BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 08-08-009 (Filed August 21, 2008)

2010 RENEWABLE ENERGY PROCUREMENT PLAN
(DRAFT VERSION)

***** PUBLIC VERSION *****

CHARLES R. MIDDLEKAUFF
CORY M. MASON
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-6971
Facsimile: (415) 973-5520
Email: CRMd@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

June 2, 2010

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

2010 RENEWABLE ENERGY PROCUREMENT PLAN

JUNE 2, 2010
(Draft Version)

TABLE OF CONTENTS

TABLE OF CONTENTS

(CONTINUED)

TABLE OF CONTENTS

(CONTINUED)

TABLE OF CONTENTS

(CONTINUED)

1 Introduction and Overview of 2010 Plan

Pacific Gas and Electric Company's (PG&E) 2010 Renewables Portfolio Standard (RPS) Procurement Plan (2010 RPS Plan) describes the actions that PG&E will undertake to meet California's mandate of 20 percent renewable deliveries through procurement from resources that meet the RPS eligibility standards. In accordance with the options provided by the November 2, 2009, "Amended Scoping Memo and Ruling of Assigned Commissioner Regarding 2010 RPS Procurement Plan" (Scoping Memo), PG&E has elected to supplement its 2009 RPS Plan. PG&E has elected this alternative given the 2009 RPS Solicitation is still in relatively early stages of the process, where short-listing has been completed and negotiations are beginning.

PG&E is committed to achieving the 20 percent RPS goal through procurement and by using the provisions of flexible compliance adopted in Decision (D.) 03-06-071 and summarized in D.08-02-008.[1] However, achieving the goal remains challenging. While PG&E has executed contracts that represent over 20 percent of its future energy needs and continues to execute additional contracts for renewable energy, PG&E's ability to meet the targets depends upon timely delivery of this renewable energy. Tight credit markets and substantially reduced capital availability, however, are continuing to present a significant challenge for a number of renewable generation facility developers who have signed contracts with PG&E. In addition, the timely development of these and other renewable energy generation facilities is subject to many uncertainties and risks, including permitting and siting, technology, fuel supply, and the construction of sufficient transmission capacity. At both the federal and state levels, programs and measures are being implemented to provide alternatives to finance renewable projects, streamline

[1] SB 107 provides that flexible compliance shall apply in all years of the RPS program, including 2010. D.08-02-008 confirmed that flexible compliance applies to all years (D.08-02-008, p. 11, and Appendix D).

project permitting activities, and expedite transmission access. PG&E believes that these programs and measures, if successfully implemented, should promote the more timely completion and commercial operation of renewable facilities on which PG&E is relying to meet the 20 percent goal.

PG&E intends to hold a 2010 RPS Solicitation in concert with ongoing efforts to conclude procurement from its earlier solicitations. In past RPS solicitations, PG&E has indicated that it expected to procure one to two percent of its retail sales annually through the annual solicitation. PG&E is again considering procuring one to two percent of its retail sales through the 2010 RPS Solicitation; however there are several uncertainties that, when resolved, may provide additional clarity to PG&E's procurement process. These uncertainties include load migration, the modification of the sales forecast upon which PG&E's RPS mandate is based, and the CPUC's temporary limit on the use of tradable renewable energy credits (TRECs) for RPS compliance.

Public Utilities Code (Pub. Util. Code) Section 399.14(a) (3) requires that RPS Plans include both resource planning information and a bid solicitation in the form of commercial documents. PG&E's 2010 RPS Plan updates the following entries in its 2009 RPS Plan and contains the items identified in Attachment A of the Scoping Memo:

- Updated strategy for achieving the optimal mix of RPS resources, based upon supply and demand;
- Updates to modifiable standard terms and conditions;
- Updated transmission analysis, specifically, clarification of the transmission ranking cost report process and a new discussion of regional transmission planning initiatives;
- Updated work plan for reaching 20 percent by 2010, including an updated assessment of impediments to success;
- Updated exercise of opportunities to build and own renewable generation facilities;

- Efforts to coordinate with the other utilities;
- New report on the Imperial Valley Bidder's Conference;
- New proposal for the streamlined review of amendments of previously approved RPS contracts;
- New inclusion of TRECs authorized by D.10-03-021; and,
- New streamlined process for short-term procurement.

A summary of the important differences between the 2009 and 2010 RPS Plans is provided in Section 3 below.

Additionally, PG&E's 2010 RPS Plan and Solicitation Protocol incorporate changes based on the guidance provided by the Commission in D.09-06-018. PG&E proposes to conduct its 2010 RPS Solicitation using the planning and commercial documents set forth below:

Part A

- 2010 RPS Plan
  - Confidential Appendix A – PG&E's Executed Renewables Contracts Above the MPR
  - Appendix B – Summary of Changes to 2010 Form Power Purchase Agreement (PPA)
  - Confidential Appendix C – Evaluation of Imperial Valley Results

Part B

- 2010 Solicitation Protocol, Including Commercial Documents

The 2010 RPS Plan was developed in a manner consistent with the specific requirements of the Pub. Util. Code Section 399.14 (a)(3) and includes assessments and discussions of: (1) supply and demand to determine the optimal mix of RPS resources; (2) the use of flexible compliance mechanisms; and (3) a bid solicitation setting forth relevant need, online dates and locational preferences, as applicable. The 2010 RPS Plan also addresses the requirement set out in D.10-03-021 that the investor-owned utilities (IOUs) include in their 2010 RPS Procurement Plans information on how the utilities intend to utilize TRECs in meeting RPS goals. Finally, pursuant to D.10-04-052 and the *Administrative Law Judge's Ruling Regarding Amendment to PG&E's 2010 RPS Procurement Plan*, issued May 12, 2010, the 2010 RPS Plan addresses PG&E's Photovoltaic (PV) Program and, in particular, the information that should be used by PG&E and the Commission in evaluating bids received in the PV Requests for Offers (RFOs) for consistency with the 2010 RPS Plan.

1.1 Supply and Demand to Determine the Optimal Mix of RPS Resources

California's RPS program requires all IOUs to increase their procurement of renewable generation by at least 1 percent of retail sales annually, until 2010, when the total amount of renewable generation must account for 20 percent of their retail sales.

As PG&E noted in its 2009 RPS Plan, tight credit markets and substantially reduced capital availability have presented a significant challenge to those seeking to increase the availability of renewables to meet future electricity needs. This challenge persists, but PG&E is hopeful that the combination of American Recovery and Reinvestment Act (ARRA) stimulus funding and recent signs of nascent economic recovery will loosen credit markets and help renewable developers overcome the financial barriers to adding more renewable supply.

Adverse economic conditions have a temporary dampening effect on utility sales growth, which slightly reduces the amount of renewable electricity needed to comply with RPS mandates in the near-term. The California Public Utilities Commission (CPUC or Commission) has also recently modified the year upon which the compliance obligation is calculated, changing the calculation from a percentage of the prior year's retail sales to the current year's retail sales or, in this case, 2010. (See D.09-11-014.) This will mitigate the impact of the 2009 reduced sales on PG&E's RPS obligation. However, regardless of the year upon which the procurement obligation is calculated, it cannot compensate for non-delivery risks posed by other persistent barriers, specifically project permitting, transmission development, and financing.

Additionally, the CPUC issued D.10-03-021 on March 16, 2010, authorizing the use of TRECs for RPS compliance. The decision provides the IOUs with an additional means of meeting RPS procurement goals, but limits the amount of TRECs that the IOUs can use for compliance in 2010 and 2011 to 25% of the annual RPS requirement. The decision also effectively re-categorizes most out-of-state bundled transactions – previously considered "delivered" RPS-eligible energy – as REC-only and therefore subject to the temporary 25% cap. In its decision, the Commission stated that the TREC cap will sunset on December 31, 2011, and directed Energy Division staff to make a recommendation to the Commission within 16 months regarding whether the TREC cap should be retained or allowed to sunset. This provision leaves the emerging TREC market in a state of uncertainty and could impact the renewable supply options available to utilities for compliance with a 33% RPS.

1.1.1 The 2010 Procurement Goal is Contingent Upon Many Factors

In addition to its ongoing procurement activity related to earlier solicitations, PG&E intends to hold a 2010 RPS Solicitation for all RPS-eligible products, including REC-only transactions. PG&E will not hold a separate solicitation specifically for REC-only products in 2010.

PG&E's prior RPS plans have indicated that it would solicit renewable energy contracts equivalent to at least 1 to 2 percent of retail sales annually, a reflection of the CPUC's Incremental

Procurement Target (IPT). For the 2010 RPS Plan, the goal is similar and PG&E's strategy is to effectively address both the near-term 20 percent compliance mandate and the longer-term 33 percent state goal by balancing near-term compliance needs and longer-term portfolio expansion and maintenance. Accordingly, PG&E expects to solicit projects delivering up to 1 to 2 percent of retail sales, while maintaining flexibility in its procurement targets as clarity is sought on several factors that will affect PG&E's RPS procurement.

Factors affecting PG&E's RPS procurement include:

- **Load Migration** – Limited expansion of Direct Access (DA) is expected to occur in the 2010 to 2013 timeframe when the 20 percent RPS mandate takes full effect. The CPUC must resolve the question of how the departures to direct access will be phased over time so that PG&E is better able to forecast its sales, and its RPS obligation, in this period.
- **Changed Calculation of Annual Procurement Target** – Pursuant to D.09-11-014, PG&E's RPS obligation is to be calculated on current year's retail sales, starting in 2010. PG&E is assessing the impact of this change on its future procurement targets.
- **Results From the 2009 RPS Request for Offers** – Negotiations for contracts bid in the 2009 RPS Request for Offers (RFO) are only recently underway. PG&E is unable to predict the amount of renewable energy deliveries it will be able to secure from this solicitation.
- **Requirements for a 33 Percent RPS or Renewable Energy Standard** – It is unclear what the requirements will be for achieving the State's goal of 33 percent renewables by 2020.

- **Authorization to Use TRECs for RPS Compliance** – PG&E will consider REC-only products for the first time as part of its 2010 RPS Solicitation, but the attractiveness of such offers will be evaluated in the context of a TREC cap in 2010 and 2011.

1.1.2 2010 Procurement Will Address Both Near-Term and Long-Range RPS Goals

PG&E has executed a variety of near-term and longer-range contracts in its efforts achieve compliance with the 2010 RPS mandate. Since it is unlikely that new projects solicited in the 2010 RPS Solicitation will achieve commercial operation in time to contribute to the 20 percent by 2010 goal, PG&E expects plans to shift its focus to longer-range contracts that contribute to on-schedule fulfillment of a 33 percent RPS goal in 2020, while continuing to pursue short-term contracts to meet its 2010 requirement. PG&E is also moving ahead with implementation of its PV Program, approved by the CPUC in D.10-04-052, that is designed to stimulate development of up to 500 MW of small and medium-scale PV installations over a five-year timeframe. Of course, if additional low-cost, high-viability project opportunities with near-term delivery dates present themselves, and meet PG&E's evaluation criteria, PG&E will consider contracting for those additional renewable resources to bolster its near-term compliance position and increase the amount of renewable energy it can deliver to its customers.

In addition to California's RPS mandates, PG&E's 2010 RPS Plan is driven by its longer-range electric procurement needs as determined through its long-term planning process and subsequent updates. The key renewable generation supply assumptions used in formulating the 2009 RPS Plan are reiterated here for the 2010 Plan:

- Flexible Compliance will be used to achieve the 2010 RPS goal, as actual deliveries of 20 percent (or more) are estimated to occur in the 2013 timeframe.
- A 75 percent average contract renewal rate is assumed for all existing RPS contracts.
- A generic procurement resource mix from future solicitations.
- Project development lead times (from solicitation to delivery) will consist of four to six years, with wind projects estimated to come online the earliest.
- Forecasted future deliveries assume that all relevant transmission interconnection and permitting issues will have been resolved.
- Utilities will be allowed to procure some amount of TRECs for RPS compliance through 2020.

1.1.3 Anticipated Renewable Energy Technologies

Market forces are the principal factors determining PG&E's renewables product mix, which can change significantly from one solicitation to the next.

1.2 Bid Solicitation Needs, On-Line Dates, and Locational Preferences

In its 2010 RPS Solicitation, PG&E is seeking energy, capacity, and TRECs to meet its RPS obligations and resource adequacy requirements. PG&E is seeking offers for deliveries commencing in 2011 or beyond. Projects with characteristics that merit a higher viability score—such as placement on disturbed land or simplified transmission interconnection requirements—are preferred. Out-of-state offers will continue to be evaluated in conjunction with their potential for delivery into California, as well as on the basis of whether an offer would be considered a bundled or REC-only transaction. The offers selected will have the best combination of market value, viability, and qualifications based on the evaluation criteria specified in the 2010 Solicitation Protocol. Additionally, as directed by D.09-06-018, PG&E will use a modified version of the Project Viability Calculator (PVC) issued by the CPUC on June 5, 2009, as a screening tool. The 2010 Solicitation Protocol explains how the PG&E-modified version of the adopted PVC will be used to evaluate bids, as ordered in D.09-06-018.

2 Program Metrics

In accordance with D.06-10-050, PG&E and the other California IOUs report their compliance with their individual Annual Procurement Targets (APT) through the filing of semi-annual Compliance Reports with the Commission. In the current report, filed on August 3, 2009 (August 2009 Compliance Report – Public Version), PG&E presented historic information and forecast procurement for each year from 2003 to 2020. The information in the August 2009 Compliance Report corresponds to the accompanying program metrics with two exceptions; the 2010 RPS Plan's time horizon is shorter, and the RPS APT has been updated to reflect the impact of D.09-11-014, which changes the calculation of the APT from 20 percent of the prior year's retail sales to 20 percent of the current year's retail sales. A summary of the program metric information presented in the August 3, 2009 RPS Compliance Report is provided in Table 1, below. Subsequent updates to program metrics may be made to reflect new information, including updated Retail Sales and Actual Procurement projections, in PG&E's March 2010 RPS Compliance Report.

2.1 Actual/Forecast Retail Sales

PG&E's non-proprietary actual and forecasted retail sales figures from its August Compliance Report are presented in Table 1. The forecast component (2009 to 2013) reflects PG&E's assumptions as of August 3,

2009. PG&E's forecast of retail sales is subject to confidential treatment and is provided only in the confidential version of this Plan.[2]

PG&E's August 2009 Compliance Report and Table 1 below do not include the impacts of load migration referenced in Section 1. PG&E may adjust the retail sales forecasts in its March 2010 RPS Compliance Report to reflect the impact of this activity to the extent it is able. Table 1 below does, however, include the changed APT calculation referenced in Section 1.

It should be noted that Community Choice Aggregation (CCA) plans are being considered in certain areas inside PG&E's service region, including Marin County and the City and County of San Francisco. These plans are at varying stages of development. If CCA programs move forward, then PG&E's retail sales would decline, and PG&E's renewable energy targets, which are equal to 20 percent of its retail sales, would decline as well. In the 2010 RPS Plan, PG&E has not reduced its sales forecast for potential departing CCA load, as the effect and timing for these plans remain uncertain.

2.2 Annual Procurement Targets

Actual annual procurement figures reported in PG&E's August 3, 2009 RPS Compliance Report are presented in Table 1. PG&E used the APT methodology outlined in D.06-10-050, Appendix A, and revised by D.09-11-014, to derive the APT.

2.3 RPS-Eligible Procurement

RPS-eligible procurement consists of two components, actual procurement and forecasted procurement, which are described below.

2.3.1 Actual Procurement

Actual procurement represents annual RPS deliveries in each of the respective years (2003 to 2008). These amounts include deliveries

[2] Confidential treatment is authorized by D.06-06-066, Appendix I Section V-C. "LSE Total Energy Forecast-Bundled Customer (MWh)." The first three years of forecast data are confidential.

from renewable resources and contracts that existed when the RPS Program was initially established, along with contracts that were subsequently executed and have since commenced delivering energy. The actual procurement figure for 2009 will be made public when PG&E submits its Federal Energy Regulatory Commission (FERC) Form 1 filing in May 2010.

2.3.2 Forecasted Procurement

Forecasted renewable procurement volumes represent estimated future deliveries of energy (2009 to 2013), from existing resources in PG&E's RPS baseline, signed contracts, offers under negotiation and from forecasted generic procurement from future solicitations and re-contracting of expiring contracts. As noted above, PG&E's forecast is based on assumptions consistent with its August 2009 Compliance Report.

2.3.3 Incremental Procurement Targets

Pursuant to D.06-10-050, the IPT represents the amount of RPS eligible procurement that the Load-Serving Entity (LSE) must purchase in a given year, over and above the total amount that the LSE was required to procure in the prior year. The 2004 to 2009 IPTs are calculated in the following manner: IPT = 1 percent of prior year retail sales, which includes power delivered to PG&E's end-use customers under the Department of Water Resources (DWR) contracts. In 2010, the IPT will be the difference between 20 percent of retail sales in 2010 and the 2009 APT. As stated in D.06-10-050, the IPT is a component of the APT and is not a separate annual procurement target. PG&E has recalculated the procurement targets for 2010 and future years in accordance with D.09-11-014 as noted above.

Table 1
Pacific Gas and Electric Company
Annual Sales and Procurement Targets (GWh)

	Actual	Actual	Actual	Actual	Actual	Actual	Fcst	Fcst	Fcst	Fcst	Fcst
Year	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Retail Sales	71,099	73,704	72,727	76,690	79,451	81,935	[redacted] [1]	[redacted] [1]	[redacted] [1]	[redacted] [1]	[redacted] [1]
APT	7,096	7,807	8,544	9,271	10,038	10,833	11,652	[redacted] [2]	[redacted] [2]	[redacted] [2]	[redacted] [2]
Actual Procurement	8,828	8,575	8,650	9,114	9,044	9,819	11,654	13,106	14,810	15,628	18,038
IPT	N/A	711	737	727	767	795	819	[redacted] [2]	[redacted] [2]	[redacted] [2]	[redacted] [2]

Abbreviations:

APT	Annual procurement target
IPT	Incremental procurement target
Fcst	Forecast
Confid.	Confidential Information

Notes:

1. Confidentiality protected under Decision 06-06-066, Appendix 1, Item V-C "LSE Total Energy Forecast-Bundled Customer (MWh)". The front three years of PG&E's own forecast of its bundled customer total energy requirements are protected. Linked cells whose values would reveal this confidential data are also redacted. This covers data from mid-year 2009 through 2013; therefore the data from all four years are redacted. The 2009 Retail Sales figure will be made public in PG&E's May 2010 FERC Form 1 filing.
2. Confidentiality protected under Decision 06-06-066, Appendix 1, Item V-C "LSE Total Energy Forecast-Bundled Customer (MWh)." Linked cells whose values would reveal this confidential data are also redacted. This covers data from mid-year 2009 through mid-year 2013; therefore the data from all five years are redacted.
3. This table has been updated to reflect the requirements of D.09-11-014. Subsequent updates to this forecast may be made to reflect new information, including revised Retail Sales and Actual Procurement projections from PG&E's March 2010 RPS Compliance Report.

2.4 Use of Flexible Compliance

From the time PG&E executes a renewable contract, actual project development can take five years or longer. Siting, permitting, construction activities, and equipment availability all contribute to the long lead time for new facilities to reach commercial operation. In recognition of this, the Commission has implemented rules allowing for flexible compliance. In general, the Commission's flexible compliance rules allow IOUs to make up current year procurement shortfalls over the following three years. This is effective for all periods before, during, and after 2010. Shortfalls are allowed without penalty if the IOU can demonstrate that non-compliance is due to one or more of the following factors:

- Insufficient response to the Solicitation;
- Inadequate Above Market Funds (AMF) to cover above-market costs;
- Seller non-performance; or
- Inadequate transmission.

As detailed in its August 2009 Compliance Report, PG&E has executed sufficient contracts to achieve more than 20 percent renewable deliveries, but actual RPS deliveries are not expected to reach or exceed the 20 percent target until the 2013 timeframe. Therefore, PG&E intends to use the provisions of flexible compliance in accordance with D.06-10-050 and D.08-02-008, in the following manner:

- PG&E intends to use its banked procurement surplus to partially offset projected future procurement deficits in 2010, 2011, and 2012.
- The allowable portions of the currently projected procurement deficits in 2010, 2011, and 2012 will be carried forward to 2013 and 2014, in accordance with flexible compliance provisions.

- Estimated procurement surpluses in 2013 to 2014 will be earmarked as far back as 2010 and 2011, respectively.

As the procurement environment changes, PG&E may adjust its flexible compliance alternatives. For example, given PG&E's near-term need for renewable generation, PG&E has attempted to procure deliveries from existing renewable facilities for a short-term period to match its deficits for the years before and after 2010. Deliveries during the 2010 to 2013 period will help PG&E fulfill its 20 percent renewables mandate while other projects are being developed. Accordingly, in Section 16, PG&E proposes modifications to the streamlined short-term contracting process authorized in D.09-06-050 that could result in more near-term deliveries from existing projects. Alternatively, given the short-term contract regulatory process adopted in D.09-06-050 has not fostered IOU access to short-term procurement market, the Commission should seriously reconsider the rules for flexible compliance to allow the IOUs additional time to meet the 2010 target.

2.5 Use of AMFs

Senate Bill 1036 directed the Commission to establish, for each electrical corporation, a limitation on the total AMFs expended above the MPR for eligible renewable energy resources procured to satisfy RPS goals.

On March 12, 2009, the Commission issued Resolution E-4199, which limited the amount of AMFs to $381,969,452 for PG&E.

On May 28, 2009, the Energy Division sent a letter to PG&E notifying PG&E that its AMF balance is zero. Because the statutorily designated funds for payment of above-market costs have been exhausted, PG&E is no longer required to procure eligible renewable resources that are priced above the MPR. However, PG&E may continue to procure power from renewable energy resources priced above the MPR on a voluntary basis, so long as the Commission has authorized the recovery of those costs in rates. In

Confidential Appendix A, PG&E provides its assessment of commitments eligible for AMFs, including contracts that are not AMF-eligible but are above the MPR.

2.6 Reasonable Use of a Procurement Margin of Safety to Account for Potential Contract Failure and Other Contingences

PG&E's experience with prior solicitations is that developers often experience difficulties with project siting, permitting, and escalating equipment prices, along with problems securing project financing. As a result, commercial online dates may be delayed and, in some cases, projects may not be developed at all and the associated Power Purchase Agreement (PPA) may be terminated. To safeguard against these risks and to provide ample warning if problems are likely to occur, PG&E uses a rigorous bid screening and evaluation process that assesses each bid's market value and resource viability, and evaluates the bidder's financial strength and project development experience.

PG&E requires developers to post project development security as an incentive to deliver power under the terms of executed PPAs. Project development security is initially $15 per kilowatt (kW), increasing within 30 days following the CPUC's approval of the contract to $100 per kilowatt-hour (kWh), multiplied by the greater of: (a) the project's expected capacity factor; or (b) 50 percent.

PG&E also engages in a milestone monitoring process to determine if counterparties are remaining on schedule with their permitting and construction activities. Recognizing that not all projects will remain on schedule or will ultimately be successful, PG&E's total procurement through its solicitations and bilateral efforts has exceeded the 20 percent target. For the period from 2004 to 2009, PG&E's actual contract signings, on average, exceeded 2 percent of retail sales in each year.

PG&E's 2010 RPS Solicitation will target renewables procurement for compliance in 2010 and beyond. Projects coming online between 2011 and 2013 will help PG&E meet its 2010 requirements using flexible compliance. Long-term projects resulting from the 2010 solicitation are likely to come online between 2013 and 2015 or later, and will help PG&E meet its longer term targets.

2.7 Any Other Relevant Data and Information Regarding Sales, Targets, Procurement, Flexible Compliance, Margins of Safety or Other Related Matters

PG&E has no additional information to provide on these topics.

3 Important Changes

3.1 Important Changes to the Plan

This section highlights, summarizes, and supports the major differences between PG&E's 2009 Plan and its proposed 2010 Plan.

3.1.1 Proposed Inclusion of TRECs in Plan

As indicated in Section 10, TRECs are now included in PG&E's 2010 Plan, based upon PG&E's compliance with all relevant conditions on the use of TRECs in D.10-03-021. As directed in ALJ Mattson's March 19, 2010 Ruling, PG&E proposes the amendments to its 2010 RPS Plan and Solicitation Protocol outlined in this document and seeks a determination by the Commission that this amended 2010 RPS Plan meets the conditions for the use of TRECs. Upon such finding, TRECs will be used for RPS compliance under the approved terms.

3.1.2 Pre-Approval of Short-Term Renewables Procurement Under Terms Similar to Assembly Bill 57 Conventional Procurement Authority

As set forth in Section 17, PG&E proposes that 5 percent of its APT should be pre-approved for procurement at certain minimum market valuations during the next five years. This proposal is modeled after the utilities' procurement authority for conventional power. The proposal should be applied to both bundled power transactions and TREC transactions.

3.1.3 Regulatory Review of Amendments to Executed, Approved RPS Contracts

In Section 11.2, PG&E proposes that Commission approval is not necessary for routine contract administration, as this is subject to quarterly contract review; Tier 1 reporting is appropriate for the utility's exercise of a pre-approved option; Tier 3 application is necessary for increases in ratepayer cost or reduction in contract value, or for issues reserved for further Commission decision; and Tier 2 Energy Division disposition is appropriate for other issues. PG&E proposes a departure from the Tier 3 process because most contract amendments do not present the same potential risk to customers as an increase in cost, and developer costs due to delay should be minimized if possible.

3.1.4 2010 RPS Solicitation, Including Protocol for Bid Submission and Form Commercial Documents

PG&E anticipates that the 2010 RPS Solicitation will follow the same schedule as used for 2009, except that all milestones should occur 12 months later. PG&E sees no reason to accelerate the solicitation for 2010 because it has a robust short-list from its 2009 RPS Solicitation and is still engaged in negotiations arising out of previous solicitations. PG&E's solicitation protocol has been changed to incorporate lessons learned from the 2009 Solicitation based on PG&E's initial work with short-listed bidders.

3.1.5 Modification of Commercial Terms

Delay in online date: Modifications to the form PPA have been made to keep the parties in contract despite delay. The total number of days for permitted extensions is now 540 for Pre-Construction plus 360 for a Post-Construction Start Date *Force Majeure* event, totaling 900 days or 2.5 years. This does not include the two 60-day cure periods for which the generator would be liable for Daily Delay Damages. The force majeure provision now includes an explicit opportunity for the developer to make repairs within the period allowed by the contract, if repairs are possible.

Curtailment: PG&E has updated the curtailment language in its form PPA to provide PG&E the flexibility to curtail any project. This operational flexibility is necessary for efficient system operation, and will allow PG&E to manage congestion costs that are borne by ratepayers. PG&E will have the flexibility to curtail the projects up to 5% of expected hours of operation, and will pay Sellers the PPA price for the hours curtailed. The Seller remains obligated to curtail if ordered by the CAISO or Participating Transmission Operator without payment.

Resource Adequacy: As described in Lessons Learned, PG&E has made changes to its protocol and form PPA to clarify that it prefers projects that have been deemed deliverable by the CAISO and that PG&E may count toward its Resource Adequacy requirement. The protocol requires Sellers to indicate whether their resource will have full capacity deliverability status or energy-only status with the CAISO. The form PPA has been modified to allocate risks that may result from the CAISO's Availability Standards and Replacement Capacity Rules.

Guaranteed Energy Production: Guaranteed Energy Production (GEP) is the minimum annual energy production required by Seller in order to comply with contractual obligations. PG&E's form PPA for 2009 required baseload resources to produce 90% of contract quantity and solar resources to produce 160% of contract quantity over two years. Wind resources were required to produce at the P95 level. This is the minimum level of output that is expected 95% of the time. In response to Seller feedback, PG&E is changing the GEP for wind resources from P-95 to 160% of contract quantity over two year.

Commercially Reasonable Efforts to Maintain ERR Status: In the event that the CEC rules determining status as an Eligible Renewable Resource ("ERR") change, Sellers are required to exercise commercially reasonable efforts to maintain their CEC certification. This year's form PPA clarifies that commercially reasonable efforts requires Sellers spend up to $10,000/MW over the delivery term to maintain ERR Status.

Other changes have been made—for example, insurance provisions have been updated, and Buyer and Seller responsibilities for EIRP costs are more clearly delineated. These are detailed in Appendix B of this Plan and in the form PPA provided as Attachment H to the Solicitation Protocol.

3.1.6 Plan for Delivery of Energy from Projects Located Outside the California Independent System Operator Balancing Authority Area to the CAISO-Controlled Grid

PG&E's 2010 Solicitation will require sellers located outside the CAISO balancing authority area to provide more detail about how they plan to deliver energy to the CAISO grid including; required infrastructure beyond the point of delivery, wheeling costs and the status of the project in the CAISO interconnection study process if the seller plans to receive resource adequacy credit.

3.1.7 Regional Transmission Planning Initiatives

This solicitation includes a request that projects identify if they are in a renewable energy zone associated with the Regional Transmission Planning Initiatives (RETI), Western Renewable Energy Zone (WREZ) or other comprehensive and official resource study effort. There is no requirement that projects participating in this solicitation locate in renewable energy zones, however, this information will be taken into consideration to the extent that it accelerates a project's online date for transmission constrained resources, alleviates environmental concerns, or alleviates other potential permitting issues.

3.1.8 Recommendation to Improve the Transmission Ranking Cost Report Process

PG&E has deleted the recommendation that it made in the 2009 RPS Solicitation Protocol to improve the Transmission Ranking Cost Report (TRCR) process and implementation through more consistent treatment of future transmission projects that do not have all required approvals. This issue was raised in 2009 because of inconsistent treatment of the Imperial Valley and Tehachapi upgrades in a prior TRCR. Projects located in the Tehachapi area (Southern California Edison (SCE) Cluster 1) were assessed a TRCR reflecting the cost of the proposed Tehachapi transmission upgrades that were being reviewed by the Commission during the issuance of the 2009 Solicitation Protocol. However, projects located near the Imperial Substation (San Diego Gas & Electric Company (SDG&E) Cluster C2) received a transmission adder that treated the Sunrise transmission project, a project that was also under review by the Commission, as a sunk cost. In its latest TRCR, SCE included two cost figures, one with and one without the Tehachapi and Antelope Transmission Projects. This revision rendered the recommendation in the 2009 Solicitation Protocol unnecessary, and therefore, it has been removed.

3.1.9 CAISO Generator Interconnection Process Reform

PG&E has deleted a discussion of the CAISO's Generation Interconnection Process Reform (GIPR) that appeared in its 2009 RPS Solicitation Protocol. Reforms have been completed and the new Large Generator Interconnection Process (LGIP) is in place.

3.1.10 Consideration Of Integration Costs In Evaluation.

In their respective 2010 RPS Plans, SCE and SDG&E proposed including renewable integration costs in the RFO evaluation process. PG&E is currently working closely with CAISO on CAISO's 33% Integration Study to assess the requirements for integrating renewable generation. This effort is intended to yield greater insight into renewable integration requirements and costs over the course of the next several months. The insights resulting from this work have the potential to be useful in informing contract evaluations as part of PG&E's future RPS solicitations. To the extent the Commission approves the inclusion of integration costs in the evaluation process for SCE's and SDG&E's 2010 RPS Plans, PG&E reserves the right to similarly include integration costs in its 2010 RPS Plan.

4 Standard Terms and Conditions

PG&E has made changes to two Modifiable Standard Terms and Conditions specified in D.04-06-014 and D.07-02-011, as modified by D.07-05-057, D.07-11-025 and D.08-04-009 in its proposed 2010 Power Purchase Agreement that were not present in its 2009 Power Purchase Agreement. These changes are summarized in Paragraphs 3 and 4 of Appendix B. Additionally, PG&E has included in its 2010 Power Purchase Agreement the new non-modifiable Standard Terms and Conditions approved by the Commission in D.10-03-021.

4.1 Modifications to Terms Other than Standard Terms and Conditions

PG&E has made updates to other terms and conditions in its 2010 Power Purchase Agreement as compared to its 2009 Power Purchase Agreement. A summary of those changes is provided in Appendix B. PG&E may suggest additional changes when it files the final version of the 2010 RPS Plan.

5 Lessons Learned

PG&E submitted its 2009 Short-List to the Energy Division on November 23, 2009 and filed its Least-Cost, Best-Fit (LCBF) Report on December 4, 2009. PG&E has not executed any PPAs with projects on its 2009 short-list so it is too early to attempt to identify any lessons learned.

Following its RPS solicitations in 2004, 2005, 2006, and 2007, and 2008 PG&E adopted several changes to its Solicitation that were based on lessons learned and the need for additional changes may materialize based upon ongoing procurement activity. Transactions from the 2008 RPS Solicitation are winding down and may be concluded by the end of the first quarter 2010. As described above, 2009 RPS Solicitation negotiations have just begun. The Independent Evaluator's Report on PG&E's 2009 RPS Solicitation (IE's Report) was submitted to PG&E and filed with the Commission on December 4, 2009. Based on the IE's Report and its experience to date, PG&E is proposing some changes to its 2010 RPS Plan.

5.1 Resource Adequacy Counting for Renewables Projects

Projects participating in the CAISO LGIP submit interconnection applications requesting either Full Capacity Deliverability or Energy-Only status. Projects may be counted toward PG&E’s RA requirement only if the CAISO makes a finding of full capacity deliverability. Energy-Only resources will not contribute to PG&E’s RA requirement.

The IE’s Report noted a concern that some participants in the 2009 solicitation have been candid about their intent to interconnect as Energy-Only resources and avoid potential network upgrade costs, while others remain silent about such plans, obtain the benefit of RA value for the purpose of short-listing, and eventually fail to deliver RA benefits to ratepayers. The IE recommended that in future solicitations PG&E explicitly require each Participant to specify whether its LGIP interconnection application was submitted for Full Capacity deliverability or Energy-Only resources. PG&E's 2010 Solicitation will be amended accordingly. PG&E’s LCBF evaluation will not assign any RA value to energy-only resources.

In addition, the CAISO Small Generator Interconnection Process (SGIP) process does not include a deliverability study. Thus, the CAISO is not currently planning to consider projects interconnecting through SGIP as deliverable, and contributing toward PG&E’s RA requirement. Projects interconnecting through SGIP may request a full capacity deliverability study, which requires Sellers to follow a schedule consistent with the CAISO’s LGIP. PG&E is working with the CAISO to encourage the CAISO to implement a more timely process for ensuring that projects less than 20 MW may be counted toward RA requirements. Until a process is implemented, unless these projects have a finding of full capacity deliverability, they will be evaluated as energy-only resources.

5.2 Counterparty Concentration

For the first time in the 2008 Solicitation, certain counterparties submitted multiple offers that totaled hundreds or thousands of megawatts (MW) per counterparty. As recommended by the IE's Report on the 2008 Solicitation, PG&E amended its 2009 LCBF protocol to limit the total MW to be short-listed from any single counterparty. However, while observing the MW limitation in the 2009 Solicitation, many parties submitted multiple offers, and some submitted offers for over 10 projects. This made it difficult for PG&E to evaluate all the offers, and to identify the most promising among them. To encourage sellers to focus on the most viable, cost-effective projects, PG&E plans to limit the number of project offers it will accept from each seller in future RPS solicitations to no more than 5 projects. Sellers may bid more than 5 projects if the aggregate total is less than 200 MW.

5.3 Credit Requirements

For its 2010 Solicitation, most credit requirements are unchanged from those in the 2009 RPS Solicitation. However, since the last solicitation, several sellers have requested an extension of time to post their offer deposits, which must be paid when the seller accepts short-list status, due to the time required to negotiate a letter of credit. In response to this feedback, PG&E is modifying its solicitation protocol to allow sellers 10 business days to post their offer deposit. PG&E has also modified the definition of Letter of Credit in the form PPA.

5.4 Short-Listing Schedule

D.08-02-008 adopted a solicitation schedule whereby all three utilities were to finalize their short-lists and notify the CPUC at the same time. In the 2009 RPS Plan decision, the Commission adopted a uniform date before which no IOU may require a bidder to execute an agreement to deal exclusively with that IOU.[3] The three IOUs have negotiated the following common schedule:

- No exclusivity agreements may be executed before November 5, 2010.
- IOUs submit their final short-lists to the Commission and their Procurement Review Groups (PRG) on November 23, 2010.
- IOUs submit their report on the bid evaluation and selection process on December 3, 2010.

5.5 Submission of Detailed Term Sheet Prior to PPA Negotiation

For 2010, PG&E is modifying its Solicitation Protocol to eliminate the requirement that all bidders submit a form PPA mark-up as part of the initial offer. Instead, participants will be asked to submit a detailed term sheet, identifying key commercial terms and conditions, and modifications sought by the Seller. PG&E will request detailed PPA mark-ups only from shortlisted bidders. This change will reduce the initial demands on participants, and will allow PG&E to focus its evaluation on key commercial issues.

5.6 Power Purchase Agreement with Purchase Option Requirements

Counterparties have expressed concern regarding how fixed price purchase options may be viewed by tax authorities. To address this, PG&E has removed the requirement that purchase options be at a fixed price and be possible only at year 5 and year 10. Instead, the purchase option may be at fair market value and the option date(s) are to be proposed in the offer. However, if a PPA offer (without a purchase option) is also being proposed for the same Project, the all-in energy and capacity price for all years for the PPA with purchase option must be identical to the price of the PPA (without purchase option) price.

[3] D.09-06-018, Conclusion of Law 17.

5.7 Joint Development and/or Joint Ownership and Purchase and Sale Agreements Product Criteria

In order to expedite the bid review process for Joint Development and/or Joint Ownership and Purchase and Sale Agreement ("PSA") proposals PG&E has requested participants submit bids which are located within the State of California and utilize "commercially proven technologies." Out-of-state proposals significantly complicate the scoring process due to PG&E's lack of familiarity with out-of-state tax laws, deliverability concerns, and potential future changes to applicable law. In addition, discouraging bids which propose the use of unproven or emerging technologies will expedite the scoring process.

5.8 New Joint Development and/or Joint Ownership Appendix

In order to expedite the scoring process for Joint Development and/or Joint Ownership offers, PG&E is requesting participants submit Attachment M, Joint Development and/or Joint Ownership – Required Detailed Participant Information. In the past, Joint Development and/or ownership proposals have often arrived incomplete or lacked important information needed to properly evaluate the offers.

6 Transmission and Flexible Delivery

PG&E continues to monitor the adequacy of transmission facilities to accommodate the level of renewable energy development expected to materialize through the RPS solicitations. For generators planning to begin deliveries in 2010, necessary upgrades to accommodate generator interconnection should already be identified and underway. For generators planning to begin deliveries in the post-2010 timeframe, several activities are underway to facilitate meeting PG&E's near-term and long-term renewable procurement goals. The following section describes PG&E's efforts to ensure the availability of transmission needed to bring renewable energy to market, PG&E's acceptance of energy delivery from anywhere in California and out of state locations, and regional transmission planning initiatives.

6.1 Transmission, Including Use of Flexible Delivery Points, Efforts to Ensure the Availability of Needed Transmission, and Efforts to Construct Needed Facilities

This section has been modified from the 2009 RPS Solicitation Protocol to include a clarification for sellers that are planning to receive resource adequacy credit under the current CAISO Tariff. PG&E continues to work on transmission projects to facilitate the delivery of renewable energy that were listed in the 2009 RPS Solicitation Protocol. PG&E continues to proactively investigate potential transmission upgrades needed to accommodate new and anticipated renewable development. In these investigations, PG&E has focused on identifying multi-purpose transmission projects, which can provide additional system benefits in addition to accommodating renewable development. Further discussions are included in Chapters 7 and 8 of PG&E's 2009 Transmission Grid Expansion Plan.[4]

Starting with the 2006 RPS Solicitation, PG&E has accepted bids for projects proposing to deliver anywhere in California and, beginning in 2007, from anywhere in the Western Electricity Coordinating Council (WECC) area. For the purposes of offer evaluation, the cost to bring power from a delivery point outside North of Path 15 (NP-15) is adjusted as appropriate during the bid evaluation process to reflect wheeling costs outside the CAISO-controlled grid and the TRCR values from the appropriate Participating Transmission Owners (PTO). During negotiation with counterparties, PG&E will continue to consider commercial arrangements to address transmission issues. For generators interconnecting to the CAISO controlled transmission system and planning to receive resource adequacy credit, CAISO Tariff currently mandates that these generators interconnect through the CAISO's reformed

[4] Pacific Gas and Electric Company, "2009 Transmission Grid Expansion Plan," March 5, 2009.

LGIP and request Full Capacity deliverability status.[5] Once the PPA is executed, the associated generation facility will be included in PG&E's Transmission Assessment and Expansion Studies in the following transmission planning cycle.[6] PG&E has identified needed transmission projects in PG&E's 2009 Transmission Grid Expansion Plan and in the CAISO 2009 Transmission Plan.[7] Specifically, PG&E has focused on expanding the availability of needed transmission, which can serve multiple purposes, via the following projects, which are discussed in Chapter 7 of the PG&E 2009 Transmission Grid Expansion Plan:

- Table Mountain – Rio Oso 230-kV Line Reconductoring and Tower Raises.
- Re-Rate the Rio Oso – Brighton 230-kV Line (in Service on May 5, 2008).
- Atlantic – Rio Oso – Gold Hill 230-kV Lines.
- Palermo – Rio Oso 115-kV Line Reconductoring.
- Rio Oso 230/115-kV Transformers.
- East Nicolaus Area Reinforcement.
- Reconfigure the Palermo – Rio Oso 115-kV Lines.
- Reconfigure the Transmission System to Normally Serve Honcut and Olivehurst Substations on the Palermo – Bogue 115-kV Line.
- Re-Rate the Bogue – Rio Oso 115-kV Line.

---

[5] Currently, generators that request Energy Only deliverability status will not receive a deliverability assessment by the CAISO and, therefore, will not meet resource adequacy requirements. See Appendix Y of the CAISO Tariff for further information.

[6] As stated in the Protocol and in the Transmission Ranking Cost Report, renewable resource projects must go through the CAISO Interconnection Process before interconnection with the PG&E system.

[7] CAISO, "2009 Transmission Plan," March 2009.

- Central California Clean Energy Transmission Project (C3ET, a new 500-kV Double Circuit Tower Line between Midway and East of Fresno).

It is also expected that additional Remedial Action Schemes (RAS) would be needed as renewable resources are added to the northern part of PG&E system. However, such RAS will need to be designed based on the specific generator to be interconnected and will be studied through the reformed CAISO LGIP.

6.2 Expanding Deliverability from Only the CAISO Control Area to Anywhere in California

The expansion of delivery points beginning with PG&E's 2006 RPS Solicitation has enhanced PG&E's renewable procurement opportunities and has resulted in an increased number of offers received through PG&E's RPS solicitations. In its 2006 RPS Solicitation, PG&E was authorized to accept offers to deliver electricity at specific points anywhere in California rather than just within the CAISO control area. PG&E continues to solicit offers for out-of-state projects that are willing to deliver to the CAISO grid. Projects from non-CAISO control areas are expected to make an important contribution to PG&E's near and long-term RPS procurement goals.

PG&E accepts offers for projects where PG&E can take title to generation at out-of-state points, as long as the energy is deliverable to California and the resource is certified as an Eligible Renewable Resource by the CEC. Participants are asked to propose and quote a price for delivery at the project busbar and a price for delivery to the CAISO grid. Participants need to include a well-defined plan to ensure energy delivery to the CAISO grid in their proposals. This includes out-of-state sellers, as well as sellers with projects located in California that are outside the CAISO control area. PG&E's 2010 Solicitation will require sellers located outside the CAISO balancing authority area to provide more detail about how they plan to deliver energy to the CAISO grid. This includes an assessment of additional infrastructure required from the point of delivery to the CAISO controlled grid, an assessment of wheeling costs on third party transmission facilities and, if the project plans to count for resource adequacy, the project's status in the CAISO's LGIP.

6.3 Regional Transmission Planning Initiatives

Considerable work has been undertaken through various stakeholder forums to identify and prioritize renewable energy potential both in California and across the Western Interconnection. Notably, the RETI and the Western Governor's Association's (WGA) WREZ efforts have identified areas with significant renewable resource potential while providing guidance on areas to avoid because of environmental and land use considerations. Additionally, the WECC Transmission Expansion Planning and Policy Committee (TEPPC) are investigating conceptual transmission plans to link potential renewable resource areas to the potential markets in the Western Interconnection. The California Transmission Planning Group (CTPG) will be undertaking technical transmission planning studies to develop transmission plans to reach California renewable energy targets. Such transmission plans will be coordinated through the WECC Planning Coordinating Committee (PCC). Transmission planning studies undertaken by the CTPG will be informed by the work undertaken by both RETI and WREZ.

Regional transmission planning studies have implications for projects requiring extensive transmission upgrades including major new transmission facilities. Several projects — including the CPUC's Long-Term Procurement Plan (LTPP), the transmission plan developed in the CTPG, and the CAISO's Transmission Plan for Renewables — will be either based upon or influenced by regional planning initiatives. Because of the importance of these initiatives in developing the necessary infrastructure to access new renewable resources, PG&E's 2010 Solicitation Protocol requests that all projects identify if they are in a renewable energy zone associated with the RETI, WREZ, or other comprehensive and official resource study effort(s). While PG&E prefers renewables projects that would require limited or no network transmission upgrades, and all information regarding a project's feasible online date will be taken into consideration in evaluating project proposals, this information will be used to the extent that a project's location within a renewable energy zone can accelerate the project's online date, addresses environmental concerns, or alleviates other potential permitting issues.

7 Consideration of Information From TRCRs and Interconnection Studies

This section has been updated based on the current TRCR considerations and includes additional requirements for sellers with projects that are not interconnecting to the CAISO-controlled grid.

7.1 Experience with the Current TRCR Process and Recommended Improvements for Consideration

PG&E's experience with the TRCR is no different from that described in its 2009 RPS Plan. PG&E has not repeated that information herein and asks that parties refer to the corresponding section of the 2009 RPS Plan. Changes to the 2009 RPS Plan are identified in Section 3, above.

7.2 Developers Must be Mindful of the Timing of Project Interconnection Studies when Preparing their Offers

While projects expecting to commence operations in 2010 should have already completed the interconnection study process as part of the CAISO's serial cluster studies, developers of projects that will come online beyond the 2010 timeframe must consider the timing of CAISO project interconnection studies when proposing the project's online date. Projects in the Transition Cluster are expected to have a Large Generator Interconnection Agreement (LGIA) by the end of 2010. The First Queue Cluster window closed on July 31, 2009. The application window for the Second Queue Cluster opened on October 1, 2009 and closes on January 31, 2010. According to the CAISO schedule, Projects in both the First and Second Queue Clusters are not expected to have an executed LGIA until the first quarter of 2012.[8] Projects submitting Interconnection Applications beginning in April 2010 will be included in either the Third or Fourth Queue Cluster windows. Projects in these windows are not expected to have an executed LGIA until the first quarter of 2013.

Because of the significant impact of a project's study cycle on the timing of project interconnection, PG&E will screen offers to identify whether the bidder's proposed commercial operation date is consistent with the project's progress in the transmission interconnection process. However, PG&E does not believe it is necessary to limit negotiations to those projects that have completed their interconnection studies or are part of the Transition Cluster.

There are situations where a project may be able to deliver energy into the transmission system reasonably soon after executing a LGIA. For example, in cases where only interconnection facilities (and no network upgrades) are needed, Section 10 of the CAISO's LGIP allows the Interconnection Customer to execute an engineering and procurement agreement with the Transmission Owner (TO) so that work may proceed on long lead time items prior to the execution of the LGIA. In such circumstances, construction of the interconnection facilities could begin shortly after executing the LGIA. Even in situations where network upgrades may be needed, the LGIA includes a provision that may allow for early

[8] Note that the CAISO GIPR also includes an expedited process for certain types of interconnection requests that may reduce the time to identify a transmission plan of service and execute a LGIA.

interconnection of a project with a potential for some limitations on operations until the network upgrades are completed.[9]

7.3 The Best Available Information Should Be Used in Bid Evaluations and Contract Negotiations

The best available information should be used in the bid evaluations and contract negotiations, provided that the application of such data to the bid is clear. If the generation project associated with the bid has received CAISO transmission information that is directly applicable to the proposed bid, then such information should be considered if it is available on a timely basis. However, if the bid under consideration is not in the Transition Cluster, judgment will be necessary as to whether the information from the Scoping and Results meetings is applicable to the bid. If a project is interconnecting at a point outside the CAISO controlled grid, then the seller should provide available and relevant information from the project's interconnection studies conducted under the applicable interconnection authority.

PG&E updates its annual TRCR to include information available from the CAISO interconnection studies provided that information is available prior to the development of the TRCR. PG&E does not recommended that the 2010 RPS TRCR be formally updated based on the results of the CAISO studies. However, information on transmission cost and timing available from the CAISO studies may be used in the negotiation and valuation of offers.

7.4 Lack of Availability of CAISO Information Should Not Delay Short-Listing of RPS Bids

Short-listing of RPS bids will not be delayed to accommodate the uncertain availability of CAISO information. Such information will be

[9] CAISO Large Generator Interconnection Agreement Section 5.9.

integrated into the IOU's evaluations and negotiations as it becomes available.

8 Potential Impediments That Remain to Reaching 20 Percent by 2010 and PG&E's Efforts to Address Them

It will not be easy to achieve 20 percent by 2010, but PG&E is fully committed to working to achieve this goal. PG&E will continue to pursue attractive opportunities that arise in RPS solicitations, bilateral negotiations, and further exploration of potential utility ownership. As noted below, there are several uncertainties associated with the development of new electric generation facilities, in general, and renewable technologies in particular, that could ultimately delay compliance by the IOUs.

8.1 Financial Issues

Tight credit markets and substantially reduced capital availability are presenting a significant challenge to those seeking to increase the availability of renewables to meet future electricity needs.

While multi-year extensions of the Investment Tax Credit (ITC) and Production Tax Credits (PTC) were authorized in October 2008, the subsequent financial market meltdown has reduced the benefit of this multi-year extension. Many renewable developers do not have enough taxable income to realize the full benefits of the tax credits for their projects. Unfortunately, the financial crisis has reduced the appetite of financial institutions—heretofore the primary segment of tax equity investors—for tax equity investments, effectively restricting access to or raising the cost of tax equity financing for developers. This additional barrier increases the financing pressure on developers who are already having difficulty securing capital.

To reinvigorate investment in renewable energy development, on February 17, 2009, the President signed the ARRA, aimed at alleviating some of the financing issues. Key provisions of the ARRA include:

- $6 billion for Innovative Technology Loan Guarantee Program which can be used to fund renewable energy systems.
- Extending the production tax credit by three years for electricity derived from wind (through 2012) and for electricity derived from biomass, geothermal, hydropower, landfill gas, waste-to-energy and marine facilities (through 2013).
- Allowing taxpayers to claim the investment tax credit in lieu of the production tax credit for renewable facilities placed in service from 2009 to 2013 (2009 through 2012 for wind).
- Providing up to $2.3 billion to fund a new 30 percent investment tax credit for investment in advanced energy facilities.
- Authorizing an additional $1.6 billion of new clean renewable energy bonds to finance facilities that generate electricity from wind, closed loop biomass, open loop biomass, geothermal, small irrigation, hydropower, landfill gas, marine renewables and trash combustion facilities.

Most of the ARRA grant funds must be obligated by the end of fiscal year 2010, and the CPUC should promptly approve the PPAs so that the maximum number of developers can tap into these benefits and commit to a project development schedule. Like most of the ARRA funds, the renewable loans and tax incentives will be allocated on a first-come, first-served basis, and PG&E has worked with developers to take advantage of stimulus funds where possible. While guidelines to implement these programs are not yet finalized, PG&E is optimistic that these programs will provide lower cost financing to renewable developers and assist in getting stalled projects underway.

8.2 Siting and Permitting of Renewable Generation Facilities

PG&E addressed the siting and permitting challenges faced by renewable generators locating in California in its 2009 RPS Plan. Since the final 2009 RPS Plan was filed in June 2009, additional steps have been taken to address these challenges. PG&E highlights a few of these changes here and, incorporates by reference, Section 8.1.2 of its June 2009 Final 2009 Renewable Energy Procurement Plan.

In October 2009, Governor Schwarzenegger and Department of the Interior Secretary Ken Salazar signed a Memorandum of Understanding (MOU) that further committed the state and federal governments to mobilize in support of streamlined permitting processes. With an explicit emphasis on taking advantage of ARRA funding, the MOU directs various state and federal agencies to create procedural mechanisms that will accelerate review and approval of projects that can begin construction by the end of 2010. While this near-term focus is welcomed, PG&E strongly supports formulation of permanent process reforms that can be implemented and utilized on a regular basis, as proposed in the MOUs. As the Energy Division's 33 Percent Implementation Analysis report points out, such improvements will be essential in achieving the state's expanded 33 percent RPS goal.

Also, on October 28, 2009, nine federal agencies, including the Departments of Agriculture, Commerce, Defense, Energy and Interior, the Environmental Protection Agency (EPA), FERC, the Council on Environmental Quality and the Advisory Council on Historic Preservation, signed an interagency agreement that will reduce time for regulatory approvals by one-third for companies that want to build new electric transmission lines across federal lands. Federal coordination on transmission project permitting should facilitate the permitting process for generation plants located on or near federal land.

Now that various reform/streamlining efforts are underway in both the permitting and transmission realms, PG&E is hopeful that the reform process will establish clear requirements that parties can satisfy in advance and that, as a result, permits and transmission plan approvals may be issued more expeditiously.

While numerous efforts are underway to streamline the permitting process for energy generating facilities located in California, projects continue to struggle in getting their permits in a timely manner, particularly compared to out-of-state projects that are able to complete the process more quickly, on a predictable schedule. This is another reason why out-of-state projects will remain an integral part of PG&E's RPS procurement strategy.

8.3 Above-Market Funds

As described in Section 2.5 above, on May 28, 2009, the CPUC sent a letter to PG&E notifying PG&E that it had exhausted its portion of the AMFs available for contract payments that are above the MPR. Since that date, PG&E has continued to voluntarily procure renewables that are priced above the MPR, subject to Commission approval and a finding that the procurement is just and reasonable and fully recoverable in rates.

PG&E will continue to evaluate renewables bids on a case-by-case basis, where appropriate, negotiate those that offer the best value for customers, and submit the resultant power purchase agreements to the CPUC for approval.

8.4 Unbundled RECs

After nearly three years of active consideration, the CPUC issued D.10-03-021 on March 16, 2010, authorizing the IOUs to use TRECs for RPS compliance. With this authorization, PG&E would expect, all other things equal, that the use of TRECs for RPS compliance would spur new renewable generation development in the WECC by providing developers with additional flexibility and revenue options. However, in light of the rules set forth in this decision, it is unclear whether the TREC authorization will result in the development of new renewable generation. The decision defines TREC (or REC-only) transactions as those that either:

- Expressly transfer only RECs, not energy; or
- Transfer RECs and energy but do not meet the Commission's criteria for a bundled RPS procurement transaction.[10]

Bundled transactions include transactions where: (1) the RPS-eligible generator's first point of interconnection with the WECC interconnected transmission system is with a California balancing authority; or (2) the transaction is dynamically transferred to a California balancing authority.[11] The decision allows PG&E to procure unbundled RECs from RPS-eligible WECC resources, but limits PG&E's use of RECs for RPS compliance in 2010 and 2011 to 25% of the APT. It also reclassifies all of PG&E's out-of-state firming and shaping transactions as REC-only and therefore subject to the REC cap. This REC limit will continue until December 31, 2011, at which point the REC cap will sunset unless the Commission takes affirmative action.

PG&E appreciates the Commission's efforts to expand the IOUs' options for RPS procurement, but is concerned that the temporary REC cap could lead to uncertainty regarding the future of the California TREC market.

[10] D.10-03-021, at p. 34.

[11] *Id*., at p. 35.

While the Commission states that the REC limitation will sunset at the end of 2011, it also orders Energy Division staff to make a recommendation within 16 months regarding whether the REC cap should be retained or allowed to sunset. This provision leaves the emerging TREC market in a state of prolonged uncertainty as buyers and sellers await the results of staff analysis and, ultimately, action by the Commission at the end of 2011.

8.5 Additional Barriers

To monitor these issues and reduce uncertainty, PG&E engages in contract management and milestone monitoring and reporting with its signed renewables contracts upon execution. As more states and countries mandate renewable procurement requirements, the resulting increase in demand has led to higher equipment prices (and longer lead times), which are making it more difficult for developers to obtain project financing in these currently unstable credit markets. This often necessitates contract renegotiation coupled with project delay, or potential project default.

PG&E's ability to meet and maintain compliance with the 20 percent renewables target by 2010 is also contingent on its ability to procure additional solar, wind, and geothermal resources in many areas that are currently transmission-constrained. Significant additional transmission upgrades in the near term will be required to deliver this energy to PG&E. Most of these upgrade projects are outside of PG&E's service area, are in various stages of planning and development, and are clustered around regions in southern California such as Tehachapi, the Salton Sea, Inyo/Kern, and north and east of Lugo.

In particular, PG&E's ability to procure additional solar resources is heavily dependent on significant transmission upgrades in southern California and the southwest United States. PG&E believes that the resource identification work undertaken by the RETI and the transmission planning recently underway at the CTPG should ultimately assist in expediting the deliverability of solar resources. RETI's purpose is to assess all competitive renewable energy zones in California (and potentially in neighboring states), identify the zones with the highest potential, prepare detailed transmission plans and facilitate generation siting and permitting. PG&E will work with SCE, the CPUC, the CEC, the CAISO and RETI, along with other stakeholders, to engage in proactive transmission planning to meet these transmission needs as quickly as possible. As specified in the CAISO's "Getting to 33% RPS" proposal, moving forward the CTPG will take the lead on technical transmission planning and analysis work in cooperation with the IOUs. RETI will maintain its role as an advisory body and stakeholder forum on transmission planning activities across the state. PG&E supports recent policy developments on this front, as the expeditious resolution of transmission issues is a critical element for both PG&E and the state in meeting the renewables targets.

9 Resource Planning and Workplan to Achieve RPS Targets

PG&E estimates that it will meet the 2010 RPS target by using the provisions of flexible compliance adopted in D.08-02-008. From the signing of the initial RPS legislation, SB 1078, in 2003 to the present, PG&E's combination of current renewables deliveries, utility ownership plans, and signed contracts for future deliveries is expected to increase renewable deliveries from 9 percent of PG&E's retail sales to more than 20 percent of retail sales. Again, PG&E anticipates actual renewable deliveries will meet the 20 percent threshold in the 2013 timeframe. Interested parties may refer to the August 3, 2009 Compliance Report for more detailed information on what resources PG&E expects to use to achieve the 20 percent RPS target.

PG&E's 2010 RPS Plan assumes that PG&E will hold a 2010 RPS Solicitation seeking additional renewable resources in an amount to be determined following resolution of the key policy and commercial issues highlighted in Section 1. With the state's goal of 33 percent renewables and the likelihood of a 33 percent renewable requirement—either through the CARB rulemaking or future legislation—PG&E will use the 2010 RPS Solicitation to fill any remaining near-term needs as necessary and to strategically meet the expanded RPS goal in a manner that best suits its customers. If, through the 2010 Solicitation, additional procurement opportunities exist and they are within PG&E's LCBF bid evaluation parameters, including, but not limited to, cost effectiveness and project viability, PG&E will consider signing additional contracts in excess of the initial target as an additional safeguard against potential contract non-performance. In addition to renewable procurement from solicitations, PG&E may also consider executing, on a bilateral basis, RPS contracts resulting from its outreach efforts.

To achieve the 20 percent by 2010 RPS target, part of PG&E's strategy is to procure a technologically and geographically diverse portfolio of renewable energy. As renewable resources are usually located in geographically remote locations, far from major load centers, additional transmission upgrades and enhancements are integral for achieving the RPS target. To facilitate reaching this target, PG&E has actively participated in the CAISO's "Getting to 33% RPS" stakeholder process to develop a new category of transmission project approval specifically for projects that facilitate achievement of California's 33 percent RPS goals.[12] Section 6 contains detailed information on PG&E's efforts in the transmission planning arena.

10 Expanded RPS Procurement Opportunities With TRECs

TRECs are now included in PG&E's 2010 Plan for compliance purposes, based upon PG&E's compliance with all relevant conditions on the use of TRECs in D.10-03-021. PG&E will consider offers for REC-only transactions that arise in its 2010 RPS Solicitation and also in the bilateral market. As directed in ALJ Mattson's March 19, 2010 Ruling, PG&E proposes the amendments to its 2010 RPS Plan included throughout the body of this document. After the Commission approves the amended 2010 RPS Plan, PG&E will begin utilizing TRECs for RPS compliance under the approved terms.

As described in Section 4 above, PG&E will amend its 2010 Power Purchase Agreement to include the non-modifiable Standard Terms and Conditions set forth in D.10-03-021. In addition, PG&E is including in its 2010 RPS Plan a REC-only form purchase agreement. Updates to the Solicitation Protocol will include the following guidance:

- The 2010 Solicitation will provide an opportunity for bidders to offer bundled power and unbundled RECs, both short-term and long-term,
- PG&E does not have a pre-determined quantity target of RECs versus bundled power, but will select the most cost-effective, viable options taking into account any procurement constraints, and
- PG&E does not intend to modify its LCBF criteria to accommodate

[12] See "Getting to 33% RPS: Establishing a New ISO Tariff Category for Renewable Transmission Projects."

TREC bids, and will evaluate TREC bids consistently with bids for bundled products.

11 Development of Utility-Owned Resources

PG&E is exploring all available options for procuring renewable energy, including the viability of utility-developed and/or owned projects. PG&E began exploring utility ownership options for renewables in its 2005 RPS Solicitation, when it sought offers for purchase of completed renewable projects and power purchase contracts with buyout options. In 2006, PG&E expanded its search to include the purchase of development sites. In 2008, PG&E broadened its offer for turnkey projects by eliminating the requirement that the seller provide fuel supply. In 2009, PG&E introduced the concept of joint development and/or joint ownership of renewable projects. The addition of joint development and/or joint ownership to the solicitation process resulted in increased developer response for utility-owned projects. However, since the desired project characteristics were loosely defined in the 2009 RPS Solicitation, several joint development and/or joint ownership projects were not viable.

Therefore, in the 2010 RPS Solicitation, PG&E will continue the concept of joint development and/or joint ownership, the purchase of developed sites and turnkey projects, but provide project guidelines for developers to be in closer alignment with PG&E's existing and proposed renewable ownership portfolio. First, PG&E will limit the offers to "commercially proven technologies." Second, in the 2010 RPS solicitation, PG&E will limit the offers to projects that are sited within the state of California. Finally, PG&E will limit the offers to projects that are of significant scale.

In addition, PG&E will remain open to utility ownership and development opportunities through bilateral negotiations and pursue utility development and ownership of renewable generation. PG&E has initiated efforts to pursue its own development and ownership of solar and wind generation, as described in the following section.

PG&E's involvement in utility ownership and development and joint development and/or joint ownership can address many of the challenges that independent developers are currently facing. These challenges include: (1) a reduced number of large institutions willing to invest in tax equity; (2) reduced availability of credit for asset-based project financing; and (3) higher required rates of return for those who can raise the necessary equity and debt capital. PG&E can use its strong balance sheet to develop and/or support selected projects that face these challenges.

11.1 Current and Future Ownership and Development Opportunities

PG&E is interested in pursuing ownership opportunities with all renewable technologies, if the projects are cost effective. At present, PG&E is pursuing ownership opportunities primarily with small hydro, wind, solar, and ocean technologies. While PG&E is exploring different ownership opportunities, it is uncertain that PG&E will continue future utility-development and/or utility-ownership beyond 2010.

Small Hydro

PG&E has initiated a multi-phase investigation of its extensive hydropower system for opportunities to expand small hydropower generation with RPS-eligible hydroelectric facilities in a manner that is both economically and environmentally sustainable, while recognizing all of the RPS rules that are in place. These opportunities include incremental efficiency improvements at existing powerhouses, new units in existing man-made water conveyance systems (conduits), and new units at some of its existing dams.

In 2009, PG&E received authorization from FERC to begin construction of a small hydro site at its Pit 3 Dam, to be named

Britton Powerhouse upon commercial operation. PG&E expects to continue this and other evaluations in 2010.

Wind

On December 3, 2009, PG&E filed Application 09-12-002 seeking authorization to purchase the 246 MW Manzana Wind Project in eastern Kern County, California. Additionally, PG&E is currently analyzing multiple wind projects which PG&E could develop and own or acquire, such as the land it owns in a well-established wind resource area in northern California. Meteorological data is currently being collected at that site to better define its potential for wind power.

Solar

On April 28, 2010, the CPUC issued D.10-04-052 approving PG&E's five-year proposal to build up to 250 MW of renewable generation resources based on solar PV technology and enter into PPAs for an additional 250 MW of solar PV generation resources following an annual RFO for third parties to develop PV facilities. The approved deployment schedule for each component of the Program is 50 MW per year, subject to certain carry over provisions. Projects will be located in PG&E's service territory and typically be 1-20 MW in size. D.10-04-052 also approved PG&E's 2 MW Pilot project near the Vaca-Dixon Substation. PG&E plans to hold competitive solicitations for the utility-owned facilities and will be submitting an advice letter regarding its proposed procurement process, as directed by D.10-04-052. PG&E also plans to conduct annual RFOs for the PPA portion of the PV Program. As directed by D.10-04-052, PG&E will convene a program forum within 60 days of the closing date of each PPA solicitation to identify solicitation components that may need refinement. PG&E's evaluation criteria and form PPAs for the PPA portion of the PV Program are described in detail in Advice Letter 3674-E, submitted on May 24, 2010.

Separate from the PV Program, PG&E is also pursuing solar development and ownership and has submitted several applications for Rights of Way (ROW) on Bureau of Land Management (BLM) properties in the Mojave for siting concentrating solar thermal power (CSP) projects.

Ocean

PG&E has obtained a preliminary permit from FERC to develop a 5 MW wave power pilot project in California's North Coast which is intended to test and demonstrate ocean wave energy technologies, the first in North America. Ocean energy technologies have been identified as an emerging renewable resource with the potential to generate significant amounts of carbon-free, schedulable power close to coastal load centers.

The Commission has authorized PG&E to incur up to $4.8 million, and the US Department of Energy (DOE) has provided an additional $1.2 million in grants to study the viability of two California coastal sites and the feasibility of developing the marine resource. Subsequent tasks include determining the appropriate method to structure ownership in the project and to procure power from third parties that would use PG&E's developed infrastructure. PG&E is also investigating additional ocean renewable technologies and development opportunities and has recently filed a preliminary permit application at FERC for a commercial wave energy facility, implemented in phases of up to 100 MW in California's Central Coast region in cooperation with Vandenberg Air Force Base.

11.2 Issues Inhibiting Utility Development and Ownership of Renewable Energy Projects

11.2.1 Cost Recovery

Reasonable ways to identify, track, and seek cost recovery for renewable energy project development efforts are needed. Prudent development requires multiple projects to be screened in the initial development phase, ensuring that only the most viable and economical project can be pursued. Generally, if the initial project development efforts lead to the construction and operation of a facility, there is a reasonable likelihood that these development costs can be recovered. However, to encourage prudent development, PG&E has proposed a mechanism in its 2011 General Rate Case (GRC) that would authorize cost recovery for the early project development expenses. Such a mechanism would encourage utilities to conduct early "prospecting" activities needed to develop renewable technologies on behalf of their customers.

11.2.2 California Property Tax Exemption

California utilities pay property tax on solar property while non-utility, locally assessed companies are property tax exempt. PG&E would be assessed property taxes at approximately 1.1 percent of the total plant cost per year.

12 Contract Amendments

In this section, PG&E comments on the process for the review of contract amendments proposed in the Assigned Commissioner's Ruling (ACR) and provides a proposal that will provide appropriate oversight and less burden on already-approved projects.

12.1 PG&E's Response to Scoping Memo Questions on Contract Amendments

PG&E agrees with the ACR proposal that routine contract changes should be managed by the utility without prior Commission approval and subsequently reported in the utility's Quarterly Contract Review (QCR) under the ERRA rules.

PG&E also agrees that additional renewables procurement at an approved price should be treated as consistent with a Commission decision and simply be reported to the Energy Division under the Tier 1 Advice Letter approach. However, Tier 1 approval should be broadened to include all contract amendments consistent with the exercise of any pre-approved option.

Finally, PG&E agrees that contract modifications that would increase ratepayer costs, or address issues explicitly reserved by the Commission for further deliberation[13] should be presented by a Tier 3 advice letter for approval in a Commission resolution.

However, the ACR proposal's use of the Tier 3 Advice Letter process for "all other" proposed changes is inappropriate because the lengthy Tier 3 process is unnecessary to make a determination of the reasonableness of proposed modifications that present limited issues for review. Requiring all "[U]nique aspects of contract administration, such as major modification of contract milestones" to be approved by a resolution by the Commission will do little to increase or improve RPS procurement; it subjects utilities to the risk of noncompliance if the Commission staff disagrees with the utility on whether a proposed change is a "unique aspect of contract administration" or "a major modification of a contract milestone," and may compel the utility to file more contract amendments under the lengthy Tier 3 process and increase Commission workload relative to the status quo.

The ACR's characterization of the Energy Division as the "gatekeeper" that screens contract amendments that require special attention is correct and the adopted procedure for review of contract amendments enable the Energy Division to assume that role. The Commission can designate contract amendments other than those mandated for Tier 1 and Tier 3 review as amendments to be submitted for Tier 2 review and be assured that important

13 *I.e.*, "require further consideration relative to explicit terms of PPA approval."

matters will be referred for a Commission resolution and vote, based on General Order 96-B, Section 7.6.1.[14]

However, the ACR's description of situations in which an advice letter may be converted to an application is overbroad. Conversion should not occur when an advice letter raises a "potentially disputed" issue because there may be no controversy; conversion should not occur automatically if "the proposed price exceeds the relevant MPR by a nontrivial amount" because the approved contract price could already exceed the MPR. A proposed amendment to an approved contract should not face a tougher regulatory hurdle than the test applied to new contracts. A stiffer test will only discourage developers from dealing with California's IOUs. The appropriate trigger for converting an advice letter to an application should be a proposed price that exceeds contract prices previously approved by Commission resolution by a reasonable factor, considering all relevant circumstances.

12.2 PG&E's Proposal – Energy Division Approval Under the Tier 2 Advice Letter Process is Appropriate for New Matters That Do Not Materially Reduce the Value of the Contract

The Tier 2 Advice Letter process should be used for changes other than those handled through routine contract administration and changes that do not materially decrease the value of the contract or increase ratepayer costs.

The Assigned Commissioner's ruling states, "Commission administration of the consideration and disposition of proposed contract amendments will, to the fullest extent feasible, be parallel to the administration and disposition of proposed contracts." Making the Tier 3

[14] Section 7.6.1 states: An advice letter will be subject to Industry Division disposition even though its subject matter is technically complex, so long as a technically qualified person could determine objectively whether the proposed action has been authorized by the statutes or Commission orders cited in the advice letter. Whenever such determination requires more than ministerial action, the disposition of the advice letter on the merits will be by Commission resolution, as provided in General Rule 7.6.2.

advice letter process the default for each and every contract amendment is unreasonable and will further diminish the appeal of developing renewables in California, particularly when the cumulative time necessary for a developer to obtain PPA approval in California is considered. For example, Table 2 below indicates the amount of time typically necessary for reviewing a PPA amendment through the Tier 3 advice letter process as compared to a Tier 2 advice letter:

Table 2
Pacific Gas and Electric Company
Time for Reviewing PPA Amendment Pursuant to Tier 3 Advice Letter Process Compared to Tier 2 Advice Letter Process

Contract Amendment Comparative Approval Timeline	Tier 2 Process (Industry Disposition)	Tier 3 Process (CPUC Resolution)	Cumulative Days	
			Tier 2	Tier 3
Protests Due	+ 20 days	+ 20 Days	20	20
Reply Due	+ 5 days	+ 5 Days	25	25
Proposed Resolution	None	+60 Days		85
Comments on Proposed Resolution		+20 Days		105
Reply Comments on Proposed Resolution		+5 Days		110
Amendment Approved	Posting to CPUC Website**	CPUC Meeting	55	115
Deadline for Request for Rehearing of Approval/Resolution	10 Days After Posting	30 Days After Issuance of Decision	65	150

** Assumes staff prepares a Tier 2 resolution within 30 days and the more complex Tier 3 resolution within 60 days.

The authority to approve certain contract amendments can be delegated to the Energy Division because the Commission has already established, through findings, that the underlying agreement is reasonable and in the best interest of ratepayers. So long as the Commission staff's actions are consistent with the Commission's decision, its approval of amendments should be deemed to constitute a "ministerial act". (See General Order 96-B Rule 7.6.1.) The staff's authority can be limited to ensure that approvals under the Tier 2 process are consistent with the Commission's RPS contract resolutions by requiring that advice letters to be submitted under Tier 3 may not be submitted under Tier 2. In the event the Energy Division finds that other amendments proposed by a Tier 2 advice letter may materially decrease the net market value of the contract, the Energy Division may exercise its discretion as the "gatekeeper" to convert the advice letter to a Tier 3 advice letter.[15]

To avoid subjecting existing contracts to potentially debilitating delay pending approval of proposed contract amendments, the Commission should adopt the following process:

LEVEL OF REVIEW	EXAMPLES OF ELIGIBLE AMENDMENT
Annual ERRA Filing	Routine contract administration (*e.g.*, minor modification of project milestones).
Tier 1 Advice Letter	Exercise of a Commission-approved option, such as additional procurement under approved terms.
Tier 2 Advice Letter	New issues other than those subject to Tier 3 review.
Tier 3 Advice Letter	1. Matters explicitly reserved for Commission consideration in the resolution approving PPA. 2. A substantial increase in ratepayer cost that has not been pre-approved.

13 Cost Containment

The Amended Scoping Memo asks whether there are additional contract terms, incentives or other features that should be considered to promote a robust market while minimizing costs to ratepayers. The specific questions in the Amended Scoping memo focus on the application and use of Time-of-Delivery (TOD) factors.

As discussed in Section 8, there are a number of challenges to RPS development in addition to these issues, such as financing and permitting, which

[15] GO 96-B Rule 7.6.1, "A utility shall designate in the advice letter whether the utility believes the advice letter is subject to Industry Division disposition. The utility's designation is not binding on the reviewing Industry Division…. Whenever such determination requires more than ministerial action, the disposition of the advice letter on the merits will be by Commission resolution, as provided in General Rule 7.6.2."

ultimately impact PPA costs.

14 TOD Factors

PG&E's 2010 RPS Plan fixes both the TOD periods and factors for the life of the contract. To ensure that the best information is indeed used, PG&E is not including specific updates to periods and factors in this filing, but proposes that, like in its 2008 and 2009 RPS Plans, those be updated when the Plan is finalized.

15 Efforts to Coordinate

The three major utilities were again encouraged to make their three Plans reasonably uniform. Because of the relatively brief interval between the issuance of the Scoping Memo and the deadline for filing the Draft 2010 RPS Plans, the three major utilities focused their efforts on new matters intended to streamline and improve the renewables procurement process.

The three utilities concurred that the schedule for a 2010 RPS solicitation should be the same as the one adopted for 2009, only one year later. That is, requests for offers pursuant to the 2010 RPS Plan should be issued at the end of June 2010 because the first half of 2010 will be occupied with procurement under the 2009 RPS Plan.

The utilities discussed alternatives to the ACR's proposed process for approval of RPS contract amendments. Finally, the utilities agreed that advance authority to procure under contracts with a delivery term of less than five years should be available for renewables procurement, just as it is for conventional power. Although the utilities agreed in principle, there was insufficient time for the drafting and adoption of a common utility proposal.

16 Imperial Valley Issues

16.1 Bidders' Conference

PG&E scheduled and held its Imperial Valley Bidders' Conference on July 21, 2009, at 3 p.m., at the same location, and less than an hour after the conclusion of its general RPS Bidders' Conference to allow those interested specifically in siting their projects in the Imperial Valley area to learn about PG&E's overall RPS solicitation process. About 25 of the estimated 160 attendees at the overall RPS Bidders' Conference remained for the Imperial Valley presentation.

PG&E presented an overview of the Commission's certification of the Sunrise Powerlink transmission project, a description of the Powerlink's features and route, the Powerlink's project development status, the Powerlink's estimated June 2012 in-service date, and the CAISO's estimate that if the Powerlink were not available, approximately 1,900 MW of renewable capacity would not be possible in the Imperial Valley. PG&E advised attendees that it encourages offers from projects located within the Imperial Valley and projects that may create significant flows on the Sunrise Powerlink. There were no significant questions about the role of the Sunrise Powerlink in facilitating the development of renewable energy generation in the Imperial Valley. However, one attendee asked why a project located in the vicinity of the Powerlink would seek to contract with PG&E. The PG&E representative indicated that the bidder might prefer the commercial terms offered by PG&E over those of the southern utilities.

16.2 Remedial Measures for 2010

The Imperial Valley results from the 2009 solicitation were sufficiently robust that the Commission should not adopt any remedial measures relative to Imperial Valley for 2010 (*e.g.*, automatic short-listing, Imperial Valley bid evaluation metric, special Imperial Valley solicitation, other). This conclusion is based upon the evaluation of Imperial Valley results and specific bids conducted by PG&E's IE. The IE's observations are presented in Confidential Appendix C and are summarized here to the extent possible without divulging confidential information.

PG&E received a significant volume of offers that proposed to construct new renewable generation facilities that would interconnect to the grid in the Imperial Valley. The transmission adders were identified and utilized as required by D.04-07-029 in the same manner as for other proposed generation interconnecting within non-CAISO control areas within California. The IE observed that direct connection into CAISO jurisdictional facilities, rather than facilities owned by third parties such as IID, allowed projects to avoid wheeling charges and resulted in the imputation of lower transmission costs during LCBF analysis.

The IE found that the number of bids received for development in the Imperial Valley area relative to the resource development potential for the area was roughly the same proportion as observed for renewable bids throughout the rest of PG&E's service territory. Generally, the percent yield of short-listed Imperial Valley Offers from all Imperial Valley Offers submitted was slightly below the yield of short-listed offers overall out of all original offers. The IE noted that the average price of Imperial Valley Offers was different from the average for all offers, probably due to the type of technology most prevalent in the Imperial Valley.

The Commission's desire that renewable resources take advantage of the Sunrise Powerlink is being met due to the economic reality that the developer's use of the Powerlink will result in lower transmission costs. Because PG&E's solicitation results for the Imperial Valley did not differ significantly from the results for PG&E's service territory in terms of bidder participation and bid success rate, no remedial solicitation activity is needed for 2010.

17 RPS Pilot Program for Short-Term Deliveries

To fulfill PG&E's need for near-term renewable energy, PG&E proposes a program to streamline the contract approval process for a limited volume of short-term transactions. Under this program, the Commission-approved protocol for pre-approval of short-term transactions for conventional power would be used for similar transactions involving energy from renewable resources. This pre-approval process is necessary to give PG&E the flexibility to compete with other LSEs for short-term transactions and to reach California's RPS goals cost effectively.

As in the case of conventional generation, short-term renewable deliveries are available for a limited term and deliveries may be required shortly after execution to make the transaction worthwhile for the counterparty. Short-term transactions are not assured of a Commission decision quickly enough under the current "one size fits all" process for the review and approval of RPS contracts. The expedited process approved by the CPUC in D.09-06-050 has not proven useful. The price and contracting conditions that were adopted in that decision are so restrictive that PG&E has found counterparties not willing to transact. This can also put PG&E at a disadvantage relative to other buyers of renewable energy where the regulatory approval process is more streamlined. The net result is that it is substantially more difficult for utilities to procure renewable generation than it is for the utility to procure power from conventional resources. This is contrary to the CPUC preferred loading order, which requires utilities to procure demand-side and renewable resources to the maximum extent possible before procuring conventional resource.

Commission pre-approval of short-term contracts that meet minimum criteria is needed for IOUs to compete with electric service providers, municipal utilities, and other LSEs that can offer prompt performance of executed short-term contracts. Ratepayers will also benefit from up-front approval because short-term deliveries represent an additional source of supply.

Accordingly, PG&E proposes a RPS program for Short-Term Deliveries, subject to the following standards for demonstrating reasonableness prior to procurement (upfront reasonableness standards). This proposal applies to bundled power transactions and TREC transactions.

- **Delivery Term** – Contract delivery term will be consistent with the current LTPP authorization (*i.e.*, D.07-12-052, Finding of Fact 79, or successor decision). Currently, the 5-year delivery term begins either at the time the contracted resources begin delivery if delivery begins within one year of execution or at the time of contract execution if delivery does not begin within one year of execution.

- **Purchased Product** – Any delivery point and any product, including TRECs, approved by the CPUC to be used for RPS compliance and meeting the CEC guidelines for delivered RPS energy. To address viability concerns, only generation from existing generating units or from those under construction with an expected commercial operation date within one year of contract execution may be procured with this mechanism.

- **Price Cap** – PG&E will establish a minimum valuation metric prior to initiating any procurement under this pilot program. Transactions would be eligible for execution under the program as long as the net value exceeded the minimum established by the CPUC. The net value for bundled renewable transactions is the cost premium of the renewable energy relative to market prices for conventional power, which includes a greenhouse gas (GHG) adder. The net value for a TREC transaction that does not include bundled power is the price of the TREC. PG&E proposes that transactions will satisfy cost reasonableness criteria under this program if the price premium would put that offer in the top two-thirds of offers from the most recent RPS solicitation short-list. For example, if the utility's short-list had 30 offers, the short-list offer would need to have a value at least as good as the 20th ranked project on the short-list. As an alternative, the CPUC could look at the average market value of recently approved RPS transactions for calculation of the price cap.

- **Volumes** – Procurement under this program would be limited to 1 percent of the current year's retail load cumulative over five years (or 5 percent of bundled sales over the 5-year period). Deliveries during the five years will count against this limit. Based on PG&E's current load forecast, 1 percent of retail sales is approximately 800 GWh, so up to 4,000 GWh of deliveries to be received within five years could be procured on a pre-approved basis. There would not be a volume limit for any particular delivery year other than the cumulative volume associated with the program.

- **Revenue Requirement Cap** – Procurement limits would be based on an overall revenue requirement cap. The cap would be calculated using the volumes and price caps above. For example, if the reasonable price premium was $50 MWh, the revenue requirement cap would be: 4,000 GWh × 1,000 MWh/GWh × $50/MWh = $200 million over the program. The utility could procure volumes in excess of 4,000 GWh so long as the cumulative premiums remained below the revenue requirement cap.

  The Director of the Energy Division will be delegated the authority to increase the revenue requirement cap beyond its originally approved level for reasons such as:

  – An IOU requests an increase;

  – There is a continuing compliance need to procure renewable energy over the next five years forward from the date of such request;

  – The program has been effective in the market as measured by market response;

  – The executed contracts within the program are deemed competitively priced as compared to the maximum valuation metric; and

  – The program has demonstrated it is an efficient way to procure RPS eligible energy.

- **Review Process** – Proposed short-term contracts will be reviewed for RPS compliance by an IE and presented to PG&E's PRG.

- **Upfront Determination of Reasonableness** – Contracts entered into in accordance with these guidelines will be reasonable *per se;* the terms of the contracts, including payments to be made by PG&E, will be deemed to be approved by the Commission and recoverable in rates, subject to Commission review of PG&E's administration of the transaction.

- **Quarterly Review** – The transactions will be reviewed for compliance with the upfront reasonableness standards in the existing procurement plan QCR which PG&E submits by advice letter.[16] Like other approved RPS costs, recovery of approved short term transaction costs will be sought in the ERRA.

PG&E believes an expedited process is essential to its ability to meet its near-term procurement targets. PG&E also believes that the same expedited process should be implemented for all three utilities, in order to ensure that all IOUs are on a level playing field when competing for renewable resources. As described in other sections of this 2010 RPS Plan, new renewable generation resources are facing multiple obstacles to development and construction, and given the resultant delays faced by many, newly developed generation simply is not available to contribute to PG&E's near-term RPS targets. Unless this proposal or a similar proposal that may be suggested by another utility is approved, IOUs have no practical means of meeting their 2010 targets and will need more time to comply with their goals.

---

[16] The Commission is currently reviewing the format of the Procurement Plan Compliance Report Quarterly Advice Letter Filing for all utilities and is considering revisions, including the addition of renewable transactions.

VERIFICATION

I am an employee of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing “2010 Renewable Energy Procurement Plan”, dated June 2, 2010. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 2nd day of June 2010 at San Francisco, California.

/s/

Valerie Winn
Manager, Renewable Energy Policy and Planning
Pacific Gas and Electric Company

Public and Redacted Appendices

Appendix A
(Redacted)

PG&E's Executed Renewables Contracts

Above MPR

PG&E Executed Renewable Contracts above MPR

RPS Contract	Project MW	GWh per Year	Cost per MWh - Levelized, Adjusted for TOD (confidential)	Estim. Nominal Above MPR ($M) (confidential)	Relevant MPR Year	Eligible for Above Market Funds?	Bilateral, Solicitation, Other?
Genesis (FPL) - Scenario Average	250	542	[redacted]	[redacted]	2008	Yes	Solicitation - 2008 RPS
Harper Lake (Mojave Solar / Abengoa)	250	616	[redacted]	[redacted]	2008	Yes	Solicitation - 2008 RPS
Geysers 2009 Aggregation	425	2,060	[redacted]	[redacted]	2008	No	Bilateral - 2008
Agua Caliente (Nextlight)	290	687	[redacted]	[redacted]	2008	Yes	Solicitation - 2008 RPS
California Valley Solar Ranch (SunPower) Phases I - III *	290	687	[redacted]	[redacted]	2007	Yes	Solicitation - 2007 RPS
Desert Topaz (Optisolar/First Solar) Phases I - III *	580	1,375	[redacted]	[redacted]	2007	Yes	Solicitation - 2007 RPS
Invenergy (Vantage Wind)	90	277	[redacted]	[redacted]	2008	Yes	Solicitation - 2008 RPS
Solaren	200	1,701	[redacted]	[redacted]	2008	No	Bilateral - 2008
Hatchet Ridge	103	303	[redacted]	[redacted]	2005	Yes	Solicitation - 2005 RPS
Solel	500	1,389	[redacted]	[redacted]	2005	Yes	Solicitation - 2005 RPS
Copper Mountain (Sempra)	48	101	[redacted]	[redacted]	2008	Yes	Solicitation - 2008 RPS
Arlington (Horizon)	104	241	[redacted]	[redacted]	2007	Yes	Solicitation - 2007 RPS
Chowchilla (Global Ampersand)	9	66	[redacted]	[redacted]	2004	No	Bilateral - 2004
El Nido (Global Ampersand)	9	66	[redacted]	[redacted]	2004	No	Bilateral - 2004
Geysers (Calpine)	175	1,061	[redacted]	[redacted]	2007	No	Bilateral - 2007
Cleantech (CalRenew)	5	9	[redacted]	[redacted]	2006	Yes	Solicitation - 2006 RPS
Shiloh II (EnXco)	150	510	[redacted]	[redacted]	2006	No	Bilateral - 2006
Mt. Poso Redhawk 2 yr ext.	43	66	[redacted]	[redacted]		No	Bilateral - 2007
El Dorado (Sempra)	10	22	[redacted]	[redacted]	2008	Yes	Solicitation - 2008 RPS
Green Volts	2	4	[redacted]	[redacted]	2006	Yes	Solicitation - 2006 RPS
PacifiCorp 2010 - 2012	100	656	[redacted]	[redacted]	2008	No	Bilateral - 2008
Montezuma (FPL)	32	102	[redacted]	[redacted]	2004	No	Bilateral - 2004
Mt Poso Cogen Plant (RedHawk / Millennium Energy) (15-Year PPA)	43	328	[redacted]	[redacted]	2008	No	Bilateral - 2007
Stockton Cogen (DTE)	45	315	[redacted]	[redacted]	2008	No	Bilateral - 2009
Solar Reserve (Rice Solar)	150	448	[redacted]	[redacted]	2008	No	Bilateral - 2009
Eurus (Sand Drag)	20	34	[redacted]	[redacted]	2009	No	Bilateral - 2009
Eurus (Sun City)	20	30	[redacted]	[redacted]	2009	No	Bilateral - 2009
Eurus (Avenal)	10	17	[redacted]	[redacted]	2009	No	Bilateral - 2009
Wheatfield (Shell 4)	97	256	[redacted]	[redacted]	2009	No	Bilateral - 2009
Big Horn II (Shell 5)	70	100	[redacted]	[redacted]	2009	No	Bilateral - 2009
Combine Hills II (Shell 6)	62	163	[redacted]	[redacted]	2009	No	Bilateral - 2009
PowerEx	N/A	330	[redacted]	[redacted]	2009	No	Bilateral - 2009
White Creek II (Shell 3)	65	171	[redacted]	[redacted]	2009	No	Bilateral - 2010
White Creek III (Shell 7)	25	66	[redacted]	[redacted]	2009	No	Bilateral - 2010
Havest Wind I (Shell 8)	28	73	[redacted]	[redacted]	2009	No	Bilateral - 2010
Havest Wind II (Shell 9)	30	40	[redacted]	[redacted]	2009	No	Bilateral - 2010
Hay Canyon Wind (Barclays)	101	277	[redacted]	[redacted]	2009	No	Bilateral - 2010

* Prices for the multi-phase projects are averages weighted by their energy deliveries per year, and their total estimated above MPR cost is the sum the cost of each phase.

Bilateral agreements are not eligible for AMF. Grey cell indicates CONFIDENTIAL information

Appendix B

Summary of Changes to 2010 Form PPA

Appendix B
Summary of Significant Changes to PG&E's
2009 Power Purchase Agreement
Reflected in PG&E's 2010 Power Purchase Agreement

Note: For definitions of capitalized term used in this Appendix, please refer to Attachment H to PG&E's 2010 Solicitation Protocol.

Changes:

1. "Generally Accepted Accounting Principles" – PG&E added this explicit definition, rather than rely on industry knowledge alone. The definition also reflects the new successor standards, expected to soon be adopted by the SEC.

2. PG&E updated the definition of "CPUC Approval" to include the additional term required by the CPUC through its February 16, 2010 Decision on TREC Transactions for RPS purposes (in the event the current stay is lifted and the provisions of such Decision must be given treatment).

3. Section 2.4 – PG&E added this Section to clarify the fact that PG&E as Buyer under this Agreement is acting solely in its merchant capacity, and that PG&E as the PTO is acting solely in its transmission-related capacity. Neither PG&E as Buyer nor PG&E as PTO are to assume the responsibilities and obligations of the other under the Agreement.

4. Section 3.1(e)(ii) – To address Seller concerns relating to using the P95 Value-type equation to determine a wind Project's Guaranteed Energy Production amount, PG&E deleted the use of the P95 Value calculation and instead used the 90% of Contract Quantity-type equation presently in the Agreement for use with all other technologies.

5. Section 3.1(k) and 3.1(k)(viii) – PG&E added the new WREGIS warranty term required by the CPUC through its February 16, 2010 Decision on TREC Transactions for RPS purposes (in the event the currently stay is lifted and the provisions of such Decision must be given treatment), and including language to introduce the concept into the language already existing.

6. Buyer Curtailment – To address the consistently expressed Seller concern regarding the extent to which Buyer (as distinguished from PTO) may cause a curtailment, PG&E added a new "Buyer Curtailment Period" system. To effectuate this new system, the following PPA Definitions or Sections were created or modified: "Buyer Curtailment Period", Buyer Curtailment Order", "Curtailment Period", "Deemed Delivered Energy", "Real-Time Settlement Interval MSS Price", "Seller Excuse Hours", 3.1(i)(iii), 3.1(o), 4.1 and [4.3][4.4]. Under the new system, Buyer

has the ability to issue a Buyer Curtailment Order and curtail Seller's generation for any reason up to a maximum amount of 5% of the Contract Quantity cumulatively per Contract Year. In exchange for the ability to so curtail, Buyer agrees to compensate Seller for the amount of Energy it would have been able to produce during such Buyer Curtailment Period by paying Seller the Contract Price for the Deemed Delivered Energy. Seller's failure to comply with Buyer's Curtailment Order results in damages owed Buyer from Seller for the amount of Energy Seller delivered in contradiction to Buyer's Curtailment order at the price of the greater of (A) 200% of the Contract Price and (B) the Real-Time Settlement Interval MSS Price, plus costs and penalties. PG&E also acknowledged the impact the operational characteristics of a specific technology may have on Buyer's ability to issue a Buyer Curtailment Order, and included a placeholder for such characteristics to be addressed.

7. Section 3.3 – PG&E modified this Section to clarify that successful completion of a "Full Capacity Deliverability Study" (new defined term) as defined by the CAISO is required in order for Resource Adequacy to be considered a portion of the Product sold to Buyer under the Agreement. PG&E further modified this Section to allocate the risks which may result from the CAISO's proposed Availability Standards and Replacement Capacity Rules.

8. Section 3.4(b) – PG&E modified this Section to more clearly and definitively state the EIRP cost allocation between PG&E and the Seller and restructured the Section to reflect that solar Projects are no longer excluded from ERIP.

9. Section 3.4(c)(ii) and (iii) and the definition of "Energy Deviations" – PG&E updated these Sections to reference post-MRTU, CAISO Tariff language. For example, all references to "Hour-Ahead" as an explicit concept from the CAISO Tariff were removed, because that term no longer appears in the current post-MRTU CAISO Tariff. Instead we refer to the "Hour-Ahead Scheduling Process", the term now used in the CAISO Tariff.

10. Sections 3.4(a)(i) and (ii) – To eliminate confusion between the relationship of the Curtailment and new Buyer Curtailment provisions with other Transmission provisions, PG&E eliminated the following language from these respective Sections: "[Seller][Buyer] shall bear all risks and costs associated with such transmission service, including but not limited to, any transmission outages or curtailment [to][from] the Delivery Point." In addition, in subsection (ii), PG&E added a specific cross-reference to the Performances Excuses Sections which specifically include treatment of Buyer Curtailment.

11. Section 3.9(c)(iii)(A) – PG&E modified the 540-day cap on Milestone achievement extensions applicable to Force Majeure Construction Events, Permitting and Transmission Delays. The total number of days for permitted extensions is now 540 days for pre-construction delays, plus an additional 360 days for a post-Construction Start Date Force Majeure event. Therefore, the aggregate

number of extension days available to the Seller is now 900 days. This does not include the two 60-day cure periods for which the Seller would be liable for Daily Delay Damages.

12. Section 5.2(a) and (c) – PG&E made adjustments to these subsections to clarify the rights of the non-defaulting Party upon an Event of Default.

13. Section 10.2(b) – PG&E added the new RPS compliance representation and warranty term required by the CPUC through its February 16, 2010 Decision on TREC Transactions for RPS purposes (in the event the currently stay is lifted and the provisions of such Decision must be given treatment).

14. Section 10.2(C) – To address the consistently expressed Seller concern regarding its exposure to changes in law resulting in cost to remain compliant with the Non-Modifiable Term and Condition contained in Section 10.2(b) (Seller's representation and warranty that throughout the Delivery Term "…the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR")… and that the Project's output delivered to Buyer qualifies under requirements of the California Renewables Portfolio Standard…" Buyer added Section 10.2(c). This new Section establishes that Seller be deemed to have undertaken "commercially reasonable efforts" to remain ERR and RPS compliant in the face of a change in law to the extent that Seller incurs costs in an aggregate up to an amount equaling $10,000/MW of the Contract Capacity, an "RPS Qualification Expenditure Amount". Upon reaching such amount, the Parties shall agree on the amount in excess of the RPS Qualification Expenditure Amount required for the Project to remain compliant. Buyer may then elect to fund the excess amount to ensure ERR and RPS qualification, or elect not to fund the excess amount, in which case Buyer will continue to purchase the Energy from the Project, and Seller shall not be required to expend any additional funds toward otherwise necessary expenditures.

15. Section 10.10 – PG&E updated the insurance provision. The changes are generally beneficial to Sellers, but continue to protect PG&E.

16. Section 10.16 – PG&E added a new Section 10.16 to establish the mechanics through which either Party could initiate negotiations for a possible purchase by PG&E of the Project from the Seller at fair market value. Previously the ownership option was addressed, if at all, through Seller's submission of a separate term sheet along with its PPA Offer. Including the ownership option in the PPA itself allows for a more cohesive Offer to be presented, if so chosen by Seller.

17. Sections 11.2(a)(i)(A) and (B) – PG&E adjusted the language to allow Sellers time to make the repairs to the facility if an independent engineer's report indicates that the facility can be repaired within the time period permitted under the PPA, thereby preventing a "Force Majeure Project Failure", which triggers a right for PG&E to terminate the PPA.

18. Appendix VI, Charts VI-1 and VI-2 – PG&E clarified the relationship between Construction Start and Commercial Operation Certification Forms and Procedures by distinctly separating the two.

19. Appendix XIII – PG&E modified the “Seller Documentation” Appendix to extend the period by which the Seller must provide the condition precedent documentation to five (5) Business Days following execution of the PPA.

20. PG&E revised the definition of “Letter of Credit” to include additional provisions regarding foreign commercial banks, including Buyer’s ability to modify the Letter of Credit form for foreign commercial banks and that the foreign commercial bank must be acceptable to Buyer.

21. Section 3.1(l)(i)(E) was modified to require more frequent data samples in order to improve forecasting. To supplement this change, in Section 3.7(f) PG&E added a cross-reference to Section 3.1(l).

Confidential Appendix C

EVALUATION OF IMPERIAL VALLEY RESULTS

Confidentiality Protected Under D.06-06-066 Appendix 1
Item VII (un-numbered category following VII G) Score sheets,
analyses, evaluations of proposed RPS projects.