:

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave.,
San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian Cherry
Vice President, Regulation and Rates
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

Self-Generation Incentive Program Handbook

November 7, 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 a testing protocol.

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

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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.

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.

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.

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

7 Waste Energy Capture technologies include Pressure Reduction Turbines and Waste Heat Capture technologies.

8 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

9 Duplicative application is considered a program infraction, See section 15.1 for Program Infractions

10 "…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.

11 Residential Load Factor estimated from California Investor Owned Utility domestic static load profiles.

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

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

14 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.

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

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

17 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.

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.

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).
   - DER which does not achieve this capacity factor over five years will not be paid full PBI

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
Telephone:	(858) 244-1177
Fax:	(858) 244-1178
Mailing Address:	California Center for Sustainable Energy Attn: Self Generation Incentive Program 8690 Balboa Ave., Suite 100 San Diego, CA 92123-1502

Southern California Edison (SCE)

Website:	www.sce.com/SGIP
Email Address:	CSIGroup@sce.com
Telephone:	(866) 584-7436
Fax:	(626) 302-3967
Mailing Address:	Self-Generation Incentive Program Southern California Edison P.O. Box 800. Rosemead, CA 91770-0800

Southern California Gas Company (SoCalGas)

Website:	www.socalgas.com/innovation/self-generation
Email Address:	selfgeneration@socalgas.com
Telephone:	1-866-DG-REBATE (1-866-347-3228)
Fax:	(213) 244-8222
Mailing Address:	Self-Generation Incentive Program Southern California Gas Company 555 West Fifth Street, GT22H4 Los Angeles, CA 90013-1011

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 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.

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

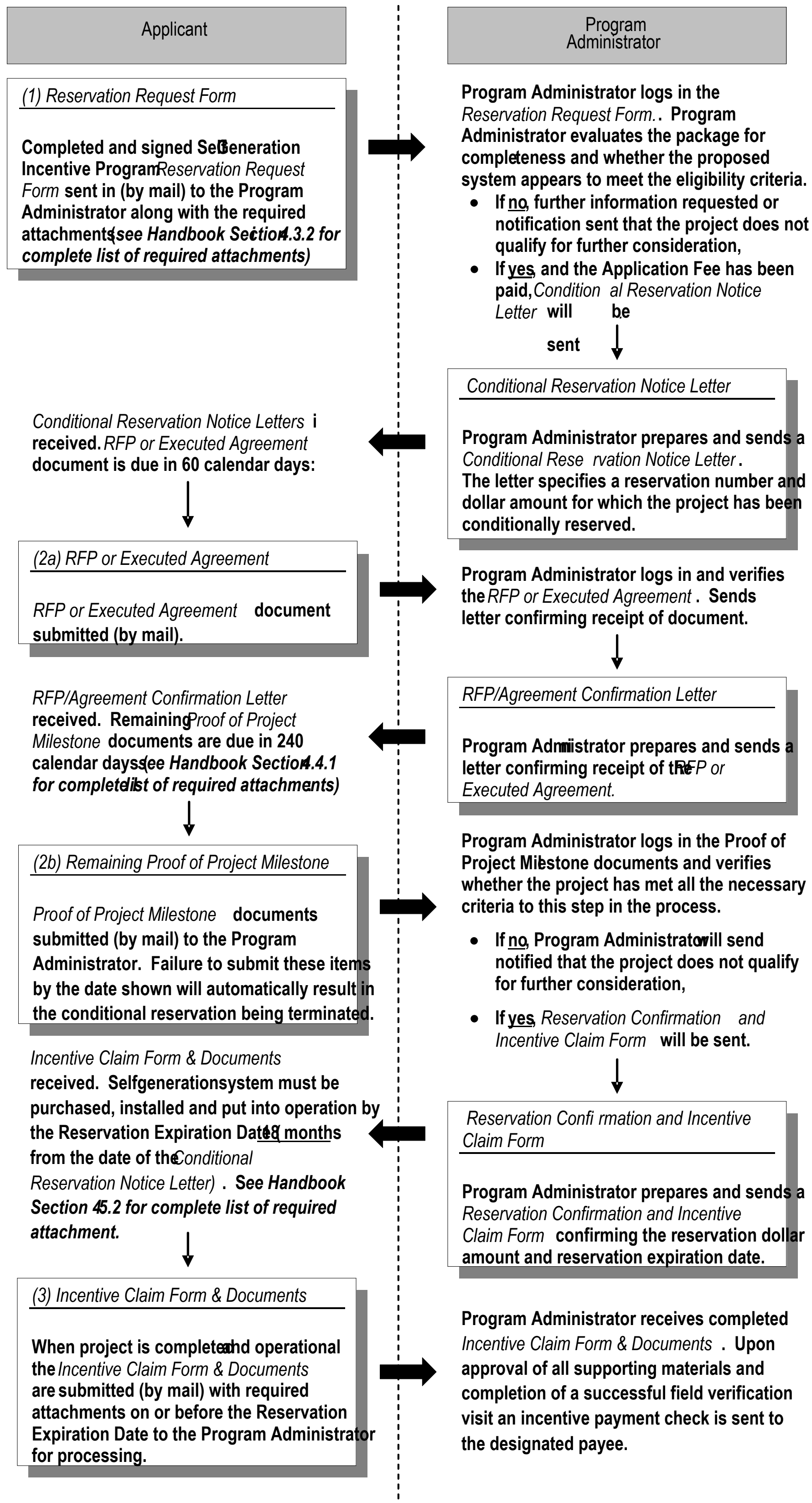

Figure 1-3 Two Step Application Process

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 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, ***Reservation Confirmation and Incentive Claim Form*** will be sent.

↓

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.

←

Reservation Confirmation and Incentive Claim Form received. Self-generation system must be purchased, installed and put into operation by the Reservation Expiration Date (12-months from the date of the ***Reservation Confirmation and Incentive Claim Form***). *See Handbook Section 4.5.2 for complete list of required attachment.*

(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[7]	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	✓

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture[7]	Fuel Cells & AES
6. Proof of Power Factor Eligibility	✓	N/A	N/A
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	✓	✓	✓
16. Documentation verifying non-profit entity status (if applicable)	✓	✓	✓
17. Preliminary Monitoring Plan (for 3 Step Applications Only)	✓	✓	✓

Required Materials	Conventional CHP	Wind Turbines & Waste Energy Capture[7]	Fuel Cells & AES
Additional Reservation Documents for Two-Step Applications			
18. Copy of Executed Contract or Agreement for Installation (includes warranty language documentation)	✓	✓	✓
19. Fuel Cleanup Equipment Purchase Order (nominated biogas projects exempt)	✓	N/A	✓
20. Renewable Fuel Affidavit	✓	N/A	✓
21. Renewable Fuel Contract	✓ Directed Biogas Renewable Fuel Only	N/A	✓ Directed Biogas Renewable Fuel Only
22. Proposed Monitoring Plan (for 2 Step Applications 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.

16) **Documentation Verifying Non-Profit Entity Status** – When applicable documentation must be provided from the Internal Revenue Service verifying non-profit entity status.

17) **Preliminary Monitoring Plan** – To be submitted with 3 Step Applications

The preliminary monitoring plan will have the following components:

Description of the proposed SGIP system

a. Description of the system with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage, etc.) by the system to the host site; the major components making up the system; and the general operating schedule of the system (e.g., is it 24x7x365 or 10x6x365, etc.); photos of the system if available.
    - Break out subsystems such as waste heat recovery systems in order to provide context for thermal energy metering systems. Provide similar descriptions for other important subsystems such as energy storage when combined with wind systems.

b. A description of the existing load at the site and identification of the sources of the fuel that would be displaced by operation of the SGIP system (i.e., electricity provided by XYZ utility or natural gas provided by ABC utility) and photos of the interface locations where the SGIP system would be located to displace the load.

Description of the metering system and metering approach, which includes:

a. An overview of the performance data to be collected (e.g., electrical, useful thermal energy, fuel consumption, etc.)

b. A simplified layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and location of the proposed metering points and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.)

Additional Requirements for Two Step Applications

18) **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.

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

20) **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.

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

22) **Proposed Monitoring Plan** – To be submitted with 2 Step Applications.

The proposed monitoring plan will have the following components:

Description of the proposed SGIP system

a. Description of the system with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage, etc.) by the system to the host site; the major components making up the system; and the general operating schedule of the system (e.g., is it 24x7x365 or 10x6x365, etc.); photos of the system if available.
   - Break out subsystems such as waste heat recovery systems in order to provide context for thermal energy metering systems. Provide similar descriptions for

other important subsystems such as energy storage when combined with wind systems.

b. A description of the existing load at the site and identification of the sources of the fuel that would be displaced by operation of the SGIP system (i.e., electricity provided by XYZ utility or natural gas provided by ABC utility) and photos of the interface locations where the SGIP system would be located to displace the load.

Description of the metering system and metering approach, which includes:

c. An overview of the performance data to be collected (e.g., electrical, useful thermal energy, fuel consumption, etc.)
d. A simplified layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and location of the proposed metering points and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.)
e. Description of the approach to be used for collecting, storing and transferring the necessary performance data
    - For example, if useful thermal energy data is to be collected, the reasoning behind the selected metering points
    - Frequency with which the data is to be collected (e.g., 15 min intervals)
    - Data storage capability and approach for transfer of data (e.g., cell modem) and frequency of reporting to PDP (e.g., daily, weekly) [this could also include frequency for reporting of data to PAs, such as monthly]
f. Identification of the metering system components by performance data type including manufacturer and model number.
    - Electrical metering equipment
    - Thermal energy metering equipment
    - Fuel consumption metering equipment
    - Data acquisition (i.e., logger) system
    - Data communication (e.g., cell modem, landline etc.) system

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 must submit a copy of the issued request for proposal (RFP or equivalent) for purchase or installation of the generating system within 60 calendar days of the date of the Conditional Reservation letter; 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	✓	✓	✓
11. Proposed Monitoring Plan	✓	✓	✓

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 or designee 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 or designee.

      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.

v. Any true-ups will be reflected in documentation outlined in section 10.5.1 for assessing compliance of directed biogas projects with renewable fuel use requirements

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 (On-site 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 five years for fuel cells or three years for all other 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.

11. **Proposed Monitoring Plan**: The proposed monitoring plan will have the following components:

    Description of the proposed SGIP system

    a. Description of the system with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage, etc.) by the system to the host site; the major components making up the system; and the general operating schedule of the system (e.g., is it 24x7x365 or 10x6x365, etc.); photos of the system if available.
        - Break out subsystems such as waste heat recovery systems in order to provide context for thermal energy metering systems. Provide similar descriptions for other important subsystems such as energy storage when combined with wind systems.
    b. A description of the existing load at the site and identification of the sources of the fuel that would be displaced by operation of the SGIP system (i.e., electricity provided by XYZ utility or natural gas provided by ABC utility) and photos of the interface locations where the SGIP system would be located to displace the load.

    Description of the metering system and metering approach, which includes:

    c. An overview of the performance data to be collected (e.g., electrical, useful thermal energy, fuel consumption, etc.)
    d. A simplified layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and location of the proposed metering points and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.)
    e. Description of the approach to be used for collecting, storing and transferring the necessary performance data
        - For example, if useful thermal energy data is to be collected, the reasoning behind the selected metering points
        - Frequency with which the data is to be collected (e.g., 15 min intervals)
        - Data storage capability and approach for transfer of data (e.g., cell modem) and frequency of reporting to PDP (e.g., daily, weekly) [this could also include frequency for reporting of data to PAs, such as monthly]
    f. Identification of the metering system components by performance data type including manufacturer and model number.
        - Electrical metering equipment
        - Thermal energy metering equipment

- Fuel consumption metering equipment
- Data acquisition (i.e., logger) system
- Data communication (e.g., cell mode, landline etc.) system

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	✓	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	✓	✓	✓
16) Performance Data Provider Documentation	✓	✓	✓
17) Final Monitoring Schematic	✓	✓	✓

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.

16) **Performance Data Provider Documentation** – The applicant must provided the name of the Performance Data Provider they are contracting with. A copy of the contract between the PDP and the applicant may be requested at the PA's discretion.

17) **Final Monitoring Schematic** - A final layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and location of the proposed metering points and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.)

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 a final approval notice letter. The incentive payment will be made in approximately 30 days from the date the final approval notice letter was sent. 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 is larger than 30 kW the metering system will be inspected and it will be verified that it follows the proposed monitoring plan and meets the metering requirements 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[8]

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.

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. PBI payments will typically commence on the date of interconnection. If necessary a three month grace period will be granted after the date of interconnection during which the project can undergo commissioning of the metering and monitoring equipment, before PBI payments commence. At the end of the commissioning period, sample data will need to be provided by the Performance Data Provider to the PA demonstrating that the metering and monitoring system is operating correctly.

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. In other words no penalty will be assessed if the actual emissions rate does not exceed 398 kg CO_2/MWh. However, PBI payments will be reduced by half in years where a project's emission rate is equal to or greater than 398 kg CO_2/MWh but less than 417 kg CO_2/MWh (i.e., 10% higher than the GHG eligibility threshold). Projects that exceed 417 kg CO_2/MWh in any given year will receive no PBI payments for that year.

Therefore:

$\text{emission rate} \leq 398 \frac{kg\ CO_2}{MWh} \rightarrow$ No penalty assessed on PBI payment

$398 \frac{kg\ CO_2}{MWh} \leq \text{emission rate} \leq 417 \frac{kg\ CO_2}{MWh} \rightarrow$ 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 6-4.

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 as defined in Appendix B – *Description of Total Eligible Project Cost*. When calculating the SGIP incentive limit, the biogas adder is not included. This limit only applies to the generator and the AES:

The limit on the generation and AES portion of the SGIP incentive will be dictated by the following equation,

$$I <= L*EPC$$

where

I = incentive as calculated in section 6.2 – Calculating the incentive (excluding biogas incentive)

L = (1- applicable investment tax credit – 0.4)

EPC = Eligible Project Costs

For biogas projects, the total incentive payment will be calculated by adding the incentive payment for biogas to the incentive or the project cost limit for the generator and AES, whichever is less.

6.7 SGIP Incentive Limit as Share of Biogas Contract

For projects using biogas, the $2.00/Watt adder does not apply to the SGIP incentive limit as share of project cost calculation described in section 6.6.

However in the case of directed biogas projects 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

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).[9]

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%
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 can 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 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.

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 on-site consumption 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. System sizing is explained in section 9.1.5. Example 9 in Appendix A is also provided for clarification purposes.

Increases or decreases in the annual generated electricity consumed on-site are used to calculate a new PBI payment.

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:

*PBI = $/kWh * generated electricity consumed on-site*

Program Administrators must be informed of arrangements made with the utility for sale of excess generation. For verification purposes proof of export documentation maybe required prior to payment.

6.16 PBI Assignment

If there is a change in ownership of the property which hosts the self generation technology the new owner/s may continue to receive the Performance-Based Incentives (PBI) and be eligible to receive future SGIP Incentives if they complete a new interconnection agreement. If the seller(s) remove the generator(s), they may continue to receive the PBI Incentive payments and be eligible to receive future PBI Incentives if the generator(s) they removed are installed within the same service territory within six months, and they complete an interconnection agreement at the new address. In either case, the PBI payment sunset date will not be extended.

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[10] 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.

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[11]

Small Commercial: Load Factor = .47[12]

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.

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. Systems that are rated at 5kW or less are exempt from the system sizing requirements.

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.

9.1.5 *System Sizing for Projects Exporting Power to the Grid*

Systems that will be exporting power to the grid will be allowed to size their generators based upon 125% of the last twelve months of electrical consumption at the site. The incentivized capacity of the generator will be based upon 100% of the last twelve months of electrical consumption at the site. The incentivized capacity will be determined by dividing the annual electrical consumption at the site (in kWh) by 8760 hours and the expected capacity factor of the technology as stated in Table 6-2. Example 9 in Appendix A is provided for clarification purposes.

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[13].
- 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.
- 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.[14]

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).

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*[15]

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 => $E / F \geq 40\%$

Where:

$E \equiv$ 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.

$F \equiv$ 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.

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.

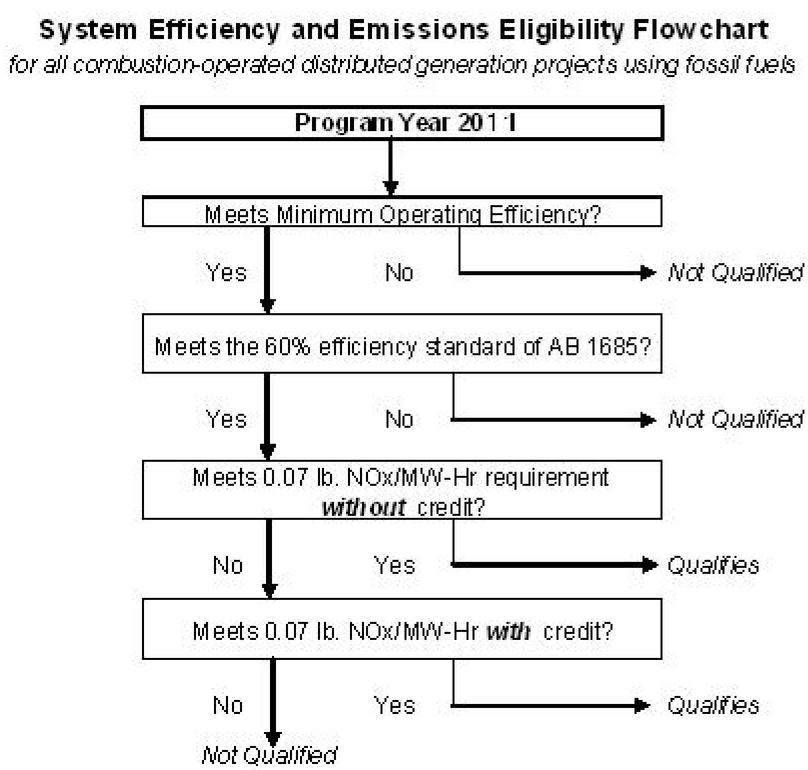

Figure 9-1 AB 1685 Eligibility Requirement Flowchart

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 useful 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[16], 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.[17]

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. [18]

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[18] 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.

[19] For natural gas, LHV ≈ HHV x 0.9

[20] 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.

[21] Self Generation Incentive Program (SGIP) CPUC Staff Proposal September 2010

[22] "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.

[23] 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.

[25] This definition of waste gas is directly from AB 1684.

[26] Thermal energy metering systems may also provide SGIP system owners with a potential means of verifying carbon emissions and carbon emission reductions

[27] Thermal energy metering systems must also have the ability to store hourly flow and temperature data that act as the basis of estimating the hourly useful thermal performance data.

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

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

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

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

[32] 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

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

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

[35] PG&E, SoCalGas and SCE are the Program Administrators for the Self Generation Incentive Program for customers in their respective service territories. The California Center for Sustainable Energy is the Program Administrator for the SDG&E service territory.

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

[37] 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.

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

Where:

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

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

MW_{Rated} ≡ System's Rated Capacity as defined in Section 9.2.

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

$MMBtu/yr_{UtilizedWasteHeat}$ ≡ 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[19]) 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)

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 for CHP Projects and Electric-Only Fuel Cells Operating on Non-Renewable Fuels

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[20] 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.

9.6 Greenhouse Gas Emission Standard for AES Projects

AES systems whether coupled with a generator or stand-alone need to maintain round trip efficiencies equal or greater than 67.9% on an annual basis in order to be eligible for PBI payments under the SGIP[21]. Round trip efficiency is defined as the ratio of the energy delivered during discharge of the AES (measured in AC) to the energy required to charge the AES (also measured in AC). The charge and discharge of the AES will be metered per the requirements of section 11 of this Handbook.

9.7 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.

9.8 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.

9.9 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.

9.10 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.

9.11 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.

9.12 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 Incentive Claim documents. Failure to submit proof of third party certification with the incentive claim documents will result in cancellation of the Project by the Program Administrator.

9.13 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.

9.14 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 Renewable Fuel Supplier		X

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[22] 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.

- 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[23] 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[24] 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 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.

10.5.1 *Directed Biogas Compliance with Renewable Fuel Use Requirements*

The following information will be needed for each directed biogas project which is required to comply with renewable fuel use requirements:

1. Renewable fuel invoices for each individual SGIP directed biogas project. If an invoice covers more than one SGIP RFU facility then the total quantity of directed biogas purchased must be allocated to individual facilities.
2. Renewable fuel invoice information for directed biogas sales outside the SGIP (if applicable).
   a. Applicable only if a SGIP directed biogas project and a project outside of the SGIP are serviced by the same biogas meter.
   b. Identification by name of customers outside of the SGIP is not requested.
3. Fuel metering information that identifies the source, quality magnitude (i.e., Btu/scf), quality basis (i.e., HHV or LHV), and amount of biogas associated with all purchases covered by renewable fuel invoices.
4. Fuel consumption meter data (i.e., the natural gas meter dedicated to the SGIP system).

5. Electricity production meter data (i.e., the electrical net generation output meter dedicated to the SGIP system).

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[25].

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 participation in the SGIP by projects larger than 30 kW. These minimum metering requirements were developed to increase owner knowledge of system performance, foster adequate system maintenance, and thereby ensure ratepayer-funded incentives result in expected levels of self generation.

All SGIP technologies larger than 30 kW must install metering and monitoring equipment that measures net electrical output from the generator. This data will be used by the Program Administrators to make PBI payment. Combined heat and power technologies will in addition install metering and monitoring equipment that measures and reports useful thermal energy delivered to the host site from the CHP system as well as fuel input to the generator. Electric-only fuel cells will also be required to measure fuel input into the generator. Advanced Energy Storage systems whether coupled with self generation equipment or operating as a stand-alone system must measure the net electrical energy during charge and discharge cycles.

11.1 Contract for PDP Service

System owners must install and maintain metering and monitoring equipment at their own cost. All System Owners are responsible for the choice and installation of the metering hardware as well as the selection of a Performance Data Provider (PDP). A list of eligible electric 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 PBI and PDP performance data. Please see Section 19 for further information regarding the transfer of production data. A list of qualified PDPs can be found on the Program Administrators websites.

It is the responsibility of the System Owners to contract with a PDP for a minimum of five years and ensure that 15 minute interval data is provided to the Program Administrator or their designee monthly for five years. The Applicant must submit the name of the PDP with the Incentive Claim Form. While it is not a requirement to provide the PAs with the PDP contract in the Incentive Claim package, the System Owner must submit the current PDP contract if requested by the Program Administrators. If the five year PDP contract is not submitted at the request of the Program Administrator, all incentives will be placed on hold.

Detailed information on these summarized metering requirements follows.

11.2 Minimum Electrical Meter Requirements

All systems larger than 30 kW must be installed with a meter or metering system which allows the System Owner and Program Administrator to determine the amount of net system energy production and allows the System Owner to support proper system operation and maintenance. 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/system_perf.php~~

11.2.1 *Data Required from Electrical Meters and Metering Responsibility*

Electrical meters installed on the SGIP project provide data used to assess performance of the system on sub-hourly, hourly, daily, monthly and annual basis across multiple years. Electric meter data may also be used to assess impact of the SGIP system on utility distribution systems; the peak system demand of the utility and net GHG emission impacts. Consequently, electrical meters must provide net electrical generator output on no less than 15 minute interval increments; be capable of storing data in the event of power outages or communication failures, and communicating results consistently to the PDP in a format that can be easily transferred to the PA for assessment and incentive payment purposes. While the following sections provide guidance on metering measurements and placement, it is the responsibility of the project owner and PDP to select, install, operate and maintain the electrical metering to supply the needed electrical performance data.

Electricity Meters shall be kept secure from Denial of Service (DOS) Attacks, Port Scanning, Unauthorized Access and other security violations. To achieve this security, Communications Interfaces to all meters must be located in a secure location and include strong password protection with either a network firewall or a Secure VPN Tunnel to limit the meter's network access to the PDP and/or a defined list of authorized users. In addition, security measures may be implemented as needed to ensure data security including restriction of direct meter access for real time data to sequential access basis.

11.2.2 *Meter Type*

For all systems receiving PBI payments the installed meter(s) may be a separate Interval Data Recording (IDR) meter(s), or a complete system that is on board the generator and is functionally equivalent to an IDR meter, recording data no less frequently than every 15 minutes. On-board meters must meet the same requirements as separate IDR meters which are outlined below.

Program Administrators may have additional meter functionality requirements for systems receiving PBI payments, as the Program Administrators will use these meters to process PBI payments, and system compatibility may be required. For example, meters and service panels must meet all local building codes and utility codes. The meter serial number must be visible after installation. ~~Each Program Administrator will maintain a publicly-available list of any additional functionality requirements. Please consult your Program Administrator to determine whether any additional requirements apply.~~

11.2.3 *Meter Accuracy*

All systems receiving a PBI incentive must install a meter accurate to within ± 2% of actual system output. This applies to on-board electrical meters as well as external IDR meters.

11.2.4 *Meter Measurement and Time Granularity of Acquired Data*

Electric meters must measure the net energy generated (kWh) and net real power delivered (kW). The PDP must log all Required Generator Performance / Output Data points no less frequently than once every 15 minutes. The elevation at installation (feet above sea level) must be reported at the time of commissioning. This information may be gathered from a geological database.

When monitoring AES systems the PDP must measure 15 minute net energy for the AES system during charging and during discharge and count the number of charge and discharge cycles during a 15 minute interval. The ~~Performance Monitoring and Reporting System~~ meter needs to generate an accurate time/date stamp.

11.2.5 *Meter Testing*

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

11.2.6 *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).

11.2.7 *Meter Communication/Data Transfer Protocols*

For all PBI systems, protocols for the minimum required performance/output data must enable any PDP to communicate with the meter and obtain the minimum required performance/output data from the meter. The data transfer protocol provided to the Program Administrator must satisfy servicing the Program Administrator requirements and have demonstrated ability to provide the minimum recorded performance/output data to the PA.

All meters must have the capability to report their data remotely. Data reporting must occur on a daily basis.

PDP Providers that fail to submit data to the Program Administrators when requested by the PA or an authorized agent of the CPUC, may be removed as an eligible PDP from the Program Administrators' approved list. It is the Host Customer and/or System Owner's responsibility to ensure the transfer of generator production data from the Performance Data Providers (PDP) to the Program Administrators.

All PDP's will need to transfer performance data via EDI 867 to the Program Administrators.

11.2.8 ***Meter Data Access***

All meters must provide the PDP provider or defined list of authorized users with the ability to access and retrieve the minimum required Net Electrical Generation Output Data from the meter using the Meter Communication / Data Transfer Protocols described in section 11.2.7.

11.2.9 ***Meter Display***

All meters must provide a display showing the meter's measured net generated energy output and measured instantaneous power. This display must be easy to view and understand. This display must be physically located either on the meter or on a remote device. For PBI, if a remote device is the only visible access, the PA may ask for verification.

11.2.10 ***Meter Memory and Storage***

All meters must have the ability to retain collected data in the event of a power outage. Meters must have the capability to store 7 days worth of data. ~~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 60 days of data in support of monthly reporting. In all cases, meters must be able to retain lifetime production.~~

11.2.11 ***Acceptable Electrical Metering Points***

The electrical metering system must meter delivered energy by having a meter at the output of the generator and after power delivery to all parasitic loads. When an on-board electrical metering system is used the meter must have multiple channels in order to monitor parasitic energy consumption as well as generator output and report net generation output. When applicable a meter must be installed 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.

11.3 Minimum Thermal Metering Requirements

All Combined Heat and Power (CHP) systems larger than 30 kW must be installed with a metering system which allows the System Owner and Program Administrator to determine the amount of useful thermal energy production and allows the System Owner to support proper system operation and maintenance. The meter must meet the minimum meter requirements of this section. All CHP systems that are 300 kW and smaller, will be allowed to use an on-board thermal metering system in order to minimize cost. The recorded data will be used to calculate the minimum system operating efficiency and

GHG emissions of the system. These calculated values will be used to monitor compliance with the Program's GHG emission limits and minimum system operating efficiency requirements.

11.3.1 *Data Required from Thermal Energy Metering Systems and Metering Responsibility*

Thermal energy metering systems installed on the SGIP project provide data used to assess thermal performance of the system; including its ability to meet on-site thermal energy demands (thereby offsetting consumption of fossil fuels), and meet thermal energy efficiency requirements prescribed by PUC 216.6. Thermal energy performance data may also be used to assess impact of the SGIP system on net GHG emission impacts.[26] Consequently, thermal energy metering systems must provide useful thermal energy performance data on no less than 15 minute interval increments; be capable of storing data in the event of power outages or communication failures; and communicating results consistently to the PDP in a format that can be easily transferred to the PA for assessment and incentive payment purposes.[27] While the following sections provide guidance on metering measurements and placement, it is the responsibility of the project owner and PDP to select, install, operate and maintain the thermal energy metering system to supply the needed useful thermal energy performance data.

Thermal Meters shall be kept secure from Denial of Service (DOS) Attacks, Port Scanning, Unauthorized Access and other security violations. To achieve this security, Communications Interfaces to all meters must be located in a secure location and include strong password protection with either a network firewall or a Secure VPN Tunnel to limit the meter's network access to the PDP and/or a defined list of authorized users. In addition, security measure may be implemented as needed to ensure data security including restriction of direct meter access for real time data to a sequential access basis.

11.3.2 *Meter Type*

The specific instrumentation required to measure useful thermal energy production will vary depending on the configuration and type of heat recovery system (e.g., liquid, steam, direct exhaust). Common flow measuring devices include insertion type or ultrasonic flow meters. Temperature measurement may be done with thermocouples. On-board thermal metering systems just as external thermal metering systems must measure useful thermal energy production. Proposed meter and sensor types shall be identified in a Monitoring Plan developed for each individual project. On-board meters must meet the same requirements as external meters which are outlined below.

11.3.3 *Meter Accuracy*

The accuracy of the metering system for useful thermal energy production must be within +/- 5%. at design conditions. This requirement applies to on-board as well as external thermal metering systems. The Monitoring Plan shall include a section describing monitoring system maintenance plans that will be implemented to ensure compliance with the accuracy requirement throughout the PBI period.

11.3.4 *Meter Measurement and Time Granularity of Acquired Data*

The PDP must log all required useful heat recovery system performance / output data points no less frequently than once every 15 minutes. Calculated values of useful heat recovery must be reported in 15 minute intervals. These values must be reported in units of MBtu/hr. The heat transfer fluid specific heat and density must be reported at the time of commissioning and then reported again to the PA if there is a change. The meter needs to generate an accurate time date stamp.

11.3.5 *Meter Communication/Data Transfer Protocols*

For all CHP systems larger than 30 kW, protocols for the minimum required performance/output data must enable any PDP to communicate with the metering system and obtain the minimum required performance data from the logger. The data transfer protocol provided to the Program Administrator must satisfy servicing the Program Administrator requirements.

All meters must have the capability to report their data remotely. Data reporting must occur on a daily basis.

PDP Providers that fail to submit data to the Program Administrators when requested by the PA or an authorized agent of the CPUC, may be removed as an eligible PDP from the Program Administrators' approved list. It is the Host Customer and/or System Owner's responsibility to ensure the transfer of CHP performance data from the Performance Data Providers (PDP) to the Program Administrators.

All PDP's will need to transfer performance data via EDI867 to the Program Administrators.

11.3.6 *Meter Data Access*

All meters must provide the PDP provider or defined list of authorized users with the ability to access and retrieve the minimum required waste heat recovery system performance data from the metering system using the Meter Communication / Data Transfer Protocols described in section 11.3.5.

11.3.7 *Meter Memory and Storage*

All meters must have the ability to retain collected data in the event of a power outage. Meters must have the capability to store 7 days worth of data. ~~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. Loggers that do not remotely report their data must retain 60 days of data in support of monthly reporting. In all cases, meters must be able to retain lifetime production.~~

11.3.8 *Acceptable Thermal Metering Points*

Proposed meter and sensor locations shall be identified in a Monitoring Plan developed for each individual project. It is recommended for direct exhaust combined cooling heating and power (CCHP) systems, that the chilled water output be measured, rather than measuring exhaust flows and temperatures as a way to calculate the useful thermal output.

11.4 Minimum Fuel Metering Requirements

All CHP systems and electric-only fuel cells, operating on non-renewable fuel, larger than 30 kW must be installed with a fuel metering system which allows the System Owner and Program Administrator to determine the amount of fuel consumption and allows the System Owner to support proper system operation and maintenance. The meter must meet the minimum meter requirements of this section. All CHP systems and electric-only fuel cells that are 300 kW and smaller, will be allowed to use an on-board fuel metering system to minimize cost. The recorded data will be used to calculate the minimum system operating efficiency and GHG emissions of the system. These calculated values will be used to monitor compliance with the Program's GHG emission limits and minimum system operating efficiency requirements.

11.4.1 *Data Required from Fuel Metering Systems and Metering Responsibility*

Fuel metering systems installed on the SGIP project provide data used to assess performance of the system; including its ability to meet minimum operating efficiency requirements. Thermal energy performance data will also be used to assess impact of the SGIP system on net GHG emission impacts. Consequently, fuel metering systems must provide performance data on no less than 15 minute interval increments; be capable of storing data in the event of power outages or communication failures; and communicating results consistently to the PDP in a format that can be easily transferred to the PA for assessment and incentive payment purposes. While the following sections provide guidance on metering measurements and placement, it is the responsibility of the project owner and PDP to select, install, operate and maintain the fuel metering system to supply the needed performance data.

Fuel Meters shall be kept secure from Denial of Service (DOS) Attacks, Port Scanning, Unauthorized Access and other security violations. To achieve this security, Communications Interfaces to all meters must be located in a secure location and include strong password protection with either a network firewall or a Secure VPN Tunnel to limit the meter's network access to the PDP and/or a defined list of authorized users. In addition, security measure may be implemented as needed to ensure data security including restriction of direct meter access for real time data to a sequential access basis.

11.4.2 *Meter Type*

External fuel gas flow measurements are typically done in one of three ways:

1. Mass flow meter
2. Calculated based upon continuous differential pressure measurements across an orifice.
3. Utility gas meter.

On-board fuel metering systems just as external fuel metering systems must measure fuel consumption by the generator. The proposed meter type shall be identified in a Monitoring Plan developed for each individual project. On-board meters must meet the same requirements as external meters which are outlined below.

11.4.3 ***Meter Accuracy***

Flow measurement must include temperature and pressure compensation and must measure standard cubic feet (at 60 °F and 1 atmosphere) to within +/- 5% at design conditions. This requirement applies to on-board as well as external fuel metering systems.

11.4.4 ***Meter Measurement and Time Granularity of Acquired Data***

The PDP must log all required generator system fuel input data points no less frequently than once every 15 minutes. Calculated values must be reported in 15 minute intervals. Data must be recorded in units of standard cubic feet per minute. The Btu content and basis (HHV/LHV) of the fuel must be reported during commissioning either through data provided by the gas company or determined by analysis. Btu content of the fuel will need to be re-analyzed and reported to the PA when there is a reason to believe it has changed. The meter needs to generate an accurate time date stamp.

11.4.5 ***Meter Communication/Data Transfer Protocols***

Protocols for the minimum required performance/output data must enable any PDP to communicate with the meter and obtain the minimum required performance data from the meter. The data transfer protocol provided to the Program Administrator must satisfy servicing the Program Administrator requirements.

All meters must have the capability to report their data remotely. Data reporting must occur on a daily basis.

PDP Providers that fail to submit data to the Program Administrators when requested by the PA or an authorized agent of the CPUC, may be removed as an eligible PDP from the Program Administrators' approved list. It is the Host Customer and/or System Owner's responsibility to ensure the transfer of fuel consumption data from the Performance Data Providers (PDP) to the Program Administrators.

All PDP's will need to transfer performance data via EDI867 to the Program Administrators.

11.4.6 ***Meter Data Access***

All meters must provide the PDP provider or defined list of authorized users with the ability to access and retrieve the minimum required Fuel Consumption Data from the meter using the Meter Communication / Data Transfer Protocols described in section 11.4.5.

11.4.7 ***Meter Memory and Storage***

All meters must have the ability to retain collected data in the event of a power outage. Meters must have the capability to store 7 days worth of data. ~~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 60 days of data in support of monthly reporting. In all cases, meters must be able to retain lifetime production.~~

11.4.8 *Acceptable Fuel Metering Points*

For fuel metering that is external to the generator an acceptable metering point is before fuel entry into the generator but downstream of any other loads (e.g., natural gas boiler, un-incentivized CHP system). For on-board metering systems the fuel must be metered before any portion is consumed by the generator. Proposed meter locations shall be identified in a Monitoring Plan developed for each individual project.

11.5 Data Privacy

Protecting the privacy of System Owners and Host Customer is of the highest order. As such, data shall be collected, processed, and reported to the System Owner and the Program Administrator in accordance with this section. The PDP may provide data to third parties, including Contractors and Host Customers (if different than the System Owners), provided the System Owner has consented in writing to the release of such performance data.

11.6 Minimum PDP Requirements

The element of the PDP service that entails the data flow between the electrical generation system and the Program Administrator that serves as the basis for PBI must, as a minimum, meet the SGIP PBI data transfer rules (Section 19).

i. ±2 % meter
ii. Data as collected and summarized by hour, day, month, and year (Excel, CSV, acceptable).
iii. Data must be associated with a specific site.
iv. Provide System Owner access to 15 minute interval kWh system production report within 24 hours of production data received by PDP
v. Provide System Owner access to 15 minute interval fuel consumption report within 24 hours of data received by PDP
vi. Provide System Owner access to 15 minute interval useful thermal production report within 24 hours of data received by PDP
vii. Notification service alerts to the System Owner indicating a non-functioning or poorly functioning system
viii. Monthly 15 minute interval kWh energy production data submittals to Program Administrator or its designee for 5 years

ix. Monthly 15 minute interval fuel consumption data submittals to Program Administrator or its designee for 5 years
x. Monthly 15 minute interval useful thermal energy production data submittals to Program Administrator or its designee for 5 years
xi. Listed and approved by the Program Administrators

The list of PDPs can be found on each PA's SGIP website and instructions for PDP requirements may be found in Section 19.

11.7 Inspection

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

11.8 SGIP Program Administrator Liability

Apart from the requirements identified herein, the PAs are not liable for the performance or non-performance of a PDP that may result in a delay of or incorrect amount of a PBI payment. The Program Handbook defines the criteria required for PDPs to participate in the Program only.

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. 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[28]. 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[29].

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.[30]
- 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
- 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[31].

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.[32]
- 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.

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 <u>did not</u> 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 <u>did</u> 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 Email: gen@pge.com

Phone: (415) 972-5676 (PG&E Generation Interconnection Hotline)
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 E-mail: 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, review of monitoring plans developed by the project developer or host site, installation of metering equipment or review/inspection of metering equipment installed by the project developer or host site, collection and transfer of data from installed system monitoring equipment, whether installed by Host Customer, System Owner, a third party, or the Program Administrator. Program Administrators or the Program Administrator's independent third-party consultant will use this data to show the performance of technologies by class (e.g. wind turbines), and may determine the performance of those technology classes as they see fit. Performance data from specific projects, however, will remain confidential.

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. Installations above 30kW will already require this type of electrical metering as a condition of the Program. Net Generation Output Meters are also required 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.

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 (15-minute interval data) to the SGIP M&E consultant on a monthly basis for the 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.[33]
   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.
   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)[34] 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.

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.

Date	Bill Number	Description
9/8/2011	Decision 11-09-015	• Adds eligibility requirements based upon greenhouse gas reductions. • Establishes an on-site emission rate that projects must beat to be eligible for SGIP participation of 379 kg CO2/MWh. • Adds Waste Heat to Power, Pressure Reduction Turbine, Internal Combustion Engine – CHP, Microturbine – CHP, Gas Turbine – CHP, Stand-Alone AES technologies to the list of eligible technologies. • Revises the incentive levels for all technologies and adds a $2.00/Watt biogas adder. • Directs that Directed Biogas can only be procured from in-state suppliers. • Eliminates maximum size restrictions given a project meets on-site load. Sets a 30 kW minimum for wind and renewable fueled fuel cell projects. • Adopts a hybrid payment structure with 50% upfront, 50% PBI based on kWh generation of on-site load for projects larger than 30 kW. Projects under 30 kW will receive the entire incentive upfront. • Adopts the following assumed capacity factors to be used in PBI calculations: 10% for AES, 25% for wind, and 80% for all other distributed energy resources. • Implements incentive decline in the following manner 10% per year for emerging technologies and 5% per year for all other technologies, beginning 1/1/2013. • Adopts a supplier concentration limit where 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. • Establishes a maximum project incentive of $5 million. • Establishes that the minimum customer investment in a project must be 40% of eligible project costs. • Establishes an SGIP incentive budget allocation of 75% for renewable and emerging technologies, and 25% for non-renewable technologies. • Determines that the Program Administration Budget will be reduced to 7%. • Establishes that projects exporting to the grid are eligible for SGIP incentives as long as they do not export more than 25% on an annual net basis. • Makes an 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. • Establishes an application fee that is 1% of the amount of incentive requested • Limits all projects to one six month extension. Request for a second extension maybe made to the Working Group. • Extends the warranty period to 10 years.

19 SGIP Data Transfer Rules

INSTRUCTIONS FOR QUALIFYING AS A PERFORMANCE DATA PROVIDER FOR THE SELF GENERATION INCENTIVE PROGRAM

The purpose of this section is to outline the required process and qualifications to be approved as a Performance Data Provider (PDP) for the Self Generation Incentive Program. This section also details the data reporting requirements (format, delivery method) and schedule for Performance Based Incentive data reports, as well as data reports on fuel consumption and useful thermal energy production. All PDPs must meet the requirements established herein in addition to the requirements set forth in the SGIP Handbook.

19.1 Background and Requirements

Utility customers participating in the Self Generation Incentive Program (SGIP) with projects larger than 30 kW are required to install performance meters to determine the net energy generated by their generation equipment. In addition to net energy generated, SGIP participants with CHP projects or electric-only fuels operating on non-renewable fuels are required to monitor fuel consumption. CHP projects operating on non-renewable fuels are additionally required to monitor useful thermal output. For customers enrolled under the SGIP Performance Based Incentive (PBI) program, data from the electric generation meters will be used to calculate their annual incentive payment. This data may be read and communicated to the Program Administrator (PA)[35] by a third-party Performance Data Provider (PDP). Customers may also elect to contract this service through their local utility company. This document provides information and instructions for non-utility providers wishing to qualify to provide PDP services.

The following are the PDP's primary responsibilities:

- Manage meter reading/data retrieval schedule
- Read and retrieve performance meter data
- Post data on appropriate Program Administrator server on a consistent and reliable schedule, per Program Administrator requirements.
- Validate performance data prior to providing to the PA using the approved validation rules outlined in this document
- Calculate annual production of generating system for incentive payment
- Format data using EDI 867 or other approved protocol

- Troubleshoot and resolve communications issues
- Store data in accordance with program requirements
- Make historical performance data available to Program Administrators as requested
- Provide technical support to Program Administrators as well as customer support
- Communicate meter/device changes to the Program Administrator
- Provide disaster recovery and data backup services as requested by respective Program Administrator
- Manage data on PDP server
- Ensure confidentiality of customer information and performance data
- Possess technical expertise and capability
- Comply with all State and Federal laws

19.2 PDP Task Requirements

19.2.1 Data Format

Data must conform to the specific program requirements (for SGIP requirements, see Section 11 of the SGIP Handbook). The PBI Data Report must include 15-minute (as defined in Section 11.2.4 Time Granularity of Acquired Data, SGIP Program Handbook) and the monthly cumulative production meter read. The Fuel Consumption Data Report must include 15-minute (as defined in Section 11.4.4 Time Granularity of Acquired Data, SGIP Program Handbook) and the monthly cumulative consumption meter read. The Useful Thermal Output Data Report must include 15-minute (as defined in Section 11.3.4 Time Granularity of Acquired Data, SGIP Program Handbook) and the monthly cumulative production meter read. All Data Reports must be formatted using the ANSI X.12 Electronic Data Interchange 867 protocol (EDI 867) unless otherwise specified. Sample EDI 867 Implementation Guides and Tutorials are available from each of the Program Administrators.

19.2.2 Data Reporting, Security and Confidentiality

The PDP is responsible to ensure timely, consistent and accurate reporting of performance data. Data must be located in a secure facility, on a secure server and have firewall and equivalent protection. The PDP must protect the confidentiality of the customer information and performance data in accordance with all program guidelines (for SGIP requirements, see Section 11 of the SGIP Handbook). The data must be transferred to each PA using a secure FTP server and each PDP must contact the appropriate PA to obtain the secure FTP address. The PDP must follow all applicable state and federal privacy and data security laws. Meter data will be read remotely no less frequently than on a daily basis. In the event there is a communication problem between the PDP and the meter, and the 15 minute interval data is accumulated over a 24 hour period, it is acceptable to take the accumulated data and divide it by the 96 fifteen minute intervals that occur over a 24 hour period for the purpose of estimating the meter's 15 minute interval data. Accumulated data for a period longer than 24 hours will not be accepted. **Other than this exception the Program Administrator is not responsible for, and will not pay any customer incentives based on missing, estimated or invalid performance data.**

19.2.3 Data Validation

The PDP must validate all data prior to posting it to the PAs secure FTP server. The following data validation rules shall apply:

- Time Check of Meter Reading Device/System (all)
- Meter Identification Check (all)
- Time Check of Meter (all)
- Pulse Overflow Check (if applicable to metering system)
- Test Mode Check (if applicable to metering system)
- Sum Check

Descriptions of these validation rules are included in Attachment A (section 19.4).

19.2.4 Payment Validation, Data Audits, and Measurement and Evaluation Program

The Program Administrators may, at their discretion, perform validations on incentive payments prior to issuing payments to customers participating in this program. The validations will compare actual yearly incentive payments with expected payments based on design specifications and expected performance data submitted with the Host Customers' approved incentive reservation documentation. If payments fall outside expected ranges for the year, the incentive payment will be withheld until the Program Administrator determines to its satisfaction the reason for the discrepancy.

The PDP will work with the Host Customer to resolve any discrepancies identified by the Program Administrator, which may include testing and/or recalibrating the meter/devices if deemed necessary. The Program Administrators are not responsible for the costs associated with investigating and resolving any such discrepancies (i.e., testing, meter replacement hardware, installation labor). However, if the Program Administrator requests an investigation that finds that the metering system is accurate, the Program Administrator will pay all reasonable and necessary costs for the investigation.

The Program Administrator will also perform random audits of PDP data to ensure accuracy and compliance with the requirements outlined in this document, or as part of the SGIP Measurement and Evaluation Program in accordance with the SGIP Handbook. Any PDP found to be in violation of any of these requirements will be subject to the penalties outlined later in this document. The Program Administrator, via the servicing local utility or its designated contractor may, at its discretion, inspect and test the performance meter or install separate metering in order to check meter accuracy, verify system performance, or confirm the veracity of monitoring and reporting services.

Any additional metering installed by or at the request of the Program Administrator will be paid for by the Program Administrator. However, in the event metering is installed during the course of an audit or investigation initiated by the Program Administrator where cheating or tampering is suspected and confirmed, the System Owner will be charged for these costs.

19.2.5 Data Retention

Raw and PDP validated interval and cumulative monthly data must be retained in accordance with appropriate program requirements (see Section 11 of the SGIP Handbook for SGIP program requirements). The PDP must be prepared to post historical interval data at the Program Administrator's request. The Program Administrator audit will include raw interval data, which is to be maintained by the PDP for comparison with validated interval data transmitted to the Program Administrator. The PDP is also responsible for providing backup and disaster recovery services for 100% of the data (in accordance with the SGIP data retention policy outlined in Section 11 of the SGIP Program Handbook)

19.2.6 Technical and Customer Support

The PDP must provide a technical support number to the Program Administrator for use during normal business hours (8am to 5pm Pacific time, Monday through Friday, except holidays) to help resolve any data availability, format or corruption issues, communication problems, server access problems, or other technical issues. Within those normal business hours, the PDP must respond to Program Administrator requests within two business days with a status report and plan for correcting the issues. The PDP must also provide a customer support number to respond to customer inquiries within two business days from the initial customer contact. Program Administrators will have the discretion to set deadlines for the resolution of data transfer problems/issues.

19.2.7 PDP Performance Exemptions

The PDP is responsible for meeting the above noted program requirements and for consistently posting performance data in accordance with the Program Administrator's scheduling and data posting requirements. Posting of performance data typically commences on the date of interconnection. If necessary a three month grace period will be granted after the date of interconnection during which the project can undergo commissioning of the metering and monitoring equipment, before posting of performance data commences. At the end of the commissioning period, sample data will need to be provided by the Performance Data Provider to the PA demonstrating that the metering and monitoring system is operating correctly.

At its discretion, the Program Administrator may grant reasonable allowances for occasional issues or technical problems, as well as for large catastrophic events such as earthquakes.

19.2.8 PDP Non-Performance

The Program Administrator will not issue incentive payments to customers based on estimated data from the PDP, nor will the Program Administrator estimate incentive payments under any circumstances. It is the PDP's responsibility to ensure timely (+ 5 days after the end of the specified reporting period) and accurate posting of validated performance data so customer incentive payments can be made. Performance data also includes fuel consumption and useful thermal output data as this information will be used to verify compliance with program rules and impact PBI payments.

The following conditions may result in penalties, suspension of activity, or revocation of PDP approval from the Program Administrator:

- Data not posted by specified date (10% of accounts serviced by PDP over a one-month period are late).
- No data received for incentive period (per customer: no data posted 2 times consecutively OR 3 times in 6 months; and/or per PDP: no data posted for 10% of accounts serviced by PDP). Submittal of corrected data or previously missing monthly data must be received in cycle sequence.
- Data not validated in accordance with program requirements over the course of the SGIP Program. (1 time)

- Estimated data posted instead of actual data. (1 time)
- Meter change information not reported within 30 days of the meter change. (3 times within 6 months)

If an audit or investigation shows a discrepancy of -/+ 5% between the PDP reported data and Program Administrator check meter production data for one data report period. This discrepancy will trigger an audit schedule set by the Program Administrator for the PDP.

The PDP will be given reasonable opportunity to correct problems identified by the Program Administrator. The Program Administrator will work with the PDP to correct any such problems and avoid unnecessary delays in issuing incentive payments to customers, to the extent feasible. However, if the PDP fails to resolve any issues to the Program Administrator's satisfaction within 60 days, which result in delays in incentive payments to customers, the following penalties may apply:

- If the problem is with a single or less than 20% of customer accounts served by the PDP, the Program Administrator will suspend PDP activity with just those affected customers. The affected customers will be notified that the PDP has been unable to resolve the specified issue within an acceptable timeframe, and they will be given a 30-day grace period to select and engage with another PDP. The original PDP will be required to transfer all historical data to the newly selected PDP. No incentive payments will be made until the customer provides a contract or similar document proving they are engaged with another PDP, If the customer fails to engage with and provide proof that they have contracted with a new PDP within the allowable grace period, the time between the grace period expiration date and the date the Program Administrator receive such proof will be deducted from the established payment period.
- .If the problem is of a more serious nature as determined by the Program Administrator and continues over 60 days, or it affects more than 20% of customers served by the PDP, the PDP's approval will be revoked and all customers will be notified that they must select another PDP. As above, no incentive payments will be made until the customer selects another PDP. The PDP will be eligible to reapply after six months upon demonstrating that they have successfully resolved all problems to the Program Administrator's satisfaction.
- If an audit or investigation shows a discrepancy between the PDP reported data and data obtained by the Program Administrator for a specific customer that is greater than +/-5%, the PDP will be responsible for reimbursing the customer or Program Administrator for any such difference if it is determined that the difference is due to PDP error. The PDP will also be put on an audit schedule by the Program Administrator. If a third audit uncovers any discrepancy

due to PDP error, the PDP's approval will be revoked and the customer given an opportunity to select another PDP as described above. Audits may be conducted as stated in the SGIP Handbook.

Unless the PDP's actions results in revocation, upon receipt of a notice from the PA with respect to the PDP's failure to provide the performance, the PDP must, as soon as reasonably practicable:

(1) perform a root-cause analysis to identify the cause of such a failure;

(2) provide the PA with a report detailing the cause of, and procedure for correcting such failure within 3 days of completion of such root-cause analysis;

(3) implement such procedure after obtaining the respective PA approval of such procedure.

19.2.9 Criteria for a PDP Appeals Process

Should the PDP disagree with a PA decision regarding a penalty, the PDP has the right to appeal to the SGIP Working Group for further consideration.

19.3 PDP Application Process

The PDP Applicant completes the attached "Application for PDP Services" and provides all documentation in the attached checklist. The PDP applicant must successfully complete the data transfer test described later in this document and submit the application for statewide PDP services to either of the PAs at the following addresses:

In PG&E's service territory, the PDP Applicant forwards the completed application and required documentation to the following:

Mail to:	Self Generation Incentive Program PO Box 7433 San Francisco, CA 94120
For questions, contact:	Program Manager, Self Generation Incentive Program Phone: (415) 973-6346 Fax: (415) 973-2510 Email: selfgen@pge.com Web: www.pge.com/sgip

In SCE's service territory, the PDP Applicant forwards the completed application and required documentation to the following:

Mail to:	Self Generation Incentive Program Southern California Edison P.O. Box 800 Rosemead, CA 91770-0800
For questions, contact:	Program Manager, Self Generation Incentive Program Phone: (866)-584-7436 Fax: (626) 302-3967 Email: CSIGroup@sce.com Web: www.sce.com/SGIP

In San Diego Gas & Electric's service territory, the PDP Applicant forwards the completed application and required documentation to the following:

Mail to:	California Center for Sustainable Energy Attn: Self Generation Incentive Program 8690 Balboa Ave., Suite 100 San Diego, CA 92123-1502
For questions, contact:	SGIP Program Manager Phone: (858) 244-1177 Fax: (858) 244-1178 Email: sgip@energycenter.org Web: www.energycenter.org/sgip

In SoCalGas's service territory, the PDP Applicant forwards the completed application and required documentation to the following:

Mail to:	Self Generation Incentive Program Southern California Gas Company 555 West Fifth Street, GT22H4

Los Angeles, CA 90013-1011

For questions, contact: SGIP Program Manager
Phone: (866)-DG-REBATE (1-866-347-3228)
Fax: (213) 244-8222
Email: selfgeneration@socalgas.com
Web: www.socalgas.com/innovation/self-generation

The Program Administrator will review the submitted documentation, determine if the PDP Applicant meets the program requirements and notify the PDP Applicant via email. The Program Administrator will review the application and respond to the PDP Applicant within 10 business days.

19.3.1 Data Transfer Test

Once the Program Administrator has reviewed and accepted the prospective PDP's application, they will contact the PDP Applicant to schedule a data transfer test.

Program Administrators will provide PDP Applicants with test data sets that the prospective PDP must download, validate, and format before submitting the Data Report back to the Program Administrator via secure FTP. The PDP Applicant is also responsible for downloading the Program Administrator's EDI 867 Implementation Guide and Tutorials from its website. The PDP must contact their respective Program Administrator for specific instructions regarding this testing process.

The Program Administrator will check the test file to ensure it complies with the guidelines and notify the PDP Applicant within 5 business days. Once the PDP is notified it has passed the test, the PDP is considered qualified. If the PDP Applicant fails the test, they will be given 2 weeks to resolve any technical or data format issues. If a PDP Applicant fails their Data Transfer Test more than 3 times, they will not be eligible to add any additional customers until such PDP Applicant passes the Data Transfer Test.

19.3.2 PDP Approval Initial Audit Period

Upon PA approval of the required PDP application documentation, and successful completion of the PDP data test procedures, the PDP will be qualified to provide PBI data to the Program Administrator for incentive payment. However, the PA's will audit the raw production data from each PDP's first data report for their first three customers for compliance with these PDP requirements. The PA will notify the PDP of noncompliance and will work to assist the PDP with resolving the issues.

19.3.3 Application to Provide PDP Services

This application and the attached documents are to be used by Applicants for approval as a Performance Data Provider (PDP). Please refer to the checklist to ensure your application includes all applicable documentation.

Company Name: ____

Primary Contact: ____

Address: ______________________________Address 2: ________________

City: ___________________________ State: _________ ZIP: _____________

Phone: (_____) ____-_______ Fax: (_____) ____-_______

Email: ____

Technical Support Contact

Contact Name: ____

Phone: (_____) ____-_______ Email: _________________________________

Customer Support Contact

Contact Name: ____

Phone: (_____) ____-_______ Email: _________________________________

Type of Data Services Provided

- ☐ Electrical Generation Metering
- ☐ Thermal Output Metering
- ☐ Fuel Consumption Metering

PDP APPLICATION CHECKLIST

Background

- ~~☐ Listed as an approved PMRS provider on the CEC's eligible list~~
- ☐ Company background (years in business, number of employees, general description, executive team, etc.)
- ☐ Meter data reading and reporting experience and capabilities, capacity, technology overview, IT capabilities, etc.

Procedures

- ☐ Meter reading and data retrieval procedures
- ☐ Data communication (frequency, scalability, types, troubleshooting, etc.)
- ☐ Process for retrieving missed reads
- ☐ Data validation procedures
- ☐ Technical Support (hours of operations, staff levels, procedures, etc.)

- ☐ Customer Support (hours of operations, staff levels, etc.)

IT Systems and Processes

- ☐ Data posting (data translation, formatting, firewall access, etc.)
- ☐ Data retention plan
- ☐ Backup and recovery plans
- ☐ Hardware and software scalability plans
- ☐ Data confidentiality and security procedures

By signing this document, the Applicant agrees to comply with all program requirements including those described in the SGIP Handbook (signature must be someone with legal authority at the PDP). Additionally, Applicant agrees to keep confidential all data received from the PA for testing. Information in this document will remain confidential.

Signature: ______________________________ Date: _________________________

Printed Name: __________________________Title:_____________________________

ATTACHMENT A

19.4 SGIP Data Validation Rules

Check	Purpose
Time Check of Meter Reading Device/system	Check for time drift of meter reading device/system outside standard
Meter ID Check	Check for the following: • Meter ID reported correctly • Meter has not been changed out • Data is being reported for correct meter
Time Check of Meter	Check for time drift of meter clock outside standard
Pulse Overflow Check	Check for the following: • Improper scaling factor in meter • Improperly sized transformer • Hardware problem
Test Mode Check	Check that data collected when meter was in test mode represents test production rather than actual production
Sum Check	Check for the following in combination meter/recorder installations: • Crossed channels between meter & recorder • Pulse relay problems Check for the following in all installations: • Invalid PT & CT ratios • Invalid meter constants

ST•867•000000984ª The ST is the start of the 867 Transaction
Set with a control number of 000000984

BPT•00•2007-04-21-09.01.08.795475•20000421•C1••••1948•1ª The BPT marks the Beginning Segment for Product Transfer and Resale where 00 is an Original data transmitted, C1 Indicates interval data value and 1 indicates cycle shift number (1 – 1st to 1st of next month, 2 – 16th to 16th of next month)

N1•55••1•006908818••41ª Identifies the Performance Data Provider (PDP) as a uniquely assigned number that is provided by SCE

REF•10•SCE-SGIP-36949ª Identifies the SGIP Project ID

REF•BT•23ª Indicates Cycle number (Report number for SCCE)

REF•59•2007-04-21-09.01.08.795434ª Identifies the prior unique transaction BPT02 number **2007-04-21-09.01.08.795434** to be corrected. Only used when BPT01=CO

PTD•PM•••OZ•ELª Identifies the type of product transfer to be physical meter information, and the product reference Identification indicates Electric Service

DTM•150••••DT•200801010000ª January 01, 2008 is the Service Period Start Date. All dates are expressed in Greenwich Mean Time (GMT).

DTM•151••••DT•200802010000ª February 01, 2008 is the Service Period End Date. All dates are expressed in Greenwich Mean Time (GMT).

REF•JH•Aª Indicates Energy is generated by the end use Customer (Addition)

REF•6W•1ª Indicates channel ID (1 for SCE)

REF•MG•O717K-001388ª The Meter Number is O717K-001388

REF•MT•KH015ª The Meter Data Type is Monthly Kilowatt Hour and 15 indicates 15 minutes interval data

QTY•32•24709ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010015ª January 01, 2008 12:15 am is the

Interval end time Date.

QTY•32•2345ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010030ª January 01, 2008 12:30 am is the Interval end time Date.

QTY•32•3734ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010045ª January 01, 2008 12:45 am is the Interval end time Date.

QTY•32•1232ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010100ª January 01, 2008 01:00 am is the Interval end time Date.

QTY•32•1535ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010115ª January 01, 2008 01:15 am is the Interval end time Date.

QTY•32•1535ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010130ª January 01, 2008 01:30 am is the Interval end time Date.

QTY•32•1535ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010145ª January 01, 2008 01:45 am is the Interval end time Date.

QTY•32•1535ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010200ª January 01, 2008 02:00 am is the Interval end time Date.

QTY•32•1235ª The KWH data for each 15 minutes interval

DTM•151••••DT•200801010215ª January 01, 2008 02:15 am is the Interval end time Date.

..

..

..

..

QTY•32•1235ª The KWH data for each 15 minutes interval

DTM•151••••DT•200802010000ª February 01, 2008 is the Interval end time Date.

****

SE•209•000000984ª Total Number of Segments is 209, Control Number is 000000984

PDF Created

19.5 867 Product Transfer and Resale Report

Functional Group ID=PT

Introduction:

This Draft Standard for Trial Use contains the format and establishes the data contents of the Product Transfer and Resale Report Transaction Set (867) for use within the context of an Electronic Data Interchange (EDI) environment. The transaction set can be used to: (1) report information about product that has been transferred from one location to another; (2) report sales of product from one or more locations to an end customer; or (3) report sales of a product from one or more locations to an end customer, and demand beyond actual sales (lost orders). Report may be issued by either buyer or seller.

Heading:

Pos. Seg. Req. Loop Notes and

No. ID Name Des. Max.Use Repeat Comments

Must Use 010 ST Transaction Set Header M 1

Must Use 020 BPT Beginning Segment for Product Transfer and

Resale

M 1

LOOP ID - N1 5

Must Use 080 N1 Name O 1

Must Use 120 REF Reference Identification O 12

Detail:

Pos. Seg. Req. Loop Notes and

No. ID Name Des. Max.Use Repeat Comments

LOOP ID - PTD >1

Must Use 010 PTD Product Transfer and Resale Detail M 1

Must Use 020 DTM Date/Time Reference O 10

Must Use 030 REF Reference Identification O 20

LOOP ID - QTY >1

Must Use 110 QTY Quantity O 1

210 DTM Date/Time Reference O 10

Summary:

Pos. Seg. Req. Loop Notes and

No. ID Name Des. Max.Use Repeat Comments

Must Use 030 SE Transaction Set Trailer M 1

Segment: ST Transaction Set Header

Position: 010

Loop:

Level: Heading:

Usage: Mandatory

Max Use: 1

Purpose: To indicate the start of a transaction set and to assign a control number

Syntax Notes:

Semantic Notes: 1 The transaction set identifier (ST01) used by the translation routines of the interchange partners to select the appropriate transaction set definition (e.g., 810 selects the Invoice Transaction Set).

Comments:

Data Element Summary

Ref. Data

Des. Element Name Attributes

ST01 143 Transaction Set Identifier Code M ID 3/3

Code uniquely identifying a Transaction Set

867 Product Transfer and Resale Report

ST02 329 Transaction Set Control Number M AN 4/9

Identifying control number that must be unique within the transaction set

functional group assigned by the originator for a transaction set

Segment: BPT Beginning Segment for Product Transfer and Resale

Position: 020

Loop:

Level: Heading:

Usage: Mandatory

Max Use: 1

Purpose: To indicate the beginning of the Product Transfer and Resale Report Transaction Set and transmit identifying data

Syntax Notes:

Semantic Notes: 1 BPT02 identifies the transfer/resale number.

2 BPT03 identifies the transfer/resale date.

3 BPT08 identifies the transfer/resale time.

4 BPT09 is used when it is necessary to reference a Previous Report Number.

Comments: BPT01 = 07 is used if previously furnished information is being provided in a new file. In this case, or if data points have been corrected, only the corrected meters' data need to be provided, even if multiple meters were originally sent If a previously transmitted file is simply being reposted for download from a server, the original designation of BPT01 = 00 or CO does not need to be changed.

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **BPT01 353 Transaction Set Purpose Code M ID 2/2**

Code identifying purpose of transaction set

00 Original

Conveys original readings for the account being reported.

52 Response to Historical Inquiry

Response to a request for historical meter reading.

CO Corrected

Indicates that the readings previously reported for the
account are being corrected.

Must Use **BPT02 127 Reference Identification O AN 1/30**

Reference information as defined for a particular Transaction Set or as
specified by the Reference Identification Qualifier

A unique transaction identification number, assigned by the originator.

Must Use **BPT03 373 Date M DT 8/8**

Date when the PDP record is created by the application (CCYYMMDD)

Must Use **BPT04 755 Report Type Code O ID 2/2**

Code indicating the title or contents of a document, report or supporting item

C1 Cost Data Summary

Interval values

Must Use **BPT08 337 Time O TM 4/8**

Time when the PDP record is created by the application (HHMM)

Must Use **BPT09 127 Reference Identification O AN 1/30**

Reference information as defined for a particular Transaction Set or as
specified by the Reference Identification Qualifier.

Will represent Cycle shift number (1 or 2)

Segment: N1 Name

Position: 080

Loop: N1

Level: Heading:

Usage: Optional (Must Use)

Max Use: 1

Purpose: To identify a party by type of organization, name, and code

Syntax Notes: 1 At least one of N102 or N103 is required.

2 If either N103 or N104 is present, then the other is required.

Semantic Notes:

Comments: 1 This segment, used alone, provides the most efficient method of providing organizational identification. To obtain this efficiency the "ID Code" (N104) must provide a key to the table maintained by the transaction processing party.

2 Three N1 segments will be used in California, with N101 = 55, 8S, and SJ, unless the values of N104 corresponding to N101 = 8S or SJ would duplicate the value corresponding to N101 = 55. The end-use customer's account numbers for the meter data management agent (N101 = 55), utility (N101 = 8S), and the energy service provider (N101 = SJ) must be placed in REF segments following these N1 segments, with REF01 = 10, 12, and 11, respectively.

3 When N101 = 55 (Meter Data Management Agent), N106 = 41 (Submitter). When N101 = 8S (Utility) and SJ (Energy Service Provider), N106 = 40 (Receiver).

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **N101 98 Entity Identifier Code M ID 2/3**

Code identifying an organizational entity, a physical location, property or an
individual

>> 55 Used to identify the party that manages meter data on behalf of another. Often referred to as the Performance Data Provider (PDP).

Must Use **N103 66 Identification Code Qualifier X ID 1/2**

Code designating the system/method of code structure used for Identification
Code (67)

1 SCE Assigned PDP identification code

Must Use **N104 67 Identification Code X AN 2/80**

PDP identification number assigned by SCE

Must Use **N106 98 Entity Identification Code O ID 2/3**

Code identifying an organizational entity, a physical location, property or an individual

41 Submitter

Entity transmitting transaction set

Segment: REF Reference Identification

Position: 120

Loop: N1

Level: Heading:

Usage: Optional (Must Use)

Max Use: 12

Purpose: To specify identifying information

Syntax Notes: 1 At least one of REF02 or REF03 is required.

Semantic Notes:

Comments: See Comments related to the N1 segment.

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **REF01 128 Reference Identification Qualifier M ID 2/3**

Code qualifying the Reference Identification

10 Account manager Code (This will be used as CSI

Project ID)

BT Reference Identifier

Indicates Cycle number/Report Number

59 Prior Incorrect Batch Number

Only used when BPT01= CO

REF02 127 Reference Identification X AN 1/30

Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier Reference the value of BPT02 for file already transmitted but intended for correction

Segment: PTD Product Transfer and Resale Detail

Position: 010

Loop: PTD

Level: Detail:

Usage: Mandatory

Max Use: 1

Purpose: To indicate the start of detail information relating to the transfer/resale of a product and provide identifying data

Syntax Notes: 1 If either PTD04 or PTD05 is present, then the other is required.

Semantic Notes:

Comments: 1 The PTD loop conveys consumption information for one meter or register, and for one commodity for metered service, over a number of metering intervals. Accounts which have multiple meters or registers require multiple PTD loops; the total consumption from multiple meters may be summarized in another PTD loop, qualified by SU, at the option of the Meter Data Management Agent. Accounts which have multiple services (e.g., both electric and gas) or multiple metered commodities require separate PTD loops for each service or commodity. For unmetered service, multiple commodities may be reported in a single PTD loop.

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **PTD01 521 Product Transfer Type Code M ID 2/2**

Code identifying the type of product transfer

PM Physical Meter Information, including data from a

meter, totalizer, or recorder.

Must Use **PTD04 128 Reference Identification Qualifier X ID 2/3**

Code qualifying the Reference Identification provided in PTD05.

OZ Product Number

Must Use **PTD05 127 Reference Identification X AN 1/30**

Reference information as defined for a particular Transaction Set or as

specified by the Reference Information Qualifier.

EL Electric Service

Segment: DTM Date/Time Reference

Position: 020

Loop: PTD

Level: Detail:

Usage: Optional

Max Use: 10

Purpose: To specify pertinent dates and times

Syntax Notes: 1 At least one of DTM02 DTM03 or DTM06 is required.

2 If either DTM05 or DTM06 is present, then the other is required.

Semantic Notes:

Comments:

Notes:

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **DTM01 374 Date/Time Qualifier M ID 3/3**

Code specifying type of date or time, or both date and time

150 Service Period Start

151 Service Period End

MRR Meter Reading

Date of special meter read

Must Use **DTM05 1250 Date Time Period Format Qualifier X ID 2/3**

Code indicating the date format, time format, or date and time format

DT Date and Time Expressed in Format

CCYYMMDDHHMM

Must Use **DTM06 1251 Date Time Period X AN 1/35**

Expression of a date, a time, or range of dates, times or dates and times

Segment: REF Reference Identification

Position: 030

Loop: PTD

Level: Detail:

Usage: Optional

Max Use: 20

Purpose: To specify identifying information

Syntax Notes: 1 At least one of REF02 or REF03 is required.

Comments: 1 A segment containing REF01 = LU is required if PTD01 = PM

2 Segment containing REF01 = MG and MT is required unless the service delivery point is unmetered, in which case a segment containing REF01 = SC is required.

3 For interval data, the metering interval corresponding to REF01 = MT must be the same for all PTD loops.

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **REF01 128 Reference Identification Qualifier M ID 2/3**

Code qualifying the Reference Identification

6W Sequence Number

Identifies channel number (identifier) when there is more than one channel on a meter measuring the same quantity (e.g., two kWh channels).

>> JH Tag

Meter Role. Valid values for REF02 are:

A = Additive (this consumption contributes to the total for the account),

I = Ignore (this consumption does not contribute to the total for the account - do nothing),

S = Subtractive (this consumption must be subtracted from the total for the account).

MG Meter Number

MT Meter Data Type (see examples in REF02)

REF02 127 Reference Identification X AN 1/30

Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier

When REF01 is MT, the meter type is expressed as a 5-character field that identifies the type of consumption measured by this meter and the interval between measurements. The first two characters are the type of consumption, expressed in the units of measure from Data Element 355, as follows:

1N Count

Indicates meter pulses

70 Volt

BY British Thermal Unit (BTU)

CF Cubic Feet

EA Each

HH Hundred Cubic Feet

K1 Kilowatt Demand

Represents potential power load measured at predetermined intervals

K2 Kilovolt Amperes Reactive Demand

Reactive power that must be supplied for specific types of customer's equipment; billable when kilowatt demand usage meets or exceeds a defined parameter

K3 Kilovolt Amperes Reactive Hour

Represents actual electricity equivalent to kilowatt hours; billable when usage meets or exceeds defined parameters

CA 867 (006) 99 April. 28, 2008

K4 Kilovolt Amperes

Measure of electrical power

KH Kilowatt Hour

TD Therms

TZ Thousand Cubic Feet

The 3-character metering interval is expressed as one of the following values:

Nnn = number of minutes from 001 to 999, DAY = daily, or MON = monthly.

For example, KHMON represents KWH per month, K1MON represents maxmum kW demand during the month, and KH015 represents kWh per 15 minutes interval.

When REF01 is LU, REF02 is not used.

Segment: QTY Quantity

Position: 110

Loop: QTY

Level: Detail:

Usage: Optional (Must Use)

Max Use: 1

Purpose: To specify quantity information

Syntax Notes: 1 At least one of QTY02 or QTY04 is required.

2 Only one of QTY02 or QTY04 may be present.

Semantic Notes: 1 QTY04 is used when the quantity is non-numeric.

Comments: 1 Each QTY/MEA/DTM loop conveys consumption information about one metering interval. QTY02 reports billable quantities, including demands, while MEA05 and MEA06 report meter readings that are used to determine the billable quantities.

2 If MEA03 contains a multiplier, QTY02 equals the product of the multiplier and the meter readings reported in MEA05 and MEA06. Until it is resolved by UIG whether a MEA segment containing a multiplier (MEA02 = MU) can also contain meter reads, it is recommended that the multiplier should be placed in a separate MEA segment within the QTY loop.

3 QTY03 is not required if the unit of measurement has been defined by the REF02 value corresponding to REF01 = MT.

Data Element Summary

Ref. Data

Des. Element Name Attributes

Must Use **QTY01 673 Quantity Qualifier M ID 2/2**

32 Quantity Sold

Normal data transmission (not estimated, adjusted, or anomalous)

Must Use **QTY02 380 Quantity X R 1/15**

The value specifying interval read in KH

Segment: DTM Date/Time Reference

Position: 210

Loop: QTY

Level: Detail:

Usage: Optional

Max Use: 10

Purpose: To specify pertinent dates and times

Syntax Notes: 1 At least one of DTM02 DTM03 or DTM06 is required.

2 If either DTM05 or DTM06 is present, then the other is required.

Semantic Notes:

Comments:

Notes: This segment may be sent to establish the date and time of the reported values, if the applicable data are available and desired by the recipient. For interval data, the ending time of each interval should be reported if the sender or receiver requires these datas

Data Element Summary

Ref. Data

Des. Element Name Attributes

DTM01 374 Date/Time Qualifier M ID 3/3

Code specifying type of date or time, or both date and time

151 Service Period End

DTM05 1250 Date Time Period Format Qualifier X ID 2/3

Code indicating the date format, time format, or date and time format

DT Date and Time Expressed in Format

CCYYMMDDHHMM

DTM06 1251 Date Time Period X AN 1/35

Expression of a date, a time, or range of dates, times or dates and times

Segment: SE Transaction Set Trailer

Position: 030

Loop:

Level: Summary:

Usage: Mandatory

Max Use: 1

Purpose: To indicate the end of the transaction set and provide the count of the transmitted segments (including the beginning (ST) and ending (SE) segments)

Syntax Notes:

Semantic Notes:

Comments: 1 SE is the last segment of each transaction set.

Data Element Summary

Ref. Data

Des. Element Name Attributes

SE01 96 Number of Included Segments M N0 1/10

Total number of segments included in a transaction set including ST and SE segments

SE02 329 Transaction Set Control Number M AN 4/9

Identifying control number that must be unique within the transaction set functional group assigned by the originator for a transaction set

20 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 may be coupled with an eligible self generation technology, or be stand alone, and must be able to discharge at rated capacity for a two hour period. Advanced Energy Storage systems coupled with fuel cells, conventional CHP, pressure reduction turbines or waste heat to power technologies 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.

PDP:

Performance Data Provider. A third party company that contracts with the SGIP Participant to read and communicate their metering data to the Program Administrators.

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.[36]

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

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

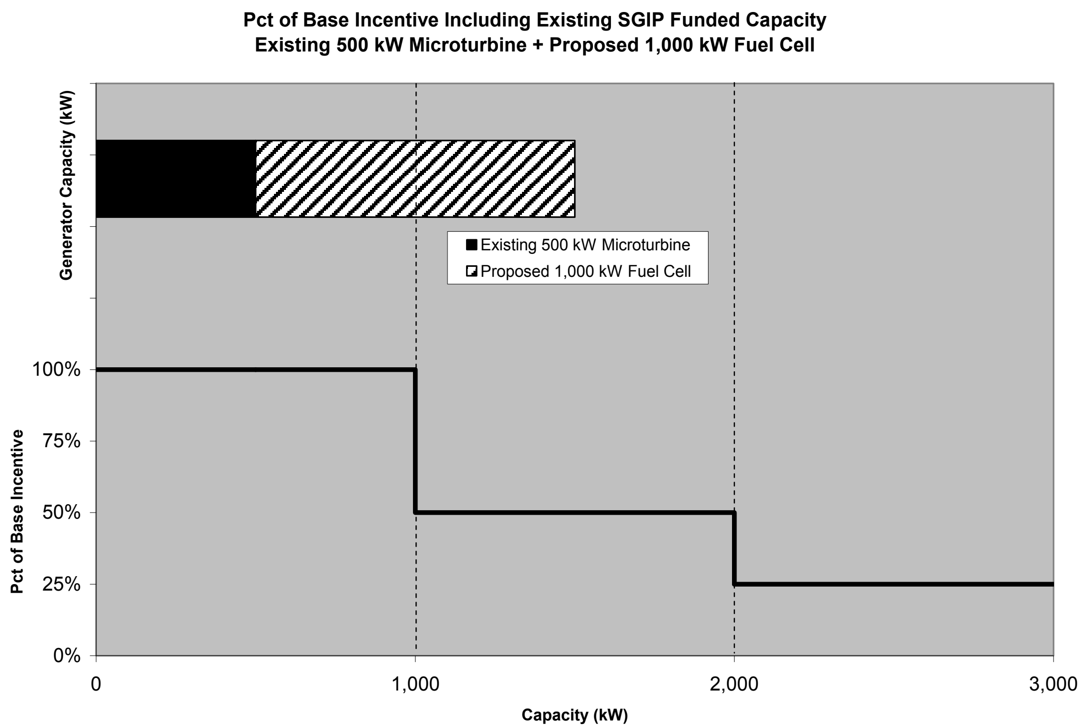
Project Cost Cap on SGIP Incentive = $13,000,000 x 30% = $3,900,000

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 section 12 for full explanation of warranty requirements)
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).[37]
    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 metering, monitoring and data acquisition equipment as defined in section 11, as well as additional on-board monitoring equipment..
11. Air emission control equipment capital 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. Renewable Fuel 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 Renewable Fuel Projects (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) = $\dfrac{\text{volume of pollutant (Vp)}}{\text{volume of exhaust (Ve)}} \times 10^6$

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.

S
ource: 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%

Appendix D - SGIP CONTRACT

SELF-GENERATION INCENTIVE PROGRAM CONTRACT

BETWEEN **PROGRAM ADMINISTRATOR, HOST CUSTOMER,** AND **SYSTEM OWNER**

This Contract is made by and between Host Customer, organized and existing under California law, jointly and severally with System Owner, organized and existing under California law, and Program Administrator, a California corporation. If a separate System Owner is not designated, the Host Customer will be the designated System Owner for the purpose of this Contract. Capitalized terms not defined herein are given the same meaning as that provided in Appendix B hereto, the Self-Generation Incentive Program Handbook.

1.0 PROJECT DESCRIPTION - This Contract is limited to the Project described on the submitted Reservation Request Form and attached hereto as Appendix A. If all Program and Contract terms and conditions are complied with, Program Administrator will pay an incentive to the party designated in the submitted Incentive Claim Form attached hereto as Appendix D. Program Administrator reserves the right to modify or cancel the incentive offer if the actual installation of Self-Generation (SG) Unit(s) differs from the proposed installation described in Appendix A. SG Unit(s) must also be installed by the date shown on the Incentive Claim Form to be issued by Program Administrator after all required Proof of Project Milestone items are submitted.

2.0 DOCUMENTS INCORPORATED BY REFERENCE - The following documents set forth additional terms, conditions and requirements of this Contract:

Appendix A – Self-Generation Incentive Program "Reservation Request Form"

Appendix B – Self-Generation Incentive Program Handbook, Revision 0 dated January 1, 2008, or as subsequently amended.

Appendix C – Renewable Fuel Affidavit (if applicable)

Host Customer and System Owner each acknowledge having received and read, and agree to be bound by Appendices A, B, and C, copies of which were previously provided or are available to Host Customer and System Owner, and the terms of which are incorporated herein by reference as though set forth in full. Should a conflict exist between this Contract and these Appendices, this Contract shall control.

3.0 OTHER PROGRAM DOCUMENTS – The following forms set forth additional terms, conditions, and requirements of the Program:

Appendix D – Self-Generation Incentive Program "Incentive Claim Form"

Appendix E – "Final Project Cost Affidavit" form

Host Customer and System Owner each acknowledge having received copies of these forms, and that these forms, when completed, set forth additional Program terms and requirements. Host Customer and System Owner further acknowledge that Appendices D and E contain certifications by Host Customer and System Owner, which certifications shall be true, accurate, and complete.

4.0 SUBMITTAL REQUIREMENTS FOR PAYMENT - As a condition of payment, the Host Customer or System Owner shall submit to Program Administrator, within the deadlines established by Program Administrator, the documents described in Appendix B, Section 4. Each document requires review and Program Administrator's written approval before Host Customer and System Owner may move on to the next stage of the application process.

4.1 **Reserving an Incentive -** Appendix A or Reservation Request Form ("RRF") describes the Project, lists the SG Unit(s) that will be installed in the Project, and estimates its size (system rated capacity according to Appendix B Section 2.5.4) and its costs (including interconnection fees and in some cases warranty costs). When Host Customer or System Owner submits the RRF to Program Administrator, it shall include the applicable items listed in Appendix B, Section 4.3.2, Program Administrator will review the RRF and, if the Project appears to meet eligibility requirements, Program Administrator will make a conditional reservation of funds for the Project and will send Host Customer and System Owner a Conditional Reservation Notice Letter, the description of which is provided in Appendix B, Section 4.3.8.

4.2 **Proof of Project Milestone -** Within the prescribed number of days, as defined in Appendix B, Section 4.4, of the date on the Conditional Reservation Notice Letter, Host Customer or System Owner must submit the applicable Proof of Project Milestone ("PPM") items listed in Appendix B, Section 4.4.1, to demonstrate to Program Administrator that the Project is progressing and that there is a substantial commitment to complete the Project.

After Program Administrator reviews the PPM items and determines that the Project has met all the necessary criteria, Program Administrator will send Host Customer and System Owner the Incentive Claim Form ("ICF"). This ICF will list the specific reservation amount and the reservation expiration date.

4.3 **Incentive Claim -** Upon Project completion and prior to the reservation expiration date, Host Customer and System Owner must complete and submit the ICF to request an incentive payment**.** In addition to the completed ICF, the Host Customer or System Owner must submit the applicable items listed in Appendix B Section 4.5.2.

5.0 FIELD VERIFICATION BY INSPECTION- After complete, proper installation of the SG Unit(s) and submittal of the applicable items listed in Appendix B Section 4, the Program Administrator or its authorized agent will schedule and complete a **Field Verification Visit** to verify that the SG Unit(s) have been installed and are operating in accordance with the RRF, ICF and required accompanying information. During the Field Verification Visit, Host Customer and System Owner must provide access to the SG Unit(s) and must demonstrate the operation of the SG Unit(s). During the Field Verification Visit, Host Customer and System Owner must ensure that someone is present for an interview that is knowledgeable about the SG Unit(s) and their operation, and must allow photographs of the SG Unit(s) and its related systems to be taken. No incentive payment can be made until the final Field Verification Visit report has been satisfactorily completed.

6.0 MEASUREMENT & EVALUATION (M&E) ACTIVITIES - As a condition of receiving incentive payments, Host Customer and System Owner must ensure that Program Administrator or its authorized agent and the Program M&E consultant have access to the Project Site(s) for all Field M&E Visits and M&E data collection activities summarized below and described in detail in Appendix B, Section 5.2.

6.1 The Host Customer and System Owner agree to participate in M&E activities as discussed in Appendix B, Section 5.2. For systems with Host Customer, System Owner, and/or third party installed monitoring equipment; the Host Customer and System Owner agree to provide system monitoring data (including but not limited to electric, gas, thermal and/or other relevant fuel input data) to the M&E consultant. Furthermore, the Host Customer and System Owner agree to cooperate with the installation of any additional monitoring equipment that the M&E consultant may deem necessary in its sole discretion.

6.2 Host Customer and System Owner agree to allow the Program Administrator or its Measurement & Evaluation contractor access to the Host Customer's Site to develop and implement a Measurement and Evaluation Plan for the SG Unit(s) and its related systems in support of Measurement and Evaluation activities discussed in Appendix B, Section 5.2. The same terms and conditions specified for Field Verification Visits in Section 5.0 will apply to such field Measurement and Evaluation Visits.

7.0 PAYMENT - The incentive payment check will be made payable to the entity designated in writing by System Owner and Host Customer on the ICF only after the appropriate documents have been submitted (within the deadlines established by Program Administrator) and approved, and the Field Verification Visit report has been satisfactorily completed, in accordance with the Program rules set forth in Appendix B. Program Administrator's determination of the incentive amount is final and the System Owner and Host Customer each agree to accept this determination. The incentive payment constitutes final and complete payment.

7.1 System Owner and Host Customer may designate in writing a third party to whom Program Administrator shall make the approved incentive payment.

8.0 REVIEW AND DISCLAIMER - Program Administrator's review of the design, construction, installation, operation or maintenance of the Project or the SG Unit(s) is not a representation as to their economic or technical feasibility, operational capability, or reliability. System Owner and Host Customer each agrees that neither of them will make any such representation to any third party. System Owner and Host Customer are solely responsible for the economic and technical feasibility, operational capability, and reliability of the Project and the SG Unit(s).

9.0 RENEWABLE FUEL LEVELS - For fuel cells running on renewable fuel, System Owner and Host Customer shall not, for five years or the life of the applicable SG Unit, whichever is shorter, use non-renewable fuel for more than 25% of its total annual fuel requirements for such SG Unit(s) in any calendar year.

9.1 In the event the System Owner or Host Customer fails to comply with Section 9.0 above, then System Owner and/or Host Customer shall, within 30 days of receipt of a written demand from Program Administrator, reimburse Program Administrator all incentive payments paid by Program Administrator pursuant to the Program and this Contract. Such reimbursement shall be in the form of a certified check or cash payable to Program Administrator.

9.2 In order to ensure payment in the event the System Owner or Host Customer fails to reimburse Program Administrator pursuant to Section 9.1 above, the Program Administrator may, in its sole discretion, require a bond or other forms of security acceptable to Program Administrator. Acceptable forms of security include cash deposit, irrevocable letter of credit, surety bond from an "A" rated company by A.M. Best, assignment of certificate of deposit, or corporate guarantee (guarantor subject to creditworthiness review).

10.0 WASTE GAS FUEL PROJECTS - For fuel cells projects running on waste gas fuel, System Owner and Host Customer shall, for the applicable five year warranty period or the life of the applicable SG Unit, whichever is shorter, operate the applicable SG Unit solely on waste gas, *i.e.*, the total annual fuel requirements for such SG Unit in any calendar year shall be 100% met by waste gas.

10.1 In the event the System Owner or Host Customer fails to comply with Section 10.0 above and Section 10.0 applies to Applicant or Host Customer's project, then System Owner and/or Host Customer shall, within 30 days of receipt of a written demand from Program Administrator, reimburse Program Administrator all incentive payments paid by Program Administrator pursuant to the Program and this Contract. Such reimbursement shall be in the form of a certified check or cash payable to Program Administrator.

10.2 In order to ensure payment in the event the System Owner or Host Customer fails to reimburse Program Administrator pursuant to Section 10.1 above, the Program Administrator may, in its sole discretion, require a bond or other forms of security acceptable to Program Administrator. Acceptable forms of security include cash deposit, irrevocable letter of credit, surety bond from an "A" rated company by A.M. Best, assignment of certificate of deposit, or corporate guarantee (guarantor subject to creditworthiness review).

11.0 TERMS AND TERMINATION

11.1 The Term of this Contract shall begin on the date that the last party signs the RRF, and shall terminate no later than twice the length of the required warranty; which for wind turbine and fuel cell systems is ten years; unless terminated earlier pursuant to the operation of this Contract, or unless modified by order of the CPUC or by written agreement of the parties.

11.2 The Contract may be terminated by Program Administrator in the event (a) System Owner or Host Customer fails to perform a material obligation under this Contract and System Owner or Host Customer fails to cure such default within 15 days of receipt of written notice from Program Administrator of such failure to perform a material obligation, or (b) any statement, representation or warranty made by System Owner or Host Customer in connection with the Program or this Contract is false, misleading or inaccurate on the date as of which it is made.

11.3 The termination of this Contract shall not operate to discharge any liability, which has been incurred by either party prior to the effective date of such termination.

12.0 PERMANENT INSTALLATION - Equipment installed under this Program is intended to be in place for the duration of its useful life. Only permanently installed systems are eligible for incentives. This means that the System Owner and/or Host Customer must demonstrate to the satisfaction of the Program Administrator that the SG Unit(s) has both physical and contractual permanence prior to Program Administrator's paying any incentive.

Physical permanence is to be demonstrated by the SG Unit(s)' electrical, thermal and fuel connections in accordance with industry practice for permanently installed equipment and its secure physical attachment 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 render the SG Unit(s) ineligible for incentives.

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 sixty (60) days prior to any change in either the Site location of the SG Unit(s), or change in ownership of the SG Unit(s).
- An additional agreement between the System Owner and the Program Administrator may be required at the Program Administrator's sole discretion in order to safeguard against the possibility of early removal and relocation of the generation system. This additional agreement, if required, must be negotiated to the satisfaction of the Program Administrator.

13.0 OTHER AGREEMENTS - All agreements involving the Project including, but not limited to, sales agreements, warranties, leases, energy service agreements, agreements for the sale of trade of RECs, and/or energy savings guarantees, must be disclosed and provided to the Program Administrator as soon as they are available and in no event later than submission of the ICF.

14.0 ASSIGNMENT- System Owner and Host Customer consent to Program Administrator's assignment of all of Program Administrator's rights, duties and obligations under this Contract to the CPUC and/or its designee. Any such assignment shall relieve Program Administrator of all rights, duties and obligations arising under this Contract. Neither System Owner nor Host Customer shall assign its rights or delegate its duties without the prior written consent of Program Administrator or its assignee, if any, except in connection with the sale or merger of a substantial portion of its assets. Any such assignment or delegation without the prior written consent of Program Administrator or its assignee, if any, shall be null and void. Consent to assignment shall not be unreasonably withheld or delayed.

System Owner and Host Customer must provide assurance of the success of a Project if assigned by providing any additional information requested by Program Administrator.

15.0 **PERMITS AND LICENSES –** System Owner and/or Host Customer, at their own expense, shall obtain and maintain all licenses and permits needed to successfully perform work on the Project.

16.0 **ADVERTISING, MARKETING AND USE OF PROGRAM ADMINISTRATOR'S NAME –** System Owner and Host Customer shall not use Program Administrator's corporate name, trademark, trade name, logo, identity or any affiliation for any reason, including soliciting persons to participate in the Project, without the prior written consent of Program Administrator. System Owner and Host Customer shall make no representations on behalf of Program Administrator.

17.0 **INDEPENDENT CONTRACTOR -** In assuming and performing the obligations of this Contract, System Owner and Host Customer are each an independent contractor and neither shall be eligible for any benefits which Program Administrator may provide its employees. All persons, if any, hired by System Owner and/or Host Customer shall be their respective employees, subcontractors, or independent contractors and shall not be considered employees or agents of Program Administrator.

18.0 **INDEMNIFICATION**

18.1 To the greatest extent permitted by applicable law, System Owner and Host Customer shall each indemnify, defend and hold harmless Program Administrator, its affiliates, subsidiaries, current and future parent company, officers, directors, agents and employees, from and against all claims, demands, losses, damages, costs, expenses, and liability (legal, contractual, or otherwise), which arise from or are in any way connected with any: (i) injury to or death of persons, including but not limited to employees of Program Administrator, Host Customer, System Owner, or any third party; (ii) injury to property or other interests of Program Administrator, Host Customer, System Owner, or any third party; (iii) violation of local, state or federal common law, statute, or regulation, including but not limited to environmental laws or regulations; or (iv) strict liability imposed by any law or regulation; so long as such injury, violation, or strict liability (as set forth in (i) - (iv) above) arises from or is in any way connected with this Contract or System Owner's or Host Customer's performance of, or failure to perform, this Contract, however caused, regardless of any strict liability or negligence of Program Administrator whether active or passive, excepting only such loss, damage, cost, expense, liability, strict liability, or violation of law or regulation that is caused by the willful misconduct of Program Administrator, its officers, managers, or employees.

18.2 System Owner and Host Customer each acknowledges that any claims, demands, losses, damages, costs, expenses, and legal liability that arise out of, result from, or are in any way connected with the release or spill of any hazardous material or waste as a result of the work performed under this Contract are expressly within the scope of this indemnity, and that the costs, expenses, and legal liability for environmental investigations, monitoring, containment, abatement, removal, repair, cleanup, restoration, remedial work, penalties, and fines arising from strict liability, or violation of any local, state, or federal law or regulation, attorney's fees, disbursements, and other response costs incurred as a result of such releases or spills are expressly within the scope of this indemnity.

18.3 System Owner and Host Customer each shall, on Program Administrator's request, defend any action, claim or suit asserting a claim which might be covered by this indemnity. System Owner and Host Customer shall pay all costs and expenses that may be incurred by Program Administrator in enforcing this indemnity, including reasonable attorney's fees. This indemnity shall survive the termination of this Contract for any reason.

19.0 **LIMITATION OF LIABILITY -** Program Administrator shall not be liable to System Owner, Host Customer or to any of their respective subcontractors for any special, incidental, indirect or consequential damages whatsoever, including, without limitation, loss of profits or commitments, whether in contract, warranty, indemnity, tort (including negligence), strict liability or otherwise arising from Program Administrator's performance or nonperformance of its obligations under the Contract.

20.0 **VENUE -** This Contract shall be interpreted and enforced according to the laws of the State of California. Sole jurisdiction and venue shall be with the courts in Los Angeles County, California.

21.0 **INTEGRATION AND MODIFICATION -** This Contract and its appendices constitute the entire Contract and understanding between the Parties as to its subject matter. It supersedes all prior or contemporaneous contracts, commitments, representations, writings, and discussions between System Owner, Host Customer, and Program Administrator, whether oral or written, and has been induced by no representations, statements or contracts other than those expressed herein.

NO AMENDMENT, MODIFICATION OR CHANGE TO THIS CONTRACT SHALL BE BINDING OR EFFECTIVE UNLESS EXPRESSLY SET FORTH IN WRITING AND SIGNED BY PROGRAM ADMINISTRATOR'S REPRESENTATIVE AUTHORIZED TO SIGN THE CONTRACT.

Notwithstanding the foregoing, this Contract is subject to such changes or modifications by the CPUC as it may, from time to time, direct in the exercise of its jurisdiction over Program Administrator. Furthermore, this Contract is subject to change or modification by the Program Working Group, as it may from time to time make to the Program in the exercise of its jurisdiction over the implementation of the Program. For purposes of this Contract, the "Program Working Group" shall constitute certain staff of each California investor-owned utility, the California Center for Sustainable Energy, California Energy Commission and the Energy Division of the CPUC.

25.0 **NO THIRD PARTY BENEFICIARIES -** This Contract is not intended to confer any rights or remedies upon any other persons other than the undersigned parties hereto.

By execution of this Contract, System Owner and Host Customer each certifies the Project meets all Program eligibility requirements, and that the information supplied in Appendix A is true and correct. System Owner and Host Customer further certify that System Owner and Host Customer have read and understand the Self-Generation Incentive Program documents described in Appendix B and agree to abide by the rules and requirements set forth in this Contract and in Appendices A, B, C, and D as applicable.

System Owner and Host Customer each declare under penalty of perjury under the laws of the State of California that 1) the information provided in the RRF is true and correct to the best of my/our knowledge, 2) they have each read the Host Customer and System Owner Agreement set forth in Appendix A and agree to terms therein; 3) SG Unit(s) described in the RRF are new and intended to offset part or all of the Host Customer's electrical needs at the Site of installation, 4) the Site of installation is located within the Program Administrator's service territory, 5) the SG Unit(s) are not intended to be used solely as a backup generator, and 6) the Host Customer and the System Owner each has received a copy of this Contract and the completed RRF.

In witness whereof, the parties have executed this Contract by executing the RRF as of the latest date on the RRF.

All communications under this Contract shall be forwarded directly to:

Self-Generation Incentive Program
Program Administrator
Pacific Gas & Electric (PG&E)
Mailing Address: P.O. Box 7433
San Francisco, Ca 94120

Overnight Mailing Address: 245 Market Street
Mail Code N7R

San Francisco, CA 94105-1797

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PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

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Los Angeles Dept of Water & Power
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Recurrent Energy
SCD Energy Solutions
SCE
SMUD
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San Francisco Public Utilities Commission
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Silo Energy LLC
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Spark Energy, L.P.
Sun Light & Power
Sunshine Design
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Western Manufactured Housing Communities Association (WMA)
eMeter Corporation