STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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January 26, 2010

Agenda ID #9195
and
Alternate Agenda ID #9196
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 09-02-019

Enclosed are the proposed decision of Administrative Law Judge (ALJ) Maryam Ebke previously designated as the presiding officer in this proceeding and the alternate decision of President Michael R. Peevey. The proposed decision and the alternate decision will not appear on the Commission's agenda sooner than 30 days from the date they are mailed.

Pub. Util. Code § 311(e) requires that the alternate item be accompanied by a digest that clearly explains the substantive revisions to the proposed decision. The digest of the alternate decision is attached.

When the Commission acts on these agenda items, it may adopt all or part of the decision as written, amend or modify them, or set them aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision and alternate decision as provided in Pub. Util. Code §§ 311(d) and 311(e) and in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Maryam Ebke at meb@cpuc.ca.gov and President

Peevey's advisor Andrew Schwartz at as2@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ CHARLOTTE TERKEURST for KVC
Karen V. Clopton, Chief
Administrative Law Judge

KVC:oma

Attachment

ATTACHMENT

This Alternate Proposed Decision (Alternate) approves Pacific Gas and Electric Company's Solar Photovoltaic Program subject to certain modifications. The Alternate differs from the Proposed Decision (PD) in the following substantive ways:

- The Alternate approves a program that includes projects in the size range of one to three megawatts (MW). The PD does not.

- The Alternate allows up to 5% of the utility-owned generation capacity authorized under this program to be from facilities less than 1 MW in size and/or roof-mounted. The PD does not allow these types of projects to be pursued under the program.

(END OF ATTACHMENT)

Decision **ALTERNATE PROPOSED DECISION OF PRESIDENT PEEVEY**
(Mailed 1/26/2010)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Implement and Recover in Rates the Costs of its Photovoltaic (PV) Program (U39E).	Application 09-02-019 (Filed February 24, 2009)

DECISION ADOPTING A SOLAR PHOTOVOLTAIC PROGRAM FOR PACIFIC GAS AND ELECTRIC COMPANY

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DECISION ADOPTING A SOLAR PHOTOVOLTAIC PROGRAM FOR PACIFIC GAS AND ELECTRIC COMPANY

1. Summary

This decision adopts a five-year solar photovoltaic program (PV Program) to develop up to 500 MWs of solar photovoltaic (PV) facilities in the range of one to 20 MWs in Pacific Gas and Electric Company (PG&E's) service territory. In addition, this decision approves a 2 MW PV pilot project.

The PV Program provides for development of both utility-owned generation (UOG) and power purchase agreements (PPA). Under the UOG portion of the PV Program, PG&E is authorized to install up to 250 MWs of UOG PV facilities from one to 20 MW in size in its service territory at a rate of 50 MW per year, subject to the carryover and drop out provisions described below. Similarly, under the PPA portion of the PV Program, PG&E will be authorized to solicit 250 MWs of electricity from PV facilities from one to 20 MW in size located in PG&E's service territory at a rate of 50 MW a year, also subject to the carryover and drop-out provisions provided below. Pricing under the PPAs will be based on the competitive solicitation with the successful bidders entering into a 20-year PPA with PG&E. To ensure that ratepayers are held essentially indifferent between projects developed by PG&E and those developed by independent power producers, the revenue requirement for the UOG portion of the PV Program shall be based on the weighted average price per kWh received in the PPA solicitations and the actual UOG system performance. Appendix A describes the adopted PV Program including the pricing methodology.

2. Background

On February 2, 2009, Pacific Gas and Electric Company (PG&E) filed this application seeking approval of a Photovoltaic Program (PV Program) and authorization to recover associated revenue requirements for the PV Program in rates. PG&E's proposed PV Program consists of the installation and operation of up to 500 megawatts (MWs) of one to 20 MWs PV generation facilities in PG&E's service territory over a five-year period. Up to 250 MWs of the program capacity will be utility-owned generation (UOG) and PG&E will procure up to 250 MWs through power purchase agreements (PPAs) with independent power producers. PG&E seeks authorization to incur an estimated $1.45 billion in capital costs for the PV Program. In addition, PG&E requests approval of a 2 MW pilot program to be started in 2009 at an estimated capital cost of $11.9 million.

Several parties filed protests and responses to the application. The Commission held a prehearing conference (PHC) on May 14, 2009. Following the PHC, the Assigned Commissioner and Administrative Law Judge (ALJ) issued a Scoping Memo and Ruling (Scoping Memo) which established the scope of issues and the schedule for the proceeding.

Parties served testimony and rebuttal testimony pursuant to the Scoping Memo schedule. Evidentiary hearings were held on September 10 through 14, 2009. The Division of Ratepayer Advocates (DRA), CAlifornians for Renewable Energy (CARE), California Large Energy Consumers Association (CLECA), Western Power Trading Forum (WPTF) and Direct Access Customer Coalition (DACC), Consumer Federation of California (CFC), Coalition of California Utility Employees (CUE), The Solar Alliance, Independent Energy Producers Association (IEP), The Utility Reform Network (TURN), California Farm Bureau Federation (Farm Bureau), and The Greenlining Institute (Greenlining) filed timely opening briefs. DRA, WPTF and DACC, CLECA, CUE, The Solar Alliance and California Solar Energy Industries Association (CALSEIA), CARE, Greenlining filed timely reply briefs. CARE and DRA requested final oral arguments pursuant to Commission Rules of Practice and Procedure. Accordingly, the Commission held a final oral argument on ___________, 2010.

On October 11, 2009, the Governor signed Senate Bill (SB) 32, (Stats. 2009, ch. 328) and Assembly Bill (AB) 920, (Stats. 2009, ch. 376) into law to take effect January 2010. SB 32 increases the size of generation facilities eligible for California's feed-in tariff program from 1.5 megawatts (MW) to 3 MW, and raises the program's statewide cap from 500 MW to 750 MW. SB 32 also establishes that the price under this program shall be based on the market price referent adjusted to include all current and anticipated environmental compliance costs subject to a ratepayer indifference test. AB 920 allows net energy metering customers with projects of up to 1 MW to sell any excess electricity they produce over the course of a year to their electric utility at a rate to be determined by the Commission.

Because both pieces of legislation require the utilities to provide compensation for electricity provided to the grid by projects similar in size and technology to those under consideration in this application, the assigned ALJ issued a ruling on October 30, 2009, requesting additional briefs on whether any aspects of SB 32 and AB 920 would impact PG&E's proposed PV Program in a way that should affect the Commission's final decision in this proceeding. DRA, TURN, PG&E, Greenlining, Solar Alliance, CFC, CARE, CALSEIA, and CUE filed timely supplemental briefs.

The proceeding was submitted on _________ upon conclusion of the final oral argument.

3. PG&E's Proposed PV Program

PG&E proposes a five-year PV Program to develop up to 500 MW of PV facilities between one and 20 MW in its service territory in northern and central California. PG&E's proposed PV Program would consist of two separate parts:

- The UOG portion of the PV Program would allow PG&E to develop up to 250 MWs of UOG at an estimated cost of $1.45 billion.
- The PPA portion of the PV Program would allow for PG&E to enter in up to 250 MW of contracts with third party developers for long-term PPAs at a pre-time of delivery (TOD) price of $246/MWh.

In addition, PG&E proposes to build a PV Pilot project of up to 2 MW in 2009, at an estimated capital cost of $11.9 million.

PG&E states that the proposed PV Program supports a number of California and Federal environmental goals including the expanded renewables goal, identified by ARB in its scoping plan, of 33% renewables by 2020, thus supporting the greenhouse gas emission reduction goals identified in AB 32. It also supports the federal energy and environmental policy objectives outlined in President Obama's energy plan.[1] PG&E emphasizes that the PV Program is designed "to expedite and simplify the regulatory approval process and to facilitate the annual, systematic development of PV resources"[2], thereby helping to meet the 2010 renewables portfolio standards (RPS) target, under flexible

1 Exhibit1 at 1-6.

2 PG&E Application at 3.

compliance. In addition, PG&E asserts that utility ownership of PV, coupled with a PPA program is beneficial for customers.[3]

The following sections provide more detailed description of the two components of the proposed PV Program.

3.1. UOG Portion of the proposed PV Program (PV UOG)

The UOG portion of the proposed PV Program would allow PG&E to develop UOG PV projects at a rate of 25 MW in 2010, 50 MW each in 2011, 2012 and 2013, and 75 MW in 2014. PG&E anticipates UOG PV projects to be between 1-20 MW, with a possibility that some projects below 1 MW may also be developed. PG&E offers no details on the total MWs for projects below 1 MW, but states that it does not anticipate these projects to constitute a significant portion of the UOG portion of the PV Program.

The UOG projects would primarily be ground mounted on land PG&E already owns or near PG&E's existing substations, although PG&E anticipates that additional land may need to be purchased and some roof-top mounted projects may also be developed. PG&E plans to make deposits to secure control of some land in advance of Commission approval of its program and proposes to include these deposits in Plant Held for Future Use (PHFU) account for recovery prior to the operation of the PV facilities.

PG&E proposes to use a competitive procurement process to solicit both bundled turnkey projects and unbundled engineering, procurement and construction (EPC) bids for the UOG PV development.[4]

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[3] Exhibit 1 at 1-6.

[4] PG&E describes unbundled EPC bids as projects where PG&E could supply owner-furnished major equipment to a construction/installation contractor. *Id.*

The proposed cost recovery of the UOG portion of the PV Program would be based on Commission approved annual capacity price targets for the program. If at the end of the PV Program period, the actual total capital costs are at or below the average target plus a contingency, PG&E proposes that it will be allowed to recover the actual capital costs of the program without any further reasonableness review, and customers will be refunded the difference with interest at the memorandum account/commercial paper rate. If, however, PG&E's average installed cost at the end of the PV UOG Program exceeds the average target, PG&E would be authorized to recover the actual capital costs up to the average target and file an application for recovery of amounts in excess of the average target. PG&E proposes to establish a memorandum account to record the difference between the revenue requirement for the UOG portion of the PV Program booked to PG&E's Utility Generation Balancing Account (UGBA) and the revenue requirement based on the actual capital costs of the UOG portion of the PV Program.

PG&E seeks Commission approval to suspend or scale back the PV UOG Program if it determines that it cannot meet the established capacity price targets or if it finds other factors impacting the use of capital.

PG&E proposes to recover the stranded cost for the UOG portion of the PV Program through a non-bypassable charge for each facility installed for a ten-year period following the commercial operation of the facility.

3.2. PPA Portion of the PV Program

The PPA portion of the proposed PV Program includes an annual solicitation for projects of 1 to 20 MWs, located in PG&E's service territory. PG&E anticipates selecting projects based on viability and energy delivery criteria. Selected projects will be required to achieve commercial operation within 18 months after the PPA is executed.

PG&E requests that the Commission adopt a standard contract form, including a non-negotiable standard price for these projects. The price for the PPAs would be based on PG&E's estimated levelized cost of energy (LCOE) for the PV UOG Program. PG&E requests that it be allowed to update both the PPA forms and the price through an advice letter filing.

PG&E seeks approval to recover the costs of the PV PPAs through PG&E's Energy Resource Recovery Account (ERRA), which was established to record, among other things, costs of PG&E's procured power. Stranded costs associated with the PPAs would be recovered over the entire term of the agreement through a non-bypassable charge.

3.3. PV Pilot Project

In addition to the 250 MW of UOG projects, PG&E proposes a 2 MW Pilot Project to "expedite the deployment of the PV Program, demonstrate PG&E's commitment to the Program, and to allow PG&E to develop and refine internal and external processes needed to develop, permit, and operate a PV facility prior to deployment of the larger PV Program."[5] PG&E proposes to book the $11.9 million revenue requirement for this project to the UGBA after the project achieves commercial operation.

3.4. Parties' Positions

CUE supports PG&E's application and urges the Commission to approve the PV Program. CUE believes the PV Program is a unique project with the

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5 PG&E's Application at 7.

potential for distribution system benefits but no transmission connection concerns and could add value in developing an additional potential path toward meeting the RPS goals.

CUE suggests that the PV Program will help the RPS goal because many of the current RPS contracts signed by IOUs have been cancelled, suspended or delayed. As a result, CUE advocates that "more projects than ultimately needed must be pursued in order to have sufficient number of projects succeed."[6] CUE also advocates that in meeting the 33% RPS goal,[7] multiple approaches and strategies must be considered to ensure sufficient amount of renewable resources are available.

CUE believes that by facilitating the development of up to 500 MWs of mid- size PV projects, the PV Program will also help fill the gap that CUE believes exists for these types of PV projects as a result of RPS solicitation. In CUE's view, this gap suggests that viable mid-size projects that could make an incremental contribution to meeting the state's RPS goals will be foregone.[8] CUE believes the Commission should fill this gap by approving the PV Program and facilitating the delivery of renewable energy from these types of projects.

DRA supports UOG as an alternative to the competitive market, but recommends denying the PV Program, because it believes the PV Program introduces heightened risk for ratepayers.[9] To begin, DRA argues that PG&E has

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6 Exhibit 401 at 5.

7 The 33% goal was established in Executive Order S-21-09, which directed the California Air Resources Board (CARB) to adopt regulations increasing California's Renewable Portfolio Standard (RPS) to 33 percent by 2020.

8 CUE's Opening Brief at 5.

9 Exhibit 100 at 1.

already signed enough RPS-eligible contracts to meet its 2010 RPS obligations. Thus, it does not need the PV Program to achieve the RPS goals.[10] DRA disagrees with PG&E's claim that the RPS process is unreliable when it comes to executing contracts. Further, DRA argues that even if some of PG&E's RPS contracts fail to come on line, the PV Program would be "an ad hoc, over-priced solution."[11] DRA notes that the PV Program would be over twice the market price referent (MPR).[12] DRA believes PG&E can meet its renewable energy goals with much cheaper alternatives, consistent with the Commission's least cost best fit (LCBF) procurement directives.[13] DRA suggests several modifications to the PV Program as ratepayer protection measures in the event the Commission decides to adopt the program.

CLECA also recommends that the Commission reject this application, asserting that the proposal is too expensive and cannot be justified. In particular, CLECA is concerned that if approved, ratepayers will be burdened with the cost of the PV Program at three times more than the existing portfolio while other less expensive renewable alternatives exist. CLECA disagrees with PG&E's claim that the PV Program will help PG&E meets its RPS goal for 2010. In CLECA's view, the contribution of the PV Program is insubstantial, because it would only add "0.5 percent to renewable energy sales by 2013, and 0.7 percent by 2014 when the UOG portion of the program is fully deployed."[14] Further, CLECA

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10 DRA Opening Brief at 5.

11 DRA's Opening Brief at 5.

12 MPR is the benchmark price for competitive renewable solicitation.

13 Exhibit 100 at 2.

14 CLECA Opening Brief at 7.

argues that to focus on small PV projects in the one to twenty MW range is not a very efficient way to obtain additional renewable power in a short time frame as these types of projects may face siting and permitting problems due to the need for multiple locations.[15] CLECA also contends that on an annual basis, because of their capacity factor, smaller PV projects produce less per KW installed than other solar and other types of renewable projects. Therefore, CLECA argues more individual PV projects will be needed to meet the RPS goals.[16]

The Farm Bureau recommends rejecting the application, echoing the concern about the cost of the program and the lack of benefit to ratepayers. In the Farm Bureau's view, the PV Program is too expensive and fails to consider other alternatives with better value and benefits.[17] The Farm Bureau is concerned about land acquisition and the threat of eminent domain for land owners. In addition, the Farm Bureau is concerned about the environmental impacts related to the project sites, and the impacts PV projects might have on neighboring agricultural lands. This concern is also echoed by CARE.

TURN only supports the PV Program with modifications. While TURN states that it is supportive of utility procurement mechanisms for small and mid-size PV facilities, it believes ratepayers will not realize the full benefits of such an approach under the PV Program unless the program is based on a competitive process to lead to the selection of the least-cots and highest value projects. TURN recommends several modifications to the proposed PV Program to allow competition, and provide performance measures.

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15 *Id*.

16 Exhibit 500 at 5.

Although initially opposed to the application, IEP now supports PG&E's application, stating the modest progress in the RPS and the opportunity for additional 250 MW of independent power as the reasons for its support.

The Solar Alliance supports the application, stating that the program "will make a positive contribution to the expanded development of renewable energy sources",[18] but recommends the use of a competitive auction for the PPAs greater than 3 MW. The Solar Alliance agrees with PG&E that projects between one and three MWs should be afforded a fixed price.[19] The Solar Alliance also proposes a slightly different schedule for the PPA portion of the program.

Greenlining urges the Commission to reject the application for a number of reasons. First, Greenlining states that PV is one of the least cost effective forms of renewable energy and believes there are less expensive technologies that could deliver renewable energy to meet the RPS goals. Second, the fixed price PPA does not allow competitive pricing. Thus Greenlining argues it prevents savings that can arise from a fully competitive market.

CARE states that the PV Program would allow additional electric generation during peak demands eliminating the need to operate fossil-fueled plants that are often cited in lower-income residential neighborhoods. For that reason, CARE supports the application.

CFC urges the Commission to reject the application. CFC lists a number of issues where it believes PG&E's application lacks detail or specificity needed to

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17 Farm Bureau Opening Brief at 4.

18 The Solar Alliance Opening Brief at 3.

19 CFC's Opening Brief at 12.

determine the reasonableness of the program's capital cost estimate.[20] For example, CFC points out that PG&E has not chosen the sites for the PV facilities and does not know how much land the PV Program will ultimately require. Therefore, CFC asserts PG&E's estimate for the cost of land is unknown. Further, CFC states a number of unknown assumptions such as the technology used, the efficiency of the panels, and whether a tracking system will be installed, could affect the cost estimate. In short, it is CFC's position that there are too many unknowns to find the UOG cost estimates reasonable.

CFC also opposes the fixed price PPA, arguing that it may result in higher costs than a competitive procurement process.

4. Need for the Program

4.1. Discussion

California has long recognized the importance and environmental benefits of renewable energy and has taken a leadership role in implementing programs to promote the development of renewables in the state. In 2002, the RPS was established under SB 1078 with the goal of increasing the share of the electricity generated from renewable sources to 20% of retail sales by 2020. The deadline for achieving this goal was subsequently accelerated in 2006 pursuant to SB 107. As currently implemented, the RPS requires electric corporations to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually, until they reach 20% by 2010. The state has also made substantial efforts to promote the deployment of solar generating facilities more specifically, recognizing some of the relative advantages solar offers as a

[20] CFC Opening Brief at 5 through 12.

renewable resource, in particular that solar output largely coincides with peak demand. The California Solar initiative (CSI) was introduced in 2006 to spur the development of renewable distributed generation in California. In 2009, in D.09-06-049, the Commission also approved a solar PV Program (SVPV) for Southern California Edison Company (SCE), which authorized SCE to deploy up to 500 of distributed systems through both PPAs and UOG installations on rooftops in its service territory. It is also state's policy that the highest priority be given to those renewable resources that can be developed most quickly.[21]

This decision, which adopts with modifications PG&E's proposed solar program, represents another significant step in advancing the development of renewable generation in California. By adopting the PV Program as modified here, the Commission reinforces the importance of renewable distributed wholesale generation as an attractive resource option in the utilities' renewable generation portfolios. Also, this decision emphasizes that procurement mechanisms and strategies other than the RPS solicitations can help facilitate the expeditious installation and operation of additional renewable facilities in California and bring benefits to the ratepayers.

Below we discuss why it is prudent to adopt the proposed PV Program subject to certain modifications. We address parties' concerns and find that the PV Program does not interfere or conflict with the RPS program or other renewable energy programs. In addition, we find that the PV Program is in the interest of ratepayers and the adopted prices are just and reasonable.

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[21] Executive Order S-21-09.

First, with respect to the RPS compliance, there is significant disagreement among parties about whether the PV Program is needed for PG&E to meet its 2010 RPS compliance obligation. We agree that on a contractual basis, PG&E has signed enough renewable contracts to meet its 2010 RPS compliance obligation, but do not believe that this fact alone indicates that adopting other programs targeting development of additional renewable projects are unnecessary or, as DRA puts it, "discretionary."

It is clear that development of renewable generation to meet the RPS goals for 2010 and beyond is a priority for this state and this Commission. While the record indicates that PG&E has contracted for enough renewable power to meet its RPS target for 2010, even with the RPS' flexible compliance rules, there is a possibility that PG&E may not meet its RPS targets because of various factors that can impede timely development of these facilities. Financing challenges, permitting delays, and transmission access represent risks that have been widely recognized as factors that can compromise the timeliness of renewable deployment, particularly given the scale of the facilities that PG&E has relied on thus far. Many renewable resources require substantial construction activities or the deployment of new transmission infrastructure to access the renewable resource[22]. Because such additions can have significant environmental impacts, the permitting process and associated uncertainties have the potential to result in

[22] For example in its July 2008 RPS quarterly report, Energy Division identified transmission as a key barrier to renewable development in California. Ongoing concerns about transmission needed to access renewable resources led to the creation of the Renewable Energy Transmission Initiative (RETI). RETI seeks to identify high value renewable resource areas in California and the west and the transmission infrastructure

Footnote continued on next page

significant delays given the type of review to which these projects are subject. Mid-size PV projects, like those proposed by PG&E in its application, however, can potentially avoid these risks and be deployed more quickly and with greater certainty insofar as these facilities can be located close to load without the need for transmission additions and, may face fewer environmental barriers and public opposition than larger scale projects. It is worth noting that environmental and public opposition to large scale projects, which can occupy several square miles of land, are not theoretical concerns in California. In 2009, in response to significant commercial interest in developing large scale renewable projects in the Mojave Desert and their potential impact on the desert environment, Senator Dianne Feinstein introduced a bill to establish the Mojave Trails National Monument. If created, the monument would prevent the deployment of large scale solar and other renewable energy facilities on lands within the monument's boundaries.[23] Some of PG&E's proposed solar projects with Brightsource, specifically those located in Broadwell Dry Lake are among the projects that would be impacted by this proposed designation.[24] Distributed

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needed to reach these areas given both economic and environmental considerations. See http://www.energy.ca.gov/reti/index.html

[23] Wallstreet Journal, "Green Battle Rages In Desert: Mojave Protection Bill Would Put Prime Solar-Power Sites Off Limits." December 23, 2009. http://online.wsj.com/article/SB126144129302900923.html.

[24] Resolution E-4269, pages 9-10 http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/107761.pdf BrightSource had been pursing project development for PPAs 5, 6 and 7 in Broadwell Dry Lake, California and has applications pending for site control with the Bureau of Land Management (BLM). PG&E explained in AL 3459-E that the Broadwell Dry Lake Projects are planned for development on BLM land that is currently being considered for national monument status, which could prevent project development.10 Our Draft

Footnote continued on next page

small scale solar PV facilities appear far less likely to elicit this kind of public opposition as they simply do not occupy vast stretches of land. In light of these factors, coupled with the modular nature of solar PV, it is reasonable to conclude that development of smaller projects can be accomplished more quickly and with less risk than larger facilities. Thus, developing these resources can be an efficient and relatively certain way of bringing additional renewable resources on line.

In its brief, DRA offers a SWOT analysis. We disagree with DRA's analysis using the SWOT (strengths, weaknesses, opportunities and threats) technique to determine the reasonableness of the program, because it does not take into account these benefits. DRA also argues that because currently there is no mechanism to quantify the value of solar displacing fossil fuel or shaving off peak demand in electric rates, ratepayers will not receive any of those benefits. Although the above benefits are not yet quantifiable, they are among the known and unique benefits of PV technology and cannot be overlooked. Thus, over the long run, adopting a program that could facilitate development of small and mid- size PV projects and help deliver renewable power to California could benefit ratepayers and help advance the state's policy goals.

Resolution identified Broadwell Dry Lake as the Projects' location and discussed the development risks of the sites. On September 18, 2009, the Los Angeles Times reported a statement from BrightSource that they , "… have ceased all activity at the Broadwell site…"11 Accordingly, we revised our Final Resolution on AL 3459-E to remove PPAs' 5, 6 and 7 site designation of Broadwell Dry Lake, California. The PPAs allow BrightSource to develop the Projects at other sites, provided certain delivery terms and conditions are met. (See Section "Energy from out-of-state Projects complies with Public Resources Code 25741" and Confidential Appendix B.)

Another factor that weighs in favor of adopting the PV Program is our interest in renewable UOG. We have previously addressed the benefits of renewable resources and have emphasized our support for renewable UOG. In D.08-02-008, the Commission stated, "First, there may be a unique and important role for utility-owned RPS generation. Utility-owned generation from renewable energy resources, for example, can put downward pressure on what are otherwise increasing renewable energy prices." Furthermore, given the current economic environment, it is clear that the utilities, like PG&E, can bring additional financial resources to bear on a market that has faced an increasingly challenging financial climate. Despite our encouragement for California utilities to pursue renewable generation, very few UOG has come forward.

Although mid size PV projects offer a number of benefits, several concerns have been raised that need to be addressed. Central among these is the issue of price and the manner in which the higher prices offered under the proposed program may conflict with the RPS program, to the detriment of ratepayers. For example, DRA is concerned that if prices offered in PG&E's PV Program are higher than the prices for projects in the RPS, developers will bypass the RPS solicitation or bilateral negotiations in favor of PG&E's PV Program.

We do not believe the PV Program, as modified herein, would conflict with the existing RPS program, because the PV Program targets only a subset of projects that in our view cannot, as a practical matter, effectively compete in an RPS solicitation owing to their relatively higher cost when compared to large scale projects. However, given the relatively greater viability these projects offer, rather than conflicting with the RPS we believe the PV Program will be complementary. DRA and others argue that this program will allow more expensive projects to move forward in lieu of lower cost facilities that would otherwise be selected if we continued to rely exclusively on the RPS program for all renewable procurement. This concern, while true to a point, does not undermine the policy rationale for moving forward with this program. As explained above, these projects, while potentially more expensive than the larger scale projects that tend to dominate the RPS solicitations, offer a number of specific benefits that we believe are not accounted for in the RPS program and, in particular, are not offered by projects of a larger scale; namely the relative ease and certainty of deployment these facilities offer. In light of these benefits, we believe the premium ratepayers may pay for these particular resources are justified, provided the price paid is the result of a competitive process. The choice implied by DRA, between building cheaper, large-scale projects on one hand, and more expensive, smaller-scale projects, like those proposed here, on the other, is a false one as it presupposes that the larger scale facilities DRA and other assume would be built in lieu of the solar projects pursued here, would actually come online in a timely manner. Our experience with the RPS thus far suggests that many of these larger projects face substantial risk to timely development.

Potential overlaps with the RPS program are also limited by the narrow focus and eligibility criteria of the PV Program adopted here. Only solar PV projects that are located in PG&E's service territory and can achieve commercial operation within 18 months of signing a contract will be eligible to participate. In contrast, the RPS does not limit projects to a specific location, nor does it require an 18 months online date. RPS projects may be located outside of PG&E's service territory and may have a different online date depending on the negotiated contract. Accordingly, the majority of the projects that are eligible to participate in the RPS would not be eligible to participate in the PV Program.

Thus, such projects would continue to be properly considered in the RPS process and would not be able to "forum shop" as DRA supposes. Again, in our view, adopting the PV Program would not hamper the RPS. On the contrary, it would facilitate the expeditious installation and operation of PV facilities that could help PG&E meet its RPS goals.

DRA's other concern, that developers with large projects will have an incentive to divide their projects into 20 MW parcels to take advantage of the PV Program prices, while a reasonable argument in the context of the pricing structure PG&E proposed in its application, is rendered largely irrelevant under the pricing methodology adopted in this decision. Presumably, a developer could fragment large projects into 20 MW parcels and forgo the RPS solicitation process if the fixed price offered under PG&E's PV Program were higher than those a project would receive under the RPS solicitation. However, as described in more detail below, rather than adopting PG&E's fixed price approach, PG&E will be required to hold competitive solicitations for the PPA component of its program. Thus, to the extent these solicitations are competitive, developers will face the same strong incentives to bid into these solicitations at their marginal cost, just as they do currently under the solicitations conducted in the RPS program.

Overall our view is that the PV Program provides a valuable approach to facilitate expeditious development of renewable generation by independent producers and could result in the timely installation of new renewable facilities in California. As such, it will help meet PG&E's RPS goals and will provide benefits to the ratepayers. For these reasons, we feel that it is reasonable to adopt such a program.

However, given the record evidence regarding the rapidly changing market for solar PV, and the reasonable concerns expressed about cost, we do not believe it is reasonable for the Commission to adopt an administratively set capital cost and price for purposes of either the UOG or the PPA component of the PV Program. Below we discuss program costs.

5. The PV Program Costs

Although we support the establishment of a solar PV Program to support the deployment of small and mid-sized PV systems as a valuable complement to the existing RPS program, we share many of the concerns raised about the program costs, specifically the concerns that the cost estimates provided are not reasonable and that the proposed UOG price does not effectively allow for the benefits of competition. In particular, we agree with the thrust of DRA's view that as proposed "neither the UOG nor the PPA component of the program will create the competitive environment that is supposed to protect the ratepayers from overpaying for renewable energy."[25] Below, we discuss why our adopted PV Program changes the pricing structure from that which PG&E proposed. We adopt a competitive solicitation for the PPA portion of the PV Program and require that the price of UOG portion be tied to the prices from the PPA solicitation.

5.1. PV UOG Cost

PG&E estimates the capital costs for the 250 MW of the UOG portion to be $1.45 billion. This corresponds to the average capital cost target of $4275/kW direct current (DC) for the entire PV UOG program.

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[25] DRA Opening Brief at 5.

PG&E's O&M cost estimate consists of labor, materials, and contracts for operation and maintenance of the PV facilities and includes a 20% contingency factor due to uncertainties in the ongoing operation of the PV facilities.[26] PG&E estimates the LCOE for the UOG portion to be $295/MWh (TOD_adjusted).

5.1.1. Parties' Positions

In previous sections, we have discussed parties' concern regarding the cost of the PV Program. The main concerns about the cost of the PV UOG are:

1. The estimates are unreasonable and unjustified.
2. The UOG price does not allow benefits from the competition.
3. The PV Program is more costly when compared to the CSI, the RPS, Southern California Edison's solar photovoltaic program (the SPVP) or other UOG projects.

5.1.2. Discussion

We do not adopt PG&E's cost estimates and the contingency factors for UOG projects. Instead, we will use the weighted average price of the PPA solicitation to determine the revenue requirement for UOG projects.

PG&E has provided cost estimates based on a 5 MW project. However, these estimates are not sufficiently supported. CFC has demonstrated that PG&E's estimates of program costs lack important details. For example, it is not clear where PG&E's plants will be built, how much land will be needed, or how much the land may cost. Greenlining also points to some deficiencies in PG&E's cost estimates. Specifically, Greenlining indicates that PG&E's cost forecast ignores the cost associated with panel disposal at the end of the panels' useful

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[26] Exhibit 1 at 5-6.

life. According to Greenlining, the panel disposal costs for the UOG portion alone could amount to about $27.5 million.[27]

We are not convinced by PG&E's response regarding the lack of cost estimates, particularly the response that the panel disposal cost was left out because of the uncertainty about how the panels would be disposed of, or the possibility that some panel manufacturers' voluntary take-back programs could reduce the costs of panel disposal. Moreover, PG&E's response that the unknown factors are implementation details is not reasonable.

These are important factors that could have significant impacts on the estimated cost of not only the UOG portion, but also the PPA portion, and the entire PV Program. Unless these cost details are known, it would be difficult to verify if PG&E's claims for the total cost of the program are accurate and reasonable. Moreover, the lack of a robust cost estimate calls into question the reasonableness of the contingency factors that are added to the cost of the PV Program. We are not persuaded that we have sufficient information to determine a reasonable price for UOG projects. Further, PG&E's estimates are based on a blend of information gained from various sources, thus it is difficult to determine their credibility.[28] Even if we did have sufficient information at this time, given a constantly changing market for solar PV, we believe such a price would be outdated in a short period of time. The record in this proceeding strongly suggests that the market for solar PV is a dynamic one, with prices changing rapidly. For example, since the release of the RETI report cited by the

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27 Greenlining's Opening Brief at 13.

28 Exhibit 603 at .

Farm Bureau in its testimony the market conditions for solar PV have changed. A more recent RETI report indicates that solar PV costs may be lower than suggested in the earlier report. In fact, the Final RETI Phase 1B report distinguishes PV among all other technologies as one with significant potential for cost reductions in the future:

> "Unlike most other renewable technologies, capital costs in the photovoltaic industry have significant potential to decrease, and there is considerable commercial interest in utility-scale "thin film" systems."[29]

Further, during hearings, PG&E's witness Wan noted that prices for PV have been declining.[30] This statement is also consistent with some of the recent trade publications showing a trend in declining PV prices over time.[31]

With respect to comparison of cost of the PV Program to other programs, we agree with DRA that it would be most reasonable to compare the cost of PV Program to projects of similar size.[32] In our view, the most relevant comparison is to RPS projects, which contain projects similar in size as the PV Program. The CSI and the SPVP do not provide a reasonable comparison because they exclusively represent smaller projects whereas PG&E's PV Program will span a much larger range of project sizes; the SPVP contains primarily 1-2 MW projects and the CSI is targeted at projects under 1 MW designed to be deployed on residential and commercial rooftops. Further, as DRA notes, PG&E has

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29 Final RETI Phase 1B report (http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF), pages 5-27.

30 TR Volume 1 at 9.

31 http://www.solarbuzz.com/FastFactsIndustry.htm.

32 Exhibit 101 at 7.

amortized the cost of the PV Program over 25 years while the SPVP's costs are amortized over 20 years. The difference in the amortization also makes it difficult to make a reasonable comparison.

Likewise, PG&E's comparison to other UOG projects in other states does not provide useful information. While PG&E has provided cost data for two projects, one in South Carolina and one in New Jersey, both are for much smaller capacity. The South Carolina project is only 10 kW and the New Jersey program is for 80 kW.[33]

Comparing the cost of PG&E's proposed PV Program to solar PV projects in the RPS indicate that the PV Program is not cost competitive relative to some of these RPS projects. As DRA notes, and based on PG&E's confidential testimony, there "are many less costly market alternatives to PG&E's PV Program."[34] Thus it would not be in the ratepayers' interest to adopt PG&E's cost estimates given information suggesting these estimates appear high relative to the market price for a similar product.

As further indicated by the pricing information from the RPS program, and our general orientation in favor of relying on the market competition, we also agree that competition could bring significant savings to ratepayers. As DRA states "unless PG&E can build and procure projects in their program for the same or less than the market already provides, then it does not make sense to

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33 We understand that the original proposal for the program in South Carolina was for 20 MW.

34 DRA's Confidential Opening Brief at 7.

approve PG&E's PV Program."[35] This is particularly true to the extent there is a sufficiently robust market capable of providing this capacity.

At the same time, as stated in previous decisions,[36] we want to encourage the development of renewable UOG as a resource option. Utilities can bring additional resources to the market, something that in today's capital constrained environment should not be dismissed out of hand, particularly in the context of renewable energy development, where tax equity financing has played such a critical role. Provided they can do so at a cost that compares favorably to market prices, there is no compelling reason to exclude the utilities from building, owning and operating renewable facilities. With this in mind, and to help ensure that ratepayers get the most value out of this program, we adopt a price for UOG projects that is based on the market price of similar PV projects, as determined through PG&E's PPA solicitation process. This price will be used in calculating the annual revenue requirement for each UOG facility PG&E chooses to install. In pursuing this approach we seek to ensure that ratepayers are essentially held indifferent between projects developed by the utility and those developed by independent power producers. Furthermore, we believe this approach, by largely holding PG&E to the same pay-for performance standards that IPPs are held to, ensures that PG&E is well-motivated to maximize the performance of these facilities over time. As explained below, PG&E is directed in this decision to conduct a solicitation for 50 MW of capacity per year from independent power producers. Each bid received in these solicitations will include a price per kWh

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35 Exhibit 101 at 3.

36 D.08-02-008, D.09-06-018 approving 2008 and 2009 RPS procurement plans for PG&E.

as well as the capacity and expected performance of each proposed project. From this information, PG&E will be able to calculate a weighted average price per kWh across the winning bids in the solicitation. When combined with the actual annual production for each of PG&E's UOG projects, this weighted average price can serve as a reasonable basis for setting the annual revenue requirement PG&E can recover in total from ratepayers, including any O&M costs, for the capacity it installs.

Each solicitation will serve as the basis for the price that PG&E can recover from ratepayers for any UOG project it chooses to undertake before the initiation of the next solicitation. Because the price will change from solicitation to solicitation, PG&E may choose to develop less than the total amount it is authorized to develop in a given period. The decision to build is purely a discretionary decision of PG&E's, presumably based on its internal assessment of whether the price derived from the PPA solicitation would provide sufficient returns. If PG&E elects to build less than the capacity it has been authorized to develop in a given year, the balance will be carried forward and be added to the capacity PG&E is authorized to develop in the subsequent year. Again, in each subsequent year, the annual revenue requirement PG&E is authorized to recover from ratepayers for the capacity it chooses to install will be based on the weighted average price of winning bids in that year's solicitation and each facility's output, as described in Appendix B.

This authorization is granted for the first 20 years of the UOG plant operation, consistent with the PPA contract terms for this program. PG&E should seek additional cost recovery guidance from the Commission via application no earlier than 2029 to address cost recovery for production from UOG facilities beyond 20 years. A more detailed description of the methodology used to derive the UOG price benchmark using the results of each solicitation is provided in Appendix A. Within 30 days after the completion of a given annual solicitation for IPP projects, PG&E should submit an advice letter to the Energy Division indicating the capacity of UOG PV facilities it intends to pursue up to the annual limit, given the weighted average price per kWh calculated from the relevant solicitation.

As another measure to ensure reasonable costs, and to mitigate other concerns raised by parties (e.g., environmental and eminent domain), we encourage PG&E to first develop land that it owns and is also close to its substations for the UOG projects before it acquires other land. We agree with DRA that while locating projects near substations could save overall costs to the ratepayers, it could result in limiting the project size because of space availability at some substations. Therefore, we do not limit the construction of UOG facilities to PG&E-owned land and substations. However, PG&E must justify its land selection if land other than its own for UOG facilities in an advice letter.

5.2. PV PPA Cost

5.2.1. Parties' Positions

In its application, PG&E proposes a fixed price for the PPAs, based on PG&E's expected LCOE for the UOG portion of the PV Program, which equates to a pre-TOD-adjusted contract price of $246/MWh. The Solar Alliance opposes the fixed price PPA for projects larger than three MWs. The Solar Alliance argues that PG&E's proposal for the fixed price PPA is inconsistent with the Commission's stated policy in D.07-12-052, which requires that all long-term procurement occur via competitive procurement mechanisms. The Solar Alliance also points out that the Commission in D.09-06-049 required a competitive process for the MWs to be developed by the independent power producers (IPPs) for the SCE PV Program and that similar requirement should apply here. The Solar Alliance shares TURN's view that third party projects could sell energy at prices below the price of the UOG and also points out that PG&E itself has recognized that a competitive solicitation could secure prices lower than the fixed price offered by PG&E. Thus, the Solar Alliance advocates a competitive auction for projects above 3 MW.

While the Solar Alliance recommends against using a fixed price PPA for projects above 3 MW, it does believe a fixed price would work well for projects under 3 MW, and suggests we conduct a workshop to determine the price for such projects.

Greenlining is opposed to the fixed price for PPAs. It argues that the fixed price works as a disincentive to bidders to lower their price.

WPTF/DDAC also argues that the fixed price conflicts with several Commission decisions, including the Commission's competitive market first approach. It notes that Commission decisions that have encouraged competitive procurement have never mentioned fixed price PPAs. It further adds that such a price would also be inconsistent with the criteria for UOG and Commission policy that encourages merchant generation development.[37] In addition, WPTF/DDAC adds that the fixed price will provide no price competition that could benefit the ratepayers.

CFC also notes that the fixed price may result in higher cots than the competitive procurement.

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[37] WPTF/DDAC Opening Brief at 4.

TURN also opposes the fixed price, stating that the fixed price could create potential windfalls for the developers. TURN argues that third party developers may be able to achieve lower prices than UOG due to many factors including the benefits of federal tax incentives, lower cost of capital, and changing market conditions, but under a fixed price structure, the financial benefits of these lower costs would be realized only by the developers. TURN advocates that to the extent that lower prices can be achieved, ratepayers should be able to benefit from these savings in the form of lower rates. Because a competitive procurement process would allow ratepayers to reap the benefits of the lower prices, TURN recommends we reject the fixed PPA price and adopt a competitive procurement process instead.

DRA also proposes that PG&E's program be modified to include cost-competitive PPA solicitations. Specifically, DRA recommends that instead of creating another renewable energy PPA solicitation process, the Commission adopt a PPA solicitation process similar to the market-based pricing mechanism, or Renewable Auction Mechanism (RAM), proposed by Energy Division Staff in R.08-08-009.

In response to the above objections to the fixed price PPA, PG&E argues that if PPA price is not fixed, several aspects of the program including project selections, contract negotiations, execution, and approval process could become more difficult and contentious and result in delays for the program. Furthermore, PG&E asserts that there is a probability that without a fixed price, projects would focus on seeking opportunities to cut costs for the purpose of the bid rather than maximizing the viability of the projects, even though those measures could threaten the long-term viability of the projects.[38] Thus, PG&E argues that the proposed fixed price PPA is what it will reasonably cost in a competitive market to build viable, mid-size PV facilities.

5.2.2. Discussion

We will not adopt a fixed price PPA as proposed by PG&E, because it has several shortcomings and there is a risk that paying PPAs a fixed price could result in higher prices for PPA contracts and lead to overpayment by the ratepayers. Furthermore, given that the price proposed by PG&E is derived from an estimate of solar system costs that we have found to be insufficiently supported, and likely to change, we do not feel it would reasonable to adopt this as a basis for the price offered to PPA projects. Instead, we adopt a competitive process for the PPA selection. As we have previously stated our preference for a competitive procurement process, this approach will ensure that this program achieves its objectives at the lowest cost to ratepayers.

Many parties raise concerns with using a fixed price PPA and suggest replacing it with a competitive process. The major criticism of the fixed price approach is that it does not result in the best prices for the ratepayers, as would a competitively-based price. This view is shared not only by those who support the PG&E's PV Program proposal, but also by others who oppose it.

DRA, while urging the Commission to deny the application, stresses that if the Commission were to approve the program, it should require competitive price bidding for the PPA portion to protect ratepayers.[39] Greenlining expresses

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[38] PG&E Reply Brief at 26.

[39] Exhibit 101 at 24.

a similar concern regarding the application and states that "the Commission should not approve a pricing scheme that forgoes savings achievable in a fully competitive market."[40] The Solar Alliance, while supporting the application, recommends a competitive procurement process. WPTF and DACC also suggest the Commission reject PG&E's fixed price approach in favor of truly competitive RFOs in order to attain the best possible price.

At the heart of the concern raised by various parties regarding the fixed price approach for the PPAs is the notion that benefits that can be achieved through meaningful price competition cannot be accrued to ratepayers. Furthermore, our ability to administratively determine the "right price" that will both encourage projects to come online while also ensure that ratepayers pay no more than they would have otherwise for the same product, is fundamentally limited. As already explained earlier, the market for solar is changing rapidly. Additionally, given the information we have from the RPS program, there is reason to believe that a competitive process may result in lower prices for this program.[41] The fixed UOG price PG&E proposes is based on an estimate of PG&E's cost for building PV projects and the result of several assumptions specific to utility ownership. These assumptions also introduce significant uncertainty and we have little confidence they represent accurate information at this point, much less going forward. In addition, as witness Jeung suggests "A number of factors impact projects economics, including location, equipment

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40 Greenlining Opening Brief at 9.

41 Confidential Exhibit 3-C-A.

prices, labor costs, and transmission costs."[42] Thus, there is no basis for adopting a fixed price for projects that not only could vary in size, but also would have different characteristics, including ownership. These project-specific attributes and associated costs are best sorted out via a competitive process where each project's specific circumstance is considered in developing its bid.

Second, even if the UOG price was reasonable a reasonable estimate for what it would cost the utility to develop these projects, PG&E has not provided any justification why the same price would also be reasonable for PPAs. As TURN correctly points out, several factors including lower costs of capital could enable third party developers to offer PPAs at prices below the forecast of UOG. Under PG&E's fixed price PPA, however, the financial benefits of the lower third party costs cannot be realized by ratepayers. Finally, there is no reason why PG&E cannot use a competitive price and still select the most viable projects.[43] The PV PPA evaluation process will be similar to the process used in the RPS RFO evaluation and will include a number of criteria, including project viability. The same evaluation process and steps as described in PG&E's testimony for the fixed price PPA could also be used for the PPAs with the competitive price. PG&E's concern that if the PPA price is not fixed it could impede the focus on selecting projects with the highest viability is not valid, because a viability assessment would remain as a factor in the selection of the projects even with competitive price added as a criterion. In other words, although it is true that

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[42] Exhibit 4 at 3-2.

[43] In fact, the Commission recently implemented the competitive procurement portion of SCE's Solar PV Program, which includes rigorous eligibility and project viability screens. See Resolution E-4299.

adding a new criterion could change the selection process, it does not follow that it will necessarily result in selection of less viable projects. Additionally, we disagree with PG&E's contention that a competitive process engenders additional complexity and will result in delays. These matters can be addressed by adopting a non-modifiable standard contract as well as specific deadlines for when winning projects have to be online.

We also decline to adopt DRA's proposal for a PPA solicitation process with RAM at this time. We may reconsider whether to incorporate the PV Program solicitation with RAM at a future date, depending on the outcome of the RAM proposal.

With regard to projects sized 1-3 MW, we do not adopt Solar Alliance's proposal that projects in this size range receive an administratively determined price rather than going through a competitive solicitation. No compelling arguments have been presented that suggest that these projects offer substantially different benefits than those offered by the other projects that would be eligible under this program and so we see no reason to accord them special treatment. This program is a means to an end, namely the expeditious deployment of solar facilities to help fulfill the state's renewable energy mandates. In our view there is not sufficient evidence on the record to believe that the smaller projects the Solar Alliance is concerned with are necessarily more effective at achieving this aim, or so much more so as to justify potentially higher costs to ratepayers to support their deployment. Therefore, we believe they should compete alongside other eligible projects. To that end, we reject Solar Alliance's proposal.

Finally, we agree with TURN that PG&E should provide information to potential bidders in the solicitation indicating preferred locations to interconnect.

This information could assist project developers to secure suitable locations to minimize the risk of facing unforeseen interconnection costs.

6. Applicable Commission Decisions and Statutes

6.1. Parties' Positions

Most parties agree that AB 920 does not impact the PV Program. However, DRA urges the Commission to consider PG&E's need for additional RPS resources through PV Program given that both SB 32 and AB 920 will increase the amount of RPS energy that PG&E will be obligated to purchase.[44] In DRA's view, purchases under AB 920 and the "must take" obligation under SB 32 would significantly increase the amount of RPS energy for PG&E, thereby reducing PG&E's RPS obligation to procure additional renewable resources.

DRA also recommends that the PV Program be limited to facilities greater than 3 MW to avoid overlap with SB 32, which also targets facilities up to 3 MW.

PG&E believes neither AB 920 nor SB 32 materially conflict with the PV Program. In PG&E's view, the PV Program is different from AB 920 in that under the PV Program none of the power may be used to offset onsite load, whereas under AB 920 PV facility's outputs must be used to offset the customer's onsite load.[45]

PG&E also believes SB 32 does not conflict with the PV Program, because facilities targeted by the PV Program would likely not want to participate in the FIT. PG&E suggests the price offered under SB 32 may not be adequate to attract

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44 DRA's Supplemental Briefs at 3.

45 PG&E's Supplemental Briefs at 4.

new investments. In addition, PG&E believes implementation of SB 32 will likely be on a different schedule from the PV Program.[46]

TURN echoes the view that AB 920 does not conflict with the PV Program, but believes gaming could occur between SB 32 and the PV Program to the extent prices offered under two programs are different. TURN contends price differential could create a situation where a minimum price guarantee and an opportunity to speculate on higher prices through a competitive process exists.[47] TURN's primary recommendation is to limit PG&E's PPA program to projects greater than three MW to eliminate any potential conflicts between the two programs.[48] CUE also supports excluding one to three MW projects from the PV Program.

CALSEIA disagrees with TURN and cautions the Commission against relying on TURN's argument. CALSEIA maintains that TURN's argument is based on the assumption that the pricing under SB 32 and the PV Program will be significantly different. Such an assumption in CALSEIA's view is speculative because the Commission has not yet determined a price for SB 32.[49]

The Solar Alliance and CFC also believe SB 32 and AB 920 do not impact PV Program. CFC, however, appears to be suggesting the Commission compare the PV Program to SB 32 and AB 920 by listing some of the elements of SB 32 and AB 920 as guidance.

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46 PG&E's Supplemental Briefs at 2.

47 TURN's Supplemental Briefs at 1.

48 TURN's Supplemental Briefs at 4.

49 CALSEIA's Supplemental Briefs at 2.

CFC also argues that PG&E's application is contrary to law because it asks for an order concerning the method of recovery of costs of new construction before the plant is built.[50] CFC refers to Pub. Util. Code § 454.8 ("Recovery of costs of new construction") and states that the Commission cannot decide the method for recovery of the costs of new construction until after it finds the plant is used and useful to the public. CFC also asserts that the PV Program will not be in compliance with Pub. Util. Code § 454.4 (c)(3), because PG&E will not be buying renewable energy through the renewable energy procurement process. According to CFC, only PPA contracts that are submitted as part of the procurement process would be in compliance with § 454.5 (c).

6.2. Discussion

AB 920 allows net energy metering customers with projects of up to 1 MW to sell any excess electricity they produce over the course of a year to their electric utility at a rate to be determined by the Commission.

Most parties believe that AB 920 does not have an impact on the PV Program because the two programs are different. We share this view. A major difference between the two programs is that PV facilities under AB 920 are required to use the power to offset on site load while under the PV Program no such requirement exists. Thus, we can reasonably conclude that the facilities that participate in AB 920 are not likely to participate in the PV Program. As such, the two programs do not conflict with each other.

The impact of SB 32 on the PV Program, however, is more complicated. SB 32 increases the size of generation facilities eligible for California's feed-in

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50 CFC opening Brief at 26.

tariff program from 1.5 MW to 3 MW, and raises the program's statewide cap from 500 MW to 750 MW. SB 32 also establishes the payment to eligible projects at a price based on the market price referent adjusted to include all current and anticipated environmental compliance costs subject to a ratepayer indifference test. A major concern expressed by the parties with respect to the impact of SB 32 on the PV Program is the potential for forum shopping. Parties are concerned that if prices under SB 32 and the PV Program are significantly different, projects will gravitate toward whichever program offers the greatest value. This can create a situation where projects that would have moved forward at a lower price may receive a higher price by electing to participate in one forum versus the other. PG&E contends that SB 32 price is unlikely to be significantly higher. Further, PG&E asserts that the SB 32 implementation timeline is uncertain. CALSEIA echoes the concern about the implementation timeline and further contends that parties' concern about price differential is speculative at this point since the Commission has not established a price for SB 32.

CALSEIA is correct that the Commission has not presently implemented SB 32, thus SB 32 prices are unknown. Given that the Commission has not yet implemented SB 32 and it is unclear at this point if the price the Commission ultimately develops will be sufficient to drive deployment of projects in the one to three MW size it seems premature to preclude such projects from participating in PG&E's proposed program. We are loathe to exclude projects that may be able to successfully compete in a solicitation because of speculative concerns that such a project might receive a higher price than what it would be offered under SB 32, assuming of course that whatever price is developed in the context of SB 32 is adequate to drive deployment. Therefore, we do not, at this time, find it reasonable to exclude projects and projects sizes that may ultimately be eligible to participate under the SB 32 mandated feed-in-tariff from the PG&E program we authorize here.

We recognize that the jointly submitted standard PPA proposed for this program, and discussed in more detail below, was specifically intended for projects greater than three MW. To ensure that sellers in the one to three MW size range can participate in the program, PG&E shall file a standard contract for these smaller projects with its Tier 3 advice letter ordered herein within 30 days of the effective date of this decision.

With respect to CFC's claim that PG&E's application is contrary to law, Pub. Util. Code § 454.8 states that:

> In any decision establishing rates for an electrical or gas corporation reflecting the reasonable and prudent costs of the new construction of any addition to or extension of the corporation's plant, when the commission has found and determined that the addition or extension is used and useful, the commission shall consider a method for the recovery of these costs which would be constant in real economic terms over the useful life of the facilities, so that ratepayers in a given year will not pay for the benefits received in other years.

It appears that CFC relies on the language in the statute to support its claim that because PG&E has not built the new facility and the Commission has not found the plant to be used and useful, the Commission cannot establish a cost recovery mechanism for the new plant. Nothing in Pub. Util. Code § 454.8 prohibits the Commission from establishing a cost recovery mechanism for an approved utility investment before the plant is built. The only requirement in Pub. Util. Code § 454.8 is that when the Commission considers a cost recovery mechanism for a new plant that is used and useful, it would consider a mechanism that would allow the cost be distributed over the useful life of the facility so that ratepayers only pay for the benefits received in that year. CFC's interpretation of the Pub. Util. Code is therefore inaccurate.

CFC claims that PG&E has failed to demonstrate that its PV Program complies with least-cost and best-fit (LCBF) principles and therefore its application should be rejected. Such an analysis is not required at this time. Section 399.14 requires PG&E to include LCBF analysis in its renewable energy procurement plan (Procurement Plan) filed with the Commission. Accordingly, PG&E shall amend its 2010 Procurement Plan to include its PV Program. The Commission will then review contracts executed under the PV Program for consistency with PG&E's approved Procurement Plan and compliance with all other relevant RPS procurement requirements.

7. PV Program Size and Schedule

7.1. Parties' Positions

PG&E originally proposed to develop UOG projects at about 50 MW annually. PG&E contends that the 50 MW per year target would be a manageable project load for developing UOG projects from one to twenty MW in size. For the PV PPA, PG&E proposed to hold annual solicitation for up to 50 MW from 2010 to 2014 and if less than 50 MW is awarded in a given solicitation, the remainder megawatts would roll over megawatts to the following year's solicitation.

The Solar Alliance and CALSEIA propose a declining schedule with 100 MWs of PPAs in the first year, 75 MWs in the second year, 50 MWs in the third year, and 25 MWs in the fourth year of the program.[51] The Solar Alliance

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[51] This proposal was jointly offered by the Solar Alliance and CALSEIA.

contends that front-loading the MWs would be an effective approach to ensuring that the entire 250 MW of the PPA program will be built.

In response to CALSEIA and Solar Alliance's proposal to front-load the MWs, PG&E endorses the concept but recommends a slightly different schedule. PG&E suggests 75 MWs each in the first and second year, and 50 MW each in the third and fourth year of the program, with the fifth year as the "clean-up"" for contract failures.[52] PG&E asserts that this schedule would allow an opportunity to take advantage of future price reductions in PV facilities and also new technologies to develop and bid into the last year of the program.

DRA also proposes that the program be scaled back to half its size to provide ratepayer protection. DRA disputes PG&E's claim that the full size of the program is needed to achieve economies of scale.

TURN proposes to consider reallocating the MWs between the UOG and PPAs after two years.

Regarding the proposal for a two-year evaluation of the allocation between the PPA and UOG program, PG&E responds that a two-year check point would create uncertainty for bulk purchases as well as administrative costs that ratepayers will have to bear. PG&E argues that some PPA projects may not be fully developed by the end of the two year term. Thus, a comparison between UOG and PPA projects under such circumstance would not be useful. Finally, PG&E argues that a two-year program check will be unnecessary because a program review is intended at the end of the 5-year of the program when results for both the UOG and PPA will be available.

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52 Exhibit 4 at 3-5.

7.2. Discussion

We adopt the PV Program for 500 MWs. PG&E will be authorized to build up to 50 MW of PV UOGs and solicit up to 50 MWs of PPAs annually.

We reject both PG&E's revised, and CALSEIA and Solar Alliance's proposed schedules to front load the MWs for PPAs. Neither has presented a convincing argument why front-loading the MWs would be beneficial. In our view, front-loading the MWs would not enable the program to take advantage of future price reductions that could become available due to technological improvements or new developments in the market. As PG&E recognizes "there may be cost effective technologies that can participate in later solicitations that do not exist today."[53] One of the key reasons for an annual solicitation would be to enable the program to take advantage of additional choices as technology evolves and new companies entering the market. As the above comments suggests, if the program was front-loaded, these potential savings would be forgone as fewer MWs would be left to participate in the future years of the program. Furthermore, as the Solar Alliance has noted, any specific schedule may be somewhat arbitrary.[54] Given these considerations, we will adopt the schedule for an annual solicitation of 50 MWs for PPAs. For the same reasons, we will adopt a 50 MW per year for the UOG portion of the PV Program. We also allow PG&E to accrue unbuilt MWs from a given year to the next year. In other words, if PG&E elects to build less than the authorized annual capacity, or if the PPA solicitation results in the selection of less MW than allotted, the remaining MWs for that year will be added to the next year's solicitation. This

[53] Exhibit 1 at 3-3.

will ensure that ratepayers will receive the benefits of potential price decreases in the future.

A different, but related issue concerns the treatment of dropouts, defined here as projects/capacity that were either selected through a solicitation or which PG&E has indicated its intent to develop, but that for various potential reasons, do not come online within the required timeframe. In the interest of helping ensure the program fulfills its overall capacity objectives, any projects and associated capacity that drops-out over the course of the program should be added to the authorized capacity that can be developed in the next available solicitation. This accrual of drop-outs should occur through the last solicitation of the program. We note, however, that this policy may create a perverse incentive for PG&E to cancel UOG projects it has declared its intent to undertake if the weighted average price from a subsequent solicitation is higher than the price from a prior solicitation. To prevent this we will not allow the output associated with the capacity that PG&E has indicated it plans to deploy in a given solicitation cycle to be pursued at a different price should these projects drop-out. In other words, the capacity that PG&E indicates it intends to deploy pursuant to the advice letter process described above effectively locks in the price that PG&E can receive for any output from this capacity. Should PG&E fail to develop this capacity within the authorized timeframe, unlike drop-outs from the PPA side of the program, this capacity will not be rolled forward. Regarding the size of the PV Program, we are not convinced that DRA's proposal to reduce the program size by half is warranted. First, as discussed earlier, a more

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[54] Exhibit 1100 at 5.

reasonable approach to ensuring ratepayer protection against high costs will be to adopt a price for the UOG that is explicitly linked to the market price of PV. Second, as DRA acknowledges there is a lack of analysis in this record as to "(a) what aspects of PG&E's programs might enjoy economies of scale, and (b) what effects changing the size of the program would have on the economies of scale."[55] Without a proper analysis, it would be difficult to draw a conclusion about how much reduction, if any, in the program size would be appropriate.

We also reject TURN's proposal to reevaluate the allocation of the MWs between UOG and PPAs to determine which cost is less. Because the adopted price structure is such that the UOG price will be tied to PPA prices, no further comparison will be needed.

We reject PG&E's proposal to suspend or scale back the PV Program without Commission authorization. While there may be factors that could justify termination of the PV Program, PG&E will be required to file an advice letter demonstrating the need to do so. However, we note that we are not requiring PG&E to build any UOG projects. This remains a discretionary decision of PG&E's based on its own assessment of the economics of pursuing these projects under the pricing methodology set forth in this decision.

Finally, in its proposal, PG&E indicated that although its UOG program would focus primarily on ground-mounted projects from one to twenty MW in size, it wished to reserve the ability to pursue some projects less than 1 MW and some roof-mounted projects. Given the pricing methodology adopted herein, we find allowing PG&E to pursue some limited number of smaller projects and/or

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55 DRA's reply Brief at 4.

roof-mounted projects reasonable. To that end we will allow PG&E to deploy projects less than 1 MW in size as well as some roof-mounted projects, provided that in aggregate these projects represent no more than 5% of the total UOG capacity authorized under this program.

8. Cost Recovery and other Performance Mechanisms, and Reasonableness Reviews

8.1. Parties' Positions

Several parties have recommended that the PV Program cost recovery be contingent upon certain level of performance of the UOG facilities and shareholders share some of the cost savings or cost overruns with ratepayers.

TURN believes PG&E should be accountable for the cost estimates and the performance of its UOG PV facilities similar to requirements in the PPAs. TURN recommends that we establish a levelized cost of energy based on the proposed costs estimates as an overall cost cap for the UOG projects. TURN also recommends a performance mechanism to link cost recovery of PG&E's UOG facilities to performance of the facilities by assessing a penalty if deliveries fall more than 10% below the initial forecast. TURN believes this would create an incentive for PG&E to select the most cost – effective projects and take all appropriate actions to properly operate and maintain them. Thus, TURN argues, it protects the ratepayers.[56]

DRA also proposes a 80/20 cost/share mechanism between ratepayers and shareholders with costs overruns above 20% to undergo a reasonableness review. CARE also supports a cost sharing mechanism. DRA suggests that the

[56] TURN Opening Brief at 8.

Commission conduct a reasonableness review of PG&E's capital expenditures and O&M costs after the fact in PG&E's General Rate Case (GRC).

PG&E does not believe it should be subject to any performance guarantee or cost sharing mechanisms. It argues that a performance guarantee mechanism would be unfair to PG&E because PG&E would not have the benefit of better-than expected performance of the facilities while it could bear the risk if facilities underperform.[57] PG&E also opposes the cost sharing mechanism as proposed by DRA and CARE, arguing that such an approach is inconsistent with traditional cost-of-service ratemaking where the Commission initially determines the costs and later will have an opportunity to decide if additional costs are reasonable.

8.2. Discussion

To ensure price protection for ratepayers, we adopt a cost cap as recommended by TURN for the maximum price ratepayers should pay for energy procured from the PV Program. However, given the lack of detail in PG&E's cost estimates as discussed above, we do not believe PG&E's estimate can be used a reasonable cap. Instead, we use the information from PG&E's 2009 RPS solicitation, which represents the market price for these projects and adopt a price cap calculated as weighted average pre-time of delivery adjusted energy price of PV projects that bid into PG&E's 2009 solicitation, where the weighting is based on the annual average expected generation from those bids. In developing this cost cap, only PV projects 20 MW or less will be included. We believe this would be a reasonable cost cap for the PPAs as PV prices are expected to decline in future years, so the price derived from the 2009 solicitation

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[57] Rebuttal testimony at 11.

would reasonably represent a maximum price for the PV projects. The specific value of the cost cap shall be kept confidential to ensure that the cost cap itself does not influence the bidding behavior of developers participating in the PPA solicitation process. Because the amount PG&E will be able to recover for UOG projects is expressly tied to the price from the PPA solicitations, this cap wil1, in effect, act as a cap for the maximum cost ratepayers would bear for UOG projects as well.

With respect to DRA's proposal for a reasonableness review, we believe the underlying concerns motivating DRA's proposal are adequately addressed through the pricing and revenue requirement methodology adopted in lieu of PG&E's proposal. Thus a reasonableness review as proposed by DRA is unnecessary. Nor do we adopt a performance guarantee mechanism. Again, since PG&E's cost recovery will be tied to the actual performance of its facilities, no additional performance guarantee will be necessary.

We do, however require that PG&E file an annual compliance filing in this proceeding with results of the PPA solicitation and UOG costs. This information will allow the Commission to compare the costs of the UOG and PPA and better understand the impacts of the program. PG&E shall file annual compliance reports with the Energy Division.[58] The annual report prepared by PG&E shall include the information outlined in Appendix A.

We adopt PG&E's proposal for recovery of the cost of the PPA portion of the PV Program through PG&E's ERRA.

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[58] The first annual compliance report will be due a year from the effective date of this decision.

9. PV PPA Contract Forms

On August 21, 2009, PG&E along with the Solar Alliance, Vote Solar Initiative, and CALSEIA submitted a form PPA for projects greater than 3 MW to 20 MW. They refer to this proposal as the Large Project PPA. The Large Project PPA replaces PG&E's original proposal which was submitted on June 19, 2009. The Large Project PPA does not contain pricing or the process for solicitation of projects. There is no agreement on a form contract for projects 3 MW and less.

9.1. Parties' Positions

DRA recommends PG&E's and the Joint Solar parties' proposed standard Large Project PPA be rejected. DRA asserts that neither DRA nor any other consumer advocate parties participated in PG&E's and the Joint Solar Parties' settlement negotiations to form the proposed Large Project PPA form. As a result, DRA contends that only sellers (i.e., the Joint Solar parties) would benefit from the negotiated contract at the expense of ratepayers.[59] DRA suggests consistent with the Energy Division Staff RAM proposal, the Commission adopt the AB 1969 feed-in tariff (FiT) contract with a few additional terms. For projects between 10-20 MW, DRA recommends that PG&E file a Tier 3 Advice Letter proposing changes to the RPS pro-forma agreement.[60]

CFC also opposes the Large Project PPA. CFC contends that the Large Project PPA as proposed has shifted risks and costs from solar developers to PG&E's customers and "in most cases, the changes increase the cost of purchased

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59 DRA Opening Brief at 12.

60 DRA Opening Brief at 12.

power to be paid by customers."[61] Specifically, CFC expresses concern with terms and conditions concerning the Compliance Costs Cap, Guaranteed Production, Modification to Contract Quantity, Project Security, Pollution and Earthquake Insurance objects and Fixed Price.[62]

CUE argues that the Large Projects PPA does not represent the interests of workers and specifically advocates that the PPA should require the independent power producers to: (1) hire only state-licensed electricians to perform electrical work; (2) invest in existing training infrastructure by requiring suppliers to hire apprentices enrolled in state-certified apprenticeship programs; and (3) pay construction workers the prevailing wage rate. CUE argues that while these terms are not required by state law, they serve important policy objectives of improved production efficiency, higher quality work product, continuity of a skilled workforce, and a guarantee that workers will receive fair wages and benefits such as health care.[63]

In response, PG&E asserts that the PPA forms "equitably allocates risk between independent developers of PV facilities and PG&E, acting on behalf of its customers, because it was an agreement reached in an arm's length negotiation between a number of parties representing competing interests."[64]

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[61] CFC Opening Brief at 22.

[62] We note that CFC's Opening Brief appears to refer to an old version of the Large Project PPA and contains several errors. The correct version of the Large Project PPA is Exhibit 13.

[63] CUE Reply Brief at 13.

[64] PG&E Opening Brief at 19.

9.2. Discussion

We adopt a modified standard PPA for the PPA portion of the PV Program. We understand DRA's concern that no consumer advocate groups were present during negotiations to form the proposed Large Project PPA form. Nonetheless, we find it reasonable to adopt a modified standard contract for PPAs for this program. As TURN has stated, a standard contract would provide some modest level of development security.[65] A modified PPA will be in ratepayers' interest because it will expedite the negotiation and commission approval of PPAs and could attract more sellers to participate in the solicitation. It will also reduce the administrative costs associated with contracting for individual PV projects due to less review and documentation requirements.

Modeling the standard contracts on the existing RPS standard contracts seems reasonable and we agree with most of the revisions to tailor the RPS standard contract to this program. However, we make a number of revisions to the Large Project PPA to minimize ratepayers' risk exposure.

First, we adopt the proposed compliance cost cap with modifications.[66] We agree with Solar Alliance that complying with changes in law and regulatory requirements may be difficult to quantify and as such may pose additional risk to the project financing. Having certainty in contract terms and obligation not only helps with securing project financing, but also gives the seller an increased

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65 Exhibit 800 at 5.

66 The compliance cost cap applies to a seller's costs associated with complying with several regulatory certifications and requirements as described in Section of the Large Project PPA. The compliance cost cap is cap on total costs over the term of the agreement not to exceed $20,000/MW. CFC's brief incorrectly refers to an old version of the proposed Large Project PPA.

ability to offer better prices. We find it is reasonable to identify a limited liability for these costs in order to facilitate financing. Therefore, we adopt the proposed compliance cost, and require that section 3.1 (o) be modified to clarify that it would only apply to costs due to changes in the law that occur after the execution of the contract. We make another revision to the Compliance Cost Cap provision and require PG&E to seek Commission authorization through an advice letter prior to making any payments above the cap to ensure that such costs are reasonable. CFC's concern with the compliance cost cap is that PG&E's ratepayers could be responsible for any compliance costs that exceed the Compliance Cost Cap. PG&E explains that the Large Project PPA does not require that PG&E pay any cost that exceeds the cap. PG&E asserts that it would first assess whether the costs were commensurate with the value of the contract. We believe this is a reasonable measure to ensure that ratepayers are not automatically subject to costs above the cap. We require PG&E to seek Commission authorization through an advice letter prior to making any payments above the cap to ensure that such costs are reasonable. PG&E witness Jeung testified during hearings that major new compliance costs are less likely to occur because compliance rules are generally well established up front. No party has identified a scenario which would indicate that the PV projects are likely to be subject to higher compliance costs or that the compliance cost cap amount is unreasonable. With the above modification, we are comfortable that the risk exposure to ratepayers is low.

With respect to the guaranteed energy production provisions, the Large Project PPA lowered the performance requirements for a seller from an average of 160% of the expected generation over a two year period to 140%. The 160% is an existing provision in the RPS pro forma and standard contracts. CFC asserts that lowering the performance requirements will increase the likelihood that PG&E will need to acquire replacement power at a higher cost to PG&E's customers.

Although we disagree with CFC's analysis, because PG&E did not provide a specific justification for this change, we do not modify the 160% requirement. In conjunction with the lower general performance requirement, the Large Project PPA also proposed lower performance requirements to cure a performance default in a prior two year period. We reject this proposal as well and require PG&E to employ 90% which is its standard pro forma provision concerning this issue. Accordingly, the Guaranteed Energy Production will be 160% and the Guaranteed Energy Production Cure will be at 90%.

Regarding the contract capacity provision, the Large Project PPA includes an option for the seller to reduce the contracted for capacity of its project in the event it fails to meet delivery requirement set forth in the PPA. Specifically, the Large Project PPA provides that a seller having failed to perform according to the delivery requirements in the PPA, may reduce its contract capacity to no less than 70% percent of the original contact capacity. In addition, if a seller opted to exercise this one-time option, it can avoid paying penalties for past performance shortages but will be required to meet delivery requirements throughout the remainder of the contract term (i.e., 160% of the expected generation over a two year period).

CFC characterizes this new provision as a way for sellers to avoid paying a penalty. PG&E explains in its reply briefs that providing this one-time option for sellers also benefits PG&E's customers because it will allow a project to continue operating and delivering without resulting in an event of default.

We agree that including this flexibility for this program strikes a reasonable balance between buyer and seller without necessarily imposing additional costs on PG&E's customers. Accordingly, the standard PPA may include the one-time option for a seller to reduce the contract capacity to no less than 70% percent of the original contract capacity.

Finally, because the size of the projects in the PV Program is limited and because these projects would be developed over a fairly short time frame, we are comfortable with the lower project development security amounts and the insurance provision proposed in the Large Project PPA.

With respect to CUE's request for PPAs to provide prevailing wage rates and other labor related requirements, we do not require such conditions, because the California Labor Code pertaining to prevailing wage does not apply to the projects under the PPA portion of the PV Program.

10. Additional Rate of Return

PG&E requests the rate of return (ROR) on rate base for the PV UOG Program be equal to its currently authorized ROR of 8.79 adopted in D.07-12-049 for 2008, plus 1 percent. PG&E claims the additional 1 percent is allowed pursuant to § 454.3 and by D.06-05-039 for renewable assets.[67] Alternatively, PG&E requests that if we find that Pub. Util. Code § 454.3 is not applicable, we grant the increase in the rate of return pursuant to § 454(a).

10.1. Parties' Positions

Greenlining opposes the additional rate of return adjustment, arguing that an increase in the rate of return would be justified only if the technology is

[67] PG&E's Application at 7.

experimental. Greenlining states that the PV Program relies on solar PV which "has been in relatively widespread use for the last three decades."[68]

CFC opposes the proposed increased rate of return addition for a different reason. CFC argues that D.06-05-039 allows an increase in the rate of return under Public Utilities Code § 454.3, however not without holding a hearing and determining that "the capital costs [of the facility], when added to its costs of operation and maintenance, result in a cost of electricity generated over the useful life of the facility less than that of electricity generated by existing facilities utilizing nuclear power or fossil fuel; and the facility is used and useful." CFC asserts "PG&E has offered no evidence which would support such a finding."[69]

10.2. Discussion

We reject PG&E's request for an additional rate of return. Under the cost recovery approach adopted herein PG&E will not enter the capital investment associated with the projects it develops into rate base and thus the issue of what rate of return it should be authorized to receive for those investments is rendered moot. As described above, the rate of return PG&E receives for these projects will be a function of how efficiently PG&E can build and operate these systems relative to the price it will receive per kWh as calculated from the PPA solicitations.

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68 Greenlining Opening Brief at 12.

69 CFC Opening Brief at 27.

11. Non-Bypassable Charge

PG&E requests recovery of any stranded costs associated with the PV Program through a non-bypassable charge.[70] PG&E believes it is allowed to recover the stranded cost associated with the PPAs over the entire term of the agreement. PG&E also believes it is allowed to recover the stranded costs associated with each facility installed for a 10-year period following commercial operation of the facility.[71]

11.1. Parties' Positions

WPTF argues that the stranded cost recovery established in D.04-12-048 applies only to utility-owned generation acquired as a result of the procurement process specified in that decision. WPTF argues that PG&E has failed to comply with that process, therefore, if the PV Program creates any stranded costs, those costs should be borne by PG&E's shareholders not its ratepayers.

11.2. Discussion

We agree with DACC that the cost of the PV Program should not be allocated to the Direct Access (DA) customers. Requiring DA customers to incur cost of the PV Program would be unreasonable and represent double payment.

The PV Program provides generation exclusively for the benefit of PG&E's bundled customers. It would be unreasonable to require DA customers to pay for the cost of the PV Program when they do not receive the program's associated benefits. Moreover, as DACC notes, DA providers are subject to RPS compliance obligations of their own and DA customers bear the compliance costs

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[70] Exhibit 1 at 6-7.

[71] Exhibit 1 at 6-7.

associated with meeting these obligations. Since PG&E's PV Program is designed to help PG&E meet its own RPS obligation, there is no RPS related benefits to DA customers. DA customers already pay for the RPS programs of their own, thus they would be paying double, if we were to impose that they also pay for PG&E's RPS obligations. Therefore, we do not allocate the cost of the PV Program to DA customers through a non-bypassable charge. Rather, PG&E's bundled customers who would directly benefit from the PV Program should be responsible for the entire cost of the program, including any stranded cost.

12. Land Deposits

PG&E proposes to include the land deposits for future PV facility in Plant Held for Future Use (PHFU) in order to recover the carrying costs of these deposits prior to the operation of the PV facilities. PG&E plans to transfer the deposits to plant in service after the PV facilities start operation.

12.1. Parties' Positions

DRA opposes PG&E's land deposit proposal. DRA argues that although the Commission may allow a utility to earn a return on the cost of property, land deposits do not qualify for such recovery because they are not "property acquired.[72] In DRA's view, property is only acquired when the land is purchased. DRA is also concerned that "allowing PG&E to earn a rate of return on land deposits would create a perverse incentive for PG&E to put down numerous land deposits in order to pad its rate base, with no risk to its shareholders."[73] DRA urges the Commission to deny PG&E's request, but

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72 DRA's Opening Brief at 9.

73 DRA's Opening Brief at 9.

should the Commission allow PG&E purchases to be treated as PHFU, DRA proposes to limit the time that a property can be held for future use to 18 months, consistent with PG&E's claim of the timeframe for bringing PV projects on line. PG&E is opposed to this treatment, because in its view, it would restrict its ability to make reasonable purchases for use in later phases of the UOG build-out.[74]

CFC is also opposed to PG&E's land proposal because PG&E has no firm plans for the use of land on which it will pay a deposit. CFC argues PG&E should not be allowed to hold such deposits in its PHFU account.[75]

In response, PG&E states that plants held in PHFU will be for building PV facilities. Therefore, it should be allowed to recover the carrying cost.

12.2. Discussion

We reject PG&E's proposal to recover the carrying costs of land deposits prior to operation of the PV facilities. As stated previously, we believe that PG&E should use its own land before it procures additional land for the UOG projects. However, as we discuss below land deposit do not qualify for cost recovery.

The Commission allows utility property held for use at a later date to be included in PHFU based the Electric Uniform System of Accounts, Account 105. Paragraph B describes the PHFU as follows:

> This account shall also include the original cost of land and land rights owned and held for future use in electric service under a plan for such use, to include land and land rights:

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74 PG&E's Opening Brief at 32.

75 CFC's Opening Brief at 29.

(1) Acquired but never used by the utility in electric service, but held for such service in the future under a plan, and (2) previously held by the utility in service, but retired from such service and held pending its reuse in the future under a plan, in electric service. (See Electric Plant Instruction 7.)

PG&E also describes PHFU as property acquired in advance for future utility use. Both definitions are consistent in that only utility owned land and land rights are eligible to be entered into PHFU. Land deposits prior to purchase of the land do not qualify as acquired or owned property per the above definition. Therefore, such deposits cannot be entered into PHFU. Only after land is purchased pursuant to a plan for PV facility construction, it will become acquired property eligible for inclusion in PHFU account.

It is worth noting that even if land deposits were allowed as PHFU, in this instance, they would not be allowed as PHFU, because PG&E has not met the requirement to provide a plan on how these lands will be used if the PV Program is terminated and PV facilities are not constructed.

13. Pilot Project

We approve the proposed Pilot Project, but adopt the actual capital cost of the project instead of what PG&E has proposed. PG&E proposes to develop a pilot project of up to 2 MW prior to regulatory approval of this application. PG&E states that the Pilot Project will likely be on its land and is intended to expedite the development of the PV Program, demonstrate PG&E's commitment to the PV Program, and allow PG&E to refine internal and external processes needed to develop, permit, construct, and operate a PV facility prior to deployment of the larger PV Program.[76] We agree that given the scale of the

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[76] Exhibit 1 at 1-5.

overall solar program, as proposed and adopted, the pilot project is a useful undertaking. PG&E estimates the capital cost of the Pilot Project at $11.9 million.

During the hearing, PG&E's witness noted that PG&E has selected a bid for its Pilot Project. The ALJ directed PG&E to file a response to several questions regarding the solicitation process. PG&E submitted its filing on September 23, 2009.

A review of PG&E's response to the ALJ questions indicates that PG&E followed a competitive process for the development of its Pilot Project. Specifically, PG&E issued a request for information to several solar PV market participants and then issued a request for proposals to a shortlist of candidates that met specific criteria, including price, system performance and operating costs, developer experience, and ability to comply with standard contract terms and conditions, all of which are common to procurement of capacity and generally used in assessing bids. In light of this, we find that PG&E's selection of the Pilot Project through a competitive process was reasonable.

We reject PG&E's proposed cost estimate for the Pilot Project. These estimates are based on the same assumptions as the UOG portion of the PV Program. As stated earlier, we reject PG&E's cost estimate for the UOG projects for lack of justification and detail. For the same reasons, we reject the capital cost estimate for the Pilot Project. Although going forward, we will explicitly hold the price customers' pay for UOG projects to the prices actually observed through the PPA solicitations, for the purposes of the Pilot Project, we recognize that PG&E did not have access to this information, thus, we authorize PG&E to recover the actual capital costs instead of the estimated cost for the Pilot Project. PG&E will be authorized to record the capital cost of the Pilot Project into its UGBA as of the effective date of this decision.

14. Parties' Motions

On October 1, 2009, DRA filed a motion to file under seal confidential portion of its opening brief.

On October 16, 2009, PG&E filed a motion to file under seal confidential version of its reply brief.

DRA's motion states that its opening brief contains information identified by PG&E as confidential and therefore not subject to public disclosure. PG&E also states that its reply brief contains confidential information. No party has opposed granting these motions. Both motions are granted.

15. Comments on Proposed Decision

The alternate proposed decision of President Michael R. Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____________ and reply comments were filed on _______________ by ________________________.

16. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Maryam Ebke is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Although on a contractual basis PG&E has procured adequate renewable power to meet its RPS target for 2010, it is unknown at this time the extent of delay or contract failure will impact these contracts.

2. New renewable projects and transmission additions face a variety of risk factors, including permitting and financing challenges that may result in contract failure or delays.

3. Smaller projects may avoid many of the risk factors that impede the timely development of larger scale renewable projects to the extent these smaller projects do not have the same land impacts, do not require the same level of project financing and permitting, and do not depend on large capacity transmission additions.

4. The output profile of solar PV largely coincides with periods of peak demand.

5. DRA's SWOT technique does not take into account some of the benefits of the small and mid-sized PV projects proposed by PG&E.

6. The PV Program will not conflict with the RPS program as it focuses on a subset of projects and technologies that cannot effectively compete in the RPS program as it is currently designed and implemented.

7. The final RETI Phase 1 B Report identifies PV technology specifically as having significant potential for capital cost reductions in the future.

8. The Commission has expressed its interest in utility proposals for utility-owned renewable projects.

9. Few renewable UOG proposals have come forward to date.

10. The PV Program as modified can help facilitate the expeditious deployment of renewable facilities including UOG projects that would not otherwise be selected through the existing RPS procurement process.

11. The pricing structure proposed by PG&E for UOG and PPA projects under its program may result in higher prices to ratepayers than would occur were a more competitive approach used.

12. PG&E's cost estimates are not sufficiently justified.

13. The CSI and the SPVP do not provide a reasonable price comparison to the PV Program given the different deployment model these programs embody.

14. Comparison to other UOG in other states does not provide useful information because the size of the projects provided for comparative purposes are much smaller than those in PG&E's proposed program.

15. Projects of a comparable size and technology that have bid into the RPS program provide the most reasonable comparison to the proposed PV Program. Under the RPS program as currently implemented, smaller scale projects, while likely to offer greater viability and speed of deployment relative to large scale projects, are unlikely to be selected owing to their higher price. This may limit the extent to which smaller scale projects participate in the RPS program.

16. A fixed PPA price may result in overpayment by ratepayers.

17. AB 920 does not overlap with the PV Program.

18. SB 32 could overlap with the proposed PV Program for projects between 1 and 3 MW.

19. The Commission has not yet implemented SB32 and it is not known at this point how the price the Commission develops will impact the deployment of projects between 1 and 3 MW.

20. The price of solar PV is anticipated to decline in the years ahead.

21. A price cost cap for PPA is a reasonable way to ensure that the costs of the solar PV Program are not excessive to ratepayers.

22. The revised Large Project PPA is reasonable.

23. PG&E should own, develop, install, operate and maintain up to 250 MW of solar PV projects up to 20 MW in size and procure 250 MW of solar PV projects up to 20 MW in size from independent solar energy providers.

24. Direct access customers should not pay for the PV Program's stranded costs.

25. Land deposits prior to purchase of the land do not qualify as acquired or owned property for recovery in PHFU account.

26. Under the alternative ratemaking treatment approach adopted herein, the return PG&E receives for projects it chooses to deploy shall be a function of the weighted average price calculated from the PPA solicitation, system performance, and the cost of deploying, operating and maintaining these systems.

27. A pilot project is a useful undertaking given the scale of the approved program and the experience PG&E can gain from pursuing this project.

28. PG&E conducted a solicitation process for the Pilot Project that includes criteria commonly used in bid selection.

29. DRA's opening brief contains confidential information.

30. PG&E's reply brief contains confidential information.

Conclusions of Law

1. The modified PV Program has many benefits and can help meet the RPS goals and should be adopted.

2. A competitive solicitation should be used to determine which projects are selected and at what price for the PPA component of PG&E's program.

3. To help ensure ratepayers are indifferent between projects undertaken by PG&E as UOG facilities and projects pursued by independent power producers, the price ratepayers pay for output from UOG facilities should be based on the price of power paid to IPP projects.

4. Allocating more capacity to earlier years of the program would not necessarily be beneficial given the dynamic nature of the solar industry and the possibility of future solar PV cost declines.

5. A price cost cap for PPA's will ensure that the costs of the PV Program are not excessive and should be adopted.

6. The revised Large Project PPA should be adopted with modifications.

7. PG&E should seek Commission authorization through an advice letter prior to making any payments above the compliance cost cap for PPAs to ensure that such costs are reasonable.

8. Under the alternative ratemaking treatment we adopt herein, granting PG&E request for a higher rate of return would be meaningless and therefore should not be adopted.

9. Direct access customers should not pay for the PV Program stranded costs.

10. PG&E should not be allowed to include the land deposits for future PV facilities in its PHFU account.

11. PG&E's pilot project should be approved.

12. It is reasonable to authorize PG&E to record the capital cost of the Pilot Project into its UGBA as of the effective date of this decision.

13. PG&E's request for a higher rate of return pursuant to Pub. Util. Code § 454.3 is rendered moot under the alternative ratemaking approach adopted herein.

14. The PV Program is consistent with Pub. Util. Code § 454.8.

15. DRA's motion to file its opening brief under seal should be granted.

16. PG&E's motion to file its reply brief under seal should be granted.

O R D E R

IT IS ORDERED that:

1. The Photovoltaic Program set forth in Appendix A to this decision is approved.

2. Pacific Gas and Electric Company shall implement the Photovoltaic Program as set forth in Appendix A.

3. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 3 advice letter with the Energy Division specifying the Photovoltaic Program implementation and administration details needed to implement the program set forth in Appendix A, including:

- Standard contract for facilities less than 3 MW in size;
- Competitive solicitation process, eligibility, and timeline for the power purchase solicitations;
- Criteria for evaluating conforming bids;
- Process for identifying preferred locations for project development to optimize the locational value of project sites, including impacts on neighboring lands;
- Generation system interconnection application process and protocols;
- Confidentiality protocols to ensure that information given by developers to Pacific Gas and Electric Company through the interconnection or bidding process is not shared with Pacific Gas and Electric Company's staff working on the utility-owned generation of the Photovoltaic Program; and
- Work papers that will be used for to calculate the annual revenue requirement Pacific Gas and Electric Company will be authorized to recover in rates, for the projects Pacific Gas and Electric Company elects to develop and operate under the utility-owned generation portion of the Photovoltaic Program, based on the methodology set forth in Appendix A.

4. Within 30 days from the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 2 advice letter to modify the description of the

Preliminary Statement of its Energy Resource Recovery Account balancing account to reflect:

- Debit entries for the utility-owned generation projects equal to the actual generation of that facility multiplied by the authorized dollar per megawatt-hour amount.
- Debit entries for the cost of the power purchase agreements.

5. Upon operation of a utility-owned photovoltaic facility, Pacific Gas and Electric Company is authorized to begin debiting to the Energy Resource Recovery Account balancing account the actual generation of that facility multiplied by the dollar per megawatt-hour amount authorized by the Commission's disposition of the advice letter described in Ordering Paragraph 10 that applies to the particular facility.

6. In Pacific Gas and Electric Company's June 2010 Energy Resource Recovery Account forecast application and each subsequent annual filing, Pacific Gas and Electric Company shall include its forecast for the following calendar year: the dollar amount it expects to be eligible to recover during that calendar year for utility-owned Solar PV projects, based on a forecast of utility-owned Solar PV generation multiplied by the applicable dollar per megawatt-hour price for each facility.

7. The accuracy of the accounting for the recovery of the revenue requirement for the utility-owned generation portion of the Photovoltaic Program shall be subject to review in Pacific Gas and Electric Company's annual Energy Resource Recovery Account compliance proceeding filed in February each year.

8. Pacific Gas and Electric Company shall not recover any costs associated with the utility-owned generation portion of the Photovoltaic Program through

any rates other than the Energy Resource Recovery Account as authorized by this Photovoltaic Program decision.

9. In order to ensure there is no double counting of Photovoltaic Program costs, Pacific Gas and Electric Company shall identify but not recover in its General Rate Case application all costs associated with the utility-owned generation portion of the Photovoltaic Program, including but not limited to, permitting, planning, engineering, construction, acquisition, deployment, operation, maintenance, and overheads.

10. Pacific Gas and Electric Company shall file a Tier 3 advice letter within 60 days of each competitive solicitation for Solar PV power purchase agreements, detailing the Solar PV projects it intends to build as Utility Owned Generation, including the number of megawatts, the location (including justification for the use of land other than existing Pacific Gas and Electric Company-owned land), the weighted average price of winning bids from the solicitation, including its detailed calculation of that figure, which shall be used in calculating the debit entries to the ERRA balancing account authorized in Ordering Paragraph No. 5. In addition, the advice letter shall specify the projected annual output of each Solar PV project that PG&E intends to build.

11. Pacific Gas and Electric Company is authorized to record the actual cost of the Pilot Project into its utility generation balancing account as of the effective date of this decision.

12. Pacific Gas and Electric Company may not enter land deposits for future utility-owned photovoltaic facilities into the account for Plant Held for Future Use.

13. Pacific Gas and Electric Company must seek Commission authorization through an advice letter prior to making any payments above the adopted power purchase agreement compliance cost cap.

14. Pacific Gas and Electric Company shall file annual compliance reports with the Energy Division as described in Appendix A. The first compliance filing is due on March 1, 2011.

15. The form power purchase agreement for projects greater than three and up to 20 megawatts, referred to as the Large Project PPA is modified as follows:

- Compliance Cost Cap (Section 3.1(o)) shall state:
    - Costs applicable to the Compliance Cost Cap are only those costs applicable under the term's definition (section 1.26) and are new costs associated with a change in law from the contract's execution date.
    - In the event compliance costs exceed the cap, Pacific Gas and Electric Company will first obtain Commission authorization to incur additional costs.
- Guaranteed Energy Production - (Section 3.1(e)(ii)(A)) shall be 160 percent as the performance metric, as set forth in Pacific Gas and Electric Company's renewables portfolio standard pro forma.
- Guaranteed Energy Production Cure (Section 3.1(e)(ii)(B)) shall be 90 percent as the performance metric, as set forth in Pacific Gas and Electric Company's renewables portfolio standard pro forma.

16. Application 09-02-019 is closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A
The Photovoltaic Program (PV Program) for Pacific Gas and Electric Company Adopted 2010

General Overview:
The Photovoltaic Program (PV Program) is a five-year program to develop up to 500 megawatts (MWs) of solar photovoltaic (PV) facilities in the range of one to 20 MWs in Pacific Gas and Electric Company (PG&E's) service territory.

Total Size of the PV Program:
500 MW

Utility-owned Generation (UOG) Portion of the PV Program:
Size: 250 MW
Schedule:

Year	2010	2011	2012	2013	2014
MW	50	50	50	50	50

MWs from a given tranche of capacity that PG&E does not indicate it intends to develop shall be added to next year's allotment. UOG drop-outs, defined as capacity PG&E has indicated it intends to build but does not ultimately pursue within the 18 month development timeframe, will not to be added to the next tranche of authorized capacity.

Project Size: Generally from one to 20 MW. Projects below 1 MW can be pursued but must not constitute more than 5% of the total authorized UOG capacity.

Project development timeline: 18 months

Location: Ground – mounted in PG&E's service territory. Projects should be developed on land PG&E already owns and close to substations. Other land selections (not owned by PG&E) must be submitted through an advice letter for approval.

Price:
PG&E shall file an advice letter within 60 days of the selection of winning bids from a solicitation, indicating the number of MWs, the location, and the

estimated calculation of the revenue requirement for the UOG facilities including the weighted average price calculated from the solicitation.

Power Purchase Agreement (PPA) Portion of the PV Program:
Size: 250 MW
Project Size: From one to 20 MW
Project development timeline: 18 months
Location: Ground-mounted in PG&E's service territory.
Schedule:

Year	2010	2011	2012	2013	2014
MW	50	50	50	50	50

Un-awarded MWs shall be added to next year's solicitation. PPA drop-outs, defined as projects that were selected via the solicitation process but which do not come online within the 18 month development timeframe will be added to the next program solicitation.

Price: PG&E shall hold a competitive solicitation annually to select winning projects.

Reporting:

PG&E shall file annual compliance reports with the Energy Division. The first compliance filing is due on March 1, 2011. PG&E shall consult with Energy Division to develop the format and content of the report. The annual report prepared by PG&E shall include, at a minimum, the following information:

Reporting on PPA portion of the PV Program

- Documentation of all solicitations issued for PPA projects;
- A description of all bids received from the PPA solicitations, including the name of bidder, location of project, bid price, and description of proposed facility (generating capacity, type of technology, annual average expected generation, interconnection point), and identification of winning bids;

- The total electrical output for all systems under PPAs that are currently selling electricity to PG&E, for each month of the previous year;
- A description of the project specific distribution and network upgrades and distribution and network upgrades generally needed to facilitate the PV PPA Program.

<u>Reporting on UOG portion of the PV Program</u>

- A description of all UOG facilities for which work has been initiated or completed in the previous year, including: capital costs, and operations and maintenance expenses, generating capacity, type of technology, annual average expected generation, description of the site (existing PG&E-owned land or newly acquired/leased, land/lease cost, proximity to substation), and progress toward completion;
- A calculation of the levelized cost of energy (LCOE) for each UOG facility that is completed and interconnected to the grid. This calculation shall include work papers showing actual amounts for all cost and electrical output entries used to calculate the LCOE;
- Electrical output by month for the previous year for each PG&E-owned UOG facility that is completed and interconnected to the grid; and
- A description of the project specific distribution and network upgrades and distribution and network upgrades generally needed to facilitate the PV PPA Program. The known or projected costs of those upgrades, associated with interconnecting each UOG facility, including all distribution and network upgrades, a listing of the UOG projects identified as triggering the need for network upgrades, and identification of the UOG projects implemented notwithstanding the need for network upgrades, and the cost of those network upgrades.

(END OF APPENDIX A)

APPENDIX B
Alternative Ratemaking Treatment Example Calculations[1]

Overview of Methodology:

A weighted average across the winning bids in any solicitation will be calculated by 1.) multiplying each respective bid's price per kWh by the share it's production over its contract life represents relative to the total production of all winning bids over their respective contract lives; and 2.) summing these values across all winning bids. This weighted average price per kWh will serve as the price input used to derive the revenue requirement PG&E shall be allowed to recover, inclusive of O&M costs, for any output generated by the capacity its elects to develop prior to the initiation of the subsequent year's PPA solicitation. For each project PG&E chooses to develop it will provide an estimated annual revenue requirement calculated by applying the weighted average price per kWH as described above to an estimate of its systems' estimated output.

Bid #	Capacity (MW)	Price per kWh	Contract Term	Total Production Over Contract (kWh)	Percent of Total Production	Contribution to Weighted Average Price per kWh
1	5	$0.26	20	175,200,000	10%	$0.03
2	2	$0.22	20	70,080,000	4%	$0.01
3	8	$0.26	20	252,288,000	15%	$0.04
4	4	$0.30	20	112,128,000	7%	$0.02
5	10	$0.18	20	367,920,000	22%	$0.04
6	5	$0.22	20	122,640,000	7%	$0.02
7	5	$0.15	20	131,400,000	8%	$0.01
8	5	$0.19	20	227,760,000	13%	$0.03
9	3	$0.26	20	131,400,000	8%	$0.02
10	3	$0.12	20	105,120,000	6%	$0.01
Total	**50**			**1,695,936,000**	**Weighted Average Price per kWh**	**$0.21**

[1] Note that all numbers provided in this example are for illustrative purposes only.

Variable	Example Value	Description
Annual System Output (kWh)	8,760,000	PG&E data: Metered Annual System Output
Assuming Value of Output Equal to Weighted Average Calculated Above	$ 1,875,889	Calculated: Annual System Output* Weighted Average Price per kWh

(END OF APPENDIX B)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated January 26, 2010, at San Francisco, California.

/s/ TERESITA C. GALLARDO
Teresita C. Gallardo

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074 or TDD# (415) 703-2032 five working days in advance of the event.