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Decision 09-12-042 December 17, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion into Combined Heat and Power Pursuant to Assembly Bill 1613.	Rulemaking 08-06-024 (Filed June 26, 2008)

DECISION ADOPTING POLICIES AND PROCEDURES FOR PURCHASE OF EXCESS ELECTRICITY UNDER ASSEMBLY BILL 1613

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DECISION ADOPTING POLICIES AND PROCEDURES FOR PURCHASE OF EXCESS ELECTRICITY UNDER ASSEMBLY BILL 1613

1. Summary

This decision adopts the policies and procedures for purchase of excess electricity from eligible combined heat and power (CHP) systems by an electrical corporation under Assembly Bill (AB) 1613. The decision adopts two separate contracts for the purchase of excess electricity from eligible CHP systems. A standard contract will be available to all eligible CHP systems up to 20 megawatts (MW) and a simplified contract will be available to CHP systems that export no more than 5 MW. Investor-owned utilities' (IOUs) offers under the AB 1613 contracts will be based on the costs of a new combined cycle gas turbine, and a location bonus shall be applied to eligible CHP systems located in high-value areas. Unless otherwise excepted, all California electrical corporations shall be required to offer these contracts. This rulemaking remains open to address implementation of a "pay-as-you-save" program.

2. Background

On June 26, 2008, we opened this rulemaking to implement the provisions of Assembly Bill (AB) 1613, codified as Pub. Util. Code §§ 2840 et seq. (Stats. 2007, ch. 713.) AB 1613 established the Waste Heat and Carbon Emissions Reduction Act which relates to the utilization of excess waste heat through combined heat and power (CHP) technologies.[1] The legislation expresses the intent to support and facilitate both consumer and utility-owned CHP systems and imposes certain requirements on the Commission, the California Energy

Commission (CEC), the California Air Resources Board (ARB) and electric corporations.

The Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (Scoping Memo) issued on November 4, 2008, divided this proceeding into two phases. The first phase of this proceeding addresses the policies and procedures for purchase of excess electricity from eligible CHP systems, including the development of a standard contract. The Scoping Memo directed the Commission's Energy Division staff to prepare a draft proposal for consideration and discussion at a workshop. On February 3, 2009, Energy Division staff submitted its proposed policies and procedures for purchase of excess electricity in the form of a draft AB 1613 contract (Staff Proposal). A workshop was held to discuss the Staff Proposal on February 27, 2009. Prior to the workshop, pre-workshop comments were filed by Fuel Cell Energy, Inc. (Fuel Cell), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Energy Producers and Users Coalition (EPUC), California Cogeneration Council (CCC), Sierra Pacific Power Corp. (Sierra Pacific), California Clean DG Coalition (CCDC), The Utility Reform Network (TURN), and Pacific Gas and Electric Company (PG&E).

Following the workshop, the assigned Commissioner and Administrative Law Judge (ALJ) issued an Amended Scoping Memo which directed parties to work together to review the Staff Proposal and propose specific revisions to the

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[1] CHP (sometimes referred to as cogeneration) is the production of two kinds of energy — electricity and thermal heat — from a single source of fuel.

terms and conditions of the draft AB 1613 contract. Parties were also asked to brief four additional issues.[2]

A Working Group, consisting of the IOUs, governmental entities, smaller utilities, CHP representatives, consumer groups and other interested parties, met during April and May to review the Staff Proposal and proposed changes. The Working Group's report (Working Group Report) was submitted on May 15, 2009. Comments on the Working Group Report and in response to the four issues were filed on June 1, 2009 by SCE, SDG&E, PG&E, TURN, the Division of Ratepayer Advocates (DRA), EPUC, the California Independent Petroleum Association, Fuel Cell, jointly by Merced Irrigation District and Modesto Irrigation Districts (jointly, Irrigation Districts), and CCDC. Reply comments were filed on June 15, 2009 by PG&E, SDG&E, SCE, Fuel Cell, Irrigation Districts, Alliance for Retail Energy Markets (AReM) and CCDC.

A simplified AB 1613 contract for small CHP systems was subsequently filed by the Working Group on June 30, 2009. Comments on this simplified contract were filed on July 10, 2009 by SCE, PG&E, jointly by SDG&E and Southern California Gas Company (SoCalGas), Fuel Cell and CCDC.

On July 31, 2009, Energy Division staff submitted its final proposal on the standard contract terms and pricing for eligible CHP systems (Final Staff Proposal). In developing the Final Staff Proposal, Energy Division staff proposed that the Commission use the following guiding principles:

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[2] These issues concerned whether a simplified contract should be developed, how the terms "indifference" and "benefitting customer" should be interpreted, and whether a maximum kilowatt limitation should be established.

- Expand the market for small to medium scale (i.e., systems no more than 20 megawatts (MW)), highly efficient CHP in California and in so doing provide significant greenhouse gas (GHG) emissions reductions.
- Be simple and transparent - terms and conditions should be the same for each utility.
- To the greatest extent possible, lower the transaction costs for the seller, the buyer, and the regulator.
- Equitably allocate financial risk, relative to project size, between the buyer and the seller.
- Facilitate interconnection of projects that efficiently utilize the existing distribution system.
- Complement, but not interfere with or replace, existing programs, such as the Self-Generation Incentive Program.
- Provide sufficient payment to stimulate untapped markets and build new projects, but not overpay.

Among other things, the Final Staff Proposal recommends:

- two separate contracts for purchase of excess electricity. A standard contract would be offered to all eligible CHP systems up to 20 MW, and a simplified contract would be offered to eligible CHP systems that export up to 5 MW;
- transferring all GHG attributes and GHG compliance costs, if any, to the buyer; and
- an interim cap of 500 MW on the amount of excess electricity to be purchased.

The Final Staff Proposal also proposed two options for the pricing of power and sought parties' comments on these proposals.

Comments to the Final Staff Proposal were filed on August 24, 2009 by SCE, Fuel Cell, DRA, CCDC, jointly by SDG&E and SoCalGas, Sierra Pacific, Mountain Utilities, and jointly by PG&E and TURN. Reply comments were filed on September 4, 2009 by SCE, Fuel Cell, CCDC, jointly by PG&E and TURN, and jointly by CCC, EPUC and the Cogeneration Association of California.

3. Threshold Issues

3.1. Commission Authority to Establish AB 1613 Purchase Price

The primary issue of dispute in this proceeding has been the extent to which the Commission has authority to establish the price to be paid by electrical corporations to eligible CHP facilities. PG&E, SCE, and SDG&E/SoCalGas (collectively, the investor-owned utilities or IOUs) assert that since power sold under AB 1613 would be considered a wholesale transaction, the Commission has limited authority in setting the price for this feed-in tariff (FIT). They note that under the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) has sole jurisdiction to set rates for wholesale power sales to and by public utilities, unless the generator is a qualifying facility (QF).[3] Therefore, the IOUs assert that if the AB 1613 CHP is not a QF, the price is solely within the FERC's jurisdiction and must be based on prices in the California Independent System Operator (CAISO) market.[4] To the extent an AB 1613 CHP is a QF, the IOUs maintain that the Commission may only set prices at utility avoided cost.[5] We disagree with the IOUs' arguments that we are limited in our

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[3] Under the Public Utilities Regulatory Policy Act of 1978 (PURPA) and the FERC regulations implementing PURPA, the states have been delegated authority to establish the rates for sale of power by QFs to the utilities at no more than avoided cost.

[4] SCE Comments, June 1, 2009, at 8; PG&E Comments, June 1, 2009, at 2-3; SDG&E/SoCalGas Comments, June 1, 2009, at 2-3.

[5] The methodology for calculating IOU payments for power purchased from QFs was adopted in Decision (D.) 07-09-040.

ability to set prices under AB 1613, because the IOUs mischaracterize the program that is being established.

We disagree with the IOUs' assertions that CHP systems participating in the AB 1613 program should be considered QFs. AB 1613 does not make any reference to the PURPA requirements, nor does it require that a CHP obtain QF status in order to be eligible to participate under AB 1613.[6] Rather, eligibility is based on meeting and maintaining specified size limitations and standards set by statute and the CEC. Moreover, we note that the purposes of PURPA and AB 1613 derive from entirely different policy concerns. PURPA was enacted to address the nation's energy crisis and to reduce dependence on foreign oil.[7] When the FERC adopted rules implementing PURPA, FERC recognized that PURPA did not preempt State environmental laws, including State zoning, air, water, and other environmental quality laws.[8]

In contrast to PURPA, AB 1613 was enacted to further environmental objectives. Indeed, purchases of power under this program will be incorporated in a utility's procurement obligations "to the extent that it is cost effective compared to other competing forms of wholesale generation, technologically

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[6] Indeed, CHP systems participating in this program never would be QFs if they do not apply to the FERC for certification to become a QF. At the time that the FERC adopted rules implementing PURPA, FERC stated that its rules encourage but did not require the development of cogeneration or small power production facilties, and FERC acknowledged that certain cogeneration facilities would be constructed or operated outside of the incentives underlying FERC's QF rules. *Small Power Production and Cogeneration Facilities-Environmental Findings* (1980) 10 FERC ¶61,314 at 61,633

[7] *See, e.g., Federal Energy Regulatory Com. v. Mississippi* (1982) 456 U.S. 742, 745-46.

[8] *Small Power Production and Cogeneration Facilities-Environmental Findings, supra*, 10 FERC ¶61,314 at 61,632.

feasible, and environmentally beneficial, particularly as it pertains to reducing emissions of carbon dioxide and other greenhouse gases."[9] Thus, whether or not there are some similarities between how the Commission would process claims under AB 1613 with how it would process claims under PURPA, this would not be a basis for finding AB 1613 preempted. Indeed, notwithstanding the requirement under section 210 of PURPA, that state commissions must administer federal standards concerning QFs, the U.S. Supreme Court held that PURPA did not violate the Tenth Amendment of the U. S. Constitution, because state commissions already had "jurisdiction to entertain claims analogous to those granted by PURPA."[10]

We further disagree with the IOUs' arguments that the Commission is regulating the price of excess electricity sold under this program. AB 1613 is not regulating wholesale generators or marketers but the electrical corporations, which purchase electric energy and then sell it in the retail market in California. Under section 201(b) of the FPA, the FERC regulates the sellers of electric power in the wholesale electricity market. However, as the Commission explained in D.07-01-039 at p. 203: "FERC regulates the wholesale sellers, not the resource portfolios, including procurement choices, of the buyer. As FERC has stated in numerous decisions, FERC leaves the reasonableness of the procurement decisions to the state commissions, because FERC does not view its

[9] Pub. Util. Code § 2842.

[10] *Federal Energy Regulatory Com. v. Mississippi*, *supra,* 456 U.S. at 760.

'responsibilities under the Federal Power Act as including a determination that the purchaser has purchased wisely or has made the best deal available.'"[11]

Further, the policy objectives of AB 1613 are to:

> [(a)] advance the efficiency of the state's use of natural gas by capturing unused waste heat, and in doing so, help offset the growing crisis in electricity supply and transmission congestion in the state.
>
> [(b)] reduce wasteful consumption of energy through improved . . . utilization of waste heat whenever it is cost effective, technologically feasible, and environmentally beneficial, particularly when this reduces emission of carbon dioxide and other carbon-based greenhouse gases.[12]

AB 1613 directs the Commission to establish an FIT for excess electricity to achieve these policy objectives. Unlike programs promoting the purchase of energy from certain types of generators, this FIT is an incentive structure to encourage the adoption of energy efficiency measures with beneficial environmental attributes – in this case, generation of excess electricity from what would have otherwise been waste heat. Thus, this program will enhance the efficiency of operation of an existing class of industrial boilers by providing incentives for their owners to install heat recovery steam generators and turbines at the tail end of these existing units. This will capture and make useful the energy already produced by boilers, which until now, had been discharged to

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[11] *See, e.g., Ameren Energy Marketing Company (*2001) 96 FERC ¶ 61,306 at 62,189 & n. 18 (and cases cited therein).

[12] Pub. Util. Code § 2840.6, subd. (a).

the atmosphere as waste heat.[13] Moreover, AB 1613's policy goal to reduce carbon-based emissions is part of the state's overall objective to reduce GHG emissions, as articulated in AB 32.[14]

Under AB 1613, a CHP system may only participate if it meets certain requirements, including complying with the CEC's guidelines for certification, meeting an oxides of nitrogen (NO_x) emissions rate standard of 0.07 pounds per megawatt-hour (MWh) and a minimum efficiency of 60 percent, complying with the GHG emission performance standard, and continuing to meet or exceed the efficiency and emissions standards throughout its operation.[15] Under the CEC's draft *Guidelines for Certification of Combined Heat and Power Systems Under the Waste Heat and Carbon Emissions Reduction Act, Public Utilities Code Section 2840 et seq.* (*CEC Staff Draft Guidelines*) issued October 2009, the CEC has proposed various standards that a CHP facility must meet in order to receive certification.[16] In addition to the efficiency and emissions standards specified under § 2843, a CHP facility would need to meet certain net electrical generating capacity, thermal energy utilization, and fuel savings standards. The *CEC Staff Draft Guidelines* further recommends annual reporting by the CHP owner/operator to

[13] This process and logic can be used to describe either topping-cycle or bottoming-cycle CHP; the policy goal to maximize the use of waste heat applies to both.

[14] AB 32 (Stats. 2006, ch. 598) requires, among other things, that the ARB adopt a statewide GHG emissions limit equivalent to the statewide GHG emissions levels in 1990, to be achieved by 2020, in consultation with this Commission and the CEC.

[15] *See* Pub. Util. Code § 2843.

[16] The *CEC Staff Draft Guidelines* may be found at http://energy.ca.gov/2009publications/CEC-200-2009-016/CEC-200-2009-016-SD.PDF.

ensure ongoing compliance. Finally as discussed in Section 3.4 below, we shall be setting an initial statewide cap of 500 MW for the program.

The IOUs, particularly SCE, have argued throughout this proceeding that the FERC has already affirmed its authority to set prices for programs such as AB 1613. We do not find these arguments persuasive. The FERC decisions relied on by the IOUs affirm that the FERC has sole jurisdiction to set rates for wholesale sales in interstate commerce in order to ensure competitive wholesale energy markets. However, as explained above, AB 1613 is encouraging the development of more efficient CHP systems that would provide environmental benefits. In order to achieve this objective, the Commission is directing the electrical corporations to incorporate these systems into the utilities' procurement obligations. Consequently, AB 1613 requires the Commission to treat these incentives for new CHP systems to reduce GHG emissions as a component of the Commission's regulation of the procurement practices of the electrical corporations, and the Commission is directing IOUs subject to its jurisdiction to offer to purchase excess electricity from eligible CHP systems under this program. Under section 201(b) of the FPA (16 U.S.C. § 824(b), Congress preserves the states' authority over such retail sales service, including determining the composition of utility portfolios subject to their jurisdiction.[17] Indeed, the FERC has acknowledged that with regard to the retail electric market, "state regulatory commissions and state legislatures have traditionally developed social and environmental programs suited to the circumstances of

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[17] *See New York v. FERC* (2002) 535 U.S. 1, 20, 23, 24, 28; *see also Connecticut Light and Power Co. v. FPC*, (1945) 324 U. S. 515, 523-531..

their states. Nothing in [FERC's Order No. 888] is inconsistent with traditional state regulatory authority in this area."[18] For example, we noted in D.08-03-018

> There is no "field preemption" [in the regulation of GHG emissions] because in enacting the FPA, Congress did not intend, either explicitly or implicitly, to occupy the field of environmental regulation of the power sector. California will be regulating in a field (GHG emissions and their reduction) that Congress has not even addressed in the FPA, nor is there any suggestion in the FPA or in its administration that Congress intended to forbid states from enacting GHG regulations on their own. The regulations we are recommending to ARB are not directed at wholesale rates or service or the other terms and conditions of wholesale sales that are the focus of the FPA. Rather, they are directed at reducing GHG emissions associated with the generation of electricity in California and with ultimate electric service within California, matters left to the discretion of the states. Nothing in the part of the FPA at issue here or its legislative history suggests that Congress intended to occupy the field of environmental regulation, which is the sole purpose of the California law and proposed regulations at issue here.[19]

The FERC is well aware that certain states require that the resource portfolios of their state-regulated utilities include generation and procurement from sources that will cause minimal damage to the environment. Thus, it has recognized the authority of the states to regulate in the area of GHG reductions.[20] Moreover, the FERC has recently determined that energy efficiency programs should be within the state's jurisdiction and stated that "CAISO should respect

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[18] *See* Order No. 888, FERC Stats. & Regs., Regs. Preambles, Jan. 1991-June 1996, ¶ 31,036, p. 31,782 (1996).

[19] D.08-03-018, at 81-82 (footnote omitted).

[20] *See e.g., American Ref-Fuel Co., et al.* (2004) 107 FERC ¶ 61,016.

California's determination that energy efficiency and demand-side resources receive the highest priority in meeting future reliability needs."[21]

Finally, a memorandum issued by the Obama Administration to the heads of Federal Executive Departments and Agencies directs these agencies to avoid preempting states in their implementation of state initiatives, such as environmental measures.[22] In the Executive Memorandum, President Obama quotes Justice Brandeis in explaining that "[i]t is one of the happy incidents of the federal system that a single courageous state may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country."[23] Similarly, in describing Congress' intent within a few years after the enactment of the FPA, the Supreme Court explained:

> Congress is acutely aware of the existence and vitality of state governments. It sometimes is moved to respect state rights and local institutions even when some degree of efficiency of a federal plan is thereby sacrificed…It may, too, think it wise to keep the hand of state regulatory bodies in this business, for the "insulated chambers of the states" are still laboratories where many lessons in regulation may be learned by trial and error on a small scale without involving a whole national industry in every experiment. [24]

These factors all support a conclusion that setting the FIT contemplated under AB 1613 would be within the Commission's authority. Although the

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21 *In re California Independent System Operator Corporation* (Docket ER-06-615) 2007 FERC LEXIS 827, 178.

22 *Memorandum on Preemption*, published May 22, 2009. *DCPD Number:* DCPD200900384. This document may be found at http://www.gpo.gov/fdsys/pkg/DCPD-200900384/pdf/DCPD-200900384.pdf.

23 *Id.*

24 *Connecticut Light & Power Company v. Federal Power Commission*, 324 U.S. at 525-530.

program will result in the California utilities' purchases of excess electricity, the program would serve the public interest by encouraging additional efficient use of energy and the resulting reduction of GHG emissions. Additionally, the program does not – and does not purport to – regulate the conduct of sellers. No seller is required to participate in this program and the program does not restrict the ability of any seller to sell its excess electricity in the CAISO market. The FIT is simply an option provided by the retail electric utilities available to the sellers, as an incentive to meet California's environmental goals.

Thus, the Commission could still set the price for California utilities to offer to pay sellers to encourage development of these highly efficient CHP facilities in order to reduce GHG emissions.

3.2. Indifference

Pub. Util. Code § 2841(b)(4) states that ratepayers not utilizing CHP systems should be "held indifferent to the existence of this tariff." Parties were asked how indifference should be determined under AB 1613. All parties state that establishing an "appropriate" level of pricing will ensure that ratepayers are indifferent to the existence of an AB 1613 tariff. However, there are varying opinions on what would be considered an appropriate level.

3.2.1. Parties' Positions

SCE maintains that prices paid for power in the day-ahead CAISO market are the appropriate measure for ratepayer indifference because "the CAISO wholesale market is where SCE would buy power if an AB 1613 system did not produce power as expected."[25] SDG&E/SoCalGas contend that ratepayers not

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[25] SCE Comments, June 1, 2009, at 8.

utilizing the CHP systems would be held indifferent only if the price is based on utility avoided cost or the CAISO day-ahead market, since these are the costs the utility would have otherwise paid for energy and capacity.[26] PG&E agrees with SDG&E/SoCalGas and further states that certain non-price contract provisions, such as operational issues, may also result in higher costs to non-CHP customers. Therefore, it contends that any costs resulting from these non-price provisions must also be accounted for to ensure non-CHP customers will be held indifferent.[27]

Fuel Cell maintains that customer indifference should not be defined by reference to utility avoided costs since QF pricing under PURPA is administratively established and must comply with Federal regulation.[28] It points out that in contrast, AB 1613 specifies the criteria for participation in the program and that there is no requirement that a CHP facility have QF status. Fuel Cell argues that indifference under AB 1613 should take into account not only the price paid for power, but also all costs and benefits associated with AB 1613. It states these possible costs and benefits would include any above- or below-market costs for power, price paid for or value received from GHG emission reductions, resource adequacy benefits, and benefits associated with added distributed generation.

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[26] SDG&E/SoCalGas Comments, June 1, 2009, at 2-3. In contrast, SCE has argued that the currently-adopted methodology for calculating utility avoided cost is not the appropriate measure for ratepayer indifference as it does not believe this methodology results in prices that accurately reflect its true avoided costs. (SCE Comments, June 1, 2009, at 9.)

[27] PG&E Comments, June 1, 2009, at 5-6.

[28] Fuel Cell Comments, June 1, 2009, at 17.

CCDC maintains that market-based pricing, such as the Market Price Referent (MPR), would ensure that ratepayers would be held indifferent to the existence of an AB 1613 tariff. It notes that the MPR has been used to determine the reasonableness of renewable energy contracts. Thus, similar to the finding of reasonableness in the context of renewable procurement, AB 1613 contracts based on MPR pricing could be considered "reasonable per se."[29] CCDC further asserts that AB 1613 contemplates that there will be benefits associated with the sale and purchase of excess energy. Thus it argues that any market-based pricing mechanism also includes the benefits of CHP to ensure indifference.

3.2.2. Discussion

We agree with parties that customer indifference is achieved when ratepayers not utilizing the CHP systems are no worse off, nor any better off, as a result of power purchased pursuant to AB 1613. While one could argue that indifference would be achieved by setting price equal to an electrical corporation's avoided cost or the market price, we do not believe that such a narrow application would be the appropriate measure in this instance. As we have previously discussed, the intent of AB 1613 is to reduce GHG emissions and other pollutants through the development of small, highly efficient CHP systems. Consequently, customers not utilizing these CHP systems will be receiving not only electricity from these systems, but also certain societal benefits.[30] As such, in order to ensure that customers not utilizing the eligible

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[29] CCDC Comments, June 1, 2009, at 11.

[30] These benefits could include environmental benefits due to reduced GHG emissions and more efficient use of waste heat and natural gas, as well as locational benefits associated with reduced congestion in certain load-constrained areas.

CHP systems are no better off, the price paid under this program should include the value of these benefits.

PG&E contends that since any potential environmental or locational benefits associated with energy sold under AB 1613 have not been quantified, there would be no basis for imposing additional costs on customers.[31] We disagree that these benefits have not been quantified. As discussed below, the price for power under the AB 1613 program will include a location bonus and costs for GHG attributes. These costs would reasonably approximate the value of the benefits obtained under the program.

In light of these considerations, we find that customer indifference under AB 1613 would not be achieved if the price paid under the program only reflected the market price of power. As discussed, since customers who are not utilizing the eligible CHP system will receive environmental and locational benefits from these systems, the price paid for power should also include the costs to obtain these benefits.

3.3. Benefiting Customers

Pub. Util. Code § 2841(e) requires that the costs and benefits associated with the new CHP tariff be allocated to all "benefiting customers" and that this term may include "bundled service customers of the electrical corporation, customers of the electrical corporation that receive their electric service through a direct transaction, as defined in [Pub. Util. Code § 331(c)], and customers of an electrical corporation that receive their electric service from a community choice

[31] PG&E Reply Comments, June 15, 2009, at 11.

aggregator, as defined in [Pub. Util. Code] Section 331.1."[32] Parties were asked to comment how broadly this term should be construed for purposes of allocating the costs and benefits associated with the AB 1613 tariff.

3.3.1. Parties' Positions

The IOUs advocate the broadest definition of "benefiting customer." SCE states that "[t]o the extent the purpose of AB 1613 is to reduce carbon emissions, all residents of the state are "benefitting customers," and the net costs should be spread equally among all bundled service customers, direct access (DA) customers and community choice aggregation (CCA) customers."[33] In support of its proposal, SCE notes that D.06-07-029 had allocated the benefits and costs of new generation to all customers in an IOU's service territory. PG&E agrees with SCE, but notes that since it is not clear what benefits would result from the AB 1613 program, benefits should be allocated based on each customer group's contribution to payment of above-market costs.[34]

Irrigation Districts assert that the definition of "benefiting customer" is limited under AB 1613 to only three categories of electrical corporation customers: bundled service customers, DA customers, and CCA customers.[35] They note that since § 2841(e) only identifies three categories of customers, it would violate the rules of statutory interpretation to include customers of publicly owned utilities (POUs) in the term "benefiting customers." Irrigation Districts list additional reasons why POU customers should not fall within the

[32] Pub. Util. Code § 2841, subd. (e).

[33] SCE Comments, June 1, 2009, at 16.

[34] PG&E Comments, June 1, 2009, at 7.

[35] Irrigation Districts Comments, June 1, 2009, at 3.

definition of "benefiting customer." First, they note that POU customers generally receive electric and distribution service from a publicly owned utility and no services from the electrical corporation. Further, they state that POU customers do not fall within the definition of a DA customer as defined in § 331, or a CCA customer, as defined in § 331.1. Finally, Irrigation Districts state that POU customers who were formerly bundled service customers have, with the exception of large municipalizations, been excepted from any non-bypassable charges associated with "new world generation."[36] Thus, they contend that since generation contracted under AB 1613 is "new world generation," even these POU customers should not be allocated any costs associated with it.

CCDC also argues that the Commission may only consider three categories of electrical corporation customers as "benefiting customers" under AB 1613.[37] It raises many of the same arguments concerning statutory interpretation as Irrigation Districts. Thus, CCDC maintains the Commission may only include one, two or all three of the customer categories listed in § 2841(e) in the term "benefiting customers."

AReM asserts that costs should only be allocated to bundled customers. It notes that the proposed Standard Contract provides that all benefits under the contract, including all GHG-related rights and benefits, are to be conveyed to the buyer (i.e., electric corporation). As such, AReM asserts that only bundled

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36 Irrigation Districts Comments, June 1, 2009, at 8 (citing D.08-09-012 at 12). In D.08-09-012, "new world generation" was defined as generation from both fossil-fueled and renewable resources contracted for or constructed by the investor-owned utilities subsequent to January 1, 2003.

37 CCDC Comments, June 1, 2009, at 12.

customers will receive any of the benefits associated with power purchased under AB 1613. [38]

AReM also disputes PG&E's conclusion that above-market costs should be allocated to all customers. AReM notes that allocation of "above-market" costs is not included in the statute. It further notes that the name of the statute is not a basis for the cost allocation proposed by the IOUs, since all load serving entities, including electric service providers, are obligated to meet the State's GHG requirements. As such, AReM believes allocation of costs to DA customers would be both anticompetitive and contrary to AB 1613.

Finally, AReM disputes the IOU's proposals that existing Commission decisions concerning cost allocation should be applied to AB 1613. It contends that the allocation methodology adopted in D.06-07-029 is not applicable because the purpose of adopting a broad definition of benefiting customer in that decision was to meet a system reliability need.[39] AReM states that AB 1613 does not make any statements concerning a need to improve system reliability, but rather includes a provision in the event procurement under the statute would adversely affect reliability.

AReM concedes that the Commission could impose a non-bypassable charge (NBC) on current bundled customers who later depart utility service and receive electric service from an electric service provider (ESP) or CCA, but contends that the mechanism adopted in D.08-09-012 is not wholly applicable. AReM states that this is because D.08-09-012 does not include the allocation of

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[38] AReM Reply Comments, June 15, 2009, at 5.

[39] AReM Reply Comments, June 15, 2009, at 5-6.

benefits to these departing customers. Therefore, AReM maintains that if the Commission were to impose an NBC, it would need to conduct a separate proceeding to determine how to calculate and distribute the associated benefits with the departing load.[40]

3.3.2. Discussion

Parties' comments raise two main considerations – which customer categories should be included in the term "benefiting customers" and what costs and benefits should be allocated to these benefiting customers. Both of these considerations must be addressed in order to properly allocate costs and benefits to ensure ratepayer indifference.

In determining which customer categories should be included in the term "benefiting customers," we must first consider whether § 2841 expressly limits the term "benefiting customers" to the three customer categories listed in the statute, as has been proposed by some parties. Section 2841(e) states, in pertinent part:

> For purposes of this section, "benefiting customers" may, as determined by the commission, include bundled service customers of the electrical corporation, customers of the electrical corporation that receive their service through a direct transaction, as defined in subdivision (c) of Section 331, and customers of an electrical corporation that receive their electric service from a community choice aggregator, as defined in Section 331.1.

A proper reading of this language would indicate that the Commission is to determine which customers are to be included in the term "benefiting

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[40] AReM Reply Comments, June 15, 2009, at 8.

customers" and that these groups may include the three categories identified in the statute. However, there is nothing in the statute stating that these are the only customer categories to be included. If the Legislature had intended the list to be inclusive, the statute would have contained more limiting language, such as "may only include" or "shall be limited to." However, it does not. Rather, § 2841(e) states that the term "*may*, as determined by the Commission, include" the categories listed. This language more reasonably supports a conclusion that the three categories listed in the statute were examples of what categories of customers could be considered "benefiting customers" and not an exhaustive list. As such, our consideration of which customer categories should be considered benefiting customers is not limited to the categories listed in § 2841(e), and may include other categories of customers.

We next consider which customer categories should be allocated the costs and benefits under AB 1613. AReM has argued that benefiting customers should be limited to only those customers that receive the power purchased under AB 1613, since the contract conveys all benefits, such as GHG-related attributes, to the buyer. In contrast, the IOUs have advocated a much broader definition of benefiting customer due to the policy objectives of AB 1613.

We do not agree that only bundled customers would receive benefits under AB 1613. Although the AB 1613 contracts have identified certain quantifiable benefits that shall be conveyed to the buyers, all customers will benefit from reduced GHG emissions, potential reduction in congestion and more efficient utilization of natural gas as a result of encouraging development of these CHP systems. Because all retail end-use customers will receive the beneficial attributes associated with these CHP systems, they would reasonably be considered "benefiting customers" under AB 1613.

This determination is supported by prior Commission decisions. For example, in allocating the costs associated with power purchased by the Department of Water Resources (DWR) between January 17 and February 2, 2000, the Commission determined that all retail end-use customers should bear cost responsibility because these purchases had served to stabilize the entire electric grid during the Energy Crisis.[41] Thus, even though not all retail end-use customers received power purchased by DWR during that time period, the overall benefits to all California customers supported a conclusion that costs for that power should be allocated to them. Similarly, all customers will benefit as a result of AB 1613 and, thus, should bear some responsibility for costs associated with these tariffs and contracts. Accordingly, we find that "benefiting customers" shall include all retail end-use customers within the service territory of the electrical corporation.

Although we find that the term "benefiting customer" is not constrained to the categories identified in § 2841(e) and should be construed broadly, we agree with Irrigation Districts that POU customers should not be included in the definition of benefiting customer. As Irrigation Districts note, § 2841.5 requires POUs, such as Irrigation Districts, to establish their own program for purchase of power under AB 1613.

Although AB 1613 provides that the benefits and costs of the electrical corporation's tariff be allocated to all benefiting customers, it does not include a similar provision for a program developed by a POU. Thus, a POU's customers would bear all responsibility for costs under the POU's program, even though all

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[41] *See* D.02-11-074, Attachment A, at 25-26.

retail end-use customers would receive the intangible benefits associated with this power. We do not believe that the Legislature intended to have POU customers bear a greater responsibility for costs under AB 1613 than other categories of customers when all customers would benefit equally. Accordingly, it would be unfair for a POU customer to be included as a benefiting customer under § 2841(e) since AB 1613 requires the POU to implement its own program. Based on these considerations, we find that "benefiting customers" shall consist of bundled service customers and customers receiving service from either an ESP or a CCA.

The second consideration is what costs should be allocated to the benefiting customers. Generally, all parties state that the above-market portion of stranded contract costs associated with customers departing bundled service may be allocated to these departing customers. We agree that this principle should be followed. However, as we have discussed in Section 3.1 above, the purpose of this FIT is to encourage the development of a certain type of CHP system that provides certain energy efficiency and environmental attributes. Thus, the FIT price may be higher than the average cost of the electrical corporation's procurement portfolio or the cost of energy in the CAISO market.

In this instance, we believe it would be reasonable to allocate the costs associated with the benefits to encourage development of this type of CHP system to all benefiting customers. As discussed in this decision, pricing under the contracts shall include costs associated with GHG attributes, in the form of GHG compliance costs, and an adder for locating within certain load areas. Since these costs would directly be associated with the benefits received by all customers, it would be reasonable to allocate these costs among all customers.

In light of these considerations, we find that the costs associated with the intangible benefits should be allocated to all benefiting customers. This shall be the costs associated with GHG attributes and for locating within certain load areas and will be allocated to benefiting customers on an equal cents/kilowatt-hour (kWh) basis. Calculation of the costs, and allocation among benefiting customers, shall be included in the electrical corporation's annual Energy Resource Recovery Account (ERRA) proceeding.

3.4. Program Cap

AB 1613 provides that "[t]he commission may establish a maximum kilowatt-hours (kWh) limitation on the amount of excess electricity that an electrical corporation is required to purchase if the commission finds that the anticipated excess electricity generated has an adverse effect on long-term resource planning or reliable operation of the grid."[42] The Final Staff Proposal recommends that the Commission adopt an interim statewide cap of 500 MW, based on the export capacity of participating CHP, which would be adjusted as part of each IOU's long-term procurement planning process.

3.4.1. Parties' Positions

The IOUs support the adoption of a program cap. SDG&E/SoCalGas contend that if the AB 1613 program were open-ended, it could be faced with the prospect of having to take power that is not needed.[43] Additionally, they present various situations that they believe would justify a limitation on the amount of excess electricity that they should be required to purchase. These include

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[42] Pub. Util. Code § 2841(a).

[43] SDG&E/SoCalGas Comments, June 1, 2009, at 4; SDG&E/SoCalGas Comments, August 24, 2009, at 9-10.

procurement under the state's renewables portfolio standards (RPS) goals and the possible lifting of the suspension of direct access.

SCE contends that AB 1613 establishes a must-take obligation to purchase CHP power, and thus, a kWh limitation is necessary to ensure that there is no adverse effect on long-term resource planning and reliable operation of the grid.[44] SCE also points to other state mandates, including energy efficiency and procurement of renewable power, that it believes necessitate establishing a limitation on the amount of power purchased under AB 1613. Therefore, it recommends that the Commission work with the CAISO to determine what this limitation should be. SCE does not oppose Energy Division staff's recommendation for a 500 MW statewide cap, but continues to recommend that the Commission work with the CAISO to establish a program limitation that considers reliability and system effects.[45]

PG&E also supports establishing an MW cap. It lists a variety of factors that should be considered before an MW cap could be established. Therefore, it recommends that a workshop be held to determine the numeric cap or that the amount be set at 1% of a utility's peak demand.[46]

Fuel Cell opposes setting any maximum MW limitation. It contends that there is no record to support a finding that purchases under AB 1613 would have an adverse impact on long-term resource planning or reliable operation of the grid.[47] It contends that participation in the AB 1613 program will be influenced

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[44] SCE Comments, June 1, 2009, at 10.

[45] SCE Comments, August 24, 2009, at 23.

[46] PG&E Comments, June 1, 2009, at 8.

[47] Fuel Cell Comments, June 1, 2009, at 20.

by pricing and other contract terms and conditions. Thus, it recommends the IOUs should only submit a request for a cap if and when the program results in adverse impacts on planning or reliability. Fuel Cell states that if the Commission does set a cap, it should be considered interim, "with the understanding that the program should be expanded over time to help meet longer-term program capacity goals."[48]

CCDC similarly opposes establishing any limit at this time. It contends that many of the concerns raised by the IOUs in support of a limit are hypothetical and notes that AB 1613 includes safeguards against the scenarios presented by the IOUs.[49] Therefore, CCDC believes that consideration of a kWh limit should not occur until the Commission finds that sale of excess power under the program does in fact have an adverse effect on long-term resource planning and grid reliability. Nonetheless, CCDC states that if an interim cap of 500 MW, allocated proportionally among the electric corporations, is adopted, this cap should be monitored on an on going basis and adjusted before purchases meet that interim cap.[50]

3.4.2. Discussion

Pub. Util. Code § 2841(a) allows the Commission to "establish a maximum kilowatt hours limitation on the amount of excess electricity that an electrical corporation is required to purchase if the commission finds that the anticipated excess electricity generated has an adverse effect on long-term resource planning or reliable operation of the grid." Although the IOUs have presented various

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48 Fuel Cell Comments, August 24, 2009, at 2.

49 CCDC Comments, June 1, 2009, at 14-15; CCDC Comments, August 24, 2009, at 4.

situations that they believe justify establishing a program limitation, most of them are speculative. We agree with Fuel Cell that participation in the AB 1613 program will be influenced by pricing and other contract terms and conditions. At this point, we find no basis to conclude that the pricing or contract terms adopted in this decision would present an immediate adverse effect on an electrical corporation's long-term resource planning or reliable operation of the grid. Further, any MW limitations should be imposed based on the specific effect of eligible CHP systems on a particular electrical corporation. Accordingly, we decline to adopt staff's recommendation to adopt an interim statewide cap of 500 MW for the AB 1613 program at this time. Should an electrical corporation subsequently find that the number of eligible CHP systems participating in this program has an adverse impact on its long-term resource planning or system reliability, it may file an application seeking authorization to establish a maximum kilowatt hours limitation on the amount of excess electricity it must purchase under this program.

4. Pricing

AB 1613 authorizes the Commission to require electrical corporations to offer to purchase "excess electricity" from eligible CHP customer generators and requires the Commission to "ensure that ratepayers not utilizing combined heat and power systems are held indifferent to the existence of this tariff."[51]

The Final Staff Proposal offered two pricing options. Pricing Option 1 is a proxy market price that includes fixed and variable inputs, and is meant to

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[50] CCDC Comments, August 24, 2009, at 5.

[51] Pub. Util. Code § 2841, subd. (b)(4).

reflect the cost of operating a "proxy" combined-cycle gas turbine (CCGT) that would be avoided if not for eligible CHP. Pricing Option 2 is based on the generation component of the retail rate tariff applicable to the host customer where the eligible CHP is installed. Parties were asked to comment on the advantages and disadvantages of each pricing option and the appropriateness of each option relative to the ratepayer indifference provision in § 2841(b)(4).

4.1. Pricing Option 1

Staff's Pricing Option 1 is a proxy market price based on the costs of a new CCGT. The pricing formula uses many inputs from the 2008 MPR, including the fixed costs associated with a new CCGT (minus GHG compliance costs[52]), variable operations and maintenance costs estimated for such a plant and the heat rate assumed for such a plant. Staff's pricing formula uses variable monthly natural gas prices based on actual market indices, instead of a forward gas price estimate like the MPR. The result of this pricing formula is an all-in price (in $/kWh) adjusted for time of delivery (based on MPR time of delivery (TOD) factors) that an eligible CHP facility would receive for every kWh of exported electricity. Staff proposes that a CCGT represents a reasonable proxy for the generation that a utility would have to procure if not for a CHP facility participating in this program. Staff also notes that since the inputs to this pricing formula have been litigated by parties in a prior Commission proceeding, these costs reasonably reflect the costs of a proxy CCGT.

SCE takes exception to the use of MPR inputs in a pricing formula for CHP. SCE argues that the MPR, which was intended as benchmark price for

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[52] See section 5.3.2.1 for discussion of GHG compliance cost allocation.

renewable procurement, "is not a proxy for avoided cost, and will result in a highly inflated price for CHP power."[53] SCE notes that the MPR uses a 20-year physical life of the generator and assumes the CCGT will never be dispatched. As such, SCE believes Option 1 would result in prices above its avoided cost. PG&E and TURN argue that the MPR is calculated to approximate the all-in costs of a fully-dispatchable CCGT that provides "firm" power, and is therefore inappropriate for a customer-owned CHP facility providing as-available power.[54]

SDG&E/SoCalGas appear to agree with staff's basic assertion that a CCGT is a reasonable proxy for avoided cost of power produced by a CHP facility.[55] They note that, "small CHP facilities will have a baseload or mid-merit grid export profile, so that its export profile is closest to that of a CCGT."[56] However, SDG&E/SoCalGas note several differences between the operating profile of a CCGT and a CHP facility, namely that a CCGT can provide firm power and ancillary services. Thus, while SDG&E/SoCalGas do not object to Option 1, they do note that the data inputs would need to be measured correctly.

CCDC and Fuel Cell support Pricing Option 1, and assert that it would serve as an appropriate measure of ratepayer indifference. Both parties note that the fixed inputs in the formula, as well as the direct link between the variable gas price input and known index prices, provide pricing certainty that will facilitate

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53 SCE Comments, August 24, 2009, at 9.

54 PG&E/TURN Comments, August 24, 2009, at 10.

55 As with PG&E/TURN, SDG&E/SoCalGas question whether paying a firm price for as-available capacity would be consistent with ratepayer indifference.

56 SDG&E/SoCalGas Comments, August 24, 2009, at 3.

financing of CHP facilities. CCDC further requests that the Commission adopt a process for updating the fixed components of the formula over time.

4.2. Pricing Option 2

Staff's Pricing Option 2 would provide payment to an eligible CHP facility for excess electricity delivered to the grid at a price based on the generation component of the host customer's otherwise applicable tariff. The exact amount of the price paid under this option will vary depending on a host customer's tariff and utility territory. Staff notes that under this option, the price paid for excess electricity will more closely reflect the cost of the electricity a host customer avoids when the CHP generation serves onsite load. Staff believes that this would attach a consistent value to all electricity generated by a CHP facility whether it offsets onsite load or is exported to the grid.

SCE, SDG&E/SoCalGas, and PG&E/TURN present various arguments against this pricing option. PG&E/TURN note that the "average generation cost" in the retail rate reflects embedded costs, including above-market legacy costs and therefore does not reflect the marginal cost of generation avoided by an eligible CHP facility. SCE contends that since Option 2 is based on average cost of generation and not market cost, it does not reflect the actual cost that a utility would have avoided but for the excess electricity from the CHP system.[57] SCE and PG&E/TURN also note that the variability in retail rates across customer classes, which can be as high as a factor of two, does not reflect actual avoided costs and "thwarts the concept of ratepayer indifference."[58] SDG&E/SoCalGas

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[57] SCE Comments, August 24, 2009, at 11.

[58] PG&E/TURN Comments, August 24, 2009, at 12.

echo the opposition raised by SCE and PG&E/TURN. They further assert that failing to link actual fuel input costs and with the price paid under the tariff could create operational problems for CHP and potentially result in grid reliability problems.[59]

CCDC notes that Pricing Option 2 will result in significant complexity and increased transaction costs for CHP customers. CCDC points out that because retail rates are regularly updated in each utility's rate cases, CHP parties would have to regularly participate in those rate cases to ensure that "the component(s) of utility rates used as the basis for AB 1613 pricing meet the criteria of AB 1613."[60] SDG&E and SoCalGas also note the significance of rate case participation. They further contend that rates in SDG&E territory were established by settlement among parties, and paying CHP for excess electricity based on the rate was not contemplated by negotiating parties.

DRA calculates that the actual price under pricing Option 2 is lower than the price under Pricing Option 1 in 4 out of 5 comparable time of use periods in both SCE and PG&E territories. Based on this, "DRA concludes that Option 2 is a superior pricing scheme to meet ratepayer indifference."[61]

4.3. Objections to Both Proposed Pricing Options

SCE and PG&E/TURN reject both pricing options proposed by staff as inappropriate. SCE asserts that both pricing options would violate the FPA, which, they argue, grants exclusive authority to FERC over wholesale price setting. PG&E/TURN take similar exception to staff's pricing options, claiming

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59 SDG&E/SoCalGas Comments, August 24, 2009, at 5.

60 CCDC Comments, August 24, 2009, at 8.

that they would both violate the ratepayer "indifference" requirement in AB 1613.

SCE and PG&E/TURN assert that the pricing is limited, depending on whether the CHP facility has QF status, to either utility avoided cost or market pricing based on the CAISO day-ahead integrated forward market.[62] SCE and PG&E/TURN maintain their proposed methods are the only ones permitted under the FPA and PURPA.

4.4. Location Bonus

Staff proposed a 10% location bonus under both pricing options for any eligible CHP located in a distribution or transmission constrained area. Staff reasoned that CHP systems situated in constrained areas could provide system benefits such as transmission and distribution upgrade deferrals and local grid stability and reliability. Staff asked parties to comment on how to determine location or distribution constrained areas for purposes of applying this bonus.

SCE and PG&E/TURN note that staff's proposed location bonus of 10% is unsupported by analysis and unreasonable.[63] They assert that the "locational marginal price" (LMP) values in the CAISO market are the only accurate reflection of actual congestion and losses on the grid.

SDG&E/SoCalGas contend that if certain facilities receive a bonus because of their favorable location, then facilities located in less than favorable

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[61] DRA Comments, August 24, 2009, at 6.

[62] PG&E/TURN, Comments, August 24, 2009, at 9; SCE Comments, August 24, 2009, at 7-8.

[63] PG&E/TURN Comments, August 24, 2009, at 13; SCE Comments, August 24, 2009, at 12.

locations should receive less.[64] SDG&E/SoCalGas also contend that CHP located in its service territory is more valuable than CHP located elsewhere in the CAISO-controlled grid given the need for local resources. They argue that locational value should only be provided to CHP located in areas with local resource adequacy requirements when contracting with the local utility.[65]

CCDC and Fuel Cell support staff's proposed location bonus. CCDC and Fuel Cell suggest that the location bonus should be provided to any location where the CAISO nodal LMP exceeds the zonal price.[66]

4.5. Discussion

We have already addressed the arguments raised by SCE, PG&E, and TURN concerning our authority to set the price under AB 1613 in Section 3.1 of this decision and do not repeat them here. Accordingly, this section will focus solely on the two pricing options proposed by staff.

Pricing Option 2 would provide for the IOUs to offer to pay for excess electricity from eligible CHP customer-generators based on the generation component of the customer's retail rate. A major advantage of adopting this option would be the relative simplicity of applying this price, as it is the same price that eligible CHP generators receive for offsetting onsite electricity usage. However, many parties raise concerns with using this pricing approach, including the fact that retail rates are often the result of settlement agreements in the utility's general rate case and are heavily tied to legacy contracts. Thus, these parties believe rates would not bear any resemblance to the actual cost of a

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64 SDG&E/SoCalGas Comments, August 24, 2009, at 6.

65 SDG&E/SoCalGas Comments, August 24, 2009 comments, at 6.

marginal unit of generation avoided. DRA believes that Option 2 is a superior pricing scheme, but it is unclear whether this conclusion is based primarily on the fact that pricing under this option is generally lower than pricing under Option 1.

We are persuaded by the concerns raised that the generation component of retail rates may not reflect the cost of the energy avoided. As such, there is a risk Option 2 could result in payments to eligible CHP facilities at a price that would not hold non-participating ratepayers indifferent. Further, since these prices will, in effect, be set in a utility's general rate case, customer-generators would not be able to forecast prices beyond the current rate period. This could serve as a deterrent to any eligible CHP systems from entering into contracts longer than three years. These considerations lead us to conclude pricing under the AB 1613 program should not be based on Option 2.

Pricing Option 1 would pay an eligible CHP customer-generator for excess electricity at a proxy market price, based on the costs of a CCGT. Staff asserts that a CCGT represents a reasonable proxy for the marginal unit of generation avoided by an eligible CHP facility. As SDG&E and SoCalGas note in their comments, the operating profile of a CHP facility most closely resembles that of a CCGT. We find that a CCGT is reasonable proxy for the marginal unit avoided by an eligible CHP facility. In light of these considerations, we shall adopt staff's proposed Option 1.

Several parties note that a CCGT represents a fully dispatchable resource and therefore provides greater value than CHP, which under this contract would

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[66] CCDC Comments, August 24, 2009, at 9; Fuel Cell Comments, August 24, 2009, at 9.

be "as-available." PG&E and TURN note that a CCGT under a utility's operational control can be dispatched to aid the utility in serving load, while a CHP facility can appear and disappear from the system as the host customer's thermal load requires.[67] These parties therefore suggest that Pricing Option 1, which is based on the all-in costs of a CCGT, would overpay CHP under this program. SDG&E/SoCalGas suggest that Pricing Option 1, which is based on a CCGT providing firm capacity, would overpay eligible CHP under this program that will only provide as-available capacity. As its justification, SDG&E/SoCalGas point to the difference between as-available capacity prices and firm capacity prices adopted for Qualifying Facilities in D.07-09-040. Joint CHP Parties, in reply comments, disagree that CHP capacity is of lesser value than firm capacity, noting that "the long history of CHP facilities in California shows that CHP facilities of all sizes provide firm, reliable sources of generation."[68]

We note that § 2843(a)(2-3) requires that an eligible CHP system must "be sized to meet the eligible customer-generator's thermal load," and must "operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat." As such, eligible CHP systems under this program are likely to operate as if they were a firm resource, in order to provide consistent thermal and electrical output to the host. While the product being delivered under the contract will be as-available and may vary based on the host-customer's onsite electrical demand, the eligible CHP facility will be

[67] PG&E/TURN Comments, August 24, 2009, at 10.

[68] Joint CHP Parties Reply Comments, September 3, 2009, at 4.

operating as a firm resource. As such, it is appropriate that these new highly efficient CHP resources receive payment based on the cost associated with generating electricity from an alternative proxy resource. Pricing Option 1, which is based on the MPR, and assumes the costs associated with building and operating a CCGT as a baseload resource, provides such a price. Furthermore, the TOD factors applied to the MPR, and proposed in Pricing Option 1, account for the value of different products such as baseload and as-available electricity. In Resolution E-4214, which adopted the 2008 MPR, the Commission stated,

> The MPR model calculates what it would cost to own and operate a baseload combined cycle gas turbine (CCGT) power plant over a 10, 15, 20 and 25-year period. The cost of electricity generated by such a power plant, at an assumed technical capacity factor and set of costs, is the proxy for the long-term market price of electricity. To ensure that the MPR represents "the value of different products including baseload, peaking, and as-available output," the IOUs apply their IOU-specific Time of Delivery (TOD) profiles to the baseload MPR when evaluating RPS renewable facilities. The application of TOD factors to the MPR result in a market price for each product and electric generating unit.[69]

[69] Resolution E-4214, at 5 (citations omitted).

The adopted pricing formula for eligible CHP under this program is the following:

Table 2 Adopted Pricing Formula	
Description	Participating eligible CHP will receive an all-in price in $/kWh, based on a proxy market price for a new combined cycle gas turbine (CCGT) with adjustments for as-available capacity value and time of delivery (TOD)[70].
Fixed Component	=Fixed Component of the 2008 MPR minus GHG compliance costs, in $/kWh based on 10-year contract.
Variable Component	=*(Monthly bidweek + Local gas transmission charge)* Heat Rate + Variable Overhead and Maintenance (O&M)* *Monthly bidweek* =monthly bidweek gas price at PG&E Citygate for PG&E, and Topock for SCE and SDG&E (monthly bidweek gas prices shall be calculated as the average of three bidweek gas indices as reported in Gas Daily, Natural Gas Intelligence, and Natural Gas Weekly) *Intrastate* =tariffed intrastate gas transportation rate for large electric generators *Heat Rate* =6,924 Btu/kWh (based on average Heat Rate from 2008 MPR) *Variable O&M* = based on variable O&M adder from 2008 MPR.
Final Price (kWh)	=[(Fixed Component + Variable Component) * TOD factor] * 1.1 Location Bonus (if applicable)

Furthermore, we find staff's proposal to include a 10% location bonus appropriate as incentive for optimal siting of CHP facilities on the grid. We agree with Fuel Cell that areas eligible for the location bonus should be identified at the outset. The location bonus shall be applied to eligible CHP systems located in high-value areas, identified as areas with Local Resource Adequacy (LRA) requirements as originally proposed by SDG&E/SoCalGas. The Local RA program, approved in D.06-06-064, is intended to ensure that Load Serving

[70] The Time of Delivery (TOD) factors and periods shall be the IOU's Renewables Portfolio Standard TOD factors and periods in place at the time of contract execution. The TOD factors in place at the time of contract execution shall apply for the entire contract duration.

Entities (LSEs) have acquired sufficient generation capacity to serve defined, transmission constrained local areas. Each year the Commission adopts Local RA requirements and identifies Local RA areas based on the California Independent System Operator (CAISO) annual study of local capacity requirements71. The CAISO study identifies the specific substations included in each Local RA area. Eligible CHP interconnected within any of the identified Local RA areas shall receive the location bonus. Each IOU shall make these Location Bonus areas, including the specific substations included in each area, publicly available on their websites. This information shall be updated each year upon adoption by this Commission of the Local RA program requirements[72]. The location bonus shall be applied for the entirety of a contract based on Location Bonus areas identified in the year the contract is executed.

While we find that the pricing formula adopted in this decision reflects the current market price for power from these eligible CHP facilities, it is possible that the formula will need to be revised in the future as the market for power from this source of generation develops. Consequently, Energy Division is directed to review subscription under the program no later than two years after this decision is issued and submit recommendations of necessary changes to the Assigned Commissioner. If subscription under the program is less than 100 MW at that time, the Assigned Commissioner reserves the right to defer this review.

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[71] The CAISO's 2008 Local Capacity Requirement (LCR) Study is available from the CAISO website, http://www.caiso.com/1c44/1c44bbc954950.html

[72] 2010 Resource Adequacy program requirements were adopted by this Commission in D.09-06-028.

5. Contract Terms and Conditions

The Final Staff Proposal recommended various modifications to the standard contract and simplified contract proposed by the Working Group. This section addresses the major issues raised by the parties in both the Working Group reports and individual comments. Minor modifications recommended by staff and not discussed below are hereby accepted and reflected in the actual contracts. The standard contract is attached to this Decision as Attachment A and the simplified contract is attached as Attachment B.

5.1. Contract Sizing and Overview

Staff proposed establishing two separate contracts, one for eligible CHP systems less than or equal to 20 MW, and another simplified contract for smaller CHP systems that export no more than 5 MW. The Final Staff Proposal recommends using the contracts submitted by the Working Group on May 15, 2009 and June 30, 2009, respectively, as the basis for these contracts.

Parties generally agree with establishing two contracts, one for larger facilities and a simplified contract for smaller facilities. The simplified contract filed by the Working Group on June 30, 2009 noted that SCE objected to the 5 MW maximum size for the simplified contract and instead preferred a 1 MW maximum size. PG&E, SDG&E, CCDC, and Fuel Cell all agreed to a 5 MW maximum export size for the simplified contract. In its comments to the Final Staff Proposal, SCE did not provide any further justification for its preferred 1 MW cutoff. Accordingly, we see no reason why the Working Group's recommended 5 MW limitation should be lowered. We herein adopt two contracts, one for eligible CHP less than or equal to 20 MW (Attachment 1), and another simplified contract for smaller CHP systems that export no more than 5 MW (Attachment 2).

CCDC requests an even further simplified contract for eligible CHP systems less than 500 kW, stating that many of the terms in the simplified contract are too onerous for these very small generators. In its reply comments, SCE notes that many of the terms CCDC identifies as onerous, such as requirements of the CAISO, may not even be applicable to very small generators.[73] It further contends that many of the terms that CCDC seeks to change were the result of compromise between all parties and that CCDC fails to provide sufficient justification why an even further simplified contract is necessary.

In comments to the Proposed Decision, Fuel Cell notes that parties involved in negotiations to develop contract terms and conditions "agreed by consensus" not to discuss a contract for very small CHP in order to agree on terms for larger facilities. However, Fuel Cell notes that it would support further effort to develop a simplified contract for smaller facilities. CCDC also recommends that a separate contract for systems less than 500 kW should be developed. It states that CHP systems that are 500 kW or less would have minimal effect on an electrical corporation's distribution system and should be allowed to participate under AB 1613 without undue costs and administrative burdens.[74] Although we decline to adopt an even more simplified contract for eligible CHP systems exporting 500 kW or less in this decision, we believe that such a contract may be beneficial in encouraging smaller customer-generators to participate in the program. Therefore, parties shall work together to identify

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[73] SCE Reply Comments, September 3, 2009, at 9-11.

[74] CCDC Opening Comments to PD, November 19, 2009, at 7-8.

contract terms in the simplified contract terms that do not apply to very small CHP. Within six months of the effective date of this decision, each electrical corporation, unless otherwise excused, shall file a Tier 2 Advice Letter with a proposed contract for purchase of excess electricity from CHP systems exporting 500 kW or less. The Advice Letter shall include a redline version of the simplified contract showing the proposed contract terms to be deleted or revised, as well as an explanation why these deletions or revisions are needed

Finally, SCE notes that nothing in AB 1613 prohibits utility-specific differences, and points to differences in the utilities distribution and transmission system configurations as reason why differences in contracts may be appropriate. Except as discussed in Section 6.1 below, we find no compelling reason why these contracts should differ and direct all utilities to adopt the same contracts.

5.2. Maximum Contracting Under Simplified Contract (Simplified Contract Term 7.02(c))

SCE proposes that a single entity may not sign contracts for delivery of more than 20 MW using this simplified contract. No other parties support this requirement. The staff proposal recommended removing any limitation on the amount that any one entity could contract for under either contract.

SCE argues that since certain provisions such as credit and collateral were removed from the simplified contract, unlimited contracting by a single entity through this contract could create a concentration of risk for the utility and its ratepayers if that entity fails. SCE assumes that the risk of contract failure is multiplied by the number of projects developed by a single CHP generator.

We find SCE's arguments unconvincing. The risk associated with an individual project is dealt with in the contract for that project. We believe the simplified contract adequately addresses risk relative to the size of the projects eligible for that contract. It is not clear that the risk of contract concentration perceived by SCE is real. For any individual project, there will be a range of stakeholders including host customer, project developer, and equipment manufacturer. The fact that a single entity may be involved in more than one project does not mean that if that entity fails, all projects associated with that entity would also fail. For example, it is conceivable that in the event of the failure by a single project developer involved in multiple projects, the host customers for those projects could simply find new developers. We also note that a limit on contracting by a single entity would be largely unenforceable. A single entity could easily establish affiliates expressly to get around this limitation.

Therefore, we do not find it appropriate or beneficial to impose a limit on how many contracts a single entity may enter into, whether for the simplified contract or the standard contract. It is not our intent to limit successful project developers or host customers interested in installing multiple projects at multiple sites from helping the state to achieve its GHG emissions reductions objectives.

5.3. Green Attributes and GHG Compliance Costs (Simplified Contract Terms 3.01, 3.03 and Definitions; Standard Contract Term 3.01(b), 3.03 and Definitions)

A major point of discussion in the proceeding related to GHG compliance costs and green attributes associated with CHP, and how these costs and benefits should be addressed in the contract. The Final Staff Proposal recommended that the Buyer (i.e., electrical corporation) should pay for GHG compliance costs for the excess electricity sold to the grid, and that any green attributes associated with the resource should transfer to the Buyer.

5.3.1. Parties' Positions

SDG&E/SoCalGas agree that it is appropriate for the Buyer to pay for the GHG compliance costs for the emissions associated with the grid-delivered electricity. They contend, however, that the costs should be paid for once and only once.[75] Put another way, if the cost of GHG compliance is embedded in either the fuel cost or in another payment, or if a free distribution of allowances to these facilities is included in a future State or Federal cap and trade program, then there is no need for the Buyer to make an additional payment to the facility. SDG&E/SoCalGas also suggest that given Pricing Option 1, the Buyer should pay up to the heat rate associated with the MPR and that the Seller should bear the rest of the GHG compliance cost for emissions associated with these less efficient units. SCE agrees with this idea of sharing GHG compliance costs; SCE suggests in its comments that the Buyer should pay for some form of compliance costs, depending on the pricing option. SCE further suggests that there should be some form of sharing because the Buyer does not have operational control. PG&E/TURN echo the concept of dispatch control as being important for GHG cost compliance. They state that the Buyer should not have to pay for emissions that could have been eliminated because of operational control.[76] PG&E/TURN further suggest that since it is a customer investment, the Seller will not optimize its investment correctly if the Seller does not pay the GHG cost.

CCDC agrees that the Buyer should take on some form of GHG compliance cost but also points out the high amount of uncertainty associated

[75] SDG&E/SoCalGas Opening Comments, August 24, 2009, at 8-9.

[76] PG&E/TURN Comments, August 24, 2009, at 3.

with California's emerging regulation of GHG.[77] Fuel Cell also echoes that a straight pass-through of costs (i.e., the Buyer bears the GHG cost/allowance retirement obligation) is the best approach in light of this regulatory uncertainty.

Fuel Cell suggests that the Commission establish a GHG principle in this decision and suggests that once more information is known about the outcome of the ARB regulatory process, the Commission could order a change to the contract. CCDC also suggests that other green attributes, such as renewable energy credits (RECs), should not be bundled in the contract. CCDC asserts that if a renewable fuel is used, then it should be compensated as such. PG&E/TURN disagree with CCDC's proposal. They note that these other environmental attributes are a component of the product being purchased.

5.3.2. Discussion

5.3.2.1. Allocation of GHG Compliance Costs

In determining how to best allocate GHG compliance costs and green attributes, we need to consider unit efficiencies, operational and dispatch control, and the size of the facility. Based on these considerations, we agree with staff's recommendation that the Buyer should pay compliance costs for the excess electricity.

PG&E/TURN's position that the Seller will not optimize its investment correctly if the Seller does not pay the GHG cost ignores the fact that AB 1613 requires CHP facilities to be new or repowered and to operate at a high operational efficiency, and includes strict technical eligibility guidelines. Similarly, although it is true that the utility will not have dispatch control over

[77] CCDC Comments, August 24, 2009, at 7.

the unit, the *CEC Staff Draft Guidelines* ensure that the electricity being sold to the grid is being produced in a highly efficient manner and meets strict standards for carbon dioxide equivalent emissions.

SCE states that while D.08-10-037 recommended that the point of compliance for the excess electricity should be on the deliverer, the cost of compliance, and who pays it, was not specified. Although it is true that D.08-10-037 recommended that the deliverer be the point of compliance for electricity sold to the grid from CHP systems, it does not follow that the deliverer should always bear the compliance cost. In a carbon constrained system, electricity's carbon content is another attribute that the facility is selling. As such, we agree with staff that the Buyer (and ultimately benefiting customers)[78] should bear reasonable GHG compliance costs for the electricity delivered to the grid.

Although we conclude that the Buyer should bear GHG compliance costs, we want to ensure that there is no double payment of these costs and that the payment is limited to the electricity exported to the grid.[79] Presently, the ARB has not yet determined the point of compliance for these small and medium (up to 20 MW), highly efficient CHP units, nor have they determined how new CHP

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[78] As discussed in Section 3.3 above, GHG compliance costs shall be allocated to all benefiting customers.

[79] In comments, PG&E and TURN asked for additional guidance on this issue. The ARB has already adopted its mandatory reporting requirements for CHP, which provides the methodology to determine the GHG emissions associated with the electricity exported to the grid; the mandatory reporting requirements methodology will determine the number of emissions that are subject to payment in this program. Rules about the mandatory reporting requirements are available online at http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

entrants will operate under a cap-and-trade system. It is also unknown how these CHP units would be handled in a larger federal system. However, even with the uncertainty surrounding future GHG compliance regimes, the principle that the Buyer shall reimburse the Seller for actual GHG compliance costs associated with the electricity sold to the grid can be applied. For compliance costs associated with procuring emissions allowances, as opposed to direct compliance costs in the form of fees or taxes, we believe that instead of reimbursing the Seller for allowance costs paid by the Seller, the Buyer shall procure allowances on behalf of the Seller. Since the utility Buyer will be procuring allowances for its entire portfolio it will be better equipped to manage allowance procurement at a lower cost for ratepayers.

As an initial matter, we note that AB 32 mandates that GHG compliance costs for electricity commence in 2012 and there is currently no GHG regime in place at the federal level. Additionally, the first compliance period under AB 32 (2012-2014) will focus on large emitters of GHG emissions, while the second compliance period (2015 and beyond) will include smaller emitters of GHG emissions. Therefore, until a compliance program is established in 2012, none of the eligible CHP systems will have GHG compliance costs.

After 2012, eligible CHP systems will either have or not have a direct GHG compliance obligation. For those CHP systems that do not have a direct GHG compliance obligation, and in turn no GHG compliance costs, there is no need for the utility to compensate the CHP facility for GHG and there will be no risk of a double payment.

In contrast, eligible CHP systems that have a direct compliance obligation will need to be compensated for any direct compliance costs that they may incur under a future GHG compliance regime. This is because the pricing method adopted in this decision is based on the costs of a proxy plant constructed and operational prior to 2012. Since there are no GHG compliance costs embedded in the price, requiring the Buyer to pay for these costs would not result in double payment.[80]

Although the utility (Buyer) would be responsible for compliance costs associated with the exported electricity portion of a CHP facility's annual compliance obligations, this obligation should only be up to the emissions associated with operating the facility at the minimum efficiency level determined by *CEC*.[81] This is reasonable, since the Buyer does not have dispatch or operational control over an eligible CHP facility. We believe that while AB 1613 seeks to foster the development of highly efficient CHP units, if the CHP operator decides to operate its plant in a sub-optimal manner, the ratepayer should not be accountable for the extra GHG compliance costs. Under the *CEC Staff Draft Guidelines*, an eligible CHP facility that is out of compliance has an opportunity to return to compliance before it is decertified. We do not believe it would be reasonable to ask utilities to bear GHG compliance costs for

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[80] We note that there is a possibility that at some point in the future the direct GHG compliance obligation on CHP facilities may be removed. There has been some discussion from ARB of imposing a compliance obligation on upstream natural gas; in this instance, the direct compliance obligation would be removed and the compliance obligation on CHP facilities would be embedded in the price of natural gas. In such a case, where GHG compliance costs are embedded in the price of natural gas, pricing Option 1 would account for this, since actual gas prices are included in that pricing formula. Therefore, if the ARB were to impose such a compliance obligation on upstream natural gas, it would no longer be necessary for the utility to compensate the CHP facility for these "indirect" GHG compliance costs and doing so would represent a double payment.

[81] Based on the *CEC Draft Staff Guidelines*, this is 1,100 pounds/MWh.

underperforming facilities. To do so would provide no incentive for an out-of-compliance CHP operator to return to compliance quickly. Therefore, the facility host will be responsible for any additional compliance obligation associated with emissions beyond the limit prescribed in the *CEC Staff Draft Guidelines* deriving from suboptimal operation of the facility.

5.3.2.2. GHG Reductions and Benefits

According to the contract, a CHP facility will convey all "green attributes" associated with the excess electricity delivered to the grid, including emissions reductions. However, the GHG emissions reductions that the facility experiences (compared to generating heat and electricity separately) cannot be isolated to delivered electricity but must be calculated on a facility-wide basis. For accounting purposes only, the utility will need to track the entire facility's avoided GHG emissions that occurred as a result of the installation of the new CHP facility. This information will be used for tracking purposes with the ARB Scoping Plan target for avoided GHG emissions from CHP. Thus, while there is no monetary value to the GHG reduction itself, for program accounting purposes the utility will count the avoided GHG emissions for any facility that signs up under this tariff.

Finally, it is worth noting that there are up to three different elements of the CHP process that will likely have a GHG compliance costs – electricity delivered to the grid (the subject of Section 5.3.2.2 above), electricity consumed on-site, and on-site thermal demand. However, under this FIT, only those compliance costs associated with excess electricity delivered to the grid are considered. Any GHG compliance costs for the other two elements are outside of the scope of the FIT, and we presume that any facility contemplating the development of CHP that would operate under the proposed tariff would consider these other compliance costs during the course of project financing, and that these other sources of GHG compliance costs will also motivate the facility to install, invest, and operate with GHG emissions efficiencies in mind.

5.3.2.3. Other Green Attributes

As mentioned in Section 3.2.2 and the discussion above, several parties argue that the contract price should be even higher to reflect the value of other green attributes. We agree that the electricity being delivered to the grid contains several attributes that have distinct societal and environmental benefits. However, as we have already explained, the adopted Pricing Option 1 includes the value of these benefits. Thus, the transfer of these green attributes are included in the price paid and are embedded in the electricity sold to the grid.

PG&E further maintains that if the Buyer is taking on the GHG risk and associated costs, then it should also receive green attributes such as RECs, if applicable. Fuel Cell maintains that the price paid will not reflect the value of RECs, and therefore the Seller should retain RECs if the Seller uses an eligible renewable fuel. As discussed above, we believe the price paid through this program reflects the value of all the green attributes associated with the power delivered from an eligible CHP facility. However, we note that an eligible CHP facility that is also RPS-eligible could choose to participate in a utility's RPS program rather than this program if the facility believes the price offered under this program is not sufficient.

While the eligible CHP systems under AB 1613 are not required to be RPS-eligible, we look to that program as a comparison. As discussed in D.08-08-028 and SB 107, all green attributes, including RECs, are included in the product sold to the grid. Thus, because the price paid and the benefit received by the customer embody green attributes, the product delivered to the grid contains all green attributes and they cannot be separated.

5.4. Delivery Point, (Simplified Contract Term 1.06; Standard Contract Term 1.03)

The utilities argue that power must be delivered to the point of interconnection with the CAISO-controlled grid, because the power must be scheduled at the CAISO. CHP parties argue that the delivery point should be the first point of interconnection with the utility grid, which may or may not be the same as the point of interconnection with the CAISO-controlled grid. The utilities imply that there are risks associated with accepting delivery at the first point of interconnection with the utility grid and having to transmit and schedule power at the point of interconnection with the CAISO-controlled grid. However, they do not explain the exact nature of the risks.

Fuel Cell suggests that there may be risks associated with either line losses associated with transmitting power over the utility's distribution system or the outright failure of the utility's distribution system.[82] Fuel Cell notes that the Delivery term in the contract accounts for line loss risk by requiring the Seller to assume all responsibility for line losses. As for the risk associated with the failure of the utility's distribution system, Fuel Cell suggests this *should* be borne by the utility.

The Final Staff Proposal recommends that delivery occur at the first point of interconnection between the facility and the grid for both contracts. The Final Staff Proposal noted that all parties except SCE agreed to this for the simplified contract. It further noted the fact that the contract equitably allocates financial

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[82] Fuel Cell Reply Comments, September 3, 2009, at 4.

risk associated with line losses between the first point of interconnection and the point of interconnection with the CAISO-controlled grid.

In comments to the Final Staff Proposal, SCE reiterated distinctions between its service territory and that of the other two utilities, which result in interconnection more frequently occurring at a point that is not under CAISO jurisdiction. PG&E states that while it and SDG&E agreed to delivery at the first point of interconnection for the simplified contract, they did not think it appropriate for the larger contract. But again, neither party articulated the nature or magnitude of the risk it would assume as a result.

Since line loss risk is addressed in the contract, and the only other risk associated with delivery has to do with utility distribution system failure, which should rightly be the responsibility of the utility, we find no compelling reason to require delivery to the CAISO-controlled grid for either contract. We find it instead appropriate for the utility to accept delivery of power at the first point of interconnection between the CHP system and the grid. We understand that in many cases, particularly for larger systems interconnecting at transmission voltage in PG&E's and SDG&E's territories, this will be the same as the point of interconnection with the CAISO-controlled grid.

5.5. Termination Rights of Buyer (Simplified Contract and Standard Contract Term 2.02(a))

The IOUs propose that signed contracts may be terminated by the Buyer based on subsequent actions by the Commission. Specifically the IOUs propose that if the Commission "in any way diminishes the Buyer's rights…to collect any above-market costs of this Agreement from Departing Load Customers" or if the Commission eliminates the mandatory purchase obligation under this program, then the Buyer can terminate existing contracts. CHP parties oppose this term arguing that it would provide uncertainty in the contract.

The Final Staff Proposal agrees with CHP parties that this contract term is unreasonable and provides too much uncertainty in the contract. SCE urges the Commission to reject staff's recommendation. It states that the utility's obligation to purchase stems from AB 1613. Thus, it argues that if AB 1613 were repealed or eliminated, or the state were to place a higher priority on other sources of generation, the utility should not be required to continue purchasing power under an AB 1613 contract.[83]

We do not find SCE's arguments persuasive. The contracts entered into under this program would be for no more than 10 years in duration and do not provide for extensions under the existing terms. Further, if AB 1613 were repealed or eliminated, the electrical corporations would not be required to enter into any more contracts. Thus, if AB 1613 were repealed or eliminated, the electrical corporations would purchase power under these existing contracts for no more than 10 years. In contrast, to allow any future regulatory action to nullify an existing contract would undermine the contract and compromise the efficacy of this program in promoting CHP deployment. Based on these considerations, we agree with staff that the IOUs' proposed term should not be included in the contract. Moreover, SCE's comments are essentially asking the Commission to include a term that would permit a utility to breach the AB 1613 contract in the future without any consequences. We decline to adopt such a provision and accept staff's proposal to eliminate this term in its entirety.

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[83] SCE Comments, August 24, 2009, at 21.

5.6. Indemnity (Simplified Contract Term 7.03(d); Standard Contract Term 9.03 (f))

The Final Staff Proposal recommends removing a provision in both contracts requiring the Seller to indemnify the Buyer against failure to deliver electricity, capacity or resource adequacy (RA) benefits. Staff reasons that such a requirement is not appropriate for an as-available contract.

SCE was the only party that thought this provision was necessary for the simplified contract. PG&E argues that while not necessary for smaller facilities under the simplified contract, it is necessary for the larger contract since the utility may incur RA penalties as a result of a facility's failure to operate. Fuel Cell notes that such penalties and requirements to provide the Seller specific RA benefits are not required by AB 1613, and inappropriate for as-available contracts.

We do not find it reasonable for a CHP generator under the simplified contract to be required to indemnify the utility against potential penalties for failure to deliver any benefits. However we do find it reasonable for larger facilities under the standard contract to be subject to such a requirement. Because the contract transfers all benefits of the power product from the CHP generator to the utility, CHP generators under the standard contract should be required to the greatest extent possible to ensure that those benefits can be used by the utility to meet its obligations. We discuss this further in Section 5.10 below.

5.7. Eligible CHP Facility Status (Simplified Contract Term 3.14; Standard Contract Terms 2.01(a) & 3.16)

AB 1613 directed the CEC, by January 1, 2010, to adopt technical guidelines for CHP systems eligible for this program. Work is ongoing at the

CEC to establish these guidelines and a process for certifying an eligible CHP facility. As previously discussed, the CEC issued its draft guidelines on October 1, 2009.

In order to be eligible for either the simplified contract or the standard contract adopted by this Commission in this decision, a CHP facility must obtain certification from the CEC as an eligible CHP facility and maintain that certification throughout the contract period. The standard contract submitted by the Working Group on May 15, 2009 included several provisions to ensure that any CHP system participating under AB 1613 had been certified by the CEC. Further, the standard contract provides that failure to maintain CEC certification throughout the contract period would represent an event of default under the contract. A similar provision shall be included in the simplified contract. The guidelines adopted by the CEC ensure that CHP facilities will provide the benefits envisioned by this program.

5.8. Qualifying Facility Status (Standard Contract Terms 1.02(f), 2.01(b), 3.10(a)(v), 3.16, 6.01(c)(xviii) & 9.02(h) and Exhibit O)

The Final Staff Proposal recommends removing all references to QFs in the contract. This recommendation is based on the Amended Scoping Memo, which clarified: "Although CHP facilities developed under AB 1613 could qualify as QFs under the Public Utilities Regulatory Policies Act of 1978, AB 1613 is not a subset of the QF Program adopted in D.07-09-040. Instead, AB 1613 focuses on a specific type of generator (i.e., new CHP under 20 MW that will meet efficiency standards established by the CEC) and does not require this type of generator to have QF status. More importantly, AB 1613 was enacted to reduce waste heat, which furthers the State's overall policy goal to reduce greenhouse gas emissions."[84]

We agree with staff's recommendation to remove any references or terms related to QFs in the contracts. As discussed in Section 3.1 above, AB 1613 does not make any references to PURPA and there is no requirement that an eligible CHP have QF status in order to participate in the AB 1613 program. Accordingly, all references and terms related to Qualifying Facilities or QFs in this contract should be deleted in their entirety. While eligible CHP facility may choose to become a QF, this shall not be a requirement of the contract.

5.9. Credit and Collateral (Standard Contract Term 1.06 and Exhibit D)

CHP parties dispute the need for Performance Assurance and Development Security. The IOUs prefer to include the bulk of credit and collateral provisions from the QF contract. The Final Staff Proposal recognizes the need for credit and collateral provisions in balancing financial risk between Buyer and Seller. Staff, however, recommends reducing the amounts of Performance Assurance and Development Security proposed by utilities.

Staff recommends Performance Assurance of 5% of expected revenue over the life of the contract instead of 12 months of expected revenue as the utilities propose. Staff recommends Development Security of $20/kW, not to rise over the project development timeline. The utilities' proposal would increase Development Security to $60/kW after 18 months into the project development timeline.

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[84] *Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, April 1, 2009, at 3.

In comments to the Final Staff Proposal, SDG&E and PG&E reassert their position that credit and collateral protect ratepayers and IOUs against CHP defaults, and are necessary to mitigate credit risk. PG&E agrees with the staff proposal that 12 months of expected Performance Assurance may be excessive given the fact that contract term lengths under this program may be as little as one year. PG&E instead proposes Performance Assurance of 10% of expected contract revenue. PG&E argues that increasing Development Security to $60/kW-year after 18 months is required to protect ratepayers from relying on CHP power for planning purposes only to find out that it is not available. PG&E does not explain why $20/kW-year is inadequate for this purpose.

We agree with staff's assessment that credit and collateral provisions can play an important role in balancing financial risk between utilities and ratepayers on the one hand and CHP project developers on the other. We note that the utilities' proposed credit and collateral requirements are based on a QF contract that contemplates much larger systems than the 20 MW maximum system size under this program. Just as parties agreed to remove the credit and collateral provision for the simplified contract as a result of the reduced level of risk associated with systems exporting less than 5 MW, we find it appropriate to reduce the level of credit and collateral provisions for systems less than or equal to 20 MW. Even credit and collateral provisions that are based on the proportional size of a project, such as those proposed here, can have a disproportionate impact on smaller project developers who are likely to face higher costs to post credit and collateral.

Since the projects and project developers participating in this program are likely to be smaller than those contemplated by the QF contract, we find it appropriate to reduce the levels credit and collateral from that contract. We note that one important role of credit and collateral is to ensure that only real and viable projects sign contracts. We find the levels of credit and collateral proposed by staff reasonable for this purpose given that the likely participants in this program will be smaller developers.

5.10. Conveyance of the Power Product (Standard Contract Term 3.01) and Resource Adequacy Benefits (Standard Contract Term 3.02)

The Final Staff Proposal recommended replacing two terms related to the Conveyance of the Power Product (3.01) and Resource Adequacy Benefits (3.02) in the standard contract with the terms proposed in the simplified contract. Staff believes that the terms in the standard contract are vague and potentially problematic and that the terms in the simplified contract sufficiently address the same issues.

PG&E argues that these terms should not be replaced, noting that these more detailed terms are relevant for larger projects and that the simplification agreed upon by parties in the simplified contract is only applicable to smaller facilities. Fuel Cell notes that it does not object to the first term. However it does object to the second. Fuel Cell notes that language in contract term 3.02 of the standard contract imposes burdensome obligations on a CHP generator that are not required by AB 1613. Fuel Cell notes that this term introduces significant risk upon a CHP facility because it would oblige the facility to commit its output to the Buyer for use in meeting its RA obligations no matter how those obligations may change in the future.

We decline to adopt staff's recommendations. These two contract terms had originally been proposed by staff in the February 3rd Staff Proposal. Standard contract term 3.01 was subsequently revised by parties as part of the Workshop Report, these revisions served to clarify the term. The Workshop

Report does not indicate any dispute between parties on the revisions to the term. No revisions were made to standard contract term 3.02.

We agree with PG&E that the more detailed terms should be retained for the standard contract. Moreover, with respect to term 3.02, under the contract the Seller will convey to the Buyer all benefits associated with the product, including energy and capacity benefits. For this, the Buyer will compensate the Seller. We find it reasonable that to the degree the capacity of CHP helps the utility meet its RA obligations, the Seller should be obliged to commit its output for this purpose. Accordingly, we retain contract terms 3.01 and 3.02 originally proposed by the Working Group for the standard contract.

5.11. Generating Facility Modifications (Standard Contract Term 3.07(b))

The IOUs propose a provision that the Seller must obtain consent of the Buyer before making any material modifications to the CHP facility. The CHP parties prefer the existing provision that a Seller must provide 30 days advance notice to Buyer of material modifications. The staff proposal recommended deleting the requirement that a Seller must obtain consent of the Buyer before making modifications to the CHP facility.

SCE claims that without this provision, a CHP generator could expand a facility’s nameplate rating or amount of export and could impact the adequacy of the interconnection facilities. Fuel Cell points out that the CHP generator’s interconnection agreement has specific capacity requirements and that if a modification to the facility would go beyond what is allowed by the interconnection agreement, then the facility would be responsible for all study fees and upgrade costs. Furthermore, Fuel Cell notes that a requirement that utility consent is required for any modifications would discourage participation.

We find no compelling reason why the utility's consent should be required by this contract for facility upgrades. Interconnection impacts will be addressed by the interconnection agreement. Furthermore, the requirement in standard contract term 3.16 that a CHP facility maintain certification as an eligible CHP pursuant to the CEC's guidelines will ensure that no modifications will increase the size above 20 MW or alter the facility beyond what is allowed for this program.

5.12. Assignment (Standard Contract Term 9.04)

The Final Staff Proposal recommends deleting the sentence "Any direct or indirect change of control of Seller (whether voluntary or by operation of law) will be deemed an assignment and will require the prior written consent of Buyer, which consent will not be unreasonably withheld." from Term 9.04. Staff notes that Fuel Cell objects to this language. Fuel Cell claims this provision would give the utility *de facto* veto rights over the CHP generator's internal business decisions.[85] Fuel Cell also notes that the contract does not give a CHP generator the reciprocal right over changes of ownership by the utility.

SCE opposes staff's recommendation, stating "it is commercially unreasonable to give the parties an unlimited right to arbitrarily change their ownership or the ownership of their parent entities."[86] PG&E and SDG&E state that this sentence may be deleted if Performance Assurance and Development Security remained in the contract. However, PG&E argues that since the Final Staff Proposal recommended reducing the Performance Assurance and

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85 Fuel Cell Reply Comments, September 3, 2009, at 9.

86 SCE Comments, August 24, 2009, at 22.

Development Security, there is a concern that a change of ownership of a CHP generator that occurs without the utility's consent would limit the utility's ability to collect damages in the event of a default.

We decline to adopt staff's recommendation. The sentence at issue clarifies what would be included as an assignment. As SCE notes, it would be unreasonable to give parties an unlimited right to arbitrarily change ownership, especially if the transfer is to an insolvent entity. Further, the provision does not grant the utility automatic veto power, but rather a right to consent, which consent will not be unreasonably withheld. We do believe, however, that Fuel Cell raises a valid concern that this term only applies to the Buyer. Concerns over assignment of the contract and solvency of a new owner apply equally to the Buyer and the Seller. Consequently, we modify Term 9.04 to read:

> Neither Party may assign this Agreement or its rights under this Agreement without the prior written consent of the other Party, which consent may not be unreasonably withheld or delayed. Any direct or indirect change of control of either Party (whether voluntary or by operation of law) will be deemed an assignment and will require the prior written consent of the other Party, which consent will not be unreasonably withheld. Notwithstanding anything to the contrary in this Section 9.04, Seller may, without the consent of Buyer (and without relieving itself from liability hereunder):
>
> (a) Transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements in accordance with Section 9.05; and
>
> (b) Transfer or assign this Agreement to an Affiliate of Seller which Affiliate's creditworthiness is equal to or higher than that of Seller.

6. Non-Contract Issues

6.1. Applicability to Electrical Corporations with Less Than 100,000 Service Connections

Section 2841(h) permits the Commission to "modify or adjust the requirements of [AB 1613] for any electrical corporation with less than 100,000 service connections, as individual circumstances merit." In its initial comments to this OIR, the California Association of Small and Multi-jurisdictional Utilities (CASMU)[87] requested that the Commission defer implementing AB 1613 for CASMU members and focus implementation only on the IOUs.[88] CASMU subsequently filed a motion on February 17, 2009, requesting that the proceeding be bifurcated to defer implementation of AB 1613 for the CASMU members. In its motion, CASMU presented two reasons to support its request. CASMU first contends that implementing the AB 1613 program for the IOUs would provide experiences that the Commission could draw upon when implementing the program for the smaller electrical corporations. It also asserts that implementing the AB 1613 program for the CASMU members would be burdensome, especially since it would be unlikely that an eligible CHP system would be located within any CASMU member's service territory. CASMU's motion was denied by an ALJ Ruling issued on August 10, 2009. In denying the motion, the ALJ Ruling stated:

> I am not persuaded that the terms and conditions for purchase of power from eligible CHP systems will vary based on the size of the electric corporation. The reduction of waste heat depends

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[87] The CASMU members include: Sierra Pacific, Bear Valley Electric Service (BVES), Mountain Utilities and PacifiCorp.

[88] CASMU Comments, July 31, 2008, at 3.

> more on the individual facility than the service territory that facility is located in. Further the Energy Division's final staff proposal appears to address the concerns raised by CASMU, as it includes a simplified contract for CHP exporting up to 5 MW and proposes and interim program cap that would be allocated proportionally between utilities based on 2008 peak demand.[89]

In comments to the Final Staff Proposal, Sierra Pacific continues to advocate that the Commission not require it to implement AB 1613 until there is an indication that a customer would seek interconnection of an eligible project. Sierra Pacific contends that if it is required to implement AB 1613, this will result in additional costs for its ratepayers. It further asserts that its current customer base has relatively small demands that are "not suitable for CHP systems."[90] Sierra Pacific states that if it is required to implement AB 1613, then it should only be required to offer the simplified contract, since its proportional share of the recommended statewide cap of 500 MW would be approximately .81 MW. However, even under that scenario, Sierra Pacific notes that the simplified contract would have to be modified, since it is not part of the CAISO-controlled grid. PacifiCorp also maintains that it should only be required to offer the simplified contract in light of its proportionate share of the 500 MW interim cap and the composition if its customer base.[91] Further, PacifiCorp states that it is located outside of the CAISO control area and therefore requests that the

[89] *Administrative Law Judge's Ruling Denying Motion of the California Association of Small and Multi-jurisdictional Utilities to Bifurcate Rulemaking 08-06-024*, August 10, 2009, at 2.

[90] Sierra Pacific Comments, August 24, 2009, at 5.

[91] PacifiCorp Opening Comments to PD, November 19, 2009, at 3-4.

simplified contract be modified to eliminate any mandatory contract provisions specific to the CAISO.[92]

Mountain Utilities requests that it be excused from participating in AB 1613 altogether. In support of this request, Mountain Utilities states that its total generation requirements are less than 5 MW for most of the year and it is not connected to transmission of any sort.[93] As such, it asserts that even the simplified contract would need to be modified to meet its unique characteristics. Finally, Mountain Utilities notes that its proportional share of the 500 MW interim program cap would be "miniscule" and would not advance the intent of AB 1613. BVES echoes many of the arguments raised by Mountain Utilities. It further contends that requiring BVES to offer 20 MW and 5 MW contracts would be misleading in light of its allocation under the interim 500 MW cap.[94] Further, it notes that not only are there no significant thermal hosts in its service territory, but there also is no room in its current resource stock for significant CHP generation.[95]

We are unpersuaded by arguments that an electrical corportation should not be required to participate in the AB 1613 program because no CHP systems are currently located in its California service territory. As we have repeatedly stated in this decision, the purpose of AB 1613 is to encourage development of small CHP systems in California. As such, the fact that CHP is not currently located in an electrical corporation's service territory is an insufficient reason to

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[92] PacifiCorp Opening Comments to PD, November 19, 2009, at 5-6.

[93] Mountain Utilities Comments, August 9, 2009, at 2.

[94] BVES Opening Comments to PD, November 19, 2009, at 6.

[95] BVES Opening Comments to PD, November 19, 2009, at 7-8.

determine that it should not be required to participate in AB 1613. Furthermore, since there shall be no initial program cap, there is currently no limitation on the amount of excess electricity that may be purchased under the program in an electrical corporation's service territory. Nonetheless, we are persuaded that the program should be modified for the CASMU members.

We find that Sierra Pacific and PacifiCorp should not be required to offer the standard contract. Instead, Sierra Pacific and PacifiCorp shall offer one of the following contracts:

1. The simplified contract adopted in this decision (Attachment B). Should Sierra Pacific and/or PacifiCorp offer this contract, they may include, as part of their Tier 3 Advice Letter filing, proposed modifications in light of their relationship to the CAISO. This filing shall include both a clean version of the simplified contract, a redline version of the simplified contract showing the proposed modifications, and an explanation of why these modifications are needed.

2. A more simplified contract for eligible CHP systems exporting 500 kW or less, as discussed in Section 5.1 above. If Sierra Pacific and/or PacifiCorp wish to offer this contract, they must file a Tier 2 Advice letter proposing this more simplified contract within six months of the effective date of this decision. If such a filing is not made within the six month period, Sierra Pacific and/or PacifiCorp shall offer the simplified contract (Attachment B).

We are also persuaded that Mountain Utilities' and BVES' unique characteristics warrant excusing it from offering either the standard contract or the simplified contract. We agree that the potential costs imposed on these corporations' ratepayers to implement either of these contracts would likely be excessive, especially in consideration of the number of eligible CHP systems that might locate within their service territories. However, even though Mountain Utilities and BVES shall not be required to offer either of these contracts, they are not excused from complying with AB 1613. Thus, if an eligible CHP system were to locate in either Mountain Utilities' and/or BVES' service territory and seek to sell its excess electricity, Mountain Utilities and/or BVES shall negotiate and enter into a contract with that eligible CHP system if the system does not have an adverse effect on Mountain Utilities' or BVES' long-term resource planning, is cost effective, technologically feasible, and environmentally beneficial. Any such contract reached shall be filed as a Tier 3 advice letter for Commission approval.

6.2. Ratepayer Funded Incentives

Several parties have proposed that this proceeding address whether or not CHP participating in this program would be eligible for incentives from the Self Generation Incentive Program (SGIP). The Final Staff Proposal sought to address this issue by clarifying that although nothing about this program would prohibit a CHP system from receiving incentives from a ratepayer funded program such as the SGIP, the issue of SGIP eligibility is outside the scope of this proceeding. Based on parties' comments, there seems to be some confusion about this.

6.2.1. Parties Comments

DRA does not believe CHP participating in this program should be eligible to receive SGIP incentives. DRA suggests striking the following language from the staff proposal, "We clarify that nothing from the AB 1613 program would prohibit a CHP system from receiving incentives from a ratepayer funded incentive program such as the Self Generation Incentive Program as long as the system meets all requirements of such program."

CCDC and Fuel Cell argue that CHP under this program should be eligible for SGIP incentives and disagree that this issue should not be addressed in this proceeding. CCDC suggests that the Commission, in this proceeding, require that the SGIP Handbook be modified to ensure that CHP participating in this program be eligible for SGIP incentives.

SCE notes that Fuel Cell's and CCDC's requests are outside the scope of this proceeding and also notes that their requests are contrary to the current rules of the SGIP. SCE cites the SGIP Handbook which states that, "Agreements that entail the export and sale of electricity from the Host Customer do not constitute on-site use of the generated electricity and therefore are ineligible for the SGIP."[96]

SCE goes on to cite several other examples in the SGIP Handbook which preclude an SGIP customer from receiving double incentives. PG&E and TURN also argue that a CHP system should not be eligible for subsidies from more than one program. They imply that the pricing options in the staff proposal represent subsidies. PG&E and TURN seem to suggest that only their pricing proposal based on the CAISO market price would not be a subsidy and therefore is the appropriate price. It is unclear if by extension they are suggesting that a CHP customer should be eligible for SGIP if the price paid under this program does not represent a subsidy.

6.2.2. Discussion

We first want to clarify the misconception highlighted in several parties' comments that the program being adopted here represents a subsidy. It is not a subsidy. AB 1613 requires that this program and the price paid to eligible CHP for excess electricity represent fair compensation for that electricity and will hold ratepayers indifferent.

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[96] SCE, September 3, 2009 reply comments, at 9.

Furthermore, AB 1613 does not prohibit an eligible CHP facility or host customer from receiving ratepayer funded incentives. In fact, customer participation in energy efficiency and other demand-side management programs is encouraged, assuming that the facility and/or customer meets the eligibility requirements of those other programs. The state is committed to the efficient and cost-effective use of energy resources and has created a number of complementary programs and policies intended to maximize resource efficiency and reduce emissions of GHG. However, those programs are completely separate and distinct from this program and wholly outside the scope of this proceeding. Therefore, staff correctly stated that eligibility for incentives from any other program will not be addressed in this proceeding.

Regarding SGIP specifically, we note that SGIP was developed to provide incentives for self-generation, as the name implies. There are specific requirements of SGIP that prohibit customers from exporting power to the grid, except under limited circumstances. However, it is conceivable that SGIP eligibility requirements may change or that there may be future programs adopted by this Commission or this state to provide incentives for CHP technologies. Such programs may provide an appropriate complement to this one. Therefore, we clarify that nothing about this program would prohibit a system from receiving incentives from another program if the system meets all requirements from that other program and the system were otherwise eligible to receive the incentive.

7. Conclusion

Based on our consideration of the record, we adopt the policies and procedures to implement AB 1613 as described in this decision. We conclude that our authority to implement a program under AB 1613 includes authority to determine the price that the electrical corporations must offer to pay for excess electricity produced by eligible CHP facilities. This price is not limited to utility avoided cost or the CAISO market price. We further conclude that in order to ensure that ratepayers are held indifferent to the AB 1613 tariff, the price paid under the tariff shall include costs associated with societal benefits associated with the electricity provided by the eligible CHP systems. These benefits would include environmental and locational benefits.

Under AB 1613, all benefiting customers shall be allocated the costs and benefits of the program. Benefiting customers under this program shall include bundled service customers and customers receiving electric service from electric service providers or community choice aggregators.

We decline to adopt any limitation on the amount of excess electricity that may be procured under this program at this time. If an electrical corporation finds that the number of eligible CHP systems participating in this program has an adverse impact on its long-term resource planning or system reliability, it may file an application seeking authorization to establish a maximum kilowatthours limitation on the amount of excess electricity it must purchase under this program

The price to be offered for excess electricity under AB 1613 shall be be based on the costs of a combined cycle gas turbine and comprised of a fixed and a variable component. There shall also be a 10% location bonus applied to eligible CHP located in high-value areas. Additionally, there shall be a pass through from the Seller to the Buyer of any GHG compliance costs associated with the excess electricity sold. All GHG attributes associated with the excess electricity sold shall also be transferred to the Buyer.

There shall be two contracts offered under the program. A standard contract would be offered to all eligible CHP up to 20 MW, and a simplified contract will be offered to eligible CHP systems that export up to 5 MW. These contracts are included as Attachments A and B, respectively, of this decision. All electrical corporations, except Sierra Pacific, PacifiCorp, Mountain Utilities and BVES, shall be required to offer both contracts. Within six months of the effective date of this decision, each electrical corporation, unless otherwise excepted, shall file a Tier 2 Advice Letter to adopt an even more simplified contract for eligible CHP systems exporting 500 kW or less.

Sierra Pacific and PacifiCorp may offer either the simplified contract (Attachment B) or the even more simplified contract for eligible CHP systems exporting 500 kW or less discussed in this decision. Mountain Utilities and BVES shall not be required to offer a standard or simplified contract, but are not excused from complying with AB 1613. Except as discussed in this decision, we adopt the Final Staff Proposal and Energy Division staff's proposed modifications to the standard and simplified contracts.

We affirm Energy Division staff's statement that AB 1613 does not prohibit an eligible CHP facility or host customer from receiving other ratepayer funded initiatives, such as the SGIP. Therefore, an eligible CHP system could receive incentives from another program if it meets all the requirements from that other program.

8. Comments on Proposed Decision

The proposed decision of the Assigned Commissioner in this matter was mailed to the parties in accordance with Section 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 filed on November 19, 2009 by SCE, jointly by SDG&E and SoCalGas, jointly by PG&E and TURN, PacifiCorp, BVES, EPUC, Sierra Pacific, San Joaquin Refining Co. (SJRC), Fuel Cell, CCDC, DRA and AReM. Reply comments were filed on November 24, 2009 by SCE, SDG&E, PG&E/TURN, CCDC, AReM, Fuel Cell and SJRC. This decision has been revised in response to comments as appropriate.

In comments, PG&E/TURN and SCE have asserted that the Commission's pricing determination is unlawful. These arguments essentially rely on the FERC's rulings in *Midwest Power Systems Inc.* (1997) 78 FERC ¶ 61,067 (*Midwest*) and *Southern California Edison Company and San Diego Gas & Electric Company* (1995) 71 FERC ¶ 61,269 (*SCE)*. This reliance is misplaced. *Midwest* held that orders of state agencies were preempted by PURPA to the extent that they require utilities to purchase power generated by QFs at rates above avoided costs. *Midwest* also found that the orders of the Iowa Utilities Board were inconsistent with the FPA to the extent they set rates charged by public utilities for wholesale sales even if utilities were not QFs. However, as we have already explained in this decision, the purpose of AB 1613 is to encourage the development of more efficient CHP systems that would provide environmental benefits. Neither PURPA nor the FPA address environmental issues, such as GHG emissions. Indeed, both *Midwest* and *SCE* stated that outside of PURPA, it would be *consistent* with federal law for states to meet their environmental goals by directing the planning and resource decisions of electric utilities under their jurisdiction or by encouraging certain alternative generation through tax incentives or other subsidies.[97]

[97] *Midwest,* 78 FERC ¶ 61,067 at 61,248; *SCE*, 71 FERC ¶ 61,269 at 62,080.

9. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Amy Yip-Kikugawa is the assigned ALJ in this proceeding.

Findings of Fact

1. Under the Federal Power Act, only the FERC may set rates for wholesale power sales to and by public utilities.

2. PURPA authorizes state commissions to set the price for power purchased by utilities from qualifying facilities.

3. AB 1613 does not require CHP facilities participating in the program to have QF status.

4. AB 1613 was enacted to encourage the adoption of energy efficient generators with beneficial environmental attributes.

5. Eligibility to participate in the AB 1613 program is based on size limitations and efficiency standards set by the CEC.

6. CHP systems must maintain or exceed the standards set by the CEC throughout the term of the contract in order to participate under AB 1613.

7. In order to achieve the objectives of AB 1613, the Commission is directing the electrical corporations to incorporate systems certified by the CEC as meeting certain efficiency and environmental standards into their procurement obligations.

8. The FERC has recognized the authority of the states to regulate in the area of GHG emissions reduction.

9. The FIT under AB 1613 is an option provided by the retail electrical utilities to eligible CHP systems selling excess electricity as an incentive to meet California’s environmental goals.

10. Customer indifference is achieved when ratepayers not utilizing the CHP systems are no worse off, nor any better off, as a result of power purchased under AB 1613.

11. CHP systems participating under AB 1613 will provide environmental and locational benefits in addition to power.

12. Since AB 1613 seeks to encourage development of a certain type of CHP system, the price paid under the contract will include incentives to encourage development of these systems.

13. All customers will receive the environmental and locational benefits produced by CHP systems participating under AB 1613.

14. Prior Commission decisions have allocated the costs of power to all retail end-use customers because the power provided overall benefits to the state.

15. Pub. Util. Code § 2841.5 requires POUs to establish their own programs for purchase of power under AB 1613.

16. POU customers would bear all responsibility for costs associated with the POU's implementation of AB 1613.

17. Once a POU develops its own power purchase program under AB 1613 and enters into contracts under the program, there is a risk that POU customers could be subject to double payment for the benefits derived under AB 1613.

18. The costs for GHG compliance and locational benefits are directly related to the benefits received by all benefiting customers.

19. Because the benefits under AB 1613 will be received equally by all benefiting customers, the costs associated with GHG compliance and any adder for locating within certain load areas should be allocated on an equal cents/kWh basis.

20. An electrical corporation should file an application seeking authorization to establish a maximum kilowatt hours limitation on the amount of excess electricity it must purchase under this program electrical corporation before a maximum MW limitation is set.

21. The Final Staff Proposal offered two options for the pricing of power purchased under AB 1613.

22. Pricing Option 1 is based on the costs of a new combined cycle gas turbine and uses many of the inputs from the 2008 MPR.

23. The operating profile of a CHP facility most closely resembles that of a CCGT.

24. Power provided under AB 1613 would be a function of the thermal requirements of the host customer.

25. The MPR assumes a fully baseload CCGT.

26. An eligible CHP facility is likely to operate as if it were a firm resource in order to provide consistent thermal and electrical output to the host.

27. Since the thermal requirements of the host customer may vary, the excess electricity produced by an eligible CHP facility may also vary.

28. Pricing Option 2 is based on the generation component of the retail rate tariff applicable to the host customer where the eligible CHP is installed.

29. Pricing Option 2 may not sufficiently reflect the cost of energy avoided and may not hold non-participating ratepayers indifferent.

30. IOU retail rates are often the result of settlements.

31. The Final Staff Proposal's pricing options include a 10% location bonus for eligible CHP systems located in a distribution or transmission constrained area.

32. The Final Staff Proposal proposes a standard contract for eligible CHP systems that are less than or equal to 20 MW and a simplified contract for eligible CHP systems that export no more than 5 MW.

33. All parties, except SCE, agreed to a 5 MW maximum export size for the simplified contract.

34. SCE failed to provide sufficient justification to adopt a lower cutoff point for the simplified contract.

35. CCDC requested an even more simplified contract for CHP systems less than 500 kW.

36. There may be some terms in the simplified contract that are inappropriate and burdensome for very small CHP systems.

37. SCE has failed to provide convincing evidence that entities that develop multiple CHP systems under AB 1613 may not utilize the simplified contract.

38. Allocation of responsibility for GHG compliance costs and green attributes must take into consideration unit efficiencies, operational and dispatch control, and the size of the facility.

39. The point of compliance does not necessarily determine which party should bear the compliance cost.

40. Benefiting customers should only pay for GHG compliance costs once.

41. Under AB 32, GHG compliance costs for electricity will commence in 2012.

42. Pricing Option 1 does not have GHG compliance costs embedded in the price.

43. If there is no direct compliance obligation, there will be no GHG costs.

44. If a CHP facility has a direct GHG compliance cost, the Buyer should compensate the facility for this cost.

45. The Buyer should only be responsible for compliance costs up to the emissions associated with operating the facility at the minimum efficiency level determined by the CEC.

46. GHG emissions reductions that the facility experiences (compared to generating heat and electricity separately) cannot be isolated to delivered electricity but must be calculated on a facility-wide basis.

47. Pricing Option 1 includes the value of green attributes associated with the excess electricity delivered to the grid.

48. The utilities do not explain why setting the delivery point as the first point of interconnection between the facility and the utility grid, rather than the point of interconnection with the CAISO-controlled grid presents more risk.

49. The risk associated with utility distribution system failure should be borne by the utility.

50. The utility's proposed buyer termination clause would create too much uncertainty and compromise AB 1613's objectives.

51. An indemnity clause against failure to deliver electricity, capacity or resource adequacy benefits is not appropriate for an as-available contract.

52. In order to be eligible to participate under AB 1613, a CHP facility must obtain and maintain certification from the CEC throughout the contract period.

53. The IOUs' proposed credit and collateral requirements are based on a QF contract that contemplates systems larger than 20 MW.

54. Parties agreed to remove the credit and collateral provision for the simplified contract as a result of the reduced level of risk associated with systems exporting less than 5 MW.

55. The CEC guidelines and certification process will ensure that a participating CHP system will not upgrade its facility above 20 MW or alter the facility beyond what is allowed under AB 1613.

56. Pub. Util. Code § 2841(h) permits the Commission to modify the requirements of AB 1613 for any electrical corporation with less than 100,000 service connections.

57. CASMU's motion to bifurcate the proceeding and defer implementation of AB 1613 for the CASMU members was appropriately denied by an ALJ Ruling.

58. Based on the composition of Sierra Pacific's and PacifiCorp's customer base, it is unlikely that an eligible CHP system exporting more than 5 MW would locate in the service territory of either of these electrical corporations in the immediate future.

59. The costs imposed on Mountain Utilities' and BVES' ratepayers to implement either of the contracts adopted in this decision would likely be excessive, especially in consideration of the number of eligible CHP systems that might locate within their service territories.

60. Since AB 1613 requires the price paid to eligible CHP for excess electricity represent fair compensation for that electricity, the price is not a subsidy.

61. AB 1613 does not prohibit an eligible CHP facility or host customer from receiving ratepayer funded incentives, provided the facility is eligible for them.

Conclusions of Law

1. Purchase of electricity under AB 1613 would serve the public interest by encouraging additional efficient use of energy and the reduction of GHG emissions.

2. Since AB 1613 seeks to incorporate more efficient CHP systems that would provide environmental benefits into a utility's procurement portfolio, it would

be within the Commission's authority to implement all aspects of AB 1613, including the price offered by the electric utility.

3. Ratepayer indifference is maintained if the price for excess electricity sold under AB 1613 includes costs reflecting the environmental and locational benefits provided by these systems.

4. It would be reasonable to allocate the costs to encourage development of eligible CHP systems to all retail end-use customers as they will receive environmental and locational benefits from the systems.

5. Pub. Util. Code § 2841(e) does not include any language that expressly limits the term "benefiting customer" to three categories of customers.

6. It would be unreasonable to include POU customers within the term "benefiting customer" since the POU is mandated to implement its own program for purchase of power under AB 1613.

7. Consistent with Pub. Util. Code § 2841(a), program cap should not be imposed until the Commission first determines that the number of eligible CHP systems participating in this program has an adverse impact on an electrical corporation's long-term resource planning or system reliability.

8. Staff's Pricing Option 2 should not be adopted.

9. Staff's Pricing Option 1 should be adopted.

10. Staff's proposal to include a 10% location bonus to encourage optimal siting of CHP facilities should be adopted.

11. The 10% location bonus should be applied if an eligible CHP system locates in an area with local Resource Adequacy (RA) requirements.

12. Parties should continue working together to develop an even more simplified contract for eligible CHP systems that export 500 kW or less.

13. It would be unreasonable to impose a limit on the number of contracts entered into by a single entity, as such a limitation could prevent successful project developers or host customers from installing multiple projects.

14. It would be reasonable to require the Buyer to share in the GHG compliance cost for electricity delivered to the grid under AB 1613.

15. It would be reasonable to have the Buyer manage the GHG risk on behalf of the Seller, as the Buyer will likely be in a better position to negotiate more advantageous deals in the carbon allowance markets.

16. The utility should not be required to pay for GHG compliance costs if the CHP operator decides to operate its plant in a sub-optimal manner.

17. The utility should only be responsible for paying for GHG compliance costs up to the emissions associated with operating the facility at a minimum efficiency level.

18. It would be unreasonable for a CHP generator under the simplified contract to be required to indemnify the utility against potential penalties for failure to deliver any benefits.

19. Since the standard contract transfers all benefits of the power product to the utility, it would be reasonable to require CHP generators to ensure that those benefits can be used by the utility to meet its obligations and indemnity the Buyer against potential penalties for failure to deliver any benefits.

20. A CHP system participating under AB 1613 that fails to maintain its certification through the contract period should be considered in default under the contract.

21. Credit and collateral provisions in the AB 1613 contracts should balance the financial risk between Buyer and Seller.

22. It would be appropriate to reduce the level of credit and collateral provisions for CHP systems participating under AB 1613 because the projects and project developers participating in this program are likely to be smaller than those contemplated by the QF contract.

23. It would be reasonable to adopt a performance assurance of 5% of expected revenue for both contracts.

24. It would be reasonable to adopt a development security of $20/kW, not to rise over the project development timeline.

25. If the capacity of CHP helps the utility meet its Resource Adequacy obligations, the Seller should be obliged to commit its output for this purpose.

26. The assignment provision in the Standard Contract should apply equally to both the Buyer and the Seller.

27. The Energy Division staff's Final Staff Proposal, submitted on July 31, 2009 should be adopted, as modified.

28. Sierra Pacific and PacifiCorp should offer either the simplified contract or the even more simplified contract for eligible CHP systems exporting 500 kW.

29. Mountain Utilities and BVES should comply with the requirements of AB 1613, but should not be required to offer either of the contracts adopted in this decision.

O R D E R

IT IS ORDERED that:

1. A standard contract for eligible combined heat and power systems up to 20 megawatts (Attachment A) and a simplified contract for eligible combined heat and power systems that export up to 5 megawatts (Attachment B) are adopted. The California electrical corporations should offer these contracts only to combined heat and power systems that are certified by the California Energy Commission as meeting the requirements of Assembly Bill 1613.

2. Energy Division staff's recommendation to base pricing on the costs of a combined cycle gas turbine is adopted.

3. Within 45 days of the date this order is mailed, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file an advice letter in compliance with General Order 96-B. The advice letter shall include tariff sheets to implement the standard contract (Attachment A) and the simplified contract (Attachment B) adopted herein. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

4. Within 6 months of the date this order is mailed, Sierra Pacific Power Corp. and PacifiCorp shall file an advice letter in compliance with General Order 96-B. The advice letter shall include tariff sheets to implement either:

    a. the simplified contract (Attachment B) with proposed modifications to account for their location outside of the California Independent System Operator-controlled grid, or

    b. a proposed simplified contract for eligible combined heat and power system less than 500Kw, as discussed in Ordering Paragraph 6 below.

5. Mountain Utilities and Bear Valley Electric Service shall be required to comply with the requirements of Assembly Bill 1613. If a combined heat and power system that is certified by the California Energy Commission under Assembly Bill 1613 wishes to locate in Mountain Utilities' or Bear Valley Electric Service's service territory, Mountain Utilities and Bear Valley Electric Service shall negotiate and enter into a contract with that eligible combined heat and power system if the system does not have an adverse effect on Mountain Utilities' or Bear Valley Electric Service's long-term resource planning, is cost effective, technologically feasible, and environmentally beneficial.

6. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Sierra Pacific Power Corp. and PacifiCorp shall convene a working group with combined heat and power parties to establish a further simplified contract for eligible CHP system less than 500Kw. Within 6 months of the effective date of this decision, each investor-owned utility shall file an advice letter in compliance with General Order 96-B. The advice letter shall include tariff sheets to implement a further simplified contract for very small combined heat and power less than 500 Kw. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

7. The costs and benefits arising from power received under Assembly Bill 1613 shall be allocated among bundled service customers of the electrical corporation, customers of the electrical corporation that receive their electric service through a direct transaction, as defined in Public Utilities Code Section 331(c), and customers of an electrical corporation that receive their electric service from a community choice aggregator, as defined in Public Utilities Code Section 331.1. The costs to be allocated, if any, shall consist of the

10% location bonus and any greenhouse gas compliance costs passed from the eligible combined heat and power system (Seller) to the electrical corporation (Buyer). These costs shall be allocated on an equal cents per kilowatt-hour basis. The calculation of the costs to be allocated, if any, shall be included in each electric corporation's annual Energy Resource Recovery Account proceeding.

8. Rulemaking 08-06-024 remains open to address implementation of a "pay-as-you-save" program.

This order is effective today.

Dated December 17, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners