Decision 10-12-055 December 16, 2010

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 GRANTING, IN PART, AND DENYING IN PART, JOINT PETITION OF PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY FOR MODIFICATION OF DECISION 09-12-042

1. Summary

This decision grants in part, and denies in part, a joint request by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company to modify Decision (D.) 09-12-042, which implemented Assembly Bill (AB) 1613 (Ch. 713, Stats. 2007). Among other things, this decision revises the methodology for setting the price to be offered by the electrical corporations to utilize pricing inputs from the most recent Market Price Referent. It corrects language in the adopted form contracts to clarify that the "Fixed Price Component" of the price is to be a constant value during the entire contract term and makes other modifications to the form contracts to clean up contractual language. The request to allow either party to procure the greenhouse gas allowance on behalf of the Seller is also approved with modifications. The request to reduce the price to be offered to reflect an as-available price is denied. Furthermore, this Decision modifies D.09-12-042 in

order to be consistent with two subsequently issued orders by the Federal Energy Regulatory Commission (FERC). The FERC orders clarified that under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 824a-3, the Commission could require California utilities to offer contracts at Commission-determined wholesale rates to eligible combined heat and power (CHP) systems which participate in the AB 1613 (Ch. 713, Stats. 2007) program, provided that the rates did not exceed the purchasing utilities' avoided costs and that the CHP systems had obtained Qualifying Facility status under the FERC's regulations.[1]

2. Background

Decision (D.) 09-12-042 (Decision) adopted 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 (Ch. 713, Stats. 2007). Among other things, this decision adopted a standard form contract available to all eligible CHP systems up to 20 megawatts (MW) and a simplified form contract for eligible CHP systems that export no more than 5 MW. Pricing under the AB 1613 form contracts was based on the costs of a proxy natural gas generation resource, and a location bonus was applied to eligible CHP systems located in high-value areas.

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[1] *See, California Public Utilities Commission, et al.* (2010) 132 FERC ¶ 61,047 at 65, *clarification granted and rehearing dismissed,* 133 FERC ¶ 61,059 at 26-31. The Federal Energy Regulatory Commission (FERC) recognized that its ruling did not apply to public agency sellers that are exempt from FERC jurisdiction under Section 201(f) of the Federal Power Act, 16 U.S.C. § 824(f). *See, California Public Utilities Commission, et al.*, 132 FERC ¶ 61,047 at 71.

On January 20, 2010, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (collectively referred to as the Joint Utilities) jointly filed an application for rehearing of the Decision on the grounds that the pricing established in D.09-12-042 is preempted by federal law and violates the ratepayer indifference standard in AB 1613. On the same day, the Alliance for Retail Energy Markets also filed an application for rehearing. On April 26, 2010, the California Public Utilities Commission (the Commission or the CPUC) issued D.10-04-055 denying both rehearing applications. D.10-04-055 further clarified that the price established in D.09-12-042 is an avoided cost.

On February 2, 2010, the Joint Utilities timely filed this Joint Petition for Modification (Joint Petition) pursuant to the requirements of Rule 16.4 of the Commission's Rules of Practice and Procedure. In filing the Joint Petition, the Joint Utilities seek to address alleged problems with the implementation of the D.09-12-042 as it currently stands.[2]

On March 4, 2010, California Clean DG Coalition (CCDC), San Joaquin Refining Company (San Joaquin), and Fuel Cell Energy (FCE) filed responses to the Joint Petition. The Utility Reform Network (TURN) and Division of Ratepayer Advocates (DRA) jointly filed a response to the Joint Petition on March 4, 2010.

On May 4, 2010, the Commission submitted a petition for declaratory order to the FERC to find that the Federal Power Act (FPA), the Public Utility Regulatory Policies Act of 1978 (PURPA) and FERC regulations do not preempt

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[2] The Joint Utilities asserted that they did not waive the claims separately raised in their Application for Rehearing.

the Commission's decision to require California utilities to offer a certain price to CHP generating facilities of 20 MW or less that meet energy efficiency requirements. On May 11, 2010, the Joint Utilities filed a separate petition for declaratory order with the FERC in which they argued that the Commission's decision is preempted by the FPA insofar as it sets rates for electric energy that is sold at wholesale.

On July 15, 2010, FERC issued an order granting in part and denying in part the cross-petitions for declaratory order (FERC Declaratory Order), which found: that "[a]lthough the CPUC has not argued that its AB 1613 program is an implementation of PURPA, we find that to the extent the CHP generators that can take part in the AB 1613 program obtain Qualifying Facility (QF) status, the CPUC's AB 1613 feed-in-tariff is *not* preempted by the FPA, PURPA or FERC regulations, subject to certain requirements."[3] The requirements were that: (1) the CHP generators … are QFs pursuant to PURPA; and (2) the rate established by the CPUC "does not exceed the avoided cost of the purchasing utility.[4]

On August 16, 2010, the Commission filed with FERC a request for clarification, or, in the alternative, a request for rehearing, which sought clarification regarding the avoided cost rates for facilities participating in the AB 1613 program.

On September 9, 2010, the Commission issued an Amended Scoping Memo and Ruling. This Ruling amended the November 4, 2008 Scoping Memo

[3] *California Public Utilities Commission et al.*, 132 FERC ¶ 61,047 at 65.

[4] *Id.* at 67.

to account for issues related to the FERC Declaratory Order and asked for further comment on certain issues brought up in the Joint Petition. On September 29, 2009, DRA filed a response to the Amended Scoping Memo. Comments in response to the Amended Scoping Memo were filed by the Joint Utilities, DRA, FCE, CCDC, San Joaquin, and Sustainable Conservation. Joint comments were filed by Pacific Corp and Sierra Pacific Power Corps (the Multijurisdictional Utilities).

On October 21, 2010, FERC issued an order, which granted the Commission's August 16, 2010 request for clarification (FERC Clarification Order).[5] In this order, FERC clarified that the state has a wide degree of latitude in setting avoided cost, can utilize a multi-tiered avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA.

3. The Joint Petition and Amended Scoping Memo

In their Joint Petition, the Utilities request the Commission modify D.09-12-042 to:

- Update the formula for calculating the price to be offered by the electric corporations in the standard and simplified contracts to utilize components from the 2009 Market Price Referent (MPR) instead of the 2008 MPR;
- Modify Exhibit C of the standard contract and Exhibit B of the simplified contract to clarify that the "Fixed Price Component" of the price to be offered is constant throughout the contract term;
- Reduce the price to be offered under AB 1613 contracts to reflect an as-available price;

[5] *California Public Utilities Commission*, 133 FERC ¶ 61,059.

- Remove the language from D.09-12-042 requiring the utilities to purchase greenhouse gas (GHG) allowances for CHP Sellers under certain circumstances; and
- Modify certain provisions of the form contracts attached to the Decision to clarify the language and contractual provisions.

The Amended Scoping Memo also asked for further clarification on a number of these issues. We consider each of the requests in the Joint Petition, as further informed by comments received in response to the Amended Scoping Memo, in Sections 4 through 12 below.

4. Updating Pricing Formula to Use 2009 MPR Inputs

The pricing formula adopted in D.09-12-042 is based on the utilities' avoided costs associated with a combined cycle gas turbine. Several inputs in the adopted pricing formula come directly from the 2008 MPR. The MPR is set annually by the Commission in accordance with Pub. Util. Code § 399.15(c) and represents the long-term market price of electricity. The MPR is used as a benchmark in the Renewables Portfolio Standard Program.

The methodology for calculating the MPR was first developed in D.04-06-015. The methodology has been revised several times since, in D.05-12-042, D.07-09-042, and most recently in D.08-10-026. Each year the Energy Division updates the cost inputs and recalculates the MPR based on this methodology.

The AB 1613 pricing formula utilizes several inputs from the 2008 MPR. These inputs include:

- Fixed Component = MPR fixed component for 10 year contract;
- Variable Operations & Maintenance = MPR variable Operations & Maintenance;

- Heat Rate[6] = MPR average heat rate for a combined cycle gas turbine; and
- Time of Delivery periods and factors.

Joint Utilities argue that the 2009 MPR, which was adopted by the Commission at the same meeting as D.09-12-042, is more up-to-date and therefore contains the most appropriate inputs to be used in the pricing formula for the AB 1613 contracts.

TURN and DRA agree with the proposed modification to use the 2009 MPR inputs instead of the 2008 MPR inputs. TURN and DRA suggest that this will reduce the cost to ratepayers.

San Joaquin generally opposes the Joint Utilities' request to modify the AB 1613 pricing formula. San Joaquin contends the Joint Utilities are simply rearguing the same points that the Commission considered and rejected in D.09-12-042. Although San Joaquin does not oppose the Joint Utilities' proposal to use pricing inputs from the 2009 MPR, it questions why this request was not made when the decision was pending. San Joaquin believes the Commission should only approve the proposed modification with the following conditions:

- Modification should only be allowed when the resulting change to the pricing formula is material (more than 5%);
- All MPR values used in the AB 1613 pricing formula should be updated, not just the limited values proposed by the Joint Utilities;
- The Commission should clarify that all updates to AB 1613 prices will occur regardless of whether the update results in an increase or decrease of the price; and

[6] Heat Rate is expressed as the number of British Thermal Units required to generate a kilowatt hour of electricity.

- Updates of AB 1613 prices should have prospective application only.

San Joaquin argues that there is no need to change the pricing option to use the 2009 MPR because the resulting price change would be immaterial. However, San Joaquin does not oppose future changes to the adopted MPR values if they result in a material impact.

FCE opposes the Joint Utilities' proposals to alter the pricing approach adopted by the Commission in D.09-12-042. It states that the Joint Petition does not offer any new legal argument or cite changing facts warranting the proposed changes. Specifically, FCE opposes the Joint Utilities' proposal to replace the 2008 MPR adopted in D.09-12-042 with the 2009 MPR because the Joint Utilities have failed to provide any substantive discussion in support of their proposal.

CCDC states that the simplified contract is the product of extensive collaborative efforts by the parties and characterizes the Joint Utilities' request as a unilateral attempt to modify certain provisions. CCDC contends it is not clear whether the Joint Utilities propose replacing the entire 2008 MPR or just the fixed component. Regardless, CCDC does not support replacing the 2008 MPR with the 2009 MPR. If however, the Commission decides to update the MPR, CCDC argues it should do so only if other than a *de minimus* change in the total MPR value has occurred and only if all the components are updated – not just those that result in a better price for the Joint Utilities.

4.1. Discussion

As discussed in D.09-12-042, the adopted pricing formula utilizes components of the MPR, as the cost of a proxy natural gas generation resource is a reasonable proxy for the marginal unit avoided by an eligible CHP facility. At the time the Decision was adopted, the most current MPR available was the 2008 MPR.[7]

Given our determination that the cost of a proxy natural gas generation resource should serve as a basis for determining the price to be offered to eligible CHP facilities under the AB 1613 program, it is reasonable that the pricing formula reflects the most current cost of a proxy natural gas generation resource. Since the MPR itself is not static, but is updated to reflect the dynamics of the market, it logically follows that the most current MPR inputs should be used in the pricing formula adopted in D.09-12-042. Therefore, going forward, the pricing formula in the form contracts shall be updated to reflect the most current MPR.[8]

We decline all proposals to make the use of the most current MPR contingent upon a more than *de minimus* change in the total MPR value. Neither CCDC nor San Joaquin has provided a sufficient basis to impose this requirement. If the pricing formula is to be based upon the most up-to-date inputs available, then the amount of change from the previous value (up or down) is irrelevant to our determination to utilize to the most current MPR.

As long as the MPR is calculated based on the costs of a proxy conventional natural gas generation resource, the four pricing components identified above from the most recent MPR shall be used in the AB 1613 pricing formula in order to determine the utilities' avoided cost for this program. Each year, upon adoption by this Commission of a new MPR calculation, each

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[7] The Commission adopted the 2009 MPR on the same day that it adopted D.09-12-042.

[8] New contracts would utilize the 2009 MPR until the 2010 MPR is adopted by the Commission.

California investor-owned utility (IOU) shall file a Tier 1 Advice Letter updating its AB 1613 tariffs and standard contracts with the new MPR inputs. The advice letters shall be filed and served within five days of the date that the order adopting the MPR is mailed. If, however, the MPR ceases to be based on a proxy natural gas generation resource or ceases to exist entirely, then the most recent MPR inputs that were developed using a proxy conventional natural gas generation resource shall continue to apply to AB 1613 contracts until otherwise modified by this Commission.

Updated pricing inputs shall only apply to new contracts executed after the effective date of this decision. The pricing for executed contracts shall be based on the pricing inputs in effect at the time the contract was executed. We do not require parties to modify contracts that have already been executed because it is important to protect contract stability and the expectations of the contracting parties.

5. Clarification of Fixed Price Component

Exhibit B of the simplified contract and Exhibit C of the standard contract, as proposed by the working group to Rulemaking 08-06-024 (R.08-06-024), included the pricing formula for each contract. In adopting the standard contract, the Commission added language and tables to Exhibit C, Section 3 to reflect the fixed price component of the AB 1613 form pricing. Both the table and added language reflect escalating prices based on the 2008 MPR. The added language was as follows:

> …the Fixed Price Component of the Monthly Contract Payment shall be the amount in the following table for the year in which the payment is being calculated.

The Joint Utilities contend the added language is in error because, taken literally, the language implies that the fixed component should escalate every year. The Joint Utilities believe that the MPR already assumes an escalation in the fixed component and has levelized that escalation so that the payments are the same during the entire period of the contract.

DRA and TURN support modification of the contract language to correct the "Fixed Price component" of the price paid to clarify that it is a constant value during the entire term of the contract.

FCE supports the Joint Utilities' proposed revision to Section 3 in Exhibit C of the standard contract to clarify that the MPR fixed price component be the amount identified for the year "in which the Agreement was executed by the Parties." However, FCE contends that the proposed redline does not match the language in Exhibit C.3 of the less than 20 MW contract and Exhibit B.3 of the Small CHP contract which refers to "the year of the Term Start Date." FCE believes it is important that the CHP contracts clearly show that, for purposes of determining the fixed price component, the relevant year is the year in which the facility initiates deliveries to the utility. FCE suggests that to eliminate any ambiguity the definition of the Term Start Date be revised to refer to the "initiation of commercial operation" or other similar language.

San Joaquin agrees with the Joint Utilities' proposal to clarify that the fixed price component of the AB 1613 price is constant over 10 years. San Joaquin disagrees with the Joint Utilities, however, about when that price is fixed. San Joaquin contends that the MPR fixed components shown in the table are determined based on the year in which a project comes on line.

CCDC agrees with the Joint Utilities that the MPR-based fixed component includes a levelized escalation for the term of the contract. CCDC generally agrees with the Joint Utilities' proposed revision to Section 3 of Exhibit C. However, CCDC notes there is some ambiguity between the revision proposed by the Joint Utilities in the text of the Joint Petition and the revision proposed in Exhibit C of the standard contract. CCDC conditions its support on its belief that the Joint Utilities intended that Section 3 of Exhibit C be revised to clarify that the fixed price component will be the amount for the year of the "Term Start Date" and that the reference to the year of execution in the text of the Joint Petition is an inadvertent error.

5.1. Discussion

We agree that the language added by D.09-12-042 is in error and that the fixed price component of the contract price does not escalate during the contract term. We also agree with FCE, San Joaquin, and CCDC that the fixed component should be based on the year in which a project is expected to begin commercial operation or come online, which is synonymous with "Term Start Date," and not the year in which the contract is signed. The "Term Start Date" is defined within Section 1.01 of the adopted contracts as the date that the project starts, in other words, the year in which a project is expected to come online, not the date the contract is signed. We therefore, modify the language of Section 3 of Exhibit C of the standard contract as follows:

> The Fixed Price Component, "FPC," for all TOD Periods shall be the amount in the following table for the year of the Term Start Date.

6. GHG Compliance Costs Not in Fixed Price Components

The fixed component of the AB 1613 pricing formula is defined as the "Fixed Component of the 2008 MPR minus GHG compliance costs, in $/kWh [kilowatt hour] based on 10-year contract."[9] The Joint Utilities ask the

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[9] See D.09-12-042 at 34, Table 2.

Commission to clarify whether: (1) GHG compliance costs that are referenced in the contract should be subtracted from the fixed component; (2) the GHG adder in the 2008 MPR should be subtracted from this fixed component; or (3) D.09-12-042 merely seeks to convey that the GHG adder in the 2008 MPR adder should not be included in this payment calculation, because GHG compliance costs are dealt with elsewhere in the contract.

FCE agrees that this point should be clarified and contends that the Joint Utilities' third interpretation is the correct characterization. It further points out that the Commission states in the Decision that the adopted approach was to have "GHG costs handled directly in the contract as a cost pass through instead of including an administratively established 'adder' in the contract price."[10] FCE does not object to this clarification of their perception of the Commission's intent.

TURN and DRA also agree that there should be some clarification on this point but do not offer any suggestion as to what that clarification should be. Although CCDC believes the Commission was clear in D.09-12-042 that the GHG adder is not already included in the AB 1613 payment calculation, it does not object to the modification proposed by the Joint Utilities if only to put an end to any efforts to further reduce AB 1613 payments.

6.1. Discussion

We agree that language adopted in Table 2 of D.09-12-042 may cause some confusion. This ambiguity stems from the fact that the fixed component of the 2008 MPR, upon which the AB 1613 pricing was based, does not include a GHG adder. GHG compliance costs in the MPR calculation are embedded in the

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[10] See FCE Response on the Joint Petition to Modification at 4.

variable component of the 2008 MPR. The Commission's intent in D.09-12-042 was to clarify that GHG compliance costs were not being paid for twice, once in the price and once as a pass through as a contract term. However, the language in D.09-12-042 apparently created some ambiguity. We agree with FCE and CCDC, the proper interpretation is that the GHG adder in the 2008 MPR variable component should not be included in the pricing formula, as GHG compliance costs are addressed elsewhere in the CHP contract. We therefore, clarify that since the fixed price components of the MPR do not include a GHG adder, and GHG compliance costs are not reflected in any way in the adopted pricing formula, no additional subtraction is necessary. GHG compliance is addressed in the contracts as a direct pass-through of actual compliance costs from the Seller to the Buyer. It does not need to be considered in the pricing formula adopted in D.09-12-042. We therefore, modify Table 2 to remove the phrase "minus GHG compliance costs."

7. Pricing of Power as an "As Available" Resource

The Joint Utilities ask the Commission to reduce the price paid under the Form Power Purchase Agreements to reflect the fact that eligible units are "as available" resources. The Joint Utilities contend that D.09-12-042 erred in concluding that the eligible CHP systems are likely to operate as if they were a firm resource and that the factors applied to the MPR and proposed in the adopted pricing formula account for the value of different products such as baseload and as available electricity.

FCE opposes the Joint Utilities proposal to reduce the feed-in-tariff price to reflect that CHP resources are "as available" because it is nothing more than repetition of arguments considered and rejected in D.09-12-042.

CCDC objects to the Joint Utilities' proposal to reduce the AB 1613 price to reflect pricing for an as available product. CCDC contends the proposal is based upon the same arguments previously raised in the underlying proceeding that the Commission previously rejected. There the Commission explained that the time-differentiated MPR pricing mechanism specifically accounted for the value of different products, including the difference in value between baseload and as-available electricity. CCDC contends that the Commission appropriately recognized that the MPR does differentiate between as available and firm baseload power. As a result, CCDC contends the Commission should reject the Joint Utilities' proposal to reduce the price under AB 1613 contracts to reflect an as-available product.

7.1. Discussion

The arguments raised by the Joint Utilities are similar to those raised in both the underlying proceeding and their joint rehearing application. The Commission has already considered and rejected theses arguments in D.09-12-042 and D.10-04-055.[11] Furthermore, Sections 1.02 and 3.02 of the Commission approved contracts for this program require the Seller to commit to an expected amount of energy production per term year and to pledge its generating capacity to the Buyer for the Buyer to use in meeting its resource adequacy obligations. In this regard, the Buyer should have reasonable expectation about the resource that will be provided from a CHP facility participating in this program.[12] The Joint Utilities do not raise any new issues of

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[11] See D.09-12-042 at 36.

[12] See D.09-12-042, Attachment A, Section 1.02(d) and 3.02.

law or fact in the Joint Petition for consideration by the Commission. Thus, we deny this request.

8. Remove Language Requiring IOUs to Purchase GHG Allowances

This issue was addressed in both the Joint Utilities' Petition for Modification and the Amended Scoping Memo.

8.1. The Joint Petition

The Joint Utilities request that the contract provision that utilities must purchase GHG allowances on behalf of CHP Sellers (Sellers) be removed. The Joint Utilities reason that they should have the choice to procure allowances on behalf of Sellers, but should not be required to do so. The Joint Utilities claim that emissions allowance decisions are complex and that in order to procure allowances on behalf of Sellers they will need more detailed information from Sellers.

DRA, TURN, and San Joaquin do not object to the proposal to modify the D.09-12-042 to remove the requirement that utilities procure GHG allowances on behalf of small Sellers. FCE similarly does not object to eliminating the requirement that the utilities procure GHG allowances on behalf of Sellers provided the Commission includes language acknowledging that many issues regarding GHG responsibilities and compliance are currently unresolved and that the Commission reserves the right to order the utilities to obtain allowances on behalf of the Sellers if doing so is necessary in order to effectuate the objectives of AB 1613.

CCDC supports the proposal to eliminate the utilities' obligation to procure GHG allowances on behalf of the Sellers but believe the utilities should have the option to do so on behalf of Sellers. CCDC suggests that D.09-12-042 be modified to make clear that the adopted GHG strategies are subject to revision pending implementation of GHG rules. Alternatively, CCDC proposes that the Commission modify the D.09-12-042 to require the utilities to work with Sellers under AB 1613 contracts to develop the most efficient, cost-effective strategy for GHG compliance with the excess energy sold under AB 1613 contracts.

8.2. The Amended Scoping Memo

The Amended Scoping Memo issued on September 9, 2010, sought additional comments on this issue. Specifically, the Ruling asked:

(1) If Sellers require reimbursement for GHG allowance costs, at what intervals should invoices be submitted to the Buyers?

(2) Is a test (market based or some other method) needed to ensure that the invoices submitted by the Seller leave the ratepayer no worse off than if the Buyer had managed these compliance costs? If so, how should the market test be structured?

Party comments reflected a wide range of views on these two questions. San Joaquin suggests that Sellers should submit invoices at the same frequency that GHG allowances are bought and sold through the auction mechanism. San Joaquin expects this to occur either quarterly or monthly. SDG&E contends that Sellers should submit an invoice for GHG reimbursement at least once per year, but no more than once per quarter. CCDC suggest that Sellers submit invoices as soon as practicable following the Seller's receipt thereof. DRA does not believe that the Commission should alter its original Decision. However, if Sellers are allowed to manage their own allowances, DRA suggests that invoices should be submitted at least annually.

PG&E and SCE reference the FERC Declaratory Order and argue that compensation to a generator cannot exceed the costs avoided by the purchasing utility. Therefore, the cost of GHG allowances should not be treated as a generator cost but as a component of the utility's avoided cost and included in payments due under the Seller's monthly invoice for delivered energy. SCE contends that any resolution of issues related to GHG costs must be consistent with the global QF Settlement Agreement[13] (QF Settlement) filed with the Commission on October 8, 2010 and PG&E, in their reply comments, agrees with SCE. FCE and CCDC reply that the Commission should ignore these comments as they are outside the scope of the Ruling and therefore erroneous.

Regarding the question of whether a test is needed to ensure that the ratepayer is left no worse off if Sellers manage their own allowances, CCDC, FCE and San Joaquin agree that no such test is needed. However, SDG&E and DRA believe that a test is needed. SDG&E argues that the simplest method would be to apply auction prices to the net allowances needed based on the volume of electricity delivered for the invoiced period of time. DRA proposes a two-point test based on the average prices the Seller and Buyer pays for allowances in the market during the year. In their reply comments, PG&E disagrees with any receipt-based approach to GHG cost reimbursement.

8.3. Discussion

We agree with FCE and CCDC that comments from PG&E and SCE regarding short run avoided cost calculations, as provided in the QF Settlement, are outside the scope of the Amended Scoping Memo and outside the record of

[13] *Joint Motion for Approval of Qualifying Facility and Combined Heat and Power Program Settlement Agreement,* filed in the following dockets: Application 08-11-001, R.06-02-013, R.04-04-003, R.04-04-025, and R.99-11-022.

this proceeding, and should therefore be disregarded.[14] Furthermore, the QF Settlement as proposed does not seek to modify any of the issues raised in this docket; so while the two matters are related, for the purposes of this issue of GHG allowance procurement associated with the AB 1613 program, any reference to a QF Settlement should have no impact on this Decision.

In addition, the FERC Clarification Order explains that compensation for environmental regulations that are an actual cost can be included in avoided cost calculations while compensation for environmental externalities can be attributed to other mechanisms, like a Renewable Energy Credit.[15] Like Renewable Energy Credits, GHG allowances are external to avoided cost rates as defined under this program (the MPR minus the GHG adder). Under a cap-and-trade program,[16] GHG allowances will be traded and operate in a separate market that will not affect capacity or energy prices paid under an avoided cost rate. As described in D.10-04-055, the price offered under the contracts in this proceeding represent a long-run avoided cost to the utility based on a new combined-cycle natural gas turbine. Consistent with the FERC Clarification Order, D.09-12-042, as revised by D.10-04-055, establishes that the

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[14] With respect to the table entitled "Illustrative Levelized Price Comparison" included by PG&E and SCE in their joint comments to the proposed decision filed on December 6, 2010, neither the table nor the underlying data is part of the record in this proceeding. Thus, they must be disregarded.

[15] *California Public Utilities Commission*, 133 FERC ¶ 61,059 at 31.

[16] California Assembly Bill 32 Scoping Plan, developed by the California Air Resources Board (ARB), contains the main strategies California will use to reduce the GHG that cause climate change. The scoping plan has a range of GHG reduction actions including market-based mechanisms such as a cap-and-trade system. The Scoping Plan was approved at an ARB meeting on December 12, 2008, and the staff proposal for a cap-and-trade regulation was released for public comment on October 28, 2010.

cost of GHG allowances associated with the electric power sold to the utility, should be paid for by the Buyer, which is a cost external to the avoided cost rate.

However, the Joint Utilities make a reasonable request in their Petition for Modification regarding which entity is best positioned to actually purchase the GHG allowances needed for an AB 1613 facility. The comments from CCDC and others suggest that the original Commission determination that the Buyer must procure the GHG allowances on behalf of the Seller might not yield the optimum outcome. Sellers that are obligated to comply with GHG regulations[17] might be better suited to procure allowances for emissions associated with their exported electricity, because it is a function they will already be performing for emissions associated with their heat needs and on-site electricity consumption.

We agree with CCDC that the original Commission determination may not yield the optimum outcome. However, unlike the Joint Utilities original petition to modify, having the Seller be solely responsible to procure GHG allowances may not yield the optimum result either. Therefore, we determine that a better outcome is for the Seller to elect who (the Buyer or the Seller) will procure the GHG allowances associated with their exported electricity.

Therefore, we modify D.09-12-042 to provide the Seller the option of procuring the GHG allowances for electric power sold to the utility on its own behalf or electing to have the Buyer perform this function.

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[17] As currently proposed in ARB's Proposed Regulation to Implement the California Cap-and-Trade Program (October 2010), only facilities that produce more than 25,000 tonnes of carbon dioxide equivalent per year are "covered entities" and obligated to comply with GHG regulation during the first compliance period. Small generators will be covered upstream beginning in 2015.

If the Seller elects to have the Buyer procure the GHG allowance, the Seller will be required to provide the Buyer with sufficient information regarding the emissions associated with their power sold to the electric utility. Provided that the Seller conveys accurate emissions information to the utilities in a timely fashion, we do not find that this will present a significant hardship to them. As was originally reasoned in D.09-12-042, the utilities will be managing GHG compliance obligations for their owned generation and will be well-suited to manage GHG allowances and compliance costs. Additionally, the combination of the adopted contracts, customer meter data, and the annual reporting requirements to the ARB will provide sufficient information for the utilities to make informed decisions regarding the compliance obligation from these resources. Once ARB finalizes its cap-and-trade regulations, Energy Division staff will issue (via Resolution) guidelines on the mechanics of this exchange (e.g., information that Sellers need to provide to the utilities, timing and frequency of the utility provision of allowances, etc.).

However, based on party comments, we expect that some Sellers will elect to manage their own GHG allowances. The Amended Scoping Memo asked the parties if it should employ a test in order to protect ratepayer interests. As commented on by San Joaquin, no test should be needed as long as the Seller purchases the allowance through a liquid and transparent market, and in a manner that is timely in terms of when the allowance must be surrendered to the regulators of the GHG program. PG&E agrees that the price paid for the allowances should be based on a public index, with the best option being the publicly available auction price. We agree. When the Seller elects to procure an allowance that will be reimbursed by the Buyer, the amount paid should be equal to the price established by the most relevant publicly available index, such as an auction, or other comparable index.

9. Contract Language Clean Up

The Joint Utilities request in their Petition for Modification that certain language in the standard contracts adopted in D.09-12-042 be "cleaned-up" to correct internal inconsistencies. They claim that there are errors in the contracts, including references and defined terms that require clarification in order for the contracts to be administered. The Joint Utilities further claim that the requested modifications do not materially change the contracts or alter the intent of the D.09-12-042, but merely correct errors. The language the Joint Utilities propose to "clean-up" is shown in Attachment A to this decision.

TURN and DRA support the Joint Utilities proposed "clean-up" of contract language. FCE does not oppose most of Joint Utilities' proposed "clean-up" of the contract language but argues that some of the proposed "clean-up" would, in fact, alter the negotiated terms and intended meaning of the CHP contracts adopted by D.09-12-042. Similarly, CCDC is concerned that the Joint Utilities are unilaterally proposing changes to mutually agreed upon terms of the simplified AB 1613 contract without discussing them with CCDC first. CCDC does not object to legitimate "clean-up" changes but believes there are certain changes that would materially change agreed upon terms.

San Joaquin contends that these changes should not be addressed in a petition to modify but should be proposed through the compliance advice letter in which the Commission will give final approval to the AB 1613 contracts.

9.1. Discussion

The contracts adopted in D.09-12-042 primarily represent negotiated terms and conditions submitted by parties in this proceeding. When parties submitted these proposed contract terms and conditions, there were several issues left unresolved. In D.09-12-042, the Commission decided these unresolved issues.

Contract terms and conditions are critically important for successful contract execution. Where errors were made in drafting the final contracts, we agree with Joint Utilities that these errors should be fixed. However, based on parties' responses to the Petition, it appears that some of the contract "clean-up" proposed by Joint Utilities goes beyond merely fixing errors. Therefore, we adopt only those contract changes that do not materially change the contracts and changes that were not opposed by any other parties. Where there was disagreement among parties, the contracts shall remain as they were adopted in D.09-12-042.

On June 21, 2010, the IOUs filed advice letters implementing the standard contract and simplified contract adopted in D.09-12-042.[18] The IOUs shall file advice letters with updated tariffs reflecting revisions to the contracts adopted in this decision. Attachment A to this decision describes the proposed revisions requested by the Joint Utilities and provides the Commission's resolution for each proposal, whether they were adopted or rejected. The utilities are directed to modify the contracts in accordance to this table (in addition to making the changes to contract provisions discussed in other sections of this Decision).

Notwithstanding the above paragraphs, the IOUs are encouraged to work with individual CHP customers and developers to ensure the success of this program. Toward that end, if there are contract modifications that contracting parties can agree to, and which do not contravene the Commission's Orders,

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[18] See PG&E Advice Letter 3696-E, SCE Advice Letter 2485-E, and SDG&E Advice Letter 2179-E.

IOUs may work with CHP customers to make those modifications to the contracts before the contracts are submitted for final approval. For instance, we note that there is no clear definition of a repowered CHP facility included in the contract, an omission that IOUs and CHP customers may want to rectify. Another example would be using a clearer definition of "Eligible CHP Facility," as commented on by parties on the proposed decision. However, no filing-extensions will be granted for any such efforts.

10. Line Loss Factor Calculation

As part of the contract "clean-up," the Joint Utilities recommended changes to Exhibit C, Section 2 of the standard contract (Exhibit B, Section 2 of the simplified contract) including adding a loss factor to the time of delivery period payment calculation, to be consistent with D.09-12-042. The Amended Scoping Memo asked parties to respond to the following question regarding a line loss factor: What is an appropriate calculation for line losses associated with moving the CHP project's power from the Delivery Point to the grid controlled by the California Independent System Operator (CAISO)?

San Joaquin recommends using the distribution loss factors that apply to QFs that interconnect to the distribution system. CCDC and FCE agree with San Joaquin. However, PG&E and SCE disagree with this approach stating that distribution loss factors are outdated and the global QF Settlement requires each Seller to install a CAISO compliant meter that will automatically adjust payments for line loss. PG&E and SCE recommend that the Commission look to the QF Settlement for provisions on delivery requirements and line loss calculations, if any. SDG&E contends that line loss factors should be calculated for each individual project.

10.1. Discussion

As mentioned previously, the October 2010 proposed QF Settlement does not seek to modify any decision in this docket and does not apply to open matters in the scope of this proceeding. We will not pre-judge a proposed settlement pending in other open dockets. Additionally, the location adjustment factors defined in the QF Settlement refer to transmission losses, not distribution losses that are under consideration in this proceeding. For these reasons, we do not believe that use of the location adjustment calculation in the QF Settlement is the appropriate reference for line loss calculations under this AB 1613 program.

However, we are persuaded by arguments from PG&E and SCE that use of the distribution loss factors, as proposed by San Joaquin, are also not appropriate. As clarified by SCE, the intent of the "loss factor" was to compensate the purchasing utility for the actual losses associated with delivering power at the first point of connection with the utility's facilities rather than the CAISO grid. Furthermore, it is clear in D.09-12-042 that the Seller is responsible for line losses from the Delivery Point to the Interconnection Point.[19] Generation Meter Multipliers and distribution loss factors established through D.01-01-007 would compensate generators for avoided losses rather than the purchasing utility for actual line loss.

We conclude that these line losses are best calculated as part of a project's interconnection process, whether that be through CAISO, Rule 21 or another interconnection process. While we understand the concern from CHP parties that this causes some uncertainty in project planning, because facilities

[19] D.09-12-042, Attachment A, § 1.03 at 3.

participating in this program are small (under 20 MW) and will generally be serving local loads, we expect in most cases the line loss factor to be 1.0.

11. Contract Option for Facilities Less than 500 Kilowatts

In D.09-12-042, the Commission directed the parties to develop a streamlined contract for very small [less than 500 kilowatt (kW)] facilities within a set period of time. The Commission granted a request by the Joint Utilities to delay development of this contract until October 2010. Because of the delay in processing the two contracts approved in December 2009, and in light of the FERC Orders, the timing of this contract will also need to be updated.

The Amended Scoping Memo asked parities to respond to the following questions:

(1) What changes are required from the adopted contracts to make a less than 500 kW contract more streamlined?

(2) What changes, if any, are required in this contract to comply with the FERC Order?

CCDC, FCE, and SDG&E all list a number of contract provisions that can be streamlined for the under 500 kW contract option. PG&E suggests that interested parties meet to negotiate amendments to the streamlined contract to appropriately reflect the delivery potential and operating characteristics of facilities offering 500 kW or less of capacity. SCE points to the global QF Settlement and contends that the "very small" contract option is not necessary. SCE also raises a question regarding if the less than 500 kW refers to a facility's nameplate or exporting capacity. The Multijurisdictional Utilities argue that given their unique territories, the Commissions should not require them to adopt the very small contract.

11.1. Discussion

We will not address SCE's argument that the QF Settlement has replaced the need for a "very small contract," since, as previously mentioned, 1) we cannot pre-judge this as yet unapproved settlement, and 2) the settlement as proposed does not modify any item in this docket. SCE also seeks to clarify whether the 500 kW threshold that would be negotiated refers to nameplate or contract capacity. To clarify, consistent with the convention employed for both the contracts approved in D.09-12-042, this streamlined contract would be for facilities with a <u>nameplate</u> capacity less than 500 kW.

We agree with the proposal made by PG&E that the parties should work together to negotiate and propose a contract for this size point. Parties made several suggestions as to which items could be simplified to reach a contract appropriate for this size threshold. We suggest that prior to commencement of negotiations, Energy Division coordinate with the parties to host a workshop to develop a list of principles that would guide the development of the streamlined contract. Similar to the timeline considered in D.09-12-042, we expect that this contract would be developed within the next six months.

12. Changes Needed to Contracts in Light of Subsequent FERC Orders

The FERC Declaratory Order states that the AB 1613 program is not preempted by the FPA or PURPA as long as: (1) the CHP generators from which the CPUC is requiring the Joint Utilities to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility."[20] Furthermore, FERC clarifies that

[20] *California Public Utilities Commission et al.*, 132 FERC ¶ 61,047 at 67.

"any ruling on the extent of federal preemption of the CPUC's AB 1613 program does not apply to public agency sellers that are exempt from Commission jurisdiction under section 201(f) of the FPA."[21]

In addition, the FERC Clarification Order supports a wide degree of latitude for the Commission to establish a utility's avoided cost; found that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided cost requirements set forth in Section 210 of PURPA and FERC regulation; and recognizes that full avoided cost need not be the lowest possible avoided cost and can properly take into account real limitations on alternate sources of energy imposed by state law.[22]

The significance of the FERC's Clarification Order is that in contrast to its *Southern California Edison Company* decisions in the 1990s, where FERC required states to consider purchases from "all sources," including coal-fired generation, in setting avoided costs, the FERC's Clarification Order rules that all sources can be limited to those that are available to the utilities under state law.[23]

In consideration of the FERC Declaratory Order, the Commission's September 2010 Amended Scoping Memo asked parties to comment on two questions:

1. What changes are necessary to the contracts approved under D.09-12-042 to reflect the requirement for QF certification in addition to the already mandated certification from California Energy Commission (CEC)?

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[21] *Id.* at 71.

[22] *California Public Utilities Commission et al.*, 133 FERC ¶ 61,059 at 26-30.

[23] *Id.* at 30.

2. If a QF already certified for and participating in the feed-in-tariff program loses its CEC certification under AB 1613 but maintains QF certification by FERC, what should the contract provide as the alternative rate for the QF (e.g., should the QF receive short run avoided cost pricing)?

Several parties commented that the contract should be amended to ensure that the Seller is in compliance with QF requirements. PG&E suggested specific changes to the definition of "eligible CHP facility" to address this issue. Furthermore, CCDC and FCE point out that public entities need not obtain QF certification and any contract changes should make this clear. SCE suggests that all QFs, including the AB 1613 QFs, utilize the QF standard contract developed in accordance the global QF Settlement.

Regarding the event that a QF loses its AB 1613 certification, CCDC, San Joaquin, and FCE contend that the QF would be eligible for the applicable QF rate, namely Short Run Avoided Cost as developed in D.07-09-040. SDG&E and PG&E contend that in such a situation, the facility would be in default of a material term of the contract and no longer entitled to participate in the AB 1613 program.

12.1. Discussion

In light of the FERC Declaratory Order, CHP facilities not exempt from FERC jurisdiction, which are participating in the AB 1613 feed-in-tariff program, must obtain QF status under PURPA requirements in order to be eligible for the avoided cost rates assigned by the Commission. The requirement to obtain QF status does not preclude the requirement for a CHP facility to also obtain certification from the CEC that it meets the higher efficiency standards as prescribed in AB 1613.

We agree with PG&E's suggested edits to the definition of "eligible facility" as applicable to address this issue. Specifically, we adopt the following change to the definition of "eligible facility" in the standard and simplified contracts for AB 1613:

> "Eligible CHP Facility" means a facility, as defined by Public Utilities Code Section 2840.2, subdivisions (a) and (b) that, (1) meets the guidelines established by the California Energy Commission pursuant to Public Utilities Code § 2843 and, (2) meets the requirements of 18 Code of Federal Regulations § 292.201, et seq., if applicable.

In the event that a facility is decertified by CEC, we agree with parties that this constitutes an event of default of the AB 1613 feed-in tariff rates under the contract. However, the CPUC cannot decertify a facility from its QF status; only the FERC can decertify a QF. If a facility were to fall below the minimum AB 1613 contract requirements, but still meet the requirements needed to retain its QF status, it would still be eligible to obtain a QF standard offer contract with a short-run avoided cost rate as ordered in D.07-09-040, if still in effect, or participate in any programs that supersede D.07-09-040. In no event may a utility unilaterally declare a default under the AB 1613 contract without the CEC decertifying the facility, just like a utility may not unilaterally declare a QF is in default under a QF contract without the FERC finding that the facility has lost its QF status. If the utility believes that a QF is not in compliance with federal standards, the utility may petition FERC to revoke the QF's status.[24]

[24] *Independent Energy Producers Association, Inc. v. CPUC* (9th Cir. 1994) 36 F.3d 848, 859.

In this regard, consistent with the "flexible pricing mechanisms," which the Ninth Circuit found were proper remedies for states[25] and the "multi-tiered avoided cost rates structure," which the FERC Clarification Order explained states may adopt for CHP generators,[26] we find that an AB 1613 compliant CHP facility is entitled to the AB 1613 pricing formula provided herein. However, in the event of decertification by the CEC, the contract should provide that the CHP generator should then be entitled to the established short-run avoided cost rate at the time of the CEC's decertification, and the utility should offer the CHP generator the standard offer contract associated with that rate. To the extent that the FERC were to revoke the QF status of the CHP generator, then the utility's obligation would be governed by the remedy provided at the time of the FERC's revocation of QF status. The utilities are directed to modify the AB 1613 contracts to be consistent with this discussion.

We do not agree with SCE's comments that changing the contract option reflects an alternative avoided cost based on facility efficiency. This is an improper assumption because avoided cost is based not on the facility's performance but on the cost avoided by the utility. As explained in D.09-12-042 and D.10-04-055, the pricing in this program represents a long-run avoided cost. D.10-04-055 states that short run avoided cost prices "adopted in D.07-09-040 do not accurately reflect the price avoided by an eligible CHP facility under the AB 1613 program."[27] In addition, D.10-04-055 reaffirms that a new combined-cycle gas turbine "represents a reasonable proxy for the generation

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[25] *Id.*

[26] *California Public Utilities Commission*, 133 FERC ¶ 61,059 at 30.

[27] D.10-04-055 at 11.

source that a utility would have to procure if not for a CHP facility participation in the AB 1613 program."[28] FERC's Clarification Order also allows for this multi-tiered approach to avoided cost.

13. 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 December 6, 2010 by FCE, DRA, TURN, CCDC, SDG&E, and jointly by PG&E and SCE. Reply comments were flied on December 13, 2010 by San Joaquin, FCE, DRA, CCDC, and jointly by PG&E and SCE. In this section we address the major issues addressed by the parties.

The Joint Utilities have argued in their comments to the proposed decision that the price offered under this program is not reflective of avoided costs. The Commission has previously found, in D.09-12-042 and D.10-04-055, that a combined cycle gas turbine is reasonable proxy for the marginal unit avoided by an eligible CHP facility under this program and the price is reflective of this proxy.[29] This price also includes a location factor which Commission staff had estimated to be approximately 10% to the extent it avoids congestion and the potential cost of upgrading transmission and distribution facilities if the CHP facility is in a congested area. Other parties supported this estimate as we noted

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[28] *Id.* at 8.

[29] See, for example, D.09-12-042 at 35.

in D.10-04-055.[30] We recognize that these are estimates of the avoided costs, because each of the utilities have filed for further increases in transmission rate cases at FERC and for higher distribution rates in Commission proceedings. Therefore, some of the avoided costs of further upgraded distribution and transmission facilities may be higher. Nevertheless, the Commission has determined that there is a need to have a legal obligation upfront to encourage CHP facilities in these congested areas, consistent with AB 1613 and PURPA. Accordingly, this 10% location bonus is a good proxy for avoiding the costs of the upgraded facilities.

With respect to determining the price paid to Sellers who choose to procure their own GHG allowances by utilizing a publically available index, CCDC suggests that the Commission modify the Proposed Decision to provide that Energy Division shall determine the appropriate index with input from stakeholders. We agree that such input would help to ensure the index is credible and publicly available.

14. Assignment of Proceeding

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

Findings of Fact

1. D.09-12-042 established a feed-in-tariff price and approved a standard AB 1613 contract for use by all eligible CHP systems up to 20 MW.

2. D.09-12-042 approved a simplified AB 1613 contract for use by CHP systems that export no more than 5 MW.

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[30] See D.10-04-055 at 10.

3. The pricing formula adopted by D.09-12-042 is based on the costs associated with a proxy natural gas generation resource. Several inputs into the pricing formula come from the MPR, established in accordance with Pub. Util. Code § 399.15.

4. The Energy Division updates the cost inputs and recalculates the MPR annually.

5. The AB 1613 pricing formula adopted by D.09-12-042 included four inputs from the 2008 MPR, including a Fixed Component, Variable Operations and Maintenance, Heat Rate, and Time of Delivery periods and factors.

6. The 2008 MPR was the most current calculation when the Commission issued D.09-12-042.

7. The fixed price component of the contract price does not escalate during the entire term of the contract.

8. The fixed price component is based on the year in which a project is expected to come online.

9. The "Term Start Date" is the date that the project starts, not the year in which the contract is signed.

10. The fixed component of the MPR, upon which AB 1613 pricing was based, does not include a GHG adder. GHG compliance costs in the MPR calculation are embedded in the variable component of the MPR.

11. GHG compliance costs are not being paid for twice but the adopted contract language created ambiguity.

12. The fixed components of the MPR do not include a GHG adder and GHG compliance costs are not reflected in any way in the adopted pricing formula. Therefore, no additional subtraction is necessary to ensure compliance costs are not paid for twice.

13. The arguments raised by the Joint Utilities to reduce the AB 1613 price to reflect pricing for an as-available product were considered and rejected by the Commission in D.09-12-042 and D.10-04-055. The Joint Utilities do not raise any new issues of law or fact in their petition for modification related to the issue of whether AB 1613 pricing should be reduced to reflect pricing for an as-available product.

14. The Joint Utilities' Application for Rehearing of D.09-12-042 was denied in D.10-04-055 and both decisions are now final.

15. Sellers that are already obligated to comply with GHG regulations may be better suited to procure allowances for emissions associated with their exported electricity because it is a function they will already be performing for emissions associated with their heat needs and on-site electricity consumption.

16. GHG allowance costs are external to market-based avoided cost rates.

17. D.09-12-042 established that GHG compliance costs should be paid for by the Buyer, with is consistent with the October 2010 FERC Clarification Order.

18. The AB 1613 contracts are primarily the result of negotiated terms and conditions submitted by the working group and parties to this proceeding.

19. The AB 1613 form contracts adopted by D.09-12-042 contain some drafting errors that create internal inconsistencies.

20. Some of the "clean-up" proposed by the Joint Utilities goes beyond correcting drafting errors.

21. Because facilities participating in the AB 1613 program are small (under 20 MW) and will generally be serving local loads, we expect in most cases the line loss factor to be one.

22. The FERC Declaratory Order found that the AB 1613 program is not preempted by the FPA or PURPA as long as: (1) the CHP generators from which

the CPUC is requiring the Joint Utilities to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility.

23. The FERC Declaratory Order states that any ruling on the extent of federal preemption of the CPUC's AB 1613 program does not apply to public agency Sellers that are exempt from Commission jurisdiction under Section 201(f) of the FPA.

Conclusions of Law

1. It is reasonable to use the most up-to-date price inputs in the pricing formula for the AB 1613 contract.

2. Since the MPR is updated annually, it is reasonable to use the inputs from the most current MPR in the pricing formula.

3. Neither CCDC nor San Joaquin provided a sufficient basis to make use of the most current MPR contingent upon a de minimus change in the total MPR value.

4. As long as the MPR is calculated based on the costs of a proxy natural gas generation resource, it is reasonable to use the MPR components in the AB 1613.

5. Updated pricing inputs should only apply prospectively to new contract executed after the effective date of this decision. The pricing for executed contracts should be based on the pricing inputs at the time the contract was executed and for the life of the contract.

6. The language added by D.09-12-042 to Exhibit C, Section 3 of the standard contract and to Exhibit B, Section 3 of the simplified contract should be modified to state that the fixed price component does not escalate during the term of the contract.

7. The fixed price component should be based on the year in which a project is expected to come online, which is synonymous with the "Term Start Date," rather than the year in which the contract is signed.

8. The language of Section 3 of Exhibit C to the standard contract and Section 3 of Exhibit B to the simplified contract should be amended to read, "The Fixed Price Component, FPC, for all TOD Periods shall be the amount in the following table for the year of the Term Start Date."

9. The language adopted in Table 2 of D.09-12-042 should be clarified to reflect the Commission's intent that GHG compliance costs are not being paid for twice.

10. Because Joint Utilities provided no new authority or facts for the Commission to consider reducing the feed-in tariff price to reflect that CHP resources are as-available, this proposed modification should be denied.

11. Modifications should be made to D.09-12-042 or to the form contracts to allow the Sellers have the option to purchase GHG allowances for GHG compliance or to have the utilities procure the allowances on behalf of the Sellers. The contracts should allow the Seller the option to either elect to manage its own allowances and request payment from the utilities or to have the utility purchase allowances for the emissions associated with the excess electricity purchased by the utility.

12. If the Sellers choose to purchase allowances, the payment should be tied to the most recent public index price, identified by Energy Division with input from stakeholders.

13. Contract language which is in error or which creates internal inconsistencies should be modified to correct such errors as set forth in Attachment A.

14. Contract language should be updated to ensure that facilities obtain Qualifying Facility status from the FERC.

15. Modifications requested by the Joint Utilities that materially change the contracts or alter the intent of D.09-12-042 should be denied.

16. Because the form contracts adopted by D.09-12-042 represent negotiated terms and conditions submitted by parties to this proceeding, they should not be modified where there is disagreement among parties.

17. Line losses for the AB 1613 program are best calculated as part of a project's interconnection process.

18. All California IOUs must file amended tariffs to reflect the revisions adopted in this decision.

19. The changes to the form contracts shown in Attachment A of this decision should be implemented in the contracts filed by each utility.

20. The FERC Clarification Order supports a wide degree of latitude for the Commission to establish a utility's avoided cost rates and finds that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided cost requirements set forth in Section 210 of PURPA and FERC regulation.

21. The FERC Clarification Order recognizes that full avoided cost need not be the lowest possible avoided cost and can properly take into account real limitations on alternate sources of energy imposed by state law.

O R D E R

IT IS ORDERED that:

1. The petition to modify of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company is granted

in part with modifications and denied in part, as set forth in Ordering Paragraphs 2-10 below.

2. Inputs from the most recently adopted Market Price Referent must be used in the pricing formula for the Assembly Bill 1613 standard and simplified contracts, as long as the Market Price Referent is calculated based on the costs of a proxy natural gas generation resource. Only new contracts executed after the effective date of this decision are impacted by updated pricing inputs. The pricing for executed contracts continues to be based on the pricing inputs in the contract at the time the contract was executed and for the life of the contract.

3. Table 2 of Decision 09-12-042 is modified to remove the phrase, "minus GHG compliance costs."

4. Each year, upon adoption by this Commission, of a new Market Price Referent calculation, each California investor-owned utility must file a Tier-1 Advice Letter updating its Assembly Bill 1613 tariffs and standard contracts with the new Market Price Referent inputs. The advice letters must be filed and served within five days of the date that the order adopting the Market Price Referent is mailed. This advice letter must also include a summary table of information about resources procured as a result of this program in the previous year and over the life of the program and updates on Location Bonus areas. Energy Division staff will provide the utilities with a template for the information to be provided in this table prior to the end of the program's first implementation year.

5. The California investor-owned utilities must revise the standard and streamlined contracts to reflect the fact that, when entering into the contract, the Combined Heat and Power Seller can (1) elect to manage its own allowances (and request payment from the California investor-owned utilities according to

the terms outlined in this reimbursement methodology) or (2) elect to have the California investor-owned utility purchase allowances for the emissions associated with their electricity exports. Energy Division staff must determine an appropriate publically available index for use in determining the price to be paid for the allowances after seeking input from stakeholders by January 31, 2012. Energy Division will make this information available to stakeholders in an appropriate manner.

6. Modified contract language for the contracts approved by Decision 09-12-042, as set forth in Attachment A to this decision is adopted. Attachment A also shows modifications we reject in this order. The approved changes must be implemented in the contracts filed by each California investor-owned utility.

7. The California investor-owned utilities must revise the standard and streamlined contracts to reflect that line losses from the Delivery Point to the Interconnection Point are determined as part of the interconnection process.

8. The California investor-owned utilities must revise the standard and streamlined contracts to reflect that in the case that a facility is decertified from participating in the Assembly Bill 1613 program, the combined heat and power generator should still be provided with the established short-run avoided cost rate at the time of decertification and the utility should offer the combined heat and power generator the standard offer contract associated with that rate unless the Federal Energy Regulatory Commission were to revoke the Qualifying Facility status of the facility.

9. Within 45 days of the date this order is mailed, Pacific Gas and Electric Company shall file a supplemental advice letter to update Advice Letter 3696-E. The advice letter must include revised tariff sheets to implement the standard contract and the simplified contract adopted in Decision 09-12-042 as modified

by Attachments A of this decision and other Ordering Paragraphs. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

10. Within 45 days of the date this order is mailed, Southern California Edison Company shall file a supplemental advice letter to update Advice Letter 2485-E. The advice letter must include revised tariff sheets to implement the standard contract and the simplified contract adopted in Decision 09-12-042 as modified by Attachments A of this decision and other Ordering Paragraphs. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

11. Within 45 days of the date this order is mailed, San Diego Gas & Electric Company shall file a supplemental advice letter to update Advice Letter 2179-E. The advice letter must include revised tariff sheets to implement the standard contract and the simplified contract adopted in Decision 09-12-042, as modified by Attachments A of this decision and other Ordering Paragraphs. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

12. Consistent with Decision (D.) 09-12-042 and any approved extensions granted by the Commission, within six months of the date this order is mailed, Sierra Pacific Power Corp. and PacifiCorp must file an advice letter in compliance with General Order 96-B. The advice letter must include tariff sheets to implement either:

a. the simplified contract approved by D.09-12-042 as modified herein (Attachment A) 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 systems less than 500 kilowatts, as discussed in D.09-12-042, Ordering Paragraph 6 by to October 18, 2010.

13. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must negotiate with the parties to develop a simplified contract for less than 500 kilowatt hour systems; if desired, Energy Division will host a workshop to establish guiding principles.

14. All changes proposed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company that would materially alter the contracts adopted in Decision 09-12-042 are denied.

15. Rulemaking 08-06-024 remains open to address the "pay-as-you-save" program.

This order is effective today.

Dated December 16, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

Peevey Attachment A