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

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

March 20, 2017

Advice Letter 5094-G

Ronald van der Leeden
Director, Regulatory Affairs
Southern California Gas
555 W. Fifth Street, GT14D6
Los Angeles, CA 90013-1011

SUBJECT: Revisions to the Self-Generation Incentive Program Handbook Pursuant to Resolution E-4824

Dear Mr. van der Leeden:

Advice Letter 5094-G is effective as of February 23, 2017.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

Russell G. Worden
Managing Director, State Regulatory Operations

February 23, 2017

ADVICE 3564-E
(Southern California Edison Company – U 338-E)

ADVICE 3814-G/5029-E
(Pacific Gas and Electric Company – U 39 E)

ADVICE 5094
(Southern California Gas Company – U 904-G)

ADVICE 76
(Center for Sustainable Energy®)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Revisions to the Self-Generation Incentive Program Handbook Pursuant to Resolution E-4824

PURPOSE

Southern California Edison Company (SCE), on behalf of Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and Center for Sustainable Energy (CSE) (collectively "Program Administrators" or "PAs"), hereby submits this Tier 1 Advice Letter conforming the Self-Generation Incentive Program (SGIP) Handbook to the modifications required by Resolution E-4824 (Resolution).

BACKGROUND

On June 23, 2016, Decision (D.)16-06-055 modified the SGIP to implement changes pursuant to statute, as required by Senate Bill 861 and Assembly Bill 1478, and to make other program changes to improve the SGIP's ability to achieve its goals.

On October 21, 2016, SoCalGas, on behalf of the SGIP PAs, filed Joint Advice Letter (AL) 5049 to revise the SGIP Handbook, as outlined in D.16-06-055.

On November 10, 2016, the SGIP PAs received seven Protests and Responses, which, as per General Order 96-B Rule 7.4.3, required a Reply by the PAs within five business days; however, the PAs requested and were granted an extension to submit their joint Reply to Protests and Responses. The SGIP PAs submitted their joint Reply to Protests and Responses on November 29, 2016.

On February 9, 2017, Energy Division issued the Resolution which approved, with modifications, SoCalGas' Joint AL 5049.

Ordering Paragraph (OP) 8 of the Resolution orders the PAs to file a Tier 1 compliance advice letter conforming the SGIP Handbook to the Resolution and its OPs within 14 days of the effective date of the Resolution.

As summarized below, the SGIP Handbook is modified in compliance with the requirements in the Resolution. The revised redlined version of the SGIP Handbook is included as Attachment A.

MODIFICATIONS REQUIRED BY THE RESOLUTION

The following items were identified by the Commission to be modified in the SGIP Handbook:

- **Ordering Paragraph 2:**

The Resolution ordered the PAs to revise the biogas adder calculation so that only the amount of biogas used that exceeds the minimum required by the biogas blending rule for that program year is used to determine the total biogas adder incentives.

Affected Sections:
6.6 – Incentive Calculation for Generation Projects
6.7 – Performance-Based Incentive Payment (PBI)

- **Ordering Paragraph 3:**

The Resolution found that the PAs estimation formula for determining annual peak demand underestimated true annual peak demand of a residential customer.[1] The Resolution therefore established a hierarchy of three different methodologies to be used to estimate annual peak demand and ordered the PAs to revise the SGIP Handbook to reflect a new estimation hierarchy.

The new estimation hierarchy is as follows: 1) use actual utility data on maximum demand over the previous 12 months to discover (not estimate) peak demand; 2) estimate maximum demand based on the customer's highest recorded interval usage over the past 12 months, using meter data; and 3) use the National Electric Code (NEC) Section 220 method.

[1] Resolution, Finding of Fact 6, p. 47.

Affected Section:
4.2.5 – System Sizing for Projects without Peak Demand Information

- **Ordering Paragraph 4:**

The Resolution harmonizes SGIP rules with previously established thresholds for storage system sizing in D.14-05-033, which set a 10 kW threshold for using an estimation methodology for determining Net Energy Metering (NEM) credits of a storage system paired with a NEM generator. As set forth in the Resolution, any SGIP energy storage project 10 kW or less in size will not be subject to a sizing requirement based on the customer's peak demand.

Affected Section:
5.3.2 – System Size Parameters

- **Ordering Paragraph 5:**

The Resolution orders that customers in SCE and PG&E territories are not required to submit their usage and demand data once they have established they are an electric customer of either SCE or PG&E through the submission of bills evidencing that fact. As CSE or SoCalGas are not electric utilities, and lack direct access to the customer's electric data, customers for these PAs will continue to be required to submit the electric load documentation.

Affected Sections:
5.4.1 – Required Documentation for Reservation Request (Energy Storage Projects)
6.10.1 – Required Documentation for Reservation Request (Generation Projects)

- **Ordering Paragraph 6:**

The Resolution orders the PAs to provide the zip codes that are wholly contained by the service area of the Los Angeles Department of Water and Power (LADWP) and the West Los Angeles (LA) Local Reliability Area. In the event that a zip code is only partially contained in these areas, a map shall be provided showing the exact location of the boundary of LADWP or the West LA Local Reliability Area in the zip code.

The West LA Local Capacity Area is within the electrical service area of the West LA Basin High Voltage Substation or a lower voltage substation that electrically connects to a West LA Basin High Voltage Substation. SCE will maintain a list that identifies zip codes located within these substation areas. Because the substation boundaries do not directly align with zip code boundaries, it is possible that zip codes listed would be partially within the West LA Local Capacity Area. An interactive map will be provided that will show the boundary of the West LA Local Capacity Area and allow the applicant to verify if the installation site address falls within this priority area. The PAs will provide a link on their respective SGIP webpages. SCE's website www.sce.com/sgip is where the West LA Local Capacity Area zip code list and interactive map will be available.

For the LADWP zip code list and service area map, the PAs will provide a link on its SGIP webpage to the LADWP website (http://www.myladwp.com/understanding_your_electric_rates) where this information can be found. The PAs are providing this information pursuant to the Commission's order. The PAs are not responsible for any information provided on the LADWP website, assumes no responsibility for use of, or reliance on, the information by any party, and no representation is made that the contents are accurate, free from error, or suitable for use for any particular purpose.

Affected Sections:
2.3.2.1 – Priority Projects
2.3.3 – Pause Period

- **Ordering Paragraph 7:**

The Resolution requires the PAs to revise the Handbook to clarify that a single 10-year service warranty for the system receiving SGIP incentives is sufficient to meet the statutory requirement for safe and commercially available equipment in the event that NRTL certification has not been achieved and in the event that Rule 21 interconnection standards do not require an additional warranty. Further, the Resolution requires the Handbook to be updated to reflect that if Rule 21 interconnection standards or NRTL certification ultimately require a separate 10-year manufacturer's warranty in addition to the 10-year service warranty, then that obligation for dual warranties stands and must be met by the developer.

Affected Section:
4.2.1 – Commercial Availability

ADDITIONAL MODIFICATIONS AND/OR CLARIFICATIONS PURSUANT TO THE RESOLUTION

The following items were identified in the Discussion section of the Resolution, and the PAs were directed by the Commission to modify and/or clarify:

- **Definition of a Developer**[2]

The "Developer" definition in the SGIP Handbook has been revised as described by the PAs in their Joint Reply to Protests and Responses.[3]

Affected Section:
4.1.5 – Developer

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[2] Resolution E-4824, p. 12.
[3] Reply to Protests and Responses to SoCalGas AL 5049, p.4.

- **Clarification on Electronic Signatures**[4]

Program Administrators will handle electronic signatures independently.

PG&E, SCE, and CSE will allow verifiable electronic signatures on all program forms requiring signatures, in a format acceptable to each administrator.[5]

SoCalGas does not accept electronic signatures on the following program forms:

- Reservation Request Form
- Proof of Project Milestone Form
- Incentive Claim Form
- Project Cost Affidavit
- Planned Maintenance Coordination Letter
- Renewable Fuel Attestation Letter - System Owner
- Renewable Fuel Attestation Letter - Fuel Supplier
- Renewable Fuel Affidavit
- Waste Gas Affidavit

- **Clarification on Metering and Monitoring Requirements**[6]

The PAs provide the following clarity regarding metering and monitoring requirements for energy storage projects paired with a renewable source:

> All energy storage projects charging at least 75% from on-site renewable generators must have the ability to demonstrate that they are charging from a renewable source through metering and monitoring so that the PAs may verify that such projects meet program requirements and justify priority in the event of a lottery. As a point of clarification, Residential systems are not required to purchase additional meters for verification. As adopted in Resolution E-4717,[7] the PAs require that all energy storage systems have the ability to provide data and allow for the use of metering and monitoring equipment that is already part of the system.

Affected Section:
5.5 – Metering and Monitoring Requirements for Energy Storage Projects

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[4] Resolution, p. 24.
[5] The PAs' websites will be updated with details regarding electronic signature requirements.
[6] Resolution, p. 32-34.
[7] Resolution E-4717, p. 8.

- **Clarification on California Manufacturer**[8]

The timing of implementation for the new California Manufacturer incentive adder is as follows:

New projects applying in years 2017-2020:

Before June 23, 2017, projects may include the 20 percent adder to their incentive if they apply with currently-eligible CA Suppliers. However, in order for these projects to receive the 20 percent adder at the time of payment, the equipment manufacturer must meet the new CA Manufacturer requirements by the time the project reaches the Incentive Claim stage. All projects using equipment from manufacturers that are not eligible for the adder under the new requirements will not receive the 20 percent adder at the time of payment, even if they applied before June 23, 2017 with a then-eligible CA Supplier.

Pre-2017 Projects:

All pre-2017 projects will be paid out according to pre-D.16-06-055 California Supplier rules. In other words, when a pre-2017 project reaches the Incentive Claim stage, it will receive the 20 percent adder if the equipment manufacturer for the project is an approved California Supplier under pre-2017 rules. This is true regardless of whether the project reaches the Incentive Claim stage before or after June 23, 2017.

- **Clarification on the Pause Period**

The Resolution made reference to the required pause period as being "no more than 20 days."[9] After verifying with the Energy Division, this was an error and in conflict with D.16-06-055, where it states:

- Page 51 of D.16-06-055: "We find this a reasonable suggestion and direct the Program Administrators to detail the specific mechanism for triggering a pause of "no less than 20 days"; and

- Conclusion of Law 52, Page 81 of D.16-06-055: "The Program Administrators will develop a system that creates a pause between incentive steps of no less than twenty days...".

The SGIP PAs clarify that the pause period is, in fact, to be "no *less* than twenty days" as ruled in D.16-06-055.

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[8] Resolution, p. 36.

[9] Resolution, p. 29 and 41.

TIER DESIGNATION

Pursuant to GO 96-B, Energy Industry Rule 5.1, this advice letter is submitted with a Tier 1 designation.

EFFECTIVE DATE

This advice filing will become effective on February 23, 2017, the same day as filed.

NOTICE

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Russell G. Worden
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Telephone (626) 302-4177
Facsimile: (626) 302-6396
E-mail: AdviceTariffManager@sce.com

Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

For SoCalGas:
Attn: Ray Ortiz
Tariff Manager - GT14D6
555 West Fifth Street
Los Angeles, CA 90013-1011
Facsimile No. (213) 244-4957
E-mail: rortiz@SempraUtilities.com

For PG&E:
Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177
Facsimile: (415) 973-1448
E-mail: PGETariffs@pge.com

For CSE:
Sachu Constantine
Director of Policy
Center for Sustainable Energy™
9325 Sky Park Court, Suite 100
San Diego, CA 92123
Email: sachu.constantine@energycenter.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

In accordance with General Rule 4 of GO 96-B, SCE is serving copies of this advice filing to the interested parties shown on the attached service lists for GO 96-B and R.12-11-005. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-3719. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Kathy G. Wong at (626) 302-2327 or by electronic mail at Kathy.Wong@sce.com.

Southern California Edison Company

/s/ Russell G. Worden
Russell G. Worden

RGW:kw/jk:cm
Enclosure

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.: Southern California Edison Company (U 338-E)

Utility type:	Contact Person: Darrah Morgan
☑ ELC ☐ GAS	Phone #: (626) 302-2086
☐ PLC ☐ HEAT ☐ WATER	E-mail: Darrah.Morgan@sce.com
	E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE			(Date Filed/ Received Stamp by CPUC)
ELC = Electric	GAS = Gas		
PLC = Pipeline	HEAT = Heat	WATER = Water	

Advice Letter (AL) #: 3564-E Tier Designation: 1

Subject of AL: Revisions to the Self-Generation Incentive Program Handbook Pursuant to Resolution E-4824

Keywords (choose from CPUC listing): Compliance

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

Resolution E-4824

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution Required? ☐ Yes ☑ No

Requested effective date: 2/23/17 No. of tariff sheets: -0-

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

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: None

Service affected and changes proposed[1]:

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

[1] Discuss in AL if more space is needed.

Protests 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
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Russell G. Worden
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Telephone: (626) 302-4177
Facsimile: (626) 302-6396
E-mail: AdviceTariffManager@sce.com

Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

And

For SoCalGas:
Attn: Ray Ortiz
Tariff Manager - GT14D6
555 West Fifth Street
Los Angeles, CA 90013-1011
Facsimile No. (213) 244-4957
E-mail: rortiz@SempraUtilities.com

For PG&E:
Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177
Facsimile: (415) 973-1448
E-mail: PGETariffs@pge.com

For CSE:
Sachu Constantine
Director of Policy
Center for Sustainable Energy™
9325 Sky Park Court, Suite 100
San Diego, CA 92123
Email: sachu.constantine@energycenter.org

Attachment A

Revisions to the Self-Generation Incentive Program Handbook Pursuant to Resolution E-4824 (Redlined Version)

Contents

Program Administrator Contact Information

Potential program participants can obtain information and apply for incentive funding through the following Program Administrators:[1]

Pacific Gas & Electric (PG&E)
Website: www.pge.com/sgip
Email Address: selfgen@pge.com
Telephone: 1 (877) 743-4112
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

Center for Sustainable Energy® (CSE)
Website: www.energycenter.org/sgip
Email Address: sgip@energycenter.org
Telephone: (858) 244-1177
Mailing Address: Center for Sustainable Energy
Attn: Self-Generation Incentive Program
9325 Sky Park Court Ste 100
San Diego, CA 92123

Southern California Edison (SCE)
Website: www.sce.com/SGIP
Email Address: SGIPgroup@sce.com
Telephone: (626) 302-0610
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~~
https://www.socalgas.com/for-your-business/power-generation/self-generation-incentive
Email Address: selfgeneration@socalgas.com
Mailing Address: Self-Generation Incentive Program
Southern California Gas Company
555 West Fifth Street, GT20B8
Los Angeles, CA 90013-1011

[1] 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, but not to both. ~~AES projects located in the shared service territory must first apply with SCE.~~

Program Overview

The Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of new qualifying technologies that are installed to meet all or a portion of the electric energy needs of a facility. The purpose of the SGIP is to contribute to Greenhouse Gas (GHG) emission reductions, demand reductions and reduced customer electricity purchases, resulting in the electric system reliability through improved transmission and distribution system utilization; as well as market transformation for distributed energy resource (DER) technologies.

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 (PA's) website. The Program Administrators are~~:~~ Pacific Gas and Electric (PG&E), Southern California Edison (SCE), the Southern California Gas Company (SoCal Gas) and the Center for Sustainable Energy® (CSE).[2]

[2] CSE is the Program Administrator for SDG&E customers.

1 Budget

1.1 Statewide Program Budget and Administrator Allocations

Authorized incentive collections through the end of 2019 total $270,165,000 ~~for Program Year 2016 total $77,190,000~~.[3] Additional funds made available through attrition will be added to Program Administrators' budgets as they become available. Authorized incentive collections ~~Allocations~~ for each Program Administrator are as follows:

Pacific Gas and Electric Company	$117,180,000 ~~$33,480,000~~
Southern California Edison Company	$ 91,140,000 ~~$26,040,000~~
Center for Sustainable Energy	$ 35,805,000 ~~$10,230,000~~
Southern California Gas Company	$ 26,040,000 ~~$7,440,000~~

The SGIP shall be administered on a continuous basis. Program Administrators will issue incentive reservations until all incentive funds have been fully allocated.[4] ~~The annual incentive budget includes authorized incentive collections and previous year carry over funds. Per Decision (D).15-12-027, Program Administrators will accept new applications for incentives until 50% of their 2016 SGIP program funds are reserved and will not disburse additional funds until further ordered by the Commission.~~

The current budget, incentive rates, and incentive steps in each Program Administrator territory are posted at www.selfgenca.com.

1.2 Budget Allocation

The budget is divided into two categories:

1. Energy Storage Technologies – 75% of funds ~~Renewable and emerging technologies~~
2. Generation Technologies – 25% of funds ~~Non-renewable fueled Conventional CHP projects~~

The ~~annual~~ incentive budget allocates 75% to energy storage technologies ~~the renewable and emerging technology category and 25% to the non-renewable fueled conventional CHP project category.~~, with 15% of the energy storage category carved out for small residential projects less than or equal to 10 kW. The small residential storage carve out is set per each Program Administrator step and operates independently of the large-scale carve out. Once the funds in the residential carve-out fifth step in an individual PA's territory are exhausted, PAs may use funds from the large-scale storage category, if available, to fund additional small residential projects as they are submitted.

[3] Available authorized incentives include 50% of 2016 collections (D.15-12-027) plus authorized incentive collections for 2017, 2018 and 2019 (D.14-12-033).

[4] Total available funding includes authorized incentive collections, funds from cancelled projects, and application fee forfeitures.

Additionally, if a single PA territory allocates more than 15% of its total energy storage funds to small residential projects, the amount of funds that exceeds 15% will count toward the statewide minimum goal of 15%. Once the minimum 15% of energy storage funds are allocated to small residential projects statewide, PA territories that have not yet allocated all of their small residential funds may transfer the funds into the large-scale storage budget category. However, before transferring funds from the small residential storage carve-out to the large-scale budget category, PAs must first file an advice letter.

The incentive budget allocates 25% to generation technologies, with a minimum of 40% of the generation category carved out for renewable generation projects.[5] The minimum amount of incentives set aside for renewable generation technologies is set statewide, across all four Program Administrators.

~~Biogas, AES and Fuel cells are all considered an emerging technology and will be funded from the renewable and emerging budget category. However, if an AES system is coupled with conventional CHP technologies operating on non-renewable fuel, they 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.~~

[5] Defined as wind, waste heat to power, pressure reduction turbines, and 100% biogas as defined by the most recent RPS guidelines.

2 Applications

2.1 Application Process

~~The 2016 Program Year will begin once the Program Year's Handbook and forms are posted to the PAs' websites and the PAs have enabled the online database to begin accepting new application submissions. Any applications received after the program has closed for the current cycle will be returned with an encouragement to apply during the next program funding cycle.~~

Applications are ~~will be~~ subject to the incentive rates of the Program Administrator to which they apply ~~and Program rules of the year in which they are submitted~~. ~~Waitlisted applications carried over from 2015 are subject to the 2016 incentive rates and Program rules.~~ Generally, applications will be assigned an incentive rate and reviewed in the order in which they are received. However, in the event that application submissions on a single day exceed available funding in a given Program Administrator's territory for a given budget and step, a lottery will be initiated. Lottery details are found in *Section 2.3.2*. Please refer to www.selfgenca.com for the most up-to-date information on current incentive steps, rates, and available funds.

2.1.1 *Application Submission*

All SGIP applications and required documents[6] at all stages of the application process must be submitted via the ~~new~~ SGIP online application database at www.selfgenca.com. **Mailed, emailed, faxed or hand delivered applications will not be accepted.** ~~Required documents at all stages of the application process (RRF, PPM and ICF) must be submitted using the SGIP online application database.~~

In order to submit an ~~a new SGIP~~ application and/or project documentation, companies or individuals must create an account and register users at www.selfgenca.com. Once the account has been confirmed, registered A~~a~~pplicants may create and edit applications.

Only complete applications may be assigned incentive funds or be placed into a lottery. ~~Applications are reviewed in the order they are received.~~ Only complete applications may receive an approved reservation. Duplicate applications or multiple submissions for the same project will be rejected.[7] Applicants must agree to the Terms of Use pertaining to the SGIP online application database in order to submit an application. The Terms of Use can be found at www.selfgenca.com.

Once an application is entered into the SGIP database and submitted for consideration within a given step, it will be retained in the database. In the event a lottery is implemented and the application is *not* selected

[6] With the exception of the application fee check that is to be mailed directly to the Program Administrator. See *Section 5.4.1* and *Section 6.10.1* for more information.

[7] Duplicative applications are considered a program infraction. See *Section 9* for information on program infractions.

for the current step, the Applicant must update relevant documentation and resubmit the application in order to be considered in the next incentive step.

2.1.2 *Signatures*

Original signed documents or scanned copies of original signed documents are required for all p~~P~~rogram provided forms.[8] ~~,~~[9] Electronic signatures are acceptable for documents created by the Contractor or Host Customer, such as the installation contract.[10] The signature on any signed document submitted to the Program Administrator shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) with the same force and effect as if such signature page were an original thereof.

2.1.3 *File Retention*

Although "wet" signatures are not required on submitted documents, original signed documentation must be retained by the Applicant, Host Customer and/or System Owner for at least five years from the date of submission. Program Administrators reserve the right to request original signed documents within the five year period.

2.2 Incentive Process Flowcharts

There are two application processes illustrated below:

- Three-Step Application Process - Figure 2.2-1
- Two-Step Application Process - Figure 2.2-2

All residential projects and ~~small (<10kW)~~ non-residential projects less than 10 kW must follow the two-step application process. Non-residential projects greater than or equal to 10 kW ~~or greater~~ must follow a three-step process.

[8] Includes: Reservation Request Forms, Proof of Project Milestone Forms, Incentive Claim Forms, and all affidavits. All forms requiring signatures from multiple parties must have all signatures submitted on one document.

~~[9] All forms requiring signatures from multiple parties must have all signatures submitted on one document.~~

[10] E-signatures may be acceptable for other program documents depending on Program Administrator territory. Please contact your Program Administrator for more information.

Figure 2.2-1: Three-Step Application Process for Public and Non-Public Entities ≥ 10 kW

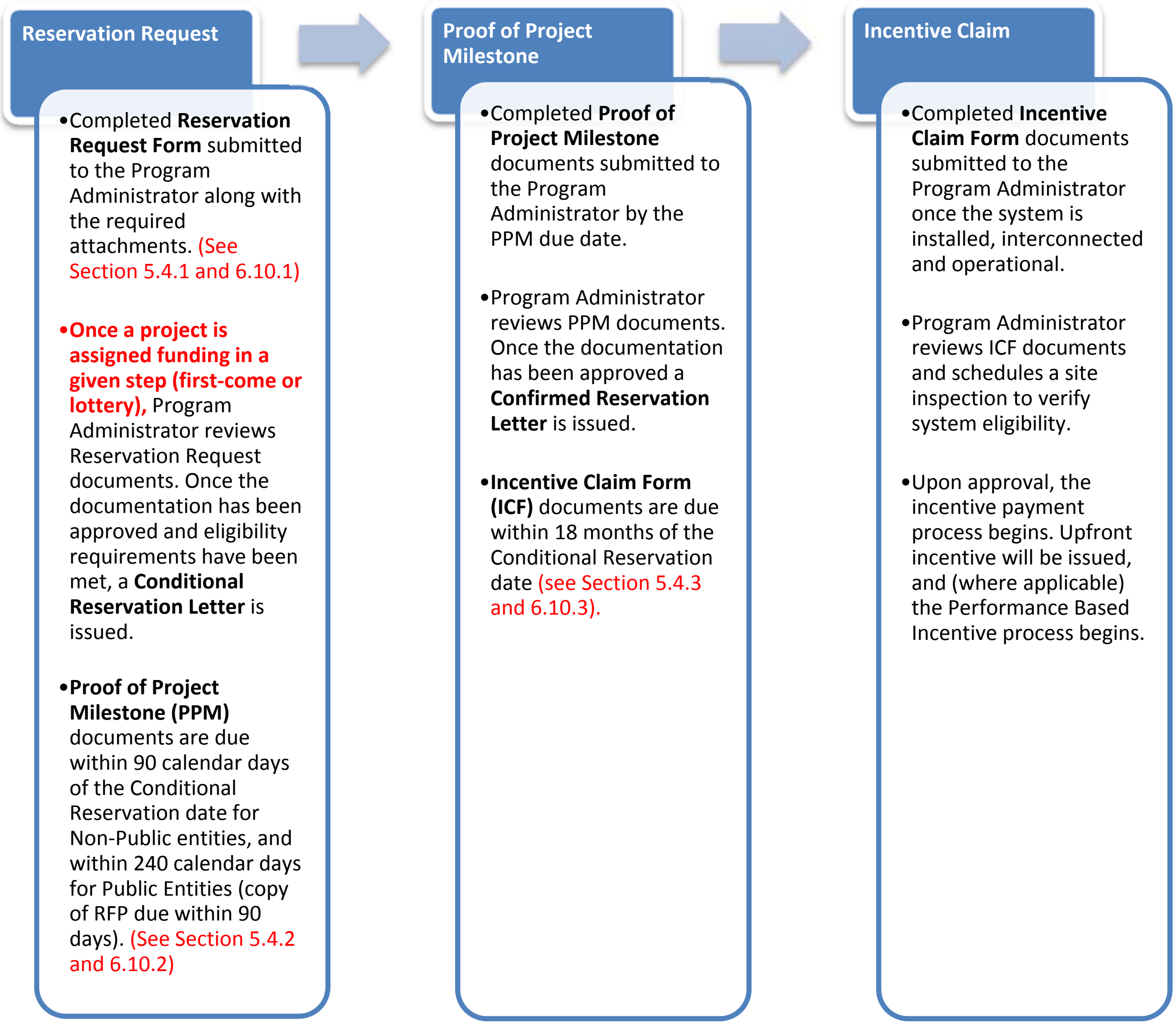


Figure 2.2-2: Two-Step Application Process for All Residential and Non-Residential Entities <10 kW

Reservation Request

- Completed Reservation Request **Form** submitted to the Program Administrator along with the required attachments. (See Section 5.4.1 and 6.10.1)
- **Once a project is assigned funding in a given step (first-come or lottery),** Program Administrator reviews Reservation Request documents. Once the documentation has been approved and eligibility requirements have been met, a **Confirmed Reservation Letter** is issued.
- **Incentive Claim Form (ICF)** documents are due within 12 months of the Confirmed Reservation date (See Section 5.4.2 and 6.10.2)

Incentive Claim

- Completed **Incentive Claim Form** documents submitted to the Program Administrator once the project is completed.
- Program Administrator reviews ICF documents and schedules a site inspection to verify system eligibility.
- Upon approval, the incentive payment process begins. Upfront incentive will be issued, and (where applicable) the Performance Based Incentive process begins.

2.3 Reservation Request

To request ~~reserve~~ an incentive, an online Reservation Request Form (RRF) must be submitted with required attachments and the application fee. (See *Section 5.4.1* and *6.10.1* for required attachments specific to storage and generation technologies.) Projects that include multiple technologies must submit separate applications for each technology.

2.3.1 *Submitting the Reservation Request*

After ~~Once~~ all Reservation Request documents have been uploaded to the SGIP online application database, Aapplicants must ~~may~~ submit their complete application package to the appropriate Program Administrator. Applicants may not submit applications in excess of the Developer cap for the active step. Once an application is assigned an incentive rate ~~received~~, the Program Administrator will review the application package to ensure the project meets all program requirements. ~~Applications will be reviewed in the order in which they are received.~~ Incentive funds may only be reserved after the Program Administrator receives and approves the Reservation Request documents.

2.3.2 *Lottery Process*

A lottery will be triggered only in the event that applications submitted on a single day exceed funds available for a given budget and step. Lotteries are to be conducted separately for large scale energy storage technologies, small residential energy storage technologies less than or equal to 10 kW, and generation technologies by Program Administrator territory, as necessary. All applications not selected in the lottery will be rejected and must reapply in the next funding step in order to receive funding.

2.3.2.1 Priority Projects

The following energy storage projects shall have priority in the SGIP lottery process:

- Energy storage projects located within the service territory of Los Angeles Department of Water and Power.[11]

- Energy storage projects located within the West Los Angeles Local Reliability Area of Southern California Edison's service territory. (The West LA Local Reliability Area zip code list and interactive map is available at www.sce.com/sgip.)

- Energy storage systems paired with an on-site renewable generator and claiming the Investment Tax Credit (ITC) or, if not claiming the ITC, charging a minimum of 75% from the on-site renewable generator.

Energy storage projects that meet more than one criterion shall be given the highest priority. A lottery will be held for the projects in the priority or non-priority category that exceeds available funding in the active step.

Generation projects shall have priority in the SGIP lottery in the following order:

1) Renewable projects using wind, waste heat to power, pressure reduction turbines, or 100% on-site biogas will be given first priority.

2) 100% directed biogas will be given second priority.

3) Blended on-site biogas will be given third priority.

4) Blended directed biogas will be given fourth priority.

A lottery will be held for the priority category that exceeds available funding in the active step.

2.3.3 *Pause Period*

When a budget category changes to the next incentive step the Program Administrator will initiate a pause period of no less than 20 days, whereby:

- No new applications within the budget category are accepted.

- The Program Administrator may perform a pre-screen to reject applications with missing documentation or applications submitted above the Developer cap, and to verify projects identified with a locational priority.

- If required, the lottery is conducted.

- After 10 days, Program Administrators will determine if the incentive level reduction for energy storage technologies shall increase from $0.05/Wh to $0.10/Wh between incentive steps based on statewide oversubscription for a given step.

[11] All projects interconnecting into LADWP's electrical grid must abide by LADWP interconnection rules.

- If a lottery is conducted, a notification of the results of the lottery is sent to Applicants. Applications that were not selected for funding in the current step through the lottery will be instructed on how to reapply for funding in the next step.
- Projects that are only able to be partially funded within a certain step must choose to reapply for funding in the next step or claim the remaining funds in the current step.[12]
- The SGIP public website is updated with information on the new incentive rate(s), available funds and the date of the next application submission opportunity.

2.3.4 *Incomplete Reservation Request*

Reservation Request documents (including the scanned copy of the application fee ~~Application Fee~~) must be complete and submitted as part of the application package. If an application is found to be missing any required information or requires additional clarification, the Program Administrator or their representative will request the information necessary to process that application further. Applicants have 15 calendar days to respond with the necessary information. If after 15 calendar days the Applicant has not submitted the requested information, the application may be cancelled. Cancelled applications may be resubmitted and will be treated as a new application (i.e. all required documents must be resubmitted) and processed in sequence along with other new applications. Funds from cancelled projects will be allocated to the currently active incentive step in the Program Administrator's SGIP incentive budget. If the Program Administrator is in a pause period when attrition occurs, the funds will be placed in the next incentive step.

2.3.5 *Approval of Reservation Request*

Upon Program Administrator approval of the Reservation Request package (Reservation Request Form and required attachments) the Applicant and Host Customer will receive a reservation letter ~~Reservation Letter if funds are available~~. The ~~There are~~ two types of reservation notice letters ~~and they~~ are based on the type of application:~~.~~

Conditional Reservation Letter (for Three-Step ~~3 Step~~ applications)

Upon approval of the Three-Step ~~3 Step~~ Reservation Request package, a Conditional Reservation Letter will be issued confirming that a specific incentive amount is conditionally reserved for project. The letter will list the approved incentive amount, the Proof of Project Milestone date ~~Date~~ and the reservation expiration date ~~Reservation Expiration Date~~. All reservations are conditional pending receipt of the Proof of Project Milestone documentation on or before the Proof of Project Milestone date ~~Date~~.

Confirmed Reservation Letter (for Two-Step ~~2 step~~ applications)

Upon approval of the Two-Step ~~2 Step~~ Reservation Request package, a Confirmed Reservation Letter will be issued. The Confirmed Reservation Letter will list the approved incentive amount and the

[12] Projects are not allowed to be assigned a "split incentive" across two or more incentive steps.

reservation expiration date ~~Reservation Expiration date~~ (12 months after the date of the Confirmed Reservation Letter). Upon project completion and prior to the reservation expiration date ~~Reservation Expiration Date~~, the completed Incentive Claim Form must be submitted along with all of the necessary documentation to request an incentive payment.

2.3.6 *Wait List and Program Closure*

Once funds have been fully allocated in the final incentive step of a Program Administrator's given budget, applications will be placed on a wait list to be funded as incentive funds become available throughout the remainder of the program. When there is enough attrition to fund wait-listed projects, wait listed projects will be assigned an incentive rate in the last step and reviewed in the order in which they were submitted. In the event that there are available funds and all wait-listed projects have been allocated funding, new applications will be subject to normal program procedures specified in *Section 2.1*. Program Administrators may continue accepting new applications until all incentive funds have been fully paid or until December 31, 2020[13], whichever comes first.

~~Program Administrators will continue accepting new applications for incentives until 50% of their 2016 SGIP program funds are reserved in each budget category. Once funds have been fully allocated, applications that have not received a reservation will be rejected and will not be placed on a wait list. Disbursement of additional program funds authorized for Program Year 2016 will be suspended until further ordered by the Commission.~~

2.4 Proof of Project Milestone

Two-Step Applications must ~~should~~ submit all Proof of Project Milestone (PPM) documents as part of their Reservation Request. For *Three-Step Applications, Non-Public Entities* have 90 calendar days from the date of the Conditional Reservation Letter to satisfy all Proof of Project Milestone criteria. For *Three-Step Applications, Public Entities* must submit a copy of the issued Request for Proposal ~~request for proposal~~ (RFP) or equivalent for purchase or installation of the system within 90 calendar days of the date of the Conditional Reservation Letter; Proof of Project Milestone documentation must then be submitted within 240 days of the date of the Conditional Reservation Letter.

2.4.1 *Submitting Proof of Project Milestone*

Once the Online Proof of Project Milestone is completed and all the required attachments are uploaded, the PPM package must be submitted to the appropriate Program Administrator via the online application database.

2.4.2 *Incomplete Proof of Project Milestone*

If the Proof of Project Milestone package is not received by the Proof of Project Milestone date ~~Date~~, the application may be cancelled by the Program Administrator.

[13] SB 861 extended SGIP administration through 2020

If the Proof of Project Milestone documentation is incomplete and/or requires clarification, the Program Administrator will request the information necessary to process that application further. Applicants will have 15 calendar days to respond with the necessary information. If after 15 calendar days the requested information has not been submitted, the application may be cancelled. Any project attrition and forfeited application fees will be allocated to the current incentive step in the Program Administrator's SGIP incentive budget. If the Program Administrator is in a pause period when attrition occurs, the funds will be placed in the next incentive step.

2.4.3 ***Approval of Proof of Project Milestone***

Once Proof of Project Milestone requirements have been successfully met, the Program Administrator will issue a Confirmed Reservation Letter. The Confirmed Reservation Letter will list the reservation dollar amount and the reservation expiration date ~~Reservation Expiration Date~~ (18 months after the date of the original Conditional Reservation Letter). Upon project ~~Project~~ completion and no later than the reservation expiration date ~~Reservation Expiration Date~~, the completed Incentive Claim Form must be submitted along with all of the necessary documentation to request an incentive payment.

2.5 **Incentive Claim**

Once the project ~~Project~~ is complete, Applicants ~~applicants~~ must request payment of the incentive amount by submitting the ~~Online~~ Incentive Claim Form (ICF) and all applicable Incentive Claim documents to the Program Administrator via the online application database. A project is considered complete when the system is completely installed, interconnected (if applicable), permitted, and capable of operating ~~producing electricity~~ in the manner ~~and in the amounts~~ for which it was designed ~~and the energy efficiency measures identified with a 2 year or less payback period have been verified as either installed or infeasible.~~ Payment will be dispersed after the Program Administrator verifies by field inspection that the system 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 ~~Reservation Expiration Date~~ with the required attachments ~~described below~~.

2.5.1 ***Submitting Incentive Claim***

Once the ~~Online~~ Incentive Claim Form is complete and all the required attachments are submitted, Applicants may submit their Incentive Claim ~~incentive claim~~ package to the Program Administrator via the online application database.

2.5.2 ***Incomplete Incentive Claim***

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

If submitted Incentive Claim documentation is incomplete and/or requires clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 30 calendar days to respond with the necessary information. If after 30 calendar days the requested information has not been submitted, the application may be cancelled. Any project attrition and forfeited application fees will be allocated to the current incentive step in the Program Administrator's SGIP incentive budget. If the Program Administrator is in a pause period when attrition occurs, the funds will be placed in the next incentive step.

2.5.3 *Field Verification Visit*

Upon receipt of a complete Incentive Claim Form package, the Program Administrator will organize a field verification visit to verify that the project's ~~Project~~ system is installed as represented in the application, is operational, is interconnected and conforms to the eligibility criteria of the SGIP. Verification includes but is not limited to:

- If the project ~~Project~~ is 30 kW and larger, 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 ~~Project~~ uses renewable fuel ~~Renewable Fuel~~, the availability and flow rate of the renewable fuel ~~Renewable Fuel~~ will be demonstrated by the Host Customer and/or System Owner.
- If the project uses waste energy ~~Waste Energy~~, the availability, temperature and production rate of the waste energy ~~Waste Energy~~ will be demonstrated by Host Customer and/or System Owner.
- Energy storage ~~AES~~ systems will be tested to validate ~~indicate~~ the ~~average~~ discharge energy capacity. ~~power output over a two hour period~~. ~~If the project involves an AES system coupled with a SGIP funded generating system, the electrical coupling of the two systems will be verified.~~ Energy storage ~~AES~~ projects will be inspected according to the Energy Storage ~~AES~~ Field Verification Protocol. HVAC-integrated S-TES systems will be tested to show they can provide enough thermal energy to turn off the compressor of the accompanying HVAC unit for the specified discharge duration period ~~at least two hours~~. Refrigeration TES systems will be tested to show they can provide enough thermal energy to turn off the compressor(s) and condenser(s) of the accompanying refrigeration system(s) for the specified discharge duration period ~~at least two hours~~.
- If the eligible system size depended on new construction or load growth, the required load will be confirmed.
- Verify system capacity rating to confirm the final incentive amount.
- ~~Implementation of energy efficiency measures identified as having a less than or equal to two year payback in the Energy Efficiency Audit.~~

Failed Field Verification

If ~~field verification results~~ the results of the field inspection are to indicate that the project ~~system~~ is not ready for approval ~~eligible~~, the Program Administrator will notify the Applicant, Host Customer and System Owner of the reasons for failure ~~system ineligibility~~. The Applicant, Host Customer and System Owner will have up to 60 calendar days to bring the project into ~~system to~~ compliance. A subsequent inspection visit may ~~will~~ be required ~~conducted~~ to determine final approval. If the Applicant, Host Customer and System Owner fail to bring the project ~~system~~ to full eligibility within the requested time, the application may be cancelled.

If the site ~~Site~~ load, renewable fuel or waste energy forecast has not yet materialized, the Applicant will be given two options:

1. Receive payment based on the site ~~Site~~ load, renewable fuel or waste energy availability (whichever is less) demonstrated at the time of initial inspection or;
2. Wait for the site ~~Site~~ load, renewable fuel or waste energy to materialize within 12-months from the date the Incentive Claim Form and documents were initially received. If the site ~~Site~~ load, renewable fuel or waste energy has not materialized within the 12-month period, the project ~~Project~~ will be paid based on the site ~~Site~~ load or system operating capacity available at the end of the 12-month period, whichever is less.

2.5.4 *Approval of Incentive Claim*

Upon final approval of the Incentive Claim ~~incentive claim~~ documentation and completed field verification visit, the Program Administrator will issue a final ICF approval letter. The incentive payment will be made approximately 30 days after the final approval letter is sent. Payment will be made to the assigned Payee as indicated on the Incentive Claim Form and will be mailed to the address provided.

2.6 Modifications and Extensions

All projects are expected to be installed as described on the Conditional and Confirmed Reservation Letter. In the event that changes are made during the development of the project and/or during the installation it is the responsibility of the Host Customer and/or Applicant ~~customer/applicant~~ to notify the Program Administrator ~~PA~~ as soon as possible. Changes to the Host Customer or project site are generally not permitted and must be approved on a case-by-case basis by the Program Administrator. Unapproved changes may result in project cancellation.

2.6.1 *Modifications Pre-ICF*

Changes pertaining to System Owner, Payee, equipment type, ~~and~~ or system capacity must be approved by the Program Administrator before the application can proceed. If the step to which a project is assigned has closed, modifications to the project will not result in additional incentive funding. At the Program Administrator's discretion, additional incentive funding for an application may be allowed only when a project is assigned to the currently active step and adequate funding is available. ~~System capacity~~

~~modifications will affect the requested incentive amount and must be approved by all parties. If the system capacity increases the higher incentive may be paid only if adequate funds are available.~~

~~All changes~~ Changes in equipment type, system capacity, Applicant, installer or other substantial changes may require ~~must include~~ new RRF and/or PPM documentation. Once the request has been approved, a new reservation letter may ~~will~~ be issued. Changes do not extend the reservation expiration date ~~Reservation Expiration Date~~.

2.6.2 *Modifications Post-ICF*

In general changes to the completed project are not allowed. In the event that a system needs to be upgraded or changed due to poor performance the Applicant ~~applicant~~ must notify the Program Administrator of new equipment information and provide updated documentation to help support performance and measurement and evaluation activities ~~Performance, and Measurement and Evaluation~~. For projects adding generation see *Section 3.2.4*.

2.6.3 *Extensions and Exceptions*

Extension requests will be reviewed on a case-by-case basis and should be submitted in writing to the appropriate Program Administrator for review. Any extension granted to either the Proof of Project Milestone or Request for Proposal due date will not extend the reservation expiration date ~~Reservation Expiration Date~~.

All projects will be limited to a maximum of three 6-month extensions of the reservation expiration date, after which the reservation expires automatically.[14] Extensions will be for special circumstances only. Additionally, extensions will not be granted to projects that have not made satisfactory progress toward completion in compliance with established milestones and requirements. Any request for a second or third extension of the reservation expiration date requires unanimous SGIP Working Group approval, and the SGIP Working Group shall notify Applicants of the SGIP Working Group's decision in writing within 30 days. When considering a request for a second or third ~~six-month~~ reservation expiration extension, the SGIP Working Group will consider:

1) Whether the project's delay is outside the control of the Host Customer ~~host customer~~;

2) Whether the project has made significant progress toward completion, and a timeline is provided showing the expected date of commissioning of the project and that interconnection of the project will fall within the third six-month extension of the project's reservation expiration date ~~Reservation Expiration Date~~; ~~and~~

[14] D.15-06-002 granted a petition for modification to increase the number of six-month extensions from two to three. ~~Note that only for projects that sought a third six-month extension prior to June 11, 2015, the effective date of D.15-06-002, the time period between the date the petition for modification was filed, November 13, 2014, and June 11, 2015 does not count toward the Reservation Expiration Date.~~

3) Whether the extension of the project's reservation expiration date will affect the Program Administrator's ability to incentivize other projects.

Eligible energy storage ~~AES~~ SGIP projects may rely on the longer of the extension granted under D.14-05-033 or the third six-month extension granted in D.15-06-002.

Any other procedure or documentation exceptions should be submitted to the appropriate Program Administrator and will be subject to Working Group approval.

3 Incentives

3.1 Incentive Rates

The incentive rates for the ~~three~~ two budget categories of ~~self-generation and storage technologies~~ the SGIP, generation and energy storage, are provided below.

~~*Table 3.1 Incentive Rates by Category*~~

~~Technology Type~~	~~Incentive ($/W)~~
~~Renewable and Waste Energy Recovery~~	
~~Wind Turbine~~	~~$1.02~~
~~Waste Heat to Power~~	~~$1.02~~
~~Pressure Reduction Turbine[1]~~	~~$1.02~~
~~Non-Renewable Conventional CHP~~	
~~Internal Combustion Engine - CHP~~	~~$0.42~~
~~Micro-turbine – CHP~~	~~$0.42~~
~~Gas Turbine – CHP~~	~~$0.42~~
~~Steam Turbine - CHP~~	~~$0.42~~
~~Emerging Technologies~~	
~~Advanced Energy Storage~~	~~$1.31~~
~~Biogas Adder[2]~~	~~$1.31~~
~~Fuel Cell – CHP or Electric Only~~	~~$1.49~~

3.1.1 *Generation Incentive Rates*

Upon program opening, total generation incentive funds are divided equally across three steps. Generation incentives decline by $.10/W between incentive steps, according to the following schedule:

Table 3.1.1 Generation Incentives per Watt (W)

	Step 1		Step 2		Step 3	
Technology Type	Initial Incentive Rate	Max Incentive w/ biogas adder	Initial Incentive Rate	Max Incentive w/ biogas adder	Initial Incentive Rate	Max Incentive w/ biogas adder
Generation Technologies	$/W	$/W	$/W	$/W	$/W	$/W

Wind	$0.90	n/a	$0.80	n/a	$0.70	n/a
Waste Heat to Power	$0.60	n/a	$0.50	n/a	$0.40	n/a
Pressure Reduction Turbine[15]	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Internal Combustion Engine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Microturbine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Gas Turbine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Steam Turbine - CHP[16]	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Fuel Cell CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00
Fuel Cell Electric Only	$0.60	$1.20	$0.50	$1.10	$0.40	$1.00

3.1.2 *Energy Storage Incentive Rates*

Upon program opening, total energy storage incentive funds are divided equally across five steps. Energy storage incentives decline by $.05/Wh between incentive steps, according to the following schedule:

Table 3.1.2 Energy Storage Incentives per Watt-hour (Wh)

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**
Energy Storage	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**
Large Storage (>10 kW)	$0.50	$0.45	$0.40	$0.35	$0.30
Large Storage Claiming ITC	$0.36	$0.31	$0.26	$0.21	$0.16
Residential Storage (<=10 kW)	$0.50	$0.45	$0.40	$0.35	$0.30

If the previous incentive step becomes fully subscribed within 10 calendar days across all Program Administrator territories, the incentive decline to the next step will be $0.10/Wh rather than $0.05/Wh.

[15] Pressure reduction turbine includes but is not limited to, any small turbine generator installed in an existing, man-made channel for delivery of water, steam or natural gas. Decision 16-06-055 allows pressure reduction turbines to be eligible for the same renewable fuel adder which is available to other generators that directly or indirectly use fuel.

[16] Steam Turbines were included in the program as a conventional topping cycle CHP technology in 2014 per Energy Division's Disposition Letter approving CSE Advice Letter (AL) 47-A, PG&E AL 3474-GA/4417-E-A, SCE AL 3038-E-A, and SoCalGas AL 4644-A.

3.1.3 ***Incentives for Technologies from a California ~~Supplier~~ Manufacturer***

An additional incentive of 20 percent will be ~~provided for the installation of eligible distributed generation or AES technologies from a California Supplier~~ added to the technology incentive for projects in which the equipment used is manufactured in California.[17] In order for a project to be eligible for the 20 percent adder, it must demonstrate that at least 50% of its capital equipment value is manufactured by an approved California Manufacturer. ~~A manufacturer is defined as any business or corporation that manufactures, or builds any component of the SGIP qualified DG system – including accessory equipment built in a dedicated CA manufacturing facility, and not on the project site itself. "California Supplier" means any sole proprietorship, partnership, joint venture, corporation, or other business entity that meets the following criteria:~~

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

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

~~iii) Employs California residents for work within the state.~~

~~And fits one of the following standards:~~

~~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/storage technologies to an SGIP recipient:For purposes of qualifying as a California Supplier, a distribution or sales management office or facility does not qualify as a manufacturer. The 20 percent adder for using a California Supplier shall be calculated on the non-renewable incentive rate before adding the additional $1.31 per watt incentive for using biogas. The incentive for each project including the California Supplier Adder shall be capped based upon the Incentive Limitations outlined in *Section 3.3.*~~

3.1.3.1 California Manufacturer Eligibility Criteria and Verification

All California Manufacturers will be required to submit an application for California Manufacturer status and proof to support each criterion below.

California Manufacturers must meet the following requirements:

[17] The incentive for each project including the California Manufacturer adder shall be capped based upon the Incentive Limitations outlined in *Section 5.2 and Section 6.6, 6.7 and 6.9.*

- Operate a manufacturing facility in California
- Licensed to conduct business in California
- Registered with a primary or secondary manufacturing NAICS code

3.1.3.2 Project Equipment Verification

Equipment is deemed to be manufactured in California if at least 50% of the value of the capital equipment has been made in a dedicated production line by an approved California Manufacturer. For the purposes of determining eligibility, the SGIP recognizes the following equipment types:

Generation	Energy Storage
Generator/Prime Mover	Storage medium (i.e. battery)
Ancillary equipment	Inverter
	Controller

3.1.3.3 How to Determine Value

Value is based on the capital cost of a single equipment type as listed above. The California Manufacturer supplying capital equipment component(s) with the largest cost percentage is the one whose California credentials will be considered. The largest cost percentage is the total value of the eligible capital equipment.

Example:

An energy storage project requests the California Manufacturer incentive adder. The project provides the following cost breakdown:

Equipment type	Company	Cost	Location Manufactured	Approved CA Manufacturer?
Advanced lithium ion batteries	ABC Company	$12,000	111 Fake Street, Los Angeles, CA 90011	Yes
Bidirectional AC-DC inverter	Lizard Inverters	$3,000	333 Jon Street, Phoenix, AZ 81234	No
Operating Controller	Nick Controllers	$2,000	4444 Real Street, San Francisco, CA 92222	Yes

- Total system cost= $17,000
- Battery cost percentage = 71%
- Inverter cost percentage = 18%

- Controller cost percentage = 11%

The capital equipment with the highest percentage cost is the battery. Since the battery was made by an SGIP approved California manufacturer, this project will be eligible to receive the 20% adder.

Beginning June 23, 2017, Program Administrators will deny requests for California Manufacturer status for manufacturers that have not met the above requirements, including suppliers which were previously approved. Also, beginning June 23, 2017, projects will receive the adder only when using equipment from an approved California Manufacturer under the above requirements. New projects that apply before June 23, 2017 with a previously approved "California Supplier" may retain the adder only if that manufacturer is re-approved under the above requirements by the Incentive Claim stage.

3.2 **Incentive Limitations**

Incentive amounts for both generation and storage projects can be limited by a number of factors, including ~~(but not limited to), Greenhouse Gas (GHG) emission reductions (for PBI projects),~~ maximum ~~project cap ($5 Million)~~ incentive amount, ~~minimum customer investment (40%),~~ total eligible project costs, sizing limitations per site ~~(3MW)~~, and ~~funding~~ incentives from other ~~ratepayer-sponsored programs~~ sources. Please refer to *Section 5.2* and sections 6.6, *6.7 and 6.9* for incentive calculations and limitations specific to energy storage and generation technologies, respectively.

3.2.1 ***Maximum Incentive Amount***

The maximum incentive amount per project shall not exceed $5 million.

3.2.2 ***Total Eligible Project Costs***

No project can receive total incentives (to include any combination of the technology incentive, biogas adder, and/or California Manufacturer ~~Supplier~~) that exceed the Total Eligible Project Costs. Submittal of Project cost details is required to report Total Eligible Project Costs and to ensure incentive limits are not exceeded. Equipment and other costs outside of the project envelope are considered ineligible project costs but must also ~~must~~ be reported.

The following costs may be included in Total Eligible Project Cost:

1. Engineering feasibility study costs.
2. Engineering and design costs.
3. Environmental and building permitting costs.
4. Equipment capital costs.
5. 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.

6. 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.
7. Construction and installation costs. For projects in which the equipment is part of a larger project, only the construction and installation costs directly associated with the installation of the energy equipment are eligible.
8. Interconnection costs, including:
   a. Electric grid interconnection application fees
   b. Natural gas grid interconnection costs
   c. Metering costs associated with interconnection
9. ~~9.~~ Warranty and/or maintenance contract costs associated with eligible project cost equipment. The cost of this component is capped at 10% of the total claimed project costs. ~~(See Section 2.4.1 Item 3 for full explanation of warranty requirements).~~
10. System metering, monitoring and data acquisition equipment as well as additional on-board monitoring equipment and costs associated with the PDP contract.
11. Air emission control equipment capital cost.
12. 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).
    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 serving the distributed generation unit.
13. 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.
14. Electricity storage devices
15. 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.
16. Sales tax and use tax.

17. 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.
18. For Steam Turbine CHP projects where new or existing boiler capacity is being increased to generate power with a steam turbine, only the incremental costs directly associated with the increased capacity is considered an eligible project cost. If the boiler or any ancillary equipment directly associated with the increased capacity received an incentive or rebate from another source, the incentive or rebate amount is an ineligible project cost and must be deducted from the eligible cost of the project.

3.2.3 ***Incentive Calculation for Site with Multiple Systems***

Program participants can apply for incentives for multiple types of systems installed at one site. The total SGIP incentive is the sum of the incentive for each type of technology. When calculating the total eligible incentive for generation technologies, 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 generation technologies within a single incentive level, the incentives are calculated in the order in which they appear in Table 3.1.1, from top to bottom. When calculating the total eligible incentive for energy storage technologies, the incentives are to be calculated sequentially until the 6 MWh limit is reached.

3.2.4 ***Calculating Incentives with Existing Systems***

A system may be installed in addition to existing systems if all program eligibility requirements are met by the project. Backup generators are not considered “existing on-site generation”.

Sites with existing systems that have met their permanency requirements: The existing SGIP system capacity is not accounted when determining the current incentive. However, if the existing system is still in operation the existing capacity must be accounted in order to best determine new system size.

Sites with existing SGIP systems that have not met their permanency requirements: The existing SGIP system 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 in which incentive capacity tier the proposed system falls. Energy storage ~~AES~~ system capacity is non additive with generation capacity for purposes of calculating the tiered incentive. The incentive calculation and capacity limits are treated separately for ~~AES~~ energy storage and generation technologies.

3.2.5 ***Calculating Incentives for Replacement Generation***

Installation of a new system intended to replace an existing system is allowed if all program eligibility requirements have been met and the replaced system has either never received incentives from the SGIP or the Energy Commission’s Emerging Renewables Program (ERP), or has received incentives from the SGIP, ~~CSI,~~ or ERP programs but has been in service for at least the applicable program’s permanency requirement. Systems that did receive incentives but have not met the appropriate program's permanency requirements may only receive incentive on the incremental increase above the existing system's rated capacity (kW for generation or kWh for energy storage). [18]

The replaced system must also be fully decommissioned and removed from the site. The Program Administrator will confirm this has been completed as part of the field verification inspection.

3.2.6 *Incentives from other sources*

Host Customers, Applicants, and System Owners are required to disclose information about all other incentives they have received, plan to receive or have applied for. For projects receiving incentives under other programs, the SGIP incentive may be reduced depending on the source of the other incentive.

- For other incentives funded 100% by Investor Owned Utility (IOU) ratepayers, the total SGIP incentive will be reduced by the full amount of the other incentive.
- For other incentives funded by Non-IOU Ratepayers, the total SGIP incentive will be reduced by 50% of the amount of the other incentive.

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 taken advantage of by 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 9.***

3.2.7 *Developer Cap*

Any single Developer is limited to 20% of the SGIP incentive funding for a given budget category in each statewide incentive step. Applicants may not submit applications for Developers in excess of the statewide Developer cap for the active step, and Program Administrators shall not issue conditional reservations to projects by a Developer that has already applied for reservations in a given step that exceed 20%. The Developer cap will be calculated separately for generation projects, large scale energy storage projects and small residential energy storage projects. The Developer cap will be established by budget step and posted prior to program opening. The Developer cap will remain fixed for each budget step once the step is opened even if total available funds change. Please see *Section 4.1.5* for the definition of a Developer.

[18] All applicable Incentive Limitations apply. *See Section 5.2* and *Section 6.6, 6.7, 6.9.*

3.3 **PBI Assignment**

If there is a change in ownership of the property which hosts the SGIP equipment, the new owner may continue to receive the Performance-Based Incentives (PBI) if the owner completes a new interconnection agreement. If the seller relocates the equipment, the owner may continue to receive the PBI incentive payments if the equipment is relocated within the same ~~PA's~~ Program Administrator’s service territory within six months and the owner completes an interconnection agreement at the new address. In either case, the PBI payment sunset date will not be extended.

4 Program Eligibility

In order to qualify for incentives, all program eligibility criteria must be satisfied. The following section details these requirements.

4.1 Program Participant Criteria

4.1.1 *Host Customer*

Any retail electric or gas distribution class of customer (industrial, agricultural, commercial or residential) of PG&E, SCE, SoCalGas, or SDG&E is eligible to be the Host Customer and receive incentives from the SGIP.[19] The Host Customer must be the utility customer of record at the site where the SGIP system is or will be located. In the event that the Host Customer's name is not on the utility bill, a letter of explanation is required that addresses the relationship of the Host Customer to the named utility customer. ~~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 from, PG&E, SCE, SDG&E, or SoCal Gas at the Site. Municipal utility customers also served by SCE, PG&E, SDG&E, or SoCal Gas at the Site are eligible.~~

The Host Customer is the exclusive incentive reservation holder ~~and has the right to designate the Applicant, energy services provider, and/or system installer~~ who is party to the SGIP Contract. The Host Customer has the authority ~~right~~ to designate the Applicant, energy service provider, and/ or Developer ~~system installer~~ and change any of these parties at any time with prior written notice to the Program Administrator. ~~The Host Customer also has the right to change these parties at any given time with prior written notice to the Program Administrator. The Host Customer may also be the Applicant and/or System Owner. The Host Customer shall be party to the SGIP Contract.~~

4.1.2 *System Owner*

The System Owner is the owner of the SGIP incentivized equipment. 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. ~~Proof of Project Milestone Form and on the Incentive Claim Form. If known at that time, the System Owner may also be designated on the Reservation Request 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.~~

[19] "…retail electric or gas distribution class of customer…" means that the Host Customer pays for and receives distribution services, as defined by their respective utility rate schedule.

In the event that the System Owner is not the Host Customer and withdraws from the project, the Host Customer 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 revised application documentation ~~a new Reservation Request Form~~ to the Program Administrator.

4.1.3 *Applicant*

An ~~the~~ Applicant is the person or entity that is responsible for completing and submitting the SGIP application and serves as the main point of contact for 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. Host Customers may elect to change the Applicant at any time with prior written notice to the Program Administrator. ~~Applicants may be third parties such as, but not limited to, engineering firms, installation contractors, equipment distributors, Energy Service Companies (ESCO), equipment lessors, etc. Host Customers may elect to change the Applicant at their discretion.~~

4.1.4 *Payee*

A ~~the~~ Payee is the person or entity ~~company~~ to whom the SGIP incentive check is made payable. ~~The Program Administrator will issue payment upon approval of application documents and successful field verification of the equipment.~~ The Payee may be any person or entity designated by the Host Customer ~~as indicated~~ on the Incentive Claim Form.

4.1.5 *Developer*

A Developer is the corporate entity that holds the contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement) with the host customer and handles the project's development activities. The Developer must fully disclose their participation in developing the project and/or ownership in the project, or that of a combination of affiliated installers/developers. The customer contract will be verified at Proof of Project Milestone to confirm the Developer's representations. When applicable, the Developer cap will apply to any combination of affiliated developers under the same majority ownership ~~the aggregate of the projects for Developers under the same parent company~~.

4.1.5.1 Developer Application Process

All SGIP projects must select a pre-approved Developer before the application may be submitted. A list of approved Developers will be available at www.selfgenca.com. Entities interested in becoming an approved SGIP Developer must submit the Developer Eligibility Application to the Program Administrators, containing the following information:

- Parent Company of Developer(s) (include addresses).
- Parent Company ownership percentage of Developer.

- Describe relationship between the Developer or combination of affiliated installers/developers or other legal entities, if applicable.
- Ownership interest of additional owners.

Additionally, if requested by the Program Administrator, Developers must provide the following documentation:

1. Articles of incorporation,
2. Certificate of incorporation,
3. Operating agreements or similar applicable organizational document of Developer and most current financial statements.

4.2 Equipment Eligibility

The SGIP intends to provide incentives for reliable, permanent and safe systems that are professionally installed and that 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. The following section describes the specific equipment eligibility criteria for systems that want to participate in the SGIP.

4.2.1 *Commercial Availability*

Commercially available, factory-new equipment is eligible for incentives. “Commercially available” means that the major system components are acquired through conventional procurement channels.

All eligible technologies must be certified for safety by a nationally recognized testing laboratory (NRTL). An application may be submitted for a device that has not yet received certification from an NRTL if the certification process is underway, however proof of certification must be submitted at the latest with the Incentive Claim documents. Failure to submit proof of certification with the Incentive Claim documents will result in cancellation of the project ~~by the Program Administrator~~.

If NRTL certification is ~~or if~~ not applicable for the technology type, it must be supported by a 10-year warranty as consistent with Rule 21 interconnection standards. In the event that Rule 21 interconnection standards or NRTL certification do not require a separate manufacturer’s warranty, a single 10-year service warranty is sufficient. If Rule 21 interconnection standards or NRTL certification ultimately require a separate 10-year manufacturer’s warranty in addition to the 10-year service warranty, then the obligation for dual warranties stands and must be met by the project.

~~Equipment must have at least one year of documented commercial availability at the time of Reservation Request. Alternatively, equipment may be eligible if system certification is obtained from a nationally recognized testing laboratory (NRTL) indicating that the technology meets the safety and/or performance requirements of a nationally recognized standard. Systems that are still in the process of certification with~~

~~a NRTL may submit a SGIP Reservation Request application before the certification process is finalized. Proof of certification must be submitted at the latest with the Incentive Claim documents.~~

4.2.2 *Interconnection*

All systems receiving incentives under the SGIP that discharge electricity[20] must be connected to the local electric utility's distribution system and must be installed on the Host Customer's side of the electric utility meter. The interconnection, operation, and metering requirements for the systems shall be in accordance with the local electric utility rules for customer generating facility interconnections. Energy storage ~~AES~~ systems must also be configured to operate in parallel with the grid.

In order to connect a 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. For more information on electric grid and/or natural gas pipeline interconnections, please contact your local utility.

Systems will be eligible to receive a reservation up to 12 months after receiving authorization to operate in parallel with the grid from the electric utility.

4.2.3 *Permanent Installation*

The intent of the SGIP is to provide incentives for equipment installed and functioning for the duration of its useful life. Only permanently installed systems are eligible for incentives. This means that the 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/or 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 the length of the applicable warranty period (10 years), is to be demonstrated as follows:

[20] For example, TES ~~HVAC-integrated S-TES~~ does not discharge electricity and therefore does not require an interconnection agreement.

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

4.2.4 *Ineligible Equipment*

The following equipment is not eligible for participation in the SGIP:

- Backup systems intended solely for emergency purposes[21]
- Any system/equipment that is capable of operating on, or switching to, diesel fuel or diesel cycle for start-up or continuous operation
- 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 (e.g. second life batteries)
- Equipment that has been interconnected for more than 12 months

4.2.5 *System Sizing for Projects without Peak Demand Information*

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~~: the highest amount of energy consumed (kWh) in a given interval in the previous 12 months of consumption at the project site divided by the duration of that interval, in hours. The most granular interval for which there is 12 months of available data should be used.

For example, if a residential customer's meter collected hourly interval data for a 12-month period, and this data revealed that the greatest hourly consumption data was 5.5kWh during the previous 12 months, then the peak demand estimate would be 5.5 kW. If the data revealed that the greatest consumption within a 15-minute interval was 5.5kWh during the previous 12 months, then the peak demand estimate would be 22 kW.

[21] 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. Adopted Affidavit Form in CPUC Resolution E-4717.

For customers with less than 12 months of history with the utility or customers that have meters incapable of recording interval usage data, methodology from Section 220 of the National Electric Code (NEC) may be used to determine instantaneous peak demand.

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

~~Residential Load Factor = .43~~

~~Commercial Load Factor = .55~~

~~Industrial Load Factor = .76~~

~~Agricultural Load Factor = .63~~

~~The resulting annual peak demand estimate should be used to determine system sizing for the proposed technology.[22]~~

4.2.6 ***Eligibility for New Technologies*** ~~***and Emerging Technologies***~~

Systems consisting of new technologies not already included in the list of eligible SGIP technologies listed in *Section 3.1.1 and Section 3.1.2* may become eligible for the SGIP ~~as an emerging technology~~ if its first commercial installation occurred less than ten years prior to SGIP funding. New ~~Emerging~~ technologies must meet all applicable eligibility and program requirements. Developers of such technologies seeking eligibility ~~through these criteria~~ must follow the Program Modification Guidelines ~~(PMG)~~ as outlined in *Section 4.2.7*.

4.2.7 ***Program Modification Guidelines*** ~~***(PMG)***~~

For the consideration of new technologies and/or SGIP rule changes, the following Program Modification Guidelines as outlined in Decision 03-08-013 should be followed:

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 ~~If the PMR is not received 10 days prior,~~ the request will roll over to the next monthly SGIP Working Group meeting.

All parties requesting a program modification will be required to meet with the SGIP Working Group during a monthly SGIP Working Group meeting to determine if the Working Group would support the PMR.

The SGIP Working Group will first determine whether or not the proposed PMR requires a modification to a prior Commission Decision ~~order~~. If the PMR is minor and non-substantive and does not require modifications to prior Commission orders, then:

~~[22] Load factors determined from the California Energy Commission's 2012 Demand Forecast (Mid Case) http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/mid_case/~~

- The Working Group will review the PMR. If accepted, the Working Group will make the appropriate changes to the Handbook.
- 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.~~34~~
- The Working Group will make a decision to accept or deny the PMR based on the new information presented in the follow-up presentation.
- The proposed program change and the Working Group recommendation(s) and rationale will be captured in the Working Group meeting minutes.
- 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 the SGIP. Information that supports the party's reasons to accept the program change must be included in the letter.
- Energy Division will then make a final decision on whether to approve the PMR.
- 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.
- If the PMR is accepted, appropriate revisions to the SGIP Handbook will be made. ~~to capture the change.~~

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

- The Working Group will review the PMR and make a recommendation to support or oppose the PMR in the same meeting.
- ~~The proposed program change,~~ The Working Group recommendation and rationale will be captured in the Working Group meeting minutes.
- 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.
- 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.

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

5 Energy Storage Technologies

The following sections outline the eligibility requirements, rating criteria, incentive calculation guidelines and application documentation requirements and metering requirements specific to SGIP energy storage projects. Additionally, all projects are subject to the general program requirements as outlined in sections 2, 3 and 4.

5.1 Rating Criteria for Energy Storage Projects

5.1.1 *Rated Capacity (W)*

The rated capacity (W) for energy storage technologies is calculated as follows:

- DC/AC systems: The nominal voltage multiplied by the amp-hour capacity multiplied by the applicable efficiency divided by the duration of discharge ((V_{DC} x Amp-Hours x (1 kW/1000W) x Applicable Efficiency) / Duration of Discharge).
  - The following specifications must be provided to calculate rated capacity:
    - Duration of discharge (hours)
    - DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and thermal management)
    - Nominal voltage (V_{DC})
    - Applicable efficiency (if necessary), which accounts for conversion, transformation, or other efficiency losses (e.g. Inverter CEC weighted efficiency, DC-DC converter efficiency, etc.)
    - The continuous maximum power output capability of the system.[23] For DC systems, this is rated in DC, and for AC systems, this is rated in AC.
- HVAC-integrated S-TES: Calculated using the Conversion Tables for HVAC-integrated S-TES found in Appendix D, based on the SEER rating and tonnage of the HVAC unit with which the S-TES system will be integrated and the climate zone in which the project is located.
- Refrigeration TES: Calculated using the Refrigeration TES kW Worksheet, and is based on the following parameters of the refrigeration system(s) with which the Refrigeration TES system will be integrated: Energy Efficiency Ratio (EER) of the compressor group, nameplate BTUh capacity of the compressor group, and maximum recorded output of the compressor group (as a percentage of nameplate compressor group horsepower), the number of condenser fans, nameplate condenser fan power, and maximum recorded output of the condenser fan group (as a percentage of nameplate condenser fan group output).

[23] Maximum continuous output might be determined by the maximum continuous discharge power/current of the system or by the continuous rated output of the inverter.

5.1.2 *Energy Capacity (Wh)*

The energy capacity (Wh) for energy storage technologies is calculated as follows:

- DC/AC systems: The nominal voltage multiplied by the amp-hour capacity multiplied by the applicable efficiency (V_{DC} x Amp-Hours x (1 kW/1000W) x Applicable Efficiency).
    - The following specifications must be provided to calculate energy capacity:
        - Duration of discharge (hours)
        - DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and thermal management)
        - Nominal voltage (V_{DC})
        - Applicable efficiency (if necessary), which accounts for conversion, transformation, or other efficiency losses (e.g. Inverter CEC weighted efficiency, DC-DC converter efficiency, etc.)
- HVAC-integrated S-TES: The rated capacity (W) multiplied by the avoided compressor(s) run-hours that the system can provide in a single discharge.
- Refrigeration TES: The rated capacity (W) multiplied by the avoided compressor(s) and condenser(s) run-hours that the system can provide in a single discharge.

5.2 Incentive Calculation for Energy Storage Projects

Incentives for a proposed energy storage system are calculated by multiplying the energy capacity (Wh) of the system by the incentive rate for the appropriate step.

Incentive = *Energy capacity (Wh) * incentive rate*

5.2.1 *Incentive Declines Based on Storage Duration*

Energy storage incentives are reduced as the duration of energy storage (Wh) increases in relation to the rated capacity (W) according to the following schedule:

Table 5.2.1 Energy Storage Incentive Duration Decrease

Storage Duration	**Incentive Rate (Pct. Of Base)**
0-2 hours	100%
Greater than 2 hours to 4 hours	50%
Greater than 4 hours to 6 hours	25%
Greater than 6 hours	0%

Example 1: 2-Hour System

200 kWh storage system at $.40/Wh =

*200,000 Wh * $.40/Wh =* ***$80,000***

Example 2: 4-Hour System

400 kWh storage system at $.40/Wh =

*200,000 Wh * $.40/Wh = $80,000*

*200,000 Wh * $.20/Wh = $40,000*

$80,000 + $40,000 = ***$120,000***

5.2.2 *Incentive Declines and Caps Based on Energy Capacity (Wh)*

Energy storage incentives are paid up to 6 MWh of capacity with tiered incentive rates. For energy storage projects that are greater than 2 MWh, incentives decline according to the following schedule:

Table 5.2.2: Tiered Incentive Rates

Energy Capacity	Incentive Rate (Pct. of Base)
0 – 2 MWh	100%
Greater than 2 MWh to 4 MWh	50%
Greater than 4 MWh to 6 MWh	25%

5.2.3 *Performance-Based Incentive Payment (PBI)*

For projects 30 kW and larger, 50% of the incentive will be paid upon project completion and verification. The remaining 50% will be paid on a performance-based incentive (PBI). Annual kilowatt hour-based payments will be structured so that under the expected ~~capacity factor~~ annual operational requirements[24] 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 discharge/offset*

Total anticipated kWh discharge/offset = *~~rated capacity * capacity factor * hours per year~~ energy capacity (kWh) * 130 full discharges[25] * five years*

[24] See *Section 5.3.3*

[25] For commercial projects only. If this was a residential project sized 30 kW or greater, 52 full discharges would be required.

For a 5-year period the PBI payment will be paid annually based on recorded kWh of electricity discharged or offset over the previous 12 months.

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

Example PBI Payment for a two-hour system:

100 kWh system at $.50/Wh

*Total incentive: 100,000 Wh * $.50/Wh = $50,000*

Upfront payment: $50,000 / 2 = $25,000

Remaining payment to be recuperated through PBI: $50,000 / 2 = $25,000

*Total anticipated kWh discharged/offset: 100 kWh * 130 full discharges * 5 years = 65,000 kWh*

$/kWh for anticipated kWh discharged/offset: $25,000 / 65,000 kWh = $0.3846154/kWh

*PBI payment per year assuming 130 full discharges: 13,000 kWh * $0.3846154/kWh = $5,000*

5.3 Eligibility Requirements for ~~Advanced~~ Energy Storage Projects

~~Advanced~~ energy storage projects may be stand-alone or paired ~~coupled~~ with ~~other SGIP eligible technologies or Photovoltaic~~ generating systems and must ~~All Advanced Energy Storage systems must have the capability to discharge its rated capacity for a minimum of 2 hours and must~~ be capable of discharging fully at least once per day. ~~Advanced~~ energy storage systems paired with wind generation must have the ability to handle hundreds of partial discharge cycles each day. ~~HVAC-integrated S-TES must provide enough thermal energy to shut off the compressor of the accompanying HVAC unit for at least two hours. Refrigeration TES systems must provide enough thermal energy to shut off the compressor(s) and condenser(s) of the accompanying refrigeration system(s) for at least two hours.~~ Residential energy storage ~~AES~~ projects, whether stand-alone or paired, must comply with additional requirements specified in the Residential Energy Storage ~~AES~~ Eligibility Affidavit designed to ensure that all residential energy storage ~~AES~~ systems participating in the SGIP will be used for more than just back-up emergency purposes.

5.3.1 *Greenhouse Gas Emission Standards ~~for AES Projects~~*

Energy storage ~~AES~~ systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5%, assuming a 1% annual degradation rate. The ten year average round trip efficiency will be verified through performance warranties, contractual requirements, or other supporting documentation. ~~Round trip efficiency is defined as the ratio of the energy delivered during discharge of the AES (measured in AC delivered or offset) to the energy required to charge the AES (also measured in AC).~~The charge and discharge of the energy storage

~~AES~~ system ~~will be metered per the requirements of *Section 5.7* of this Handbook and~~ will account for all ancillary loads.

5.3.2 ***System Size Parameters***

System size requirements are applicable for systems that are rated above 10 ~~5~~kW. Systems that are rated at 10 ~~5~~kW or less are exempt from the sizing requirements.

~~Advanced~~ Energy storage projects, whether paired or stand-alone, may be sized up to the Host Customer's previous 12-month annual peak demand (kW) ~~or for Advanced Energy Storage Projects coupled with generation technologies, the CEC-AC rated capacity of the PV system or SGIP eligible technology at the proposed Site. When coupled with a Wind Turbine the AES system's rated capacity cannot be larger than the Host Customer's previous 12-month annual peak demand at the proposed Site~~. For new construction or projects with future load growth, projects can be sized up to future peak demand, but the load must be substantiated before the incentive can be paid. HVAC-integrated S-TES systems must be sized no larger than the tonnage of their accompanying HVAC unit and cannot be integrated with HVAC units greater than 20 tons. Refrigeration TES systems must be sized no larger than the tonnage of their accompanying refrigeration system(s).

5.3.3 ***Operational Requirements***

Commercial systems are required to discharge a minimum of 130 full discharges per year. Residential systems are required to discharge a minimum of 52 full discharges per year. A "full discharge" is the equivalent of discharging the SGIP-incentivized energy capacity, whether it is during a single or multiple discharges.[26]

5.3.4 ***Paired with On-site Renewables***

To be considered paired with and charging from on-site renewables, energy storage systems must either be claiming the Investment Tax Credit (ITC) or, if not claiming the ITC, charge a minimum of 75% from the on-site renewable generator.

5.3.5 ***Demand Response Dual Participation***

Energy storage projects funded through the SGIP are eligible to provide demand response services or participate in demand response programs.

[26] Each discharge does not have to be a 100% depth of discharge, but the aggregate amount of discharges over the year must equate to 130 full discharges.

5.4 Application Documentation Requirements for Energy Storage Projects

5.4.1 *Required Documentation for Reservation Request*

Energy storage applications must provide a copy of the following:

Table 5.4.1: Reservation Request Requirements

Required Materials
1. **Completed Reservation Request Form** *(All Projects)*
2. **Application Fee** *(All Projects)*
3. **Equipment Specifications** *(All Projects)*
4. **Proof of Utility Service/ Load Documentation** *(All Projects)*
5. **Preliminary Monitoring Plan** *(All ~~3-Step~~ Applications >=30 kW and/or projects paired with on-site renewable generators)*

Two-Step Applications should also include all applicable Proof of Project Milestone Documents *(as outlined in Section 5.4.2)* as part of their Reservation Request

1. **<u>Online Reservation Request Form</u>** *(All Projects)*

   All applicants are required to complete the online Reservation Request Form (RRF). This online form is used to provide project details, contact information, and signed declarations. Residential energy storage projects must also fill out the Residential Energy Storage Eligibility Affidavit portion of the RRF.

   The RRF must be printed and signed by the Applicant, Host Customer and System Owner (if not Host Customer). A copy of the signed document must be uploaded to the online application database and the information contained on the signed copy of the RRF must match the information provided on the online RRF.

2. **<u>Application Fee</u>** *(All Projects)*

   The application fee is equal to ~~1%~~ 5% of the requested incentive amount, payable by check, cashier check or money order, and should reference the project by site address.[27] The application fee is the only required document that must be mailed directly to the Program Administrator ~~and must be received within 15 days of application submission~~, however a scanned copy of the application fee must also be uploaded for each project[28] in the application portal with the reservation request

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

[28] A single application fee check for each project is required.

documentation. After a project is assigned to an incentive step, the application fee check must be mailed within 7 calendar days. If the check is not mailed within 7 calendar days, the project may be cancelled. Application fee checks returned by the financial institution without payment may result in cancellation of the application.

The application fee will be refunded upon completion and verification of the installed SGIP project. Prior to project completion, application fees are non-refundable once a Conditional Reservation or Confirmed Reservation has been issued.[29] All forfeited application fees will be allocated to the Program Administrator's ~~SGIP incentive budget~~ current incentive step.

3. **Equipment Specifications** *(All Projects)*

Manufacturer equipment specifications for all major components of the system, such as the storage component, as well as the inverter, DC-DC converter, controller and/or additional system components when applicable, are required. ~~Additionally, for technologies that discharge electricity, it must include a capacity rate based on the average discharge power output over a two hour period.~~ Rated capacity (kW), energy capacity (kWh), and round trip efficiency[30] for the storage system must be provided.

DC/AC systems must provide all specifications necessary to calculate the rated capacity and energy capacity, such as:

- Duration of discharge (hours)
- DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and thermal management),
- Nominal voltage (V_{DC}),
- Inverter CEC-AC efficiency
- DC-DC converter efficiency
- Inverter continuous power output rating (kW)
- The continuous maximum power output capability of the system.[31] For DC systems, this is rated in DC, and for AC systems, this is rated in AC.

HVAC-integrated S-TES must provide the TES system equipment specifications, HVAC system equipment specifications identifying the SEER and tonnage of the HVAC unit and the climate zone in which the project is located.

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

[30] AC-AC for AC systems and DC-DC for DC systems

[31] Maximum continuous output may be determined by the calculated maximum continuous discharge power of the energy storage system or by the continuous rated power output of the inverter depending on which is less.

Refrigeration TES systems must provide TES system equipment specifications, refrigeration system equipment specifications, the Refrigeration TES kW Worksheet and backup documentation of any site-specific conditions, if relevant.

4. **Proof of Utility Service & Load Documentation** *(All Projects)*

   Participation in the SGIP is restricted to customers who are located in PG&E, SCE, SoCal Gas 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 utility bill indicating the account number, meter number, Site address, and Host Customer name. Customers applying in PG&E and SoCalGas territory must also submit a copy of a recent gas utility bill. For new construction, the Host Customer must submit confirmation from the serving utility that their Site is within the Program Administrator's service territory. For projects applying in CSE and SoCalGas territory, ~~In addition, all~~ applications for technologies that discharge electricity to the onsite load must include a copy of the previous 12-months of electric consumption including maximum demand and kWh consumption to confirm that the participating generation system meets the program sizing requirements. Electric utility customers of SCE and PG&E are not required to submit their 12 month electric consumption and demand data. SDG&E customers are also required to submit an Authorization to Receive Customer Information form, signed by the utility customer of record that authorizes CSE to access utility account information.

   If the energy storage system is being sized based on new or future load growth (i.e. new construction or load growth due to facility expansion or other load growth circumstances) applications must include an engineering estimate with appropriate substantiation of the Site's annual peak demand forecast. 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.

5. **Preliminary Monitoring Plan** *(All ~~3 Step~~ Applications >=30 kW and/or projects paired with on-site renewable generators)*

   The preliminary monitoring plan should demonstrate the following components:

   Description of the proposed SGIP system:

   Description of the system with an overview of the energy services to be provided by the system to the host site; the major components making up the system; and the ~~general~~ intended operation of the system (e.g., demand charge management of the facility or specific end-use equipment, TOU energy arbitrage, shifting excess renewable generation, etc.); Include photos and/or diagrams of the system if available.

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:
An overview of the performance data to be collected and a simplified layout of the system showing major components and location of the proposed metering points and data to be collected at those points is required.

~~Two Step Applications will include (as part of their Reservation Request) a Proposed Monitoring Plan as outlined in Section 2.4.1 Item 5.~~

Description of the approach to be used for collecting, storing and transferring the necessary performance data:

- For example, if electrical energy ~~discharged~~ performance 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 Program Administrators, such as monthly]

Identification of the metering system components by performance data type (including manufacturer and model number)

- Electrical metering equipment (AC meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on http://www.gosolarcalifornia.ca.gov/equipment/index.html)
- Thermal energy metering equipment
- Data acquisition (i.e., logger) system

Systems Pairing with On-site Renewable Generators:
Energy storage systems paired with on-site renewable generators must provide a description of:

- The anticipated charge and discharge schedule of the system demonstrating that the system complies with ITC operational requirements or, for projects not claiming the ITC, will be charged at least 75% from renewables;
- The metering that will be used to verify that the system is being charged from renewables;
- The ability to provide data to verify operation in the event of an audit.

Additional Requirements for Two Step Applications

All 2 step applications must include as part of their Reservation Request materials, all applicable requirements of the Proof of Project Milestone. *See Section 5.4.2*.

5.4.2 ***Required Documentation for Proof of Project Milestone***

Energy storage applications must provide a copy of the following:

Table 5.4.2: Proof of Project Milestone Requirements

Required Materials
1. **Completed Proof of Project Milestone Form** *(All 3-Step Projects)*
2. **Copy of RFP or equivalent after 90 days** (*Public Entity Projects Only)*
3. **Copy of Executed Contract or Agreement for Installation** *(All Projects)* • Includes Required Warranty Documentation
4. **Energy Efficiency Audit** *(All Projects)*
~~**5. Proposed Monitoring Plan (*All Projects >=30 kW*)**~~

1. **Online Proof of Project Milestone Form** *(All 3-Step Projects)*[32]

The Online Proof of Project Milestone Form must be completed and signed by the Applicant and representatives with signature authority for both the System Owner and Host Customer (if not Host Customer). The online form must identify updated project information including the installation contractor's name, telephone number and contractor license number. All systems must be installed by an appropriately licensed California contractor 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.

2. **Request for Proposals (RFP) Documentation** *(Public Entities Only)*

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 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 90

[32] Not required for 2-Step Applications as part of the Reservation Request Package.

calendar days of the date the Conditional Reservation Letter. Proof of Project Milestone documentation must then be submitted within 240 days of the date the Conditional Reservation Letter.

3. **Executed Contract and/or Agreement for System Installation** *(All Projects)*

   A copy of the executed contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement) is required. The contract/agreement must be legally binding and clearly spell out the terms and scope of work. Purchase and/or installation agreements must also include system equipment and eligible system costs. All contracts/agreements must be signed by appropriate representatives (Host Customer, Installer, and/or System Owner) who are a party to the agreements of the SGIP reservation.

   - As part of the Executed Contract, all storage systems are required to include a minimum *10 year service warranty*. A service warranty ensures proper maintenance and continued project performance. The service warranty must cover the system maintenance to include (but not limited to) system support, problem diagnosis, on-site repair and preventative maintenance. The warranty should also include language to guarantee the continued performance of the system over the warranty period. The System Owner must provide proof of warranty and maintenance contract, and specify the warranty and maintenance contract start and end dates.

4. **Energy Efficiency Audit** *(All Projects)*

   An Energy Efficiency Audit (EEA) report issued within the past five years ~~identifying the payback periods for all prescribed measures~~ is required. EEA reports must be issued by a Program Administrator, utility, or qualified vendor/consultant. ~~Any measures identified with a payback period of two years or less must be implemented prior to receipt of the upfront incentive payment. Implementation of the required measure will be verified during the field verification visit.~~ The cost of the EEA can be limited to 5% of the requested incentive payment.

   A Title 24 energy efficiency compliance report issued within the past three years may also be used in lieu of an Energy Efficiency Audit. A copy of the Title 24 building permit documentation should be submitted.

5.4.3 *Required Documentation for Incentive Claim*

Energy storage applications must provide a copy of the following:

Table 5.4.3: Incentive Claim Requirements

Required Materials
1. **Completed Incentive Claim Form** *(All Projects)*
2. **Proof of Authorization to Interconnect** *(Projects that interconnect with the electrical grid)*

Required Materials
3. **Project Cost Affidavit and Breakdown Worksheet** *(All Projects)*
4. **Building Permit Inspection Report** *(All Projects)*
5. **Substantiation for New or Expanded Load (if applicable):** *(All Projects)*
6. **Final Monitoring Schematic** *(All Projects >= 30 kW and/or projects paired with on-site renewable generators)*
~~7. **Energy Efficiency Measure Installation Affidavit and/or Non-feasibility documentation** *(All Projects)*~~

1. **Online Incentive Claim Form** *(All Projects)*

   The ICF information must be complete, accurate and represent the actual system and/or fuel information as installed (including system size and type). It must also be signed by the Applicant, Host Customer and System Owner (if not the Host Customer).

2. **Proof of Authorization to Interconnect** *(Projects that interconnect with the electrical grid)*

   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. 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 should be submitted as proof of Authorization to Interconnect.

   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.

3. **Project Cost Affidavit and Breakdown Worksheet** *(All Projects)*

   A signed Project Cost Affidavit and a Project Cost Breakdown Worksheet substantiating the claimed eligible Project cost (as defined in S*ection 3.2.2*).

4. **Building Permit Inspection Report** *(All Projects)*

   A copy of the final building inspection report (or proof of exemption) demonstrating that the Project meets all codes and standards of the permitting jurisdiction. Contact your local permitting jurisdiction to learn about permitting requirements.

5. **Substantiations for New Construction or Expanding Load** *(All Projects)*

   For Projects where Host Customer estimated the future load to justify system size, applications must include documentation demonstrating that the load forecast has materialized.

6. **Final Monitoring Schematic** *(for projects that are 30 kW or larger and/or projects paired with on-site renewable generators)*

The final monitoring schematic is an electrical single line diagram (SLD) that includes the energy storage system, the inverter, the PBI meter, the utility meter, the load panel and, when applicable, the on-site renewable generator with which the energy storage system is paired. ~~A final layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and the location of the proposed metering points, meter IDs, and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.).~~ Documentation must also be provided if there is a change in the make and model of the meters to be used (from what was submitted with the ~~Proposed~~ Preliminary Monitoring Plan at the ~~Proof of Project Milestone~~ Reservation Request).

The Applicant must also provide the name of the Performance Data Provider (PDP) they are contracting with. A copy of the contract between the PDP and the Applicant may be requested at the Program Administrator's discretion.

~~**7 Energy Efficiency Installed Measure Affidavit and/or Non-feasibility documentation for Technology Projects**~~

~~The Energy Efficiency Installed Measure Affidavit acknowledges that all Energy Efficient Measures with a payback period of two years or less have been installed at the project site. If measures with a 2 year payback were not installed a non-feasibility report from the contractor is required.~~

5.5 Metering & Monitoring Requirements for Energy Storage Projects

For PBI purposes, ~~a~~All SGIP technologies 30 kW or larger ~~and/or storage projects paired with and charging from on-site renewable generators~~ must install metering and monitoring equipment that measures net electrical output or offset from the system(s). Conversely, storage projects less than 30 kW that are paired with and charging from on-site renewable generators must have the ability to provide data in the evet of an audit, and may utilize metering and monitoring equipment that is already part of the system. Energy storage systems~~, whether coupled with self-generation equipment or operating as a stand-alone system,~~ that discharge electricity must measure the net electrical energy during charge and discharge cycles. TES must measure electrical energy when charging. HVAC-integrated S-TES systems must monitor and report the power (kW offset) and energy (kWh offset) that would have been consumed by the HVAC unit to provide the same amount of cooling provided by the S-TES system by monitoring outside air temperature and when the S-TES system turned off the compressor of the HVAC unit. Refrigeration TES systems must report the power (kW offset) and energy (kWh offset) that would have been consumed by the refrigeration system(s) to provide the same amount of cooling provided by the Refrigeration TES system by monitoring the operating setpoints of the refrigeration system(s), cooling load on the refrigeration system(s), and when the Refrigeration TES system turns off the compressor(s) and condenser(s) of the refrigeration system(s).

System owners must install and maintain metering and monitoring equipment at their own cost and are responsible for the choice and installation of the metering hardware. All AC electric meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on http://www.gosolarcalifornia.ca.gov/equipment/index.html.

It is also the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years. PDPs will be tasked with recording performance data from the installed metering and monitoring equipment and submit it to the Program Administrators on a monthly basis.

All installed electrical meters ~~(electrical, thermal and fuel)~~ must fulfill the following requirements:

- 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 and/or logger.
- All meters must have the capability to report their data remotely.
- Data reporting must occur on a daily basis.
- 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.
- All meters must provide the PDP provider or defined list of authorized users with the ability to access and retrieve the minimum required data from the meter using the Meter Communication / Data Transfer Protocols described in *Section 7.1*.
- The meters will be inspected as part of the project inspection process.

The following section details the minimum meter requirements per type of meter installed ~~(electrical, thermal, fuel)~~.

5.5.1 *Minimum Electrical Meter Requirements*

All systems 30 kW and larger and/or storage projects paired with and charging from on-site renewable generators 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 charge and discharge and allows the System Owner to support proper system operation and maintenance.

Electrical meters installed on the SGIP project provide data used to assess performance of the system, to analyze impact of the SGIP system on utility distribution systems, the peak system demand of the utility and net GHG emission impacts.

- **Meter Type**

All systems are allowed to use on-board electrical meters, however, the meter must meet the minimum meter requirements of this section. For all systems receiving PBI payments, the installed meter(s) may be a separate Interval Data Recording (IDR) meter(s), or a complete onboard system that is functionally equivalent to an IDR meter, recording data no less frequently than every 15 minutes. 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.

- **Acceptable Electrical Metering Points**

For AC energy storage systems ~~that discharge electricity~~, a meter(s) must be installed on the AC side(s) of the energy storage device and account for power delivery to all parasitic loads including thermal management and power conditioning. For DC electrical energy storage systems, a meter(s) must be installed at a point within the electrical system to measure the charge and discharge of the energy storage device and account for power delivery to all parasitic loads, including thermal management and power conditioning (such as DC to DC conversion). For TES systems, one or more meters must be installed to directly meter or measure the data points necessary to calculate the rate and quantity of charge (in kW/kWh) and the rate and quantity of discharge (in kW/kWh offset).

- **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.

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

Electric meters must measure the net energy ~~generated or offset~~ charged and discharged (kWh) and net real power ~~delivered or offset~~ charged and discharged (kW)[33]. The PDP must log all required energy storage performance / output data points no less frequently than once every 15 minutes. The PDP must measure 15 minute energy and real power for the energy storage system during charging and discharging and account for all ancillary loads. ~~When coupled with a wind turbine the meter must count the number of charge and discharge cycles.~~ The meter needs to generate an accurate time/date stamp.

- **Meter Testing and Certification**

± 2% AC electrical 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).The accuracy rating of ±2% meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV). DC electrical meters must also have a ± 2% accuracy pertaining to the monitoring of power (kW) and energy (kWh), as specified by the meter manufacturer.

- **Meter Display**

All meters must provide a display capable of showing the measured net ~~generated output or offset~~ charge and discharge energy output and measured instantaneous power ~~or power offset~~[34] during charging and discharging. This display must be easy to view and understand and must be physically

[33] For AC systems, measured in AC. For DC systems, measured in DC

[34] ~~Power offset would apply to technologies that discharge thermal energy to offset electrical consumption.~~

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.

6 Generation Technologies

The following sections outline operational eligibility, system size, fuel blending, incentive calculation, application documentation requirements and metering requirements specific to SGIP generation projects. Additionally, all projects are subject to the general program requirements as outlined in sections 2, 3 and 4.

6.1 Operational Eligibility Requirements for Projects Operating on Blended Fuel

The following section describes the operational eligibility requirements for participating generation technologies using any amount of fossil fuel.

6.1.1 *Minimum Operating Efficiency Requirements*

All generation technologies using blended fuel ~~Conventional CHP systems and fuel cells operating on non-renewable fuel~~ must meet or exceed a minimum operating efficiency requirement without the inclusion of renewable fuel. The systems can satisfy this requirement by either meeting:

1. Waste heat utilization requirements **OR**
2. Minimum electric efficiency

To facilitate minimum operating efficiency requirements and determine system eligibility, a Minimum Operating Efficiency Worksheet is available for download from the Program Administrators' websites.

Waste Heat Utilization

To meet minimum waste heat utilization, CHP systems must meet the requirements of Public Utilities Code 216.6, which are expressed in the following equations:[35]

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

And,

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

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).

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

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

$F_{LHV} \equiv$ the generating system's ***annual*** Lower Heating Value (LHV) non-renewable fuel consumption.

Minimum Electric Efficiency[36]

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

Electrical Efficiency = $E / F_{HHV} \geq 40\%$

Where:

$E \equiv$ the generating system's rated electric capacity as defined in *Section 6.1.5*, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh.

$F_{HHV} \equiv$ the generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity.

6.1.2 ***NOx Emission & Minimum System Efficiency Standards***

Systems using blended fuel ~~In addition to the minimum operating efficiency requirement, all conventional CHP systems using non-renewable fuels~~ must not exceed a NOx emissions standard of 0.07 lbs/MW-hr and/or must meet the 60% minimum system efficiency requirement.[37]

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:

CHP System Efficiency = $(E + T) / F_{HHV} \geq 60\%$

Electric only System Efficiency = $E / F_{HHV} \geq 40\%$

Where:

$E \equiv$ the generating system's rated electric capacity as defined in *Section 6.1.5*, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh

$T \equiv$ the generating system's useful waste heat recovery rate (Btu/hr) at rated capacity.

$F_{HHV} \equiv$ the generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity.

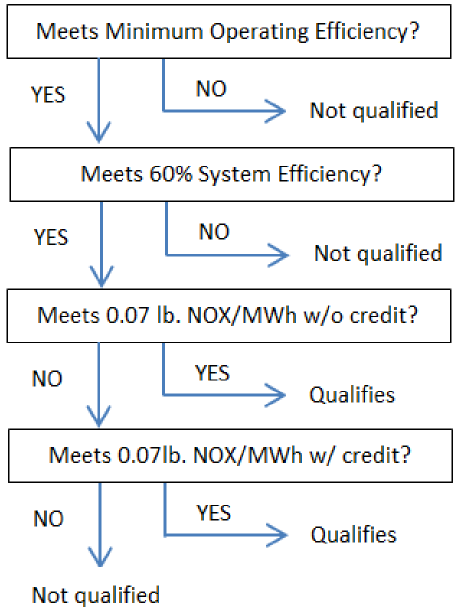
[36] This requirement was included as an alternative requirement to meeting Public Utilities Code 216.6 in compliance with AB 2778.

[37] An emission credit for waste heat utilization may be used to adjust the final emissions determination of eligibility.

CHP systems using blended ~~For any conventional CHP systems using non-renewable~~ fuels that fail to meet the NOx emission standard but meet the 60% minimum system efficiency standard, may be eligible to receive an emission credit for waste heat utilization.

~~Conventional~~ CHP systems operating solely on waste gas are exempt from the NOx 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 on-site net air emissions benefit compared to permitted on-site emissions if the project does not operate. Waste gas systems, though exempt from NOx emission requirements, still must meet the minimum operating efficiency requirement.

Figure 6.2.2: CHP System Efficiency and NOx Emissions Eligibility



6.1.3 *Greenhouse Gas Emission Standards*

The GHG eligibility factor is established based on the year in which the application is accepted. GHG eligibility for electric only systems is based on the First-Year Average factor. GHG eligibility for CHP systems is based on the ten year average factor. The ten-year average and first-year factors for years 2016 through 2020 are listed below.

Table 6.1.3: SGIP GHG Eligibility Emissions Factors, kgCO₂/MWh

Application Year	**2016**	**2017**	**2018**	**2019**	**2020**
10-Year Average	350	347	344	340	337
First-Year Average	334	332	329	325	321

- ### Greenhouse Gas Emission Standards for CHP Systems

~~Conventional~~ CHP ~~and CHP fuel cell projects~~ systems operating on ~~non-renewable~~ blended fuel must emit GHG emissions at a rate equal or lower than ~~350 kg CO2/MW-hr averaged over the first ten years of operation~~ the applicable ten-year average factor. 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[38] 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 nominal boiler efficiency

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

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 and averaged over the years in operation.

- **Greenhouse Gas Emissions Standards for Electric-Only Systems**

Electric-only systems operating on ~~non-renewable~~ blended fuel must demonstrate they will emit GHG emissions at a rate lower than ~~350 kg CO2/MWh averaged over ten years of operations~~ the applicable annual average over ten years of operations, accounting for performance degradation, in order to receive SGIP incentives. For example, 2017 ten-year average (347 kg CO_2/MWh) is equivalent to a first-year emissions rate of 332 kg CO_2/MWh.

The ASME PTC 50-2002 will be used to determine the system's first year electrical efficiency and first year emission rate. The ten year average can be verified through performance warranties, contractual requirements, or other supporting documentation. Alternatively, the ten-year cumulative average net power of the fuel cell coupled with the fuel input rate (HHV) can 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 CO2/MMBtu for the conversion of natural gas to CO2. 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.

6.1.4 *Reliability Criteria*

~~Conventional~~ CHP systems operating on ~~non-renewable~~ blended fuel 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.

6.1.5 *Rating Criteria for System Output*

The generating system rated capacity is the net continuous power output of the packaged prime mover/generator under the conditions defined below for each technology. In order to determine the net continuous power output, all ancillary loads must be subtracted from the gross output of the generator.

Ancillary loads are defined as equipment loads, added as part of the SGIP generator project, necessary for the operation of the generator (e.g. fuel compressors, intercooler chillers, pumps associated with waste heat recovery, blowers used to transport renewable fuel, fuel clean-up equipment). 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 Letter is sent, 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.

- ~~Microturbine, internal combustion engine, gas turbine and fuel cell technologies operating on non-renewable blended fuel, the generating system rated capacity is the net continuous power output of the packaged prime mover/generator at ISO conditions.~~
- Steam turbine CHP rated capacity is the net continuous power output of the packaged prime mover/generator at the average pressure and temperature of the steam produced by a boiler operating on ~~non-renewable~~ blended fuel.
- For on-site biogas projects, the generating system capacity is the operating capacity based on the average annual available renewable fuel flow rate, including allowable non-renewable fuel at ISO conditions.[39]
- For directed biogas projects, 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.
- Pressure reduction turbine technologies rated capacity is based upon the average pressure drop across and flow through the turbine, when flow exists, as determined by historical flow and pressure data from the previous year, if available, or from an engineering estimate if new construction or expanded load. Eligible technology system rated capacity must be substantiated with documentation from the manufacturer.

6.2 Capacity Factors

Generation systems are expected to operate at the following capacity factors:

Table 6.2: Assumed Capacity Factors

Technology Type	Capacity Factor
Wind turbine	25%

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

All other generation	80%

6.3 Operational Eligibility Requirements for Renewable Technologies and Generation Projects Operating on 100% Renewable Fuel

Generation systems operating on 100% renewable fuel are not subject to the operational requirements above. However, they are subject to all rating and sizing criteria below.

6.3.1 *Rating Criteria for System Output of Renewable Technologies*

The generating system rated capacity is the net continuous power output of the packaged prime mover/generator under the conditions defined below for each technology. In order to determine the net continuous power output, all ancillary loads must be subtracted from the gross output of the generator. Ancillary loads are defined as equipment loads, added as part of the SGIP generator project, necessary for the operation of the generator (e.g. fuel compressors, intercooler chillers, pumps associated with waste heat recovery, blowers used to transport renewable fuel, fuel clean-up equipment)

- Wind turbine technologies, less than 30 kW in capacity, a minimum hub height of 80 feet is required. No height limitation is imposed for turbines equal to or larger than 30 kW. For wind turbines of all sizes the wind turbine's rated capacity is based upon the highest electrical output from the manufacturer's power output curve for wind speeds up to 30 mph including inverter losses.
- Waste heat to power technologies rated capacity is based on the average waste heat production rate and temperature, when waste heat is available, as determined by historical waste heat and temperature data from the previous year, if available, or from an engineering estimate if new construction or expanded load.
- Pressure reduction turbine technologies rated capacity is based upon the average pressure drop across and flow through the turbine, when flow exists, as determined by historical flow and pressure data from the previous year, if available, or from an engineering estimate if new construction or expanded load. Eligible technology system rated capacity must be substantiated with documentation from the manufacturer.

6.4 Sizing Requirements for all Generation Systems

The following system sizing requirements are applicable for systems that are rated above 5 kW.

6.4.1 *System Sizing for Wind Turbines*

Host customers with a previous 12 month annual peak demand that is less than 333 kW may size wind turbine projects up to 200% of the annual peak demand at the proposed site. If the Host customer's annual peak demand is greater than or equal to 333 kW, wind turbine projects may be sized up to 300% of the peak demand at the proposed site. Sites hosting existing generation, must also meet these sizing limits including both the capacity of the proposed wind turbine and the capacity of any existing generators (excluding any backup generators).

6.4.2 *System Sizing for PRT, Waste Heat to Power, CHP and Fuel Cells*

Pressure reduction turbine, waste heat to power, steam turbine, 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 backup generators) must be no more than the host customer's maximum site electric load.

In order to reduce GHG emissions and optimize system efficiency, CHP systems using blended fuel must not exceed the on-site thermal load with the recovered waste heat on an annual basis.

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

Systems that will be exporting power to the grid will size their generators based upon 125% of the last twelve months of electrical consumption (kWhs) 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 6.3*.

6.4.4 *System Sizing for RES-BCT Customers*

Any local governments participating in the RES-BCT tariff (AB 2466) or any customer participating in FC-NEM (fuel cell customers who have been determined by the CPUC to achieve reductions in emissions of greenhouse gases pursuant to subdivision (b) of PU Code § 2827.10, and meets the emissions requirements for eligibility for funding set forth in subdivision (c) of PU Code Section 379.6, and has commenced operation on or before January 1, 2015) may size their systems to the total annual electrical load at the site where the generating system is located and the benefiting site(s) combined. However, they are only eligible for incentives up to the total annual electrical load (kWh) at the site where the generating system is located. Local government sites participating in the RES-BCT tariff must comply with the 5 MW cap per site.

6.4.5 *System Sizing Limitations - Ineligible Host Customer Loads*

The following loads cannot be considered when sizing a system:

- Customers who have entered into contracts for distributed generation services (e.g. distributed generation 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 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 and energy storage 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.

6.5 Eligible Fuel Requirements

Eligible fuels are those that produce useful energy when undergoing combustion or a chemical reaction and are classified as renewable, non-renewable, or blended.[40]

6.5.1 *Renewable Fuel Blending Requirements*

All gas generation technologies are required to blend a minimum amount of renewable fuel beginning in 2017. The minimum percentage is determined by the year in which the application is accepted. The table below incorporates the minimum renewable fuel blending requirements by application year.

Table 6.5.1: Minimum Renewable Fuel Blending Requirement

Application Year	% Renewable Fuel Required
2016	0%
2017	10%
2018	25%
2019	50%
2020	100%

6.5.2 *Directed Biogas Project Requirements*

Directed biogas projects must meet the following eligibility requirements and conditions:

- Directed renewable fuel must be injected into a common carrier pipeline system that is either within the Western Electricity Coordinating Council (WECC) region or interconnected to a common carrier pipeline system located within the WECC region.

6.5.3 *Directed Biogas Renewable Fuel Audits*

Program Administrators or a third-party designee will conduct an annual audit of the renewable fuel invoices for ten years after the renewable fuel contract commences to verify ~~compliance with the~~

[40] For the purposes of SGIP, renewable resources such as wind, pressure, waste heat, and water are not categorized as a fuel.

~~requirement to procure renewable fuel to meet at least 75% of the generator's total~~ renewable fuel consumption.

The audit and verification will use metered fuel consumption data for SGIP directed biogas projects; invoices from SGIP participants for directed renewable fuel purchases; documentation/verification on any deliveries of directed renewable fuel along the path from the SGIP participant back to the original directed renewable fuel supply source; and documentation to verify the amount and energy content of directed renewable fuel injected into the path. To complete the audit, the Program Administrator or a third-party designee will request all pertinent information from the system owner and/or ~~biogas~~ renewable fuel provider at the completion of each year after renewable fuel contract start date.

If invoices show that nominated renewable fuel deliveries fell below ~~75% of the generator's~~ the generator's committed renewable fuel demand during any 1 year period, the SGIP Program Administrators ~~will~~ may request that the system owner refunds the appropriate renewable fuel SGIP incentive amount and reserve the right to request a refund of additional costs associated with the administrative and legal fees incurred by the Program Administrators.

6.5.4 ***Renewable Fuel Commitment Modifications***

Customers are required to meet their renewable fuel commitment throughout the permanency period. In the event that modifications are made applicants are required to notify their Administrator.

- **Modifications Pre-ICF** – applicants must notify their administrator as soon as practical but no later than ICF. Increase of renewable fuel percent prior to the completion of the project may not automatically increase incentive amount.
- **Modifications Post-ICF –** applicants must notify their Administrator within 90 days of any changes made to the contract and amount of renewable fuel. Increase in amount of renewable fuel may not result in an incentive increase. Additionally, the host customer must provide to the Program Administrator with all pertinent documentation.

6.5.5 ***Pressure Reduction Turbine Requirements***

Pressure reduction turbines operating in a steam system the boiler fuel used to generate the steam may be blended or 100% renewable, and as such would be eligible for the renewable fuel adder. The source of the renewable fuel may be on-site or directed. The temperature and flow rate of steam to the pressure reduction turbine will be used along with the boiler efficiency to determine the amount of fuel used to generate steam supply to the turbine. The adder would apply only to the renewable fraction of the boiler fuel necessary to operate the pressure reduction turbine.

6.6 Incentive Calculation for Generation Projects

Incentives for a proposed generation system are calculated by multiplying the rated capacity (W) of the system[41] by the incentive rate for the appropriate technology type and step.

***Incentive** = rated capacity * incentive rate*

~~Incentives for blended projects are calculated by multiplying the rated capacity (W) of the system by the technology incentive rate, plus the rated capacity of the system, multiplied by the percentage of renewable fuel multiplied by the renewable fuel (RN) adder rate ($.60/watt).~~

~~***Incentive** = (rated capacity * incentive rate) + (rated capacity* % RN Fuel*RN adder rate)*~~

Incentives for 100% renewable fuel and blended fuel projects are calculated by multiplying the rated capacity of the system by the technology incentive rate, plus the rated capacity of the system, multiplied by the percentage of renewable fuel above the minimum requirement, multiplied by the renewable fuel adder rate ($.60/watt).

Incentive = (rated capacity * incentive rate) + (rated capacity * % above min RN Fuel * RN incentive)

6.6.1 *Incentive Declines Based on Generation Capacity*

SGIP incentives are paid for up to 3 MW of capacity with tiered incentive rates. For projects that are greater than 1 MW, the incentives identified in Table 3.1.1 decline according to the following schedule:

Table 6.6.1: Tiered Incentive Rates

Capacity	Incentive Rate (Pct. of Base)
0 – 1 MW	100%
>1 MW – 2 MW	75%
>2 MW – 3 MW	50%

6.7 Performance-Based Incentive Payment (PBI)

On-site biogas, wind, waste heat to power and pressure reduction turbine projects 30 kW and larger will be paid 50% of the full incentive amount upon project completion and inspection. The remaining 50% of the incentive will be paid annually over five years. Annual payments will be structured

[41] For more information on rating criteria for system output, see *Section 6.1.5*.

so that based upon the expected capacity factor and renewable fuel commitment (if applicable) a project would receive the entire stream of performance payments in five years.

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

Total anticipated kWh production *= rated capacity * anticipated 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 or offset over the previous 12 months.

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

Directed biogas projects 30 kW and larger will be paid 50% of the technology incentive upon project completion and inspection. The remaining 50% of the technology incentive will be paid annually over five years. Annual kilowatt hour-based technology payments will be structured so that under the expected capacity factor, a project would receive the entire stream of performance payments in five years. Additionally, the renewable fuel adder will be paid annually over five years. Annual renewable fuel adder payments will be structured so that, under the expected fuel consumption, a project would receive the entire renewable fuel adder for which it was approved.

$/kWh *= remaining 50% of technology incentive / total anticipated kWh production over 5 years*

Total anticipated kWh production *= rated capacity * anticipated 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.

PLUS

Renewable Incentive Annual Payment = ((rated capacity % above min RN fuel * RN adder rate) / 5) * (actual capacity factor / anticipated capacity factor)*

Both on-site and directed biogas projects will receive a prorated PBI payment for the percentage of renewable fuel that is actually consumed.

6.7.1 *PBI Payments for Export to the Grid Projects*

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.

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 may be required prior to payment.

6.8 Renewable Fuel Annual Payment Requirements

The following outlines the data and verification requirements for directed and on-site renewable fuel annual payments of systems 30kW and larger.

6.8.1 *Directed Renewable Fuel Verification*

The amount of directed renewable fuel procured will be verified prior to issuing annual fuel payments. For Directed Renewable Fuel users, applicant or Performance Data Provider (PDP) must provide monthly data of the amount of directed renewable fuel consumed on a monthly basis. This information must be provided through the SGIP database as part of the performance data requirements. Additionally, the applicant or PDP will be required to provide the source, path, and destination of the renewable fuel. Data reporting will commence one month after the initial payment. The following information and documentation must be provided on a monthly basis:

1. **Transportation Path and Energy Accounting**

The PDP must upload supporting documentation (i.e. invoices) reporting the amount of renewable fuel that was documented on the Directed Renewable Fuel Verification Form. Supporting documentation includes but not limited to:

- Documentation from the source showing the amount of directed biogas being moved onto the pipeline. Any non-renewable gas added at the source must be identified.
- Documentation from the gas transmission system showing:
- Receipt of directed biogas (from source, storage, or other pipelines)
- Pipeline losses or fees paid in gas (not carried over)
- Positive or negative imbalances (carried over)
- Delivery of directed biogas to either another pipeline, storage facility, or California utility receipt point

2. **Gas Fuel Consumption**

The PDP must provide gas fuel consumption documentation from the gas utility matching the directed renewable fuel receipts reporting the metered total energy input to the generator. Utility gas fuel consumption receipts must be reported on a quarterly basis.

It is the responsibility of the PDP to supply the renewable fuel use documentation and to ensure that the renewable fuel is reported to the Program Administrator or their designee on a monthly and quarterly basis for five years.

6.8.2 *On-site Renewable Fuel Verification*

All on-site renewable fuel projects 30 kW and larger are required to install a fuel metering system that reports both renewable and non-renewable fuel. The PDP is required submit both renewable and non-renewable fuel data on a monthly basis.

The System Owner must provide make, model, specifications, and serial number of installed revenue grade gas meters

It is the responsibility of the system owner to contract with a performance data provider (PDP) for a minimum of five years and ensure that both renewable and non-renewable fuel data is provided to the Program Administrator or their designee monthly for five years.

6.9 Incentive Limitations for Projects using Renewable Fuel

The following sections outline the incentive limitations for projects using renewable fuel. Additionally, all generation projects are subject to the general incentive limitations as outlined in *Section 3.2*.

6.9.1 *Limitations on PBI based on GHG Emissions Reductions*

PBI payments will be reduced or eliminated in years that do not result in the required GHG emissions reductions. Because many factors may lead to a project performing below expected levels of efficiency, there is a 5% exceedance band before penalties are assessed.[42] The following example describes how a PBI payment for a 2017 project would be affected:

- PBI payments will be reduced by half in years where a project's cumulative emission rate is equal to or greater than 364 kg CO_2/MWh (i.e., 5% higher than 347 kg CO_2/MWh) but less than 382 kg CO_2/MWh (i.e., 10% higher than 347 kg CO_2/MWh).
- Projects that equal or exceed a cumulative emissions rate of 382 kg CO_2/MWh will receive no PBI payments for that year.

$$emission\ rate < 364\ \frac{kg\ CO_2}{MWh} \rightarrow \text{No penalty assessed on PBI payment}$$

$$364\ \frac{kg\ CO_2}{MWh} \leq emission\ rate\ < 382\ \frac{kg\ CO_2}{MWh} \rightarrow \text{PBI payment reduced by 50\%}$$

$$emission\ rate\ \geq 382\ \frac{kg\ CO_2}{MWh} \rightarrow \text{No PBI payment for that year}$$

The table below illustrates the eligibility emission factors for blended fuel generation projects for the years 2017 through 2020:

[42] D.11-09-015, §4.3.2. pg 32

Table 6.9.1: Eligibility Emission Factors for Blended Fuel Generation Projects

Program Year	Eligibility Emission Factor	Year 1 to 5
2017	Baseline	347
	5% Exceedance	364
	10% Exceedance	382
2018	Baseline	344
	5% Exceedance	361
	10% Exceedance	378
2019	Baseline	340
	5% Exceedance	357
	10% Exceedance	374
2020	Baseline	337
	5% Exceedance	354
	10% Exceedance	371

6.9.2 *Limitations on PBI Adjustments based on Renewable Fuel Verification*

All gas generation technologies must meet minimum renewable fuel requirements to be eligible for incentives. However, the annual renewable fuel PBI payment will be adjusted according to the verified consumption. PBI projects whose annual consumption fails to meet the minimum renewable fuel requirement, will forfeit the annual renewable fuel adder payment.

6.9.3 *Incentive Limit for the Renewable Fuel Adder*

In the case of directed projects, the adder is compared to the cost of the renewable fuel contract and should not exceed the cost difference between the renewable fuel contract and a similar contract for standard natural gas. Projects utilizing 100% on-site renewable fuel will receive the full renewable fuel adder. Projects utilizing blended fuel, where renewable fuel is either on-site or directed, the incentive will be prorated to the percentage of fuel that is actually consumed based on audits which are conducted throughout the PBI period.

6.9.4 *~~Non-Renewable~~ Blended Fuel Generating Systems Converted to 100% Renewable Fuel*

~~Non-renewable~~ Blended SGIP-funded generating systems can be converted to 100% renewable fuel and receive the additional renewable fuel adder if the conversion takes place no later than 1 year from the first SGIP incentive payment. However, these conversions are only eligible to receive the additional renewable fuel adder; and all project costs caps are still applicable.

For systems under 30kW the ~~biogas~~ renewable fuel adder will be paid upon completion of conversion. For systems 30kW and larger, 50% will be paid upon completion, and the remaining 50% will be included in the annual PBI payments. The recalculated PBI incentive payments will be based on the following calculation:

PBI Rate ($/kWh) = (remaining Incentive ($) + ½ RN fuel adder x Rated Capacity (kW) x (1000W/kW)) / (rated capacity of the generator (kW) * 8760 (hrs/year) * capacity factor * number of years payments will be made)

6.9.4.1 Renewable Fuel Conversion Reservation Request

All renewable conversion reservation requests will follow a 2-step process and must include the following applicable documents (see *Section 6.10.1* & *Section 6.10.2* for document details):

1. Reservation Request Form Application Fee
2. Proof of Adequate Renewable Fuel

6.9.4.2 Renewable Fuel Conversion Incentive Claim

Once the conversion has been completed, applicants are required to submit an Incentive Claim Form with the following applicable documents (see *Section 6.10.3* for document details):

1. Incentive Claim Form: Project Cost Affidavit and a Project Cost Breakdown Worksheet (as defined in S*ection 3.2.2*)
2. Final Permits
3. Substantiations:
    a. Renewable fuel (on-site renewable fuel)
    b. Fuel Cleanup Skid Cost Documentation (on-site renewable fuel only)
    c. Renewable Fuel Documentation & Contract Commencement (directed renewable fuel only)
    d. Renewable fuel metering specifications
4. Final Monitoring Schematic (for projects that are 30 kW or larger) to include the name of the Performance Data Provider (PDP).

6.10 Application Documentation Requirements for Generation Projects

Applications are required to meet all documentation requirements on time. Documents are based on the application timeline. The following sections describe the required documents based on the specific step.

6.10.1 *Required Documentation for Reservation Request*

Generation applications must provide a copy of the following:

Table 6.10.1: Reservation Request Requirements

Required Materials
1. Completed Reservation Request Form *(All Projects)*
2. Application Fee *(All Projects)*

Required Materials	
3.	**Equipment Specifications** *(All Projects)*
4.	**Proof of Utility Service/ Load Documentation** *(All Projects)*
5.	**Preliminary Monitoring Plan** *(All 3-Step Applications >=30 kW)*
6.	**Minimum Operating Efficiency Worksheet w/Backup Documentation** *(Blended Projects Only)*
7.	**Proof of Adequate Fuel or Waste Energy Resource** *(Renewable Fuel, Waste Energy, Waste Gas Projects Only)*

Two-Step Applications should also include all applicable Proof of Project Milestone Documents *(as outlined in Section 6.10.2)* as part of their Reservation Request

1. **Online Reservation Request Form** *(All Projects)*

   All applicants are required to complete the online Reservation Request Form (RRF). This online form is used to provide project details, contact information, and signed declarations.

   The RRF must be printed and signed by the applicant, host customer and system owner (if not host customer). A copy of the signed document must be uploaded to the online application database and the information contained on the signed copy of the RRF must match the information provided on the online RRF.

2. **Application Fee** *(All Projects)*

   The application fee is equal to ~~1%~~ 5% of the requested incentive amount, payable by check, cashier check or money order, and should reference the project by site address.[43] The application fee is the only required document that must be mailed directly to the Program Administrator ~~and must be received within 15 days of application submission~~, however a scanned copy of the application fee must also be uploaded for each project[44] in the application portal with the reservation request documentation. After a project is assigned to an incentive step, the application fee check must be mailed within 7 calendar days. If the check is not mailed within 7 calendar days, the project may be cancelled. Application fee checks returned by the financial institution without payment may result in cancellation of the application.

[43] 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.

[44] A single application fee check for each project is required.

The application fee will be refunded upon completion and verification of the installed SGIP project. Prior to project completion, application fees are non-refundable once a Conditional Reservation or Confirmed Reservation has been issued.[45] All forfeited application fees will be allocated to the Program Administrator's ~~SGIP incentive budget~~ current incentive step.

3. **Equipment Specifications** *(All Projects)*

Manufacturer equipment specifications for all major components of the system are required, in addition to the nameplate capacity, rated capacity (kW) efficiency and, if necessary, fuel consumption and waste heat recovery rate of the system.

Proof of power factor eligibility is also required for microturbines, internal combustion engines, gas turbines and stream turbine CHP applications (where applicable) and 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.

4. **Proof of Utility Service & Load Documentation** *(All Projects)*

Participation in the SGIP is restricted 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 utility bill indicating the account number, meter number, site address, and Host Customer name. Customers applying in PG&E and SoCalGas territory must also submit a copy of a recent gas utility bill. For new construction, the Host Customer must submit confirmation from the serving utility that their site is within the Program Administrator's service territory. For projects applying in CSE and SoCalGas territory, ~~In addition, all~~ applications for technologies that discharge electricity to the onsite load must include a copy of the previous 12-months of electric consumption including maximum demand and kWh consumption to confirm that the participating generation system meets the program sizing requirements. Electric utility customers of SCE and PG&E are not required to submit their 12 month electric consumption and demand data. SDG&E customers are also required to submit an Authorization to Receive Customer Information form, signed by the utility customer of record that authorizes CSE to access utility account information.

If the generation system is being sized based on new or future load growth (i.e. new construction or load growth due to facility expansion or other load growth circumstances) applications must include an engineering estimate with appropriate substantiation of the site's annual peak demand forecast. Suggested methods of demonstrating load growth include Application for Service with corresponding equipment schedules and single line diagram; building simulation program reports

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

such as eQUEST, EnergyPlus, EnergyPro, DOE-2, and VisualDOE; or detailed engineering calculations.

5. **<u>Preliminary Monitoring Plan</u>** *(All 3 Step Applications >=30 kW)*

The preliminary monitoring plan should demonstrate the following components:

Description of the proposed SGIP system:

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.); Include 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.

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:

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

Two Step Applications will include (as part of their Reservation Request) a Proposed Monitoring Plan as outlined in *Section 6.10.2*.

6. **<u>Minimum Operating Efficiency Worksheet w/Backup Documentation</u>** *<u>(Blended Projects Only)</u>*

The Minimum Operating Efficiency Worksheet (MOEW) is used to evaluate a project's technical ability to meet the following requirements:

a) Minimum operating efficiency requirement which can either be satisfied by meeting:

Waste Heat Utilization *<u>or</u>*

Minimum Electrical Efficiency Requirements

b) Thermal Load Coincidence

c) CHP System Efficiency and NOx Emission Qualification

d) Greenhouse Gas Emission Standard

e) Electrical Load Coincidence (Electrical Export Eligibility)

a) Minimum Operating Efficiency Calculations

The MOEW is a spreadsheet used to evaluate the project's estimated minimum operating efficiency over 10-years. Additionally, the MOEW verifies the first year minimum operational efficiency for Electric-only fuel cells. All applications proposing blended renewable-fueled technologies must provide backup documentation along with the MOEW. CHP systems must additionally include engineering calculations with documented assumptions regarding the site's thermal load. 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.

Specifically, the following applicable documentation must be provided:

- *Generator & Thermal System Description*

  The application must include the performance and capacity specifications for the proposed 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 MOEW 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.

b) <u>Thermal Load Coincidence</u>

Thermal load coincidence is calculated in the worksheet by comparing the waste heat recovered to the thermal load on an annual basis. The backup documentation listed above for the forecast of generator thermal output and forecast of thermal load magnitude will be sufficient to meet this operating efficiency requirement.

c) <u>CHP System Efficiency and Proof of NOx Emission Qualification</u>

Applications must include documentation substantiating that the generating system meets or exceeds the 60% minimum system efficiency and NOx emissions are at or below the applicable emission standard. One of the following documents must be included 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[46] for the proposed generating system as configured for the Site.

- CARB distributed generation certification

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

- 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. Units that do not pass the emission standard may use emission credits. If the application claims NOx emissions 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.

d) Greenhouse Gas Emission Rate Testing Protocol *(Electric-Only Fuel Cells)*

Electric-only fuel cells operating on ~~non-renewable~~ blended fuel must provide the ASME PTC 50-2002 test as backup documentation to the MOEW. Please see *Section 6.1.3 f*or further information.

e) Electric Load Coincidence *(Electrical Export Eligibility)*

The application must include the monthly electrical load for the previous 12 months. This information will be used in the MOEW to determine electrical load coincidence with electrical generation on an annual basis. If the generator is eligible to export electricity to the grid, the electrical generation will be compared to 125% of electrical load on an annual basis.

7. **Proof of Adequate Fuel or Waste Energy Resource** *(Renewable Fuel, Waste Gas & Waste Energy Projects)*

On-site Biogas Projects 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 permanency period.

Biogas Projects utilizing Directed Renewable Fuel must include documentation of the forecasted fuel consumption of the generator over the life of project.

Projects utilizing Waste Gas Fuel (microturbines, internal combustion engines, gas turbines and steam turbine CHP waste gas fuel applications only) 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 permanency period.

Proposed Pressure Reduction Turbine applications must include an engineering survey or study confirming adequate temperature, pressure and flow within the piping system, and the generating system's rated capacity. The rated capacity must be based upon the average pressure drop across and flow through the turbine, when flow exists, as determined by historical flow and pressure data from the previous year if available, or from an engineering estimate if new construction or expanded load. Additionally, the survey or study must show that the capacity factor for the proposed project will be greater than or equal to 40% based upon conditions over the course of a full year, or from an engineering estimate for future conditions.

<u>Proposed Waste Heat to Power applications</u> must include an engineering survey or study confirming adequate waste heat production rate and temperature, and the generating system's rated capacity. The rated capacity must be based upon the average waste heat production rate and temperature, when waste heat is available, as determined by historical waste heat and temperature data from the previous year if available, or from an engineering estimate if new construction or expanded load. Additionally, the survey or study must show that the capacity factor for the proposed project will be greater than or equal to 40% based upon conditions over the course of a full year, or from an engineering estimate for future conditions~~.~~

<u>Proposed Wind projects</u> must include an engineering survey or study evaluating the annual average wind speed at the hub height of the wind turbine. The study must confirm that the average annual wind speed is equal to or greater than 10 mph (4.5 m/s). The wind resource can be verified using wind resource maps from NREL or the CEC and standard formulas for correcting for differences in tower heights or by gathering wind data on site at the turbine's proposed hub height for one year.

<u>Additional Requirements for Two Step Applications</u>

All 2 step applications must include as part of their Reservation Request materials, all applicable requirements of the Proof of Project Milestone. *See Section 6.10.2*.

6.10.2 ***Required Documentation for Proof of Project Milestone***

Generation applications must provide a copy of the following:

Table 6.10.2: Proof of Project Milestone Requirements

Required Materials
1. **Completed Proof of Project Milestone Form** *(All 3-Step Projects)*
2. **Copy of RFP or equivalent after 90 days** (*Public Entity Projects Only)*
3. **Copy of Executed Contract or Agreement for Installation** *(All Projects)* • Includes Required Warranty Documentation
4. **Energy Efficiency Audit** *(All Projects)*
5. **Proposed Monitoring Plan** *(All Projects >=30 kW)*

Required Materials
1. **Completed Proof of Project Milestone Form** *(All 3-Step Projects)*
6. **Proof of Fuel Contract and Documentation** *(Renewable Fuel and Waste Gas Projects Only)* • Renewable Fuel Contract *(Directed Renewable Fuel Only)* • Directed Renewable Fuel Attestation – System Owner & Fuel Supplier *(Directed Renewable Fuel Only)* • Renewable Fuel Affidavit *(On-site Renewable Fuel Only)* • Fuel Clean-up *(On-site Renewable Fuel Only)* • Waste Gas Fuel Affidavit *(Waste Gas Fuel Only)*

1. **Online Proof of Project Milestone Form** *(All 3-Step Projects)*[47]

The Online Proof of Project Milestone Form must be completed and signed by the applicant and representatives with signature authority for both the system owner and host customer (if not host customer). The online form must identify updated project information including the installation contractor's name, telephone number and contractor license number. All systems must be installed by an appropriately licensed California contractor 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.

2. **Request for Proposals (RFP) Documentation** *(Public Entities Only)*

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 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 90 calendar days of the date the Conditional Reservation Letter. Proof of Project Milestone documentation must then be submitted within 240 days of the date the Conditional Reservation Letter.

3. **Executed Contract and/or Agreement for System Installation** *(All Projects)*

A copy of the executed contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement) is required. The contract/agreement must be legally binding and clearly spell out the terms and scope of work. Purchase and/or installation agreements must also include system equipment and eligible system costs. All contracts/agreements

[47] Not required for 2-Step Applications as part of the Reservation Request Package.

must be signed by appropriate representatives (Host Customer, Installer, and/or System Owner) who are a party to the agreements of the SGIP reservation.

- As part of the Executed Contract, all generation systems are required to include a minimum *10 year service warranty* (with the exception of wind turbines which must have a minimum 20 year service warranty). A service warranty ensures proper maintenance and continued project performance. The service warranty must cover the system maintenance to include (but not limited to) system support, problem diagnosis, on-site repair and preventative maintenance. The warranty should also include language to guarantee the continued performance of the system over the warranty period. The system owner must provide proof of warranty and maintenance contract, and specify the warranty and maintenance contract start and end dates.

4. **Energy Efficiency Audit** *(All Projects)*

An Energy Efficiency Audit (EEA) report issued within the past five years ~~identifying the payback periods for all prescribed measures~~ is required. EEA reports must be issued by a Program Administrator, utility, or qualified vendor/consultant. ~~Any measures identified with a payback period of two years or less must be implemented prior to receipt of the upfront incentive payment. Implementation of the required measure will be verified during the field verification visit.~~ The cost of the EEA can be limited to 5% of the requested incentive payment.

A Title 24 energy efficiency compliance report issued within the past three years may also be used in lieu of an Energy Efficiency Audit. A copy of the Title 24 building permit documentation should be submitted.

5. **Proposed Monitoring Plan** *(All Projects that are 30 kW or larger)*

The proposed monitoring plan should demonstrate the following components:

Description of the proposed SGIP system(s)

Description of the system(s) with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage, etc.) by the system(s) to the host site; the major components making up the system(s); and the general operating schedule of the system(s) (e.g., is it 24x7x365 or 10x6x365, etc.). Include photos of the system(s) 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.

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(s) (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

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

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 Program Administrators, such as monthly]

Identification of the metering system components by performance data type (including manufacturer and model number)

- Electrical metering equipment (AC meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on http://www.gosolarcalifornia.ca.gov/equipment/index.html)
- Thermal energy metering equipment
- Fuel consumption metering equipment
- Data acquisition (i.e., logger) system

6. **Proof of Fuel Contracts and Documentation** *(Renewable Fuel and Waste Gas Projects Only)*

Copy of Executed Renewable Fuel Contract *(Directed Renewable Fuel Only)*

The 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.

The SGIP Program Administrator or designee has the right to audit and verify the generator's 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 and the contract should include a forecast for the system's anticipated fuel consumption.

The contract should include a quarterly true-up mechanism in which the customer and renewable fuel supplier 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.

- If less on-site fuel is consumed than renewable fuel is nominated into the pipeline, then parties agree to a financial make-whole provision.
- If more on-site fuel is consumed than renewable fuel is nominated into the pipeline, then parties agree to a make whole provision, such that Customer Generator consumes renewable fuel, as measured annually.

Directed Renewable Fuel Attestation *(Directed Renewable Fuel Only)*
Attestation letter from the system owner of the intent to notionally procure renewable fuel and attestation from the fuel supplier that the fuel meets the applicable renewable portfolio standard eligibility requirements for renewable fuel injected into a natural gas pipeline.

Renewable Fuel Use Affidavit *(On-site Renewable Fuel Only)*
Application documentation must include a signed affidavit that projects will not switch to non-renewable fuel for a period of ten years for all technologies. The SGIP Program Administrator has the right to audit and verify the generator's renewable fuel consumption upon request over the life of the contract.

Fuel Cleanup Equipment Purchase Order *(On-site Renewable Fuel Only)*
When applicable, application documentation must include a purchase order for Renewable Fuel cleanup equipment that lists the fuel cleanup equipment as a separate invoice item.

Waste Gas Fuel Use Affidavit *(Waste Gas Only)*
When applicable, application documentation must include a signed affidavit that Projects will be fueled solely (100%) with Waste Gas for a period of ten years.

6.10.3 *Required Documentation for Incentive Claim*

Generation applications must provide a copy of the following:

Table 6.10.3: Incentive Claim Requirements

Required Materials
1. **Completed Incentive Claim Form** *(All Projects)*
2. **Proof of Authorization to Interconnect** *(Projects that interconnect with the electrical grid)*
3. **Project Cost Affidavit and Breakdown Worksheet** *(All Projects)*
4. **Final Permits** • **Building Permit Inspection Report** *(All Projects)* • **Air Permit Documentation** (*Non-Renewable Fuel Only)*

Required Materials
5. **Substantiations:** • **New or Expanded Load** *(All Projects)* • **Renewable or Waste Resource** *(On-site Renewable Fuel and Waste Energy Only)* • **Fuel Cleanup Skid Cost** *(On-site Renewable Fuel Only)* • **Renewable Fuel Documentation/Contract Commencement** *(Directed Renewable Fuel Only)* • **Renewable Fuel Metering Specifications** *(Directed Renewable Fuel Only)*
6. **Planned Maintenance Coordination Letter** *(>=200 kW CHP Systems Only)*
7. **Final Monitoring Schematic** *(All Projects >= 30 kW)*
~~8. **Energy Efficiency Measure Installation Affidavit and/or Non-feasibility documentation** *(All Projects)*~~
9. **PBI Setup Sheet** *(All Projects >= 30kW)*

1. **Online Incentive Claim Form** *(All Projects)*

   The ICF information must be complete, accurate and represent the actual system and/or fuel information as installed (including system size and type). It must also be signed by the applicant, host customer and system owner (if not the host customer).

2. **Proof of Authorization to Interconnect** *(Projects that interconnect with the electrical grid)*

   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. 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 should be submitted as proof of Authorization to Interconnect.

   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.

3. **Project Cost Affidavit and Breakdown Worksheet** *(All Projects)*

   A signed Project Cost Affidavit and a Project Cost Breakdown Worksheet substantiating the claimed eligible Project cost (as defined in S*ection 3.2.2*).

4. **Final Permits**

   Building Inspection Report *(All Projects)*

A copy of the final building inspection report (or proof of exemption) demonstrating that the Project meets all codes and standards of the permitting jurisdiction. Contact your local permitting jurisdiction to learn about permitting requirements.

Air Permitting Documentation *(Non-Renewable Fuel Only)*

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 (or proof of exemption).

5. **Substantiations:**

New Construction or Added Load *(All Projects)*

For Projects where host customer estimated the future load to justify system size, applications must include documentation demonstrating that the load forecast has materialized.

Renewable Fuel or Waste Energy Resource *(On-site Renewable Fuel and Waste Energy Only)*

For Projects where the host customer, applicant or system owner provided renewable fuel estimates or Waste Energy resource estimates, applications must include documentation demonstrating that the on-site Renewable Fuel or Waste Energy resource has materialized.

Fuel Cleanup Skid Cost Documentation *(On-site Renewable Fuel Only)*

On-site biogas projects must include documentation substantiating the fuel cleanup skid cost.

Renewable Fuel Documentation & Contract Commencement *(Directed Renewable Fuel Only)*

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. Documentation should also be submitted showing that the contract has commenced and the supplier has begun nominating the renewable fuel into the pipeline (e.g. one month fuel invoice). The project will be given up to one year from the date the Incentive Claim was received by the SGIP Program Administrator for commencement of the contract. However, no incentive will be paid until the contract has commenced.

Renewable Fuel Metering Specifications *(Directed Renewable Only)*

Documentation should also be provided to include make, model, specifications and serial number of installed revenue grade electric NGOM and gas meters.

6. **Planned Maintenance Coordination Letter** *(CHP Projects >=200 kW Only)*

When applicable, applications with microturbine, internal combustion engine, gas turbine and steam turbine CHP systems operating on blended fuel sized greater than 200 kW must include a maintenance coordination letter to the host customer's electric utility. The maintenance coordination letter shows the system owner will schedule planned maintenance only between October and March and, if necessary, only during off-peak hours and/or weekends during the months of April to September.

7. **Final Monitoring Schematic** *(for projects that are 30 kW or larger)*

~~A final layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and the location of the proposed metering points, meter IDs, and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.).~~The final monitoring schematic includes an electrical single line diagram (SLD) that includes the generator, the PBI meter, the utility meter, and the load panel. CHP projects must also include a Process and Instrumentation Diagram (P&ID) that shows the configuration of the generator(s), heat recovery system, pumps, heat exchangers, and thermal load equipment as well as the fuel and thermal metering points. Documentation must also be provided if there is a change in the make and model of the meters to be used (from what was submitted with the Proposed Monitoring Plan at the Proof of Project Milestone).

The applicant must also provide the name of the Performance Data Provider (PDP) they are contracting with. A copy of the contract between the PDP and the applicant may be requested at the Program Administrator's discretion.

~~**8. Energy Efficiency Installed Measure Affidavit and/or Non-feasibility documentation for Technology Projects**~~

~~The Energy Efficiency Installed Measure Affidavit acknowledges that all Energy Efficient Measures with a payback period of two years or less have been installed at the project site. If measures with a 2 year payback were not installed a non-feasibility report from the contractor is required.~~

9. PBI Setup Sheet *(for projects 30 kW or larger)*

The PBI setup sheet must include information for all meter(s) installed for the purpose of monitoring system performance. The meter IDs listed on the PBI setup sheet must also match the meter IDs specified on the Final Metering Schematic.

6.11 Metering & Monitoring Requirements for Generation Projects

All SGIP technologies 30 kW or larger must install metering and monitoring equipment that measures net electrical output from the system(s). In addition to electrical output, fuel input metering into the generator(s) is required for all conventional CHP and fuel cell technologies, regardless of fuel type. CHP technologies operating on blended fuels must also install metering and monitoring equipment that measures and reports useful thermal energy delivered to the site from the CHP system.

System owners must install and maintain metering and monitoring equipment at their own cost and are responsible for the choice and installation of the metering hardware. All AC electric meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on http://www.gosolarcalifornia.ca.gov/equipment/index.html.

It is also the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years. PDPs will be tasked with recording performance data from the installed metering and monitoring equipment and submit it to the Program Administrators on a monthly basis.

All installed meters (electrical, thermal and fuel) must fulfill the following requirements:

- 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 and/or logger.
- All meters must have the capability to report their data remotely.
- Data reporting must occur on a daily basis.
- 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.
- All meters must provide the PDP provider or defined list of authorized users with the ability to access and retrieve the minimum required data from the meter using the Meter Communication / Data Transfer Protocols described in *Section 7.1.*
- The meters will be inspected as part of the project inspection process.

The following section details the minimum meter requirements per type of meter installed (electrical, thermal, fuel).

6.11.1 *Minimum Electrical Meter Requirements*

All systems 30 kW and larger 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.

Electrical meters installed on the SGIP project provide data used to assess performance of the system, to analyze impact of the SGIP system on utility distribution systems, the peak system demand of the utility and net GHG emission impacts.

- **Meter Type**

All systems are allowed to use on-board electrical meters, however, the meter must meet the minimum meter requirements of this section. For all systems receiving PBI payments, the installed meter(s) may be a separate Interval Data Recording (IDR) meter(s), or a complete onboard system that is functionally equivalent to an IDR meter, recording data no less frequently than every 15 minutes. 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.

- **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.

- **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.

- **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 meter needs to generate an accurate time/date stamp.

- **Meter Testing and Certification**

± 2% meters required for PBI for AC systems must be tested according to all applicable ANSI C-12 testing protocols pertaining to the monitoring of power (kW) and energy (kWh).The accuracy rating of ±2% meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV). DC electrical meters must also have a ± 2% accuracy pertaining to the monitoring of power (kW) and energy (kWh), by the meter manufacturer.

- **Meter Display**

All meters must provide a display showing the meter's measured net generated energy output or offset and measured instantaneous power. This display must be easy to view and understand and 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.

6.11.2 *Minimum Thermal Metering Requirements*

All CHP systems 30 kW and larger running on blended fuel 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. 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 will also be used to assess impact of the SGIP system on net GHG emission impacts[48] and minimum system operating efficiency requirements.

[48] Thermal energy metering systems may also provide SGIP System Owners with a potential means of verifying carbon emissions and carbon emission reductions.

- **Meter Type**

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 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.

- **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.

- **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.

- **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. The sum of four consecutive intervals would represent the industry standard rate of Useful Heat Recovery 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.

6.11.3 *Minimum Fuel Metering Requirements*

All CHP systems and electric-only Fuel Cells 30 kW and larger and regardless of fuel type or renewable fuel blending percentage 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. In the case of onsite blended fuel projects, the metering system must allow the Program Administrator to determine the amount of renewable and non-renewable fuel consumption. 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.

- **Meter Type**

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. 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.

- **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. For on-site blended fuel projects there must be separate meters for the renewable fuel and the non-renewable fuel. Proposed meter locations shall be identified in a Monitoring Plan developed for each individual project.

- **Meter Accuracy**

Flow measurement must include temperature and pressure compensation and must measure standard cubic feet (at 60 °F and 1 atmosphere) to within $\pm$ 5% of maximum flow for the generator at design conditions. This requirement applies to on-board as well as external fuel metering systems.

- **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 hour. Calculated values must be reported in one hour 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.

7 Metering & Data Collection

This section describes the requirements for data reporting, PDP application process, data security, and measurement and evaluation activities.

7.1 Data Reporting and Transfer Rules – Contract for PDP Services

It is the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years and ensure that performance data is provided to the Program Administrator or their designee monthly for five years. A list of qualified PDPs can be found on the Program Administrators websites.

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 and net electrical energy discharged or offset for energy storage ~~AES~~ systems for incentive payment
- Format data using an approved SGIP format.
- 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

The purpose of the following section is to outline the data reporting requirements (format, delivery method) and schedule for submitting data reports to the Program Administrators.

7.1.1 ***Data Format***

Meter data must conform to the SGIP program requirements as set forth in *Section 5.5* and *Section 6.11* (15-minute electrical and thermal data as well as hourly fuel data, when applicable).

The PDP is responsible for submitting the incoming meter data to the Program Administrators on a monthly basis in the following two formats: Meter Interval Report and Application Interval Report. The Application Interval Report will be used for calculating the Annual Performance Based Incentive payments. The Meter Interval Report will be referenced as needed to support the data submitted for payment processing in the Application Interval Report. Both file types may be used for reporting and/or auditing purposes.[49]

The data file format for submission will be ".csv". The file formats are designed for bulk submission of data for any number of applications in a single calendar month. However, the file types (Meter Interval and Application Interval) must be submitted in separate files. If a Performance Data Provider is contracted to report data for more than one Program Administrator, they shall submit a separate file for each Program Administrator to maintain the confidentiality of the data.

7.1.2 ***Meter Reading and Data Submission Timeline***

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 estimate the meter's 15-minute interval data. For more information, refer to The PDP Specification. 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.

Data for a SGIP project must be submitted in full calendar months. Once a month of data has been collected, the PDP has up until the 1st of the following month to validate, format, and submit the Meter and Application Interval data for that project. Annual PBI Incentive Payment amounts will only be processed after a full year of data has been submitted for the project.

For new SGIP projects, data recording for PBI Payment purposes should typically commence on the 1st of the month following the initial 50% Incentive Payment. Customers may choose to submit data since interconnection, if interconnection has occurred within the past 6 months. Any request for an alternate data collection commencement date will require Program Administrator approval.

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[49] For a detailed description of the Meter and Application Interval Reports and submittal processes, please refer to The PDP Specification.

7.1.3 *Online Submission Process*

All performance data will be submitted via the SGIP online application database PDP Upload Portal. The portal will be accessed through www.selfgenca.com. Files that are submitted via e-mail will not be accepted.[50]

7.1.4 *PDP Data Validation*

The PDP must validate all data prior to submitting it to the PAs. 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
- Spike Check
- kVARh Check

Descriptions of these validation rules are included in The PDP Specification.

7.1.5 *Data Audits & Payment Validation*

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 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 System Owner 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.

[50] Please refer to The PDP Specification for a detailed description of the data submittal process.

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.

7.1.6 ***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. 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.

7.1.7 ***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 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
- Data not validated in accordance with program requirements
- Estimated data posted instead of actual data
- Meter change information not reported within 30 days of the meter change.
- If an audit or investigation shows a discrepancy of $\pm$ 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.

Upon receipt of a non-performance notice from the PA, 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.

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 production data from the Performance Data Providers (PDP) to the Program Administrators. The System Owner is responsible for resolving any issues relative to PBI and PDP performance data.

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.

7.1.8 ***Data Retention***

Monthly performance data must be retained in accordance with 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.

7.1.9 ***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.

7.1.10 ***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.

7.2 PDP Application Process

Any entity may choose to become a Performance Data Provider for the SGIP. Providers interested in becoming a PDP for the SGIP must submit information detailing their qualifications to become a PDP for the program. All PDPs must meet the requirements established herein in addition to the requirements set forth in the other metering sections of the SGIP Handbook. Interested parties may apply to qualify as a PDP for the SGIP program at any point in time.

To apply to qualify as a PDP, the Applicant completes the SGIP PDP Application and provides all documentation in the attached questionnaire[51]. Note that the PDP Applicant may submit one application for statewide PDP services to any of the Program Administrators. The Program Administrator will review the submitted documentation, determine if the PDP Applicant meets the program requirements and send the PDP Applicant a conditional approval letter if all requirements are met. Upon conditional PDP approval, the Applicant may contact the SGIP online application database provider to set up an account for the PDP Upload Portal.

7.2.1 *Data Transfer Test*

Once the prospective PDP has accumulated a month worth of data for the first SGIP project they must contact the SGIP online application database provider to schedule a data transfer test. The prospective PDP must create, format and validate Application Interval and Meter Interval Reports for all types of data services they are applying for (electrical, thermal and fuel, and/or energy storage ~~AES~~) and submit the test files to the SGIP online application database via the PDP Upload Portal.

The Program Administrator will check the test files to ensure they comply with the SGIP guidelines. If the PDP Applicant fails the data transfer test and report approval, they will be given 2 weeks to resolve any technical or data format issues. Upon successful completion of the PDP data test procedures, the PDP will receive a final approval notice and will be qualified to provide PBI data to the Program Administrator for incentive payment.

7.3 Data Privacy and Security

Protecting the privacy of System Owners and Host Customer is of the highest order. As such, data shall be collected, processed, and reported by the PDP to the System Owner and the Program Administrator in accordance with this section. 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. The PDP must also follow all applicable state and federal privacy and data security laws.

[51] Please refer to The PDP Specification and the Program Administrators' websites for the PDP Application and detailed application instructions.

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. Electricity, thermal and 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 physically secure location and include strong password protection with either a network firewall or encrypted connection 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.

7.4 Measurement & 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 system equipment and participate in Measurement and Evaluation (M&E) activities as required by the CPUC for five-years. M&E activities will be performed by the Program Administrator (PA) or the PA'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 PA. This data will be used 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.

7.4.1 *M&E Field Visits*

During the course of the Project, the PA or the PA's independent third-party consultant may require one or more visits to the Site for M&E purposes. These site visits can occur before, during or after startup of the 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 by the PA or its consultants (*see Section 2.5.3*), which are used to determine eligibility of the installed system and occur during the Incentive Claim stage of the application process.

7.4.2 *M&E Metering Requirements*

All SGIP systems require installation of metering devices to measure and record electrical output or offset, waste heat, and fuel consumption for M&E purposes. For installations 30kW and larger, the PAs may collect this information from the data submitted by the Performance Data Providers (PDP) for PBI payment purposes. For projects under 30kW, the PA or the PA's independent third-party consultant may install meters to collect M&E data at the Program's expense.

The Host Customer and System Owner agree to provide system monitoring data (15-minute interval data for electrical and thermal and hourly for fuel consumption) to the SGIP M&E consultant on a monthly basis for the duration of five years.

7.4.3 *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 installed by the Program 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. Dispute Resolution and Infractions

8 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 the Program Administrator or his or her designated representative and the Host Customer, System Owner and/or Applicant or their designees. 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 parties shall meet, and 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. 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.

9 Participant Performance and Infractions

9.1 Participant Performance

All participants[52] are expected to follow program rules and eligibility requirements. Failure to do so will result in warnings and/or infractions. Please see *Section 9.2* for additional information regarding warnings and infractions. Program Administrators will exercise their judgment in issuing warnings and assessing infractions. In an effort to ensure participant performance, all participants will be required to maintain a high level of performance in each of the following categories:

- Application
- Inspection
- Attrition and Extensions
- Data Reporting
- SGIP Online Application Database Operation
- Developer

9.1.1 *Application*

Applications must be submitted with complete and accurate documentation and must meet all deadlines. Applications with incomplete, falsified, or inaccurate documentation[53] or that do not meet required due dates may receive warnings and/or result in an infraction.

9.1.2 *Inspection*

All projects may be inspected at any time during project's permanency period and are expected to meet document and operational requirements of the program. Failure to do so will count as a failed inspection. Participants with a high statewide inspection failure rate may forfeit future participation and/or all active applications/incentive.

9.1.3 *Attrition and Extensions*

Participants are expected to submit committed projects. Cancelled withdrawn applications will be counted towards attrition rate. Participants with a high attrition rate may forfeit future participation and/or all active applications/incentives.

Participants are also expected to meet project milestone due dates as originally assigned. Excessive extension requests among a participant's applications may receive warnings and/or result in an infraction.

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[52] For the purpose of this section, participant is defined by an entity or group of entities submitting applications, data, or developing and/or installing SGIP projects.

[53] Including criteria that would grant higher priority in the event of a lottery.

9.1.4 *Data Reporting*

Participants are required to submit all necessary operational and performance data. Participants submitting data past their designated due date may receive warnings. Participants that do not submit data at all for their projects may be subject to an infraction. Any falsified or blank submissions will result in an automatic infraction.

9.1.5 *SGIP Online Application Database Operation*

Participants are required to comply with the Terms of Use of the SGIP database for all accounts, applications, and PBI data submissions. Non-compliance with the Terms of Use or attempting to circumvent the SGIP database application policies or procedures will result in an automatic infraction.

9.1.6 *Developer*

An infraction may be issued if the Developer of a project does not fully and/or accurately disclose Developer and ownership information as listed in *Section 4.1.5*.

9.2 Infractions

Infractions are any actions that circumvent program policy or requirements, or have the intent to do so, in addition to low performance levels. Infractions can be issued to any participant, as defined in *Section 4.1.* The Program Administrators will evaluate program infractions, ~~exercise their judgment in assessing~~ which may include gross negligence or intentional submission of inaccurate project information~~ in an attempt to collect more incentive dollars.~~. Program infractions may be determined at any stage of the SGIP process and are applicable statewide. 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. The sanction maybe applicable to all parties involved in the project and is not limited to the Host Customer~~. The following sanctions may be applied:

- Suspension or expulsion from future program participation
- Cancellation of existing projects
- Application fee forfeiture
- Fiscal or programmatic audit

9.2.1 *Issuance of Warnings and Infractions*

If a Program Administrator determines that an infraction may be warranted, a notice will be sent to the violating participant. Participants may be issued one or more warnings before being issued an infraction; however, serious violations may result in an immediate infraction. Participants may receive no more than three warnings before an infraction is issued. Infractions will be reviewed by all SGIP Program Administrators and will be communicated to the participant.

Definitions and Glossary

~~**Advanced Energy Storage:** Technologies able to store energy that can be discharged as useful energy at another time in order to directly supply electricity or offset electricity consumption. Unless specified otherwise, AES in the SGIP Handbook applies to all eligible storage technologies, including mechanical, chemical, or thermal energy storage.~~

~~**AES:** Advanced Energy Storage~~

Amp-hour Capacity or Nominal Capacity (Ah for a specific C-rate): The total Amp-hours available when the battery is discharged at a continuous current over a specified period of time (specified as a C-rate) from 100 percent state-of-charge to a specified cut-off voltage.

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. Functions as the main point of communication between the SGIP Program Administrator for a specific SGIP Application.

Application Interval Report: Monthly meter data report provided by the Performance Data Provider (PDP). The Application Interval Report format will be the same for all PDPs and all Applications as specified by the Program Administrators. The data in this file will be will be validated upon upload and used for the calculation of Annual PBI payments. An Entry in this file shall represent the combined data readings of all meters associated with a particular SGIP Application Code.

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.

Blended Fuel: A blended fuel is a combination of any renewable fuel with a non-renewable fuel and where the amount of renewable fuel is less than 100%. Projects using less than 100% of an eligible renewable fuel will be identified as a blended project equivalent to their renewable fuel percentage.

California Manufacturer ~~Supplier~~: A California Manufacturer operates a manufacturing facility in California, is licensed to conduct business in California and is registered with a primary or secondary manufacturing NAICS code. Equipment is deemed to be manufactured in California if at least 50% of the value of the capital equipment has been made in a dedicated production line by an approved California Manufacturer.~~ Is any sole proprietorship, partnership, joint venture, corporation, or other business entity that manufactures eligible distributed generation technologies in California and that meets the criteria outlined in Handbook *Section 3.1.1*~~

CSE: Center for Sustainable Energy™

CEC: California Energy Commission

~~**Coupled:** Two technologies paired with each other and considered together on the same electrical circuit. For example, AES coupled with an eligible generating system; the energy from the generating system is used to charge the Advanced Energy Storage (AES).~~

CPUC: California Public Utilities Commission

Developer: A Developer is the corporate entity that holds the contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement) with the host customer and handles the project's development activities.

Directed ~~Biogas~~: A directed renewable fuel is produced and captured at a different location than the project site of the electrical generation facility. The renewable fuel is delivered to the facility through a common carrier pipeline, which must be demonstrated through a procurement contract. A directed renewable fuel must be injected into a common carrier pipeline system that is either within the Western Electricity Coordinating Council (WECC) region or interconnected to a common carrier pipeline system located within the WECC region. ~~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.

Energy Capacity or Nominal Energy for DC/AC systems (Wh (for a specific C-rate)): The total watt-hours available when a storage system is discharged at a continuous current over a specified period of time (specified as a C-rate) from 100 percent state-of-charge to the cut-off voltage.

Energy Storage: Technologies able to store energy that can be discharged as useful energy at another time in order to directly supply electricity or offset electricity consumption. Unless specified otherwise, "energy storage" in the SGIP Handbook applies to all eligible storage technologies, including mechanical, electrochemical, or thermal energy storage.

Energy Storage Paired with and Charging from an On-site Renewable Generator: Energy storage system that is paired with an on-site generator and charges at a minimum 75% from the generator.

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.

Fuel Cell: Power plants that produce electricity through an electrochemical reaction with a fuel source.

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

HVAC-integrated S-TES: Small thermal energy storage systems integrated to offset peak energy consumption of direct expansion refrigerant based air conditioning units less than or equal to 20 tons.

~~**Hybrid Project:** Project on a Site that includes two or more different technologies. A separate application is required for each technology.~~

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, SoCal Gas 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.

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

ITC: Investment Tax Credit

Meter Interval Report: Monthly meter data report provided by the Performance Data Provider (PDP). The Meter Interval Report format will vary by PDP. The PDPs shall format their report so that it includes all meter and sensor data recorded over the measured interval at a minimum 15-minute frequency, with the exception of Fuel Consumption, which shall be measured and reported hourly. This report should be formatted as specified by SGIP program requirements. ~~(see Appendix – ES spec).~~

Non-Renewable Fuel: A non-renewable fuel includes fossil fuels and synthetic fuels. Synthetic fuels are fuels derived from materials that are not renewable or fossil fuels. SGIP eligible fossil fuels are gasoline, natural gas and propane. SGIP eligible synthetic fuels include, but are not limited to, the direct use or synthesis of fuels sewage sludge, industrial waste, medical waste or hazardous waste. ~~Includes fossil fuels and synthetic fuels not generated from a renewable resource.~~

On-Site: An on-site renewable fuel is produced and captured at the same location as the site of the electrical generation facility. Additionally, the renewable fuel is delivered from the source to the generating system via a dedicated pipeline. A dedicated pipeline is defined as only physically capable of delivering gas to the generating facility.

Paired: Two or more technologies located on the same electrical circuit and behind the same utility electrical meter.

Parallel Operation: The simultaneous operation of a self-generator with power delivered to 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 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.

Pressure Reduction Turbine: If a facility with a high pressure fluid (e.g., steam, water, natural gas, etc.) distribution network and pressure reduction valve(s), installs a turbine to replace or operate in parallel with these pressure reduction valve(s), then the application is considered a Pressure Reduction Turbine.

Program Year: January 1 through December 31.

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

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.[54]

Refrigeration TES: Thermal energy storage systems integrated to offset peak energy consumption of direct expansion refrigerant-based refrigeration systems.

Renewable Fuel: A renewable fuel is a non-fossil fuel categorized as one of the following: biodiesel or gas derived from digester gas, landfill gas or biomass. SGIP projects can use one or more eligible renewable energy sources, as identified by the Renewable Portfolio Standard (RPS). ~~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.

Round Trip Efficiency: Ratio of the energy delivered during discharge of the energy storage system to the energy required to charge the energy storage system.

SCE: Southern California Edison

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

SDG&E: San Diego Gas and Electric

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

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

SoCalGas: Southern California Gas Company

Stand-alone Energy Storage ~~AES~~: An energy storage ~~AES~~ system located on a Host Customer project site that does not also host a generating technology.

Steam Turbine CHP: If a facility with a steam distribution network installs a steam turbine that is placed between the boiler and the steam distribution network, and steam pressure is increased, then the application is considered a Steam Turbine CHP. Pressure can be increased either through the purchase of new boilers or by increasing the pressure on existing boilers. In either case, boiler fuel usage per unit of steam production increases with boiler pressure.

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

TES: Thermal Energy Storage

Thermal Energy Storage: Technologies able to store energy and discharge it at a later time as thermal energy to offset electricity consumption.

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

Waste Heat to Power: If a facility discarding heat as a result of commercial or industrial processes installs a turbine driven by the discarded heat, then the application is considered a Waste Heat to Power system. These systems typically involve a heat recovery system, which transfers the waste heat to a working fluid which drives the turbine.

Legislation and Regulatory Background

Date	Bill Number	Description
9/6/2000	AB 970	Assembly Bill required the CPUC to initiate load control and distributed generation activities.
3/27/2001	D 01-03- 073	CPUC Decision complying with Assembly Bill 970 and establishing the Self Generation Incentive Program. Implementation of PU Code Section 399.15(b), Paragraph 4-7; Load Control and Distributed Generation Initiatives.
06/01/2001	D. 01-06-035	CPUC Decision establishing waste heat recovery standards for SGIP. Requires Energy Branch to develop reliability criteria.
01/18/2002	Letter on Reliability Criteria	CPUC Energy Branch Letter establishing reliability criteria requirements for level 3 technology applications received after January 1, 2002
02/07/2002	D. 02-02-26	CPUC Decision addressing eligibility of customers served by electric municipalities, maximum size and annual program budget.
04/04/2002	D. 02-04-004	CPUC Decision clarifying Applicant's ability to receive incentive funding from multiple sources. Addressing SCAQMD's PTM of Decision 01-03-073
09/19/2002	D. 02-09-051	CPUC Decision adding technology level 3-R, which establishes a new level of incentives. Contains specific requirements for projects using renewable fuels for level 3-R. Addressing Capstone's PTM
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 2267	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.

Date	Bill Number	Description
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.

09/08/2011	CPUC D.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 CO_2/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 rates 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 30 kW and larger. 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

Date	Bill Number	Description
		• Limits all projects to one six month extension. Request for a second extension may be made to the Working Group. Extends the warranty period to 10 years
	ADVICE LETTER 4410-G	ADVICE LETTER COMPLYING WITH RESOLUTION E-4519Proposed Amendments to the Self-Generation Incentive Program Handbook to Conform to Resolution E-4519. Changes to the RTE for AES technologies and elimination of certain data formatting requirements for PDP providers
	ADVICE LETTER No. 3253-G/3940 –E	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.
	ADVICE LETTER No 3253-G-A/3940–E-A	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
5/24/2012	Decision 12-05-037	• Orders that all technologies previously eligible for the Emerging Renewables Program should be immediately eligible for the SGIP Determines that consolidating the ERP and SGIP programs now is preferable to perpetuating two competing programs that serve the same types of technologies and policy purposes

Date	Bill Number	Description
5/20/2014	SB 861	• Extended SGIP funding through 2019 and extended SGIP administration until January 1, 2021 • Directed the Commission to update the factor for avoided greenhouse gas emissions based on the most recent data available to the State Air Resources Board • Established eligibility requirements for distributed technologies that: reduce demand from the grid by offsetting some or all of the customer's onsite load, are commercially available, safely utilize the existing T&D system, and improve air quality by reducing criteria air pollutants • Specified that SGIP incentive recipients are subject to data collection and site inspections upon request • Directed the Commission to develop a capacity factor for each technology in the SGIP • Directed the Commission to consider the cost of greenhouse gas emissions reductions, peak demand reductions, system reliability benefits, and other measurable factors when allocating program funds between eligible technologies • Change the California supplier requirement to "manufactured in California" • Specified that the SGIP will be evaluated on the following performance measures: reductions of GHGs, reductions of air pollutants, amount of energy reductions measured in energy value, reductions of customer peak demand, capacity factor, value to T&D system measured in avoided cost of upgrades and replacement, ability to improve onsite electricity reliability
09/27/2014	AB 1478	• Clarified that eligible technologies can shift onsite energy use to off-peak times
12/18/2014	Decision 14-12-033	• Decision authorizing Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company to continue to collect funds for the Self-Generation Incentive Program pursuant to Public Utilities Code Section 379.6 as amended by Senate Bill 861
	ADVICE LETTER 47-A	• Advice Letter to propose modifications to the SGIP Handbook to include revised capacity rating methodologies for Pressure Reduction Turbine (PRT) and Waste Heat to Power (WHP) technologies • Included conventional topping cycle Steam Turbines in the program.

Date	Bill Number	Description
6/11/2015	Resolution E-4717	• Approval of Advice Letter No. PGE 3552-G/4563-E, CSE 55, SCE 3165-E, SCG 4741, filed January 20, 2015, to incorporate Residential AES Operational Requirements Affidavit into the SGIP Handbook.
6/11/2015	D.15-06-002	• Approval of Program Administrator's Petition for Modification to allow a maximum of three six-month extensions, filed November 13, 2014.
7/1/2015	Advice Letter No. CSE 60, PG&E 4663-E, SCE 3242-E, SCG 4828.	• Compliance Advice Letter to incorporate third six-month extension into the SGIP Handbook.
7/17/2015	Disposition Letter for Advice Letter CSE 56	• Approval of CSE Advice Letter 56, filed on February 17, 2015, to incorporate kW, kWh offset methodologies, and other associated changes for HVAC-Integrated Small TES systems.
11/19/2015	D.15-11-027	• Decision Revising the GHG Emissions Factor to Determine Eligibility to Participate in the SGIP. • GHG Emissions Factor revised to 350 kg $CO2_2$/MWh averaged over 10 years for non-renewable generation technologies. • For technologies that are subject to a 1% annual degradation rate, the fFirst-year GHG Emissions Factor for Electric-Only Fuel Cellsis set at 334 kg $CO2_2$/MWh., assuming a 1% annual degradation rate. • Storage devices should demonstrate an average round trip efficiency of at least 66.5% over ten years to qualify for SGIP, which is equivalent to a first-year round trip efficiency of 69.6%.
12/16/2015	Advice Letter No. CSE 66, PG&E 4759-E, SCE 3327-E, SCG 4904	• Advice Letter to incorporate kW, kWh offset methodology and other associated changes for refrigeration TES. • Advice Letter became effective January 15, 2016.
12/17/2016	D.15-12-027	• Decision Partially Suspending Disbursement of 2016 Program Year Funds and Acceptance of New Applications for the Self-Generation Incentive Program. • Half of 2016's program year funds are available to fund new applications at the beginning of the year. • The PAs shall not disburse any additional funds authorized for program year 2016 until further ordered by the Commission.
12/21/2015	Advice Letter No. PG&E 3663-G/4763-E, CSE 67, SCE 3331-E, SCG 4907	• Compliance Advice Letter incorporating the GHG Emissions Factor from D.15-11-027 into the SGIP Handbook. • Advice Letter became effective January 1, 2016.
6/23/2016	D. 16-06-055	• Decision Revising the SGIP Pursuant to SB 861, AB 1478, and Implementing Other Changes

Date	Bill Number	Description
		• Divided SGIP budget 75% storage, 25% generation • Created renewable and small residential storage carve outs. • Revised incentive rates for all SGIP technologies. • Made several substantial changes to the SGIP. • Resolved several petitions for modifications regarding Distributed Wind Energy Association, pressure reduction turbines and biogas incentive, PowerTree's request to extent deadlines, and Maas Energy's request to investigate the February 23, 2016 program opening.

Appendix A - System Calculation Example

Efficiency Calculations

Example #1: 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.

Appendix B – Combustion Emission Credit Calculation

Micro-turbine, internal combustion engine, gas Turbine and steam turbine CHP 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: [55]

$Lb/MWh_{w/credit} = Lb/hr_{EmissionRate} / (MW_{Rated} + MW_{ProcessHeat})$ ≡ 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 6.1.5*.

$MW_{ProcessHeat} = (MMBtu/yr_{UtilizedWasteHeat} / 3.4\ MMBtu/MWh) / EFLH/yr$ ≡ 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[56]) 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

55 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.

[56] For natural gas, LHV ≈ HHV x 0.9

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

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/brake horsepower-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 effect 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) $= \dfrac{\text{volume of pollutant (Vp)}}{\text{volume of exhaust (Ve)}} \times 10$

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[57]

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

Lean-burn Engines, natural gas fueled[58]

Pollutant	Factor
NOx	80
VOC	212
CO	123

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

[58] Factors provided from Waukesha

GM/Bhp-hr to Lb/MW-hr

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%

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

Appendix D – Conversion Tables for HVAC-Integrated S-TES

Before 1984	kW Offset Table with Source Multiplier of 1.															
8 SEER	Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	1.0	1.6	2.3	3.5	4.2	4.8	6.1	7.3	8.6	9.2	10.5	11.1	12.4	15.5	18.7	25.0
2	1.4	2.3	3.1	4.8	5.6	6.5	8.2	9.8	11.5	12.4	14.1	14.9	16.6	20.8	25.0	33.4
3	1.3	2.1	2.9	4.5	5.3	6.0	7.6	9.2	10.8	11.5	13.1	13.9	15.5	19.4	23.3	31.2
4	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.5	11.1	11.9	13.5	14.3	15.9	20.0	24.0	32.1
5	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.4	11.0	11.8	13.4	14.2	15.8	19.8	23.8	31.8
6	1.4	2.2	3.0	4.7	5.5	6.3	7.9	9.6	11.2	12.0	13.7	14.5	16.1	20.2	24.3	32.5
7	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.1	13.8	14.6	16.3	20.4	24.5	32.8
8	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.1	13.8	14.6	16.3	20.4	24.5	32.8
9	1.4	2.2	3.0	4.7	5.5	6.3	7.9	9.6	11.2	12.0	13.7	14.5	16.1	20.2	24.3	32.5
10	1.5	2.3	3.2	4.9	5.8	6.7	8.4	10.1	11.9	12.7	14.5	15.3	17.1	21.4	25.7	34.4
11	1.5	2.4	3.3	5.1	6.0	6.9	8.6	10.4	12.2	13.1	14.9	15.7	17.5	22.0	26.4	35.3
12	1.4	2.3	3.1	4.8	5.7	6.5	8.2	9.9	11.6	12.5	14.2	15.0	16.7	21.0	25.2	33.7
13	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.1	13.8	14.6	16.3	20.4	24.5	32.8
14	1.5	2.3	3.2	4.9	5.8	6.7	8.4	10.1	11.9	12.7	14.5	15.3	17.1	21.4	25.7	34.4
15	1.6	2.5	3.4	5.2	6.1	7.0	8.9	10.7	12.5	13.4	15.3	16.2	18.0	22.5	27.1	36.2
16	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.5	11.1	11.9	13.5	14.3	15.9	20.0	24.0	32.1

1984 - 1991	kW Offset Table with Source Multiplier of 1.															
8.9 SEER	Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.9	1.5	2.0	3.2	3.8	4.3	5.5	6.6	7.8	8.3	9.5	10.1	11.2	14.1	16.9	22.7
2	1.3	2.0	2.8	4.3	5.1	5.9	7.4	8.9	10.4	11.2	12.7	13.5	15.0	18.9	22.7	30.3
3	1.2	1.9	2.6	4.0	4.7	5.5	6.9	8.3	9.7	10.5	11.9	12.6	14.0	17.6	21.2	28.3
4	1.2	2.0	2.7	4.2	4.9	5.6	7.1	8.6	10.0	10.8	12.2	13.0	14.5	18.1	21.8	29.2
5	1.2	1.9	2.7	4.1	4.8	5.6	7.0	8.5	9.9	10.7	12.1	12.9	14.3	18.0	21.6	28.9
6	1.2	2.0	2.7	4.2	4.9	5.7	7.2	8.7	10.1	10.9	12.4	13.1	14.6	18.3	22.0	29.4
7	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.5	22.2	29.7
8	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.5	22.2	29.7
9	1.2	2.0	2.7	4.2	4.9	5.7	7.2	8.7	10.1	10.9	12.4	13.1	14.6	18.3	22.0	29.4
10	1.3	2.1	2.9	4.5	5.2	6.0	7.6	9.2	10.7	11.5	13.1	13.9	15.5	19.4	23.3	31.2
11	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.4	11.0	11.9	13.5	14.3	15.9	19.9	24.0	32.0
12	1.3	2.1	2.8	4.4	5.1	5.9	7.5	9.0	10.5	11.3	12.9	13.6	15.2	19.0	22.9	30.6
13	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.5	22.2	29.7
14	1.3	2.1	2.9	4.5	5.2	6.0	7.6	9.2	10.7	11.5	13.1	13.9	15.5	19.4	23.3	31.2
15	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.2	13.8	14.7	16.3	20.4	24.6	32.9
16	1.2	2.0	2.7	4.2	4.9	5.6	7.1	8.6	10.0	10.8	12.2	13.0	14.5	18.1	21.8	29.2

1992 - 2005	kW Offset Table with Source Multiplier of 1.															
9.7 SEER	Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.8	1.3	1.9	2.9	3.5	4.0	5.1	6.1	7.2	7.7	8.8	9.3	10.4	13.0	15.7	21.0
2	1.2	1.9	2.6	4.0	4.7	5.4	6.8	8.2	9.7	10.4	11.8	12.5	13.9	17.4	21.0	28.1
3	1.1	1.7	2.4	3.7	4.4	5.0	6.4	7.7	9.0	9.7	11.0	11.7	13.0	16.3	19.6	26.2
4	1.1	1.8	2.5	3.8	4.5	5.2	6.6	7.9	9.3	10.0	11.3	12.0	13.4	16.8	20.2	27.0
5	1.1	1.8	2.4	3.8	4.5	5.1	6.5	7.8	9.2	9.9	11.2	11.9	13.2	16.6	20.0	26.7
6	1.1	1.8	2.5	3.9	4.6	5.3	6.6	8.0	9.4	10.1	11.4	12.1	13.5	16.9	20.4	27.3
7	1.1	1.8	2.5	3.9	4.6	5.3	6.7	8.1	9.5	10.2	11.6	12.2	13.6	17.1	20.6	27.5
8	1.1	1.8	2.5	3.9	4.6	5.3	6.7	8.1	9.5	10.2	11.6	12.2	13.6	17.1	20.6	27.5
9	1.1	1.8	2.5	3.9	4.6	5.3	6.6	8.0	9.4	10.1	11.4	12.1	13.5	16.9	20.4	27.3
10	1.2	1.9	2.7	4.1	4.8	5.6	7.0	8.5	9.9	10.7	12.1	12.8	14.3	17.9	21.6	28.9
11	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.4	22.2	29.6
12	1.2	1.9	2.6	4.0	4.8	5.5	6.9	8.3	9.8	10.5	11.9	12.6	14.0	17.6	21.2	28.3
13	1.1	1.8	2.5	3.9	4.6	5.3	6.7	8.1	9.5	10.2	11.6	12.2	13.6	17.1	20.6	27.5
14	1.2	1.9	2.7	4.1	4.8	5.6	7.0	8.5	9.9	10.7	12.1	12.8	14.3	17.9	21.6	28.9
15	1.3	2.1	2.8	4.4	5.1	5.9	7.4	9.0	10.5	11.3	12.8	13.6	15.1	18.9	22.8	30.4
16	1.1	1.8	2.5	3.8	4.5	5.2	6.6	7.9	9.3	10.0	11.3	12.0	13.4	16.8	20.2	27.0

2006-2009	kW Offset Table with Source Multiplier of 1.															
12 SEER	Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.6	1.1	1.5	2.4	2.8	3.3	4.2	5.1	5.9	6.4	7.3	7.7	8.6	10.8	13.0	17.4
2	0.9	1.5	2.1	3.3	3.9	4.5	5.6	6.8	8.0	8.6	9.8	10.4	11.5	14.5	17.4	23.3
3	0.9	1.4	2.0	3.1	3.6	4.2	5.3	6.4	7.5	8.0	9.1	9.7	10.8	13.5	16.3	21.8
4	0.9	1.5	2.0	3.2	3.7	4.3	5.4	6.6	7.7	8.3	9.4	10.0	11.1	13.9	16.8	22.5
5	0.9	1.4	2.0	3.1	3.7	4.2	5.4	6.5	7.6	8.2	9.3	9.9	11.0	13.8	16.6	22.2
6	0.9	1.5	2.0	3.2	3.8	4.3	5.5	6.6	7.8	8.3	9.5	10.1	11.2	14.1	16.9	22.7
7	0.9	1.5	2.1	3.2	3.8	4.4	5.5	6.7	7.9	8.4	9.6	10.2	11.3	14.2	17.1	22.9
8	0.9	1.5	2.1	3.2	3.8	4.4	5.5	6.7	7.9	8.4	9.6	10.2	11.3	14.2	17.1	22.9
9	0.9	1.5	2.0	3.2	3.8	4.3	5.5	6.6	7.8	8.3	9.5	10.1	11.2	14.1	16.9	22.7
10	1.0	1.6	2.2	3.4	4.0	4.6	5.8	7.0	8.2	8.8	10.1	10.7	11.9	14.9	17.9	24.0
11	1.0	1.6	2.2	3.5	4.1	4.7	6.0	7.2	8.5	9.1	10.3	11.0	12.2	15.3	18.4	24.7
12	0.9	1.5	2.1	3.3	3.9	4.5	5.7	6.9	8.1	8.7	9.9	10.5	11.7	14.6	17.6	23.6
13	0.9	1.5	2.1	3.2	3.8	4.4	5.5	6.7	7.9	8.4	9.6	10.2	11.3	14.2	17.1	22.9
14	1.0	1.6	2.2	3.4	4.0	4.6	5.8	7.0	8.2	8.8	10.1	10.7	11.9	14.9	17.9	24.0
15	1.0	1.7	2.3	3.6	4.2	4.9	6.1	7.4	8.7	9.3	10.6	11.3	12.5	15.7	18.9	25.3
16	0.9	1.5	2.0	3.2	3.7	4.3	5.4	6.6	7.7	8.3	9.4	10.0	11.1	13.9	16.8	22.5

2010-2014	kW Offset Table with Source Multiplier of 1.															
13 SEER	Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.4	0.8	1.1	1.8	2.1	2.4	3.1	3.8	4.4	4.8	5.5	5.8	6.5	8.1	9.8	13.2
2	0.6	1.1	1.5	2.4	2.9	3.3	4.2	5.1	6.0	6.5	7.4	7.8	8.7	10.9	13.2	17.6
3	0.6	1.0	1.4	2.3	2.7	3.1	3.9	4.8	5.6	6.0	6.9	7.3	8.1	10.2	12.3	16.5
4	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0
5	0.6	1.0	1.5	2.3	2.7	3.2	4.0	4.9	5.7	6.1	7.0	7.4	8.3	10.4	12.5	16.8
6	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
7	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
8	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
9	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
10	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
11	0.7	1.2	1.6	2.6	3.1	3.5	4.5	5.4	6.4	6.8	7.8	8.3	9.2	11.6	13.9	18.6
12	0.7	1.1	1.6	2.5	2.9	3.4	4.3	5.2	6.1	6.5	7.4	7.9	8.8	11.0	13.3	17.8
13	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
14	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
15	0.7	1.2	1.7	2.7	3.1	3.6	4.6	5.6	6.5	7.0	8.0	8.5	9.4	11.9	14.3	19.1
16	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0

6/2014 After	kW Offset Table with Source Multiplier of 1.															
14 SEER	Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.4	0.8	1.1	1.8	2.1	2.4	3.1	3.8	4.4	4.8	5.5	5.8	6.5	8.1	9.8	13.2
2	0.6	1.1	1.5	2.4	2.9	3.3	4.2	5.1	6.0	6.5	7.4	7.8	8.7	10.9	13.2	17.6
3	0.6	1.0	1.4	2.3	2.7	3.1	3.9	4.8	5.6	6.0	6.9	7.3	8.1	10.2	12.3	16.5
4	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0
5	0.6	1.0	1.5	2.3	2.7	3.2	4.0	4.9	5.7	6.1	7.0	7.4	8.3	10.4	12.5	16.8
6	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
7	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
8	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
9	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
10	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
11	0.7	1.2	1.6	2.6	3.1	3.5	4.5	5.4	6.4	6.8	7.8	8.3	9.2	11.6	13.9	18.6
12	0.7	1.1	1.6	2.5	2.9	3.4	4.3	5.2	6.1	6.5	7.4	7.9	8.8	11.0	13.3	17.8
13	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
14	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
15	0.7	1.2	1.7	2.7	3.1	3.6	4.6	5.6	6.5	7.0	8.0	8.5	9.4	11.9	14.3	19.1
16	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0

Appendix E – Updates to the GHG Emissions Factor Section 379.6(b)(2) as Amended by Senate Bill 861

SGIP GHG Emissions Eligibility Factor – The Equation

We find that to calculate the GHG emissions eligibility factor, it is reasonable to use the following equation:

GHG EF = (0.5(EROLF * (1 – WFP) + EROP* WFP) + 0.5 *
(1-RPS% * (1 – LLF)) * (ERBLF* (1 – WFP) + ERBP * WFP))/(1 – LLF)

Where:

GHG EF = greenhouse gas emission factor

EROLF = operating margin emission rate of load-following plants = 382 kgCO2/MWh

WFP = weighting factor for peaker plants = 10%

EROP = operating margin emission rate of peaking plants = 544 kgCO2/MWh

RPS% = average RPS portfolio requirement for the program year (i.e., project years 6 – 10)

ERBLF = build margin emission rate of load-following plants = 368 kgCO2/MWh

ERBP = build margin emission rate of peaking plants = 524 kgCO2/MWh

LLF = line loss factor = 8.4%

Substituting the adopted values for Program Year 2016 into this equation yields:

GHG EF = (0.5 (382 kgCO2/MWh * (1 – 0.10) + 544 kgCO2/MWh * 0.10) + 0.5
(1-0.40 * (1 – 0.084)) * (368 kgCO2/MWh * (1 – 0.10) + 524 kgCO2/MWh *
0.10))/(1 – 0.084)

GHG EF = 350 kgCO2/MWh

Share of Avoided Renewables in Calculating SGIP GHG Emissions Eligibility Threshold

Assumed RPS Targets 2020 – 2030, with and without Line Loss Adjustments

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Nominal RPS	33.0 %	34.8 %	36.5 %	38.3 %	40.0 %	41.7 %	43.3 %	45.0 %	46.7 %	48.3 %	50.0 %
Adjusted RPS	30.2 %	31.8 %	33.4 %	35.0 %	36.6 %	38.2 %	39.7 %	41.2 %	42.8 %	44.2 %	45.8 %

Note: The adjusted RPS is calculated as the product of the nominal percentage and (1 – the line loss factor)

Average Share of Avoided Renewable Energy in Build Margin by Program Year

Program Year	2016	2017	2018	2019	2020
Build Margin RPS, Nominal	40.0%	41.7%	43.3%	45.0%	46.7%
Build Margin RPS, Adjusted for line losses	36.6%	38.2%	39.7%	41.2%	42.7%

Note: The build margin for each program year is the simple average of the RPS percentages for years 6 – 10 after the program year. For example, the program year 2016 average share of renewable energy avoided equals the average of the RPS targets for 2022 through 2026.

SGIP GHG Eligibility Emissions Factors, kgCO2/MWh

Program Year	2016	2017	2018	2019	2020
10-Year Average	350	347	344	340	337
First-Year Average	334	332	329	325	321

Calculation of Minimum Round-Trip Efficiency

Line Loss On Peak	10.3%				
Line Loss Off Peak	5.3%				
Degradation Rate	1.0%				
First Year RTE	69.6%				
Ten-Year Avg RTE	66.5%				
Sum of Ann'l GHGs	0				

Year	Off-peak ER	On-peak ER	GHG emitted	GHG avoided	Net GHG per MWh
1	382	544	580	606	-27
2	382	544	585	606	-21
3	382	544	591	606	-15
4	382	544	597	606	-9
5	382	544	603	606	-3
6	368	524	587	584	3
7	368	524	593	584	9
8	368	524	599	584	15
9	368	524	605	584	21
10	368	524	611	584	27