

CHP Program Settlement Agreement Term Sheet

October 8, 2010

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CHP Program Settlement Agreement: Term Sheet

1 Goals and Objectives

1.1 Settlement Goals and Objectives

- 1.1.1 Develop a State combined heat and power (CHP) program (CHP Program).
- 1.1.2 Create a smooth transition from the existing QF CHP PURPA Program to a State-administered CHP Program.
- 1.1.3 Settle all CHP/QF litigation referenced in Section 14.

1.2 State CHP Program

1.2.1 Policy Objectives

- 1.2.1.1 Section 372(a) of the California Public Utilities Code states: “it is the policy of the state to encourage and support the development of cogeneration technology as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply, and promote local business growth.”
- 1.2.1.2 The Energy Action Plan II states: “The loading order identifies energy efficiency and demand response as the State’s preferred means of meeting growing energy needs. After cost effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation.”
- 1.2.1.3 The purpose of the State CHP Program is to encourage the continued operation of the State’s Existing CHP Facilities, and the development, installation, and interconnection of new, clean and efficient CHP Facilities, in order to increase the diversity, reliability, and environmental benefits of the energy resources available to the State's electricity consumers.
- 1.2.1.4 These policies and purposes will be achieved by a State CHP Program that procures CHP as set forth in this Settlement, retains existing efficient CHP, supports the change in operations of inefficient CHP to provide greater benefits to the State, and replaces CHP that will no longer be under contract with the IOUs with new, efficient CHP.
- 1.2.1.5 In addition, this State CHP Program will secure additional Greenhouse Gas (GHG) emissions reduction benefits, consistent with the reduction targets of Assembly Bill (AB) 32, by adding new, efficient CHP.

1.2.2 CHP Program Objectives

- 1.2.2.1 Greater regulatory and market certainty for CHP Facilities;
- 1.2.2.2 Retains existing CHP GHG emissions reduction benefits;
- 1.2.2.3 Encourages the upgrade of the inefficient CHP Facilities in the IOUs' electric portfolios into efficient CHP through repowering or change of operations;
- 1.2.2.4 Provides an orderly exit strategy for CHP Facilities that cannot participate, or are unsuccessful, in the new CHP Program;
- 1.2.2.5 Encourages the development of new, clean and efficient CHP;
- 1.2.2.6 Recognizes the distinct products provided by CHP in order to procure cost-effective and efficient CHP power;
- 1.2.2.7 To the extent available, sustains and enhances reductions in GHG emissions from existing facilities and incrementally adds new CHP with the goal of reducing GHG emissions consistent with AB 32;
- 1.2.2.8 Achieves other benefits for California and electricity consumers in the IOUs' Service Territories;
- 1.2.2.9 Establishes a platform for a State CHP Program with identified features through 2020, and sets a framework for a sustained State CHP Program beyond 2020; and
- 1.2.2.10 Provides Power Purchase Agreement (PPA) options for CHP Facilities.

1.2.3 Facility Owner Goals and Objectives

- 1.2.3.1 On-site reliability;
- 1.2.3.2 Cost control;
- 1.2.3.3 Improvement in business and regulatory certainty;
- 1.2.3.4 Fuel efficiency through the use of a single fuel to produce two energy products, specifically thermal and electrical energy;
- 1.2.3.5 Compliance with GHG regulations; and
- 1.2.3.6 Maintaining CHP Program certainty.

1.2.4 Societal Goals and Objectives

- 1.2.4.1 Fuel efficiency through the use of a single fuel to produce two energy products, specifically thermal and electrical energy;
- 1.2.4.2 Reduction in GHG emissions and criteria pollutant emissions from avoided combustion of fossil fuel;

- 1.2.4.3 Grid reliability and/or local area reliability, including self-service of power supply for facilities' loads in resource-constrained areas;
 - 1.2.4.4 Reduction in transmission and distribution energy losses;
 - 1.2.4.5 Securing CHP generation resources as part of a diversified portfolio of resources for California generation supply; and
 - 1.2.4.6 Support for California's manufacturing, industrial and commercial base without cross subsidization by electric customers.
- 1.2.5 Bundled IOU Customer Goals and Objectives
- 1.2.5.1 Securing cost-effective GHG reductions;
 - 1.2.5.2 Providing system, grid, and local area reliability;
 - 1.2.5.3 Reducing transmission and distribution losses and investment;
 - 1.2.5.4 Moving to viable, market-based compensation for QFs with Legacy PPAs and CHP resources to sustain California CHP operations at fair prices; and
 - 1.2.5.5 Complementing other existing State policy programs that reduce GHG emissions.
- 1.2.6 GHG Emissions Reduction Goals and Objectives
- 1.2.6.1 Maintain existing GHG benefits in the IOUs' portfolios attributable to CHP; and
 - 1.2.6.2 Achieve additional GHG emissions reductions beyond those benefits already provided by the existing CHP fleet towards the California Air Resources Board (CARB) Scoping Plan statewide target goal of 6.7 million metric tons (MMT) from efficient CHP. In the Settlement this is referred to as the CARB Combined Heat and Power Recommended Reduction Measure (CARB CHP RRM).¹

2 Settlement Periods

2.1 Transition Period

- 2.1.1 The Transition Period is a period in which a CHP Facility will either obtain a new PPA as per Section 4, sell into the wholesale market, shut down, or cease to export to the grid.

¹ As referenced on pages 43-44 of the “Approved Scoping Plan” adopted by the CARB at its December 11, 2008 Board meeting. http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

2.1.2 The Transition Period will begin on the Settlement Effective Date and shall not extend beyond July 1, 2015.

2.2 Initial Program Period and Targets

2.2.1 The Initial Program Period shall commence on the Settlement Effective Date, and shall conclude 48 months thereafter.

2.2.2 Each IOU shall enter into new PPAs with CHP Facilities and Utility Prescheduled Facilities as further described in Section 5 as follows:

2.2.2.1 SCE: 1,402 MW

2.2.2.2 PG&E: 1,387 MW

2.2.2.3 SDG&E: 160 MW.

2.3 Second Program Period and Targets

2.3.1 The Second Program Period shall commence at the end of the Initial Program Period and end December 31, 2020.

2.3.2 For CHP procurement in the Second Program Period, the IOUs will procure the following:

2.3.2.1 Any portion of the IOUs' MW Targets that was not attained in the Initial Program Period.

2.3.2.2 SDG&E shall procure an additional 51 MW.

2.3.2.3 Additional CHP capacity to meet the IOUs' GHG Emissions Reduction Targets as established by the CPUC in the Long Term Procurement Planning (LTTP) proceeding, taking into account the progress toward the MW Targets in the Initial Program Period.

3 Transition PPA Matters

3.1 Eligibility for a Transition PPA

3.1.1 A CHP Facility currently selling to an IOU under a Legacy PPA or an extension thereof that is expiring during the Transition Period, may sign a Transition PPA with the same IOU-Buyer.

3.1.2 The Transition PPA begins upon the expiration of the Legacy PPA or extensions of a Legacy PPA and ends at the election of the Seller but no later than the last day of the Transition Period.

3.1.3 The capacity and energy that the CHP Facility may sell to the IOU under the Transition PPA are limited to an amount consistent with the QF's historical deliveries under its Legacy PPA, but energy delivery may be lower upon the election of the Seller.

3.1.4 The Transition PPA is unavailable to CHP Facilities whose owners elect under the CHP Program to sell to the IOUs outside of the competitive solicitation process, including CHP Facilities selling under a bilateral PPA, the Optional As-Available PPA, and CHP Facilities eligible to sell to the IOUs pursuant to the AB 1613 Feed-In Tariff. During the Settlement Term, QFs who elect to sign a Transition PPA waive their rights to sign a CHP PPA that is not obtained through competitive procurement, bilateral negotiations or the under 20 MW nameplate PURPA must-take obligation.

3.2 Pricing of Transition PPAs

3.2.1 Capacity prices shall be paid as established in Decision 07-09-040.

3.2.2 Energy pricing will be Short Run Avoided Cost (SRAC) as defined in Section 10 below.

3.3 Form of Transition PPA

3.3.1 The Transition PPA is the QF Standard Offer Contract (SOC) modified for the Transition Period. The Standard Form Transition PPA is attached hereto as Exhibit 4.

3.4 Modifications

3.4.1 Modifications of the SOC for the Transition PPA are described in part as follows: (The terms and conditions of the attached Transition PPA govern)

3.4.1.1 Double penalties under the Transition PPA and CAISO Tariff for failure to deliver capacity for Transition PPA and the CHP RFO Pro Forma PPA.

Under both the applicable CAISO Tariff and the PPAs there are penalties for failure to deliver capacity or scheduled energy. Parties agree that only a single, and not double, penalty shall apply to such deliveries and schedules.

Accordingly, the CAISO Tariff penalties pursuant to the Standard Capacity Product shall be treated as follows:

If Buyer is the Scheduling Coordinator, and if the Generating Facility is subject to the terms of the Availability Standards, Non-Availability Charges, and Availability Incentive Payments as contemplated under Section 40.9 of the CAISO Tariff, then any Availability Incentive Payments will be for the benefit of Buyer and for Buyer's account and any Non-Availability Charges will be the responsibility of Buyer and for Buyer's account.

If Buyer is not the Scheduling Coordinator, and if the Generating Facility is subject to the terms of the Availability Standards, Non-Availability Charges, and Availability Incentive Payments as contemplated under Section 40.9 of the CAISO Tariff, then any Availability Incentive Payments will be for the benefit of Seller and for Seller's account and any Non-Availability Charges will be the responsibility of Seller and for Seller's account.

3.4.1.2 Sale of Additional Dispatchable Capacity beyond the Transition PPA Capacity Product

This option for Additional Dispatchable Capacity is viewed as being limited to a few CHP facilities, each with unique operational constraints. A specific amendment to the Transition PPA is required to accommodate Additional Dispatchable Capacity.

The Transition PPA shall provide that a Seller may elect to deliver a standard capacity product (including associated energy and RA with such capacity) at the Transition PPA firm capacity and energy prices or as-available capacity and energy prices. In addition to these standard products, a Seller may elect to sell to Buyer under a Transition PPA Additional Dispatchable Capacity above the standard contract capacity set forth in the Transition PPA (Additional Dispatchable Capacity). Buyer must negotiate in good faith for 120 days to amend the Transition PPA to incorporate a competitive market price for the Additional Dispatchable Capacity. If negotiations are unsuccessful, Buyer and Seller will mediate the terms of the amendment using the mediation procedures set forth in Section 10.02 of the Transition PPA. Within ninety (90) days after the Transition PPA is executed by Buyer and Seller, Seller shall designate the initial Additional Dispatchable Capacity offered to Buyer for the term of the PPA. In addition, such Additional Dispatchable Capacity will be offered with an associated fixed heat rate, or fixed heat rate curve, established by the Seller. The fixed heat rate or fixed heat rate curve will be used as the applicable heat rate in the energy price formula calculated pursuant to Section 10.2.1.1. Additional Dispatchable Capacity must meet CPUC/CAISO requirements for RA and such capacity must be offered and provided in a manner consistent with CAISO Tariff and Protocols. Parties will work in good faith to get clarification from CAISO to implement this section according to the CAISO Tariff and Protocols on a case-by-case basis in advance of any deliveries of electric power pursuant to this provision.

In order to be eligible to provide Additional Dispatchable Capacity pursuant to this section, the Seller must have twenty-five (25) MWs or more capacity available as Additional Dispatchable Capacity; provided, however, that the Seller must schedule such capacity in quantities of at least 10 MW for scheduled delivery.

After the initial designation of Additional Dispatchable Capacity a Seller providing such capacity to Buyer on a firm basis shall offer such capacity no later than thirty (30) days before the annual Resource Adequacy year-ahead showing each year during the term of the Transition PPA. Such Additional Dispatchable Capacity will include a fixed heat rate, or fixed heat rate curve, established by the Seller.

If the Buyer elects not to accept Seller's offer of Additional Dispatchable Capacity for the term of the Transition PPA, then the Buyer, as the Scheduling Coordinator, will facilitate an alternative sale and delivery of the Dispatchable Capacity to the CAISO market, as long as such capacity meets the CAISO determined requirements for compliance with the CAISO Tariff and Protocols. Such alternative sale and delivery shall be consistent with the applicable CAISO Tariff and Protocols for such sales. The Seller shall have financial responsibility for any applicable CAISO charges or penalties for deviations in the delivery of the Additional Dispatchable Capacity, so long as such charges

or deviations are due to actions of the Seller. Seller shall receive CAISO revenues and charges associated with the delivery of any Additional Dispatchable Capacity into the CAISO markets.

When the IOU is not the Scheduling Coordinator and elects not to accept Seller's offer of Additional Dispatchable Capacity for the term of the Transition PPA, the IOU will facilitate the scheduling and delivery of the Transition PPA Power Product in cooperation with the Seller's Scheduling Coordinator. Seller may undertake any necessary actions with the CAISO or any other jurisdictional entity to facilitate a delivery or sale of Additional Dispatchable Capacity pursuant to this Section 3.4.1.2.

Any resulting amendment to the Transitional PPA must contain terms that allow proper operation consistent with CAISO requirements and appropriate settlement terms consistent with the risk sharing and optional product purchase described above.

- 3.4.2 Section 3.07: The amount of capacity and energy may be modified pursuant to Section 3.07 in the Transition PPA, provided that any CHP Facility modification under Section 3.07 shall not increase the GHG costs of the IOU as a result of a change in the CHP Facility pursuant to Section 3.07. The Seller shall render the Buyer indifferent to GHG cost increases resulting from Section 3.07.
- 3.4.3 CHP Facilities Operating under Transitional SO1s
- 3.4.4 QFs that previously delivered firm capacity under a Legacy PPA or other CHP PPA, and petitioned the CPUC for this firm contract option before January 1, 2010, can elect to sign a firm capacity Transition PPA and shall be paid under such PPA as if deliveries commenced on January 1, 2010. Eligible petitioners under this section are: (1) Mid-Set Cogeneration Company, QF ID # 25C123E02; (2) Coalinga Cogeneration Company, QF ID #25c124E01; (3) Sargent Canyon Cogeneration Company, QF ID #18C052E01; (4) Salinas River Cogeneration Company, QF ID #18C053E01; (5) Berry Petroleum Company Taft/Kern, QF ID #25C151E01; (6) Graphic Packing Int'l (Blue Grass) Santa Clara, QF ID #08C023E01; (7) Berry Petroleum Company Taft/Kern, QF ID# 25C099E01; (8) Berry Petroleum, QF ID #2224 – Newhall II; and, (9) US Borax, QF ID #2019 – U.S. Borax and Chemical Corp.
- 3.4.5 Curtailment
 - 3.4.5.1 Seller shall promptly curtail the production of the Power Product (as defined in the PPAs attached to this Settlement) upon receipt of a notice or instruction from the CAISO, which may be communicated by Buyer if Buyer is the Scheduling Coordinator. Such notice or instruction shall only be provided when the CAISO orders curtailment and the Scheduling Coordinator implements such curtailment in compliance with the CAISO Tariff or applicable orders to avoid or address a declared System Emergency.
 - 3.4.5.2 Seller shall promptly curtail the production of the Power Product upon receipt of a notice or instruction from the Transmission Provider, which may be communicated by Buyer if Buyer is the Scheduling Coordinator. Such notice

or instruction shall only be provided when curtailment of the Power Product is required to comply with:

- 3.4.5.2.1 A CAISO curtailment declared pursuant to Section 3.15 (a) or Transmission Provider declared Emergency Condition, subject to the interconnection agreement between the Seller and the Transmission Provider; or
- 3.4.5.2.2 Transmission Provider's maintenance requirements, subject to the interconnection agreement between the Seller and the Transmission Provider.
- 3.4.5.3 Notwithstanding the above, except as may be required in order to respond to any Emergency Condition or System Emergency, Buyer shall, consistent with FERC Order 888 and the interconnection agreement between the Seller and the Transmission Provider and with the applicable provisions of the CAISO Tariff:
 - 3.4.5.3.1 Use reasonable good faith efforts to coordinate Transmission Provider's curtailment needs with Seller to the extent it can influence such needs; or
 - 3.4.5.3.2 Request the Transmission Provider and CAISO limit the curtailment duration.
- 3.4.5.4 If Seller has entered into a Participating Generator Agreement (PGA) or Qualifying Facility Participating Generator Agreement (QF PGA) with the CAISO, or an interconnection agreement, the terms of the applicable PGA or QF PGA and the applicable interconnection agreement with respect to CAISO or Transmission Provider curtailments, shall govern the rights and obligations of Buyer and Seller to the extent any provision of this Section 3.4.5 is inconsistent with such applicable PGA or QF PGA, and interconnection agreement.
- 3.4.5.5 In the event Seller interconnects with an individual or entity other than the CAISO, the Seller shall adhere to any reliability curtailment order by such individual or entity pursuant to the applicable tariff provisions of such individual or entity.

4 CHP Procurement Processes

4.1 Overview

- 4.1.1 This section outlines various procurement methods encompassed in this CHP Program to meet the MW Targets and GHG Emissions Reduction Targets.

4.2 CHP RFOs

- 4.2.1 Each IOU shall conduct RFOs exclusively for CHP resources (CHP RFOs) as a means of achieving its MW Target and GHG Emissions Reduction Targets, consistent with the terms of this Settlement.

4.2.2 Eligibility

4.2.2.1 Any CHP Facility with a nameplate larger than 5 MW may bid into the CHP RFO, including CHP Facilities seeking firm and as-available capacity PPAs, provided that the CHP Facility meets the definition of cogeneration under California Public Utilities Code §216.6 and the Emissions Performance Standard established by Public Utilities Code §8341 (Senate Bill 1368). A CHP Facility must meet the federal definition of a qualifying cogeneration facility under 18 CFR §292.205 implementing PURPA.

4.2.2.2 CHP Facilities converting to Utility Prescheduled Facilities. A CHP Facility that met the PURPA efficiency requirements (18 C.F.R. §292.205) as of September 2007 and converts to a Utility Prescheduled Facility is also eligible to participate in the CHP RFOs. After the Existing CHP Facility converts to a Utility Prescheduled Facility, it may be either a Qualifying Facility or an Exempt Wholesale Generator if the facility otherwise meets the criteria in this Section 4.2.2.2.

4.2.3 Term. The maximum term for PPAs resulting from the CHP RFO shall be:

4.2.3.1 Up to seven (7) years for Existing CHP Facilities, both firm capacity and as-available capacity or Expanded CHP Facilities, if they do not provide credit and collateral as set forth in Section 4.2.8. An Existing CHP Facility is one that was operational before the Settlement Effective Date.

4.2.3.2 Up to twelve (12) years for New CHP Facilities, Repowered CHP Facilities, or Expanded CHP Facilities if they provide credit and collateral as set forth in Section 4.2.8. A New CHP Facility is one that becomes operational after the Settlement Effective Date and a Repowered CHP Facility is one that repowers after the Settlement Effective Date.

4.2.4 Pricing

4.2.4.1 Defined according to the executed PPA.

4.2.4.2 Buyers and Sellers will not assert that the prices in the PPAs executed as a result of the CHP RFOs or bilateral negotiations are inconsistent with the Buyer's avoided costs as defined by PURPA.

4.2.5 CHP RFO Scope, Evaluation and Selection Criteria

4.2.5.1 A CHP Facility may also elect to participate in an all-source RFO or a renewable energy solicitation provided it meets the eligibility requirements for the solicitation.

4.2.5.2 The CHP RFO will recognize that CHP has unique attributes.

4.2.5.3 CHP offers shall be compared only to other CHP offers within the CHP RFO process.

- 4.2.5.4 The IOU shall conduct an evaluation process, including an analysis of market value, in its CHP RFO process.
- 4.2.5.5 When evaluating an offer from an Existing CHP Facility, the IOU should evaluate the energy that is being delivered to the grid from that CHP Facility.
- 4.2.5.6 CHP offers shall be evaluated on all of the CHP Program goal characteristics, including GHG emissions.
- 4.2.5.7 Each IOU shall use an Independent Evaluator (IE) similar to that used in other IOU RFO processes. It is preferable that the IE have CHP expertise and financial modeling experience.
- 4.2.5.8 The PRG advises and the IE shall review the entire CHP RFO process.
- 4.2.6 The CHP RFO Pro-Forma PPA is attached as Exhibit 5. The CHP Pro-Forma PPA may be modified on a bilateral basis during negotiations for a particular CHP PPA or Utility Prescheduled Facility PPA. As set forth in Section 4.2.12 below, the IOUs may also offer other contract options in the CHP RFO.
- 4.2.7 Modifications of the SOC for the CHP RFO Pro-Forma PPA are described in part as follows: (The terms and conditions of the attached CHP RFO Pro-Forma PPA govern)
 - 4.2.7.1 Remove all standard-offer pricing terms.
 - 4.2.7.2 GHG Compliance Cost: Seller must offer both options below:
 - 4.2.7.2.1 Seller assumes GHG Compliance Cost, and
 - 4.2.7.2.2 Seller elects to pass-through GHG Compliance Costs to Buyer.
 - 4.2.7.3 Seller and Buyer may elect a hybrid approach for GHG cost recovery. For example, Buyer covers GHG costs up to a certain Heat Rate and Seller assumes additional costs above that Heat Rate. This hybrid approach may create an efficiency incentive for the Seller to provide additional reductions of GHG emissions.
- 4.2.8 Credit and Collateral provisions for New, Repowered, or Expanded CHP Facilities
 - 4.2.8.1 Credit and collateral provisions shall apply only to PPAs for New CHP Facilities, Repowered or Expanded Facilities CHP Facilities.
 - 4.2.8.1.1 An IOU may request additional offers for different credit and collateral terms from New CHP Facilities, Repowered CHP Facilities or Expanded Facilities in RFO Bid solicitations; and such options will be considered according to the terms and conditions of such options.
 - 4.2.8.2 Credit and collateral provisions for an Existing CHP Facility will not be required in any CHP PPA but may be requested by an IOU in CHP RFOs or bilateral negotiations and will be evaluated by IOUs and Sellers accordingly.

- 4.2.8.3 Performance Assurance for New or Repowered CHP Facilities shall be established equal to the value from one of the following options, and the selection of the option is at the election of the Seller:
- 4.2.8.3.1 Twelve (12) months of capacity payments
 - 4.2.8.3.2 Twelve (12) months of revenues
 - 4.2.8.3.3 Five percent (5%) of anticipated revenues projected over the term of the PPA (*e.g.*, 5% of revenues over the course of a 12 year PPA would be approximately seven (7) months of anticipated revenues);
 - 4.2.8.3.4 Negotiated performance assurance value and conditions for providing security for such Performance Assurance.

4.2.8.4 Cross-default Provision

- 4.2.8.4.1 The Seller may provide a Letter of Credit to the Buyer. In the event of cross default event implicating the Letter of Credit, the Seller must provide a substitute Letter of Credit within five (5) to ten (10) Business Days.
- 4.2.8.4.2 Any cross-default provision in a CHP PPA shall apply specifically to the Seller and the Seller's guarantor under the CHP Pro-Forma PPA (and not a parent of the Seller, a subsidiary of the Seller or an affiliate of the Seller, unless they are the guarantor).
- 4.2.8.4.3 In addition to the default provisions contained in the attached applicable PPAs, the following two scenarios of potential default conditions are acknowledged by the Parties to be addressed by PPA credit and collateral terms and conditions:
 - 4.2.8.4.3.1 Scenario 1: If Seller breaches a CHP PPA with the Buyer, and Buyer has another PPA with Seller, then cross default could be triggered; provided that another PPA means a PPA between the specific Seller, as signatory and as referenced in Section 4.2.8.4.2, and the specific IOU Buyer, as signatory to such PPA. Another PPA is a contract between the Buyer and Seller for electric power, and not a contract for other goods or services.

Scenario 2: If the guarantor becomes uncreditworthy for the guarantee, or its credit rating is downgraded to below investment grade by either Moody's or Standard & Poor's or Fitch then default could be triggered; provided that the Seller may prevent such trigger by providing another form of credit within ten (10) Business Days.

4.2.9 Efficiency Performance Obligations and Compliance

The Efficiency Performance Obligation shall apply as incorporated into the final CHP RFO PPA, and the 60% efficiency in the Optional As-Available PPA.

Failure to meet the Efficiency requirement in the CHP PPA throughout the Term shall be, at the Buyer's election, an Event of Default under the PPA. The failure to meet the annual Efficiency requirement may be determined by the Seller's report to CARB (CARB GHG Emissions Reduction Report), the Seller's report to the IOUs pursuant to the CHP QF Compliance Monitoring Program, or other information available to the IOU, such as the loss of a thermal host. If the Seller is out of compliance with the Efficiency Performance Obligation, Buyer shall issue to Seller a written notice of an Efficiency Performance Deficiency. Within three (3) months of its receipt of the notice, Seller will provide Buyer with a plan to cure the Efficiency Performance Deficiency. Buyer shall accept or reject the plan within 30 days of receipt. From the date of written notice from the Buyer of acceptance of the Seller's cure plan, Seller shall have six (6) months to execute the plan and cure the Efficiency Performance Deficiency. If Buyer rejects the cure plan, then Buyer and Seller shall confer to resolve the issues. A Seller meeting these cure provisions shall not incur a default under the PPA.

If a Seller fails to provide an adequate showing that it cured the Efficiency Performance Deficiency within the six (6) month cure period, and does not secure a waiver from the IOU, that Seller is subject to the otherwise applicable default provisions in the PPA.

Seller may have up to two cure periods during the term of the applicable PPA for no more than two Efficiency Performance Deficiencies. A second cure period is available to Seller only if Seller is able to cure the first Efficiency Performance Deficiency. A third Efficiency Performance Deficiency is, at the election of Buyer, an Event of Default pursuant to section 6.2 of the applicable PPA and there is no applicable cure period.

4.2.10 Curtailment: Reliability

4.2.10.1 Seller shall promptly curtail the production of the Power Product (as defined in the PPAs attached to this Settlement) upon receipt of a notice or instruction from the CAISO, which may be communicated by Buyer if Buyer is the Scheduling Coordinator. Such notice or instruction shall only be provided when the CAISO orders curtailment and the Scheduling Coordinator implements such curtailment in compliance with CAISO Tariff or applicable orders to avoid or address a declared System Emergency.

4.2.10.2 Seller shall promptly curtail the production of the Power Product upon receipt of a notice or instruction from the Transmission Provider, which may be communicated by Buyer if Buyer is the Scheduling Coordinator. Such notice or instruction shall only be provided when curtailment of the Power Product is required to comply with:

4.2.10.2.1 A CAISO curtailment declared pursuant to Section 3.15 (a) or Transmission Provider declared Emergency Condition, subject to the interconnection agreement between the Seller and the Transmission Provider; or

- 4.2.10.2.2 Transmission Provider's maintenance requirements, subject to the interconnection agreement between the Seller and the Transmission Provider.
- 4.2.10.3 Notwithstanding the above, except as may be required in order to respond to any Emergency Condition or System Emergency, Buyer shall, consistent with FERC Order 888 and the interconnection agreement between the Seller and the Transmission Provider and with the applicable provisions of the CAISO Tariff:
 - 4.2.10.3.1 Use reasonable good faith efforts to coordinate Transmission Provider's curtailment needs with Seller to the extent it can influence such needs; or
 - 4.2.10.3.2 Request the Transmission Provider and CAISO limit the curtailment duration.
- 4.2.10.4 If Seller has entered into a PGA or QF PGA with the CAISO, or an interconnection agreement, the terms of the applicable PGA or QF PGA and the applicable interconnection agreement with respect to CAISO or Transmission Provider curtailments, shall govern the rights and obligations of Buyer and Seller to the extent any provision of this Section 4.2.10 is inconsistent with such applicable PGA or QF PGA, and interconnection agreement.
- 4.2.10.5 In the event Seller interconnects with an individual or entity other than the CAISO, the Seller shall adhere to any reliability curtailment order by such individual or entity pursuant to the applicable tariff provisions of such individual or entity.
- 4.2.11 Curtailment: Economic
 - 4.2.11.1 The CHP Pro-Forma RFO PPA will contain an option, specifically, an Economic Curtailment Option (ECO), that may be selected by the CHP RFO participant and the participant may bid zero under this option.
 - 4.2.11.2 The Buyer can only instruct the Seller to curtail production in those hours when the CAISO published Day-Ahead Integrated Forward Market (IFM) results indicate there is a negative EZ-Gen Hub Locational Marginal Price (LMP)² or negative System Marginal Energy Cost (SMEC) as defined and set forth in the CAISO Tariff.
 - 4.2.11.3 The ECO offered by the CHP RFO participant must contain the fixed MWhs shown in the table entitled Curtailment Period Cap below, for each calendar quarter and on-peak and off-peak time period. The differences between the Seller's Day-Ahead Forecast ("i.e., the schedule Seller provides to Buyer by 5:00 PPT on the day before the Trading Day") and the Economic Curtailment Limit (ECL) schedules submitted over the applicable period must be equal to the Curtailment Period Cap shown in the CHP RFO offer.

²

NP15, SP15 or ZP26, based on the location of the CHP Facility.

Curtailment Period Cap

Calendar Quarter	On-Peak (MWhs) ³	Off-Peak (MWhs) ⁴	Total (MWhs)
Jan –Mar	TBD by Seller	TBD by Seller	TBD by Seller
Apr – June	TBD by Seller	TBD by Seller	TBD by Seller
July –Sept	TBD by Seller	TBD by Seller	TBD by Seller
Oct – Dec	TBD by Seller	TBD by Seller	TBD by Seller
Total	TBD by Seller	TBD by Seller	TBD by Seller

Once a Curtailment Period Cap is reached for any quarterly period (either on-peak or off-peak), no additional economic curtailment is available to the Buyer in that quarterly on-peak or off-peak period. Any MWhs not called by the Buyer in any period cannot be rolled over to another period.

- 4.2.11.4 Those Sellers electing the ECO will provide two Day-Ahead power delivery schedules to the Buyer: a Seller’s Day-Ahead Forecast in accordance with the existing terms of the CHP Pro-Forma RFO PPA, and an ECL Schedule indicating the amount of MWhs that Seller offers to be curtailed in each hour for the next day.
- 4.2.11.5 By 2 pm or one hour after receiving published IFM results, whichever is later, Buyer may instruct the Seller to curtail deliveries down to the ECL Schedule, if the IFM indicates a negative EZ-Gen Hub LMP or negative SMEC for such hour. Within one hour of the Buyer’s economic curtailment order, Seller shall provide a binding notice of Seller’s intention to either implement the Buyer’s economic curtailment order (curtailment order) or maintain its Seller’s Day-Ahead Forecast for the negative EZ-Gen Hub LMP or negative SMEC hour(s). If the Seller chooses to maintain its Seller’s Day-Ahead Forecast, it will contemporaneously notify the Buyer of its pricing election pursuant to Section 4.2.11.7.
- 4.2.11.6 If Buyer orders an economic curtailment for a schedule hour and Seller curtails to its ECL Schedule, then the energy payment pursuant to the RFO PPA will be made by Buyer to Seller for Seller’s Day-Ahead Forecast.
- 4.2.11.7 If Buyer orders an economic curtailment for a schedule hour and Seller elects not to curtail to its ECL Schedule, then energy payments for that schedule hour will be made pursuant to the Seller’s election as provided under Section 4.2.11.5 for all deliveries above the ECL Schedule at:
 - 4.2.11.7.1 IFM Pricing: Seller will pay the Buyer either the negative SMEC or the negative EZ-Gen Hub LMP, provided if both prices are

³ On-Peak TOU period includes PG&E’s Peak and Partial Peak, SCE’s On-Peak and Mid-Peak, and SDG&E’s On-Peak and Semi-Peak.

⁴ Off Peak TOU period includes Off-Peak and Super Off-Peak for all three IOUs.

negative Seller will pay the average of the two negative prices for that scheduled hour, or

- 4.2.11.7.2 Real Time Collar Pricing: Seller will be paid for energy deliveries above the ECL Schedule at the Real Time (RT) SMEC subject to the designated floor of negative \$50.00 per MWh and ceiling value of the PPA energy price (collar values). The collar values would be, incorporated into the RFO PPA and could not be changed over the term of the PPA. If the hour has a negative RT SMEC, the negative SMEC would be paid by the Seller to the Buyer down to the floor value. If the RT SMEC is positive, the Buyer would pay the Seller the RT SMEC for that hour up to the ceiling value.
- 4.2.11.8 If, at the end of a calendar quarter in the table above, Seller has not offered the Curtailment Period Cap, then Seller will pay Buyer the shortfall at \$50 per MWh for the applicable period.
- 4.2.11.9 For those hours where the Buyer has ordered an economic curtailment, the difference between the Seller's Day-Ahead Forecast and the ECL Schedule will count toward the Curtailment Period Cap irrespective of whether or not the Seller chooses to curtail its operation.
- 4.2.11.10 If Seller curtails, any economic curtailment hour will not be included in the penalty assessment for failure to meet Seller's scheduled amounts and all CAISO charges and penalties, if any, for schedule deviations associated with curtailment will be borne by the Buyer.
- 4.2.11.11 For capacity payment calculation purposes, the Seller's Day-Ahead Forecast will be used for any hour affected by the curtailment so as to not impact the capacity payment. This is necessary due to the physical limitations of the CHP Facilities, such as ramp rates, to respond to the curtailment order.

EXAMPLES

For a given hour, assume
Contract energy Price = \$30/MWh
DA EZ-Gen Hub LMP = -\$9
DA SMEC = -\$11
Seller's Day-Ahead Forecast Energy = 100 MWs
Curtailment Period Cap = 1,000 MWs
RT SMEC Collar = + \$30/MWh/- \$50/MWh

Case 1 (4.2.11.6). Assume Seller's ECL Schedule is 90 MWs and Seller agrees to curtail deliveries in response to the order. Seller delivers 90 MWs but is paid for all 100 MWs of the Seller's Day-Ahead Forecast at \$30/MWh. Seller gets credit for 10 MWs toward fulfilling the Curtailment Period Cap.

Case 2 (4.2.11.6). Assume Seller's ECL Schedule is 80 MWs and Seller agrees to curtail deliveries in response to the order. Seller delivers 80 MWs but is paid for all 100 MWs of the Seller's Day-Ahead Forecast at \$30/MWh. Seller gets credit for 20 MWs toward fulfilling the Curtailment Period Cap.

Case 3 (4.2.11.7.1). Seller notifies Buyer that it will deliver the Seller's Day-Ahead Forecast quantity (100 MWs) and accept IFM pricing (Average = -\$10/MWh) for deliveries in excess of the ECL Schedule (90 MWs). Seller is paid the contract price of \$30/MWh for 90 MWs and owes Buyer \$10 per MWh for the 10 MWs of energy that was not curtailed. Seller receives credit for 10 MWhs toward fulfilling the Curtailment Period Cap.

Case 4 (4.2.11.7.2). Seller notifies Buyer that it will deliver the Seller's Day-Ahead Forecast quantity (100 MWs) and accept the RT collar pricing for deliveries in excess of the ECL Schedule (90 MWs). Seller will be paid for 90 MWs at the contract price of \$30/MWh.

- a. If the RT SMEC for that hour is -\$20/MWh, Seller will pay Buyer for the 10 MWs at a price of \$20/MWh.
- b. If the RT SMEC for that hour is -\$75/MWh, Seller will pay Buyer for the 10 MWs at a price of \$50/MWh as limited by the price exposure collar.
- c. If the RT SMEC for that hour is \$250/MWh, Seller will be paid for the 10 MWs at a price of \$30/MWh as limited by the price exposure collar.

In each case (4a, 4b and 4c) Seller receives credit for 10 MWhs toward fulfilling the Curtailment Period Cap.

4.2.12 PPA Options in CHP RFOs

As part of the bid package for each CHP-Only RFO, each IOU may request offers with specific (1) credit and collateral, (2) voluntary curtailment, and (3) dispatchability terms that differ from the CHP RFO Pro Forma PPA. As part of the bid package, IOUs may also offer the all source RFO in addition to the CHP-Only RFO and may also sign a hybrid contract of the two.

In IOU evaluations of final offers from CHP bidders, the IOUs will give preference to Pro Forma offers with no options, relative to non-Pro Forma offers, to the extent that such Pro Forma offers are competitive with the non-Pro Forma offers.

For example, assume there are 10 RFO bids, 6 Pro Forma bidders and 4 non-Pro Forma bidders. If the 5 of the 6 Pro Forma bidders (those offering the product contemplated by the program) are competitive (based upon the standards in the Settlement and are otherwise commensurate with the product solicited) the IOU would choose those 5 bids and cannot choose the 4 non-Pro Forma bidders in lieu of Pro-Forma bidders; this does not preclude the IOU from selecting the 4 non-Pro Forma bidders. Non-Pro Forma bids cannot replace or substitute for the selection of Pro Forma bids.

4.3 Bilaterally Negotiated PPAs

- 4.3.1 Bilaterally negotiated and executed CHP PPAs or Utility Prescheduled Facilities PPAs are part of the procurement options in this CHP Program.

- 4.3.2 Use of an IE shall be required for any negotiations between an IOU and its affiliate and may be used, at the election of either the Buyer or the Seller, in other negotiations.
- 4.3.3 Pricing, terms, and conditions will be according to the executed and approved PPA.
- 4.4 AB 1613 Feed-In Tariff
 - 4.4.1 Feed-In Tariff for equal to or less than 20 MW (nameplate) CHP Facilities that are New CHP Facilities/Repowered CHP Facilities (Assembly Bill 1613 (codified in California Public Utilities Code §2840 *et seq.*, which establishes the Waste Heat and Carbon Emissions Reductions Act)(R.08-06-024)) are part of the procurement options in this CHP Program.
- 4.5 PURPA Program for QFs 20 MW or Less (QF PPAs)
 - 4.5.1 The CPUC will continue to administer a QF Program under PURPA for QFs 20 MW or less. QFs must continue to meet the QF requirements established by PURPA and any FERC rules as amended from time to time (18C.F.R. Part 292, §292.203 *et seq.*) implementing PURPA.
 - 4.5.2 QFs that are equal to or less than 20 MW nameplate will be provided a QF PPA containing standard terms and conditions for eligible Qualifying Facilities.
 - 4.5.3 Eligible QFs may continue to operate under the PURPA must-take obligation program. Any CHP Facility meeting the CHP RFO eligibility requirements may also submit an offer in the CHP RFO or seek alternative contracting options; however, the IOUs must continue to offer QF PPAs to these QF CHP Facilities.
 - 4.5.4 Pricing
 - 4.5.4.1 Energy prices will be SRAC as set forth in Section 10.
 - 4.5.4.2 Capacity prices will be as specified in D.07-09-040.
 - 4.5.5 The QF PPA for QFs equal to or less than 20 MW is based on the SOC and is attached as Exhibit 6.
- 4.6 As-Available Procurement Alternatives and Optional As-Available PPA
 - 4.6.1 As-Available CHP Facilities are eligible for several procurement alternatives under the CHP Program, including the CHP RFOs, bilaterally negotiated PPAs, the AB 1613 Feed-In Tariff and the PURPA Program for QFs 20 MWs or under. In addition to these alternatives for the procurement from as-available CHP Facilities, there is also an Optional As-Available PPA.
 - 4.6.2 Optional As-Available PPA is subject to the following terms and conditions:
 - 4.6.2.1 Eligibility
 - 4.6.2.1.1 Gas-fired CHP Facilities with nameplates greater than 20 MW, but average annual deliveries less than 131,400 MWh (as specified in D.07-09-040 and D.08-09-024).

- 4.6.2.1.2 The as-available project host(s) must consume, consistent with Public Utilities Code §218(b), at least 75% of the total electricity generated by a Topping Cycle CHP Facility or at least 25% of the total electricity generated by a Bottoming Cycle CHP Facility. For purposes of this section, “CHP Facility” includes all CHP units serving the host’s thermal or electric loads consistent with Public Utilities Code §218(b).
- 4.6.2.1.3 For Topping Cycle or Bottoming Cycle with supplemental firing, the as-available CHP Facility must meet sixty percent (60%) efficiency calculated by dividing the total annual useful thermal and electrical output by the total annual fuel use, based on Higher Heating Value. There will be no efficiency requirement for a Bottoming Cycle CHP Facility with no supplemental firing.
- 4.6.2.2 Capacity Pricing: The capacity price shall be set consistent with the as-available capacity price in D.07-09-040, subject to escalation as provided in that decision, and shall be applied up to a maximum of 20 MW of deliveries measured on an Integrated Hour. For purposes of this section, an Integrated Hour is the sum of all measured meter intervals for the applicable hour.
- 4.6.2.3 Energy Pricing: Energy scheduled on a day-ahead basis and delivered up to 20 MW per hour in a given hour based on the lesser of Day-Ahead scheduled energy or metered deliveries will be priced at SRAC.
 - 4.6.2.3.1 Energy scheduled on a Day-Ahead basis and delivered above 20 MW per hour in a given hour will be priced at the MRTU Day-Ahead Market PNode energy price.
 - 4.6.2.3.2 Seller shall schedule all deliveries with the IOU on a Day-Ahead basis in advance of timing required for Buyer to schedule energy into the CAISO Day-Ahead market (8 hours in the CAISO day-ahead market).
 - 4.6.2.3.3 Unscheduled energy incremental to scheduled energy in a given hour shall be priced at the MRTU real time PNode price for such energy, thus Seller shall pay any applicable CAISO Charges and receive all CAISO Revenues attributable to unscheduled deviations between Seller’s scheduled and metered deliveries for such incremental energy. Applicable CAISO Charges for deviations shall be the responsibility of the Seller.
 - 4.6.2.3.4 The Performance Tolerance Band under Scheduling and Delivery Deviation (SDD) Energy Adjustment and the SC Trade Tolerance Band shall be set at the greater of (a) three (3) percent of the Seller’s Final Energy Forecast divided by the number of Settlement Intervals in such hour or (b) three (3) MWh divided by the number of Settlement Intervals in such hour.
- 4.6.2.4 The term of an Optional As-Available PPA shall be up to seven (7) years at the discretion of the Seller. If the Seller chooses a PPA term of five (5) years or

greater, the Seller will provide on a confidential basis to the IOU sufficient information for the IOU to confirm that the CHP Facilities comply with the Emissions Performance Standard, if such standard is applicable to the CHP as an as-available facility.

- 4.6.2.5 The SOC is the basis for the development of the Optional As-Available PPA, and is attached here as Exhibit 7.
- 4.6.2.6 (Intentionally omitted)
- 4.6.2.7 Seller shall comply with the applicable provisions of the CAISO Tariff as determined by the CAISO.
- 4.6.2.8 Buyer, at Seller's election, shall be Seller's Scheduling Coordinator. At Seller's option, Seller may establish and pay for a Scheduling Coordinator (SC) ID for the CHP Facility.
- 4.6.2.9 GHG emissions reductions associated with New, Repowered, or Expanded CHP under an Optional As-Available PPA shall be the amount of GHG emissions reductions from the entire CHP Facility as, as set forth in Section 7.
- 4.6.2.10 Average MW (AMW) Energy Delivery Cap for the Optional As-Available PPAs
 - 4.6.2.10.1 There is no specific MW capacity target for the Optional As-Available Program.
 - 4.6.2.10.2 There is a cap on energy deliveries from all of the Optional As-Available PPAs measured each year in AMW for each IOU (AMW Cap) until the AMW Cap is reached. The AMW Cap shall be: PG&E: 75 AMW, SCE: 75 AMW, SDG&E: 10 AMW. An Optional As-Available PPA will remain available to eligible CHP Facilities in an IOU Service Territory until the IOU's AMW Cap has been reached. The IOU shall report annually on the determination of reaching the AMW Cap until the cap is reached. The IOU may choose to offer a PPA to a CHP Facility although the IOU has exceeded its AMW Cap, in its sole discretion.
 - 4.6.2.10.3 To determine progress toward an IOU's AMW Cap, AMW will be calculated by dividing MWh of deliveries under an Optional As-Available PPA by the total hours in the year.
- 4.6.2.11 Counting Rules for Optional As-Available PPA Enrollment and MW Targets
 - 4.6.2.11.1 Each gas-fired CHP Facility eligible pursuant to Section 4.6.2.1 (including bottoming-cycle CHP Facilities) with an existing CHP PPA or which had a CHP PPA within twenty-four (24) months before the CHP Facility provides notice of its intention to execute an Optional As Available PPA may upon expiration or termination of its CHP PPA execute an Optional As-Available PPA provided the IOU for the Service Territory where the CHP Facility is located

has not reached its AMW Cap. AMW deliveries from these CHP Facilities may be counted toward the AMW Cap using deliveries as reported in the IOU's most recent public information such as FERC Form 1 or CEC Annual Power Disclosure Report and towards the IOU MW Target. If the CHP Facility re-contracts with an IOU upon expiration or termination of its PPA, the procuring IOU may count the full project capacity toward its CHP MW Target. If there are multiple IOUs procuring power from the same CHP Facility, then the procured contract capacity for each IOU shall be counted respectively;

4.6.2.11.2 An as-available Seller eligible pursuant to Section 4.6.2.1 (including Bottoming Cycle CHP Facilities) that has not had a PPA with an IOU at any time, or whose CHP PPA terminated more than twenty-four (24) months before the CHP Facility provides notice to secure an Optional As-Available PPA, may execute an Optional As-Available PPA provided the IOU in the Service Territory where the CHP Facility is located has not reached its AMW Cap. AMW of deliveries from these CHP Facilities may be counted toward the AMW Cap using, if available, deliveries as reported in publicly available reports such as FERC Electric Quarterly Reports or the most recent FERC Form 1. If such reports are not available, the counting for the AMW Cap for such CHP Facilities shall rely upon either the Seller's forecast of AMW delivery from the CHP Facility, or actual deliveries to the IOU, if available; and thereafter from available public information to establish AMW deliveries, *e.g.*, FERC Form 1 data. AMW deliveries from these CHP Facilities may be counted toward the MW Targets. If there are multiple IOUs procuring power from the same CHP Facility then the AMW deliveries for each IOU shall be counted respectively;

4.6.2.11.2.1 AMW of deliveries from a New CHP Facility or Repowered CHP Facility eligible for an Optional As-Available PPA will count toward an IOU's AMW Cap. The capacity of such a CHP Facility may be counted toward the MW Targets. Capacity for a New CHP Facility or Repowered CHP Facility shall be established using a one-time Capacity Demonstration Test, net of auxiliary or station power.

4.6.2.11.2.2 A CHP Facility currently operating under an evergreen Legacy PPA may not terminate its evergreen Legacy PPA to obtain a new Optional As-Available PPA. Neither the MW nor the AMW of deliveries under these CHP PPAs may be counted toward the MW Targets or the AMW Cap. If, however, the CHP Facility adds new capacity, it may receive an Optional As-Available PPA for any deliveries that are determined to be associated with the new capacity, and the MW of new capacity shall be counted toward the MW Targets.

4.7 IOU-Owned CHP

- 4.7.1 IOU-owned CHP counts towards the IOUs' GHG Emissions Reduction Targets for the Second Program Period, but not for the 3,000 MW Target. The counting from these resources is capped at 10% of the IOUs' GHG Emissions Reduction Target.

4.8 Utility Prescheduled Facilities

4.8.1 Eligibility

- 4.8.1.1 A CHP Facility that met the PURPA efficiency requirements as of September 20, 2007 and converts to a Utility Prescheduled Facility is eligible to participate in a CHP RFO or to obtain a PPA through bilateral negotiations or amend an existing Legacy PPA through bilateral negotiations.
- 4.8.1.2 New PPAs with Utility Prescheduled Facilities (not Legacy PPA Amendments) count towards the MW Targets if the existing QF PPA expires before the end of the Transition Period. For SDG&E, any procurement of a Utility Prescheduled Facility (regardless of the date of expiration of the CHP PPA) counts toward SDG&E's MW Target.
- 4.8.1.3 Amendments to Legacy PPAs to convert to a Utility Prescheduled Facility count towards each IOU's GHG Emissions Reduction Targets.

4.9 New Behind the Meter CHP Facilities

- 4.9.1 New CHP Facilities that are behind the meter including the Self-Generation Incentive Program (SGIP) and New CHP Facilities that do not export to the grid are part of the procurement options in this CHP Program.

4.10 Approval of PPAs

- 4.10.1 IOUs will utilize a Tier 2 Advice Letter for Existing CHP Facilities that execute the CHP RFO Pro Forma PPA without material modification.
- 4.10.2 IOUs will utilize a Tier 3 Advice Letter for all other PPAs (new, repowering or existing PPAs that contain any material modification of the PPAs approved in this Settlement).
- 4.10.3 PPAs of less than five (5) years do not require advance CPUC approval according to existing CPUC policy. Such CHP PPAs should be included in the IOU Quarterly Compliance Reports (QCRs) and CHP Program Semi-Annual Report specified in Section 8.1.1, below.
- 4.10.4 Emissions Performance Standard (EPS) Approval for PPAs
 - 4.10.4.1 For those PPAs equal to or greater than five (5) years in length that are submitted to the CPUC in a Tier 2 or Tier 3 Advice Letter, the CPUC must make a specific finding that the PPA with the Generating Facility is in compliance with the Emissions Performance Standard.

- 4.10.4.2 The Sellers must provide sufficient information, on a confidential basis as necessary, to the IOUs to allow the IOUs to make a sufficient showing of compliance with the EPS for all PPAs with terms five (5) years or greater.
- 4.10.4.3 For those PPAs equal to or greater than five (5) years in length that are not submitted to the CPUC in a Tier 2 or Tier 3 Advice Letter, the Buyer shall use reasonable efforts to obtain a letter from the CPUC Energy Division acknowledging that the Generating Facility is in compliance with the EPS (EPS Compliance Letter). The Buyer will not execute the applicable PPA until the CPUC Energy Division provides the EPS Compliance Letter.

4.11 Seller Reporting Requirements for PPAs

Subject to CPUC confidentiality rules applicable to the information being reported, on an annual basis, Seller will provide a report to the IOU showing the annual used thermal output, total electricity generation, and fuel consumed. Such report shall be provided within five (5) Business Days after the CARB Mandatory GHG Emissions Annual Reports are due to CARB or a successor regulatory agency.

CHP QFs will continue annual reporting to the IOUs pursuant to the CPUC-approved CHP QF Monitoring Program for CHP QFs. If the CHP Facility is not a QF, it will provide the same data to the IOUs and CPUC as is contained in the CHP QF Compliance Monitoring Program report, and on the same schedule.

4.12 Timing of Commencement of Delivery

An IOU may record in the CHP Program Reports as progress towards obtaining its MW Targets and GHG Emissions Reduction Targets the MWs, GHG Credits or GHG Debits associated with the PPA at the time of execution. If the CPUC subsequently disapproves such PPA, or if an executed PPA terminates before beginning deliveries, the IOU shall remove any MW, GHG Credits or GHG Debits from such disapproved or terminated PPA from its CHP Program Reports.

Subject to force majeure conditions, Sellers under PPAs for Existing CHP Facilities will be required to commence deliveries on the earlier of the following two dates: (a) two (2) years after PPA execution; or (b) the Term Start Date specified in the PPA. Subject to force majeure conditions, Sellers under PPAs for New CHP Facilities or Repowered CHP Facilities will be required to commence deliveries on the earlier of the following two events: (a) five (5) years after CPUC approval of the PPA, or (b) the Term Start Date in the PPA. Subject to force majeure conditions, Sellers under PPAs for Expanded CHP Facilities will be required to commence deliveries on the earlier of the following two events: (a) three (3) years after CPUC approval of the PPA, or (b) the Term State Date in the PPA. The IOU's procedures and administration of the PPAs, including milestone provisions should target these timeframes for the start of the term. For good cause the Buyer and Seller may agree to delay the commencement of the term.

5 MW Targets

5.1 IOUs' MW Targets

- 5.1.1 The IOUs' combined CHP MW Targets will be 3,000 MW of capacity. The MW Targets may be met through any of the CHP Procurement Processes described in Section 4.

5.1.2 The allocation of the 3,000 MW for the Initial Program Period shall be as follows:

Utility	MW Target A	MW Target B	MW Target C	IOU Total MW Target
SCE	630 MW	378 MW	394 MW	1,402 MW
PG&E	630 MW	376 MW	381 MW	1,387 MW
SDG&E	60 MW	50 MW	50 MW	160 MW
Total Targets	1320 MW	804 MW	825 MW	2,949 MW*

*To meet the total of 3,000 MW, SDG&E will have an additional 51 MW Target by 2018 in the Second Program Period.

5.1.3 Each IOU shall enter into PPAs to meet the MW Targets and GHG Emissions Reduction Targets consistent with the CHP Procurement Processes listed in Section 4.

5.1.4 CHP RFOs

5.1.4.1 Each IOU shall conduct three RFOs during the Initial Program Period to seek PPAs for the portion of the MW Targets set forth in Section 5.1.2., not otherwise procured by other procurement processes described in Section 4 (Net MW Target(s)).

5.1.4.2 The CHP RFOs during the Initial Program Period shall be scheduled at regular intervals, provided the first CHP RFO is initiated within ninety (90) days of the Settlement Effective Date.

5.1.4.3 The amount of CHP sought in each CHP RFO during the Initial Program Period shall not be less than the Net MW Target for each IOU. An IOU may procure MWs in excess of the MW Targets in Section 5.1.2 above relying upon an RFO or any other CHP Procurement Processes listed in Section 4.

5.1.4.4 If an IOU does not meet its MW Targets identified in Section 5.1.2 at the end of any particular RFO, the portion of the unmet MW Target shall be rolled over into the subsequent MW Target for procurement.

5.1.4.5 Any MW shortfall that occurs in the Initial Program Period shall be rolled over into the Second Program Period to reach the 3,000 MW Target; however, such shortfall may also be addressed by other actions deemed appropriate by the CPUC.

- 5.1.4.6 The number of CHP RFOs in the Second Program Period to meet MW Targets, if any, shall be established in the LTPP proceedings. Except for SDG&E there are no established MW Targets in the Second Program Period. There are GHG Emissions Reduction Targets in the Second Program Period as defined in Section 6.
- 5.1.4.7 The number of CHP RFOs in the Second Program Period shall be established in the LTPP proceedings.
- 5.1.4.8 The MWs required in the Second Program Period may be limited or expanded, as determined by the CPUC in the LTPP process, but shall be no less than the MW Targets for the Second Program Period specified in Section 5.1.2 above.

5.2 MW Counting Rules

- 5.2.1 The timing for procuring the MW Targets shall be as provided in Section 5.1.2.
- 5.2.2 PPAs executed during the period between September 1, 2009 and the Settlement Effective Date count towards the IOUs' MW Targets and GHG Emissions Reduction Targets.
- 5.2.3 Progress towards the MW Targets for Existing CHP Facilities shall be determined as follows:
 - 5.2.3.1 For the purposes of Section 5.2 regarding MW counting, Existing CHP Facilities are gas-fired Topping Cycle CHP Facilities that exported and delivered electric power to an IOU listed by QF ID number in each IOU's July 2010 Cogeneration and Small Power Production Report (July 2010 Semi-Annual Report) – "Contract Nameplate," as amended, if necessary. The MWs counted for New PPAs executed with Existing CHP Facilities will be the published Contract Nameplate value, unless otherwise noted in this Settlement.
 - 5.2.3.2 CHP PPAs executed with QFs who formerly sold to the IOUs and are not listed in the July 2010 Semi-Annual Reports will count towards the MW Targets based on the Contract Nameplate (or for PG&E the "operating size") in the most recent Cogeneration and Small Power Production Semi-Annual Report, if any, in which the CHP was listed. If not listed as contract nameplate, the contract nameplate in the most recent QF or CHP PPA will be counted.
- 5.2.4 Exceptions Related to Counting for Existing CHP Facilities
 - 5.2.4.1 To the extent the full net output is offered by an Existing CHP Facility but is not procured by the IOU, only the capacity procured by an IOU shall count towards any IOU's MW Target.
 - 5.2.4.1.1 For example – if a 50 MW capacity CHP Facility from the July 2010 Semi-Annual Report offers 40 MW for procurement, and the IOU procures less than 40 MW, only the capacity procured will count towards the IOU's MW Target. If the CHP Facility sells the full 40 MW offered, then the IOU may count the full 50 MW of capacity reported in the July 2010 Semi-Annual Report.

- 5.2.4.2 Coal-fired, wood waste, and renewable QFs in an IOU's portfolio as of July 2010 will not count towards the IOU's MW Targets.
 - 5.2.4.3 Any Existing CHP Facility that does not export power to the grid will not count toward the IOU's MW Target, including existing SGIP facilities.
 - 5.2.4.4 If an IOU contracts with an Existing CHP Facility that is currently operating in the State but has never sold to an IOU, the capacity from such CHP Facility will be determined by a Capacity Demonstration Test. This test will determine the CHP Facility's capability to serve on site and PUC §218(b) loads and provide net exports to the grid, excluding auxiliary/station power load.
 - 5.2.4.4.1 If a CHP Facility elects and is eligible under the Optional As-Available Program, the specific counting rules of that program shall apply for the purpose of calculating the subscription cap in the Optional As Available Program.
 - 5.2.5 A New CHP Facility for the purpose of Section 5.2 means gas-fired Topping Cycle CHP Facilities and Bottoming Cycle CHP Facilities using waste heat. The capacity of a New CHP Facility to be used to count progress towards the MW Targets shall be established by a Capacity Demonstration Test. The CHP Facility's capacity, as demonstrated by this test, shall exclude auxiliary/station power load.
 - 5.2.5.1 The MWs of capacity for PPAs executed pursuant to the AB 1613 Feed-In Tariff and SGIP shall be the CHP Facility nameplate reported to the IOUs by the Seller, applicant or system owner applicable to such facility.
 - 5.2.5.2 The MWs of capacity for behind the meter CHP Facilities other than SGIP will be the capacity reported to the CEC by the Generating Facility owner and other power plant owners.
 - 5.2.6 A Repowered CHP Facility for the purpose of Section 5.2 means gas-fired Topping Cycle CHP Facilities and Bottoming Cycle CHP Facilities using waste heat. The MW to be used to count progress towards the MW Targets shall be determined by a Capacity Demonstration Test after the CHP Facility re-power is completed. The Capacity Demonstration Test will determine the increment of additional project capacity, which will count towards the procuring IOU's MW Target. The total MWs to count progress will be the additional project capacity combined with the Contract Nameplate in each IOU's July 2010 Semi-Annual Report. In the event the Capacity Demonstration Test results in a value lower than the value determined as set forth in the July 2010 Semi-Annual Report, the July 2010 Semi-Annual Report value will count toward the IOU's MW Target.
- 5.3 CHP Program MW Counting Precedent or Use
- 5.3.1 The Parties acknowledge that the MW counting pursuant to this Section 5, or the specific, individual project capacity counting levels for the CHP Program shall not establish a precedent or be used for any other purpose, or with any other agency for establishing available capacity from any individual CHP Facility.
- 5.4 Justification for Failure to Meet MW Targets

Any IOU that is unable to meet its MW Target must make a showing to justify its inability to meet the MW Target. Lack of sufficient offers can be used as a reason to justify failure to procure the MW Targets and GHG Emissions Reduction Targets. The efficiency of the CHP Facility participating in the IOUs' procurement programs as compared to the Double Benchmark, offer prices in excess of levels as provided herein, and the amount of GHG emissions reductions may be valid justifications for missing the IOU MW Targets and GHG Emissions Reduction Targets. Lack of need or portfolio fit arguments shall not be used as reasons to justify failure to procure the MW Targets, but are reasons to justify an inability to meet the GHG Emissions Reduction Targets.

- 5.4.1 Offer prices: If the IOU claims that CHP RFO offer prices are excessive, the IOU must refer to independent or publicly-available sources. For example, when making a justification on the basis of price of new or repowered fossil fuel-fired generation, the IOU may compare offer prices to prices reflected in sources such as Cambridge Energy Research Associates' capital cost index, CPUC estimates of new fossil fuel-fired generation, CEC estimates of new fossil fuel-fired generation, forward market prices, or other similar third-party information regarding the cost of new generation CHP Facilities in California.

6 GHG Emissions Reduction Targets

6.1 Strategy

- 6.1.1 By approving this Settlement, the CPUC will adopt a strategy to reduce statewide GHG emissions by the following means:
 - 6.1.1.1 Maintaining the existing GHG emissions reduction attributable to the efficient Existing CHP Facilities and reducing GHG emissions from the inefficient Existing CHP Facilities, as defined in 7.1.3, by encouraging the repower, conversion to Utility Prescheduled Facilities or retirement of such CHP Facilities; and,
 - 6.1.1.2 Increasing the efficiency of the CHP fleet by adding efficient CHP resources to the IOUs' electric portfolios to make progress towards the CARB CHP RRM;
 - 6.1.1.3 Allocating a portion of the CARB CHP RRM to other non-IOU load serving entities to increase the amount of efficient CHP in the State; and,
 - 6.1.1.4 Achieving the GHG Emissions Reduction Targets by December 31, 2020.

6.2 IOUs' GHG Emissions Reduction Targets

- 6.2.1 Existing: Maintaining GHG Emission Reductions from Existing CHP
 - 6.2.1.1 The IOUs shall maintain an equivalent amount of GHG emissions reductions attributable to the gas-fired Topping Cycle CHP Facilities included in each IOU's July 2010 Semi-Annual Reports for PPAs that expire in the Initial Program Period.
- 6.2.2 New GHG Reductions: IOU GHG Emissions Reduction Targets

- 6.2.2.1 In addition to 6.2.1.1., this Settlement establishes a GHG target of 4.3 MMT based on the CARB Scoping Plan estimates that, by 2020, the State can add 4,000 MW of additional efficient CHP. These 4,000 MW are estimated to reduce GHG emissions by 6.7 MMT. The CARB CHP RRM does not have specific allocations to the IOUs.
- 6.2.2.2 The Parties agree that the portion of the CARB CHP RRM allocated to the IOUs as part of this CHP Program can be derived by multiplying the current, or any revised statewide CARB CHP RRM, by the IOUs' percentage shares of statewide retail electric sales, as determined by the most current CEC data.
- 6.2.2.3 The CARB CHP RRM resulting in emissions reductions of 6.7 MMT and IOU and ESP/CCA retail sales of 72% presently yields a total allocation of 4.8 MMT to the IOUs and ESPs/CCAs. The amount of retail sales attributable to ESPs is currently estimated as 10% of total electricity sales in the IOU Service Territories. Reducing the 4.8 MMT by the amount of ESP/CCA retail electric sales yields a target of 4.3 MMT for the IOUs' bundled service customers.
 - 6.2.2.3.1 IOU and ESP/CCA retail sales within IOU service territories currently represent 72% of total electricity sales in the State (this calculation does not consider customer generation). The percentage of IOU Service Territory retail sales based on CEC data from 2007 is as follows: SCE (45.6 %); PG&E (43.9 %); and SDG&E (10.5 %). It is expected that, as the electric market continues to evolve, the portion of electric sales attributable to each IOU will change. Thus, the proportion of the CARB CHP RRM attributable to each IOU will change.
 - 6.2.2.3.2 As CEC data regarding percentage of retail sales is updated and published, the CPUC staff will calculate and post on the CPUC website an update to the portion of each IOU's GHG Emissions Reduction Target that is based on the CARB CHP RRM.
 - 6.2.2.3.3 During the Initial Program Period, the GHG Emissions Reduction Target is set for the IOUs, but may be adjusted among the IOUs, as a group, and the ESPs and CCAs on an individual basis if each ESP/CCA has responsibility for procuring CHP, or as a group if the CPUC requires the IOUs to purchase CHP power on behalf of the ESP/CCA, based on changes in retail electric sales. This adjustment will be based upon the updated and published CEC data.

6.3 ESP and Community Choice Aggregator (CCA) Portion of the CARB CHP RRM

- 6.3.1 This Settlement adopts an initial allocation of the CARB CHP RRM of 4.3 MMT for the IOUs' bundled service customers and 0.5 MMT (4.8 MMT-4.3 MMT = 0.5 MMT) for the non-IOU load serving entities serving Direct Access (DA) customers and CCA customers in the IOUs' Service Territories (non-IOU LSEs).
- 6.3.2 The Parties prefer that the non-IOU LSEs procure their respective shares of the CARB CHP RRM by entering into their own PPAs with CHP Facilities. If the non-IOU LSEs

are not required to procure their respective shares of the CARB CHP RRM then, as set forth further in Section 13.1.2, the IOUs will obtain CHP and each non-IOU LSE will be allocated cost responsibility for GHG reductions attributable to CHP based on its proportion of statewide retail sales.

- 6.3.3 To the extent the amount of electric sales attributable to non-IOU LSEs increases or decreases during the term of the Settlement, the IOU and non-IOU LSE allocations of the CARB CHP RRM shall be adjusted annually by the CPUC Energy Division based on updated and published CEC retail sales data.
- 6.3.4 To the extent a CCA provides service or commences service in an IOU's Service Territory; the IOU's portion of the CARB CHP RRM and corresponding GHG Emissions Reduction Targets shall be adjusted to account for the CCA's service in that Service Territory consistent with the methodology set forth in Section 6.2.2.3.1, above. The remainder of the CARB CHP RRM, currently estimated as 1.9 MMT, should be the responsibility of POUs or entities not regulated by the CPUC.
- 6.3.5 The Parties support proportional MW Targets and GHG Emissions Reduction Targets for all POUs in California at CARB and/or in other statewide or national venues.

6.4 Method to Determine Each IOU's GHG Emissions Reduction Target

- 6.4.1 For the purposes of this section regarding GHG Emissions Reduction Target counting, Existing CHP Facilities are gas-fired Topping Cycle CHP Facilities that exported and delivered electric power to an IOU as listed by QF ID number in each IOU's July 2010 Semi-Annual Report – as “Contract Nameplate.” The IOUs proportional share of the CARB CHP RRM in effect during the Second Program Period is established in this Settlement as 4.3 MMT, but may be superseded by a modification of the CARB CHP RRM regarding the goal of securing 6.7 MMT of incremental GHG reductions from incremental CHP resources or changes in CEC published retail electric sales.
- 6.4.2 Add any GHG Emissions Reduction Target shortfall or subtract any surplus from Existing CHP Facilities, as determined at the end of the Initial Program Period.
 - 6.4.2.1 In 2015, after the Initial Program Period, all Parties, in conjunction with CPUC Energy Division staff, will meet and confer to determine the status of the Existing CHP Facilities from each IOU's July 2010 Semi-Annual Reports for purposes of determining any GHG Emissions Reduction Target shortfall or surplus.
 - 6.4.2.2 For Existing CHP Facilities that shut down during the Initial Program Period, the GHG reductions will be calculated against the previous two calendar years of data compared to the Double Benchmark.
 - 6.4.2.3 The net of the GHG Debit or GHG Credit calculated from the CHP Facilities that are no longer operational will be added/subtracted to the share of the CARB CHP RRM allocated to the IOUs as a group.
- 6.4.3 Coal-fired, wood waste, and renewable CHP will count towards the GHG Emissions Reduction Targets.

- 6.4.4 Calculate each IOU's allocated portion of the CARB CHP RRM based on its percentage of retail electric sales at that time, as determined by updated and published CEC data; and,
- 6.4.5 Add or subtract net changes from each IOU's GHG Credits and GHG Debits from all sources not included in Section 6.4.2 above during the Initial Program Period.
- 6.5 Each IOU's GHG Emissions Reduction Target for the Second Program Period will be calculated and submitted to the CPUC by the IOUs in their Semi-Annual CHP Program Reports.
- 6.6 The IOUs' GHG Emissions Reduction Target for the Second Program Period is subject to review and revision in the LTPP process.
- 6.7 Changes to the CARB CHP RRM
 - 6.7.1 If CARB, pursuant to an official CARB document modifies the CARB CHP RRM to revise the goal of securing 6.7 MMT of incremental GHG reductions from incremental CHP resources, the GHG Emissions Reduction Targets adopted by this Settlement will be adjusted accordingly, so long as the CPUC adopts such modification in the LTPP process. The GHG Emissions Reduction Targets may also be adjusted by the CPUC in the LTPP process, provided that changes in the GHG Emissions Reduction Targets do not affect the MW Targets specified in this Settlement.
 - 6.7.2 Changes to the GHG Emissions Reduction Targets resulting from a change to the CARB CHP RRM adopted between LTPP decisions may be implemented by the CPUC via a Tier III advice letter process.
 - 6.7.3 If the CARB CHP RRM is modified without a specific allocation by CARB to the IOUs, the methodology set forth in Section 6.2.2.3 for determining the IOU allocation of the CARB CHP RRM will remain the same, and the corresponding GHG Emissions Reduction Targets will be updated consistent with that methodology. During the Second Program Period, the CARB CHP RRM allocations will be adjusted annually by the CPUC Energy Division based upon updated and published CEC retail sales data.
 - 6.7.4 It is expected that new CHP Facilities, including Repowered CHP Facilities, may provide IOUs with meaningful GHG emission reductions to meet the CARB CHP RRM. Such expectations will be incorporated in the evaluation criteria and may change to reflect revisions to CARB's Scoping Plan or related regulations.
 - 6.7.5 AB32 or Federal Delay or Elimination

If AB 32 CARB GHG compliance is delayed or suspended or superseded by a federal program for all or any portion of the Second Program Period, the IOUs shall sustain the GHG reduction benefit derived from applying a fixed double benchmark equaling 8,300 Btu/kWh and an 80% boiler to gas-fired CHP Facilities in the Existing CHP Facilities resources fleet. In addition to sustaining the GHG reduction benefit pursuant to this subsection, the IOUs shall procure any other MW Targets or GHG Emissions Reduction Targets established in the LTPP process for the Second Program Period.
- 6.8 Advocating at CARB and in other Forums

- 6.8.1 The Parties agree to support and advocate for the terms of this Settlement before CARB and in all other forums.
- 6.8.2 Notwithstanding the above section, the Parties reserve the right to advocate before CARB, the CPUC or any successor agency for modification of: (a) the CARB CHP RRM; (b) the Double Benchmark used to measure GHG emission reductions from CHP; (c) the IOU obligations to procure CHP capacity in the Second Program Period, or GHG Emissions Reduction Targets from CHP Facilities.
- 6.8.3 Parties are free to advocate at CARB or the CPUC in favor of maintaining or modifying the current definition of the Double Benchmark for a CHP Facility for a period longer than the term of the PPA. For example, Parties may advocate for the application of the Double Benchmark for the operating life of the CHP Facility.

6.9 Justification for Failure to Meet GHG Emissions Reduction Targets

Any IOU that is unable to meet its GHG Emissions Reduction Target must make a showing to justify its inability to meet the GHG Emissions Reduction Target. Asserted justifications for missing the GHG Emissions Reduction Targets may include that:

- 6.9.1 The efficiency of the CHP Facility participating in the IOU’s procurement programs is inefficient compared to the Double Benchmark, except as otherwise measured pursuant to Section 7.3;
- 6.9.2 The offer prices are in excess of levels as provided herein; and
 - 6.9.2.1 Offer prices: If the IOU claims that CHP RFO offer prices are excessive, the IOU must refer to independent or publicly-available sources. For example, when making a justification on the basis of price of new or repowered fossil fuel-fired generation, the IOU may compare offer prices to prices reflected in sources such as Cambridge Energy Research Associates' capital cost index, CPUC estimates of new fossil fuel-fired generation, CEC estimates of new fossil fuel-fired generation, forward market prices, or other similar third-party information regarding the cost of new generation CHP Facilities in California.
- 6.9.3 A lack of need exists.

7 GHG Emission Accounting Methodology

7.1 GHG Accounting Principles

- 7.1.1 Progress toward the IOUs' GHG Emissions Reduction Targets will be determined by a GHG Credit or GHG Debit. A “+” counts as a GHG Credit which will count toward the IOU's then-current GHG Emissions Reduction Target from CHP resources. A “-” counts as a GHG Debit, which will count against the IOU's then-current GHG Emissions Reduction Target. This same methodology applies if the CPUC requires CCAs/ESPs to procure on their own behalf.
- 7.1.2 Except otherwise noted in Section 7.3, the Parties agree to measure the amount of GHG emissions from CHP Facilities as compared to the current Double Benchmark in place at the time of PPA execution or, for a Utility Prescheduled Facility, execution of a new

PPA or a Legacy PPA Amendment. The Double Benchmark is intended to reflect the GHG emissions that would have occurred if the same amount of electricity and thermal output were obtained from conventional generation resources and a stand-alone boiler. The Double Benchmark measures the additional amount of GHG emissions that otherwise would exist if the CHP Facility did not exist.

- 7.1.3 For the purposes of GHG accounting, an “efficient” CHP refers to one that reduces emissions as compared to the Double Benchmark. An “inefficient” CHP refers to one that increases GHG emissions as compared to the Double Benchmark.
 - 7.1.4 CHP PPAs that are required by law to be executed by the IOU outside of the RFO or bilateral procurement processes, meaning PURPA contracts, feed-in tariffs (*e.g.*, AB 1613 Feed-In Tariff) or other mandated programs or PPAs will not count as a GHG Debit to the IOU. Efficient CHP Facilities as compared to the Double Benchmark will be counted as a GHG Credit.
- 7.2 The Double Benchmark, which may be later modified pursuant to this Settlement, is as follows:
- 7.2.1 The Heat Rate for the electricity generated is 8,300 BTU/kWh HHV at the busbar and excluding line losses.
 - 7.2.2 The thermal efficiency of a standard boiler is 80%.
 - 7.2.3 If the Double Benchmark is modified by CARB in a superseding Scoping Plan, regulation, or by the CPUC in a subsequent CPUC decision, the modified Double Benchmark shall be applied only on a prospective basis. The revised Double Benchmark shall apply to a CHP Facility that executes a PPA on or after the adoption date of the modified Double Benchmark. Changes to the Double Benchmark will not modify the MW Targets in this Settlement.
- 7.3 Detailed GHG Accounting Methodology to Measure Progress Toward the IOUs’ GHG Emissions Reduction Targets
- 7.3.1 Projects counted as a GHG Credit (+)
 - 7.3.1.1 New CHP Facilities: Efficient New CHP Facilities as compared to the Double Benchmark will count as a GHG Credit toward the contracting IOU's GHG Emissions Reduction Target regardless of where the CHP Facility is located. Measurement is based on the Double Benchmark in place at the time of PPA execution compared to the anticipated operations reflected in the PPA.
 - 7.3.1.2 Physical Change From a Repowered CHP Facility, MW Expansion, or Fuel Change (*e.g.*, an existing coal plant converts to a less GHG intensive fuel): Counts as a GHG Credit for the IOU. The measurement is the difference between i) the previous two (2) calendar years of operational data compared to the Double Benchmark in place at the time of PPA execution and ii) the anticipated change in operations as identified in the PPA compared to the Double Benchmark.
 - 7.3.1.3 CHP Facility Change In Operations or Conversion to a Utility Prescheduled Facility: Counts as a GHG Credit. Measurement is based on the Baseline year

emissions minus the projected PPA emissions and emissions associated with replacing one hundred percent (100%) of the decreased electric generation at a time differentiated Heat Rate. The Baseline year emissions are the average of the previous two (2) calendar years of operational data.

7.3.1.4 Existing inefficient CHP Facility shuts down: Counts as a GHG Credit toward the CARB CHP RRM of the IOU that previously contracted with the CHP.

7.3.1.4.1 If the thermal need continues, the measurement is the Double Benchmark in place at the time of the shut-down compared to the previous two (2) calendar years of operational data.

7.3.1.4.2 If the thermal need no longer exists, measurement is based on the Baseline year emissions minus the projected PPA emissions and emissions associated with replacing one hundred percent (100%) of the decreased electric generation at a time differentiated Heat Rate. The baseline year emissions are the average of the previous two (2) calendar years of operational data. The IOU shall demonstrate the thermal need no longer exists.

7.3.2 Projects counted as a GHG Debit (-)

7.3.2.1 Inefficient New CHP Facilities: Inefficient New CHP Facilities will count as a GHG Debit toward the contracting IOU's GHG Emissions Reduction Target. Measurement is based on the Double Benchmark in place at the time of PPA execution compared to anticipated operations reflected in the PPA.

7.3.2.2 Shut-down or Retirement of an existing, efficient CHP Facility and the thermal need continues: There is a GHG Debit for the IOU who previously contracted with the CHP equal to the amount of the GHG emissions reduction of the CHP Facility as compared to the Double Benchmark against the previous two calendar years of operational data.

7.3.2.3 Physical Change, a Repowered CHP Facility, MW Expansion or Fuel Change (e.g., an existing coal plant converts to a less GHG intensive fuel): A less efficient facility counts as a GHG Debit toward the IOU target. The measurement before the change is the previous two (2) calendar years of operational data compared to the Double Benchmark in place at the time of PPA execution; the measurement after the change is the anticipated operations reflected in the PPA compared to the Double Benchmark.

7.3.3 Projects counted as Neutral

7.3.3.1 Existing CHP Facility with no change in operations: Regardless of contract status (*i.e.*, a new PPA with an Existing CHP Facility or one that sells to the market) the CHP Facility is considered neutral for GHG accounting purposes.

7.3.3.2 Efficient Existing CHP Facility shuts-down and the thermal need is discontinued: If the host facility does not put in boilers, then there is no change to the IOU GHG Emissions Reduction Target.

- 7.3.3.3 Inefficient projects required by law to execute (including PURPA <20 MW, as-available, and feed-in tariffs): Count as neutral toward the GHG Emissions Reduction Target.

7.4 Effective Date for Accounting of Changes in GHG Credits and GHG Debits

- 7.4.1 The GHG benefit shall be calculated at the time of execution of the CHP PPA (includes RFO, bilateral agreement, Feed-In Tariff, as-available, PURPA <20 MWs). The calculation of the GHG Credit or GHG Debit attributable to the CHP Facility shall not be altered for the term of the PPA for the purposes of counting progress towards the IOUs' GHG Emissions Reduction Targets, regardless of a change to the Double Benchmark or modifications to the CARB Scoping Plan regarding the goal of securing 6.7 MMT of incremental GHG reductions from incremental CHP resources. If revised by a CARB determination and adopted by the CPUC in the LTPP proceeding, the modified Double Benchmark shall only apply to a CHP Facility that executes a PPA on or after the adoption of the modified Double Benchmark.
- 7.4.2 For an efficient CHP Facility that terminates its operations, the effective date shall be the date operations terminate.
- 7.4.3 For an existing CHP Facility with a change in operations, the effective date will be the date a new CHP PPA is executed by both Parties or, if there is no new PPA, the date on which the CHP Facility commences its change in operations.
- 7.4.4 PPAs executed during the period between September 1, 2009 and the Settlement Effective Date count towards the IOUs' MW Targets and GHG Emissions Reduction Targets.
- 7.4.5 SGIP or behind-the-meter CHP Facilities are counted at the time operations commence.

8 CPUC Jurisdictional Entities' Semi-Annual CHP Program Reports

8.1 General Description

- 8.1.1 Each CPUC Jurisdictional Entity shall prepare a semi-annual report (CHP Program Semi-Annual Report) detailing progress towards both MW Targets and GHG Emissions Reduction Targets.
- 8.1.2 Purpose: To track and report progress towards the CPUC Jurisdictional Entities' GHG Emissions Reduction Targets and MW Targets.
- 8.1.3 Responsible Parties: The CPUC Jurisdictional Entities will each prepare and update a CHP Program Report that they will submit to the CPUC Energy Division. The CPUC Energy Division will be responsible for verifying the accuracy of the data and collating the data to develop publicly-available reports as provided herein.
- 8.1.4 Availability: The CPUC Energy Division will post on the CPUC website public versions of the detailed updates for each CPUC Jurisdictional Entity, and maintain and publish a summary tracking progress toward both MW Targets and GHG Emissions Reduction Targets. This report shall be in addition to the IOUs' semi-annual reports on QF status.

8.1.5 Format: The CPUC Energy Division will determine the format of the CHP Program Reports. The Parties recommend Microsoft excel worksheet, with tabs for summary, including but not limited to PPAs with All Existing CHP Facilities, PPAs with New CHP Facilities or Repowered CHP Facilities, terminated PPAs, and with retired or shut down CHP Facilities.

8.1.6 Frequency: Semi-annual.

8.2 Overview of CHP Program Report Content

8.2.1 Summary to include: CHP Facility PPAs or other procurement and termination of CHP Facility PPAs by all CPUC Jurisdictional Entities by year, number of PPAs, capacity, GHG accounting (GHG Credits and GHG Debits).

8.2.2 Tracking in the report will begin upon execution of a new PPA by the Buyer and Seller for all CHP Facilities including existing, repowered or new, and excluding Transition PPAs, and Legacy PPAs (except where an amendment to a Legacy PPA results in an incremental change to GHG Emissions Reductions, in which case the tracking shall begin on the date of the execution of a Legacy PPA Amendment).

8.2.3 CHP Program Reports will include:

8.2.3.1 A tally of all CHP MWs deemed, pursuant to the Settlement, to count towards progress in meeting the IOUs' MW Targets, including a breakdown by IOU Service Territory.

8.2.3.2 A tally toward overall GHG Emissions Reduction Targets, including the GHG emissions reductions attributable to CHP Facilities that currently have PPAs with the IOUs, including breakdown by IOU Service Territory.

8.2.3.3 Each tally shall include MWs, GHG Credits and GHG Debits and shall be broken down by the following mutually exclusive categories:

8.2.3.3.1 Executed CHP Facility PPAs (but not yet delivering),

8.2.3.3.2 Operational CHP Facility PPAs,

8.2.3.3.3 Amended PPAs, and

8.2.3.3.4 Terminated CHP Facility PPAs including facility shut downs.

8.3 Report Content for New PPAs

8.3.1 The following table shows the public report content for:

8.3.1.1 Existing CHP Facilities entering into new PPAs (excluding Transition PPAs or Legacy PPA C1 Amendments)

8.3.1.2 New CHP Facilities, Repowered CHP Facilities and Expanded Facilities.

Item	Description
All Identification Numbers	Facility ID number and name, as per the PPA/CHP PPA CAISO ID number, CEC ID number, Energy Information Administration (EIA) ID number, CARB ID number
Location	IOU Service Territory/ESP/CCA etc.
Type of Program under which CHP Facility has been procured	Bilateral, CHP-only RFO, All Source RFO, AB 1613 Feed-In Tariff, As-Available, PURPA \leq 20 MW, SGIP, Utility Prescheduled Facility PPA, Section 3.07 modified CHP Facilities
Power Product	CHP Facility Contract Nameplate (MW) (define in report) Contract Capacity (MW) Energy deliveries under the Optional As-Available Program measured in AMW
Fuel Type	For example: natural gas, biomass, pet-coke, etc.
Contract Execution Date	Mm/dd/yyyy
Online Date	Mm/dd/yyyy
GHG Credits/ GHG Debits	Reflect figures pursuant to GHG accounting rules in Section 7 of the Settlement to determine GHG Credits/GHG Debits, and effective dates of change to GHG accounting. This value remains static for counting purposes for the life of the PPA.
Double Benchmark	The Double Benchmark reference point, <i>e.g.</i> , 8,300 Btu/kWh and 80% boiler efficiency.
Technology Type	Microturbine, etc.
Topping Cycle or Bottoming	Topping Cycle or Bottoming Cycle Classification

Item	Description
Cycle	

8.4 Report Content for Legacy PPA C1 Amendments, Utility Prescheduled Facilities or Other Changes in Operations

8.4.1 The following table shows the public report content for Legacy PPA C1 Amendments, Utility Prescheduled Facilities or other changes in operations.

8.4.2 Amendments to Legacy PPAs for CHP Facilities that convert to Utility Prescheduled Facilities will record the same information as in the table in Section 8.3 plus:

Item	Description
All Identification Numbers	Facility ID number and name, as per the PPA/CHP PPA CAISO ID number, CEC ID number, EIA ID number, CARB ID number
Location	IOU Service Territory/ESP/CCA etc.
Amendment Date	Mm/dd/yyyy
GHG Credits /GHG Debits	Reflect figures pursuant to GHG accounting rules in Section 7 of the Settlement to determine GHG Credits/GHG Debits, and effective dates of change to GHG accounting.
GHG Credit /GHG Debit Measurement	As per the GHG accounting rules in Section 7.
Effective Date of Change in Operations	Mm/dd/yyyy

8.5 Report Content for Terminated PPAs and Facilities that Cease Operations

8.5.1 The following table shows the public report content for Terminated PPAs and facilities that cease operations.

8.5.2 Terminated PPAs with CHP Facilities – (includes CHP Facilities with PPAs that are terminated for any reason during the Settlement Term (*i.e.*, expired, retired, or facilities that cease operations).

8.5.2.1 Facilities that cease operations shall indicate whether the thermal need remains or is discontinued.

Item	Description
Facility Name	Name as it appears in the PPA
All Facility ID Numbers	Facility ID number and name, as per the PPA, CAISO ID number, CEC ID number, EIA ID number, CARB ID number
Location	IOU Service Territory/ESP/CCA, etc.
Type of Program under which CHP had been procured	Bilateral, CHP-only RFO, All Source RFO, AB 1613 Feed-In Tariff, As-Available, PURPA \leq 20 MW, SGIP, Utility Prescheduled Facility PPA, Legacy PPA, Section 3.07 modified facilities
Power Product	Facility Contract Nameplate (MW) Energy deliveries under the Optional As-Available PPA measured in AMW
Fuel Type	For example: natural gas, biomass, pet-coke, etc.
PPA Termination or Ceases Operating	Mm/dd/yyyy
Thermal Load Status	Discontinued/Ongoing
GHG Credits /GHG Debits Measurement	As per the GHG accounting rules in Section 7.

9 CHP Auditor

9.1 Description of CHP Auditor

9.1.1 This section addresses the role of the CHP Auditor(s) for the CHP RFOs in the Settlement. This section also sets forth non-disclosure obligations for Confidential Information, the right to seek and secure information, designation criteria, and other matters.

9.1.2 Purpose and Role of the CHP Auditor(s). The purpose and role of a CHP Auditor is to be an informed advocate for CHP interests regarding the implementation of the CHP

Program. CHP Auditor(s) will only be designated under this section if, upon written notice, an IOU does not, or anticipates it will not, meet any of the following: a MW Target established by this Settlement; a GHG Emissions Reduction Target established by this Settlement; or any MW Target or GHG Emissions Reduction Target established by the CPUC in the LTPP after the Settlement Effective Date.

- 9.1.3 Payment of CHP Auditor(s). The CHP Parties may retain the CHP Auditor(s) subject to the conditions and approval processes set forth herein. The CHP Parties will bear the costs of the CHP Auditor. The sponsoring CHP Party (or Parties) for any individual CHP Auditor will bear the costs of such CHP Auditor.
- 9.1.4 Permitted Reporting by the CHP Auditor and the Applicable Non-Disclosure Agreement. The CHP Auditor(s) shall execute and is subject to non-disclosure restrictions set forth in the CHP Auditor Non-Disclosure Agreement (NDA), which is attached as Exhibit 8. With the exception of the twenty-four (24) month restriction in Section 9.5.3, if the CPUC, the courts or another legal authority modifies the requirements applicable to a reviewing representative of IOU Confidential Information, the NDA shall be updated to reflect such modifications (Applicable NDA). The CHP Auditor shall be bound by the terms and conditions of the Applicable NDA executed for a particular RFO on the conditions in the Applicable NDA at the time of execution. Updates to Applicable NDAs, if any, as provided under this section, shall apply only prospectively for NDAs executed after such updates. Subject to the terms and conditions of the Applicable NDA, the CHP Auditor may:
 - 9.1.4.1 Before the CPUC, and all divisions thereof, and the IOU's Procurement Review Group (CPUC forum) report on the IOU's conduct of and procurement decisions arising from a particular CHP RFO, using any information, including the Confidential Information obtained by the CHP Auditor from the IOU.
 - 9.1.4.2 Before any other forum, report, assess, recommend or advocate CHP procurement policies, targets or actions based upon the CHP Auditor's experience auditing a CHP RFO or other RFOs, including the procurement of additional CHP capacity to meet CHP procurement targets established by the CPUC, additional actions to promote the success of the CHP Program, or advocate any other action related to CHP policy or procurement that the Auditor deems appropriate. Actions by the Auditor under this section shall be consistent with the goals and objectives of the Settlement, and the Auditor(s) may not reveal Confidential Information pursuant to the Applicable NDA. For actions under this section the Auditor(s) may express qualitative opinions regarding the CHP Program and related matters based upon the Auditor's experience, provided that the CHP Auditor does not reveal Confidential Information.
 - 9.1.4.3 Before any other forum, the CHP Auditor(s) shall secure the advance approval of any affected IOU of the disclosure of any aggregated data derived from the IOU's Confidential Information that the CHP Auditor proposes to disclose. The affected IOU's advance approval shall be timely in contemplation of the circumstances of the disclosure and the IOU's consent shall not be unreasonably withheld. The IOU's decision on whether to allow use of data must be based on CPUC confidentiality rules in place at that time and on the terms of the Applicable NDA.

- 9.1.4.4 The Auditor(s) may also reference any public information, including any information publicly disclosed by any IOU Independent Evaluator.
- 9.1.4.5 The NDA, among other things, shall provide procedures for the Auditor to comply with lawful orders from a commission, court or other lawful authority compelling disclosure of Confidential Information.

9.2 IOU Notice Triggering Audit

- 9.2.1 An IOU will provide written notice to those CHP Parties on the new service list for this Settlement that the CPUC will create for the CPUC review of this Settlement, that it will not meet, or anticipates that it will not meet any of the following: a MW Target established by this Settlement; a GHG Emissions Reduction Target established by this Settlement; or any MW Target or GHG Emissions Reduction Target established by the CPUC in the LTPP after the Settlement Effective Date.
- 9.2.2 An IOU shall provide notice at the earliest practicable time based upon an IOU's expectation that it will not achieve any one of the following in a particular CHP RFO: a MW Target established by this Settlement; a GHG Emissions Reduction Target established by this Settlement; or any MW Target or GHG Emissions Reduction Target established by the CPUC in the LTPP after the Settlement Effective Date; provided that such notice shall be no later than the earlier of (1) Buyer's Advice Letter requesting approval of results from any CHP RFO solicitation, or (2) within five (5) Business Days of any presentation by the Buyer to the Buyer's PRG indicating that the Buyer will not achieve one of the above targets.

9.3 Time Period for Audit Review

- 9.3.1 The CHP Auditor(s) shall have up to ninety (90) calendar days (Audit Period) from the date of the receipt of the Confidential Information that was previously provided to the Independent Evaluator for a particular CHP RFO to present findings to the CPUC. If the CHP Auditor(s) require(s) additional time to present such findings, the Director of the CPUC Energy Division may, upon good cause shown, extend the Audit Period up to one hundred and eighty (180) calendar days. The CHP Auditor shall provide a written request to the Director of the CPUC Energy Division for such extension with a copy of the request simultaneously provided to the affected IOU.
- 9.3.2 Any pending CHP audit will not provide good cause for a delay in the IOU's completion of the procurement process for any CHP RFO.
- 9.3.3 A CHP Audit that exceeds ninety (90) calendar days will not provide good cause for delay of an IOU in commencing the next CHP RFO; provided that the IOU may condition procurement in subsequent RFOs upon final resolution of pending RFO audits in order to avoid procurement in excess of established MW Targets or GHG Emissions Reduction Targets.

9.4 Receipt and Review of Confidential Information and Other Relevant Data

- 9.4.1 The CHP Parties shall provide the IOU with notice of the identity of the designated CHP Auditor(s) for the CHP RFO. Within ten (10) Business Days of the receipt of such notice, the IOU will provide the Confidential Information to the CHP Auditor(s)

that was provided to the Independent Evaluator, if the CHP Auditor has executed and submitted an Applicable NDA as provided by this Section 9 with the particular IOU whose RFO is audited. The CHP Auditor(s) shall not be entitled to receive Confidential Information prior to the time the IOU receives the CHP Auditor's executed NDA.

- 9.4.2 At a minimum the Confidential Information shall include all information provided to the subject CHP RFO's Independent Evaluator. Notwithstanding anything to the contrary in this Settlement, the CHP Auditor is not entitled to review any proprietary models used by an IOU in an RFO, provided that all inputs and outputs of the model used in the RFO shall be provided to the CHP Auditor.
- 9.4.3 In addition to the right to secure access to all information provided by the IOU to the Independent Evaluator working on the particular CHP RFO, the CHP Auditor(s) shall also have the right to secure additional information that is reasonably required to evaluate the IOU procurement decisions in connection with a CHP RFO. The IOUs shall respond in full to all data requests from CHP Auditor(s) within ten (10) Business Days. The Parties agree that the Director of the CPUC Energy Division shall promptly address and resolve any disputes over the relevance of or access to data sought by the CHP Auditor(s).
- 9.4.4 The Parties agree that there is no waiver of rights or positions regarding access to confidential data resulting from future changes by the CPUC, court or other lawful authority on the issue of confidentiality. The obligations and responsibilities of the CHP Auditor(s) with regard to maintaining confidentiality of the Confidential Information shall be specified in the Applicable NDA.

9.5 Designation, Notice, Conflict of Interest Review and Number of CHP Auditors

- 9.5.1 The CHP Parties shall endeavor to agree upon a single CHP Auditor, but may designate no more than two CHP Auditors for each CHP RFO under this section; provided that IEP shall have the right to designate one Auditor, and collectively CCC-CAC-EPUC shall have the right to designate one Auditor.
- 9.5.2 The CHP Parties shall provide notice to the CPUC Energy Division director (Director) of the name of any designated CHP Auditor(s) for a specific conflict of interest review. The Director shall evaluate the curriculum vitae for any designated auditor, determine if any applicable conflict of interest restrictions exist for the designee(s) within five (5) Business Days and notify the IOU that the Director has determined that the designated CHP Auditor(s) is/are acceptable. The Director will certify the designated CHP Auditor(s) within five (5) Business Days, during which the Director shall review conflict(s) of interest for the CHP Auditor(s) under the following conditions: (1) the direct ownership interest in any bidder in the particular RFO subject to the CHP audit, or (2) a breach of a non-disclosure agreement in an CHP RFO audit review or any other NDA. If the Director identifies any other conflict of interest standard that the Director reasonably believes needs to be applied to the CHP Auditor, the Director shall meet and confer with all affected Parties to discuss the need for such other standard(s).
- 9.5.3 Each CHP Auditor must certify in writing, prior to the receipt of Confidential Information, that he or she will not engage, beginning on the date of the delivery of Confidential Information, and thereafter for a period of twenty four (24) months in: (a)

a transaction for the generation, purchase, sale or marketing of electrical energy, and/or capacity, and/or related products, including specifically electricity related financial products (meaning derivatives, swaps or options), at wholesale in the State of California, (b) a transaction for the purchase, sale or marketing at wholesale of natural gas commodity, assets, including specifically natural gas related financial products (meaning derivatives, swaps or options), for electric generation, purchase or sale purposes in the State of California, (c) preparing offers and/or bidding strategies, bidding on, or purchasing of electric power plants in the State of California or the substantive supervision of any employees whose duties include such responsibilities with regard to those activities, subject to the following Section 9.5.4, or (d) mergers and/or acquisitions of entities that own or control electric generation and/or natural gas assets or commodity associated with electric generation in the State of California, (e) consulting with or advising others in connection with any activity set forth in subparagraphs (a), (b), (c) or (d) of this Section 9.5.3.

- 9.5.4 The CHP Auditor(s) may not share the Confidential Information with any third party, including any co-worker or employee, except to provide necessary technical, administrative and clerical support of no more than three (3) individuals for the Auditor's work; provided that such party is also subject to the NDA for the affected IOU and each provision of Section 9. The CHP Auditor may directly supervise employees, office colleagues or co-workers, but shall establish rules to eliminate any substantive supervision of activities identified in Section 9.5.3, above. For example, any third party, including a supervisor, employee, office colleague or co-worker of a CHP Auditor shall not have any substantive involvement in reviewing, providing guidance to or reviewing the results of the analysis derived from the Confidential Information.

10 SRAC Energy Pricing Structure

10.1 Applicability

- 10.1.1 The SRAC energy price applies to the following:

10.1.1.1 Transition PPAs;

10.1.1.2 Legacy PPAs, if another option in Section 11 is not selected;

10.1.1.3 QF PPAs; and

10.1.1.4 Optional As-Available PPAs.

10.2 Methodologies and Formulae

- 10.2.1 The following formulas and methodologies for determining the SRAC energy price shall replace the CPUC-adopted SRAC formula as of the first day of the second calendar month beginning after the Settlement Effective Date (SRAC Commencement Date) and are set forth below:

10.2.1.1 Method for Determining the SRAC Energy Price. Subject to Sections 10.2.2 through 10.2.7, as of the SRAC Commencement Date, the SRAC energy price must be calculated using the following formula:

$$\text{Energy Price } \$/\text{kWh} = ((\text{Applicable HR} * \text{BTGP}/1,000,000) + \text{VOM}) * \text{TOU} + \text{LA} + \text{GHG Charges}$$

Where:

Applicable HR = The Heat Rate for the specified time-period, per the following table:

Calendar Year(s)	Heat Rate (Btu/kWh)
2011	8,700
2012	8,225
January 1, 2013 through December 31, 2014	8,125
January 1, 2015 and beyond	Market Heat Rate

BTGP = Calendar month Burner Tip Gas Price (\$/MMBtu), per D.07-09-040 and CPUC Resolution E-4246 (as such Resolution may be modified from time to time by the CPUC);

VOM = Calendar month avoided variable O&M (\$/kWh), per D.07-09-040 and CPUC Resolution E-4246 (as such Resolution may be modified from time to time by the CPUC);

GHG Charges = means all taxes, charges or fees, assessed with the implementation and regulation of Greenhouse Gas emissions with respect to the Generating Facility imposed by any Governmental Authority, such as the CARB’s AB 32 Cost of Implementation Fee (as defined in Title 17 C.C.R. §95200). For example, if the charges are assessed on but not included in fuel consumption or gas costs, the Applicable Heat Rate or Burner Tip Gas Price will be used to derive the dollars per kilowatt-hour charge. On January 1, 2015 or the commencement of the First Compliance Period, the GHG Charges will equal zero in the above formula.

TOU (i.e., time-of-use) = The TOU factors are, as of the SRAC Commencement Date, as follows for each IOU:

TOU Factors if Buyer is PG&E		
	Summer	Winter
Peak	1.2564	N/A
Partial-Peak	1.1535	1.1395
Off-Peak	0.9155	0.9628
Super Off-Peak	0.7439	0.8216
Off-Peak TOU factors will be calculated as a residual – similar to the current method – to preserve the correctness of the monthly hourly weighting. An example for Period A – Summer is: [Number of hours in month – (1.2564 * Number of Summer Peak hours in month) – (1.1535 * Number of Summer Partial-Peak hours in month) – (0.7439 * Number of Summer Super Off-Peak hours in month)] / Number of Summer Off-Peak hours in month		

TOU Factors if Buyer is SCE		
	Summer	Winter
On-Peak	1.4251	N/A
Mid-Peak	see below	1.2185
Off-Peak	0.8526	see below
Super Off-Peak	N/A	0.7760
Summer Mid-Peak = (Total # hours in month - (1.4251 * # of Summer On-Peak hours in month) - (0.8526 * # of Summer Off-Peak hours in month)) / # of Summer Mid-Peak hours in month Winter Off-Peak = (Total # hours in month - (1.2185 * # of Winter Mid-Peak hours in month) - (0.7760 * # of Winter Super Off Peak hours in month)) / # of Winter Off-Peak hours in month		

TOU Factors if Buyer is SDG&E		
	Summer	Winter
On-Peak	1.411	1.224
Semi-Peak	1.106	1.106
Off-Peak	0.986	0.933
Super Off-Peak	0.645	0.711

PG&E and SDG&E may update the TOU factors in their respective SRAC postings at the beginning of each calendar year using the energy-only portion of the time-of-use factors (as adjusted by PG&E and SDG&E, as applicable and if necessary, to reflect their respective CPUC-approved time-of-use periods) set forth in their most recent RPS Program solicitation (*e.g.*, 2012 time-of-use factors are those used in Buyer's 2011 RPS Program solicitation). SCE may update its TOU factors annually through an appropriate filing with the CPUC.

$$LA \text{ (i.e., hourly location adjustment, in \$/kWh)} = LMP_{QF} - LMP_{Trading \text{ Hub}}$$

Where the hourly location adjustment will be based on the hourly Day-Ahead prices and actual hourly generation by the Generating Facility for delivery to Buyer as follows:

LMP_{QF} (in \$/kWh) = The hourly Day-Ahead Locational Marginal Price at the point of interconnection with the CAISO-controlled electric system associated with the Generating Facility; and

$LMP_{Trading \text{ Hub}}$ (in \$/kWh) = The hourly Day-Ahead Locational Marginal Price of the trading hub where the Generating Facility is located (*i.e.*, SP15 Existing Zone Generation Trading Hub (formerly SP15), NP15 Existing Zone Generation Trading Hub (formerly NP15), or ZP26 Existing Zone Generation Trading Hub (formerly ZP26), as applicable, or any successor thereto).

- 10.2.2 Energy Price During the Floor Test. If there is a cap-and-trade program in California for the regulation of GHG, as established by CARB (and/or by a different Governmental Authority pursuant to federal or state legislation), then, during the Floor

Test Term, the SRAC energy price will be the higher of the two formulas provided in Sections 10.2.2.1 and 10.2.2.2 (the GHG Floor Test):

$$10.2.2.1 \text{ Energy Price } \$/\text{kWh} = ((\text{Market Heat Rate} * \text{BTGP}/1,000,000) + \text{VOM}) * \text{TOU} + \text{LA}$$

Where:

Market Heat Rate (Btu/kWh) = As defined in Section 17;

BTGP (\$/MMBtu) = As set forth above;

VOM (\$/kWh) = As set forth above;

TOU = As set forth above; and

LA (\$/kWh) = As set forth above.

OR

$$10.2.2.2 \text{ Energy Price } \$/\text{kWh} = ((\text{Applicable HR} * (\text{BTGP} + \text{GHG Allowance Price}) / 1,000,000) + \text{VOM}) * \text{TOU} + \text{LA} + \text{GHG Charges}$$

Where:

Applicable HR = (A) 8,225 Btu/kWh through December 31, 2012, (B) 8,125 Btu/kWh from January 1, 2013 through December 31, 2014; and (C) Actual HR (as defined in Section 17) from January 1, 2015 until the end of the Floor Test Term;

BTGP (\$/MMBtu) = As set forth above;

GHG Allowance Price (\$/MMBtu) = Allowance Cost (\$/MT) * 117lbs of GHG per MMBtu / 2,204.6 lbs per MT

Where:

Allowance Cost (\$/MT) = The cost of one Allowance, determined using the GHG Auction clearing price from the latest GHG Auction that has taken place during the calendar quarter immediately preceding the date that Buyer's payment is due to Seller; *provided, however*, that if there is no GHG Auction held during the applicable time-period, then the Allowance Cost is determined in accordance with Section 10.2.6.

VOM (\$/kWh) = As set forth above;

GHG Charges (\$/kWh) = As set forth above;

TOU = As set forth above; and

LA (\$/kWh) = As set forth above.

- 10.2.3 Free Allowance Reporting and Allocation. If, at any time, Buyer makes a monthly payment to Seller utilizing the GHG Floor Test formula set forth in Section 10.2.2.2, then Buyer shall deduct from the monthly payment to Seller for the applicable month the value of the Free Allowances disclosed in and based on all Free Allowance Notices that have not already been applied to a prior payment to Seller; provided, however, that if Buyer, using reasonable efforts, is unable to process such payment adjustment for the applicable month, then Buyer shall make such payment adjustment to the next monthly payment due to Seller. For any month that Buyer utilizes the formula set forth in Section 10.2.2.1 to make a monthly payment to Seller, Buyer shall maintain a record of the value and quantity of all Free Allowances disclosed in the Free Allowance Notices, if any, and shall deduct the value of such Free Allowances to any subsequent monthly payment due to Seller where Buyer calculates such monthly payment utilizing the formula set forth in Section 10.2.2.2 until such time that the value of all such Free Allowances are expended.
- 10.2.4 In order for Buyer to make the payment adjustment set forth in the immediately preceding paragraph, Seller agrees to deliver to Buyer, within twenty (20) calendar days of receiving any Free Allowances, a Free Allowance Notice for the applicable month, which Free Allowance Notice must include all Additional GHG Documentation. Buyer shall value any such Free Allowances using the same methodology Buyer uses in valuing the Allowance Cost, as set forth above.
- 10.2.5 Buyer will review the Annual GHG Reports described in Section 10.3 to determine if there is any discrepancy in the payments made by Buyer to Seller for GHG Compliance Costs during the course of the applicable calendar year. To the extent Buyer determines that there is any such discrepancy, (i) if Buyer owes Seller an additional payment for GHG Compliance Costs, then Buyer shall make such additional payment in a subsequent monthly payment to Seller under the Applicable PPA, or (ii) if Seller owes Buyer a payment refund for GHG Compliance Costs, then Buyer shall offset such payment refund amount in a subsequent monthly payment to Seller under the Applicable PPA. If the Applicable PPA terminates before Buyer is able to make such additional payment for GHG Compliance Costs or offset such GHG Compliance Costs payment refund from Seller's monthly payments, as applicable, then Buyer or Seller, as applicable, shall pay all remaining payment amounts due within the thirty- (30) day period before the termination of the Applicable PPA.
- 10.2.6 Determining Allowance Costs under the GHG Floor Test if there is No GHG Auction. This Section 10.2.6 is applicable if no GHG Auction has been held during the time-period for which the Allowance Cost variable set forth in Section 10.2.2.2 is to be determined. In such an instance, publicly available indices will be used to determine the price for the applicable period. If no such indices exist, SCE, SDG&E and PG&E, on the one hand, and CAC, EPUC, CCC and IEP, on the other hand, shall negotiate in good faith to reach an agreement on setting the Allowance Cost variable. If, after negotiating for fifteen (15) Business Days, the Parties are not able to reach agreement on setting the Allowance Cost variable, then SCE, SDG&E and PG&E, on the one hand, and CAC, EPUC, CCC and IEP, on the other hand, shall each select, within fifteen (15) calendar days after such failed negotiations, price quotations from two (2) different Reference Market-Makers, for a total of four (4) price quotations. The Allowance Cost variable for the applicable time-period will be determined by taking the average of the four (4) price quotations so selected by the Parties.

- 10.2.7 Energy Price from the end of the Floor Test Term. As of the end of Floor Test Term, the SRAC energy price must be calculated in accordance with the following formula:

$$\text{Energy Price } \$/\text{kWh} = ((\text{Market Heat Rate} * \text{BTGP}/1,000,000) + \text{VOM}) * \text{TOU} + \text{LA}$$

Where:

Market Heat Rate (Btu/kWh) = as defined in Section 17;

BTGP (\$/MMBtu) = As set forth above;

VOM (\$/kWh) = As set forth above;

TOU = As set forth above; and

LA (\$/kWh) = As set forth above.

10.3 Reporting Requirements

- 10.3.1 From the SRAC Commencement Date through the end of the term of the Applicable PPA (and for any period following the termination of the Applicable PPA to the extent relating back to the term of the Applicable PPA), Seller shall provide to Buyer the following information (together, the Annual GHG Reports):

10.3.1.1 On or before the fifth (5th) Business Day following Seller's timely submission to CARB (or any other authorized Governmental Authority having jurisdiction in California) of the CARB Mandatory GHG Emissions Annual Report, or such other annual report submitted to CARB, detailing the GHG emissions of the Generating Facility for the applicable calendar year (as verified by an independent third party, if applicable) (the CARB Annual Report), Seller shall deliver such CARB Annual Report to Buyer; and

10.3.1.2 To the extent not set forth in the CARB Annual Report (or if Seller is no longer required to submit the CARB Annual Report for any reason), then Seller shall submit to Buyer, along with the CARB Annual Report (or, if Seller is no longer required to submit the CARB Annual Report for any reason, then on the sixtieth (60th) Business Day following the end of the applicable calendar year), the following information for the applicable calendar year, which, in each case, must be verifiable and of settlement quality: (1) the Useful Thermal Energy Output of the Generating Facility; (2) total fuel usage of the Generating Facility; (3) the total amount of GHG emissions attributable to the Generating Facility, the electrical energy used to serve the Site Host Load, the Useful Thermal Energy Output of the Generating Facility; (4) the total electrical energy produced by the Generating Facility, the electrical energy used to serve the Site Host Load, and the energy delivered to Buyer; and (5) the number of Allowances (including Free Allowances) held and/or surrendered by Seller for such calendar year (during any period where the SRAC energy price is calculated in accordance with Section 10.2.2).

- 10.3.2 If Buyer requires any other information not delineated in Section 10.3.1 in order to comply with any GHG emissions reporting requirements adopted by CARB and/or by

any other Governmental Authority and imposed on Buyer (other than the information that Seller must provide in accordance with Section 10.3.3), then SCE, SDG&E and PG&E, on the one hand, and CAC, EPUC, CCC and IEP, on the other hand, shall promptly meet and confer regarding such other information that Buyer requires and negotiate in good faith to reach a mutually acceptable agreement. Buyer and Seller shall be bound by any agreement as to any information required by Buyer, as described in the foregoing, between PG&E, SCE and SDG&E, on the one hand, and CAC, EPUC, CCC and IEP, on the other hand, in accordance with the foregoing.

10.3.3 Each Party shall deliver to the other Party, or before the tenth (10th) Business Day following receipt of a notice from the other Party, such information as such other Party is required to report to any authorized Governmental Authority pursuant to the Settlement.

10.3.4 To the extent that the information provided by the disclosing Party in accordance with this Section 10.3 is Confidential Information, the receiving Party shall treat such Confidential Information with the same degree of care that it currently treats the data and information provided by QFs under the existing CHP QF Compliance Monitoring Program.

10.4 Market Disruption Event

10.4.1 If, on or after the date that the Market Heat Rate applies to and is used in the calculation of the energy price and until the end of the term of the Applicable PPA, there occurs a Market Disruption Event, then the Market Heat Rate for the affected Trading Day(s) must be determined by reference to the Market Heat Rate for the first Trading Day thereafter on which no Market Disruption Event exists; provided, however, that if the Market Heat Rate is not so determined within five (5) Trading Days after the Market Disruption Event, then PG&E, SCE and SDG&E, on the one hand, and CAC, EPUC, CCC and IEP, on the other hand, will negotiate in good faith to reach an agreement on a Market Heat Rate (or a method for determining a Market Heat Rate), and if such negotiating parties have not so agreed on or before the twelfth (12th) Trading Day following the first Trading Day on which the Market Disruption Event occurred or existed, then the Market Heat Rate will be determined in good faith by taking the average of the price quotations for energy and relevant Trading Days that are obtained from no more than two (2) Reference Market-Makers selected by PG&E, SCE and SDG&E, on the one hand, and CAC, EPUC, CCC and IEP on the other hand (for a total of four (4) price quotations). Buyer and Seller shall be bound by any agreement as to a Market Heat Rate (or a method for determining a Market Heat Rate) between PG&E, SCE and SDG&E, on the one hand, and CAC, EPUC, CCC and IEP, on the other hand, in accordance with the foregoing.

10.5 Seller's Responsibility

10.5.1 Other than Buyer's payment to Seller for GHG Compliance Costs and GHG Charges as set forth in payment formulae in Section 10.2 above, Seller is solely responsible for all GHG Compliance Costs and all other costs associated with implementation and regulation of GHG emissions with respect to Seller or the Generating Facility.

11 Legacy PPA Matters for All Existing QFs

11.1 Energy and Capacity Pricing

- 11.1.1 Unless a Legacy PPA is otherwise amended to specify an alternate energy price or pricing methodology, SRAC shall be as set forth in Section 10.
- 11.1.2 QFs with Legacy PPAs may execute the Amendment to Legacy PPAs, which shall include energy pricing options identified as Options A, B, C1, C2, and C3, and other terms, as attached hereto as Exhibits 1, 2, and 3.
- 11.1.3 If no capacity price is set in the Legacy PPAs, other than the administratively determined price, the capacity price shall be as set in D.07-09-040.

11.2 Other Matters

- 11.2.1 The Parties' objective is to assure that a CHP or Utility Prescheduled Facility operating under an extension ordered by the Commission in D.07-09-040 will be able to deliver power without interruption pursuant to the extension of the Legacy CHP PPA until the first day of the term, meaning the initial date of the delivery of power, of a new or amended PPA (Subsequent PPA). Extensions of Legacy CHP PPAs ordered by the Commission pursuant to D.07-09-040 shall remain in effect until the date the Seller commences power deliveries under a Subsequent PPA pursuant to this Settlement. For example, the end delivery date of the extension of the Legacy CHP PPA would be Monday and the first day of the term of the Subsequent PPA would be Tuesday. This would allow continued delivery of power without interruption under an approved and effective Subsequent PPA. The Parties shall use all reasonable efforts to meet conditions that would permit transition from the extensions to an approved and effective Subsequent PPA within one hundred and twenty (120) days after the Settlement Effective Date. Absent good cause shown, the extension of the Legacy CHP PPA shall terminate and the term of the Subsequent PPA commence no later than one hundred and twenty (120) days after the Settlement Effective Date. Good cause shall include pending regulatory approvals from the CPUC, CAISO or other Governmental Authority that prevents the delivery of power under a Subsequent PPA. In the event of a dispute, the QF may submit a letter to the Director of the CPUC Energy Division (with a copy to the IOU with a right to respond) setting forth the particular facts that explain why the CHP Facility cannot move to the Subsequent PPA and asking for a further extension. The Director of Energy Division will act on this letter within thirty (30) days and the extension of the Legacy CHP PPA shall remain in effect during the period of review. Such requests shall not be unreasonably repetitive or designed primarily to delay termination of the extension of the Legacy CHP PPA. The Parties will comply with Commission orders or actions of the Director of CPUC Energy Division related to the termination of the extension of the Legacy CHP PPA.
- 11.2.2 Legacy PPAs, and extensions of PPAs ordered by the CPUC, shall remain in effect under the terms and conditions specified in such PPAs and extensions of such PPAs, subject to the following section.
- 11.2.3 A QF with a Legacy PPA can bid into a CHP RFO or otherwise make use of any applicable CHP Procurement Process.

11.3 Non-Binding Forecasting Requirements for Legacy PPAs

11.3.1 General Requirements. The Buyer and Seller shall make good faith efforts to abide by the forecast requirements and procedure described below and shall agree upon reasonable changes to these requirements and procedures from time to time as necessary to:

11.3.1.1 Support Buyer's compliance with the CAISO's scheduling requirements related to the PPA;

11.3.1.2 Accommodate changes to the Buyer's and/or Seller's respective generation technology and organizational structure; and

11.3.1.3 Address changes in the operating and Scheduling procedures of Seller, Buyer and the CAISO, including automated Forecast and outage submissions.

11.3.2 The Buyer and Seller agree that the Forecasts generated by, or otherwise resulting from, the forecasting requirements and procedures in this Section 11.3 are non-binding on Seller, the Generating Facility or the Site Host.

11.3.3 Seller's Forecasting Submittal Procedures

11.3.3.1 30-Day Forecast.

11.3.3.1.1 No later than 30 days before the first day of the following Initial Forecast Month, Seller shall provide Buyer with a Forecast for the 30-day period commencing on the first day of the Initial Forecast Month using the Web Client.

11.3.3.1.2 If the Web Client becomes unavailable, Seller shall provide Buyer with the Forecast by e-mail at [**Buyer to provide contact information**] or by telephoning Buyer's generation operations center at [**Buyer to provide contact information**].

11.3.3.1.3 The Forecast, and any updated Forecasts provided pursuant to Section 11.3.3 shall (i) not include any anticipated or expected electric energy losses between the meter(s) used for measuring the energy sold to Buyer by Seller and the point of delivery of the energy delivered to Buyer by Seller, and (ii) limit hour-to-hour Forecast changes to no less than 250 kWh during any period when the Web Client is unavailable. Seller shall have no restriction on hour-to-hour Forecast changes when the Web Client is available.

11.3.3.2 Weekly Update to 30-Day Forecast.

11.3.3.2.1 Commencing on or before 5:00 p.m. California time of the Wednesday before the first week covered by the Forecast provided pursuant to Section 11.3.3.1, and on or before 5:00 p.m. California time every Wednesday thereafter for the remainder of the term of the PPA, Seller shall update the Forecast for the 30-day period

commencing on the Sunday following the weekly Wednesday Forecast update submission.

11.3.3.2.2 Seller shall use the Web Client, if available, to supply this weekly update or, if the Web Client is not available, Seller shall provide Buyer with the weekly Forecast update by e-mailing or telephoning Buyer at the e-mail address or telephone number listed in Section 11.3.3.1.

11.3.3.3 Further Update to 30-Day Forecast.

11.3.3.3.1 As soon as reasonably practicable and commensurate with Seller's knowledge, Seller shall provide Forecast updates to take into account expected changes in daily, hourly and real-time deliveries from the Generating Facility for any cause, including changes in the Generating Facility ambient conditions, a Forced Outage or a Real-Time Forced Outage, any of which results or is expected to result in a material change to the Generating Facility's deliveries (whether in part or in whole).

11.3.3.3.2 This updated Forecast pursuant to this Section 11.3 must be submitted to Buyer via the Web Client by no later than:

11.3.3.3.2.1 5:00 p.m. California time on the day before the day in which Day -Ahead trading occurs in accordance with the Western Electricity Coordinating Council Preschedule Calendar (as found on the Western Electricity Coordinating Council's website) is impacted by the change, if the change is known to Seller at that time,

11.3.3.3.2.2 The Hour-Ahead Scheduling Deadline, if the change is known to Seller at that time,

11.3.3.3.2.3 If the change is not known to Seller by the timeframes indicated in Sections 11.3.3.2.1 and 11.3.3.2.2 immediately above, no later than 20 minutes after Seller becomes aware of the event which caused the expected energy production change.

11.3.3.3.3 Seller's updated Forecast must contain the following information:

11.3.3.3.3.1 The beginning date and time of the event resulting in a change in the availability of the Generating Facility and expected hourly energy production in MWh/h;

11.3.3.3.3.2 The expected ending date and time of the event;

11.3.3.3.3.3 The expected energy production or available generation capacity, as applicable, in MWh; and

11.3.3.3.3.4 Any other information required by the CAISO as communicated to Seller by Buyer.

- 11.3.4 Buyer is responsible for all CAISO charges and is entitled to receive all CAISO revenues.
- 11.3.5 Except as set forth in this Section 11.3, there shall be no modification of Seller's existing communication protocols and designated contacts with Buyer, if any, including any requirement to notify Buyer of Generating Facility parallel operation or separation from the electrical system.

12 CAISO Tariff Compliance

12.1 CAISO Tariff Compliance for New PPAs

- 12.1.1 As reflected in the applicable PPAs, all CHP Facilities subject to the CAISO Tariff shall comply with applicable CAISO Tariff provisions as determined by the CAISO no later than the time when the CHP Facility begins deliveries under any PPA entered into pursuant to this Settlement. CAISO approved revenue quality metering and telemetry shall be installed in compliance with CAISO requirements within six (6) months following execution of such contract, subject to any extension granted by the CAISO.
- 12.1.2 The Parties acknowledge that the CAISO may condition, waive, extend or modify applicable conditions for interconnection, metering or other CAISO jurisdictional matters to the extent permitted by the CAISO Tariff provisions applicable to CHP Facilities. Pending installation of CAISO approved revenue quality metering and telemetry for a CHP Facility, the IOU shall provide the CAISO with any necessary revenue meter and telemetry data as requested by the CAISO.

13 IOU Cost Recovery for CHP Program PPAs

13.1 Cost Allocation and Departing Load Charges

- 13.1.1 The IOUs will enter into CHP PPAs for up to twelve (12) years. CPUC D.04-12-048, D.06-07-029 and D.08-09-012 limit the recovery of power procurement PPA costs to ten (10) years. This Settlement is conditioned on a CPUC Decision approving this Settlement which supersedes the provisions of D.06-07-029 and D.08-09-012 as follows: (1) the relevant costs (either "above market costs" or "net capacity costs," as appropriate) of this CHP Program can be recovered through Non-Bypassable Charges and (2) the same relevant costs of new PPAs entered into pursuant to the CHP Program can be recovered through Non-Bypassable Charges for the term of the CHP PPA, subject to the restrictions herein.
- 13.1.2 One of the two following methods for allocation of CHP procurement costs shall uniformly apply to all ESPs and CCAs. The choice of the two methods referenced in this section shall be determined by the CPUC on review of this Settlement. The same method shall be used for all three IOUs.
 - 13.1.2.1 If the CPUC determines that all ESPs and CCAs should procure CHP generation for their customers, then the relevant CPUC decisions (potentially including D.04-12-048, D.06-07-030 and/or D.08-09-012) shall be superseded to the extent necessary to authorize the allocation of all above-market costs associated with the IOU portion of the CHP Program on a vintaged basis to

future Direct Access (DA) and CCA customers and all future Departing Load Customers, except for Departing Load Customers served by CHP Facilities as provided in Public Utilities Code §218(b) (CHP Departing Load Customers), through the Cost Responsibility Surcharge (CRS). The calculation of the above-market costs of the CHP Program to be added to the CRS would follow the same methodology adopted in D.06-07-030.

13.1.2.2 If the CPUC determines that the IOUs should purchase CHP generation on behalf of DA and CCA customers, then the D.06-07-029 (and D.08-09-012 if necessary) shall be superseded to the extent necessary to authorize the IOUs to recover the net capacity costs associated with the CHP Program from all bundled service, DA and CCA customers and all Departing Load Customers except for CHP Departing Load Customers, on a non-bypassable basis. The net capacity costs of the CHP Program shall be defined as the total costs paid by the IOU under the CHP Program less the value of the energy and any ancillary services supplied to the IOU under the CHP Program. No energy auction shall be required to value such energy and ancillary services. In exchange for paying a share of the net costs of the CHP Program, the LSEs serving DA and CCA customers will receive a pro-rata share of the RA credits procured via the CHP Program.

13.1.3 The Parties agree that they will not advocate charging load served by CHP that meets the criteria of Public Utilities Code §218(b) and §216.6 for the costs of the CHP Program through any cost allocation mechanism.

13.1.4 The current Non-Bypassable Charges applicable to Customer Generation Departing Load (CGDL) as of December 31, 2009 include only the DWR Bond Charge, Nuclear Decommissioning and the Public Purpose Program charge. The Parties agree to oppose (or not support) any proposal before the CPUC not otherwise required by statute that would result in the application of “new generation” costs as defined in D.04-12-048 and D.08-09-012 or cost allocation mechanism (CAM) charges to CHP CGDL, or that would re-characterize the costs currently recovered through those mechanisms such that they would apply to CHP CGDL in the future. However, Parties reserve the right to argue that future programs not currently within the scope of “new generation” as defined in D.08-09-012⁵ should be treated as Public Purpose Programs.

13.1.5 In recognition of the new cost recovery mechanisms contemplated by this Settlement, the Parties agree to advocate exclusion from the Competition Transition Charge (CTC) of any above-market costs associated with purchases of power from a CHP Facility via a PPA entered into pursuant to this Settlement. However, the above-market costs of QF procurement via Legacy PPAs may continue to be recovered through CTC for the life of those contracts.

13.2 IOUs’ Energy Resources Recovery Accounts

⁵ “New Generation” as defined in D.08-09-012 includes “generation from both fossil fueled and renewable resources contracted for or constructed by the investor-owned utilities subsequent to January 1, 2003.” D.08-09-012, note 1.

- 13.2.1 The IOUs shall recover the cost of all payments made pursuant to PPAs and PPA Amendments executed under this CHP Program in their respective Energy Resources Recovery Accounts, subject only to the reasonable administration of these PPAs and PPA Amendments.

14 Settlement of Pending and Anticipated Litigation

14.1 Retroactive Adjustment of SRAC Prices

- 14.1.1 If the CPUC adopts the Settlement and FERC terminates, subject to reinstatement, the PURPA must take obligation for QFs over 20 MW, the IOUs will withdraw with prejudice all SRAC retroactive price adjustment claims and challenges and such claims and challenges cannot be revived. As long as the FERC 210(m) suspension stays in place, the Parties may neither raise new claims nor seek retroactive adjustments of SRAC prices paid to QFs during the Settlement Term based on the grounds that SRAC prices violate PURPA avoided cost requirements or based on an argument that alternative pricing theories or methodologies would be preferable to the SRAC methodologies set forth in the Settlement. However, the IOUs may adjust payments to QFs based on other issues that arise in the administration of the PPAs, *e.g.*, billing errors, metering errors, fraud.

14.2 Released Claims

- 14.2.1 QFs over 20 MW will not have the right to new five (5)-year and ten (10)-year PPAs ordered in D. 07-09-040 during the Settlement Term.
- 14.2.2 CCC will withdraw its motion for an order implementing the prospective QF program PPA options adopted in D.07-09-040.
- 14.2.3 All Parties will waive all retroactive claims for energy and capacity adjustment for periods including, but not limited to:
- 14.2.3.1 SRAC Remand Dispute (R.99-11-021) (December 2000 – March, 31 2001),
- 14.2.3.2 SCE's SRAC Update application (A. 08-11-001) (April 2004 – July 31, 2009), and
- 14.2.3.3 PG&E's and SDG&E's pending refund application (September 2007 – July 31, 2009).
- 14.2.4 SCE/TURN will withdraw its Petition for Writ of Review of D.07-09-040 and D.08-07-048 at California Court of Appeal (Case B210398). Parties will withdraw cross claims in that case.
- 14.2.5 SCE, PG&E, and SDG&E will withdraw their application for rehearing of D.09-04-032.
- 14.2.6 SCE, PG&E, SDG&E, and TURN will withdraw their application for rehearing of D.09-04-034.
- 14.2.7 CAC, EPUC, and IEP will withdraw their applications for rehearing of D.09-04-032.

- 14.2.8 CAC and EPUC will withdraw their application for rehearing of D.09-04-034.
- 14.2.9 The CPUC shall close with prejudice its reconsideration of the Administrative Heat Rates as ordered in D.08-11-062.
- 14.2.10 Application or petitions regarding CHP Facilities on Transitional SO1 agreements or extensions will be withdrawn.
- 14.2.11 The IOUs will withdraw Advice Letters PG&E AL 3197-E, SDG&E AL 1958-E, and SCE AL 2200-E to implement new Standard Offer Contracts pursuant to D.07-09-040.
- 14.2.12 The IOUs shall withdraw the Petition for Modification of D.07-12-052 (LTPP Decision) regarding QF capacity.

14.3 Confidentiality

- 14.3.1 The Parties agree that they shall abide by the CPUC rules regarding Confidential Information as set forth in CPUC decisions and as modified by the CPUC, the courts or the legislature.
- 14.3.2 Parties reserve all rights to advocate for their respective positions before the CPUC, the courts or the legislature regarding the confidentiality of IOU procurement information.

15 Federal Energy Regulatory Commission 210(m) Application

15.1 PURPA §210(m) Application at the FERC⁶

- 15.1.1 The IOUs will submit a joint application under Section 210(m) of PURPA and 18 C.F.R. §§ 292.309 – 292.310 to FERC (“Joint Application”) requesting a termination of the PURPA purchase requirement.
- 15.1.2 The IOUs will provide the other parties to the Settlement including QFs who are members of the CHP Parties’ organizations (“Other Parties to the Settlement”) an opportunity to review and provide comment to the IOUs on the Joint Application prior to it being filed and the IOUs will use good faith in considering and incorporating comments consistent with the Settlement.
- 15.1.3 The Joint Application shall be filed under 210(m)(1)(C). The Joint Application will reference the following four components to demonstrate that the application meets the statutory requirements of Section 210(m)(1)(C): MRTU, RA Capacity, RPS Program, and CHP Program Settlement.
- 15.1.4 The Other Parties to the Settlement will have the right to intervene and file comments on the Joint Application, but will not protest nor otherwise oppose the termination of the PURPA purchase obligation, consistent with Section 15.1.3 above. Nothing herein prohibits the IOUs from filing a reply to comments consistent with Section 15.1.3.

⁶ Order 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, 117 FERC ¶ 61,078 (2006).

- 15.1.5 The Other Parties to the Settlement will provide the IOUs an opportunity to review and provide comment to the Other Parties to the Settlement on their respective comment on the Joint Application prior to the comment being filed and the Other Parties will use good faith in considering and incorporating comments consistent with the Settlement.
- 15.1.6 The Joint Application will not be filed until after the CPUC issues a decision approving or disapproving the Settlement.
- 15.1.7 Subject to the situations described in Sections 15.1.9, 15.1.10, and 15.1.12 below, the IOUs and the Other Parties to the Settlement (collectively, the IOUs and the Other Parties to the Settlement, “the Parties”) agree that all advocacy in all forums will be consistent with the Settlement, the Joint Application, and Section 15.1.3.
- 15.1.8 The Parties reserve their rights to seek rehearing and appeal a FERC decision granting or denying the Joint Application.
- 15.1.9 If a non-settling party protests or otherwise opposes the Joint Application, nothing herein prohibits the Parties from replying. In addition, the Parties shall: (1) meet and confer within three (3) days to determine if they can reach agreement on advocacy positions consistent with the Settlement, the Joint Application and Section 15.1.3; and (2) make a good faith effort to agree on bases for advocacy within seven (7) days consistent with the Settlement, the Joint Application, and Section 15.1.3; thereafter, including requesting that FERC convene a Settlement Conference under Rule 601. If the Parties are unsuccessful in reaching resolution of advocacy positions as contemplated by this section, each Party shall have the right to file in support or opposition to the protest consistent with the Settlement, the Joint Application and Section 15.1.3.
- 15.1.10 The Other Parties to the Settlement do not waive the right to file at FERC for a reinstatement of a particular IOU’s PURPA purchase obligation if the IOU breaches its obligations under the Settlement or the CHP Program adopted in the Settlement is not successfully implemented, based upon the IOU’s failure to meet the targets established by the CPUC pursuant to the Settlement, without justification as provided for in the Settlement. The Other Parties to the Settlement cannot file for a reinstatement until the CPUC or the Energy Division Director makes a determination in writing that the IOU’s failure to meet the targets was not justified. The Other Parties to the Settlement shall not file for a reinstatement of a particular IOU’s PURPA purchase obligation earlier than the announcement of the results of the second RFO for that IOU. The IOUs retain the right to argue that termination of the PURPA purchase requirement should be sustained and/or that relief should be solely on the basis of Section 210(m)(1)(A) in response to a reinstatement filing.
- 15.1.11 If at any time , after the Section 201(m)(1) termination has been granted by FERC, a filing is made at FERC, or any other applicable authority, by a third party seeking relief from the Section 210(m)(1) termination or reinstatement of the IOU PURPA purchase obligation, or any successor provision, the Parties shall: (1) meet and confer within five (5) days to determine if they can reach agreement on advocacy positions; and (2) make a good faith effort to agree on bases for advocacy within five (5) days thereafter that will preserve the grounds for termination set forth in Section 15.1.3, above. If the Parties are unsuccessful in reaching resolution of advocacy positions as contemplated

by this section, each party shall have the right to file in support or opposition to the filing seeking relief from the termination.

15.1.12 .If the Joint Application is denied, the IOUs reserve the right to file a new application that does not comply with the procedures set forth above.

15.2 FERC Reinstatement of PURPA Obligation

15.2.1 If FERC reinstates the IOUs' obligation to purchase pursuant to Section 210(m) then the following applies:

15.2.1.1 SRAC pricing stays in place until changed by the CPUC.

15.2.1.2 The amendments signed by Legacy QFs stay in place for the term of the amendments without change, including SRAC contained in such amendments.

15.2.1.3 Parties may advocate for changes to SRAC pricing.

15.2.1.4 Prior claims for and challenges to retroactive price adjustments cannot be revived, but Parties may advocate for retroactive adjustments to SRAC pricing in accordance with existing Court and CPUC decisions unless and until modified by the Courts or CPUC and may petition or otherwise advocate for changes in rules and decisions on retroactive adjustments.

15.2.1.5 If the CPUC sets SRAC at a market-based price, excluding certain administrative adjustments such as O&M adders, there will be no retroactive pricing for the period such market-based SRAC formula is in effect. However, the IOUs may adjust payments to QFs based on other issues that arise in the administration of the PPAs, *e.g.*, billing errors, metering errors, fraud.

15.2.1.6 If the CPUC sets SRAC at a price based in whole or in part on administrative or non-market based components, excluding certain administrative adjustments such as O&M adders, rather than a market-based price SRAC, Parties may advocate for a return to a market-based SRAC price and may advocate for the retroactive application of an adopted market-based SRAC pricing change in accordance with existing Court and CPUC decisions unless and until modified by the Courts or CPUC.

15.2.1.7 Obligations to conduct additional CHP RFOs or conduct alternative CHP Procurement Processes under the Settlement shall be suspended, including the MW Targets and GHG Emissions Reduction Targets; provided the CPUC may on grounds other than the Settlement direct the procurement of CHP resources. CHP PPAs executed prior to the suspension remain in full force and effect. Any procurement targets to be established by the CPUC in the LTPP remain in place unless and until modified by the CPUC in a subsequent proceeding.

15.2.1.8 Designation of Legally Enforceable Obligation under Section 210(m). The Parties agree that any existing CHP PPA, any existing extension agreements, and any Standard Offer PPA or Pro-Forma PPA executed pursuant to this Settlement will constitute a legally-enforceable obligation as provided in Section 210(m).

16 Conditions Precedent and Subsequent to Settlement Effective Date

16.1 Approval of Settlement by CPUC

- 16.1.1 This Settlement shall be submitted and approved in all open QF dockets. This Settlement resolves all open and pending issues in all the following open dockets: R.04-04-003, R.04-04-025, A.08-11-001, R.99-11-022, R.06-02-013.

16.2 Conditions Precedent to Effectiveness of the Settlement

- 16.2.1 Final and non-appealable FERC approval of the IOUs' application to terminate their PURPA purchase obligation, subject to reinstatement in accordance with Section 210(m);
- 16.2.2 Final and non-appealable approval of the Settlement by the CPUC as submitted for approval without revisions unacceptable to any Party or in an alternative form that is acceptable to all Parties;
- 16.2.3 As part of the Settlement approval process, CARB support, in written form, for the Settlement. Examples of such support can be, but are not limited to, pleadings, comments to the CPUC or a letter of support. CARB support must be provided to the CPUC no later than CPUC approval of this Settlement;
- 16.2.4 The CPUC Decision adopting the Settlement will supersede certain portions of existing CPUC decisions as occurs with any subsequent CPUC decision or order;
- 16.2.5 D.06-07-029 and D.08-09-012 are superseded as follows: (1) the relevant costs (either "above market costs" or "net capacity costs" as appropriate) of this CHP Program can be recovered through Non-Bypassable Charges consistent with Section 13 herein; and (2) the same relevant costs of new PPAs entered into pursuant to the CHP Program can be recovered through Non-Bypassable Charges for up to twelve (12) years consistent with Section 13 herein.
- 16.2.6 The Procurement obligations in this Settlement and under the RPS Program supersede and replace the QF MWs in D.07-12-052.
- 16.2.7 All Parties will execute and be bound by the Settlement on the Settlement Effective Date and shall support and defend this Settlement in all forums, including but not limited to the CPUC, FERC, CEC, CARB and the federal and state Legislature. CCC, CAC and EPUC will sign on behalf of their members and an appendix to the Settlement will contain the names of all of the current members of each of the organizations and each such member will be bound by the Settlement. IEP members and other QFs will have the option to sign a QF PPA amendment, which will include agreement to be bound by the Settlement. An amendment or execution of the Settlement will not be required to bind the members of CCC, CAC and EPUC. CCC, CAC and EPUC will represent that it is authorized to represent each listed member and that it has provided a copy of the Settlement to each of its members.
- 16.2.8 To the extent the Generating Facility has Green Attributes associated with the Related Product (as Green Attributes and Related Product are defined in each of the form PPAs

attached to this Settlement), such Green Attributes shall be counted or credited toward the purchasing IOU's RPS Program or any successor program.

16.3 Conditions Subsequent to Effectiveness of Settlement

- 16.3.1 If CARB subsequently adopts regulations directly imposing a MW Target or GHG Emissions Reduction Target that differs from the Settlement for the Second Program Period, the IOUs' obligations to purchase from CHP to meet the MW Target or GHG Emissions Reduction Target will remain in place until such time as the CPUC is able to consider such change in an LTPP or other pertinent proceeding.

17 Glossary of Defined Terms

AB 1613 Feed-In Tariff: As defined in Section 4.4.1.

Actual HR: The Heat Rate that must be used in accordance with and subject to the terms set forth in Section 10.2.2.2, which Heat Rate Buyer shall calculate, on the date of the commencement of the First Compliance Period, using the following formula:

Actual HR = The average of the Daily HR_n for each delivery or flow date in the two (2) year period immediately preceding the commencement of the First Compliance Period

Where:

$$\text{Daily } HR_n = [EP_n - VOM_n] / [GP_n + GT_n]$$

Where:

EP_n = The average of the Day Ahead hourly electric energy prices, as determined by the Integrated Forward Market (as defined in the CAISO Tariff) for (i) SP15 Existing Zone Generation Trading Hub (formerly known as SP15), or its successor, if Buyer is SCE or SDG&E, and (ii) NP15 Existing Zone Generation Trading Hub (formerly known as NP15), or its successor, if Buyer is PG&E;

VOM_n = Calendar month avoided variable O&M for the applicable month (\$/kWh), per D.07-09-040 and CPUC Resolution E-4246 (as such Resolution may be modified from time to time by the CPUC);

GP_n = The applicable daily gas price index, which is (i) Platt's Gas Daily (currently SoCalGas gas indices) if Buyer is SCE or SDG&E, or (ii) Platt's Gas Daily (currently SoCalGas and PG&E Malin gas indices), if Buyer is PG&E; and

GT_n = The gas transportation rate for the applicable month, per CPUC Resolution E-4246 (as such Resolution may be modified from time to time).

Additional GHG Documentation: Documentation necessary to allocate Free Allowances to energy delivered by Seller to Buyer, which documentation consists of the following, in each case for the time-period to which the Free Allowances are to apply: (a) the total amount of GHG emissions attributable to the Generating Facility, the electrical energy used to serve the Site Host Load, the Useful Thermal Energy Output of the Generating Facility; and the energy delivered to Buyer; (b) the Useful Thermal Energy Output of the Generating Facility; (c) the total electrical energy produced by the Generating Facility, the electrical energy used to serve the Site Host Load, and the energy delivered to Buyer; and (d) total fuel usage of the Generating Facility.

Allowance: A limited tradable authorization (whether in the form of a credit, allowance or other similar right), allocated to, issued to or purchased by, Seller, the Site Host or a Related Entity of Seller, with respect to the Generating Facility, to emit one MT of GHG, in accordance with a cap-and-trade program in California for the regulation of GHG, as

established by CARB (and/or by a different Governmental Authority pursuant to federal or state legislation), and as applied to the GHG emitted by the Generating Facility.

AMW: For purposes of this Settlement, the average MW deliveries from the Optional As-Available PPAs as determined in accordance with Section 4.6.2.10.3.

AMW CAP: There is a cap on energy deliveries from all of the Optional As-Available PPAs measured in AMW. The AMW Cap shall be: PG&E: 75 AMW, SCE: 75 AMW, SDG&E: 10, as defined in Section 4.6.2.10.2.

Annual GHG Reports: As defined in Section 10.3.1.

Applicable NDA: As defined in Section 9.1.4.

Applicable PPA: Any power purchase agreement between Buyer and Seller that requires Buyer to calculate the energy payment due to Seller under such agreement in whole or in part based on SRAC.

Availability Incentive Payments: As defined in the CAISO Tariff.

Availability Standards: As defined in the CAISO Tariff.

Baseline: Specific to GHG Accounting, as defined in Section 7.3.1.3.

Bottoming Cycle CHP: A cogeneration facility in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for power production, and as otherwise provided in 18 CFR Section 292, *et seq.*

Burner Tip Gas Price: As determined in CPUC Decision 07-09-040 and CPUC Resolution E-4246 (as such Resolution may be modified from time to time by the CPUC).

Business Day: Any day except a Saturday, Sunday, the Friday after the United States Thanksgiving holiday, or a Federal Reserve Bank holiday that begins at 8:00 a.m. and ends at 5:00 p.m. local time for the Party sending a notice or payment or performing a specified action.

Buyer: The party responsible for purchasing electric energy, capacity or other power products delivered by Seller in a PPA.

CAISO: The California Independent System Operator Corporation or successor entity.

CARB: The California Air Resources Board, or any successor entity.

CARB Mandatory GHG Emissions Annual Report: Reporting of greenhouse gases by major sources is required by the California Global Warming Solutions Act. The Air Resources Board approved a mandatory reporting regulation in December 2007, which became effective January 2009. See Section 10.3.1.1.

CARB CHP Recommended Reduction Measure or RRM: As referenced on pages 43-44 of the "Approved Scoping Plan" adopted by the CARB at its December 11, 2008 Board meeting. http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

CARB Scoping Plan: the “Approved Scoping Plan” adopted by the CARB at its December 11, 2008 Board meeting.

http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

CAISO Tariff: The CAISO Operating Agreement and Tariff, including the rules, protocols, procedures and standards attached thereto, as the same may be amended or modified from time to time and approved by the FERC, or any successor entity.

CAISO-Approved Quantity: The total quantity of electric energy that Buyer Schedules with the CAISO and the CAISO approves in its final schedule which is published in accordance with the CAISO Tariff.

CCA or Community Choice Aggregator: Any city, county, or city and county, or group of cities, counties, or cities and counties, whose governing board or boards elect to combine the loads of their residents, businesses, and municipal facilities in a community wide electricity buyers’ program, as specified in Public Utilities Code §331.5.

CEC: California Energy Commission.

CHP: Combined Heat and Power system or cogeneration means the sequential use of energy for the production of electrical and useful thermal energy (Public Utilities Code §216.6). As defined in Section 1.1.1.

CHP Auditor: As provided in Section 9.

CHP Facility or CHP Facilities: A facility that meets the federal definition of a qualifying cogeneration facility under 18 C.F.R. §292.205.

CHP Party or CHP Parties: Any of the following associations, or an individual member of or group of individual members of such associations – California Cogeneration Council (CCC), Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC); the Independent Energy Producers Association (IEP); and Sellers that execute the Legacy PPA Amendment.

CHP Program Semi-Annual Report: As defined in Section 8.1.1.

CHP Procurement Processes: Procurement processes for CHP resources by the IOUs that count toward the MW and/or GHG Emissions Reduction Targets as specified in the Settlement. These include the CHP RFO PPAs, bilaterally negotiated and executed CHP PPAs, the AB 1613 Feed-In Tariff, QF Standard Offer CHP PPAs for eligible CHP Facilities pursuant to PURPA, Optional As Available PPAs for eligible CHP Facilities, certain IOU-owned CHP, existing CHP that converts to a Utility Prescheduled Facility, and new behind the meter CHP.

CHP QF Compliance Monitoring Program: The existing CPUC QF Compliance Monitoring Program, established by Decision 91-05-007.

CHP RFOs: As defined in Section 4.2.1.

CHP RFO Pro-Forma PPA: As defined in Section 4.2.6.

Capacity Demonstration Test: Buyer shall conduct a Capacity Demonstration Test of the Generating Facility under the CHP PPA to determine the MW to count towards the MW Targets. The Capacity Demonstration Test shall be conducted as defined in the attached PPAs.

Confidential Information: All oral or written communications exchanged between the Parties on or after the Settlement Effective Date relating to the implementation of the CHP PPA, including information related to Seller's compliance with operating and efficiency standards applicable to a qualifying cogeneration facility or fuel use standards applicable to a qualifying small power production facility. Confidential Information does not include (i) information which is in the public domain as of the Settlement Effective Date or which comes into the public domain after the Settlement Effective Date from a source other than from the other Party, (ii) information which either Party can demonstrate in writing was already known to such Party on a non-confidential basis before the Settlement Effective Date, (iii) information which comes to a Party from a bona fide third-party source not under an obligation of confidentiality, or (iv) information which is independently developed by a Party without use of or reference to Confidential Information or information containing Confidential Information.

CPUC: the California Public Utilities Commission.

CPUC Jurisdictional Entities: the IOUs, ESPs and CCAs.

D.: A CPUC Decision.

DA: Direct Access. As defined in Section 6.3.1.

Day-Ahead: As defined and may be modified in the CAISO Tariff.

Day-Ahead Market: The forward market for energy and ancillary services to be supplied during the settlement period of a particular Trading Day that is conducted by the CAISO, and other Scheduling Coordinators. This market closes with the CAISO's acceptance of the final Day-Ahead Schedule.

Day-Ahead Schedule: A schedule prepared by a Scheduling Coordinator or the CAISO before the beginning of a Trading Day. This schedule indicates the levels of generation and demand scheduled for each settlement period of that Trading Day.

Departing Load Customers: Includes CGDL, TMDL and NMDL customers as defined in SCE's existing DL-NBC, CGDL-CRS, TMDL and NMDL tariff schedules; as CGDL, TMDL, and NMDL in PG&E's existing E-DCG, E-NMDL and E-TMDL tariff schedules; and in SDG&E's existing E-DEPART tariff schedules.

Designated Capacity Product: As defined in Section 3.4.1.2.

Direct Access Customers: Customers located within the IOU Service Territory of an IOU who purchase electricity from an ESP.

Double Benchmark: The Double Benchmark measures the amount of GHG emissions that otherwise would exist if the CHP Facility did not exist. The Double Benchmark, which may be later modified pursuant to this Settlement, contains the following assumptions:

(a) the heat rate for the electricity generated is 8,300 BTU/kWh at the busbar and excluding line losses; and (2) the thermal efficiency of a standard boiler is 80%.

Efficiency Performance Deficiency: Failure to meet annual efficiency requirements under the terms of the PPA, as defined in Section 4.2.9.

Efficiency Performance Requirement: A contractual requirement to meet certain levels of efficiency as defined in the PPA or AB 1613 Feed-In Tariff.

Emergency Condition: As set forth in the Transmission Provider's LGIA, SGIA or other distribution-level FERC-jurisdictional interconnection agreement with Seller, as applicable; *provided, however*, that if Seller interconnects pursuant to Tariff Rule 21, "Emergency Condition" means "Emergency", as defined in such Tariff Rule 21.

Emissions Performance Standard or EPS: The Emissions Performance Standard adopted by the CPUC in D.07-01-039 and as it may be revised in subsequent decisions.

ESP or Electric Service Provider: An entity that is licensed by the CPUC to provide electric power service to Direct Access Customers under Public Utilities Code §§218.3 and 394, or subsequent statutes.

Existing CHP Facility(ies): An Existing CHP Facility is one that was operational before the Settlement Effective Date.

Expanded CHP Facilities: Means (i) an existing topping-cycle CHP Facility that, on or after the Settlement Effective Date, has added at least one new combustion turbine and increased the Power Rating of the Generating Facility by not less than 90% of the Power Rating of the largest existing combustion turbine at the Generating Facility, or (ii) an existing bottoming-cycle CHP Facility that has increased its total Power Rating by at least 30% as compared to the Power Rating before such expansion.

EWG or Exempt Wholesale Generator: An unregulated power generator that is allowed to sell wholesale power as an independent energy producer, and is exempt from the Public Utility Holding Company Act of 1935.

FERC: The Federal Energy Regulatory Commission, or successor agency.

First Compliance Period: The first period of time for compliance with a cap-and-trade program in California for the regulation of GHG, as established by CARB (and/or by a different Governmental Authority pursuant to federal or state legislation). There will be no more than a single First Compliance Period.

Floor Test Term: From the date the First Compliance Period commences for a period of three (3) years.

Free Allowance: Any Allowance freely allocated to Seller or the Generating Facility by CARB or an authorized Governmental Authority (or any entity authorized by such Governmental Authority).

Free Allowance Notice: The notice, delivered by Seller to Buyer in accordance with the Applicable PPA, that sets forth the aggregate quantity of Free Allowances received by

Seller during the applicable time-period and sets forth the allocation of such Free Allowances in accordance with the following:

- (i) The allocation of Free Allowances by CARB (or any other Governmental Authority) to the energy generated by the Generating Facility and delivered to Buyer during the applicable time-period; or
- (ii) If CARB (or any other Governmental Authority) does not allocate Free Allowances received by Seller as described in subsection (i) above, then Seller shall set forth in the Free Allowance Notice the quantity of Free Allowances allocated to the energy generated by the Generating Facility and delivered to Buyer during the applicable time-period (FA_d) utilizing the following formula:

$$FA_d = FA_t * [G_e / (G_e + G_t)] * [E_d / (E_{sh} + E_d)]$$

Where:

FA_t = Total number of Free Allowances received by Seller with respect to the Generating Facility for the applicable time-period;

G_e (in MTs) = Emissions of GHG attributed to the total amount of electric energy produced by the Generating Facility for the applicable time-period (calculated in accordance with the formula set forth in Section 95112 of the California Code of Regulations, or any successor thereto, which calculation must be set forth in the Free Allowance Notice);

G_t (in MTs) = Emissions of GHG attributed to the Useful Thermal Energy Output produced by the Generating Facility for the applicable time-period (calculated in accordance with the formula set forth in Section 95112 of the California Code of Regulations, or any successor thereto, which calculation must be set forth in the Free Allowance Notice);

E_d (in kWh) = Energy generated by the Generating Facility and delivered to Buyer for the applicable time-period; and

E_{sh} (in kWh) = Electric energy generated by the Generating Facility and used to serve the Site Host Load for the applicable time-period; or

- (iii) If the CARB (or any other Governmental Authority) does not allocate the Free Allowances received by Seller, as described in (i) above, and there is no available formula in any applicable rule or regulation for the calculation of G_e and G_t , as described in (ii) above, then Seller shall include in the Free Allowance Notice the total amount of emissions of GHG attributed to the electric energy period (G_e , in MTs) and the Useful Thermal Energy Output (G_t , in MTs) produced by the Generating Facility for the applicable time-period based on the two following formulas:

$$G_e = G * (\text{Useful Power Output} / (\text{Useful Power Output} + \text{Useful Thermal Energy Output}))$$

$$G_t = G * (\text{Useful Thermal Energy Output} / (\text{Useful Power Output} + \text{Useful Thermal Energy Output}))$$

Where:

G (in MTs) = Total emissions of GHG produced by the Generating Facility for the applicable time-period;

Useful Power Output (in MMBtu) = As defined in 18 CFR §292.202(g), or any successor thereto;

Useful Thermal Energy Output (in MMBtu) = As defined in 18 CFR §292.202(h), or any successor thereto;

Upon determining G_e and G_t in subsection (iii) above, Seller shall then calculate for and provide the quantity of Free Allowances attributed to energy generated by the Generating Facility and delivered to Buyer for the applicable time-period (FA_d) using the formula set forth in subsection (ii) of this definition.

Forced Outage: As set forth in the CAISO Tariff.

Forecast: The hourly forecast of (i) the total electric energy production of the Generating Facility (in MWh) when the Generating Facility is not PIRP-eligible, or (ii) the available total generation capacity of the Generating Facility (in MW) when the Generating Facility is PIRP-eligible, in each case net of the Site Host Load and Station Use.

Generating Facility: Seller's electric energy production facility set forth in the PPA.

GHG Auction: Any auction or other sale-by-bid event applicable to California and by an authorized Governmental Authority (or any entity authorized by such Governmental Authority) for the sale of Allowances.

GHG Charges: Means all taxes, charges or fees, assessed with the implementation and regulation of Greenhouse Gas emissions with respect to the Generating Facility imposed by any Governmental Authority, such as the CARB's AB 32 Cost of Implementation Fee (as defined in Title 17 C.C.R. §95200). For example, if the charges are assessed on but not included in fuel consumption or gas costs, the Applicable Heat Rate or Burner Tip Gas Price will be used to derive the dollars per kilowatt-hour charge. On January 1, 2015 or the commencement of the First Compliance Period, the GHG Charges will equal zero in the above formula.

GHG Compliance Costs: The cost of Allowances, as determined in accordance with Section 10.2.

GHG Credit: A positive GHG Emissions Reduction from a Generating Facility as defined in Section 7 of the Settlement.

GHG Debit: An increase in GHG emissions from a Generating Facility as defined in Section 7 of the Settlement.

GHG Emissions Reduction Target: The procurement targets defined in Section 6.

GHG Floor Test: As defined in Section 10.2.2.

Governmental Authority: Any governmental authority responsible for the regulation of GHG in California, including (i) any federal, state, local, municipal or other governmental authority, (ii) any governmental, regulatory or administrative agency, commission, lawfully exercising or entitled to exercise any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power, or (iii) any court or governmental tribunal.

Greenhouse Gas or GHG: Emissions released into the atmosphere of carbon dioxide (CO₂), nitrous oxide (N₂O) and methane (CH₄), which are produced as the result of combustion or transport of fossil fuels. Other greenhouse gases may include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF₆), which are generated in a variety of industrial processes. Greenhouse gases may be defined or expressed in terms of a MT of CO₂-equivalent, in order to allow comparison between the different effects of gases on the environment; *provided, however*, that the definition of the term 'Greenhouse Gas', as set forth in the immediately preceding sentence, shall be deemed revised to include any update or other change to such term by CARB and/or any other Governmental Authority.

Heat Rate: For purposes of this Settlement, the value obtained, in BTU per kWh, when the fuel input, on a Higher Heating Value basis, in BTU is divided by generation, net of Station Use, in kWh.

Higher Heating Value or HHV: The high or gross heat content of the fuel with the heat of vaporization included; the water vapor is assumed to be in a liquid state.

Hour-Ahead Scheduling Deadline: Thirty (30) minutes before the deadline established by the CAISO for the submission of schedules for the applicable hour.

IE or Independent Evaluator: The duties of an IE are generally described in CPUC D.07-12-052 at pp. 136-142.

Initial Program Period: The period commencing on the Settlement Effective Date and concluding forty-eight (48) months thereafter.

Initial Forecast Month: The first calendar month for which Seller provides to Buyer a 30-day Forecast pursuant to Section 11.3, which must be the first calendar month commencing no earlier than 30 days after Settlement Effective Date and no later than 60 days after such date.

IOU: An investor owned-utility, including PG&E, SCE and SDG&E.

IOUs: PG&E, SCE and SDG&E collectively.

Joint Application: As defined in Section 15.1.1.

July 2010 Semi-Annual Report: Each IOU's July 2010 Cogeneration and Small Power Production Semi-Annual Reports, as defined in Section 6.2.1.1.

Legacy PPA(s): All Existing QF or CHP PPAs, including extensions of such PPAs, in force and effect on the Settlement Effective Date with any IOU that has not expired by its terms and conditions, excluding PPAs entered into pursuant to the RPS Program.

Legacy PPA Amendment: An amendment to a Legacy PPA which is attached to this Term Sheet as Exhibits 1, 2, and 3.

LGIA (Large Generator Interconnection Agreement or Standard Large Generator Interconnection Agreement): As set forth in the CAISO Tariff.

Legacy PPA C1 Amendment: An amendment to a Legacy PPA which allows the IOU to schedule operations of the CHP Facility or Utility Prescheduled Facility.

Locational Marginal Price: As defined and may be modified in the CAISO Tariff.

LTTP: The CPUC's Long-Term Procurement Plan proceeding for the IOUs, or its successor proceeding.

Market: The MIF calculation adopted in D.07-09-040 and Resolution E-4246 with 100% Market Heat Rate and 0% Administrative Heat Rate. Market Heat Rates shall be defined as provided in Resolution E-4246. The Parties agree to rely on the 12-month forward indices adopted by the CPUC in Resolution E-4246, unless the direction to use such indices is modified by the CPUC.

Market Disruption Event: With respect to any MHR Source, any of the following events: (i) the permanent discontinuation or material suspension of trading in the exchange or in the market specified for determining a Market Heat Rate; (ii) the temporary or permanent discontinuance or unavailability of the MHR Source; or (iii) the temporary or permanent closing of any exchange specified for determining a Market Heat Rate. For purposes of this definition, "temporary" means five (5) or more continuous Trading Days.

Market Heat Rate: The 12-month forward market heat rate, calculated for each calendar pricing month utilizing the methodology set forth in CPUC D.07-09-040 and CPUC Resolution E-4246 (as such Resolution may be modified from time to time by the CPUC) for (i) SP15 Existing Zone Generation Trading Hub (formerly known as SP15), or its successor, if Buyer is SCE or SDG&E, and (ii) NP15 Existing Zone Generation Trading Hub (formerly known as NP15), or its successor, if Buyer is PG&E.

Megawatt (MW): One thousand kilowatts (1,000 kW) or one million (1,000,000) watts.

Megawatt Hour (MWh): One thousand kilowatt-hours.

MRTU: The Market Redesign and Technology Upgrade implemented by CAISO on April 1, 2009.

MHR Source: The relevant publications used to determine the Market Heat Rate.

MMT: Million Metric Tons.

MT(s): Metric Ton(s)

MW Target(s): As provided in Section 5.

NDA: Non Disclosure Agreement as defined in Section 9.1.4 and attached as Exhibit 8.

Net MW Targets: MW Targets in each RFO in the Initial Program Period.

New MW Target(s): As defined in Section 5.1.4.1.

New CHP Facility: A CHP Facility that became operational after the Settlement Effective Date.

Non-Availability Charges: As defined in the CAISO Tariff.

Non-Bypassable Charge: A charge to Departing Load Customers to recover the costs of PPAs entered into by an IOU for their benefit while they were IOU bundled customers.

Non-IOU LSE: A load serving entity other than PG&E, SCE, and SDG&E. See Section 6.3.1.

Optional As-Available Program: Available for generators that deliver less than 20 MW, on average to the Buyer, as provided in Section 4.6.

Optional As-Available PPA: A PPA option for CHP generators that deliver less than 20 MW, on average, to the Buyer, as provided in Section 4.6, and the form of which is attached to this Settlement as Exhibit 7.

Other Parties to the Settlement: As defined in Section 15.1.2.

PIRP (Participating Intermittent Resource Program): The CAISO's intermittent resource program initially established pursuant to Amendment 42 of the CAISO Tariff in FERC Docket ER02-922-000, or any successor program that Buyer determines accomplishes a similar purpose.

PG&E: Pacific Gas and Electric Company.

Party: A single party to the Settlement from among CCC, CAC, EPUC, IEP, PG&E, SCE, SDG&E, TURN, and DRA.

Parties: CCC, CAC, EPUC, IEP, PG&E, SCE, SDG&E, TURN, DRA.

PNode: As defined in the CAISO Tariff.

POUs: Publicly-owned utilities including municipal utilities (utilities owned by branches of local government) and/or co-ops (utilities owned cooperatively by customers).

Power Rating: The electrical power output value indicated on the generating equipment nameplate.

PPA: A power purchase agreement between a Seller and Buyer.

PRG: The group of non-market participants established in D.02-08-071 as an advisory group to review and assess the details of the IOUs' overall procurement strategy, RFOs, specific proposed procurement contracts and other procurement processes.

PURPA: The Public Utility Regulatory Policies Act of 1978, as amended, 16 U.S.C. §§823a, 2601, *et seq.*

QCRs: IOU Quarterly Compliance Reports submitted to the CPUC.

Qualifying Facility or QF: An electric energy generating facility that complies with the qualifying facility definition established by PURPA and any FERC rules as amended from time to time (18 Code of Federal Regulations Part 292, Section 292.203 *et seq.*) implementing PURPA and has filed with FERC (i) an application for FERC certification, pursuant to 18 Code of Federal Regulations Part 292, Section 292.207(b)(1), which FERC has granted, or (ii) a notice of self-certification pursuant to 18 Code of Federal Regulations Part 292, Section 292.207(a).

QF PPA: A PPA with standard terms and conditions for a QF with a nameplate capacity of 20 MWs or less.

Real-Time Forced Outage: A Forced Outage which occurs only after 5:00 p.m. California time on the day before a Trading Day impacted by such Forced Outage.

Reference Market-Maker: A leading dealer in the energy market that is not a Related Entity of either Party and that is selected by a Party in good faith among dealers of the highest credit standing which satisfy all the criteria that such Party applies generally at the time in deciding whether to offer or to make an extension of credit. Such dealer may be represented by a broker.

Related Entity: With respect to either Party, any individual or entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with such Party. For purposes of the Applicable PPA, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

Repowered CHP Facilities: A CHP Facility that, on or after the Settlement Effective Date, has had its prime mover(s) replaced or refurbished, as follows:

- If the CHP Facility contains combustion turbines, then each combustion turbine must be replaced with:
 - A new combustion turbine that has been certified as new by the original manufacturer of the equipment *provided, however*, that the CHP Facility that has replaced its combustion turbines with a substantially identical engine (e.g., as is common during major overhauls of aeroderivative combustion turbines or as part of a spare engine program), does not qualify as a Repowered CHP Facility; or
 - A refurbished combustion turbine, so long as such refurbished combustion turbine has been certified by the entity that refurbished such combustion turbine (which may be the manufacturer) to achieve Heat Rate and total power output performance guarantees comparable to a new combustion turbine, prior to operational degradation; or
- If the CHP Facility contains only steam turbines, then each steam turbine must be replaced with a refurbished steam turbine, which refurbishment must have been accomplished with new or near-new condition parts, and which include (i) a

replacement of all stop and throttle control valves, seals, bearing, rotors, and turbine blades of each steam turbine, and (ii) a replacement or rebuilding of the stationary part of each steam turbine back to new condition, including seal system, lube oil system and all associated piping and auxiliary equipment.

In addition to the above requirement, (1) the repowering of the Generating Facility as described in this definition must be completed before the Term State Date, (2) Section 1.02(a) of the CHP PPAs must provide that the Generating Facility will be a Repowered CHP Facility on the Term Start Date, and (3) Seller must provide to Buyer a written certification, including all supporting data, from a qualified independent engineer, which certification must provide that the total useful life of the CHP Facility (including, as applicable, the combustion turbine(s), the steam turbine(s), the electrical generator(s) and the heat recovery steam generator) will operate for at least the Term of this Agreement, subject to industry standard maintenance practices.

Resource Adequacy Benefit or RA Benefit: The resource adequacy benefits associated with the generating capability of the CHP Facility or Utility Prescheduled Facilities that can be used to meet the IOU's obligations under any CPUC resource adequacy Rulings. Resource Adequacy Benefits shall include any local, zonal or otherwise locational attributes associated with the CHP or Utility Prescheduled Facilities.

RPS Program: The State of California Renewable Portfolio Standard Program, as codified at California Public Utilities Code §399.11, *et seq.*

SCE: Southern California Edison Company.

Schedule: The action of Scheduling Coordinator, or its designated representatives, of notifying, requesting, and confirming to the CAISO, the CAISO-Approved Quantity of electric energy.

Scheduling Coordinator: Scheduling coordinators (SCs) submit schedules and bids and provide settlement-ready meter data to the CAISO.

SDD: Scheduling and Delivery Deviation as set forth in Exhibit K of each of the QF PPA, Transition PPA, Optional As-Available PPA, and CHP RFO PPA.

SDG&E: San Diego Gas & Electric Company.

Second Program Period: The period of time commencing from the end of the Initial Program Period and concluding on December 31, 2020.

Self-Generation: A generation facility dedicated to serving on site load or a particular retail customer, often located on the customer's premises. The facility may either be owned directly by the generator or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

Self Generation Incentive Program (SGIP): SGIP provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter.

Seller: The Party responsible for generating and delivering electric energy to Buyer in accordance with a PPA.

Service Territory: The state, area or region served principally by a single IOU, subject to service provided by ESPs and CCAs to customers in such state, area or region.

Settlement: That certain Settlement Agreement, dated October 8, 2010, filed by the Settling Parties in CPUC R.04-04-025, R.04-04-003, A.08-11-001, R.99-11-022, and R.06-02-013.

Settlement Effective Date: The date that is the later of the two following events: (1) final and non-appealable CPUC approval of the Settlement in its entirety in a form that is agreeable to each Party; and (2) a final and non-appealable order from FERC approving the IOUs' Joint Application to terminate their PURPA purchase requirement under Section 210(m) of the Energy Policy Act of 2005, 117 FERC ¶61,078 (2006).

Settlement Term: The period beginning on the Settlement Effective Date and ending December 31, 2020.

SGIA (Small Generator Interconnection Agreement): The form of Interconnection Request (as defined in the CAISO Tariff) pertaining to a Small Generating Facility (as defined in the CAISO Tariff), which is attached to the CAISO Tariff as Appendix T.

Site Host: The entity or entities purchasing or otherwise using the Site Host Load or Useful Thermal Energy Output from the Generating Facility.

Site Host Load: The electric energy and capacity produced by or associated with the Generating Facility that serves electrical loads (other than Station Use) of Seller or one or more third parties conducted pursuant to California Public Utilities Code §218(b).

SRAC or Short Run Avoided Cost: Short Run Avoided Cost, as set forth in Section 10.

SRAC Commencement Date: As defined in Section 10.2.

Standard Offer Contract or SOC: The QF PPA that was developed by the Parties in order to comply with D.07-09-040 and submitted for approval by the IOUs through Advice Letters PG&E AL 3197-E, SDG&E AL 1958-E, and SCE AL 2200-E, each as proposed to be modified by the CPUC in proposed final Resolution E-4242 dated September 10, 2009 and revised on October 20, 2009.

State CHP Program or CHP Program: The program established in this Settlement for CPUC-jurisdiction entities to procure from CHP Facilities and Utility Prescheduled Facilities.

Station Use: The electric energy produced by the Generating Facility that is (i) used within the Generating Facility to power the lights, motors, control system and other electrical loads that are necessary for Operation, (ii) consumed within the Generating Facility's electricity energy distribution system as losses needed to deliver electricity to the Site Host Load, and (iii) consumed within the generator collection system as losses between the generator(s) and the high voltage side of the Generating Facility output transformer(s)."

System Emergency: As set forth in the CAISO Tariff.

Tariff Rule 21: The interconnection standards of the Transmission Provider for distributed generation adopted by the CPUC in D.00-11-001 and D.00-12-037, as modified by the CPUC.

Tier 2 Advice Letter: As defined in the CPUC's General Order 96-B or its successor.

Tier 3 Advice Letter: As defined in the CPUC's General Order 96-B or its successor.

Topping Cycle CHP Facility: A cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the reject heat from the power production process is then used to provide useful thermal energy, and as otherwise provided in 18 CFR §292.205, *et seq.*

Trading Day: The day in which Day-Ahead trading occurs in accordance with the Western Electricity Coordinating Council's Preschedule Calendar (as found on the WECC's website).

Transition PPA: A short-term PPA between a CHP currently selling to an IOU under a Legacy PPA or extension thereof that begins on the expiration of the Legacy PPA and ends at the conclusion of the Transition Period, the form of which is attached to this Settlement as Exhibit 4.

Transition Period: The period beginning on the Settlement Effective Date and ending on July 1, 2015.

Transmission Provider: Any individual or entity responsible for the interconnection of the Generating Facility with the interconnecting utility's electrical system or the CAISO Controlled Grid or transmitting the Metered Energy (as defined in the PPAs attached to this Settlement) on behalf of the Seller from the Generating Facility to the Delivery Point (as defined in the PPAs attached to this Settlement).

Useful Thermal Energy Output: As defined in 18 CFR §292.202(h) and modified by the Energy Policy Act of 2005, or any successor thereto.

Utility Prescheduled Facility: An Existing CHP Facility that has changed operations to convert to a utility controlled scheduled dispatchable generation facility, including but not limited to an EWG.

Web Client: A Buyer provided Web based system or an email address designated by Buyer.