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November 2, 2015

Via Electronic Filing and U.S. Mail
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Public Utility Commission of Oregon
Attention: Filing Center
PO Box 1088
Salem OR 97308-1088

Re: UM 1744 – NW Natural’s Application of an Emission Reduction Plan

Attention Filing Center:

Enclosed for filing in Docket Number UM 1744 is Portland General Electric Company’s Motion for Leave to File Supplemental Testimony of Joe Barra/300. This document is being filed by electronic mail with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

A handwritten signature in blue ink, appearing to read "J. Richard George", with a long, sweeping horizontal line extending to the right.

J. Richard George
Assistant General Counsel

JRG:rff
Enclosures

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1744

In the Matter of

NW Natural – Application of an Emission
Reduction Program

MOTION FOR LEAVE TO
SUPPLEMENT TESTIMONY OF
PORTLAND GENERAL ELECTRIC
COMPANY

I. INTRODUCTION

Pursuant to OAR §860-001-0420, Portland General Electric Company (“PGE” or “Company”) hereby requests that the Oregon Public Utility Commission (“OPUC” or “Commission”) grant it leave to file supplemental testimony and exhibit submitted with this motion. Good cause exists to allow PGE to supplement prior testimony as it is highly relevant to the issues in this proceeding. PGE has attempted to consult with the other parties to this docket in accordance with OAR §860-001-0420(2). Northwest Natural, Staff and PacifiCorp have indicated that they reserve the right to respond to PGE’s filing, and CUB and Climate Solutions have indicated that they generally do not oppose PGE’s motion.

II. BACKGROUND

PGE filed response testimony in this proceeding on August 28, 2015 responding to Northwest Natural (“NW Natural”) UM 1744 Application for Carbon Emissions Reduction Program filed on June 24, 2015. The testimony addressed three key points for PGE:

1. As a matter of policy, is it appropriate to use ratepayers' funds to promote fuel switching;

2. As a matter of policy it is inappropriate to use funds collected from electric utility customers for electric energy efficiency to promote natural gas conservation;
3. The methodology used by NW Natural in calculating the avoided greenhouse gas emissions associated with displaced utility electric generation contains significant analytical flaws.

NW Natural is seeking approval for a carbon emission reduction program to provide financial incentives to encourage customers to install Combined Heat & Power systems (the CHP Program). NW Natural proposes to estimate carbon reductions from displaced utility generation using regional eGRID data for non-baseload fossil fuel generation from 2010. NW Natural points to guidance from the EPA's Combined Heat & Power Partnership to support this methodology.

PGE has multiple objections to the methodology. First, the EPA guidance is to use the proposed methodology *in the absence of consistent and complete utility import and export data*. For NW Natural sited projects in PGE's service territory, the Commission should rely on accurate, current data from the utility resources being displaced. Second, NW Natural proposes to "lock-in" the incentive payment for carbon reductions for 10 years. PGE understands the desirability of a fixed project incentive, but objects to it being based on outdated information that will not accurately reflect actual carbon reductions. It appears that NW Natural is choosing its numbers to create an optimal cost effectiveness and carbon reduction outcome rather than using more accurate and realistic numbers.

After its testimony was filed, PGE became aware of a July 10, 2015 California Public Utility Commission [Proposed] Decision Revising the Greenhouse Gas Emission Factor to Determine Eligibility to Participate in the Self-Generation Incentive Program Pursuant to Public

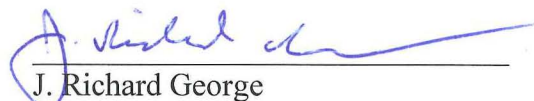
Utilities Code Section 379.6(b)(2) as Amended by (California) Senate Bill 861 (“Proposed Decision”). This Proposed Decision is evidence that others in the region are recommending methodologies that are consistent with PGE’s proposed methodology set forth previously in its testimony for estimating carbon reductions associated with Combined Heat & Power Systems. Staff has asked PGE to share its methodology and advocate for its use (Staff/300, Klotz/9-10), and the Proposed Decision helps do that. The Proposed Decision is probative in examining various factors and components of determining CHP carbon reduction claims and will be useful to the parties and Commission in examining NWN’s CHP Proposal. PGE requests that the Commission allow PGE to supplement its prior testimony with PGE / 300 / Barra and Exhibit 301. The supplemental testimony provides a brief question and answer litany establishing the foundation for Exhibit 301, which is the Proposed Decision PGE is moving to include as an exhibit to its testimony.

III. CONCLUSION

For the reasons set forth above, PGE respectfully requests that the Commission enter an order granting PGE leave to supplement its pre-filed direct evidence in this proceeding and accept for filing the Motion for Leave to Supplement Testimony and attached exhibits.

DATED this 2nd day of November, 2015.

Respectfully submitted,



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**BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON**

UM 1744

**In the Matter of
NORTHWEST NATURAL GAS COMPANY,
dba NW NATURAL,
Application for Approval of Emission
Reduction Program**

Portland General Electric Company

**Supplemental Testimony of
*Joe Barra***



November 2, 2015

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I. Introduction and Summary

1 **Q. Please state your name and position with Portland General Electric Company**
2 **(PGE).**

3 A. My name is Joe Barra. I am a Senior Consultant in Customer Strategy & Business
4 Development.

5 **Q. Are you the same Joe Barra that previously provided testimony in this proceeding?**

6 A. Yes.

7 **Q. Do you wish to supplement your testimony?**

8 A. Yes.

9 **Q. How would you supplement your testimony?**

10 A. I am seeking to include the attached Exhibit, “[Proposed] DECISION REVISING THE
11 GREENHOUSE GAS EMISSION FACTOR TO DETERMINE ELIGIBILITY TO
12 PARTICIPATE IN THE SELF-GENERATION INCENTIVE PROGRAM PURSUANT
13 TO PUBLIC UTILITIES CODE SECTION 379.6(b)(2) AS AMENDED BY SENATE
14 BILL 861” that was filed with the Public Utilities Commission of the State of California.

15 **Q. Why did you not include this proposed decision as an exhibit to your previously-**
16 **filed testimony?**

17 A. I was unaware of this proposed decision prior to the filing of my prior testimony.

18 **Q. Why do you want to supplement your prior testimony with this exhibit?**

19 A. This proposed decision provides evidence that others in the region are proposing
20 methodologies for estimating the carbon reductions associated with CHP projects that are
21 consistent with PGE’s suggestions in this docket. It also provides an example that

1 applies PGE's principles in calculating carbon reductions for CHP projects that I believe
2 will be helpful to the parties and the Commission in considering and evaluating NWN's
3 proposal.

II. Qualifications

4 **Q. Mr. Barra, please state your educational background and qualifications.**

5 A. I received a Bachelor of Arts degree from William Patterson University in 1973. Since
6 joining PGE in 1994, I have managed new product and business development initiatives,
7 including those related to distributed generation. From 1988 to 1993, I managed new
8 product development and directed energy services for commercial and industrial
9 customers of PacifiCorp.

List of Exhibits

<u>PGE Exhibit</u>	<u>Description</u>
301	Decision Revising the Greenhouse Gas Emission Factor to Determine Eligibility to Participate in the Self-Generation Incentive Program Pursuant to Public Utilities Code Section 379.6(b)(2) as Amended by Senate Bill 861.



STATE OF CALIFORNIA

EDMUND G. BROWN JR., *Governor***FILED****PUBLIC UTILITIES COMMISSION**505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-32987-10-15
02:21 PM

July 10, 2015

Agenda ID #14144
Quasi-Legislative

TO PARTIES OF RECORD IN RULEMAKING 12-11-005:

This is the proposed decision of Assigned Commissioner Picker. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 13, 2015 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ KAREN V. CLOPTONKaren V. Clopton, Chief
Administrative Law Judge

KVC:vm2

Attachment

COM/MP6/vm2

PROPOSED DECISION

Agenda ID # 14144
Quasi-Legislative

Decision **PROPOSED DECISION OF COMMISSIONER PICKER**
(Mailed July 10, 2015)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding
Policies, Procedures and Rules for the
California Solar Initiative, the Self-
Generation Incentive Program and Other
Distributed Generation Issues.

Rulemaking 12-11-005
(Filed November 8, 2012)

**DECISION REVISING THE GREENHOUSE GAS EMISSION FACTOR TO
DETERMINE ELIGIBILITY TO PARTICIPATE IN THE SELF-GENERATION
INCENTIVE PROGRAM PURSUANT TO PUBLIC UTILITIES CODE
SECTION 379.6(b)(2) AS AMENDED BY SENATE BILL 861**

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APPENDIX A

**DECISION REVISING THE GREENHOUSE GAS EMISSION FACTOR TO
DETERMINE ELIGIBILITY TO PARTICIPATE IN THE SELF-GENERATION
INCENTIVE PROGRAM PURSUANT TO PUBLIC UTILITIES CODE
SECTION 379.6(b)(2) AS AMENDED BY SENATE BILL 861**

Summary

Pursuant to Public Utilities Code Section 379.6(b)(2), this decision updates the greenhouse gas emission factor that determines eligibility to participate in the Self Generation Incentive Program.¹ The updated factor explicitly reflects the displaced emissions from existing capacity and the avoided need for new capacity. The emission factor for generation technologies is updated from 379 kilograms carbon dioxide per megawatt hours (kgCO₂/MWh) to 360 kgCO₂/MWh. In addition, the minimum required round-trip efficiency for storage technologies is updated from 63.5% to 66.5%. This proceeding remains open.

1. Background

Senate Bill (SB) 412 (Kehoe, Stats. 2009, ch. 182) extended the Self-Generation Incentive Program (SGIP) until January 1, 2016 and directed the California Public Utilities Commission (Commission) to adopt rules that limit eligibility for the program to “distributed energy resources that the commission, in consultation with the State Air Resources Board (ARB), determines will *achieve reductions of greenhouse gas emissions...*” (*Emphasis added.*) SB 412 is codified at, among other code sections, Public Utilities (Pub. Util.) Code Section 379.6.

On September 8, 2011, the Commission adopted Decision (D.) 11-09-015, which implemented SB 412 and set a greenhouse gas (GHG) emission rate

¹ All code references are to the Public Utilities Code unless otherwise indicated.

eligibility threshold of 379 kgCO₂/MWh. As a result, fossil-fuel consuming technologies with GHG emission rates above that threshold were not permitted to receive incentives from the SGIP program. In adopting this rule, D.11-09-015 based the 379 kg CO₂/MWh avoided emissions factor, in part, on the factor of 437 kg CO₂/MWh used in California ARBs AB 32 Scoping Plan (2008) to estimate the benefits of avoided grid electricity based on the average emissions of natural gas electricity generation.²

In D.11-09-015, the Commission adjusted the ARB's emission factor of 437 kgCO₂/MWh downward by 20% to reflect that utilities' electricity procurement resource mix included roughly 20% of renewable resources, as required under the then-effective Renewable Portfolio Standard (RPS) statute.³ Additionally, in D.11-09-015, the Commission noted that adjusting the ARB's emissions factor downward to reflect the utilities' 20% RPS procurement was likely conservative because the RPS program procurement target had increased to 33% of retail electricity procurement by the target date of 2020, which would likely to further reduce the emissions of avoided grid purchases.

In D.11-09-015, the Commission also supported the downward adjustment of the ARB's emissions factor of 437 kgCO₂/MWh because the ARB's figure was based on the weighted average emission rate of natural gas-fired power plants from 2002 to 2004 and did not reflect the lower emission rate of newer more

² Assembly Bill 32 (AB 32) required the ARB to develop a Scoping Plan to describe the approach California will take to reduce GHG to achieve the goal of reducing emissions to 1990 levels by 2020. The Scoping Plan was first considered by the ARB in 2008. AB 32 required that it be updated every five years. ARB approved the First Update to the Climate Change Scoping Plan on May 22, 2014.

³ Section 399.11 et seq. These code sections have been revised since the issuance of D.11-09-015.

modern gas-fired generation units that SGIP projects may avoid going forward.⁴ The emission factor adopted in D.11-09-015 incorporates a 7.8% average transmission and distribution line loss factor to estimate the GHG emissions of the additional electricity displaced by consuming electricity that is generated on-site.

Regarding energy storage technologies, Energy Division's September 2010 Staff Proposal calculated the minimum round trip efficiency that would be required to avoid GHG emissions and arrived at 67.9%. Staff recommended requiring a minimum round trip efficiency of 70% in order to be conservative. D.11-09-015 approved storage for SGIP participation but did not comment on the minimum round trip efficiency requirement. Following the decision, the program administrators filed Advice Letter (AL) PG&E 3253-G/3940-E *et seq.* to revise the SGIP Handbook to reflect the changes ordered by the Commission. In the AL, the program administrators proposed requiring a minimum round trip efficiency of 67.9%.

The Energy Division issued a disposition letter approving the AL, but it was appealed by California Energy Storage Association (CESA). Addressing that appeal, the Commission issued Resolution E-4519 accepting CESA's proposed 5% differential in line loss factors between peak and off-peak, with the effect being that the minimum round trip efficiency needed to qualify for SGIP decreased from 67.9% to 63.5%.

⁴ D.11-09-015 at 15.

SB 861 (Budget Act of 2014, Stats. 2014, ch. 35) further extended SGIP from January 1, 2016 to January 1, 2021 and added § 379.6(b)(2), a provision requiring the Commission to update the GHG emissions eligibility factor. This subsection provides as follows:

On or before July 1, 2015, the commission shall update the factor for avoided greenhouse gas (GHG) emissions based on the most recent data available to the State Air Resources Board for GHG emissions from electricity sales in the self-generation incentive program administrators' service areas as well as current estimates of GHG emissions over the useful life of the distributed energy resource, including consideration of the effects of the California Renewables Portfolio Standard.

As part of the Commission's process to update the GHG emissions eligibility factor in compliance with § 379.6(b)(2), the assigned Commissioner in this proceeding issued a ruling on March 27, 2015 requesting parties to comment on ten questions related to the calculation of the GHG emissions avoided by generation and storage technologies.

Parties filed comments between April 14 and 16, 2015.⁵ Several parties filed reply comments on April 23, 2015.⁶

⁵ Doosan Fuel Cell America (Doosan), the Office of Ratepayer Advocates (ORA), Southern California Gas Company (SoCalGas), National Fuel Cell Research Center (NFCRC), California Clean DG Coalition (CCDGC), FuelCell Energy (FCE), Southern California Edison Company (SCE), California Solar Energy Industries Association (CALSEIA), Center for Sustainable Energy (CSE), Center for Energy Efficiency and Renewable Technologies (CEERT), Bloom Energy, California Cogeneration Council (CCC), EtaGen, SolarCity, San Diego Gas & Electric Company (SDG&E), Cogeneration Association of California, Pacific Gas and Electric Company (PG&E), California Energy Storage Alliance (CESA), Fuel Cell & Hydrogen Energy Association (FCHEA).

⁶ SoCalGas, SCE, EtaGen, CCDGC, CSE, SDG&E, Bloom Energy, PG&E, CESA, and SolarCity.

2. SGIP System Performance Over Time

We first address the performance of the SGIP-incentivized systems and the duration of time over which GHG emissions are required to occur. To meet the SGIP GHG eligibility requirements, D.11-09-015 found that SGIP systems must emit GHGs at a rate less than the adopted GHG emission factor when averaged over a ten year period and assuming annual performance degradation of 1%. For pure electric fuel cells and for AES systems, this determination is made for specific model types and then applied to all applications with those model types. For Combined Heat Power (CHP), however, because the GHG impact depends on the design of the heat recovery system and on its operation, D.11-09-015 orders that each individual application be reviewed for GHG emissions eligibility compliance.⁷

2.1. SGIP Project Performance Degradation

In D.11-09-015 the Commission noted, “Staff’s analysis of fossil-fuel based [Distributed Energy Resources] technologies rested on a few key assumptions: 1) the electrical conversion efficiency of all technologies degrades at a rate of 1% per year....”⁸ The March 27, 2015 Assigned Commissioner Ruling (ACR) asked for comment on the degradation assumption. Of those parties responding to this question, about half⁹ believe that the 1% annual degradation rate assumption is adequate and appropriate. Among those who argue otherwise, Fuel Cell Energy favors a 2% annual assumption for all projects, or else a different number for each technology type. EtaGen and CSE favor a different number for each

⁷ D.11-09-015 at 16.

⁸ D.11-09-015 at 14.

⁹ Bloom, CESA, Doosan, PG&E, SolarCity.

technology type, with values to be determined based on historical analysis. CCC argues that well-maintained facilities experience no degradation over time and, if anything, offer opportunities for improvements. CCDC believes that actual degradation is lower than 1% and asks the Commission to use manufacturer data to determine more accurate values. SCE states that a 2 to 3% degradation rate for energy storage systems is more appropriate.

No party has provided compelling evidence pointing to a different assumed degradation factor, and so we will keep the current assumed degradation rate at 1%.

2.2. Length of GHG Emissions Comparison Period

The March 27, 2015 ACR asked for parties to comment on whether any revisions should be made to the current 10 year requirement. Most parties supported maintaining the 10 year rule. However, CCC supported extending the period to 15 years on the basis that natural gas plants will be the avoided resource base through at least 2030. We acknowledge that some SGIP-funded systems will likely operate for more years than others, but we refrain from extending the comparison period because we are concerned that a longer period may serve to penalize equipment that is expected to last longer. Furthermore, we favor the administrative simplicity of using the same evaluation period for all technologies.

3. The Updated Avoided GHG Emissions Factor for Generation Technologies under § 379.6(b)(2)

To update the avoided GHG emissions eligibility factor for SGIP projects, we address three key questions:

First, do SGIP projects: (1) reduce generation output from existing dispatchable generation facilities (the operating margin effect), (2) reduce the need for new generation facilities that would otherwise have been built to serve the load met by the SGIP projects (the build margin effect), or (3) produce both an operating margin effect and a build margins effect?

Second, what data or estimates should be used for the GHG emission rates of fossil-fired generation offset by SGIP projects?

Third, what line loss percentage should be used to account for the line losses avoided by generating electricity for use on site, which is typical for any SGIP eligible projects?

We address these questions below.

3.1. Operating Margin or Build Margin Methodology

The March 27, 2015 ACR asked parties to address the question of whether SGIP projects avoid GHG emissions by reducing the output from existing facilities operating on the margin or from the capacity of facilities that would otherwise be built.¹⁰

3.1.1. Generation Technology

Nearly all parties agree that SGIP generation projects displace generation from a combination of combined cycle gas turbines (CCGTs) and simple cycle combustion turbines (CTs) and that new gas-fired plants will be slightly more

¹⁰ The ACR referred to this issue as the short-run and long-run effects but noted that it is also known as the operating margin and build margin effects. Since the nomenclature led to some confusion in the comments on the ACR, we consistently use the terms operating margin and build margin in this decision.

efficient than existing plants. However, the choice between the two approaches – operating margin or build margin - could have a large impact on the final avoided emission rate if the technologies adopted for new generation differ significantly from the existing fleet of dispatchable resources. Importantly, with few, if any, exceptions the resources built to serve California’s electricity load for the foreseeable future will consist of gas-fired and renewable energy facilities. The inclusion of renewable facilities among the portfolio of plants used to set the build margin rate decreases the avoided emissions rate compared to the operating margin.

In D.11-09-015, the Commission assumed SGIP projects would avoid the need for new generation, meaning that the Commission found that SGIP projects affect the build margin and avoid the need for utilities to procure new renewable capacity as well as new fossil-fired capacity. This finding was based, in part, on the fact that the Pub. Util. Code, specifically the statutorily based RPS program, obligates the utilities and other load serving entities to meet their retail loads with a certain percentage of renewable energy.

To the extent the utilities’ sales forecasts account for energy efficiency and self-generation, both of which reduce the utilities’ sales, they would need to procure both less renewable energy and less conventional energy than they would in the absence of energy efficiency and self-generated electricity.

Parties presented different opinions on this topic. Generally, no position was unanimously endorsed. Some expressed clear support for an operating margin approach.¹¹ Under an operating margin approach, SGIP resources would

¹¹ These parties are Bloom Energy, CCDGC, Doosan, EtaGen, Fuel Cell Energy, FCHEA, NFCRC, ORA, SoCalGas, and SCE.

be assumed to offset only the emissions of a generator that operates on the margin at the time the SGIP resource operates; SGIP technologies would not be assumed to offset any zero-emission resources unless the marginal generator in California happened to be a zero-emission resource. However, SCE, one of the parties supporting an operating margin approach, nevertheless suggests that “cumulative SGIP projects do affect long run resources” and recommends emission factors that incorporate the RPS effect.¹² Others express clear support for a build margin approach, although one of these parties, CCC, asserts that SGIP projects will not avoid new renewable energy capacity.¹³

Determining whether SGIP and other self-generation projects affect procurement of new renewable capacity hinges on whether the utilities’ load forecasts, upon which they base their renewable capacity purchase decisions, account for load reductions due to self-generation. The answer is straightforward. As CESA explains in its reply comments, the utilities’ load forecasts, as approved in the Long Term Procurement Planning (LTPP) proceeding, are derived from the California Energy Commission’s (CEC’s) biennial Integrated Energy Policy Report (IEPR) and the ten-year demand forecasts incorporated therein. CESA observes that the CEC’s 2014 – 2024 demand forecast specifically cites SGIP as one of the “major programs designed to promote self-generation” that are accounted for in the demand forecast.¹⁴

¹² SCE April 17, 2015 opening comments at 2 and 8.

¹³ CCC, CESA, CalSEIA, PG&E, SDG&E, and Solar City.

¹⁴ CESA reply comments at 3, *citing to California Energy Demand 2014 – 2024 Final Forecast. Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand and Energy Efficiency* at 38-39.

In light of the CEC's accounting for SGIP in the demand forecast, SGIP, in conjunction with the utilities' other demand-side programs, likely have some impact on the procurement of energy capacity. However, it is difficult to ascertain at what point self-generation and other demand-side measures affect the decision to procure new capacity. As explained in the World Resources Institute's GHG reduction guidelines document (World Resources Institute's GHG Guidelines) cited in the ACR, during periods of overcapacity, projects may only displace the operating margin for some period of time before they affect the build margin.¹⁵

In the most recent Commission LTPP decision authorizing procurement of new capacity, the Commission found that new capacity would not be needed in either the SCE or SDG&E territories before 2022.¹⁶ Due to the lack of near-term need for new capacity at the system and local levels and the fact that procurement decisions for new capacity are generally made several years in advance of new capacity coming online, we find it reasonable to assume that SGIP projects will primarily avoid the need for generation from existing resources in the near-term.

However, over the longer-term, we assume that SGIP projects will offset the need for new capacity. Determining the timing of the avoidance of new capacity would necessitate analysis of factors specific to the locations and generation profiles of each project. In order to account for both types of avoided

¹⁵ Broekhoff, D., 2007. *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*. World Resources Institute. (See Box 8.3.)
<http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf>.

¹⁶ D.14-03-004 at 2.

generation effects while balancing the need for an acceptable level of administrative complexity, we adopt a methodology that assigns equal weight to the short-term and long-term effects over a ten-year time span.

3.1.2. Renewable Capacity Avoided by SGIP Projects

Having found above, that SGIP projects are likely to have some long-term effect on new capacity, we now address the question of whether SGIP projects avoid the need for renewable capacity in addition to gas-fired capacity.

The methodology adopted in D.11-09-015 and incorporated into the SGIP Handbook assumes SGIP projects displace renewable energy generation in proportion to the statutorily-mandated amount of RPS procurement required at the time. As described earlier, this method implicitly assumes a build margin effect from the first year of operations.

SCE, CESA, CALSEIA, and SolarCity support the continued application of an avoided renewable capacity assumption. SCE, which supports an assumption of a predominately short-term grid impact, nevertheless argues that the SGIP eligibility should start with the GHG emission rates of gas-fired power plants from the CEC's Quarterly Fuel and Energy Report (also referred to as QFER) data, reduced by the required RPS percentage for each of the first five years of the project's operations.¹⁷ CALSEIA and SolarCity support assuming that SGIP projects displace 40% renewables given the Governor's goal of meeting half of the state's projected electricity load with renewable energy procurement by 2030.

SoCalGas, EtaGen, CCDC, and CCC take the position that AB 327 eliminated the connection between customer measures and wholesale

¹⁷ SCE April 17, 2015 opening comments at 8.

renewables by creating the 2020 target of 33% as a floor instead of a ceiling. Therefore, they claim that no assumptions can be made based on renewable procurement targets.¹⁸

While AB 327 permits the Commission to require utilities to procure more than the minimum amounts prescribed by the RPS statute, the Commission has not exercised that authority. Moreover, the parties making this argument fail to explain why this would fundamentally change the interaction between the renewable energy requirements and the build margin. As long as any future renewable energy requirements are based on a percentage of retail sales, the rationale underlying D.11-09-015 still applies: the utilities would forecast their loads, taking into account SGIP and other demand side measures, and submit compliance plans demonstrating sufficient procurement of renewable capacity to meet the higher standard set by the Commission.

Therefore, we find it reasonable to adopt a methodology that assumes 33% avoided renewable capacity for the long-term share of the GHG emission rate threshold, with an adjustment to reflect line losses. Furthermore, the fact that we, or the Legislature, could increase the RPS requirement in the near future renders a 33% avoided renewable capacity assumption rather conservative. However, until either the legislature codifies a higher RPS or we act on the authority granted by AB 327 and explicitly adopt a higher standard than the RPS minimum, we will not assume a higher avoided renewable capacity than 33%.

¹⁸ EtaGen April 17, 2015 opening comments at 4-5. EtaGen states that “With this change in law, it is not possible for SGIP projects to displace renewable capacity procurement since utilities are now free to procure renewable capacity that generates energy in amounts greater than the RPS floor.”

We find a line loss adjustment reasonable because, while the RPS program requires utilities to procure a certain percentage of renewable energy as a share of their *retail* sales, no adjustment is made for the line losses that occur to deliver energy to customers. As a result, a given RPS target results in a lower percentage of renewable energy as a share of the wholesale energy procured to serve customers. For example, attaining a 33% RPS target on a grid with 10% line losses results in a 29.7% ($33\% * (1-10\%)$) share of renewable energy at the wholesale level.

Therefore, the build margin calculation should account for the smaller share of renewable energy actually displaced at the wholesale level.

3.2. Data Source - Emission Rates for Gas-Fired Generation Facilities

We next address the issue of what data should be used for determining the GHG emission rate of gas-fired generation facilities. As noted in the March 27, 2015 ACR, § 379.6(b)(2) directs the Commission to update the GHG eligibility factor “based on the most recent data available to the State ARB for GHG emissions from electricity sales in the self-generation incentive program administrators’ service areas.”

As several parties indicated, the ARB does not collect data that would help to estimate avoided emissions on either an operating margin or build margin basis. The ARB collects, and reports, total emissions for all stationary facilities emitting 10,000 metric tons of CO₂ equivalent or more per year. However, the ARB neither collects nor reports nameplate capacity or net electricity generated by facility. Furthermore, the ARB does not assign emissions in any way to the utilities’ service areas. Therefore, we must rely on other sources of data to calculate marginal emission rates.

3.2.1. Operating Margin Effect - Emission Rates

Because the necessary data is not reported to the ARB, and thus not available for our use, parties recommend using data from the CEC. SCE suggests relying on the CEC's Quarterly Fuel and Energy Report, which provides monthly data on power plant rated capacity, generation, fuel type, and fuel consumption. SCE suggests that capacity factors can be derived to determine which plants are marginal and fuel consumption and generation data can be used to calculate GHG emission rates for the marginal plants.¹⁹

EtaGen and Doosan also recommended using CEC data but refer to a 2014 CEC draft staff paper (2014 CEC Draft Staff Paper) that analyzed historic QFER data to separately estimate the average heat rates of load-following²⁰ and peaking resources.²¹ In this 2014 CEC Draft Staff Paper, the CEC staff collected historic data from 2004 through 2013 and extrapolated heat rates out to 2023 using a linear regression. EtaGen calculated an average 10 year avoided emission value using the values from Table 1 of the 2014 CEC Draft Staff Paper, arriving at a final emission factor of 449 kgCO₂/MWh.²² However, this factor incorporates a peaker plant weighting that we find excessive, as discussed below.

¹⁹ SCE April 17, 2015 opening comments at 2.

²⁰ Load-following power plants run during the day and early evening. They either shut down or greatly curtail output during the night and early morning, when the demand for electricity is the lowest. The exact hours of operation depend on numerous factors. One of the most important factors for a particular plant is how efficiently it can convert fuel into electricity.

²¹ California Energy Commission, 2014. *Estimating Fuel Displacement for California Electricity Reductions: Summary of Staff's Proposed Method*.
http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/Estimating_Fuel_Displacement_Summary.pdf.

²² EtaGen April 17, 2015 opening comments of at 8-9.

Bloom Energy suggests using data from a 2014 CEC report on the efficiency of gas fired generation (CEC Thermal Efficiency Report).²³ This report provides heat rates for California gas-fired generation from 2001 through 2013 based on CEC's QFER data. Bloom Energy favors excluding aging steam-generation plants, which are run primarily for reliability purposes, and cogeneration plants, which typically do not respond to changes in load.²⁴ Table 2 of the report shows that 2013 average heat rates are 7,205 and 10,268 Btu/kWh, respectively, for combined cycle and peaker plants.

Several parties recommend reasonable approaches to calculating the avoided GHG emissions from existing power plants. As most parties who took a position on the data sources have agreed, we believe that at least as an interim measure, data collected by the CEC provide the best data for the purpose of calculating the GHG emissions of marginal power plants in California. We will continue to work with CEC staff and ARB to identify sources of data collected by ARB that may be useful to further refine the avoided emissions estimates. Rather than reinventing the wheel by analyzing raw QFER data, we find that the CEC staff has conducted analysis that is useful to determining the emissions rate of gas-fired resources. While we find the linear regression approach proposed by CEC staff promising, at this time the CEC has not issued a final report and, therefore, we are reluctant to rely on the draft methodology.

We find it reasonable to rely on the 2013 data from the CEC Thermal Efficiency Report, as recommended by Bloom Energy. The heat rate for

²³ Nyberg, M. *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update*. California Energy Commission, 2014. CEC-200-2014-005.

²⁴ Bloom Energy April 17, 2015 opening comments at 7-8.

load-following plants, as cited in the report, was 7,205 Btu/kWh and the heat rate for peaker plants was 10,268 Btu/kWh. Using the United States Environmental Protection Agency's standard conversion factor of 53 kgCO₂/MMBtu, we find that these heat rates are equivalent to emission rates of 382 kgCO₂/MWh and 544 kgCO₂/MWh respectively.

3.2.2. Build Margin Effect - Emission Rates

We now address emission rates for peaker and load-following plants in the build margin. Because the conversion efficiencies of these technologies continue to improve, the emission rates of the new gas-fired plants displaced by SGIP projects and other demand-side measures will be lower than the existing plants whose output is avoided on the operating margin.

Most parties did not support the finding of a build margin effect. As a result, only a few parties provided information concerning the emission rates of new gas-fired units. SolarCity supports the continued use of 368 kgCO₂, adopted in D.11-09-015.²⁵ EtaGen suggests that any proposed deviations to the baseload heat rates in the 2014 CEC Draft Staff Paper take into account that only dry cooled combined cycles would ever be permitted in California and that such plants would be 5-10% less efficient.²⁶

CCC refers to values from the California Independent System Operator (CAISO) on the costs and performance of new generating units in California.²⁷ Because the data source cited provides a range of heat rate values for both CCGTs and CTs, CCC proposes taking the mid-point value for each. CCC

²⁵ SolarCity April 17, 2015 opening comments at 11.

²⁶ EtaGen April 17, 2015 opening comments at 4.

²⁷ CCC April 17, 2015 opening comments at 7.

arrives at recommended values of 393 kgCO₂ for CCGTs and 504 kgCO₂ for CTs. The value provided for CCGTs is actually slightly higher than the emission rate of the existing fleet using the 2013 CEC data cited by Bloom Energy. Because that value is higher than the performance of the existing fleet, we will continue to use the current value of 368 kgCO₂. As EtaGen observed, that value may need to be revisited when we have more operating data on new dry-cooled plants in California.

The value for new CTs proposed by CCC is more than 7% lower than the efficiency of the existing fleet. It is worth noting that the emissions rate of the existing fleet of CTs is lower than the assumed value for a new CT used in the current SGIP Handbook, which is 575 kgCO₂. This value is now outdated and we will revise it accordingly. The new value proposed by CCC would constitute a substantial reduction in efficiency relative to the existing fleet, and we are not certain that efficiency is plausible under realistic operating conditions.

Therefore, we find that, in the absence of better data, the same efficiency improvement (between the existing plants in the operating margin and the future avoided plants in the build margin) assumption should be applied to CTs that we have adopted for CCGTs – namely, a heat rate reduction of 3.7%. This results in an assumed emissions rate of 524 kgCO₂ for new CTs.

3.2.3. Weighting Load-Following and Peaker Plants in the Final Emission Rate

In order to determine a final emission rate under § 379.6(b)(2), the contribution of load-following and peaker plants must be weighted to account for the approximate amount of time spent operating on the margin – which would be the amount of time potentially displaced by SGIP projects.

Parties presented a variety of positions. EtaGen generally supported the linear regression approach in the 2014 CEC Draft Staff Paper. EtaGen, however, disagrees with the weighting of load-following and peaking plants. The 2014 CEC Draft Staff Paper suggests that an avoided marginal emission factor should weight peaking resources by the amount of electricity produced as a share of all electricity produced by the facilities deemed to comprise the peaking and load-following categories.

EtaGen, Bloom Energy and the CCC recommend that the weighting of peaker plants reflect the time these facilities operate and are thus likely to provide the marginal source of electricity. This approach to weighting peaker and load-following plants is more consistent with the methodology described in the World Resources Institute's GHG Guidelines.²⁸

EtaGen recommends using the highest capacity factor of any single peaking power plant from the CEC's QFER data, which, according to EtaGen, is 20.6%, the capacity factor of the KRCD Malaga Peaking Plant in 2013. We find that using the highest single capacity factor of any peaking plant in California results in an overly generous estimate of the number of hours peaker plants are likely to be displaced by SGIP projects.

In contrast to the approach proposed by EtaGen, Bloom Energy cites the CEC Thermal Efficiency Report, which indicates that the average capacity factor of peaker plants in 2013 was 5.1%. While this approach would be more

²⁸ Broekhoff, D., 2007. *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*. World Resources Institute.
<http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf>.

reasonable than the value suggested by EtaGen, it may underestimate the number of hours that peaker plants spend on the margin because plants that operate for very few hours pull down the average. The average capacity factor of all peaker plants does not necessarily represent the number of hours that peaker plants spend on the margin because more efficient plants should generally operate at higher capacity factors and provide the marginal unit during many hours when less efficient plants are not operating.

CCC cites the CAISO's 2013 *Annual Report on Market Issues and Performance*, which indicates that based on the economics of combustion turbine operations, new combustion turbines are estimated to have operated at an approximately 8% capacity factor during the 2010 to 2013 time period. We find this estimate to be more representative of the amount of time that peakers are likely to provide the marginal resource because newer, more efficient combustion turbines should operate more often than the average of all peaker plants. Therefore, we adopt 8% as the weighting factor to apply to peaker plants in the calculation of marginal emission rates.

3.3. Line Losses Avoided by SGIP Projects

The calculation of an avoided GHG emission rate for SGIP projects and other demand-side measures must account for the line losses that they save by providing electricity for on-site consumption.²⁹ The current methodology uses a consistent statewide assumption of 7.8%, which, like the avoided emission rate for gas-fired generation, was adopted from ARB's 2008 Scoping Plan. As CESA

²⁹ In this section we only address the average line losses that will be used for generation projects. On-peak and off-peak line losses for storage projects are discussed in a separation section of this decision.

notes, the 7.8% value used by ARB was taken from the CEC's 2007 energy demand forecast for 2008 – 2018.³⁰ This number is now several years out of date and should be updated.

Parties have proposed three different data sources that may be used to update the line loss factor. CESA recommends using a 2011 CEC study on transmission losses. While that study provides a range of values based on 2008 and 2009 data, CESA suggests using 6.2%, which is the midpoint of the range in the CEC study.³¹ SCE cites the same study but states that it provides a value of 7.25% for “overall system losses.” SCE recommends using utility-specific factors found in the report. Bloom Energy suggests 7.3% from a different CEC report, the 2015 – 2025 demand forecast.³² CCC and EtaGen both cite the same loss factors disaggregated by utility and by the transmission, sub-transmission, and distribution portions of the system.^{33 34} Their approaches use data from CAISO, PG&E's 2014 GRC Phase 2 testimony, SCE's 2015 GRC Phase 2 testimony, and a data response from SDG&E in R.14-07-002. The proposed total line loss factor differs slightly because it appears that EtaGen added the separate loss factors together whereas CCC calculates a product of

³⁰ CESA April 17, 2015 opening comments at 11-12.

³¹ CESA April 17, 2015 opening comments at 12, *citing* to Wong, Lana, 2011. *A Review of Transmission Losses in Planning Studies*. California Energy Commission at 24. Available at http://www.energy.ca.gov/2011_publications/CEC-200-2011-009/CEC-200-2011-009.pdf.

³² Bloom Energy April 17, 2015 opening comments at 12, *citing* to Kavalec, Chris, 2015. *California Energy Demand Updated Forecast, 2015-2025*. California Energy Commission, CEC-200-2014-009-CMF

³³ CCC April 17, 2015 opening comments at 5.

³⁴ EtaGen April 17, 2015 opening comments at 6.

1 minus each loss factor. Although EtaGen, like CCC, provides a table with loss factors for each utility, EtaGen proposes using one statewide, load-weighted average factor of 8.7%. CCC does not state that utility-specific factors should be used, but presumably that is CCC's intent because it does not provide a statewide average.

We find the data provided by CCC and EtaGen persuasive and we will adopt this approach to calculate the line loss factor that partially determines the SGIP avoided GHG emission factor. In order to maintain a simpler and more uniform program structure, we prefer to use one statewide average line loss factor and accordingly we adopt the approach described by EtaGen. However, EtaGen errs in adding the individual components together. Using the multiplicative calculation used by CCC, we derive a final line loss factor of 8.4%.

4. SGIP GHG Emissions Eligibility Factor – The Equation

Based on the above, we find that to calculate the GHG emissions eligibility factor, it is reasonable to use the following equation:

$$\text{GHG EF} = (0.5(\text{ER}_{\text{OLF}} * (1 - \text{WFP}) + \text{ER}_{\text{OP}} * \text{WFP}) + 0.5 * (1 - \text{RPS}\% * (1 - \text{LLF})) * (\text{ER}_{\text{BLF}} * (1 - \text{WFP}) + \text{ER}_{\text{BP}} * \text{WFP})) / (1 - \text{LLF})$$

Where:

GHG EF = greenhouse gas emission factor

ER_{OLF} = operating margin emission rate of load-following plants = 382 kgCO₂/MWh

WFP = weighting factor for peaker plants = 8%

ER_{OP} = operating margin emission rate of peaking plants = 544 kgCO₂/MWh

RPS% = RPS portfolio requirement = 33%

ER_{BLF} = build margin emission rate of load-following plants = 368 kgCO₂/MWh

ER_{BP} = build margin emission rate of peaking plants = 524 kgCO₂/MWh

LLF = line loss factor = 8.4%

Substituting the adopted values into this equation yields:

$$\text{GHG EF} = (0.5 (382 \text{ kgCO}_2/\text{MWh} * (1 - 0.08) + 544 \text{ kgCO}_2/\text{MWh} * 0.08) + 0.5 (1-0.33 * (1 - 0.084) * (368 \text{ kgCO}_2/\text{MWh} * (1 - 0.08) + 524 \text{ kgCO}_2/\text{MWh} * 0.08)))/(1 - 0.084)$$

$$\text{GHG EF} = 360 \text{ kgCO}_2/\text{MWh}$$

Therefore, we find that, pursuant to § 379.6(b)(2), to be eligible for SGIP incentives, gas-fired technologies must emit GHGs at a rate no higher than this emission factor averaged over the first ten years of operation, and the calculation of a project's emissions must take into account the assumed 1% annual degradation in electrical efficiency.

5. Combined Heat and Power

We now address two issues specific to combined heat and power (CHP) projects: (1) whether to update the boiler efficiency factor, and (2) whether to differentiate between on-site consumption of CHP generation and exports to the grid.

5.1. Boiler Efficiency Factor

Regarding the first issue, because SGIP CHP projects displace useful thermal output that would have otherwise been provided by boilers, we find that an assumed boiler efficiency is needed to credit CHP project for avoided boiler fuel. Notably, the assumed boiler efficiency factor could significantly impact the eligibility of CHP projects because the higher the assumed boiler efficiency, the fewer GHG emissions avoided by a CHP project.

Most parties recommended continuing to use the current 80% boiler efficiency factor. These parties claimed that existing or "legacy" boilers generally

achieve the 80% level of efficiency or less. Only PG&E supported a higher boiler efficiency factor. PG&E recommended that the benchmark for boilers be modified to reflect the efficiency of currently available boilers. PG&E claimed that all new boilers sold in California must comply with a minimum 79 to 80% efficiency but supported a higher assumed efficiency – of 85% – because mid-efficiency boilers with efficiencies ranging from 83 to 88% are readily available and rebates are provided for this class of boilers. No party submitted data regarding either the vintage of boilers displaced by SGIP-funded CHP projects or the penetration of mid- and high-efficiency boilers sold in California.

Increasing the assumed boiler efficiency might be justified if a large number of SGIP-funded CHP projects avoid the need for a *new* boiler and if most of the new boilers installed in recent years in California were more efficient than the minimum levels required by California law. However, we have no data regarding either the vintage of boilers displaced by SGIP-funded CHP projects or the penetration of mid- and high-efficiency boilers sold in California.

Accordingly, we find it reasonable to retain the 80% assumed boiler efficiency for SGIP CHP projects. We may reconsider this value if parties provide data in the future regarding the extent to which SGIP-funded CHP projects displace new boilers and the prevalence of mid- and high-efficiency boilers among recently purchased boilers in the California market.

5.2. Differentiating between On-Site Usage of CHP Generation and Exports to the Grid

The second topic specific to SGIP CHP projects raised in the ACR is whether non-Net Energy Metering (NEM) exports from SGIP CHP projects should be compared only to fossil-fired plants for purposes of calculating avoided emissions.

Calculating a different rate of avoided emissions based on fossil-fuel or a different resource mix becomes moot if no build margin effect is assumed because the electricity produced by CHP units will only displace electricity from existing, dispatchable plants. Most of the parties commenting on this topic recommended no differentiation based on their opposition to finding that SGIP projects have a build margin effect.³⁵ SCE supported a methodology with an RPS-interaction effect but suggested against adopting a different emission standard for non-NEM exports because there have been very few non-NEM grid exporting projects and because SGIP only allows up to 25% of the energy generated on-site to be exported.³⁶ SoCalGas similarly pointed out the rarity of non-NEM exporting projects and suggested that most non-NEM projects have protection relays to prevent exports.³⁷

Accordingly, we find it reasonable to refrain from adopting a separate avoided GHG emission rate for non-NEM exports from SGIP CHP projects on the basis that no party supports the adoption of a separate avoided GHG emission rate for non-NEM exports from SGIP CHP projects and the apparent scarcity of projects that would benefit from a separate rate.

6. Energy Storage

The March 27, 2015 ACR asked if, given the changing nature of energy resources serving California's load, the current assumptions for calculating the avoided GHG emissions for SGIP energy storage are still valid. Energy storage

³⁵ See, e.g., April 17, 2015 opening comments of CCC, California Clean DG Coalition, Fuel Cell Energy, and SoCalGas.

³⁶ SCE April 17, 2015 opening comments at 7.

³⁷ SoCalGas April 17, 2015 opening comments at 6-7.

systems are typically net *consumers* of electricity. Therefore, unlike other SGIP technologies, energy storage systems increase load. However, as recognized in D.11-09-015 and the current SGIP Handbook, storage may reduce GHG emissions by shifting load from hours in which marginal demand is met by less-efficient plants.

The current SGIP methodology assumes that storage devices charge during off-peak hours and discharge during peak hours. The net emission impact of operating SGIP energy storage systems are estimated using the emission rate of a new CT as a proxy for the emissions avoided by reducing demand during peak hours and the emission rate of a new CCGT plant as proxy for the off-peak marginal emissions rate.

In response to the ACR, PG&E and SCE recommended maintaining the current assumption for now but improving the avoided emissions estimate in the future through additional analysis, such as the use of production cost modeling.³⁸

SolarCity stated that its energy storage systems operate in the range of 80% to 86% round trip efficiency, but SolarCity recommended a minimum 75% round trip efficiency to not preclude participation by emerging technologies. SolarCity provides no analysis of the GHG impacts of the 75% rate to support its position.³⁹

CESA stated that the assumption that CTs are marginal during peak hours and CCGTs are marginal during off-peak hours is no longer valid. As the percentage of renewable energy in California's supply grows, renewables will increasingly operate as the marginal resource. Citing analysis by CAISO and

³⁸ SCE April 17, 2015 opening comments at 7; PG&E April 17, 2015 opening comments at 10-11.

³⁹ Solar City April 17, 2015 opening comments at 9-10.

E3, CESA stated that some negative pricing is already occurring in the CAISO markets and CAISO forecasts that renewable curtailment will increase substantially under a 40% RPS.⁴⁰

CESA recommended using a production cost model rather than relying on broad assumptions regarding the resources incremented and decremented by the dispatch of storage systems. In order to develop an estimate of a roundtrip efficiency that will yield GHG savings, CESA retained a consultant, Energy Exemplar, to run the PLEXOS production cost model, which is also used by CAISO.

Energy Exemplar modeled the WECC interconnect using the 40% RPS scenario data from CAISO and found that the addition of 412.5 MW of storage with two hours of capacity and 60% round-trip efficiency reduced annual GHG emissions by nearly 204 thousand tons of CO₂ and reduced renewable curtailment by 8%.⁴¹ It appears that CESA simply selected the 60% round-trip efficiency value for the PLEXOS model runs rather than attempting to find the minimum round-trip efficiency value that would yield GHG savings.

We find that the production cost modeling approach, as recommended by CESA, is a promising method for determining the GHG emissions eligibility threshold for SGIP energy storage as well as generation technologies. Nevertheless, we do not adopt it today because more time is needed to vet the assumptions regarding storage dispatch and other factors influencing the outcome of the PLEXOS results. While parties commented on the increasing likelihood of renewables operating on the margin and associated curtailment,

⁴⁰ CESA April 17, 2015 opening comments at 5-10.

⁴¹ CESA April 17, 2015 opening comments at 19-20.

significant curtailment is not expected to occur until renewables reach 40% of the portfolio, with most of that curtailment expected from solar.⁴² Furthermore, as noted previously, the state has not yet officially adopted a 40% or 50% RPS.

Therefore, we do not find it reasonable to rely on scenarios that assume renewable percentages above 33% by a particular date. However, when more data and operational experience exists to demonstrate that storage avoids solar curtailment, we may revisit the assumption that storage primarily affects the dispatch of CTs and CCGTs. We further find it is reasonable to continue to base SGIP GHG eligibility for energy storage systems on the emission rates of CCGTs and CTs. For the emission rate assumptions, we find it reasonable to apply both the operating margin and build margin emission rates for generation technologies and the 50/50 weighting of the two effects as discussed in Section 3.

6.1. Line Loss Factors

The other factor we must address regarding storage eligibility concerns the assumed line loss factors during peak and off-peak hours, which affects the minimum round-trip efficiency. Storage is expected to charge primarily during off-peak hours and discharge during peak hours. Because line losses are substantially lower during off-peak hours and higher during peak hours, lower round-trip efficiencies are required to reduce emissions overall than would be the case if one value for average losses were used instead.

Few parties addressed this issue. SolarCity asked that we retain the 5.3% off-peak and 10.3% on-peak loss factors adopted in Commission Resolution E-4519. CESA recommended that the difference between the on-peak and

⁴² CESA April 17, 2015 opening comments at 7.

off-peak line loss factors be increased from 5% to 10%⁴³ but does not provide specific on-peak and off-peak factors or a basis for calculating the factors that would yield a 10% differential. Therefore, in the absence of adequate information, we find it reasonable to retain the current 5.3% and 10.3% values.

Based on the parameters discussed above for operating margin emission factors, build margin emission factors, line losses, and performance degradation, energy storage projects should achieve a minimum round-trip efficiency of 66.5% over ten years of operations to qualify for SGIP. The full calculation is shown in Appendix A.

7. Safety Considerations

We find that the determination of a GHG emission rate pursuant to § 379.6(b)(2) for technologies to be eligible to participate in the SGIP raises no safety considerations.

8. Comments on Proposed Decision

The proposed decision of Commissioner Picker in this matter was mailed on _____ to the parties in accordance with § 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were timely filed on ____ by ____, and reply comments were timely filed on ____ by _____. The proposed decision has been modified where appropriate in response to the comments and reply comments filed.

⁴³ CESA April 17, 2015 opening comments at 17.

9. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Regina DeAngelis and Karin Hieta are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. On September 8, 2011, the Commission adopted Decision (D.) 11-09-015, which implemented SB 412 and set a GHG emission rate eligibility threshold of 379 kgCO₂/MWh.
2. The 379 kg CO₂/MWh avoided emissions factor adopted in D.11-09-015 was based on the factor of 437 kg CO₂/MWh used in ARB's 2008 AB 32 Scoping Plan to estimate the benefits of avoided grid electricity.
3. D.11-09-015 adjusted this 437 kgCO₂/MWh factor downward by 20% to reflect the fact that the utilities' electricity resource mix includes renewable resources required under the RPS statute.
4. D.11-09-015 stated that ARB's emissions factor of 437 kgCO₂/MWh was "based on the [weighted average] emission rate of gas-fired power plants from 2002 to 2004, and it does not reflect the lower emission rate of newer gas-fired units that SGIP projects may avoid going forward."
5. D.11-09-015 adopted a 7.8% average transmission and distribution line loss factor to account for the electricity and associated emissions saved by serving load with on-site generation.
6. D.11-09-015 adopted a time frame of 10 years for evaluating whether SGIP projects reduce GHG emissions and an assumed degradation in electrical conversion efficiency of 1% per year.
7. Storage technologies do not directly emit GHGs; they may cause emissions to occur when they charge and displace emissions when they discharge.

8. In resolution E-4519 the Commission determined that a minimum round-trip efficiency for storage technologies of 63.5% was required for a storage device to be GHG reducing.

9. SB 861 extended SGIP from January 1, 2016 to January 1, 2021 and added § 379.6(b)(2).

10. Insufficient data was provided to merit changing the assumed 1% per year degradation in conversion efficiency.

11. No party provided compelling reasons to revise the 10 year time frame for evaluating whether GHG emissions reductions occur.

12. New customer-sited generation may displace emissions from existing dispatchable generation facilities (the operating margin effect), reduce the need for new generation facilities that would otherwise have been built to serve the load met by the SGIP projects (the build margin effect), or affect both the operating and build margins.

13. California's RPS program requires utilities to procure enough renewable energy to meet a certain percentage of their retail loads with renewable energy by 2020.

14. The Commission authorizes utilities to procure new capacity for reliability purposes using the CEC's Integrated Energy Policy Report (IEPR) forecasts as a basis.

15. Utilities use the IEPR forecasts as a basis to calculate their renewable net short positions to determine how much renewable energy capacity to procure to comply with the RPS targets.

16. The CEC's 2014-2024 demand forecast cites SGIP as one of the "major programs designed to promote self-generation" that are accounted for in the demand forecast.

17. During periods of overcapacity, projects may only displace the operating margin for some period of time before they affect the build margin.

18. In D.14-03-004, , the Commission found that new capacity would not be needed in either the SCE or SDG&E territories before 2022.

19. The Commission has yet to exercise the authority granted by AB 327 to require the utilities under our jurisdiction to procure more than the minimum 33% prescribed by the RPS statute.

20. The RPS program requires load serving entities to procure a certain percentage of renewable energy as a share of their retail loads. Because no adjustment is made for the line losses that occur to deliver energy to customers, a given RPS target results in a lower percentage of renewable energy as a share of the wholesale energy procured to serve customers.

21. ARB collects, and reports, total emissions for all stationary facilities emitting 10,000 metric tons of CO₂ equivalent or more per year. ARB neither collects nor reports nameplate capacity or net electricity generated by facility, nor does ARB assign emissions in any way to the utilities' service areas.

22. The CEC's Quarterly Fuel and Energy Report provides monthly data on power plant rated capacity, generation, fuel type, and fuel consumption.

23. The CEC's *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update* report uses CEC's QFER data to derive heat rates by generation technology for the years 2001 through 2013. The report shows that 2013 average heat rates are 7,205 and 10,268 Btu/kWh, respectively, for combined cycle and peaker plants, equivalent to emission rates of 382 kgCO₂/MWh and 544 kgCO₂/MWh, respectively.

24. Because the conversion efficiencies of gas-fired technologies continue to improve, the emission rates of the new gas-fired plants displaced by SGIP

projects and other demand-side measures will usually be lower than the existing plants whose output is avoided on the operating margin.

25. In California, efficiency improvements of gas-fired technologies may be partially offset if only dry cooled combined cycle plants, which are 5 – 10% less efficient than wet-cooled units, are permitted in the future.

26. The 2013 CAISO *Annual Report on Market Issues and Performance* provides a mid-point estimate of 393 kgCO₂ for new CCGTs and 504 kgCO₂ for new CTs in California.

27. The value provided for CCGTs in the CAISO report is slightly higher than the emission rate of the existing fleet of CCGTs in 2013 according to the CEC Thermal Efficiency Report.

28. The emissions rate of the existing fleet of CTs, according the CEC Thermal Efficiency Report, is lower than the assumed value of 575 kgCO₂ for a new CT used in the current SGIP Handbook.

29. World Resources Institute's GHG Guidelines document recommends weighting generation resources in the calculation of marginal emission rates according to the proportion of time that they provide the marginal source of generation.

30. Neither the share of electricity generated nor the average capacity factor of a type of a generation resource provides an accurate estimate of the amount of time that a resource type spends on the margin.

31. The 2013 CAISO *Annual Report on Market Issues and Performance* estimates that new combustion turbines, which should operate more frequently than older less-efficient peaker units, operated at an approximately 8% capacity factor during the 2010 to 2013 time period.

32. The calculation of an avoided GHG emission rate for SGIP projects and other demand-side measures must account for the line losses that they save by providing electricity for on-site consumption.

33. D.11-09-015 set a single statewide assumption of 7.8% line losses, consistent with ARB's 2008 Scoping Plan and the CEC's 2008 - 2018 demand forecast.

34. The CEC's 2015 - 2025 demand forecast uses an assumed line loss factor of 7.3%.

35. Bottom-up distribution loss data from filings submitted by each utility and transmission loss data derived from CAISO wholesale price data yield a statewide average line loss factor of 8.4%.

36. Because CHP projects displace the useful thermal output that would have otherwise been provided by boilers, an assumed boiler efficiency is needed to credit CHP project for avoided boiler fuel consumption.

37. The assumed boiler efficiency currently in use for SGIP is 80%.

38. Electricity exports from CHP systems and other non-NEM sources do not lower retail load and therefore do not displace new renewable generation under the RPS program.

39. An assumed efficiency of 80% is reasonable for the existing fleet of boilers.

40. New mid-efficiency boilers are available with efficiencies ranging from 83-88%.

41. No data have been provided in this proceeding regarding the extent to which SGIP CHP projects may displace new boilers that would have otherwise been installed rather than existing boilers with several years of useful life remaining.

42. No data have been provided in this proceeding regarding the market penetration of mid- and high-efficiency boilers.

43. Very few non-NEM grid exporting projects have been installed under SGIP and many non-NEM projects have protection relays to prevent exports.

44. Energy storage may reduce GHG emissions by shifting load from hours in which marginal demand is met by less-efficient plants, such as simple cycle peaker units, to hours in which highly efficient CCGTs operate on the margin.

45. The current SGIP methodology assumes that storage devices charge during off-peak hours and discharge during peak hours. The methodology estimates the net emission impact using the emission rate of a new CT as a proxy for the emissions avoided by reducing demand during peak hours and the emission rate of a new CCGT plant as proxy for the off-peak marginal emissions rate.

46. The operating margin and build margin emission rates for CCGTs and CTs used to determine storage eligibility should be consistent with the emission rates used to determine eligibility for generation technologies.

47. CESA submitted production-cost modeling results demonstrating that storage devices with round-trip efficiencies as low as 60% will reduce GHGs in the WECC territory.

48. Parties did not thoroughly vet CESA's production cost model runs.

49. SGIP currently assumes 10.3% line losses during peak hours and 5.3% during off-peak hours.

50. Parties did not provide adequate information to support changing the peak and off-peak line loss factors.

Conclusions of Law

1. The assumption of 1% annual performance degradation for all SGIP eligible technologies is reasonable and should be maintained.
2. The 10 year time frame for evaluating whether SGIP projects reduce GHG emissions is reasonable and should be maintained.
3. Under the present circumstances on California's grid, it is reasonable to weight the build margin and operating margin effects on a 50/50 basis in the avoided GHG emission factor methodology for SGIP projects under § 379.6(b)(2).
4. It is reasonable to set the operating margin emission rate for CCGTs and CTs at 382 kgCO₂/MWh and 544 kgCO₂/MWh, respectively.
5. It is reasonable to maintain the build margin emission rate for new CCGTs at 368 kgCO₂/MWh.
6. It is reasonable to assume a reduction in the GHG emission rate of new CTs relative to the existing fleet comparable to the 3.7% expected reduction for CCGTs using the operating margin and build margin values adopted for CCGTs.
7. It is reasonable to set the build margin emission rate for CTs at 524 kgCO₂/MWh.
8. It is reasonable to set the avoided GHG emissions calculations for SGIP projects using a statewide average line loss factor of 8.4%.
9. Assuming that new renewable capacity is avoided in the build margin in proportion to the current 33% RPS requirement is conservative because the Legislature or the Commission may increase the renewable requirement in the future.
10. The share of renewable energy avoided in the build margin effect should be adjusted for line losses to reflect that the RPS obligations are defined relative to total retail load.

11. It is reasonable to revise the SGIP GHG emissions eligibility threshold under § 379.6(b)(2) for generation technologies to 360 kgCO₂/MWh.

12. Under § 379.6(b)(2), it is reasonable for GHG-emitting technologies to demonstrate they will emit GHG emissions at a rate no higher than 360 kgCO₂/MWh during their first ten years of operations, accounting for performance degradation, in order to receive SGIP incentives.

13. It is reasonable for SGIP projects to continue to use an assumed boiler efficiency of 80%.

14. It is reasonable for SGIP projects to not include a separate marginal emission rate for exports from non-NEM projects.

15. SGIP should continue to use a peak line loss factor of 10.3% and off-peak line loss factor of 5.3% to determine the minimum round-trip efficiency for storage projects.

16. When calculating the minimum round trip efficiency for storage devices, SGIP should use the operating margin and build margin emission rates for CCGTs and CTs that are applied when calculating avoided emissions for generation projects.

17. Storage devices should demonstrate an average an annual round trip efficiency of 66.5% over ten years to qualify for SGIP under § 379.6(b)(2).

ORDER

IT IS ORDERED that:

1. Within 30 days of the effective date of this decision, the Center for Sustainable Energy, Pacific Gas and Electric Company, Southern California Edison Company, and Southern California Gas Company shall jointly file a Tier 1 Advice Letter revising the Self-Generation Incentive Program Handbook to

modify the greenhouse gas emissions standard to 360 kilograms carbon dioxide per megawatt hour and to modify the minimum average round-trip efficiency for energy storage projects to 66.5%.

2. Rulemaking 12-11-005 remains open.

This order is effective today.

Dated _____, at San Francisco, California.

Appendix A: 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