Public

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

2012 RENEWABLE ENERGY PROCUREMENT PLAN (DRAFT VERSION)

MAY 23, 2012

Public

TABLE OF CONTENTS

TABLE OF CONTENTS

(CONTINUED)

TABLE OF CONTENTS

(CONTINUED)

TABLE OF CONTENTS

(CONTINUED)

LIST OF APPENDICES

1 Introduction and Overview of 2012 Plan

Pacific Gas and Electric Company's (PG&E or the Company) 2012 Renewables Portfolio Standard (RPS) Procurement Plan (Plan) describes the actions that PG&E will undertake to meet California's 33 percent RPS mandate and associated interim RPS requirements through procurement from resources that meet the RPS eligibility standards.

PG&E is committed to achieving California's RPS goals. In fact, the Company is well-positioned to meet the 33 percent RPS mandate and projects that it will comply with its 2011-2013 Compliance Period RPS requirement of an average of 20 percent deliveries over that period. PG&E also projects that it will meet its second (2014-2016) and third (2017-2020) Compliance Period RPS requirements. Based upon the compliance outlook provided in this Plan, PG&E's 2012 RPS Solicitation (2012 RPS Solicitation) will focus on cost-effective procurement intended primarily to position PG&E to be able to satisfy an ongoing 33% RPS requirement beyond the third Compliance Period.

Despite the significant progress towards RPS compliance noted in this document, the Plan also describes the complexity and uncertainty inherent in renewables development, in forecasting operational performance, and in forecasting retail sales. Accordingly, the Plan describes multiple need scenarios to address potential RPS compliance outcomes. PG&E's planned procurement activities also incorporate a minimum margin of over-procurement designed to mitigate the RPS-eligible project failure and delay concerns that are the focus of the RPS statute's mandatory minimum margin of over-procurement.[1]

1.1 Overview of 2012 Plan

This Plan demonstrates that while PG&E is well-positioned to meet its near-term RPS compliance requirements and has made significant progress toward increasing its procurement of renewable resources in the last several

---

[1] *See* Cal. Pub. Util. Code §§ 399.13(a)(4)(D), 399.15(b)(5)(B)(iii).

years, PG&E will need to continue procuring eligible renewable resources to fill its long-term need, which is during the latter part of the third Compliance Period and continuing past 2020. PG&E intends to procure steady and moderate volumes of incremental long-term volumes over the next several years to help it reach, and then sustain, the 33 percent RPS goal. PG&E's 2012 RPS procurement goal for its 2012 RPS Solicitation, reflected in the 2012 RPS Solicitation Protocol and supported by the Plan's RPS need quantification, is to add to its RPS portfolio approximately 1,000 gigawatt-hours (GWh) per year of RPS-eligible deliveries offering high portfolio value through new long-term contracts. These volumes would be in addition to any volumes PG&E procures through the Renewable Auction Mechanism (RAM) Program, the Feed-in Tariff (FIT) program, the Qualifying Facility (QF) program, and the Photovoltaic (PV) Program.

The Company will rely primarily on existing competitive procurement processes to meet its incremental RPS procurement needs. This includes procuring resources through the general RPS solicitations, such as the 1,000 GWh per year targeted in the 2012 RPS Solicitation, and also through the RAM Program, the FIT program, the QF program, and the PV Program. PG&E believes that relying on these established competitive solicitation processes will lower costs for customers and provide fair opportunities for all developers to offer cost-competitive renewable products that fit PG&E's portfolio need.

While PG&E is committed to meeting California's RPS mandate, achieving these ambitious goals presents challenges. PG&E's ability to comply with the RPS procurement requirement targets remains contingent on a number of factors outside of PG&E's control, including the ability of independent power producers that have executed Power Purchase Agreements (PPAs) with PG&E to overcome development and transmission challenges. Equally important, the operational reliability challenges created by adding a large amount of new intermittent resources to the California electric grid must be addressed. The anticipated costs of integrating the various RPS resource types need to be explicitly captured in the evaluation and selection process. Solving these grid integration challenges in an efficient way is vital to providing PG&E's customers with safe, cost-effective, and reliable electric service.

The Plan was developed in a manner consistent with the framework specified in the April 5, 2012 Assigned Commissioner's Ruling (ACR)[2] and the specific requirements of Public Utilities Code Section 399.13 (a)(5)(A)-(F), including discussion of: (1) annual and multi-year supply and demand to determine the optimal mix of RPS resources with deliverability characteristics including peaking, dispatchable, baseload, firm, and as-available capacity; (2) potential compliance delays; (3) a bid solicitation setting forth the need for eligible renewable resources of each deliverability characteristic, required online dates, and any locational preferences; (4) a status update of the development schedule of all eligible renewable energy resources currently under contract; (5) consideration of mechanisms of price adjustments associated with the cost of key components for renewable energy resource projects with online dates more than 24 months after the contract execution date; (6) and an assessment of the risk that an eligible renewable energy resource will not be built or that its construction will be delayed, with the result that the electricity will not be delivered as required by the contract. The Plan also addresses other requirements set forth in the 2012 Plan ACR, including cost forecasts of already-executed RPS contracts and forecasts of additional procurement needed to fill PG&E's identified long-term compliance need. Finally, the Plan addresses new

2 "Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 Et Seq. and Requesting Comments on New Proposals," issued April 5, 2012 in R.11-05-005 (the "2012 Plan ACR").

proposals included in the 2012 Plan ACR to modify the existing RPS procurement and review process.

As instructed in the 2012 Plan ACR, PG&E coordinated the format of its Plan with Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E). Together, these investor-owned utilities (IOUs) agreed to the use of the primary Section headings and appendices outlined in the Table of Contents to the Plan. PG&E also coordinated with SCE and SDG&E and consulted with the Energy Division to produce the standardized methodology and template included at Appendix 2. PG&E intends to continue collaborating with the other IOUs and the Energy Division in the future to further standardize the RPS procurement planning framework to help facilitate public review and understanding of the RPS procurement processes.

1.2 Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

California's RPS program requires nearly all load-serving entities (LSEs), including the IOUs, Publicly-Owned Utilities (POUs), Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs), to gradually increase their procurement of renewable generation until that generation serves at least 33 percent of the state's retail load on an ongoing basis. While PG&E intends to actively pursue the procurement of incremental renewable generation, and to work with Sellers to facilitate the completion and operation of new renewable facilities that are already under contract with PG&E, there still remain significant challenges to developing an adequate supply of renewable generation to meet California's challenging 33 percent goal. The following section provides an overview of recent regulatory changes impacting procurement decisions.

1.2.1 Commission Implementation of SB 2 (1x)

Senate Bill (SB) 2 (1x), enacted in April 2011and effective as of December 11, 2011, made significant changes to the RPS program, most notably extending the RPS goal from 20 percent of retail sales of all California IOUs, ESPs, and CCAs by the end of 2010, to a goal of 33 percent of retail sales of IOUs, ESPs, CCAs, and POUs by 2020. SB 2 (1x) modified and changed many details of the RPS program, including the addition of portfolio content categories for incremental (i.e., post-June 1, 2010) procurement, modification of compliance rules, replacement of the cost containment regime applicable to renewable energy generation, and the adoption of multi-year compliance requirements through 2020.

The California Public Utilities Commission issued an Order Instituting Rulemaking (OIR) to implement SB 2 (1x) in May 2011 and subsequently issued several rulings, decisions, and proposed decisions implementing certain "high priority" issues needed to implement the complex provisions of SB 2 (1x). Implementation is ongoing and Commission action on remaining key issues may impact PG&E's procurement need and actions going forward, notwithstanding the forecasts and projections included in this Plan.

1.2.1.1 Portfolio Content Requirements

As outlined in detail in Section 2, Commission Decision (D.) 11-12-052 defined portfolio content categories associated with RPS procurement contracts or ownership agreements executed after June 1, 2010 and RPS-eligible utility owned generation (UOG) online after June 1, 2010. A Proposed Decision (PD) implementing the 33% RPS Program compliance rules (discussed in Section 1.2.1.3 below) further describes the volumes of deliveries from resources that meet each of the portfolio content categories that may be used to meet RPS requirements in each compliance period going forward. In addition, Commission decisions authorize the Energy Division to develop additional information requirements concerning portfolio content requirements and usage restrictions.

Regulatory clarity surrounding product content categories eligible for RPS compliance is critical to enabling additional RPS procurement because SB 2 (1x) requires that Category 1 products[3] constitute a growing share of a retail seller's incremental procurement, from a minimum of 50 percent in Compliance Period 1 to a minimum of 75 percent in Compliance Period 3 and thereafter. While the remaining procurement in each compliance period may come from Category 2[4] and Category 3[5] products, SB 2 (1x) limits Category 3 products to 25 percent of incremental procurement in Compliance Period 1, decreasing to 10 percent of incremental procurement in Compliance Period 3.

1.2.1.2 Compliance Period Targets

As implemented by D.11-12-020, each retail seller is required to meet the following RPS procurement quantity requirements beginning on January 1, 2011:

- Twenty percent of its combined bundled retail sales during the first compliance period (2011-2013).
- A percent of its combined bundled retail sales during the second compliance period (2014-2016) that is equal to the results of the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).

---

3 Category 1 products are generally those that are interconnected to a California Balancing Authority (CBA) or are delivered in real-time to a CBA without the use of substitute energy. *See* Cal. Pub. Util. Code § 399.16(b)(1). *See also* D.11-12-052 at 75-76.

4 Category 2 products are generally those products not meeting the Category 1 definition and that are firmed and shaped using incremental electricity. *See* Cal. Pub. Util. Code § 399.16(b)(2). *See also* D.11-12-052 at 76-77.

5 Category 3 products are generally unbundled Renewable Energy Credits (RECs). *See* Cal. Pub. Util. Code § 399.16(b)(3). *See also* D.11-12-052 at 77-78.

- A percent of its combined bundled retail sales during the third compliance period (2017-2020) that is equal to the results of the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
- 33 percent of combined bundled retail sales in 2021 and all years thereafter.

1.2.1.3 Compliance Rules

On April 24, 2012, Administrative Law Judge (ALJ) Simon issued a PD Setting Compliance Rules for the RPS Program. The Proposed Decision, if finalized, would provide rules regarding (1) transitioning between the 20 percent RPS Program and the 33 percent RPS Program as of January 1, 2011, including rules regarding a retail seller's ability to qualify for a "safe harbor" to eliminate 20 percent RPS Program net deficits as of December 31, 2010; (2) how grandfathered[6] contracts may be used going forward; (3) requirements to pursue minimum quantities from long-term contracts; (4) time limits for retiring RECs in the Western Renewable Electricity Generation Information System (WREGIS) for purposes of RPS compliance; (4) measuring compliance with the portfolio content rules; (5) rules regarding the banking of excess procurement; (6) RPS compliance reporting requirements; and (7) the timing to file any requests for enforcement waivers or reductions in the portfolio content category requirements. The resolution of these issues may impact the amount and timing of PG&E's procurement efforts.

---

6 "Grandfathered" contracts are those that count in full toward RPS procurement requirements, notwithstanding the new 33% RPS Program restrictions on product content category or banking. Such contracts must have been executed prior to June 1, 2010 and meet other statutory criteria. *See* Cal. Pub. Util. Code § 399.16(d).

1.2.2 TRECs

As described above, SB 2 (1x) created new portfolio content categories that limit LSEs' abilities to use unbundled RECs and certain other out-of-state renewable products for RPS compliance. The Legislature put these restrictions into place just after the Commission had finalized a lengthy proceeding to define and authorize the use of "Tradable RECs" or TRECs, for RPS compliance.[7]

It is important to recognize that TRECs are a Commission-developed category of product that is different than the new statutory Category 3 product; Category 3 products are almost certainly TRECs, but some TRECs could fall within Category 1 or Category 2. The Commission has clarified that certain rules from D.10-03-021 as modified by D.11-01-025 (the TREC Decision) continue to apply in the 33% RPS Program, including:

- The temporary price cap, which is set to expire on December 31, 2013, of $50/REC for any TREC contract;
- The prohibition on selling RECs from the first three years of a contract that is for TRECs if that contract has been earmarked to apply to a shortfall in a retail seller's annual procurement target under the 20% RPS Program; and
- The prohibition on unbundling RECs from the first three years of a contract that is for bundled RPS procurement if that contract has been earmarked to apply to a shortfall in a retail seller's annual procurement target.

As part of this RPS procurement planning proceeding, PG&E requests that the Commission declare that the remainder of the TREC Decision has been superseded and preempted by SB 2 (1x) and therefore is no longer effective. In particular, PG&E notes that Ordering Paragraphs 17 (limiting IOU procurement of TRECs to 25% of "their annual procurement targets … beginning with the 2010 compliance

---

7 *See* D.10-03-021, as modified by D.11-01-025.

year") and 32 (requiring advice letter filings for TREC transactions to include information regarding the compliance status of the IOU with the TREC Decision's quantity limitations) are now in conflict with or made superfluous and/or redundant by the portfolio content provisions of Public Utilities Code Section 399.16. To avoid unnecessary complexity and market confusion regarding the applicable regulatory requirements, the Commission should repeal the TREC Decision except for the specific provisions the Commission has already explicitly found to continue to be effective.

1.2.3 Cost Containment

Customer costs are impacted by the direct procurement of renewable resources, the associated incremental transmission costs, and any future grid integration costs that are necessary. These costs have only begun to appear on PG&E's customers' bills and will likely increase as renewable power under contract to PG&E comes online in more significant quantities.

PG&E is committed to working with the Commission and stakeholders to implement SB 2 (1x) and the RPS Program in an efficient and cost-effective manner and to, whenever possible, mitigate these costs and their effects. On January 24, 2012, the Commission issued a Ruling in Rulemaking ("R.") 11-05-005 seeking comments on the procurement expenditure limitation for the RPS Program. PG&E submitted comments on that Ruling. The Commission's scoping ruling in this proceeding found that cost containment was a relatively high priority, but the Commission has not provided a more specific timeline for adoption of a procurement expenditure limitation.

PG&E believes the procurement expenditure limitation should be clear, stable and meaningful in order to promote regulatory certainty and support procurement planning. The costs of all RPS-eligible procurement, including all eligible renewable resource procurement programs and RPS-eligible UOG, that an electrical corporation uses for RPS compliance should be credited toward the limitation.

The only reasonable reading of SB 2 (1x) requires that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding "a de minimis increase in rates."[8] While the January 24, 2012 Ruling did not seek input as to the meaning of "a de minimis increase in rates," it is critical that the Commission clearly define this phrase to ensure that electrical corporations understand and can plan for their RPS procurement obligations within the context of the cost cap.

1.2.4 QF/CHP Settlement

In D.10-12-035, the Commission approved the Qualifying Facility and Combined Heat and Power Settlement (QF/CHP Settlement). One element of the QF/CHP Program established by the QF/CHP Settlement is a form PPA for QFs that are 20 MW and under. This form QF PPA is available to both RPS-eligible and non-RPS eligible QFs at terms of maximum seven years for existing facilities and ten years for new facilities. The QF/CHP Settlement became effective on November 23, 2011, and provides another opportunity for RPS-eligible QFs that satisfy the program criteria to contract with PG&E.

---

[8] Cal. Pub. Util. Code § 399.15(f).

1.3 Status of Efforts to Bring New RPS-Eligible Facilities Online and Deliver RPS-Eligible Energy to Customers

1.3.1 Increasing Success in the Development of Renewable Energy Projects

The ability of PG&E to meet its 33% mandate is highly dependent on the ability of the counterparties with which PG&E has PPAs to successfully develop their RPS projects. Over the past year, PG&E has observed increasing success in its counterparties' abilities to do so and now expects a significant number of projects to come online in the 2012-2015 period. Therefore, the RPS need calculated in the 2012 RPS Plan reflects a higher rate of anticipated success of PG&E's existing portfolio of projects under development than PG&E has used in prior procurement plans.

To the extent that the regulatory or financial environment changes in a way that decreases the likelihood of success for projects in PG&E's portfolio that are under contract but not yet in operation, or that threatens the viability of existing projects, PG&E's projected incremental RPS need also will change. Accordingly, the RPS need set forth in this Plan is meant only as a snapshot in time, based on a series of dynamic assumptions that are likely to change. With each future RPS Procurement Plan, and as needed as part of advice letter filings seeking approval of individual RPS procurement contracts, PG&E will update its need demonstration.

In addition, PG&E will have a number of expiring contracts in coming years with facilities that may have additional life. Some of these expiring contracts with existing RPS-eligible generators may be available for re-contracting and may be re-contracted for if offered at competitive prices. New contracts with existing facilities will be considered along with contracts for new facilities. Critical messages are being delivered to owners of existing facilities, particularly those who will want contract extensions. First, PG&E is not seeking shorter-term contracts that will not contribute to an ongoing long-term need well beyond 2020. Second, if existing facilities have contracts that do not expire in the near term, now is the time to seek long-term extensions. Several years from now, it is conceivable that PG&E will not be seeking long-term RPS contracts, and facilities without contracts will be competing for contracts with other non-RPS generators for incremental energy and capacity needs, but not RPS need.

1.3.2 Challenges to Renewable Energy Deployment Remain

The timely development of renewable energy generation facilities is subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, securing financing, technology, fuel supply, and the construction of sufficient transmission capacity. These factors and others discussed in Section 3 may require PG&E to seek a reduction in its portfolio content requirements or a waiver of its overall RPS procurement requirements, as provided for in Sections 399.15(b) (5) and 399.16(e) of the Public Utilities Code..

In addition, the Production Tax Credit (PTC) expires at the end of 2012 for wind resources and at the end of 2013 for other resources. The Investment Tax Credit (ITC) expires in 2016. This can create price and financing uncertainty for projects that may have not long-term contracting opportunities prior to the end of 2016 but want to take advantage of available tax incentives.

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

PG&E's 2012 RPS Solicitation seeks RPS-eligible products that will enable PG&E to comply with its RPS obligations and Resource Adequacy (RA) requirements. Specifically, PG&E is seeking offers for the following bundled products: Long-term (10 years or longer) contracts for Category 1 (preferred) or Category 2 products with a strong preference for deliveries beginning in 2019-2020. PG&E also requests bids for long-term Category 3 products, contingent upon the Commission's final compliance rules concerning Category 3 products. PG&E notes that its ability to use such Category 3 products for compliance diminishes over time, and therefore its need for those products will also diminish over time. PG&E seeks total procurement of about 1,000 GWh in the 2012 RPS Solicitation.

Projects in PG&E's service territory are preferred, as are projects with characteristics that merit a higher viability score, such as completed Phase II Transmission Cost Studies or simplified transmission interconnection requirements. Out-of-state offers will continue to be evaluated with an emphasis on the ability of the offer's volumes to qualify as a Category 1 or Category 2 product.

The offers selected will have the best combination of market value, portfolio adjusted value (PAV), viability, and qualifications, based on the evaluation criteria specified in the 2012 Solicitation Protocol. Additionally, PG&E will evaluate the project viability of each offer using the June 2, 2011 CPUC Project Viability Calculator (PVC).

1.4.1 2012 Procurement Will Address Long-Range RPS Goals

As discussed throughout this 2012 Plan and more specifically in Sections 2 and 6, PG&E currently projects that it will be in compliance during the interim Compliance Periods leading to an ongoing 33% RPS requirement. Recognizing the amount of time required to develop renewable energy projects and the potential for future project failures, PG&E's plan is to embark on a multiple year strategy to procure modest volumes each year, focused on purchasing for longer-term needs, which will enhance PG&E's ability to satisfy an ongoing 33% RPS requirement post-2020.

1.4.2 Changes to RPS Form PPA and Bid Solicitation Protocol

PG&E's 2012 RPS Solicitation will seek long term PPAs for products with delivery terms commencing in 2019-2020. As discussed throughout this 2012 RPS Plan and more specifically in Section 8, Appendix 5 to the Plan, and Appendix 6 to the Plan (the Draft 2012 RPS Solicitation Protocol), PG&E has made changes to the RPS Form PPA and Bid Solicitation Protocol. These changes reflect changing market conditions and PG&E's RPS need, and are intended to create greater incentives for full contract performance.

Since issuing its 2011 RPS Solicitation, PG&E has modified the credit and collateral requirements for developers seeking to enter into a PPA. For example, the project development security (PDS) requirement, initially set at $50 per kilowatt in the 2011 RPS Form PPA, has been increased to $300 per kilowatt for Category 1 and Category 2 products in the 2012 RPS Form PPA. In addition, PG&E modified its requirements for posting letters of credit to reflect financial market conditions and such conditions' potential impact on the credit ratings of many banks that Sellers may use to post PDS and delivery term security amounts, by (1) adjusting the credit rating requirement for a letter of credit issuer from at least "A" to "A-" from S&P or "A2" to "A3" from Moody's, with a stable outlook designation, and (2) limiting the amount of credit posted in the form of a letter of credit by any one issuer.

Further, to address challenges related to the expiration of the PTC and ITC, and to mitigate potential project viability concerns, PG&E has eliminated the Tax Credit Mitigation Option available in previous Form PPAs. In the past, this provision allowed developers to seek price adjustments if these subsidies were to expire. By eliminating this option, PG&E expects to receive offers from developers who are committed and able to fulfill contractual requirements without the guarantee of financing subsidies. PG&E has also made several changes related to delay provisions, outage reporting, curtailment orders, guaranteed energy production and greenhouse gas (GHG) reporting obligations described in further detail in Section 8.2.

PG&E's Bid Solicitation Protocol is also revised to reflect 2012 RPS procurement goals. PG&E's 2012 RPS Solicitation strives to be more streamlined, with clearly articulated product requests and reduced data requirements for bidders. Specifically, PG&E expresses a preference for long term contracts for Category 1 and 2 products delivering in 2019-2020. Category 3 bids are requested, however, PG&E's willingness to execute long term Category 3 products is contingent upon the Commission's adoption of banking rules.

PG&E plans to adjust its least-cost, best-fit (LCBF) methodology primarily to evaluate bids relative to PG&E's PAV, which includes explicit integration cost adders. PG&E previously assessed an offer's value using a net market value (NMV) calculation. While NMV assesses the value of a transaction relative to market forward curves, the PAV methodology uses NMV as an initial valuation and then makes additional adjustments that take into account the impact a transaction will have on the PG&E portfolio. PG&E proposes to use a basic integration cost adder of $7.50/Megawatt hour (MWh) (2008$), the same value for integration cost as used in the 2010 Long Term Procurement Plan (LTPP) proceeding,[9] which translates to approximately $8.50/MWh in

---

9 *See* February 10, 2011 Administrative Law Judge's Ruling Modifying System Track I Schedule and Setting PreHearing Conference, Attachment 2, "Standardized Planning Assumptions (Part 2 – Renewables) for System resource Plans" issued in R.10-05-006 at 28.

2013. The integration cost adder will be applied to resources that are considered intermittent, although resources with some reduced levels of intermittency may be subject to lower integration cost adders, as determined on a case-by-case basis. Further detail regarding revisions to the LCBF methodology is provided in Section 8.3.

1.5 Utility-Ownership of RPS Resources and Renewable Investments

1.5.1 Utility-Owned Renewable Projects

PG&E is not seeking bids for Purchase and Sale Agreements (PSAs) or sites for UOG through this 2012 RPS Plan. Nonetheless, PG&E is open to considering bilateral offers for exceptional opportunities to build renewable generation or to invest in renewables that are cost-effective and present high value to customers. PG&E will follow the process identified in its LTPP for submitting any additional RPS-eligible UOG for approval by the Commission. PG&E continues to include utility-owned small hydroelectric generation and solar PV generation in the Plan's RPS procurement and cost forecasts.

The only UOG renewable projects PG&E has in active development are the PV projects for the 250 MW UOG PV Program, described in further detail in Section 13.1.1. Consistent with PG&E's goal of complying with its RPS goals in the most cost-effective ways, PG&E is open to additional renewables ownership opportunities if they present high value relative to other procurement options.

1.6 Sales of RPS Procurement

PG&E has not entered into any contracts to sell excess RPS procurement. The RPS need and cost projections included in the Plan do not include any sales of contracted deliveries.

PG&E is continuing to assess the value to PG&E's customers of sales of excess procurement and will consider such sales if the value of the sale is greater than value of banked procurement.

1.7 Summary of RPS Cost and Rate Impact Data

The ACR required PG&E to provide historic and forecasted RPS cost and rate information as part of the Plan. To fulfill this requirement, PG&E coordinated with SCE and SDG&E and consulted with the Energy Division to produce the standardized methodology described in Section 11 and the template included in Appendix 2. In Table 11-1 PG&E also voluntarily provides further data incorporating certain Commission-approved or mandated RPS procurement programs to supplement the detail provided in Appendix 2. Per PG&E's consultation with the Energy Division, the annual rate impact presented in Tables 1 and 2 of Appendix 2 and Table11-1 reports a total cost of RPS-eligible deliveries, not the additional cost incurred in order to procure RPS-eligible resources instead of the equivalent amount of non-RPS-eligible resources. Thus the annual rate impact does not provide the reader with an estimate of the renewable "premium" that customers pay relative to a non-RPS-eligible power alternative. Rather, the annual rate impact is defined as an annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively an estimate of a system average bundled rate for RPS-eligible procurement and generation.

Actual historical procurement and generation costs of RPS-eligible resources, aggregated by technology type from 2003-2011, are provided in Table 1 of Appendix 2. Table 1 of Appendix 2 reflects settled contract costs with PPA counterparties, and an estimate of annual costs attributable to RPS-eligible UOG. These costs are divided by total bundled retail sales in each applicable year to reflect an estimated system average rate impact of RPS-eligible procurement and generation. Using this methodology, Table 1 of Appendix 2 shows that the rate impact of RPS-eligible procurement increased from 0.7 cents/kWh in 2003 to 1.4 cents/kWh in 2011. Further detail regarding the methodology underlying Table 1 of Appendix 2 is provided in Sections 11.1.1 and 11.1.3.

Table 2 of Appendix 2 provides a forecast of PG&E's future expenditures from 2012-2020 of all RPS-eligible procurement and generation either (1) approved to date; or (2) executed prior to April 5, 2012, but pending CPUC approval. These two categories of forecast expenditures are also separated by technology type. The forecast data set forth in Table 2 of Appendix 2 does not align with the RPS need scenarios described in Section 6, which reflect estimated contract failure or anticipated delays. In contrast, the costs associated with RPS-eligible procurement and generation in Table 2 of Appendix 2 assume no failure rate; that is, all contractual volumes are forecast at 100% of expected volumes, including forecast estimates of annual costs attributable to RPS-eligible UOG.

Furthermore, the costs reported in Table 2 do not present a complete picture of the potential customer cost impacts from the RPS program, because Table 2 of Appendix 2 omits three key categories: (1) additional costs PG&E will incur in order to procure the requisite amounts from Commission-approved or mandated RPS procurement programs; (2) additional costs PG&E will incur in order to procure any RPS-eligible procurement resulting from future competitive solicitations, including the 2012 RPS Solicitation, that are needed to ensure ongoing compliance with the RPS Program procurement requirements; and (3) non-procurement costs that can be directly attributed to the RPS program, specifically the associated incremental transmission costs and potential future integration costs.

The annual rate impact of forecasted procurement is detailed in Table 2 of Appendix 2, illustrating that the average rate impact associated with RPS-eligible resources is forecasted to increase to [redacted] in 2020. Further detail regarding the methodology underlying Table 2 of Appendix 2 is provided in Sections 11.1.2 and 11.1.3.

PG&E also provides supplemental information not specifically required in the ACR incorporating the estimated impact of certain Commission approved or mandated RPS procurement programs in Table 11-1. Specifically, Table 11-1 includes estimates of (1) forecast RAM procurement costs; (2) forecast PV PPA Program procurement costs for years 2-5 of the program; and (3) forecast FIT procurement costs. Table 11-1 does not, however, include forecasted costs of procurement resulting from future competitive solicitations, including the 2012 RPS Solicitation.

Table 11-1 illustrates that, after adding the forecasted costs of these three additional programs, the average rate impact increases to [redacted] in 2020. Further detail regarding the methodology underlying Table 11-1 is provided in Section 11.2.

2 Assessment of RPS Portfolio Supplies and Demand

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

Meeting the State's aggressive renewable energy goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E is working to procure cost-effective resources that will enable it to achieve SB 2 (1x)'s increase in California's RPS target to 33% of delivered energy from RPS-eligible facilities. As implemented by D.11-12-020, retail sellers of electricity that, like PG&E, procured at least 14 percent of retail sales in 2010 as RPS-eligible resources, are required to procure the following quantities of RPS-eligible products beginning on January 1, 2011:

- Twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).
- A percent of the combined bundled retail sales during the second compliance period (2014-2016) that is consistent with the following formula:

(.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).

- A percent of the combined bundled retail sales during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
- 33 percent of combined retail sales in 2021 and each year thereafter.

To determine its incremental need for renewable power during each of the three compliance periods, and thereafter, PG&E maintains a forecast of expected deliveries from its executed portfolio and all pre-approved procurement and ownership programs (e.g., the PV Program, the RAM, and the renewable FIT). Based on this forecast, PG&E presently expects to have sufficient deliveries through the end of 2013 to comply with the first compliance period mandate (2011 – 2013), and to significantly exceed the procurement targets set for the second compliance period (2014 – 2016).[10] Before applying excess procurement from the first and second compliance periods, PG&E will need additional volumes to comply with the third compliance period requirements. Incremental procurement decisions will take into account uncertainties associated with the success of projects in the portfolio that are not yet constructed and the continued performance of existing projects in the portfolio. To better ensure compliance through the third compliance period and post-2020, PG&E will be procuring long-term volumes with initial product delivery dates no later than the latter part of the third compliance period to: (1) ensure compliance during the third compliance period, and (2) ensure additional projects are added to the portfolio and begin delivering by 2020 to help achieve ongoing compliance with the 33% RPS requirement.

10 PG&E details the methods, assumptions and results of this forecast in Section 6 (“Quantitative Information”) of the Plan.

2.1.1 Supply – PG&E's Need for and Plan for Procuring Resources That Satisfy the Three Portfolio Content Categories

As discussed in Section 1, SB 2 (1x) significantly changed the RPS Program, effectively creating a new 33% RPS Program to supersede the prior 20% RPS Program. The new 33% RPS Program contains specific product content requirements, including increasingly stringent limitations on LSEs' ability to use Category 2 and Category 3 products for RPS compliance. Implementation of several key aspects of the legislation is ongoing, including but not limited to issues concerning: transitional issues between the 20% and 33% RPS programs; compliance and enforcement rules, including rules concerning the banking of excess procurement from one compliance period into future compliance periods; and a procurement expenditure limitation to replace the 20% RPS Program's cost control regime. The timing and resolution of these significant implementation issues could impact the supply of renewable generation in California, including the development of new renewable facilities.

In December 2011, the Commission issued D.11-12-052 to define the three statutory portfolio content categories of eligible renewable resources that retail sellers may use for RPS compliance. These three portfolio content categories apply to RPS procurement contracts or ownership agreements signed after June 1, 2010 and UOG that comes online after the same date (together, Incremental Procurement). Contracts that were executed on or before June 1, 2010 and that meet other criteria set forth in California Public Utilities Section 399.16(d) are grandfathered into the 33% RPS Program and count in full toward RPS compliance, notwithstanding the portfolio content category limitations.

PG&E's 2012 RPS Solicitation Protocol seeks offers meeting any of the three portfolio content categories, although the solicitation focuses on long-term contracts because of both incremental need and the desire to purchase products that are bankable. Additionally, all other factors equal, PG&E's evaluation criteria (described more fully in Section 8) grant a preference to Category 1 products, followed by Category 2 products, and finally Category 3 products, in that order. This preference follows from SB 2 (1x)'s requirement that Category 1 products constitute the largest share of PG&E's Incremental Procurement, increasing from a minimum of 50% in Compliance Period 1 to a minimum of 75% in Compliance Period 3 and thereafter.

2.1.1.1 Category 1 Products

To qualify under Category 1, a product must consist of energy bundled with its associated REC, and the RPS-eligible resource generating the product or the product from that resource must:

- Have its first point of interconnection to the Western Electricity Coordinating Council (WECC) transmission grid within the metered boundaries of a CBA area;
- Have its first point of interconnection with the electricity distribution system used to serve end user customers within the metered boundaries of a CBA area;
- Be scheduled into a CBA without substituting electricity from another source provided that, if another source provides real-time ancillary services required to maintain an hourly or sub-hourly import schedule into the CBA, only the fraction of the schedule generated by the facility from which the electricity is procured is Category 1; or
- Be scheduled into a CBA pursuant to a dynamic transfer agreement between the balancing authority where the generation facility is interconnected and the CBA into which the generation is scheduled.[11]

11 D.11-12-052 at 75-76.

2.1.1.2 Category 2 Products

SB 2 (1x) places restrictions on the sum of Category 2 and Category 3 products that PG&E may credit toward compliance during each compliance period (with additional restrictions on Category 3 products discussed in Section 2.1.1.3 below). This sum may not exceed 50% of PG&E's Incremental Procurement in the first compliance period. The allowed sum decreases to 35% of PG&E's Incremental Procurement in the second compliance period and decreases further to 25% of Incremental Procurement in the third compliance period and thereafter.

Category 2 products are generated by RPS-eligible facilities outside of California and are firmed and shaped with substitute electricity providing incremental electricity for delivery into a CBA within the same calendar year. An initial contract for substitute energy must be submitted for Commission review in conjunction with the PPA for the RPS-eligible generation, and the initial substitute energy contract must have a term of either (1) 5 years; or (2) as long as the term of the contract for the RPS-eligible PPA, whichever is less. Furthermore, RECs from a Category 2 product may not be unbundled.[12]

2.1.1.3 Category 3 Products

Pursuant to D.11-12-052, Category 3 products include unbundled RECs or any other product or fraction thereof that is not eligible for Category 1 or 2.[13] PG&E may not credit toward RPS compliance any Category 3 products that exceed 25% of

---

[12] *Id.* at 76-77.

[13] *Id.* at 77-78.

Incremental Procurement in the first compliance period, decreasing to 15% of Incremental Procurement in the second compliance period, and finally decreasing to 10% of Incremental Procurement in the third compliance period and thereafter.

2.1.1.4 TRECS

As noted in Section 1, certain Commission-imposed limitations on the price and unbundling of contracts that qualify as TRECs (which may include products in any of the 33% RPS Program portfolio content categories) continue to apply. PG&E seeks clarification as part of the Commission's decision on this Plan that quantity limitations and other requirements imposed on TREC transactions prior to enactment of SB 2 (1x) are no longer effective following SB 2 (1x).

2.1.2 Supply – Existing Portfolio and Market Trends

Since its 2011 RPS Plan, PG&E has revised its estimate of the overall success rate of its existing RPS portfolio that is under development and not yet online. This revision is mainly driven by the observed progress of key projects in PG&E's portfolio, many of which met significant development milestones over the course of 2011. Relatively inexpensive project financing, made possible by tax incentives (e.g., the PTC and ITC) and by the recently expired stimulus subsidies available through the American Recovery and Reinvestment Act of 2009 (ARRA) – such as the Department of Energy (DOE) loan guarantee, Treasury grant, and Bonus Depreciation programs – have enabled many projects to move forward into construction. Progress in the siting and permitting of projects was also a factor driving PG&E's revised success rate estimate.

PG&E expects that the above-described tax and cash subsidies, combined with an excess supply of some renewable energy projects, will drive relatively low project pricing in the near term. These market conditions are evident in the robust responses to PG&E's renewable solicitations over the past year. The competitiveness of those solicitations has been driven specifically by price decreases in PV resources. However, under current statute, these existing tax and cash subsidies will expire by the end of the second compliance period. This will create price uncertainty for projects that will be commissioned in 2017 and beyond.

More generally, the timely development of renewable energy generation facilities is subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, financing, technology viability, fuel supply, and the construction of sufficient transmission capacity. While PG&E intends to actively pursue the procurement of new, incremental renewable generation through competitive solicitations, and to work with Sellers to facilitate the completion and operation of new renewable facilities that are already under contract with PG&E, there still remain significant challenges to developing an adequate supply of renewable generation to meet and sustain California's challenging 33 percent goal.[14]

2.1.3 Demand

After three consecutive years of flat or declining sales, PG&E currently forecasts modest growth in retail sales in 2012 and beyond. These increases are driven by an improving economy, but are

---

14 PG&E details the challenges to developing an adequate supply of renewable generation to meet its 33% RPS requirement in Section 3 ("Potential Compliance Delays").

moderated by the increasing impacts of conservation, energy efficiency, and customer-side generation.

In addition to retail sales forecasts, PG&E's long-term demand for new RPS-eligible deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio; and (2) the need to include in its procurement activities a minimum margin of over-procurement (as further discussed in Section 7). For purposes of calculating its demand for RPS-eligible products and its compliance net short, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted, although these resources are encouraged to submit cost-competitive bids into PG&E's RPS procurement solicitations.

2.2 PG&E's 2012 RPS Procurement Goal

PG&E's 2012 RPS Solicitation seeks to fill the net short RPS compliance position identified in Section 6 through procurement of RPS-eligible products through long-term contracts with deliveries equivalent to approximately 1,000 GWh annually. This goal addresses PG&E's identified need in the third compliance period and beyond.

PG&E's identified RPS need and 2012 RPS procurement goal, however, is only a snapshot in time. They are dependent on many extremely dynamic factors, including:

- **Load Migration** – Limited expansion of Direct Access (DA) will likely occur in the 2012 to 2020 timeframe, as well as potential additional load migration to CCAs. PG&E may adjust its procurement goals in the future based on developments related to DA and CCA load migration.
- **Implementation of SB 2 (1x)** – A number of SB 2 (1x) implementation details that may impact PG&E's RPS compliance position and/or demand for specific product categories have not yet been resolved, including:
  - **Adoption of Compliance Rules** – Certain compliance rules applicable to the 33% RPS program, including the ability to apply excess

procurement in one compliance period to future compliance periods including beyond 2020, are pending adoption by the CPUC.

- **Procurement Expenditure Limitation –** SB 2 (1x) replaces the prior RPS cost control regime. Specifically, SB 2 (1x) provides that the Commission "shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard."[15] In developing the procurement expenditure limitation, the Commission must ensure that the "limitation is set at a level that prevents disproportionate rate impacts."[16] Should PG&E's RPS-related expenditures reach the cost cap eventually put into place by the Commission, PG&E's demand for additional RPS-eligible products may decrease. Implementation of SB 2 (1x)'s procurement expenditure provisions is ongoing.

- **Implementation of SB 32 FIT** – In developing its forecasted RPS need, PG&E included forecasted procurement under the SB 32 FIT for eligible renewable products up to 3 MW. The Commission has not yet implemented the SB 32 FIT, and PG&E's assumptions regarding the product type and quantities eligible under the expanded tariff are subject to change pending the Commission's final decisions. PG&E assumes total procurement of 112 MW for purposes of calculating its incremental need.[17]

- **Implementation of QF/CHP Settlement** – In D.10-12-035, the Commission approved the QF/CHP Settlement. One element of the QF/CHP Program established by the QF/CHP Settlement is a form PPA for QFs that are 20 MW and under. This form QF PPA is available to both RPS-eligible and non-RPS eligible QFs at a maximum term of seven years for existing facilities and ten years for new facilities. As a must-take obligation similar to the renewable FIT, the level of subscription to this procurement option, and the length of delivery terms selected by QFs seeking these contracts,

---

15 Cal. Pub. Util. Code § 399.15(c).

16 Cal. Pub. Util. Code § 399.15(d)(1).

17 *See* "Future Volumes from Pre-Approved Programs" assumptions on page 3 of Appendix 3 for additional forecasting assumptions.

could impact PG&E's demand and need for additional RPS-eligible resources. PG&E assumes no resources are procured from this category for purposes of calculating its incremental need.

2.3 2012 Procurement Will Address Long-Term RPS Goals

As discussed above, PG&E will solicit offers for only long-term (i.e., 10 years or longer in duration) contracts in the 2012 RPS Solicitation Protocol.[18] The offers selected will have the best combination of market value, PAV, viability, and qualifications, including how well a resource alternative matches PG&E's portfolio needs, based on the evaluation criteria specified in the 2012 Solicitation Protocol.

While PG&E is focusing on contracts for bundled RPS-eligible products with deliveries commencing in the latter part of the third compliance period, the Company will continue to monitor its first and second compliance period positions and may procure additional volumes for those compliance periods if revised need calculations warrant doing so. Additionally, PG&E will consider offers in the 2012 RPS Solicitation for long-term Category 3 products. Finally, PG&E is continuing to assess the value to its customers of sales of any excess RPS procurement. PG&E will consider such sales if the value of the sale is greater than value of banked procurement.

2.3.1 Anticipated Renewable Energy Technologies and Alignment of Portfolio with Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market forces and the portfolio fit of RPS-eligible resources in order to determine PG&E's renewables product mix. In its RPS planning phase, PG&E does not identify a specific renewable energy technology or energy product (e.g., baseload, peaking as-available, or non-peaking

---

18 While it will seek long-term (10 year or greater in delivery term) products in the 2012 RPS Solicitation, PG&E (under the QF/CHP Settlement) is required to offer PURPA PPAs at a maximum tenor of seven years for existing facilities and ten years for new facilities for QFs 20 MW or less.

as-available) that it is seeking to align, or fit, with a specific load need in its portfolio. Instead, PG&E identifies a RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon.

Based on this RPS need, PG&E evaluates the PAV of offers during the procurement phase. In particular, PG&E begins its assessment with its market valuation methodology. Market value represents a resource's NMV from a market perspective, based on its costs and benefits, regardless of its fit with the rest of PG&E's portfolio. Once a NMV is determined, PG&E will adjust an offer's initial NMV using its PAV methodology, which takes into account the impact a transaction will have on PG&E's portfolio. For example, the PAV methodology differentiates offers by the certainty of the energy likely to be received from the resource associated with the offer. To the extent intermittent resources result in less certain output, PG&E may discount the value of those deliveries. A more detailed description of PG&E's PAV methodology is provided in Section 8 of this Plan.

3 Potential Compliance Delays

PG&E continues to be committed to meeting the State's ambitious renewable energy goals, and to the success of California's 33% RPS program. Nonetheless, in order to provide the Commission and the public with a comprehensive perspective of its renewable procurement and compliance strategy, PG&E recognizes the many uncertainties and risks inherent in the development of renewable energy generation facilities.

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E has gained familiarity with the recurring obstacles confronting renewable energy developers. These include the permitting and siting of projects, securing financing, mitigating technology risks, securing reliable and economic fuel supplies, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these issues. However, even with these efforts, significant challenges remain which could ultimately delay PG&E's ability to meet California's RPS goals. This section describes the most significant compliance risks and some of the steps PG&E is taking to mitigate them.[19]

3.1.1 Project Financing

The environment for project financing has markedly improved since the financial markets froze in 2008. While credit markets remained tight through 2010, in 2011 the United States saw a record $11.3 billion in disclosed asset financed renewable projects.[20] This was largely made possible by the recently expired DOE Section1705 Loan Guarantee, Section1603 Treasury Grant, and Bonus Depreciation programs established through the ARRA. The Treasury Grant program alone has supported approximately two-thirds of the nearly 26 gigawatts (GW) of renewables capacity added from 2009 through 2011. While the program ended in 2011, half of the 2 GW of solar and 12 GW of wind capacity forecast to be added in 2012 began construction in 2011 in order to qualify for the Treasury Grant subsidy.[21] In addition, remaining tax subsidies, such as the ITC and PTC, which effectively subsidize the costs of building or operating renewable facilities, are expected to drive relatively low project pricing in the immediate future.

---

19 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to California Public Utilities Code Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements. Dynamic external factors may change PG&E's assessment over time of its ability to comply with the RPS compliance requirements.

20 "Q1 2012 North America PV Market Outlook." Bloomberg New Energy Finance 15 Feb. 2012, English ed. Print.

21 "Treasury Grants End, Strategic Investors Take Note." Emerging Energy Research: On Point Analysis 29 March 2012: n. page.1 09 May 2012.

Notwithstanding these developments, project finance may again become an impediment to renewable project development in the near term. Industry observers expect project financing costs to rise as a result of the phase-out of the ARRA renewable policy supports and uncertainty over whether the PTC and ITC subsidies, which expire in 2012 and 2016, respectively, will be extended. It is worth noting that this uncertainty can make securing financing for projects with mid-term online dates extremely challenging, and that PG&E's identified need for additional volumes of RPS-eligible products, and its 2012 RPS procurement goal, focuses on projects with online dates after the PTC and ITC expire.

3.1.2 Siting and Permitting of Renewable Generation Facilities

PG&E addressed the siting and permitting challenges faced by renewable generators located in California in its 2011 RPS Plan. Since then, California has taken many steps to address these challenges.

For instance, California's Legislature passed five new bills regarding renewable project permitting and development in the 2011 legislative session. The first, Assembly Bill (AB) 1x 13, was signed into law by Governor Jerry Brown in August. The bill aligns the siting and permitting of renewable energy power plants, particularly those in the Mojave and Colorado deserts, with the Desert Renewable Energy Conservation Plan (DRECP) in an effort to streamline the review and approval of renewable energy projects in those areas.

Four additional bills received Governor Brown's signature:

AB 900: streamlines judicial review of challenges made under the California Environmental Quality Act (CEQA);[22]

[22] http://gov.ca.gov/news.php?id=17240

SB 16: establishes permit review deadlines for renewable projects;[23]

SB 618: allows the conversion of nonproductive Williamson Act lands for solar power use;[24] and

SB 267: exempts solar PV and wind projects from preparing water supply assessments.[25]

These bills will continue to streamline and simplify the permitting and siting of renewable energy projects in California. PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of offers to PG&E's 2012 and future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects.

At the same time, significant permitting and siting hurdles remain for renewables projects. For example, while some of the lawsuits described in PG&E's 2011 RPS Plan have been resolved through mediation, outstanding and potential future lawsuits still fuel project viability concerns. In addition, renewable developers, particularly those of wind and solar projects, continue to face challenges related to farmland designation and Williamson Act Contracts, tribal and cultural resources areas, and protected species. Additionally, projects that took advantage of the Fast-Track permitting process implemented by federal and state agencies have nonetheless become mired in permitting disputes which, some observers believe, resulted from or were

---

23 http://gov.ca.gov/news.php?id=17230

24 http://www.mondaq.com/unitedstates/x/152132/Land+Law/SB+618+Provides+Limited+Williamson+Act+Relief+for+Solar+Developers

25 http://www.californiaenvironmentallawblog.com/esa/governor-brown-signs-two-more-bills-to-streamline-renewable-energy-development-in-california-sb-267/

exacerbated by the very attempts designed to expedite the permitting process.

PG&E will continue to partner with other stakeholders to address these issues, but many of these challenges remain for projects under contract to PG&E and may ultimately affect the success of a project.

3.1.3 Transmission and Interconnection Reform

Over the past few years, the California Independent System Operator (CAISO) and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how all of these projects would be connecting into the California grid has become increasingly challenging. The growth in these requests has, in turn, extended estimated project development timelines, which creates a significant barrier to financing projects endeavoring to come online within tight contractual milestone dates. Similarly, the growth in interconnection requests has made it difficult to estimate reliable interconnection study results and to identify necessary transmission build-outs.

To improve the management of the transmission planning and interconnection processes, the CAISO has developed the Transmission Planning Process and Generator Interconnection Procedures (TPP-GIP) Integration, currently pending approval of the CAISO Board of Governors. The new process is expected to identify and approve ratepayer-funded transmission additions and upgrades under a single comprehensive process. It will provide incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations.[26] PG&E supports efforts to integrate these two processes, but

---

[26] The TIP-GIP Integration proposes a method for awarding transmission capacity to generation projects considered most viable, for the areas of the grid where the volume of interconnection requests exceed the capacity of transmission developed through the transmission planning process

recognizes that TPP-GIP may introduce additional uncertainty to projects located in areas with overwhelming levels of interconnection requests, if these projects are not allocated transmission capacity and do not receive upgrade reimbursements. In addition, the sheer volume of interconnection requests continues to generate significant challenges.

3.1.4 Procurement Expenditure Limitations for the RPS Program

As discussed throughout this Plan, PG&E is making progress towards meeting California's RPS procurement mandates. Nevertheless, PG&E recognizes that these mandates will have a significant cost impact on its customers.

When California's legislature passed SB 2 (1x) in 2011, it required the CPUC to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS from causing "disproportionate rate impacts." [27] If rate impacts become disproportionate, unless additional procurement can be undertaken with only "de minimis" rate impacts, electrical corporations may refrain from entering into new contracts or constructing facilities.[28]

PG&E plans to make every effort to procure least-cost and best-fit renewable resources. However, recognizing the likely cost impact that RPS procurement will have on its customers, PG&E strongly supports the establishment of a clear, stable, and meaningful procurement expenditure limitation that both informs procurement planning and decisions, and promotes regulatory and market certainty.

(TPP).

27 Cal. Pub. Util. Code § 399.15(d)(1).

28 Cal. Pub. Util. Code § 399.15(f).

The only reasonable reading of SB 2 (1x) requires that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding a de minimis increase in rates. This may allow PG&E to stop procuring RPS-eligible electricity short of the compliance requirements set forth in D.11-12-020.

3.2 The 2012 Solicitation Protocol and Form PPA Seek to Minimize Potential Compliance Delays

Notwithstanding past compliance delay challenges, PG&E saw significant progress in the ability of its counterparties to overcome these obstacles and to meet key development milestones over the course of 2011. PG&E is optimistic that, as the renewables market develops, its counterparties' success in overcoming these obstacles will continue to develop as well.

To safeguard against project viability risks and to provide ample warning if project delays are likely to occur, PG&E uses a rigorous bid screening and evaluation process that assesses each bid's market value and resource viability and evaluates the bidder's financial strength and project development experience. Additional steps that PG&E has and will take are further outlined below.

3.2.1 Project Financing

Since issuing its 2011 RPS Solicitation, PG&E has increased the credit and collateral requirements for developers seeking to enter into a PPA. This provides greater incentives for the delivery of power under the terms of executed PPAs.

For instance, the PDS requirement, initially set at $50 per kilowatt in the 2011 RPS Form PPA, has been increased to $300 per kilowatt for Category 1 and Category 2 products in the 2012 RPS Form PPA. To address challenges related to the expiration of the PTC and ITC, and to mitigate potential project viability concerns, PG&E has eliminated the Tax Credit Mitigation Option available in previous Form PPAs. In the past, this provision allowed developers to seek price adjustments if these subsidies were to expire. By eliminating this option, PG&E expects to receive offers from developers who are committed and able to fulfill contractual requirements without the guarantee of financing subsidies.

3.2.2 Siting and Permitting

PG&E changed a number of key provisions and requirements in its 2011 RPS Form PPA so as to mitigate siting and permitting risks. Among these was a decrease (from 18 months to 6 months) in allowed delays related to permitting (and transmission), which has been retained in the 2012 RPS form PPA. PG&E believes that this change accomplishes two important objectives. First, it incentivizes developers with highly viable projects to submit bids into the solicitation. Second, it bounds the uncertainty associated with a project's online date, thus improving PG&E's ability to forecast the potential volume of RPS generation available for compliance.

In addition, over the past year, PG&E has implemented a formal environmental due diligence process, which uses detailed Geographic Information System (GIS) data, to assess potential environmental and siting issues associated with bids received through its renewable solicitations. The provisions that facilitate this due diligence process remain in the 2012 RPS Form PPA.

Finally, PG&E will continue to engage milestone monitoring activities for projects procured via the 2012 RPS Solicitation, as more fully described in Section 4 ("PDSR Update"). Close monitoring of contract performance allows PG&E to determine if counterparties are on schedule with their permitting and construction activities.

3.2.3 Transmission and Interconnection

PG&E previously made changes to its protocol and Form PPA to clarify that it prefers: (1) projects that have been deemed deliverable by the CAISO; and (2) projects that PG&E may count toward its RA requirement. The 2012 protocol continues to express these preferences and requires Sellers to indicate whether their resource will have full capacity deliverability status or energy-only status with the CAISO. In addition, PG&E has revised its deliverability criteria to reflect the projected timing of CAISO's Generation Interconnection Queue Cluster Phase II study.

PG&E will continue to monitor challenges related to project transmission and interconnection and adjust its 2012 protocol to reflect current market conditions.

3.2.4 Cost Containment

PG&E will continue to make best-efforts to mitigate customer cost impacts by procuring cost-effective renewable resources, primarily through general or targeted solicitations. However, PG&E will consider bilateral proposals that offer exceptional value for customers.

3.3 PG&E's Risk-Adjusted Analysis Accounts for Estimated Compliance Delays

As described in Section 5 ("Risk Assessment") and calculated in Section 6 ("Quantitative Information"), PG&E employs a deterministic approach to quantifying its remaining need for incremental renewable volumes. Deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E's net short calculation.

3.4 Assessment of How Potential Compliance Delays Will Impact PG&E's Procurement Decisions

PG&E's experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. To hedge against compliance delays, PG&E has set procurement targets that exceed volumetric requirements under the previous 20% RPS program. As described in the previous section, PG&E's net short calculation continues to account for anticipated project delays or failures.

In order to ensure that it can meet its RPS procurement requirements over the three compliance periods leading up to 2020, and maintain annual deliveries equal to 33% of its retail sales after 2020, PG&E intends to procure volumes in quantities that will eliminate PG&E's projected RPS net short. In addition, and as described in Section 7 ("Minimum Margin of Over-Procurement"), PG&E's current expected RPS need calculation incorporates a statutory minimum margin of over-procurement to account for some anticipated project failure and delays in PG&E's existing portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 33% RPS program procurement targets, PG&E cannot predict with certainty the circumstances, or the magnitude of the circumstances, that may arise in the future affecting the renewables market or individual project performance. PG&E's ability to comply with its RPS procurement requirement targets remains contingent on a number of factors outside of its control.

4 Project Development Status Update

4.1 Project Status Monitoring Process

PG&E has an extensive program for monitoring the development status of RPS-eligible projects from PPA execution until commercial operation. Activities include: periodic written reports from developers and phone calls to discuss the reports; informal meetings, emails and conference calls; site visits; and independent research.

4.1.1 Monthly Reporting Process

Most of PG&E's PPAs require developers to submit periodic, usually monthly, reports on the development status of their projects. The form of the monthly reports is typically provided as an appendix to the PPAs, and requests updates on past, present and future activities related to the project, the status of various aspects of the project, and anticipated delays. PG&E's standard monthly progress report form requires status reporting or updates in the following areas:

- Contract Milestones
- Financing
- Permitting and Governmental Approvals
- Site Control
- Design and Engineering
- Major Equipment Procurement
- Construction
- Interconnection
- Startup Testing and Commissioning

PG&E's contract managers and engineers review the reports to evaluate project progress, identify updates that need further clarification, and identify potential obstacles to timely deliveries. PG&E schedules a teleconference following the receipt of each report to review the report, ask clarifying questions, and seek further information on any issues raised in the report or other forums during the previous month. Contract managers also use this time to request additional information required to understand project status, or to better understand and address issues affecting the industry more broadly. Information gathered during the monthly reporting process is recorded in PG&E's information systems, where it can be used for evaluation of individual project status, or analysis of the larger portfolio.

PG&E ensures that reports are submitted as required by the PPAs. Each month, PG&E tracks that written reports were received and teleconferences conducted as required by the PPAs.

4.1.2 Site Visits

In addition to receiving status reports from developers, PG&E has a team of construction monitoring engineers who periodically conduct site visits to projects in PG&E's portfolio that are under development. Contract managers and other PG&E personnel may also attend these visits from time to time. Sites visits are guided by the developers and focus on the current progress at the site and any known issues with the project. Construction monitoring engineers assess whether the observed progress at the site matches the progress as reported by the developer, and independently assess the status and quality of the work being performed at the site. The engineers produce written site visit reports after site visits are complete.

4.1.3 Additional Monitoring Activities

In addition to the written reports from developers, conference calls and site visits, PG&E may assess a project's development status using information drawn from other sources, as necessary, including:

- News media, which may contain information about major progress or issues at projects, information about owners or developers, or developments in the broader industry.
- Local, state and federal permitting web sites.
- Developer and industry web sites.
- Transmission and interconnection studies from the CAISO, other balancing authorities and transmission owners. These may include interconnection studies for individual projects, provided by developers, or publicly-available studies published by the balancing authorities.

These sources may provide more current or additional information compared to that provided in the periodic written reports and conference calls, and may help PG&E identify potential issues that require further investigation.

PG&E also contacts counterparties informally as needed to request additional information.

4.2 Development Schedules

Using the information gathered through the monitoring processes described above, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for construction start (if applicable) and commercial operation of the projects. PG&E also tracks other indicators, which are reported to the Commission in PG&E's semi-annual RPS Project Development Status Report (PDSR). These indicators have historically served as strong indicators of the progress and likely success of a project, and include: CPUC approval status; permitting status; interconnection status; financing status; and construction status. The latest version of the PDSR, served on the RPS rulemaking docket on March 1, 2012, includes 32,742 data cells covering 306 RPS-eligible contracts in PG&E's portfolio.

Information on completed milestones and estimates of construction start date (CSD) and commercial operation date (COD) are based primarily on the developers' estimates provided during the monthly reporting process. These estimates are evaluated against known timelines for CPUC approval, permitting, and interconnection and known project-specific issues. Individual contract managers evaluate and estimate each project's progress towards these milestones, and each month this information is reviewed by a team of contract managers and engineers. The consensus estimates for this information are then memorialized in PG&E's information systems.

The evaluation of each project's ability to achieve key projects milestones is used to inform PG&E's risk assessment, discussed in Section 5. The risk assessment, in turn, provides inputs into the modeling used to identify PG&E's projection of RPS procurement need discussed in Sections 2 and 6 and, ultimately, the 2012 RPS procurement goal identified in Section 8.

4.3 Project Development Status Update

Appendix 4 to the Plan addresses the ACR's requirement that PG&E provide an update on the development schedule of all eligible renewable energy resources currently under contract but not yet delivering generation.[29] The table in Appendix 4 elaborates upon the most recent PG&E PDSR by focusing specifically on the most important development status indicators that are considered in PG&E's RPS risk assessment process, and by updating the data in these columns to include current information as of May 14, 2012.[30] This Section of the Plan also elaborates on the PDSR by providing key project development indicators for PG&E's RPS Portfolio as a whole.

4.3.1 Portfolio-Wide Development Summary

Within PG&E's active[31] portfolio, there are 87 RPS-eligible projects that were executed post-2002 and which led to incremental RPS procurement.[32] Thirty-eight of these contracts have achieved full commercial operation under their PPAs with PG&E. Forty-nine contracts have not achieved full commercial operation under their PPAs with

---

[29] ACR at 9.

[30] The table in Appendix 4 includes PPAs procured through the RAM and PV Programs, but does not include small renewable feed-in tariff (AB 1969) PPAs, due to the large number of AB 1969 PPAs. PG&E currently has 102 executed AB 1969 PPAs in its portfolio, totaling 106.5 MW of capacity. These AB 1969 projects are in various stages of development, with 22 already delivering to PG&E under an AB 1969 PPA. Status information on these PPAs is available at http://www.pge.com/feedintariffs/.

[31] Active portfolio includes projects that were executed (and not terminated or expired) as of March 31, 2012.

[32] This does not include amended post-2002 QF contracts, UOG projects, or AB 1969 projects.

PG&E. Of the 49 contracts that have not achieved full commercial operation under their PPAs with PG&E, two are phased PV projects that are not yet complete, but are currently delivering energy from early phases of the projects. Eighteen are under construction. The remaining are either under development but not yet under construction, or are complete but have not achieved full commercial operation under their PPAs with PG&E. Four projects (Mt. Poso, Coram Brodie, Vasco Winds, and Montezuma II Wind) achieved commercial operation under their PPAs since the most recent PG&E PDSR.

5 Risk Assessment

To determine its incremental need for renewable power (using the deterministic modeling described in more detail in Section 6) PG&E maintains a forecast of expected online dates and deliveries from its RPS portfolio. This section describes PG&E's approach to risk categorization and consequent impacts on the quantitative assessment of its RPS procurement need.

5.1 Risk Categorization

To account for the development risks associated with securing project siting, permitting, transmission and interconnection, and problems securing project financing, PG&E categorizes its portfolio of contracts for renewable projects under development into four project risk categories:

1. **Completed and Under Construction [Low Risk]** – This is the population of projects that have officially begun construction, existing facilities undergoing upgrades, or completed facilities not yet delivering under their contract with PG&E. Based on empirical experience and industry benchmarking, PG&E estimates that this population of projects is highly likely to deliver expected volumes per their contractual time horizon.

2. **Approved or Mandated Programs for Small Renewables [Low Risk]** – This category represents actual and projected volumes from PG&E's 500 MW Solar PV Program, as well as its allocated capacity for both the

RAM Program and the up to 3 MW FIT (SB 32) Program. Included in this category are the CPUC-approved volumes (or, in the case of the FIT, the volumes legislatively mandated) under each program from both executed and future contracts.

3. **Under Development [Medium Risk]** – This is the population of projects that are progressing with pre-construction development activities without foreseeable and significant delays.
4. **Closely Watched [High Risk]** – This category represents deliveries from projects experiencing considerable development challenges. Also included in this category are once-operational projects that have ceased delivering and are unlikely to restart.

The data collected by PG&E through its project monitoring activities, as summarized in Section 4, provides the factual basis that PG&E managers use, in combination with their best professional judgment, to subjectively determine a given project's risk profile.

As further discussed in Section 6, this deterministic approach to forecasting renewable deliveries accounts for project risk by excluding deliveries from projects in the "Closely Watched" category from PG&E's forecast. Projects in all other categories are assumed to deliver 100% of contract volumes over their respective terms.

Using this "bottoms-up" deterministic approach, PG&E currently estimates a long-term volumetric success rate of approximately 78% for its portfolio of executed-but-not-operational projects. This success rate is simply a "snapshot" in time and is highly dependent on the very dynamic general conditions in the renewable energy industry, discussed in more detail in Section 3, as well as project-specific conditions. However, as described in Section 2, PG&E has seen a general trend within its RPS portfolio toward higher rates of success in reaching key development milestones. For instance, throughout most of 2011 PG&E's forecast of RPS deliveries assumed (based on then-available project development monitoring reports) a 60% long-term success rate for executed-but-not-operational projects.

5.2 Use of Risk Categorization in the Quantitative Assessment Incorporates Assumed Margin of Over-Procurement, and Informs PG&E's Determination of Procurement Need

The risk categorization approach described in this section, which is based upon the data provided in Section 4, is a key input into the deterministic model described in Section 6. Specifically, this approach to risk categorization yields two key inputs into the model: (1) a determination regarding whether a specific project's contractual deliveries should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay; and (2) the assumed commencement of deliveries for projects included in the model (so long as deliveries commence within the allowed delay provisions in the contract).

By excluding projects at high risk of delay or failure in its forecast, PG&E can establish its current expected need for incremental renewable resources. Additionally, PG&E incorporates a reasonable margin of over-procurement, as required by the RPS statute,[33] and as discussed further in Sections 6 and 7.

PG&E intends to procure steady and moderate incremental long-term resources over the next several years. As explained further in its 2012 RPS Solicitation Protocol, PG&E is focused on procuring long-term volumes with start dates towards the latter part of the current decade to ensure sufficient volumes during the third compliance period and after 2020.

---

[33] Cal. Pub. Util. Code §§ 399.13(a)(4)(D); 399.15(b)(5)(B)(iii).

6 Quantitative Information

This section describes the methodology used to produce PG&E's net short calculation, provided in spreadsheet form as Appendix 1, and describes the implications of that calculation for PG&E's RPS compliance outlook and RPS procurement strategy.

6.1 Quantitative Methodology Used to Assess PG&E's Ten Year RPS Compliance Outlook and Procurement Need

Appendix 1 depicts PG&E's expected compliance position over the three periods set forth in SB 2 (1x), as well as associated volumetric deliveries and surpluses/deficits, on both a period and annual basis. As discussed in Section 6.3, Appendix 1 also shows a more pessimistic and a more optimistic need scenario to provide a possible range of outcomes and incremental need.

6.2 Deterministic Criteria

PG&E employs a deterministic approach to developing a risk-adjusted forecast of RPS-eligible deliveries from its existing portfolio. PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting this expected incremental need for renewable volumes. (See Section 5 for additional information about the definition of "Closely Watched" projects.)

In reviewing the project development monitoring reports summarized in Section 4, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":

- Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.).
- Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data).
- Significant regulatory contract approval delays (12 months or more after filing) with no clear indication of eventual authorization.
- Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability.

- Whether a PPA amendment has been executed but has not yet received regulatory approval.
- Knowledge that a plant has ceased operation or plant owner's/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive or the sole criteria used to categorize a project as "Closely Watched." For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

In addition to these project-specific criteria, PG&E utilizes more objective and general assumptions about the performance of its overall RPS portfolio – including, for example, expected generation from existing resources – to produce its current expected need calculation quantified in Appendix 1. These assumptions are included in this Plan as Appendix 3.

6.3 Range of Anticipated Need

PG&E's current expected need calculation is a snapshot of its anticipated residual demand for long-term renewable volumes and is based on project-specific information and renewables market trends that are current as of the filing of this Plan. Given the dynamic nature of both its RPS portfolio and the renewables market in general, PG&E has also calculated more pessimistic and more optimistic need scenarios to provide a range of future incremental need.

Under its current expected need case, PG&E's deterministic model yields an approximate 22% long-term failure rate in expected deliveries from executed-but-not-operational projects. PG&E's more pessimistic and more optimistic need scenarios bookend this failure rate by +/- 10% points. That is, in the more pessimistic need case, PG&E assumes a 32% long-term failure rate from executed-but-not-operational projects, while in its more optimistic need case it assumes a 12% long-term failure rate.

Only executed-but-not-operational projects are considered in these calculations.[34] The more pessimistic and more optimistic scenarios, along with the current expected need calculation, represent a reasonable approximation of PG&E's potential range of demand for incremental renewable resources.

In addition to the success rate of current executed contracts, PG&E considers two additional factors when assessing its RPS procurement need: (1) the statutory margin of procurement to address project failure or delay in its future contracted volumes (which can be considered along with the success rates of the existing RPS portfolio); and (2) an additional margin of over-procurement to address annual operational variability in load and deliveries that are unrelated to project development obstacles. These additional considerations are discussed in more detail in Section 7.

6.4 Quantitative Results

The methodology described above, and reported in Appendix 1 as the current expected need scenario, demonstrates that PG&E's existing RPS portfolio is expected to provide sufficient RPS-eligible deliveries to meet PG&E's RPS compliance requirements in the first compliance period (2011–2013). Additionally, PG&E expects to significantly exceed the RPS procurement targets set for the second compliance period (2014–2016).

Notwithstanding its forecast of limited near-term need, PG&E has fairly significant incremental need over the third compliance period (2017-2020) (prior to applying any excess procurement from earlier compliance periods) and beyond in order to maintain a 33% RPS level. As illustrated by the results of its

[34] Projects that have begun delivering energy to PG&E while still officially under construction, such as PV projects built in a modular or phased fashion, are considered to be delivering energy for this purpose and are not included in the 22 percent failure result described in Section 5.1.

current expected need scenario analysis, PG&E estimates that it will need approximately 7,000 GWh of cumulative renewable volumes (prior to applying any excess procurement) to satisfy third compliance period (2017-2020) procurement targets. In the more pessimistic need scenario described in Section 6.3, PG&E would be unable to erase its third compliance period shortfall even with the use of its surplus bank of deliveries. After 2020, PG&E's current expected need scenario indicates a 9,000 GWh annual shortfall (prior to applying excess procurement), when compliance will be measured annually. This significantly increased need in the early part of the next decade is driven by a large volume of expiring contracts in that time frame.

PG&E proposes to procure its identified long-term and ongoing RPS need through steady and moderate volumes in each annual solicitation, targeting new resources as well as existing resources that will be expiring over the next decade. Based on this current expected need assessment, PG&E plans to seek 1,000 GWh in long-term incremental RPS procurement as part of its 2012 RPS Solicitation, with deliveries starting in 2019 or 2020. This immediate future procurement is one step in a multi- year procurement strategy that seeks to capture the market costs of renewables over time by procuring PG&E's identified long-term and ongoing RPS need through steady and moderate volumes purchased over time. Volumes procured through future solicitations may vary and will depend on a combination of the ultimate success of current executed-but-not-operational projects, as well as the competitiveness of existing resources seeking new long-term contracts.

PG&E recognizes that its expected demand will need to be frequently reassessed. PG&E intends to update this need calculation as part of each future RPS Plan, and to provide any necessary interim updates to support the reasonableness of executed PPAs it files for Commission approval.

6.5 Use of Surplus Bank

Although excess banked[35] RPS procurement is included in PG&E's compliance forecast, PG&E does not plan to rely on its projected bank balance to meet its long-term compliance obligations. Any strategy that relied on banked excess volumes to meet long-term compliance obligations would create a need for a very significant quantity of incremental procurement soon after the bank was exhausted and likely would be extremely challenging, both practically (i.e., timing project online dates) and operationally. PG&E presently intends to use banked excess procurement primarily to provide a compliance cushion that smooths short-term delivery shortfalls caused by unanticipated project failures or delays or under performance of existing projects leading up to 2020, and beyond, as applicable.

7 Minimum Margin of Over-Procurement

PG&E consider two components of compliance margins of procurement (effectively over-procurement): (1) a statutory margin of procurement to address some anticipated project failure or delay – both for existing projects and future contracts; and (2) an additional margin of procurement to address operational variability in load and deliveries that are unrelated to project development obstacles. This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need and the development of its 2012 RPS procurement goal.

7.1 Statutory Minimum Margin of Over-Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[36] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS

---

35 *See* page 4 of Appendix 3 for a description of PG&E's forecasting assumptions related to the banking of surplus procurement.

36 Cal. Pub. Util. Code § 399.13(a)(4)(D).

procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[37]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). Currently these adjustments result in a long-term volumetric reduction in expected deliveries from executed-but-not-operational contracts of approximately 22%. Based on this calculated long-term failure rate, PG&E considers 22% to be its current margin of over-procurement – that is, the volumetric margin of over-procurement upon which PG&E currently relies to meet its RPS compliance requirements with its existing portfolio of renewable resources.[38] PG&E's current long-term failure rate calculation is based on best estimates of project performance and other information. The rate of actual project failures or delays may prove to be higher or lower.

Given the long lead time PG&E has to fill the need identified in the third compliance period and its estimated 9,000 GWh post-2020 annual shortfall, and the still-to-be-determined availability of competitive volumes from existing resources with expiring contracts, PG&E currently believes that procuring steady and moderate volumes in each annual solicitation over the coming years should be sufficient to meet its RPS targets. As a result, PG&E does not propose to

---

37 *Id.*at 399.15(b)(5)(B) (iii).

38 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has matured – and projects are proposed to PG&E at more advanced stages of development – PG&E has observed a decrease in the expected failure rate of its overall portfolio. Put another way, the more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS program, resulting in lower current projections of project failure than have been discussed in past policy forums.

incorporate an explicit margin of over-procurement for its incremental contracting in the volumes it seeks in its 2012 RPS Solicitation, although PG&E's overall RPS portfolio clearly accounts for significant future project failure.

In the future, PG&E may also deem it prudent to over-procure when acquiring incremental renewable volumes, and would count such volumes towards satisfying a statutory minimum margin of procurement. The specific level of over-procurement will be contingent on PG&E's anticipated need at the time, as informed by actual success/failure rates of the existing portfolio, changes or expected changes in its load forecast, and actual retention of expiring volumes from existing facilities, among other factors.

7.2 Voluntary Compliance Margin of Over-Procurement

The RPS statute provides that an IOU may voluntarily propose a margin of over-procurement above the statutory minimum margin of procurement.[39] PG&E believes that an additional voluntary compliance margin of over-procurement could be important to address the variability in its load and RPS deliveries that are unrelated to the project failures and delays taken into consideration as part of the statutory minimum margin of procurement. These additional factors include, for example: (1) hydropower variability impacting generation portfolio mix and RPS deliveries in a given year; (2) exercise of rights under RPS PPAs to reduce contractual delivery guarantees; (3) curtailment of deliveries due to congestion or integration; (4) force majeure events that reduce RPS-eligible deliveries; (5) economic uncertainties leading to higher than expected load growth; and (6) increases in load due to lower than expected migration to other retail sellers.

In preparation for this filing, PG&E performed a sensitivity analysis on its portfolio to quantify the variability that the above factors might create. This analysis concluded that a voluntary over-procurement margin could need to be

39 *Id.* at § 399.13(a)(4)(D).

equal to an additional 1% to 2% of total retail sales.[40] Based on this analysis, PG&E could in the future plan to procure a long-term voluntary margin of over-procurement equal to 1.5% of total retail sales, although the precise volumetric margin would depend on then-current data and operational concerns current at that time, including the size of the banked volumes in the portfolio.

As with the statutory margin of over-procurement for incremental contracting addressed above, PG&E does not propose to incorporate a voluntary margin of over-procurement in the quantities it seeks in its 2012 RPS Solicitation. At this time, PG&E will use expected excess procurement in the near term to smooth the annual variations discussed above. As with the statutory margin of over-procurement, PG&E reserves the right to update its voluntary margin of over-procurement in future RPS Plans and to procure amounts in future RPS Solicitations that incorporate its voluntary margin of over-procurement, should expected banked procurement fall below the level necessary to support this margin and, ultimately, to achieve a portfolio that can maintain 33% RPS energy on an annual basis post-2020.

8 Bid Selection Protocol, Including Least-Cost, Best-Fit Methodologies

8.1 Overview of 2012 RPS Solicitation Protocol and RPS Form PPA

The schedule for PG&E's 2012 RPS Solicitation and all solicitation documents are included in the RPS Solicitation Protocol. PG&E's 2012 RPS Form PPA is attached to the Solicitation Protocol. Redlines showing changes to the Solicitation Protocol are found in Appendix 7 and the RPS Form PPA are found in Attachment H to Appendix 7.

---

[40] For example, a low precipitation year can cut deliveries from small hydroelectric facilities by as much as 40%. PG&E estimates that, over the 2020-2022 period, deliveries from these facilities will average approximately 1,750 GWh per year, or slightly over 2% of total retail sales. Reducing these deliveries by 40% would mean that PG&E would have to procure additional RPS-eligible energy equal to more than 0.8% of total retail sales to make up for this annual deficit. This amount would be increased by any additional operational or load issues from the year.

8.1.1 2012 RPS Procurement Goals

PG&E's 2012 RPS Solicitation seeks RPS-eligible products that will enable PG&E to comply with its RPS and RA obligations. Specifically, PG&E is seeking offers for the following bundled products: Long-term (10 years or longer) contracts for Category 1 (preferred) or Category 2 products with a strong preference for deliveries beginning in 2019-2020. PG&E also requests bids for long-term Category 3 products, contingent upon the Commission's final compliance rules concerning banking. Specifically, PG&E's interest in Category 3 products is contingent upon a finding that long term Category 3 RECs that are within the portfolio content category limitation for each respective compliance period will not be deducted from bankable volumes. PG&E notes that its ability to use such Category 3 products for compliance diminishes over time, and therefore its need for those products will also diminish over time. Category 3 offers do not need to start in the 2019-2020 period, but PG&E notes that it has a greater portfolio need for such products. PG&E is flexible on the start date for Category 3 products but likely has more eligible volume during the first compliance period. PG&E seeks total annual long-term procurement of about 1,000 GWh in the 2012 RPS Solicitation.

Projects in PG&E's service territory are preferred, as are projects with characteristics that merit a higher viability score, and projects with less uncertainty on total cost impact, such as those with completed Phase II Transmission Cost Studies or simplified transmission interconnection requirements. Out-of-state offers will continue to be evaluated with an emphasis on the ability of the offer's volumes to qualify as a Category 1 or Category 2 product. Category 2 projects are less preferred because of limited RPS volume flexibility for such products.

Category 2 projects should not require PG&E to take on delivery and cost risks any different from Category 1 projects.

The offers selected will have the best combination of value, viability and qualifications based on the evaluation criteria specified in the 2012 Solicitation Protocol. Additionally, PG&E will use as a screening tool the PVC issued by the CPUC on June 2, 2011.

8.1.2 Relationship between Identified RPS Procurement Need and 2012 Procurement Goals

As further described in Sections 2 and 6, this Plan forecasts PG&E's incremental RPS need through 2022. With this 10 year timeframe in mind, the RPS portfolio by 2022 should be consistently generating 33% or more for the long-term. PG&E's forecast for incremental RPS need starts with a deterministic model. All RPS resources in PG&E's portfolio are designated either succeeding or failing. The deterministic results simply include the full generation from RPS resources that are assumed to succeed.

Additionally, as discussed in Section 7, the identified need in order to maintain an ongoing 33% RPS requirement after 2020 incorporates a statutory minimum margin of over-procurement to account for some anticipated project failure and delays in PG&E's existing portfolio. Due to some anticipated failures from projects in PG&E's portfolio that are not yet operational and that numerous contracts will expire prior to 2022, PG&E has fairly significant incremental RPS need by 2022 and beyond in order to maintain a 33% RPS requirement on an annual basis.

PG&E's proposes to procure steady and moderate volumes in each solicitation, targeting new as well as existing resources that will be expiring over the next 10 years. The procurement volume from new resources over the next several years will depend on a combination of the ultimate success of current projects in PG&E's portfolio that are not yet operational as well as the competitiveness of existing resources.

These considerations, when taken as a whole, led to the 2012 RPS procurement goal included in the 2012 RPS Solicitation Protocol.

8.1.3 Key Issues and Changes in the 2012 RPS Solicitation Process

PG&E's 2012 RPS process is more streamlined than in the past, with a more clearly articulated request for product, clear identification of product preferences, and reduced data requirements for bidders. PG&E may make modifications to the 2012 Solicitation Protocol and PPA as market conditions evolve prior to solicitation issuance. Key changes from the 2011 Solicitation include:

Seeking only PPAs: The 2011 RPS Solicitation and previous RPS Solicitations have sought offers for turn-key ownership offers, such as PPAs with buyout options and sites for development. PG&E has observed that project viability and cost competitiveness have significantly increased in the broader RPS market over the past several years. PG&E is confident that PPAs have a good chance of resulting in cost-effective, viable RPS-eligible projects at this time. PG&E will not, therefore, solicit ownership offers in this Plan and the 2012 RPS Solicitation will only seek offers from third-party PPAs.

However, PG&E may consider exceptional opportunities to build renewable generation or to invest in renewables that are cost-effective and present high value to customers.

Only Long-Term Offers: Previous solicitations have sought offers for short-term and long-term resources. Given PG&E's compliance position in the near-term, PG&E does not have short-term RPS needs.

Thus, the Solicitation is focused on long-term transactions that will contribute to an ongoing 33% requirement well beyond 2020. Such long-term contracts have the additional potential benefit of being eligible to be banked across compliance periods.

Product Preferences: As described above, PG&E's preference is for products with delivery terms beginning in 2019-2020. Consistent with earlier Solicitations, PG&E's preference is for resources in PG&E's service territory, and then for projects within the CAISO. Category 3 products are an exception to the request for start dates in 2019-2020, since PG&E's ability to use these products for compliance is larger during the earlier compliance periods.

Interconnection Status: Previous RPS Solicitations had no requirement for Sellers to have applied for or received an interconnection study. In order to ensure that PG&E has more accurate information as to the interconnection costs and upgrades required, PG&E's 2012 RPS Solicitation will require that Sellers have at least the equivalent of a Phase I study from the CAISO. Based on the current CAISO study schedule, PG&E expects that projects in Cluster V will have Phase 1 studies before 2012 RPS Solicitation bids are due in early 2013. PG&E expects that Cluster IV Sellers will have their Phase II studies as well. PG&E will continue to accept both energy-only and fully deliverable offers, and will include applicable RA value in the valuation process.

Credit: The focus in PG&E's 2012 RPS Solicitation is on projects with online dates beginning no earlier than 2019. The potential for unexpected obstacles in project development increases with the long lead time between PPA execution and the date on which the project must be completed or begin to sell renewable energy to PG&E. These obstacles include not only development challenges but market conditions that could impact the cost of equipment or construction of the facility and impact Sellers' ability to deliver at the agreed-upon price. In order to ensure that Sellers have a strong incentive to meet their obligations under the PPA, including the contract price, and in order to ensure that if they cannot, customers will be sufficiently protected, PG&E has increased project development security (PDS) in the 2012 Form RPS PPA from $50/kW to $300/kW. The PDS is due 30 days after Commission approval of the PPA and remains in place until commercial operation of the project. The $15/kW PDS required after PPA execution l and the delivery term security requirements that apply after commercial operation are unchanged from 2011. In addition, PG&E modified its letters of credit requirements to reflect financial market conditions and the resulting potential impact on the credit ratings of many banks that Sellers may use to post PDS and delivery term security amounts, by (1) adjusting the credit rating requirement for a letter of credit issuer from at least "A" to "A-" from S&P or "A2" to "A3" from Moody's, with a stable outlook designation; (2) limiting the amount of credit posted in the form of a letter of credit by any one issuer; (3) enabling PG&E to modify the form of letter of credit to impose additional conditions if the issuing bank is foreign; and (4) including provisions that enable PG&E to require a substitute letter of credit if the issuing bank's credit rating is placed on a negative credit watch or watch list.

Solicitation Streamlining: PG&E received feedback from bidders in the 2011 RPS Solicitation encouraging PG&E to make the offer submittal process simpler. In response to that feedback, PG&E is making two changes. First, all offer submittals only need to be electronic. There will be no need for paper offer packages. Second, PG&E has reduced some of the project information requested at offer submittal used to assess project viability and environmental risk. Additional information will be requested from shortlisted bidders.

8.2 Modifications to Commercial Terms in the 2012 RPS Form PPA

PG&E describes below the key substantive modifications to the 2011 RPS Form PPA that are reflected in the 2012 RPS Form PPA. A detailed table summarizing the modifications is included as Appendix 5.

<u>Credit</u>: PPA changes have been made consistent with the modifications described in Section 8.1.3 above.

<u>Excused Delays for Transmission</u>: The PPA includes provisions for excused delays in meeting the guaranteed construction and commercial operation milestones in the event of permitting or transmission delays. PG&E has modified the transmission delay provision to allow Sellers to claim a delay both before and after construction start, but retains the six month limit on such delay. Previous versions of the PPA required Sellers to claim a transmission delay before construction start. The provision has also been broadened to allow Sellers to use the transmission delay provision in the event that the interconnection facilities or any needed network upgrades are expected to be delayed beyond the guaranteed commercial operation date of the generating facility. PG&E has also added language to the force majeure definition to state expressly that Sellers may not claim force majeure for events that would otherwise be considered under the permitting or transmission delay provision.

<u>ITC/PTC Price Adjustment and Excused Delay</u>: PG&E has deleted provisions that allowed PG&E and Sellers to elect to delay the either of the guaranteed milestones or terminate the PPA in the event that ITCs or PTCs are not extended. As stated in Section 3.1.1 PG&E's procurement goal focuses on projects with online dates after the PTC and ITC expire. Accordingly, Sellers should price their projects given expectations regarding available tax credits

associated with their anticipated online dates, taking on all risk associated with whether such tax credits will be available.

Outage Reporting: PG&E has made minor modifications to outage reporting requirements to help ensure that PG&E will be in compliance with RA rules and will be able to count the project capacity toward its RA requirement.

Curtailment Order: The RPS Form PPA has always required Sellers to curtail the generating facility's output in response to a Curtailment Order from the CAISO. For 2012, PG&E has added any warning, forecast or anticipated overgeneration as an additional CAISO directed curtailment that will qualify within the existing Curtailment Order definition in the PPA. This provision addresses the scenario in which PG&E, as the scheduling coordinator for Seller's project, may be asked by the CAISO to curtail generating facilities in anticipation of a potential overgeneration on the transmission system rather than waiting until the overgeneration occurs and causes a system emergency. This change is designed to ensure that all potential CAISO directed curtailment scenarios are addressed in the PPA.

TODs: The draft RPS Plan reflects the Time of Delivery (TOD) factors used in PG&E's 2011 RPS Solicitation. Consistent with the RAM Protocol, PG&E's 2012 protocol provides two sets of TOD factors: one for full capacity deliverability projects and one for energy-only projects. PG&E plans to update the TOD factors and may update the TOD periods for 2012 prior to solicitation issuance.

Payments for Baseload Projects: To ensure that projects providing PG&E with baseload delivery profiles do not significantly alter their energy delivery profile, annual payments based on prices adjusted for TOD will be limited to 105% of the contract price, which could result in sellers reimbursing PG&E if the seller unnecessarily takes advantage of the Super-Peak delivery periods, which allow up to 230% of contract price in the highest-valued TOD period.

PPA Clarifications: These clarifications improve the PPA intent, and do not represent significant changes in obligations for buyer or seller. The specific clarifications apply to Guaranteed Energy Production, GHG Reporting obligations, CAISO Charges, Insurance, FERC standard of review, and related provisions. Additionally PG&E has removed the Limited Operation, Prevailing Wage, and Discussion Concerning Buyer Purchase of Project. The purpose for these changes is described in Appendix 5.

8.3 Description of the Least-Cost, Best-Fit Criteria and Evaluation Process

This section presents changes to the LCBF methodology that PG&E expects to implement for its 2012 solicitation. PG&E plans to begin its assessment with NMV, as it has done in previous years. NMV compares an offer's cost to its energy and capacity benefits. Energy and capacity benefits are calculated using forward curves and forecasts of market prices for energy and capacity. PG&E notes that there currently exists significant uncertainty regarding design of RA markets in California, especially for delivery years beyond 2015. Therefore, the NMV calculation of capacity benefits may evolve as more information is known about market design or as uncertainty remains.

PG&E plans to adjust NMV to account for elements that impact an offer's value in the context of PG&E's bundled electric portfolio. NMV is a measure of an offer's market value on a stand-alone basis, and does not take into account the rest of PG&E's bundled electric portfolio. PG&E denotes as Portfolio-Adjusted Value (PAV) the value resulting from PG&E's adjustments to NMV. In the 2012 RPS Solicitation, PAV adjustments replace the Portfolio Fit criterion used in past RPS solicitations.

Changes in portfolio composition, market conditions, and regulatory or legislative developments may result in changes to the adjustments and calculations that yield PAV. For the calculation of PAV in the 2012 RPS solicitation, PG&E plans to include adjustments for the following elements:

a) Location: As described above, PG&E has a preference for projects in its service territory. This preference is influenced by constraints in the market that may limit the amount of capacity in SP15 that PG&E can count toward its RA requirement. Capacity located closer to PG&E's load is likely to have more value for PG&E's bundled electric portfolio. The long-term need for new resources in PG&E's service territory is also more likely to be mitigated by a new resource in NP15 than a new resource located in SP15. Offers for RPS energy from resources in NP15 will have an equal or higher PAV than comparable offers from resources in SP15.

b) Resource Adequacy: As noted above, there is currently significant uncertainty regarding design of RA markets in California and the NMV calculation of capacity benefits may evolve. Reflecting these conditions, the calculation of PAV will evolve too.

c) Portfolio Need for RPS Energy: As noted above, PG&E believes it has sufficient RPS energy in its portfolio to meet RPS compliance needs until the third compliance period, and has a strong preference for offers with deliveries beginning in 2019 or later. PG&E will consider how an offer contributes to PG&E's overall portfolio need for RPS energy. Offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV than comparable offers that deliver RPS energy in periods when PG&E's portfolio does not need RPS energy. In previous solicitations, this concept was included in the Portfolio Fit criterion.

d) Uncertainty Regarding Project Output: Managing a resource that produces energy in patterns that do not predictably match the resource's schedule adds cost to PG&E's bundled electric portfolio. Offers from resources with greater certainty in energy production will have higher PAV than comparable resources that have greater uncertainty in energy production.

PG&E accounted for this in previous RPS solicitations in the Portfolio Fit criterion, which differentiated between firm and intermittent deliveries.

e) Integration Costs: In the 2012 RPS Solicitation, PG&E plans to include an explicit adjustment for integration cost. This adjustment for integration cost is intended to account for the increased costs of dispatching additional generators and procuring sufficient ancillary services from flexible resources to integrate an increased amount of renewable generation into the grid. Pursuant to Commission direction,[41] PG&E has not included an adder for integration cost in previous RPS solicitations. However, significant work has been undertaken in the past year by the CAISO, CPUC and other stakeholders on developing a common understanding of the additional requirements associated with integrating renewables into the grid. In its standardized planning assumptions for use in the 2010 LTPP proceeding, the CPUC included integration costs for the purposes of selecting RPS portfolios.[42] For purposes of the 2012 RPS solicitation, PG&E proposes to use an integration cost adder of $7.50/MWh (2008$),[43] the same value for integration cost as used in the 2010 LTPP proceeding. The integration cost adder will be applied to resources that are considered intermittent, although resources with some reduced levels of intermittency may be subject to lower integration cost adders, as determined on a case-by-case basis.

f) Number of Hours of Buyer Curtailment: PG&E values the flexibility associated with Buyer Curtailment. The PPA requires Sellers to offer at least 250 hours of Buyer Curtailment, for which the Seller will be compensated. The PPA also allows Sellers to offer more hours of curtailment, and to specify the price they would be paid for energy deemed delivered in those hours. For offers providing additional hours of

---

41 As mandated by D. 11-04-030, PG&E used a "zero" adder for integration costs in evaluating bids in its 2011 RPS Solicitation.

42 *See* February 10, 2011 Administrative Law Judge's Ruling Modifying System Track I Schedule and Setting PreHearing Conference, Attachment 2, "Standardized Planning Assumptions (Part 2 – Renewables) for System resource Plans" issued in R.10-05-006 at 28.

43 An integration cost adder of $7.50/MWh (2008$) translates to approximately $8.50/MWh in 2013.

curtailment, NMV will include the value of the difference between market energy price and contractual payments for deemed deliveries, and PAV will include any additional value to the portfolio of increased flexibility because of the additional hours of curtailment.

g) Tenor: As described above, PG&E prefers long-term transactions to match long-term RPS need. A countervailing consideration is that longer-term transactions may pose greater project risk because of uncertainty in market conditions. Offers for delivery periods beginning in 2019 or later, with smaller tenors (e.g., 10 to 15 years), fit better in PG&E's bundled electric portfolio and will have higher PAV than comparable Offers with greater tenors (e.g., 20 years or greater).

h) Transmission Costs: PG&E considers transmission costs borne by ratepayers in the evaluation process. Transmission costs are discussed in more detail in Section 9.

8.4 New Proposals in ACR Regarding the RPS Solicitation Process

8.4.1 Standardized Variables in LCBF Market Valuation

The ACR proposes that the IOU's LCBF analysis of 2012 bids should allow bids to be ranked by their NMV metrics, which incorporate the benefits and costs of the resource offered.[44]

PG&E agrees with, and has been consistently applying in previous RPS solicitations, this principle of net market valuation in ranking RPS Solicitation bids. As discussed above, PG&E plans to further differentiate among bids by using PAV to account for elements that impact a bid's value in the context of PG&E's bundled electric portfolio. Measures of NMV assess bids on a stand-alone basis and do not take into account the rest of an IOU's bundled electric portfolio. PAV is intended to rectify this omission.

---

44 ACR at 16-17.

For purposes of the 2012 RPS Solicitation, PG&E proposes to modify the ACR's list of standardized variables. In its valuation, PG&E incorporates "congestion costs" into location adjustments for energy and capacity values. Therefore, PG&E suggests removing the variable "G" (congestion costs) as a separate variable from the equation of NMV and incorporating the effect of congestion into the variables "E" and "C", energy value and capacity value, respectively.

PG&E supports the inclusion of integration costs as part of the bid evaluation process. As the statewide portfolio of intermittent energy grows, it is appropriate to include an integration cost for intermittent resource bids to account for the increased costs of integrating intermittent renewable resources into the grid.

PG&E agrees that the LCBF inputs and calculations should be reviewed and verified for reasonableness and accuracy by an Independent Evaluator (IE) as well as publicly disclosed when possible. However, there are inputs that the Commission has already determined are market-sensitive, including some proprietary forecasts of energy and capacity values, and these should not be publicly disclosed. The ACR proposal also suggests that inputs and calculations should be consistent with LTPP authorizations. It is unclear what is meant by "LTPP authorizations." PG&E notes that many inputs and calculations, such as transmission network upgrade and integration costs, have not been authorized in any LTPP decision. PG&E suggests that the language in the ACR may be too narrow and should be modified to allow for inputs and calculations sourced from other regulatory authorities.

The ACR also requests comment as to whether its proposed methodology can also be applied to resources that are categorized pursuant to Public Utilities Code § 399.16(b)(2) and § 399.16(b)(3).

PG&E believes that this methodology can be applied to both of these categories of resources with little or no modification. For those resources in § 399.16(b) (2), the additional firming and shaping costs can be captured in the Post-Time-of-Delivery cost variable.

Resources that correspond to § 399.16(b)(3) can also be effectively ranked by the proposed methodology. For unbundled REC resources, many of the values will be zero, such as energy and capacity value, but the basic equation for NMV is still applicable. One slight modification is that the definition of the variable "P," which has been proposed to be the Post-Time-of-Delivery Adjusted PPA Price, will need to be modified to be the REC contract price for this category of resources.

8.4.2 Preliminary Independent Evaluator Report

The ACR proposes a change to the way the IE reports on an IOU's RPS solicitation processes by splitting the Preliminary IE Report into two parts.[45] The first part would address the bid solicitation materials, including LCBF methodology, and would be submitted with the IOU's proposed RPS Procurement Plan. The other part would address the bid solicitation, evaluation, and selection process, and would be submitted with the IOU's shortlists.

PG&E does not oppose the proposal on a going-forward basis (beginning with the 2013 RPS Plan), provided that the first part of the Preliminary IE Report is limited to an evaluation of how the LCBF criteria would be used in evaluation of the bids, since this may relate to the fairness of the solicitation. However, PG&E is concerned about the proposed expansion of IE involvement beyond the traditional role of assessing whether the solicitation was conducted in a fair and objective

---

45 ACR at 18-19.

manner by the suggestion that the IE should additionally assess the "procurement targets and objectives."[46] Determination of procurement targets and objectives is not appropriate to delegate to an IE; the Commission has long recognized a "flexibility with accountability" principle that leaves substantial discretion to the IOUs to conduct RPS procurement planning since they are ultimately accountable for demonstrating that they were reasonable in planning to meet the RPS obligations.[47] Given this principle, the Commission's review of procurement targets and objectives should not require IE review.

Given the short timeline for development of the draft 2012 RPS Plans, the preliminary IE report should only be required, if at all, beginning in the 2013 planning cycle, and additional time should be allotted in the schedule to allow for its inclusion.

8.4.3 Shortlists Expire After 12 Months

The ACR proposes to preclude the IOUs from executing a PPA with a Seller more than 12 months after shortlisting.[48] Sellers whose bids expire in that period would be required to bid into the next solicitation in order to execute a PPA with an IOU.

This proposal would potentially force the IOUs to "close-out" solicitations within a year. However, it would potentially delay execution of PPAs that are beneficial to ratepayers, without significant benefit.

PG&E agrees that if there is a new solicitation underway for the same products, it is reasonable to compare a PPA still under negotiation with the projects that have been received in the pending solicitation, even if the PPA has resulted from an older solicitation. However, PG&E

---

46 *Id.*at 19.

47 *See* D.11-04-030 at 11-12.

48 ACR at 21-22.

sees little added benefit in requiring the Seller to rebid, and in putting that project on the same schedule as bids that have just been received, if that project has already been fully vetted for project viability, the project fits within the approved procurement plan and procurement strategy, and the value of the project is competitive with the previous and current solicitations.

In addition, this proposal would be problematic if a subsequent solicitation is delayed for an extended period of time. In that case, the prohibition on continuing to negotiate the contract after 12 months would become a de facto bar to the developer and the IOU signing a contract.

8.4.4 Two-Year Procurement Authorization

PG&E appreciates the ACR's effort to streamline the procurement process by providing two year authorization for RPS procurement. Under the ACR proposal IOUs would be required to file a Tier 3 advice letter justifying why or why not they intended to conduct a solicitation, support for that decision including updated portfolio assessment, and updated solicitation material, if appropriate. IOUs would be required to hold solicitations simultaneously.[49]

The major potential benefit of this approach would be to reduce administrative burdens on the Commission and all parties. This approach would also be complimentary to Commission adoption of a clear, stable and meaningful RPS procurement expenditure limitation designed to support long-term procurement planning. PG&E recommends that the Commission establish a single limitation applicable to each electric utility to apply to procurement from 2011 through 2020, with a potential revisit and modification in 2015. PG&E may use the adopted procurement expenditure limitation to inform the level of

---

49 ACR at 22-23.

procurement it is able to enter into without incurring disproportionate rate impacts during any given two-year period.

However, PG&E is concerned that unless the scope of the proposed Tier 3 Advice Filing is narrowly set, and a timely schedule for review and approval of the Tier 3 Advice Filing is enforced, the Advice Filing could turn into simply a full RPS Plan, and the proposal may fail to provide any new benefit.

In addition, the CPUC should reconsider the requirement that all IOUs conduct their solicitations on the same timeline. This requirement was originally implemented at a time when there were significantly fewer RPS suppliers and IOUs were procuring higher volumes. Allowing IOUs the flexibility to issue solicitations on different schedules could provide more regular market information, and provide suppliers more opportunities to participate in multiple solicitations.

8.5 Lessons Learned

Based on PG&E's experience with the 2011 RPS Solicitation, and based on ongoing negotiations with 2011 RPS shortlisted parties, PG&E has made several changes for its 2012 RPS Solicitation. Those changes are described in Sections 8.1.3 and 8.2 above.

9 Estimating Transmission Costs for the Purpose of RPS Procurement and Bid Evaluation

This Section discusses PG&E's approach to estimating transmission costs associated with RPS procurement and how PG&E will incorporate those estimated costs into its methodology to evaluate procurement opportunities. PG&E also responds in this Section to the new proposals in the ACR related to transmission.

9.1 Proposed Approach to Estimating and Incorporating Transmission Costs in RPS Bid Evaluations

PG&E's LCBF methodology includes the consideration of potential transmission network upgrade costs in the valuation and ranking process.

Transmission network upgrades are typically upfront funded by participants, and refunded after commercial operation. The costs are borne by customers as part of transmission rates. PG&E expects to use project-specific cost estimates from participants' interconnection studies to determine a transmission adder. However, depending on the timing of and results of the Cluster IV Phase II studies, and the Cluster V Phase I studies, PG&E may use the Transmission Ranking Cost Report (TRCR) results if more appropriate. The draft TRCR results will be filed on June 27, 2012, and will be provided as an attachment to the updated 2012 Solicitation Protocol. For projects that are fully deliverable, PG&E will consider both reliability and delivery network upgrades. For energy-only Projects, PG&E will consider only reliability network upgrades when calculating a transmission adder. Any transmission cost adders attributed to the Project will also be considered in bid ranking.

9.2 New Proposal to Use CAISO Transmission Cost Study Estimates in LCBF Evaluations

The ACR proposes that, to the extent transmission cost estimates from the CAISO Generator Interconnection Process (GIP) studies (or equivalent) are available, the IOUs should rely on this data for their LCBF evaluations rather than the cost estimates from the TRCRs to more accurately reflect a bid's value to the ratepayers.[50]

PG&E supports this proposal as generally consistent with PG&E's evaluation methodology in prior RPS solicitations. Specifically, in prior RPS solicitations, PG&E calculated a transmission adder that adjusted Offer prices to include the cost, if any, of bringing the power from the generating facility to PG&E's network. Each bid was associated with a transmission cluster based upon the location of the facility. If a CAISO interconnection study had been completed for the project, the costs in that report were used for bid evaluation. If

50 ACR at 19.

no study was completed, the project's transmission costs were estimated based upon either the ability to affect deliveries to PG&E's load through exchanges, other commercially-recognized means, or transmission costs were assigned using the TRCR methodology. In its 2011 RPS Request for Offers (RFO), PG&E used the lesser of the transmission adder or alternative commercial arrangements in determining the market value of bids and selecting the shortlist.

As reflected in the 2012 RPS Solicitation Protocol, PG&E suggests taking the proposal a further step by requiring that bids include a Phase I study in order to be eligible to participate in PG&E's 2012 RPS Solicitation. This new requirement will ensure that PG&E has additional information regarding the interconnection costs and upgrades required that may provide more accurate valuation of the project. Given the proposed Solicitation issuance in the fourth quarter of 2012 and bids due in early 2013, it is likely that participants in CAISO's GIP Cluster V will have Phase I studies, and that participants in CAISO's GIP Cluster IV will have Phase II studies.[51] The requirement for a Phase I study is consistent with requirements that the CPUC has previously implemented in the RAM proceeding.[52] In addition, it is consistent with, but does not go as far as, suggestions in the ACR that an IOU's primary shortlist must consist of projects that have a Phase II study.

Although PG&E is proposing that Sellers have a Phase I study or equivalent to demonstrate progress toward project development and to have some initial information regarding interconnection costs, PG&E cautions the CPUC against adopting an inflexible rule that would require IOUs to use CAISO

---

51 *See* the CAISO's Final Proposal of the Integration of Transmission Planning and Generator Interconnection Procedures (TPP-GIP Integration) integrated process and timeline schedule at 10. http://www.caiso.com/Documents/FinalProposal-TransmissionPlanning_GeneratorInterconnectionProceduresIntegration.pdf

52 *See* August 18, 2011 Resolution E-4414 at 13 ("IOUs shall require a seller to have completed a System Impact Study, a Phase 1 Interconnection study, or have passed the WDAT or GIP Fast Track screens in order to participate in a RAM auction.").

studies if they are available to the exclusion of other indicators of interconnection costs. Although CAISO studies are intended to be project-specific analyses, and TRCRs are high-level proxy costs, PG&E does not always find that CAISO interconnection studies lead to a more accurate estimate of the actual interconnection cost. This is because CAISO Phase I costs are intended to be an upper bound on project costs, while TRCR costs are intended to forecast actual or likely costs (rather than an upper bound). If a CAISO interconnection cluster contains projects that are unlikely to be developed, then the Phase I study estimates are likely to overestimate the actual interconnection costs of other projects in the same cluster. Additionally, CAISO Cluster IV Phase I studies were not project-specific, but rather were conducted by region. Finally, an inflexible rule could lead to inequitable outcomes if some projects bid into the solicitation do not have project-specific interconnection studies, while other offers in the same area have CAISO studies. If the CAISO Phase I estimate for the projects in that area is higher than the TRCR proxy cost, it may not lead to the most cost-effective procurement decision and may “penalize” the project that is farther along in the interconnection process.

In sum, PG&E agrees with the proposal that CAISO interconnection studies can offer valuable input regarding the total cost of an RPS procurement opportunity, and PG&E recommends that all bids should be accompanied by at least Phase I studies in order for this information to be taken into consideration. However, PG&E and the other IOUs should not be prohibited from using TRCR proxy costs rather than the Phase I studies when, in the IOU’s best judgment and in consultation with the IE, use of the Phase I estimate would lead to an inequitable or unreasonable outcome.

9.3 New Proposal to Create Two Shortlists Based on Status of Transmission Study

The ACR proposes the creation of primary and provisional shortlists.[53] The only way to be on the primary shortlist is to have a CAISO Phase II study or equivalent (or to already be interconnected or not require any transmission system upgrades). The proposal would preclude execution of any contract on the provisional shortlist prior to receipt and consideration of a Phase II study or equivalent. The stated goal is to rely on more accurate estimates of transmission costs in the bid evaluation process and to ensure that a project's total cost and the value to ratepayers are both considered by the IOU and the Procurement Review Group prior to contract execution.

PG&E recognizes the potential value in receiving Phase II studies to support the evaluation of bids received in the RPS solicitations, but it recommends against adoption of the proposal as written. One benefit of the proposal is that it would reduce uncertainty associated with network upgrade costs, since Phase II studies are generally far more accurate than Phase I study estimates. Nonetheless, the risk of this proposal is that it could preclude IOUs from seizing fleeting and unique procurement opportunities that could significantly reduce RPS implementation costs for their customers. For example, a PPA with a Phase I study could be significantly cheaper than a project with a Phase II study, even considering a high-end Phase 1 estimate of transmission costs. If PG&E is prohibited from negotiating and executing a PPA with that resource until it has expended considerable time and financial resources in securing a Phase II study, the counterparty may prefer to find another LSE that is less constrained in its procurement process.

9.4 New Proposal to Utilize the Commission's RPS Procurement Process to Minimize Transmission Costs

Another new proposal set forth in the ACR aims to minimize the need for transmission upgrades by utilizing the Commission's procurement process and approval authority to enforce the limits of available deliverability capacity as

---

53 ACR at 20-21.

determined by the CAISO's transmission planning and interconnection studies.[54] While PG&E supports the goal of avoiding unnecessary high-cost, long-lead time network upgrades, PG&E has two primary concerns with this proposal: (1) the proposal aims to enforce thresholds at too early of a stage in the procurement process; and (2) the proposed process is redundant with the CAISO's Integration of TPP-GIP, which aims to minimize unnecessary transmission build-out for Clusters V and beyond.[55] While this proposal may be appropriate for Cluster IV, PG&E cautions applying this proposal as the default going forward.

To the extent that the proposal is applied for Cluster 4, PG&E recommends two modifications to the proposal. First, instead of limiting the number of projects that IOUs can shortlist, it would be more appropriate to use the PPA approval process to enforce the limits of deliverability capacity. Additionally, projects requesting interconnection as energy-only should not be constrained by the deliverability capacity limits, and IOUs should have the flexibility to negotiate contracts with such projects should they provide competitive value even without offering RA credit.

9.4.1 Constraining Procurement at the Shortlisting Stage Is Premature

The ACR proposes applying a rationing procedure to reduce the size of IOUs' shortlists, to the extent that the total volume of megawatts shortlisted by all IOUs exceeds the threshold capacity in an area, based on the CAISO's determination of available deliverability. To the extent this proposal is applied to Cluster IV projects, PG&E believes that it would be premature to apply a rationing procedure to the IOU's shortlist.

---

54 *See* ACR at 24-29.

55 The CAISO's TPP-GIP Integration aims to better integrate the transmission planning and generation interconnection procedures so that ratepayer-funded transmission additions and upgrades are identified and approved under a single comprehensive process, for projects entering the interconnection queue in cluster 5 or later. In particular, it proposes a method for awarding transmission capacity to generation projects considered most viable, for the areas of the grid where the volume of interconnection requests exceed the capacity of transmission developed through the transmission planning process. *See* more http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionPlanning_GeneratorInterconnectionIntegration.aspx

Ranking the projects in a definitive manner at the shortlisting stage of the solicitation process limits the projects for which an IOU can enter into negotiations. In addition, such projects that are not initially identified in the "best ranking subset" may ultimately prove to be the most viable for reasons that were not clear during the initial shortlisting process, especially since shortlists change significantly and frequently until the point of execution. IOUs need to have the flexibility to enter into negotiations with a broad pool of bidders and to conduct the due diligence that accompanies those negotiations.

To the extent that a rationing procedure is applied, IOUs should be able to negotiate with all projects on their shortlists. It is possible that the PPA negotiations will naturally cull the number of projects to an amount of MWs within the CAISO thresholds. If there is still an excess of MWs after IOUs execute PPAs, the CPUC could apply the rationing procedure and use the PPA approval process to enforce the thresholds at that point. This would likely provide better information to the Commission to allow the final decisions on ranking to better reflect LCBF principles than if the cull occurred at the shortlist stage.

In terms of prioritizing the "best ranked projects" among the IOUs, PG&E requests that the Commission fully describe the methodology it would use to evaluate and allocate projects equitably among the three IOUs. The proposal presents significant challenges with comparing and ranking PPAs which have different terms and conditions and have been selected after application of different valuation methodologies across the IOUs. For example, an IOU using higher forward energy curves for valuation purposes may submit PPAs that appear more competitive when comparing NMV across the IOUs.

Finally, the interaction between the rationing and IOU's need to meet procurement requirements for compliance is not addressed in this proposal. For example, it is not clear how the Commission plans to address a scenario where the ration an IOU receives is not sufficient to meet procurement requirements needed for compliance. To the extent this occurs, an IOU may be eligible for a waiver of enforcement due to insufficient supply created by a condition outside of its control.[56]

9.4.2 Energy-only Projects Should Not Be Constrained Based on Deliverability Capacity

If the proposal is adopted with regard to Cluster IV, projects requesting interconnection as energy-only should not be constrained by the deliverability capacity limits since they are not seeking deliverability and will not provide RA value.

Energy-only projects can be competitive with projects seeking to provide capacity value. IOUs should have the flexibility to procure from an energy-only resource if the bid evaluation methodology determines that such a resource provides the highest value at lowest cost according to the LCBF principles.

10 Consideration of Price Adjustment Mechanisms

The ACR requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index, price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[57] The underlying statutory requirement is narrower, focusing solely on price adjustments "associated with the costs

---

56 *See* Cal. Pub. Util. Code § 399.15(b)(5)(B).

57 ACR at 14.

of key components."[58]

PG&E will consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Obviously, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces that rate stability that the legislature has found is a benefit of the RPS program.[59] In order to maximize the RPS program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[60]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the Consumer Price Index (CPI). The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the

---

58 Cal. Pub. Util. Code § 399.13(a)(5)(E).

59 *See* Cal. Pub. Util. Code § 399.11(b)(5).

60 *See* D.11-04-030 at 33-34.

derivative and speculative character of these types of transactions.

11 Summary of Cost Quantification Results

The ACR requires PG&E to provide historic and forecast RPS cost information and rate impact information as part of the Plan.[61] This information is intended to update the data underlying the Commission's February 3, 2012 report to the Legislature pursuant to SB 836 and to supplement information provided in comments on the January 24, 2012 Ruling in R.11-05-005 regarding implementation of the RPS cost containment provisions.[62] As required by the ACR, PG&E coordinated with SCE and SDG&E, and consulted with the Energy Division, to produce the standardized methodology and template included at Appendix 2.

11.1 Summary of Cost Quantification Methodology and Results

Appendix 2 quantifies the cost of RPS-eligible procurement—both historical (2003-2011) and forecast (2012-2020). As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales. Forecasted future costs in Table 2 of Appendix 2 may be compared with actual historic costs in Table 1 of Appendix 2.

11.1.1 Joint IOU Cost Quantification Appendix 2, Table 1 (Actual Costs)

Table 1 of Appendix 2 presents PG&E's actual RPS-eligible procurement and generation costs from the time period 2003-2011. The values in Table 1 of Appendix 2, rows 2-8 represent the settled contract costs with all RPS-eligible contracts in PG&E's portfolio, with one exception. In row 5, PG&E does not capture the full costs of its existing

61 ACR at 14-15.

62 *Ibid.*

contracts with Irrigation Districts and Water Agencies (Agency or Agencies) that supply power to PG&E from multiple RPS- and non-RPS-eligible hydro units.[63] However, PG&E has included the cost of its existing contract with Solano Irrigation District in its Appendix 2, tables 1 and 2. Solano Irrigation District is (1) solely RPS-eligible and (2) the only existing Agency agreement executed prior to 2012 with RPS-eligible deliveries continuing into, and past, the third compliance period.

Additionally, rows 9 and 10 represent an estimate of the annual costs attributable to PG&E's utility-owned hydroelectric and solar PV projects that are RPS-eligible. In order to estimate the annual costs attributable to PG&E's utility-owned hydroelectric projects that are RPS-eligible, PG&E calculated an annualized capacity cost based on the net book value of its RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14 percent. PG&E's historical operation and maintenance (O&M) costs for each year (2003-2011) were added to the annualized capacity cost. In order to estimate the annual costs attributable to PG&E's utility-owned PV projects, PG&E calculated a levelized cost of electricity for each project and multiplied this value by the project's historical generation.

From 2003 to 2011, PG&E's annual RPS-eligible procurement and generation costs have increased approximately $500 million in total, beginning at $512 million in 2003 and increasing to $1.017 billion in 2011. The majority of PG&E's historical costs is attributable to biomass, geothermal, and wind resources under contract to the Utility.

---

63 PG&E reports the aggregate costs (specifically debt service and operation and maintenance) of its contracts with Irrigation Districts and Water Agencies (Agency or Agencies) by Agency. Each Agency's costs include the costs to operate and maintain multiple Agency units (including RPS-eligible units and non-RPS-eligible units) and project facilities (dams and waterways). Since the Agency cost assignments are not made by individual powerhouse, PG&E cannot assign costs to the suite of Agency contracts on the basis of RPS-eligibility at this time.

11.1.2 Joint IOU Cost Quantification Template Appendix 2, Table 2 (Forecast Costs)

The values in Table 2 of Appendix 2, rows 2-11 and 16-25 are a forecast of PG&E's future expenditures on all RPS-eligible procurement and generation either (1) approved to date or (2) executed prior to April 5, 2012 but pending CPUC approval. PG&E's forecast in Table 2 of Appendix 2 assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. Rows 23 and 24 include the forecasted cost attributable to PG&E's RPS-eligible UOG, including all 250 MW of its PV program. Using the capital cost methodology described in Section 11.1.1, PG&E estimated its future annual costs attributable to its utility-owned hydroelectric projects that are RPS-eligible by adding an O&M expense to its annualized capital cost. In order to estimate its future O&M cost, PG&E escalated its 2011 O&M expense by 5% annually for each year (2012-2020). In order to estimate the annual costs attributable to PG&E's utility-owned PV projects, PG&E calculated a levelized cost of electricity for each project and multiplied this value by the project's forecasted generation.

From 2012 to 2020, PG&E's annual RPS-eligible procurement and generation costs from its existing contract and utility-owned portfolio will increase by approximately [redacted], assuming no contract failure. This increase from [redacted] in 2012 to [redacted] in 2020 is primarily attributable to the addition of a significant quantity of new contractual volumes (1) needed to reach California's aggressive renewable energy goals; and (2) forecasted to be purchased largely from solar contracts, both PV and thermal, assuming no contract failure. To the extent that existing contracts do not materialize or PG&E procures additional volumes through future RPS solicitations and Commission-approved or mandated RPS procurement programs, PG&E's forecasted procurement costs listed in Table 2 of Appendix 2 may increase or decrease.

11.1.3 Incremental Rate Impacts

The ACR requires PG&E to provide an "Incremental Rate Impact – per year" defined as the total actual and forecasted annual rate impacts from the procurement of RPS eligible generation from 2003-2020.[64] As required by the ACR, PG&E coordinated with SCE and SDG&E, and consulted with the Energy Division in order to define this item as an annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively an estimate of a system average bundled rate for RPS-eligible procurement and generation. While this formula does not provide the reader with an estimate of the renewable "premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix 2 do illustrate the potential rate of growth in RPS costs and the impact that this growth will have on average rates, all else equal.

As show in Tables 1 and 2 of Appendix 2, the costs of the RPS program have only begun to appear in customers' rates. For example, row 14 in Table 1 of Appendix 2 shows an annual rate impact within the range of 0.7 ¢/kWh and 1.4 ¢/kWh from 2003 to 2011, meaning the average rate impact from RPS-eligible procurement has nearly doubled in approximately eight years. However, this growth rate accelerates, which is clearly shown in Table 2 of Appendix 2. [redacted].

64 ACR at 15.

11.2 Forecasted Procurement Costs from Future Procurement Attributable to PG&E's PV Program, the Renewable Auction Mechanism, and the Implementation of the SB32 Feed-in-Tariff

While the ACR requires PG&E to provide the historic and forecast RPS cost and rate impact information presented in Tables 1 and 2 of Appendix 2, this subsection provides additional data not specifically required in the ACR. Specifically, Table 11-1 shows the additional costs PG&E may incur in order to procure the requisite amounts from Commission-approved or mandated RPS procurement programs. The individual assumptions for the Commission-approved or mandated RPS programs are listed in the bullets below.

- Forecast RAM Procurement Cost: To quantify the costs of RAM Auctions 2-4, PG&E assumes first deliveries from a generic mix of volumes to begin 24 months after contract execution in July 2012, January 2013 and July 2013. PG&E's generic mix consists of a contract quantity assumed to be 20% baseload and 80% as available and priced at a nominal levelized cost of electricity (LCOE) derived from the LCOEs reported in the Energy and Environmental Economics, Inc. (E3) 33% RPS calculator.[65] For example, a generic PV project beginning deliveries in July 2014 will be priced at ~ $118/MWh. PG&E selected the lowest LCOE (i.e., $107/MWh in 2010 dollars) from the E3 33% RPS calculator as its representative PV cost and escalated the 2010 value by 2.5% annually to estimate PV project costs for varying online dates.
- Forecast PV Program Procurement Cost: To quantify the costs of PV Program RFOs in years two through five of the program, PG&E assumes first deliveries consistent with the timing developed from the first PV PPA RFO. For example, PG&E forecasts year two deliveries to begin in February 2014 since expected commercial online dates from program year

65 *See* http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm. E3's 33% RPS Calculator uses inputs from California's Renewable Energy Transmission Initiative, the California Independent System Operator, the U.S. Army Corps of Engineers, and others to develop capital and operations and maintenance costs of renewable energy technologies. Additional information about this calculator may be found in the "33% RPS Implementation Analysis" section of http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm.

one were estimated to be February 2013.[66] PG&E's Forecast PV PPAs are priced at the representative LCOEs described in bullet one.

- Forecast FIT Procurement Cost: To quantify the costs of additional procurement for eligible products up to 3 MW under the SB 32 FIT program, PG&E assumes first deliveries from a generic mix of volumes to begin 30 months after contract execution starting in September 2012 and continuing through September 2013. PG&E's generic mix consists of a contract quantity assumed to be one-third baseload, one-third non-peaking as-available, and one-third peaking as-available and priced at $89.23[67] pre-TOD.

Table 11-1 provides a fuller picture of the growth in customer costs as projects from executed contracts and Commission-approved or mandated RPS procurement programs begin to come online in significant quantities, particularly in 2015 and thereafter. While Table 11-1 provides a more complete picture of the potential customer cost impacts from direct procurement, it omits any RPS-eligible procurement resulting from future competitive solicitations, including the 2012 RPS Solicitation, that are needed to ensure ongoing compliance with the RPS Program procurement requirements. Additionally, Table 11-1 omits non-procurement costs that can be directly attributed to the RPS program, specifically the associated incremental transmission costs and potential future integration costs. PG&E is well aware of these cost impacts and will mitigate them whenever possible.

---

66 *See* Advice Letter 3877-E, page 1.

67 See Proposed Decision of ALJ DeAngelis "DECISION REVISING FEED-IN TARIFF PROGRAM, IMPLEMENTING AMENDMENTS TO PUBLIC UTILITIES CODE SECTION 399.20 ENACTED BY SENATE BILL 380, SENATE BILL 32, AND SENATE BILL 2 1X AND DENYING PETITIONS FOR MODIFICATION OF DECISION 07-07-027 BY SUSTAINABLE CONSERVATION AND SOLUTIONS FOR UTILITIES, INC.", issued on March 20, 2012 in R.11-05-005.

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
FORECASTED FUTURE EXPENDITURES ON RPS-ELIGIBLE PROCUREMENT AND GENERATION COSTS, INCLUDING FUTURE AMOUNTS FROM CPUC-APPROVED OR MANDATED RPS PROGRAMS

	($ Thousands)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	Total CPUC-Approved RPS-Eligible Procurement and Generation Cost [Row 26 in Table 2, Appendix 2]	[redacted]								
2	Total Executed But Not CPUC-Approved RPS-Eligible Contracts [Row 12 in Table 2, Appendix 2]	[redacted]								
3	Forecast RAM Procurement Cost [Future PPAs only]	$0	$0	$27,197	$121,449	$144,683	$144,126	$143,941	$143,756	$143,941
4	Forecast PV Program Procurement Cost [Future PPAs only]	$0	$0	$11,833	$25,036	$38,582	$52,247	$53,207	$52,941	$52,778
5	Forecast FIT Procurement Cost [Future PPAs only]	$0	$0	$0	$16,290	$41,326	$41,366	$41,283	$41,233	$41,421
6	**Total Cost** [Sum of Rows 1 through 5]	[redacted]								
7	Bundled Retail Sales (Thousands of kWh)	[redacted]				77,356,033	77,774,983	78,247,068	78,703,900	79,423,331
8	**Incremental Rate Impact***	[redacted]								

* Incremental Rate Impact is equal to Row 6 divided by Row 7. While the item is labeled “Incremental Rate Impact,” the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable “premium.” In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

12 Other RPS Planning Considerations and Issues

12.1 Contract Amendments

In this section, PG&E describes the process for regulatory approval of amendments to previously executed and approved RPS contracts.

The Tier 1 Advice Letter process is used when PG&E exercises a contract option under a previously approved RPS PPA, such as additional, incremental renewables procurement at the PPA approved price.

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

The Tier 3 Advice Letter process is used for amendments that would increase PPA costs, address issues explicitly reserved by the Commission for further deliberation, or materially decrease the value of a PPA. In general, PG&E will consider price adjustments where the revised price and terms of the contract enhance the value of the deal for PG&E's customers, taking into account qualitative RPS goals. PG&E will continue to submit a Tier 3 advice letter for any amendments for which additional CPUC approval is required or when PG&E feels it is warranted.

Routine contract changes are managed by PG&E without prior Commission approval and subsequently reported in the Quarterly Contract Review.

12.2 Amendments to Contracts and Form Contracts Related to Credit Rating Standard Adjustment

Due to the recent and ongoing turmoil in the financial markets and the uncertain credit rating of many banks that Sellers may use to post performance assurance pursuant to their RPS contracts, PG&E has adjusted its credit rating standard for the banks issuing letters of credit on Seller's behalf from at least "A" to "A-" from S&P or "A2" to "A3" from Moody's, with a stable outlook designation

(“Updated Credit Rating”). In case of conflicted ratings from S&P and Moody’s, the lower credit rating prevails.

In keeping current with changes in the financial markets, PG&E recently reviewed its credit rating requirements for issuers of letters of credit (“LOCs”) and found that the industry, which includes other utilities such as SCE and SDG&E, (1) for the most part has minimum credit rating standards of A- from S&P or A3 from Moody’s, for issuers of LOCs, and (2) shows indications that few banks may have a credit rating above their respective sovereign ratings. Therefore, the Updated Credit Rating remains a strong indication of the health of the credit issuer in light of new stricter rating measures.

PG&E believes that a proactive adjustment in the form of the Updated Credit Rating will provide several benefits to customers and PG&E. First, it will provide Sellers with wider access to qualified banks, which will enhance the ability to comply with contractual agreements. Second, it will reduce PG&E’s credit concentration risk to certain banks. Finally, PG&E will continue to be aligned with current industry standards and mitigate additional Seller credit costs.

Given current financial market conditions and industry practice, PG&E will include the Updated Credit Rating in (1) its RPS contracts that are currently under negotiation, but are not yet executed and (2) its future form contracts submitted to the CPUC for approval prior to the issuance of a new PG&E solicitation. However, PG&E has previously executed RPS contracts and CPUC-approved non-modifiable form contracts as part of RPS solicitations, which contain PG&E’s prior credit rating requirement of at least “A” from S&P or “A2” from Moody’s (“Prior Credit Rating”). Therefore, PG&E is requesting that the CPUC provide PG&E with the authority through its approval of the 2012 RPS Plan to do the following without further approval from the CPUC:

- amend executed RPS contracts with the Prior Credit Rating to reflect the Updated Credit Rating to the extent a Seller requests such amendment or Seller's issuer of a LOC is downgraded; and

- amend non-modifiable RPS form contracts which have been approved or are pending approval by the CPUC for the following programs:
  - RAM[68]
  - PV (large and small)[69]

While this 2012 RPS Plan is pending approval by the CPUC, including PG&E's request to amend its executed RPS contracts and its approved or pending non-modifiable RPS form contracts ("Interim Period"), PG&E may take the following actions to address the need for the Updated Credit Rating and the current financial market status, if requested by a Seller:

- Provide Seller with additional time to find a replacement issuer for a LOC using the Prior Credit Rating, as long the LOC posted during the Interim Period meets the new Updated Credit Rating requirement; or
- Waive the Prior Credit Rating and allow a Seller to provide LOC from an issuer with the Updated Credit Rating; and/or
- Mutually agree with a Seller on a reasonable solution to address any issues with the Prior Credit Rating.

PG&E may take any or all of the above actions during the Interim Period, but only to the extent that the actions are reasonable and conform to PG&E internal credit standards.

If the CPUC does not approve PG&E's request to include the Updated Credit Rating in executed RPS contracts upon a Seller's request, including those done during the Interim Period or to amend non-modifiable RPS form contracts, then PG&E will be required to seek approval of such amendments by advice

---

68 *See* PG&E Advice Letter 4032-E (submitting updated RAM form contract in compliance with Resolution E-4489).

69 *See* Resolution E-4368; PG&E's Advice Letter 3786-E (submitting updated PV form contracts in compliance with Resolution E-4368).

letter for each executed RPS contract and each non-modifiable RPS form contract from each solicitation. This process will be time consuming and inefficient for PG&E as well as CPUC staff. In addition, the time period for that process along with the approval process for the 2012 RPS Plan may place at risk certain Sellers who are unable to perform under their contracts with the Prior Credit Rating.

13 Important Changes from 2011 RPS Plan

This section describes the most significant changes between PG&E's 2011 RPS Plan and its 2012 RPS Plan. This section also provides updates since 2011 on the Commission-approved RPS procurement programs. A complete redline of the Plan against PG&E's 2011 RPS Plan is included in the filing. Additionally, Appendix 5 provides a summary of the key changes made to the 2012 RPS Form PPA, and Section 8 summarizes significant changes made to the 2012 RPS Solicitation Protocol.

13.1 Summary of the Important Changes between the 2011 and 2012 RPS Procurement Plans

Reference	Area of Change	Summary of Change	Justification of Change
Sections 1 & 2	Portfolio Content Requirements and Categories	Updated RPS Portfolio Supplies and Demand due to recent changes in legislation and Commission decisions, including the content categories 1, 2, and 3.	D.11-12-052
Section 1	Compliance Period Targets	Updated RPS Compliance Targets per D.11-12-020.	D.11-12-020. See Section 1.2.1.2 for further details.
Section 1	Compliance Rules	Proposed Decision would provide more clarifying rules on how to calculate and justify compliance position.	Proposed Decision (April 24, 2012) See Section 1.2.1.3 for further details.
Section 1	TRECs	Updated language based on recent legislation. Request explicit repeal of TREC Decision other than provisions the Commission has ordered remain in effect.	SB 2 (1x)
Section 1 & 13	UOG	PG&E does not currently have plans to pursue any UOG projects.	ACR, dated April 5, 2012. See Sections 1 and 13 for further details.
Section 2	Assessment of RPS Portfolio Supplies and Demand	Explains PG&E's supply and demand for renewables to maintain compliance with current legislation.	ACR, dated April 5, 2012. See Section 2 for further details.

Reference	Area of Change	Summary of Change	Justification of Change
Section 4 & Appendix 4	Project Development Status Report	Provided an update on the development of RPS resources currently under development.	ACR, dated April 5, 2012. See Section 4 and Appendix 4 for further details.
Section 5	Risk Assessment	Describes PG&E's approach to risk categorization and consequent impacts on the quantitative assessment of its RPS procurement need.	ACR, dated April 5, 2012. See Section 5 for further details.
Section 6, Appendix 1, & Appendix 3	Quantitative Information	Describes the methodology used to produce PG&E's net short calculation and describes the implications of that calculation for PG&E's RPS compliance outlook and RPS procurement strategy.	ACR, dated April 5, 2012. See Section 6, Appendix 1, and Appendix 3 for further details.
Section 7	Minimum Margin of Over-Procurement	Discusses how PG&E's minimum margin of over-procurement methodologies were incorporated into PG&E's quantitative analysis of its RPS need and into the development of its 2012 RPS procurement goal	ACR, dated April 5, 2012. See Section 7 for further details.
Section 8	Bid Selection Protocol	Discusses PG&E's 2012 procurement goals and the relationship between RPS needs and RPS goals. Summarizes major changes to 2012 Protocol and modifications to commercial terms.	ACR, dated April 5, 2012.See Section 8 and the Draft Protocol for further details.
Section 8	LCBF Methodologies	Updated to include PG&E's PAV methodology and to include an integration cost adder.	ACR, dated April 5, 2012.See Section 8.3 for further details.
Section 8	New Proposal - Standardized Variables in LCBF Market Valuation	PG&E agrees with, and has been consistently applying in previous RPS solicitations, the principle of net market valuation in ranking RPS Solicitation bids.	ACR, dated April 5, 2012. See Section 8.4 for further details.
Section 8	New Proposal - Preliminary Independent Evaluator Report	PG&E does not oppose the proposal on a going forward basis (beginning with the 2013 RPS Plan) to the extent that the IE's first part of the Preliminary IE Report would be limited to an evaluation of how the LCBF criteria would be used in evaluation of the bids, since this may relate to the fairness of the solicitation but has some concerns.	ACR, dated April 5, 2012. See Section 8.4 for further details.

Reference	Area of Change	Summary of Change	Justification of Change
Section 8	New Proposal - Shortlists Expire After 12 Months	PG&E agrees that if there is a new solicitation underway for the same products, it is reasonable to compare a PPA still under negotiation with the projects that have been received in the pending solicitation, even if the PPA has resulting from an older solicitation. But, assuming that is done, PG&E sees little added benefit in requiring the Seller to rebid.	ACR, dated April 5, 2012. See Section 8.4 for further details.
Section 8	New Proposal - Two Year Procurement Authorization	PG&E appreciates the ACR's effort to streamline the procurement process and recommends that the Commission establish a single cost limitation applicable to each electric utility to apply to procurement from 2011 through 2020, with a potential revisit and modification in 2015.	ACR, dated April 5, 2012. See Section 8.4 for further details.
Section 9	Estimating Transmission Costs for the Purpose of RPS Procurement and Bid Evaluation	Discusses PG&E's approach to estimating transmission costs associated with RPS procurement and how PG&E will incorporate those estimated costs into its methodology to evaluate procurement opportunities.	ACR, dated April 5, 2012. See Section 9 for further details.
Section 9	New Proposal - Use CAISO Transmission Cost Study Estimates in LCBF Evaluations	Discusses PG&E's response to the new proposal to use the CAISO transmission cost study estimates in the LCBF evaluations.	ACR, dated April 5, 2012. See Section 9.2 for further details.
Section 9	New Proposal - Create Two Shortlists Based on Status of Transmission Study	PG&E recognizes the potential value in receiving Phase II studies to support the evaluation of bids received in the RPS solicitations, but it recommends against adoption of the proposal as written.	ACR, dated April 5, 2012. See Section 9.3 for further details.
Section 9	New Proposal - Utilize the Commission's RPS Procurement Process to Minimize Transmission Costs	While PG&E supports the goal of avoiding unnecessary high cost, long-lead time network upgrades, PG&E has some concerns with this proposal.	ACR, dated April 5, 2012. See Section 9.4 for further details.
Section 10	Consideration of Price Adjustment Mechanisms	Summarizes PG&E's position on proposed price adjustment mechanisms.	ACR, dated April 5, 2012
Section 11 & Appendix 2	Summary of Cost Quantification Results	Summarizes PG&E's historic and forecasted RPS cost and rate information.	ACR, dated April 5, 2012. See Section 11 and Appendix 2 for further details.
Section 12	Other – Credit Rating	PG&E seeks specific authority to amend the credit requirements in its existing RPS PPAs without the need to seek subsequent Commission approval of each such amendment.	See Section 12 for further details.

13.1.1 Update on Photovoltaic Program

In D.10-04-052, the Commission approved PG&E's PV Program, which is a five-year program designed to promote the development of distributed PV facilities in PG&E's service territory, with a focus on ground-mounted projects in the one to 20 megawatt (MW) range. The Commission authorized PG&E to own and operate 250 MW of PV facilities in the one to 20 MW range and to enter into long-term PPAs with 20 year terms for 250 MW of similar facilities.

Both the UOG and PPA portions of the program are underway. Program Year 1 of PG&E's 250 MW UOG PV Program is comprised of three solar stations including Five Points (15 MW), Westside (15 MW), and Stroud (20 MW). These stations have been operational since October 2011. For Program Year 2, three additional solar stations - Huron (20 MW), Cantua (20 MW), and Giffen-A (10 MW) are nearing completion and expected to be operational before October 2012. PG&E's Program Year 3 is underway and comprised of Gates (20 MW), West Gates (10 MW), and Guernsey (20 MW) solar stations. Construction on Program Year 3 projects is expected to begin this year. Sites for Program Years 4 and 5 are in the process of being finalized.

The PPA portion of the program has seen a robust response in solicitations for both Program Year 1 and 2. PG&E signed three PPAs for a total of 50 MW under Program Year 1: Recurrent Energy (20 MW), Westlands Solar Farms (18 MW), and Fotowatio Renewable Ventures (now SunEdison) (12 MW). On April 3, 2012, PG&E issued the Program Year 2 RFO and received bids on May 3rd. PG&E plans to execute final PPAs for Program Year 2 by August 2012.

13.1.2 Update on RAM Program

In D.10-12-048, the Commission approved the RAM Program to facilitate the development of smaller renewable projects. D.10-12-048 requires the IOUs to conduct a total of four solicitations, two per program year for two years. PG&E issued its first RAM solicitation in November 2011, and executed four contracts for a total of 63 MW. PG&E has issued its second RAM solicitation, which will close on May 31, 2012, pursuant to the schedule adopted by the Commission in Resolution E-4414. PG&E also held its second RAM bidders conference and first RAM annual forum on May 16, 2012.

13.1.3 Update on FIT Program

In D.07-07-027, the Commission adopted tariffs and standard contracts to implement AB 1969 for the development of a FIT for RPS-eligible projects that are 1.5 MW and less. The Commission subsequently approved PG&E's Electric Schedules E-SRG and E-PWF that provide a tariff and form contract for eligible, small RPS facilities. SB 32 expanded the AB 1969 FIT Program to eligible renewable generators that are 3 MW and less. In R.11-05-005, the Commission has been working on a process to implement SB 32. PG&E and numerous other parties have filed comments on program elements, including the pending Proposed Decision, which addresses several program elements, including the pricing mechanism. In addition, the IOUs have worked with several parties to develop a single joint proposed PPA that is awaiting Commission approval. PG&E expects that the updated SB 32 FIT program will be ready for implementation in late 2012.

13.1.4 Update on UOG Procurement

PG&E is not currently developing any UOG projects other than those UOG solar projects included as a part of PG&E's PV Program (discussed above) and is not soliciting turn-key ownership offers, such as PPAs with buyout options and sites for development, in the 2012 RPS Solicitation. However, consistent with PG&E's goal of complying with its RPS goals in the most cost-effective way, PG&E is open to additional renewables ownership opportunities if they present high value relative to other procurement options.

Small Hydro

PG&E continued evaluations of its extensive hydropower system for opportunities to expand small hydropower generation with RPS eligible hydroelectric facilities in a manner that is both economically and environmentally sustainable, while recognizing all of the RPS rules that are in place.

Since 2011, incremental efficiency improvements continued at existing Poe Powerhouse (Unit 2 completed February 2011 and Unit 1 scheduled for completion June 2012) and Rock Creek Powerhouse (Unit 2 scheduled for completion October 2012 and Unit 1 scheduled for completion June 2013).

In 2010, PG&E had deferred construction of a small hydro site at its Pit 3 Dam, to be named Britton Powerhouse; during 2011 the deferral (to evaluate the effect of newly discovered fault activity in the region) continued and is presently expected to continue through December 2012.

PG&E continued its evaluation of potential new units at its Chalk Mountain Powerhouse (Pit 4 Dam) and Rock Creek Dam sites, requesting (February 2011) and receiving (October 2011) new FERC Preliminary Permits for both sites.

PG&E expects to continue these and other activities in 2012.

VERIFICATION

I am an employee of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing "2012 Renewable Energy Procurement Plan," dated May 23, 2012. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on this 23rd day of May 2012 at San Francisco, California.

/s/

Brooke Reilly
Manager, Renewable Energy Policy and Planning
Pacific Gas and Electric Company

APPENDIX 1

Quantitative Information

Confidentiality Protected Under D.06-06-066 Appendix 1
Item VII F and G Renewable Resource Contracts under RPS program –
Contracts with Supplemental Energy Payments (SEPs) and Contracts without SEPs.

Appendix 1: Quantitative Information
(Net Short Calculations)

Current Expected Need Scenario

#		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
2	**Compliance Period Requirement**		20.0%			23.3%			30.0%			33%	33%
3	**Compliance Period RPS Position (%)**		21.2%			30.9%			27.8%			24.9%	21.8%
4	**Annual RPS Position (%)**	19.4%	[redacted]				31.9%	30.7%	28.0%	26.9%	25.7%	24.9%	21.8%
5	**Surplus/(Deficit) compared to Annual Targets* (GWh)**	(486)	[redacted]				5,330	2,851	(784)	(3,219)	(5,816)	(6,482)	(9,062)
6	**Surplus/(Deficit) compared to Compliance Period Requirement (GWh)**	[redacted]							(6,967)			(6,482)	(9,062)
7	**Surplus Procurement ("Bank")**												
8	**Volumes (Banked) or Withdrawn from Bank**	[redacted]							6,967			6,482	6,456
9	**Revised Surplus/(Deficit)**								0			0	(2,606)
10	**Revised Compliance Period RPS Positions (%) with Use of Bank**								30.0%			33.0%	29.8%
11	**Cumulative Banked Volumes (GWh)**					19,906			12,939			6,456	0

The Current Expected Need scenario incorporates the deterministic criteria outlined in Section 6.2, which excludes deliveries from the Closely Watched projects, while all other projects are modeled at 100% of expected deliveries.

Pessimistic (High Need) Scenario

#		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
13	**Compliance Period Requirement**		20.0%			23.3%			30.0%			33%	33%
14	**Compliance Period RPS Position (%)**		20.4%			27.1%			25.7%			23.0%	19.9%
15	**Annual RPS Position (%)**	19.4%	[redacted]				28.4%	28.4%	26.0%	24.9%	23.7%	23.0%	19.9%
16	**Surplus/(Deficit) compared to Annual Targets* (GWh)**	(486)	[redacted]				2,597	1,063	(2,363)	(4,785)	(7,373)	(8,023)	(10,586)
17	**Surplus/(Deficit) compared to Compliance Period Requirement (GWh)**	[redacted]							(13,458)			(8,023)	(10,586)
18	**Surplus Procurement ("Bank")**												
19	**Volumes (Banked) or Withdrawn from Bank**	[redacted]							9,575			0	0
20	**Revised Surplus/(Deficit)**								(3,883)			(8,023)	(10,586)
21	**Revised Compliance Period RPS Positions (%) with Use of Bank**								28.8%			23.0%	19.9%
22	**Cumulative Banked Volumes (GWh)**					9,575			0			0	0

For purposes of creating a range around the Current Expected Need Scenario, and as detailed in Section 6.3, the Pessimistic Scenario applies a failure rate of 32% to expected deliveries from projects that are not yet operational. In this scenario volumes from Closely Watched projects are also modeled at 78% of contract quantities (as opposed to 0% of contract quantities in the Current Expected Need Scenario), as the long-term failure rate calculation is applied to the entire portfolio.

Optimistic (Low Need) Scenario

#		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
26	**Compliance Period Requirement**		20.0%			23.3%			30.0%			33%	33%
27	**Compliance Period RPS Position (%)**		21.0%			30.1%			29.7%			26.9%	23.8%
28	**Annual RPS Position (%)**	19.4%	[redacted]				32.0%	32.4%	30.0%	28.9%	27.7%	26.9%	23.8%
29	**Surplus/(Deficit) compared to Annual Targets* (GWh)**	(486)	[redacted]				5,415	4,172	799	(1,631)	(4,221)	(4,885)	(7,459)
30	**Surplus/(Deficit) compared to Compliance Period Requirement (GWh)**	[redacted]							(881)			(4,885)	(7,459)
31	**Surplus Procurement ("Bank")**												
32	**Volumes (Banked) or Withdrawn from Bank**	[redacted]							881			4,885	7,459
33	**Revised Surplus/(Deficit)**								0			0	0
34	**Revised Compliance Period RPS Positions (%) with Use of Bank**								30.0%			33.0%	33.0%
35	**Cumulative Banked Volumes (GWh)**					17,844			16,963			12,078	4,619

For purposes of creating a range around the Current Expected Need Scenario, and as detailed in Section 6.3, the Optimistic Scenario applies a failure rate of 12% to expected deliveries from projects that are not yet operational. In this scenario volumes from Closely Watched projects are also modeled at 88% of contract quantities (as opposed to 0% of contract quantities in the Current Expected Need Scenario), as the long-term failure rate calculation is applied to the entire portfolio.

**** Assumed annual targets are: 2011-2012 (20% annually), 2014 (21.7%), 2015 (23.3%), 2016 (25%), 2017 (27%), 2018 (29%), 2019 (31%), and 2020 (33%). These targets are illustrative only and not enforceable.***

APPENDIX 2

2012 RPS Procurement Information Related to Cost Quantification

Confidentiality Protected Under D.06-06-066 Appendix 1
Item VII F and G Renewable Resource Contracts under RPS program –
Contracts with Supplemental Energy Payments (SEPs) and Contracts without SEPs.

Appendix 2: 2012 RPS Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 1
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs								
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2	Biogas	$25,762	$23,856	$25,623	$22,823	$24,126	$23,379	$23,769	$18,079	$15,390
3	Biomass	$215,078	$217,923	$217,279	$222,125	$238,524	$259,957	$262,086	$263,994	$246,535
4	Geothermal	$110,572	$111,778	$108,720	$118,523	$199,143	$282,227	$200,357	$260,053	$240,510
5	Small Hydro	$50,609	$45,442	$78,618	$88,033	$52,827	$61,144	$43,289	$55,600	$81,951
6	Solar PV	$0.358	$0.270	$0.310	$0.205	$0.051	$0.051	$2,554	$10,180	$33,365
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Wind	$65,244	$74,912	$66,061	$67,116	$98,203	$102,516	$199,475	$224,089	$340,673
9	UOG Small Hydro	$44,936	$45,059	$46,526	$47,556	$47,933	$49,009	$47,567	$49,684	$52,099
10	UOG Solar	$0	$0	$0	$0	$227	$452	$473	$1,520	$6,506
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$512,201**	**$518,970**	**$542,827**	**$566,176**	**$660,983**	**$778,683**	**$779,570**	**$883,199**	**$1,017,030**
13	Bundled Retail Sales [Thousands of kWh]	71,099,363	72,113,608	72,371,532	76,356,279	79,078,319	81,523,859	79,624,479	77,485,129	74,863,941
14	**Incremental Rate Impact***	**0.72 ¢/kWh**	**0.72 ¢/kWh**	**0.75 ¢/kWh**	**0.74 ¢/kWh**	**0.84 ¢/kWh**	**0.96 ¢/kWh**	**0.98 ¢/kWh**	**1.14 ¢/kWh**	**1.36 ¢/kWh**

* Incremental Rate Impact is equal to Row 12 divided by Row 13. While the item is labeled “Incremental Rate Impact”, the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable “premium”. In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row. For example, the cost of an unbundled REC procured from a wind facility is only reported in the Unbundled RECs row.

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs								
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Biomass	[redacted]	[redacted]	[redacted]	$0	$0	$0	$0	$0	$0
4	Geothermal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	[redacted]	[redacted]	[redacted]	[redacted]	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Bundled Retail Sales [Thousands of kWh]	[redacted]	[redacted]	[redacted]	[redacted]	77,356,033	77,774,983	78,247,068	78,703,900	79,423,331
14	**Incremental Rate Impact[2]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	Biomass	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Geothermal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Small Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Solar PV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Solar Thermal	$0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	UOG Small Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	UOG Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	Bundled Retail Sales [Thousands of kWh]	[redacted]	[redacted]	[redacted]	[redacted]	77,356,033	77,774,983	78,247,068	78,703,900	79,423,331
28	**Incremental Rate Impact***	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

2 Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact", the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium". In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

APPENDIX 3

Other Modeling Assumptions Incorporated In Quantitative Information

Appendix 3: Other Modeling Assumptions Informing Quantitative Calculation

	Assumptions
Bottoms-Up Delivery Assumptions (Signed Contracts) *Excluding RAM and PV program*	• Except for the "Closely Watched" contract category (see Section 5.1), all signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract.
Operational Projects *Contracts Executed Post-2002*	• Forecast is based on contract volumes or three year historical average output (for projects with at least a full calendar year of deliveries if more than 12 months of actual delivery data is available). • Year 2012 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
Baseline Non-Hydro *Pre-2002, QF Contracts*	• PG&E forecasts non-hydro QF projects at 95% of their 3-year average output (2008 – 2010), with the slight reduction based on the observation that, for a variety of reasons, these older resources (as a portfolio) have tended to under-deliver when compared to their average historical performance. • Year 2012 deliveries: Recorded meter data (as available) replaces forecasted deliveries for all projects.
Baseline Small Hydro *Pre-2002 QF, Irrigation District, and legacy utility-owned assets*	• Projects are forecast at 75% of normal for 2012 (based on PG&E's latest internal hydro delivery forecast), and 100% of normal for future years. • Year 2012 deliveries: Recorded deliveries are used in place of forecasts as they become available.

<table>
<tr><td>Re-contracting</td><td>For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained:
PG&E does not yet have contractual commitments for these expiring volumes;
A number of the expiring contracts are with aging generating facilities with limited remaining useful life;
Contract-renewal bids may not be competitive with offers for new projects received in the current or future solicitations; and
Assuming re-contracted volumes obscures PG&E’s current real need for additional energy in later years.
Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources.
This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E’s semi-annual RPS compliance filing that only shows PG&E’s current contractual commitments.</td></tr>
<tr><td>Shortlisted Projects

From 2011 Solicitation or Bilateral Offer</td><td>No shortlisted projects are included in PG&E’s forecast.
Only executed contracts, or generic deliveries from pre-approved procurement programs (i.e., PV Program, RAM, and Feed-In Tariffs) are included in PG&E’s forecast.</td></tr>
</table>

Future Volumes from Pre-Approved Programs	**Feed-in Tariffs (AB 1969 and SB 32)** • All deliveries from executed contracts are assumed at 100% of contract volumes. • Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date. • SB 32 Program starts September 1st, 2012; contracts will be executed at the same pace from September 1st, 2012 until September 1st, 2013. • SB 32 projects will come online 30 months after execution. First volumes appear March 1st, 2015 and will ramp up until March 1st, 2016. • Total capacity procured for SB 32 projects is ~112 MW, and portfolio mix (capacity factor) will be 33% Non-Peaking As-Available (25%), 33% Peaking As-Available (25%), and 33% Baseload (85%).
	Renewable Auction Mechanism (RAM) • Assume full program subscription (420.9 MW), and a projected technology mix of 20% baseload/non-peaking and 80% as-available product. • Assume first deliveries begin 24 months after contract execution for new projects (6 month regulatory approval, 18 month project development). Commission Resolution issued on April 19, 2012 allows for additional project delay provisions. PG&E will incorporate these new provisions to future iterations of its forecasting model. • Generic delivery assumptions (including technology, term, generation profile, and initial deliveries) are adjusted upon actual contract execution.
	Solar PV Program (PPA) • Assume that deliveries from Project Years (PY) 2-5 are consistent with those of PY 1 (~105 GWh/year), and that projects come online consistent with PY1 COD. • All deliveries from PY 1-5 are assumed at 100% of contract volumes. **Solar PV Program (UOG)** • For planning purposes, assume annual installation of 50 MW, and that PY 3-5 projects begin deliveries in Q3 of respective year.

Compliance Period and Reasonable Progress Target Assumptions	As implemented by D.11-12-020, retail sellers of electricity are required to procure the following quantities between 2011 and 2020: • Twenty percent of the combined bundled retail sales during the first compliance period (2011-2013). • A percent of the combined bundled retail sales during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales). • A percent of the combined bundled retail sales during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
Bundled Retail Sales	• Forecasts of 2011-2020 retail sales are generated by PG&E, and may be updated throughout the year as additional data becomes available. • Current forecast reflects impact of load-migration from DA/CCA. • The same retail sales forecast is used in the semi-annual RPS Compliance Reports, LTPP and ERRA filings, and advice letter filings. • Monthly recorded sales replace forecasts as current year (e.g., 2012) progresses.
Banking	• PG&E assumes that (1) Category 3 products that do not exceed applicable portfolio content limits are not deducted from bankable volumes, (2) grandfathered (pre-June 1, 2010) short-term products are bankable, and (3) that volumes banked before December 31, 2020 may be applied in any post-2020 period. • A Proposed Decision (PD) governing the accounting for the banking of excess volumes across compliance periods was issued on April 24, 2012. PG&E's accounting is consistent with the direction set forth in the PD. PG&E's forecast will be revised to the extent that the rules set forth in the final Decision differ from the assumptions described here.

APPENDIX 4

Status Update on All RPS Resources Under Contract but Not Yet Delivering Generation

Confidentiality Protected Under D.06-06-066 Appendix 1
Item VII F and G Renewable Resource Contracts under RPS program –
Contracts with Supplemental Energy Payments (SEPs) and Contracts without SEPs.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
2	IOU ID	Project Name	Primary Developer	Technology Type	Contract Capacity (MW)	Expected Energy (GWh)	Energy Delivery Status	Vintage	CPUC Approval Status	Financing Status	Permit Status	Guaranteed Construction Start Date	Expected or Actual Construction Start Date	Construction Status	Status of Interconnection Agreement	Guaranteed COD	Expected or Actual COD
3	33R084	Agua Caliente Solar Project	NRG Energy, Inc.	Solar Photovoltaic - Ground mount	290	688	Delivering	New	CPUC Approved	[redacted]	Complete	[redacted]	8/8/2011	[redacted]	Signed	3/2/2015	[redacted]
4	33R118	Alpaugh 50	GCL Solar Energy, Inc.	Solar Photovoltaic - Ground mount	50	83	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	2/1/2013	[redacted]
5	33R119	Alpaugh North	GCL Solar Energy, Inc.	Solar Photovoltaic - Ground mount	20	33	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	11/1/2012	[redacted]
6	33R078	Alpine Solar Project	NRG Energy, Inc.	Solar Photovoltaic - Ground mount	66	140	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	9/27/2012	[redacted]
7	33R120	Atwell Island	ENCO / Samsung	Solar Photovoltaic - Ground mount	20	33	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	8/23/2012	[redacted]
8	33R073	AV Solar Ranch One	Exelon	Solar Photovoltaic - Ground mount	230	592	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	1/9/2015	[redacted]
9	33R136	Blackspring Ridge IA	Greengate Power Corp.	Wind	150	445	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	[redacted]	6/24/2014	[redacted]
10	33R137	Blackspring Ridge IB	Greengate Power Corp.	Wind	150	445	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	[redacted]	6/24/2014	[redacted]
11	[redacted]																
12	33R068	BrightSource VI	BrightSource	Solar Thermal	200	573	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	12/1/2016	[redacted]
13	33R069	BrightSource VII	BrightSource	Solar Thermal	200	573	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7/1/2017	[redacted]
14	33R166	Copper Mountain Solar 2	Sempra U.S. Gas & Power	Solar Photovoltaic - Ground mount	150	303	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	[redacted]	7/15/2015	[redacted]
15	33R121	Corcoran	GCL Solar Energy, Inc.	Solar Photovoltaic - Ground mount	20	33	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	6/15/2013	[redacted]
16	33R138	Desert Center Solar Farm	NextEra Energy Resources, LLC	Solar Photovoltaic - Ground mount	300	619	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Signed	9/9/2015	[redacted]
17	33R099	DTE Stockton	DTE Energy Services, Inc.	Biomass	45	328	[redacted]	Re-start	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	[redacted]	6/30/2013	[redacted]
18	33R162	FRV Orion Solar	FRV Orion Solar II, L.P.	Solar Photovoltaic - Ground mount	12	28	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10/4/2013	[redacted]
19	33R090	Genesis Solar Energy Project	NextEra Energy Resources, LLC	Solar Thermal	250	524	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	11/30/2014	[redacted]
20	33R031	GV1	GreenVolts, Inc.	Solar Photovoltaic - Ground mount	2	5	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/31/2011	[redacted]
21	33R135	Halkirk I Wind Project	Capital Power L.P.	Wind	150	484	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	8/24/2012	[redacted]
22	33R126	Hay Canyon Wind (Barclays)	Barclays Bank PLC	Wind	100	250	Delivering	Existing	Pending approval	[redacted]	Complete	[redacted]	N/A	Complete	Signed	10/1/2010	10/1/2010
23	33R065	Hidden Hills Ranch Unit 1	BrightSource	Solar Thermal	200	573	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7/1/2014	[redacted]
24	33R066	Hidden Hills Ranch Unit 2	BrightSource	Solar Thermal	200	573	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7/1/2015	[redacted]
25	33R052	High Plains Ranch II	NRG Energy, Inc.	Solar Photovoltaic - Ground mount	210	550	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/26/2013	[redacted]
26	33R088	High Plains Ranch III	NRG Energy, Inc.	Solar Photovoltaic - Ground mount	40	112	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/31/2012	[redacted]
27	33R063	Ivanpah Unit 1	NRG Energy, Inc.	Solar Thermal	118	304	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	7/1/2013	[redacted]
28	33R064	Ivanpah Unit 3	NRG Energy, Inc.	Solar Thermal	130	336	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/31/2013	[redacted]
29	33R147	Kiara Anderson Plant	Kiara Solar, Inc.	Biomass	6.8	50	[redacted]	Re-power	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/31/2011	[redacted]
30	33R021	Liberty V Biofuels Power	Liberty V Biofuels Power, LLC	Biomass	5	35	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	[redacted]	12/31/2009	[redacted]
31	33R243	Mammoth G3 (Ormat)	Ormat Nevada Inc.	Geothermal	14	99	Delivering	Existing	CPUC Approved	[redacted]	Complete	[redacted]	N/A	Complete	[redacted]	11/1/2013	[redacted]
32	33R144	Mesquite Solar 1	Sempra U.S. Gas & Power	Solar Photovoltaic - Ground mount	150	305	Delivering	New	CPUC Approved	[redacted]	Complete	[redacted]	5/16/2011	[redacted]	Signed	7/18/2014	[redacted]
33	33R089-AR	Mojave Solar Project	Abengoa Solar	Solar Thermal	250	617	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	11/21/2014	[redacted]
34	33R134	Nine Canyon Wind (Barclays)	Barclays Bank PLC	Wind	14	33	Delivering	Existing	Pending approval	[redacted]	Complete	[redacted]	N/A	Complete	Signed	10/1/2010	10/1/2010
35	33R163	North Sky River Energy Center	NextEra Energy Resources, LLC	Wind	163.2	497	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/31/2012	[redacted]
36	33R148	North Star Solar 1	NorthLight Power, LLC	Solar Photovoltaic - Ground mount	60	136	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6/30/2013	[redacted]
37	33R133	Potrero Hills Landfill	DTE Biomass Energy	Biogas Generation	8	56	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6/15/2015	[redacted]
38	33R160	Recurrent Kansas South	Recurrent Energy LLC	Solar Photovoltaic - Ground mount	20	48	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2/19/2013	[redacted]
39	33R097-AR	Rice Solar Energy Amended and Restated	SolarReserve	Solar Thermal	150	449	[redacted]	New	Approved - Amendment Pending Approval	[redacted]	Complete	[redacted]	[redacted]	[redacted]	[redacted]	12/1/2015	[redacted]
40	33R067	Sandy Valley SEGS	BrightSource	Solar Thermal	200	573	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7/1/2015	[redacted]
41	33R167	Shiloh IV	enXco, Inc	Wind	100	269	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	12/31/2012	[redacted]
42	33R091	Sierra Pacific Industries REC PSA	Sierra Pacific Industries	Biomass	0	100	Delivering	Existing	Pending approval	[redacted]	Complete	[redacted]	N/A	Complete	Signed	N/A	[redacted]
43	33R062	Solaren	Solaren Corporation	Space Solar	200	1700	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6/1/2016	[redacted]
44	33R132	Sunshine Landfill	DTE Biomass Energy	Biogas Generation	20	140	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Signed	12/15/2014	[redacted]
45	33R056	Topaz Solar Farm	Mid-American Energy	Solar Photovoltaic - Ground mount	550	1066	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	8/18/2015	[redacted]
46	33R087	Transalta REC	TransAlta Corporation	Wind	0	175	[redacted]	New	Pending approval	[redacted]	Complete	[redacted]	[redacted]	Complete	Signed	9/27/2010	[redacted]
47	33R244	West Antelope (TUUSSO)	TUUSSO Energy, LLC	Solar Photovoltaic - Ground mount	20	53	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	11/1/2013	[redacted]
48	33R245	Western Antelope Blue Sky Ranch A (Silverado)	Silverado Power	Solar Photovoltaic - Ground mount	20	48	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	11/1/2013	[redacted]
49	33R161	Westlands Solar Farms PV1	Westlands Solar Farms LLC	Solar Photovoltaic - Ground mount	18	36	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8/19/2013	[redacted]
50	33R122	White River	GCL Solar Energy, Inc.	Solar Photovoltaic - Ground mount	20	33	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Signed	4/1/2013	[redacted]
51	33R246	Wind Resource 1 (CalWind)	Calwind Resources, Inc.	Wind	8.71	15	Delivering	Existing	CPUC Approved	[redacted]	Complete	[redacted]	N/A	Complete	[redacted]	11/1/2013	[redacted]

APPENDIX 5

Changes in the 2012 RPS PPA Compared to the Form RPS PPA Filed With the CPUC on May 11, 2011

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
Global		Removed all terms and instructions applicable to Short Term Offers.	Per the 2012 RPS Plan, PG&E is no longer seeking offers under ten years.
Global		Removed "but not limited to" after the word "including."	The rule of interpretation in 2.2(h) explained that "including" shall not be considered a limitation.
See the following Sections: 3.3 (Resource Adequacy), 3.4[(b)] [(c)] (iii) (B) (Monthly Forecast of Availability), and 3.7(b) (Planned Outages).		All provisions requiring the Seller to give Buyer outage notice or availability of the generating facility have been modified to require that the notice be provided by the earlier of 90 days before the first day of the month of the applicable event or 30 days before Buyer's monthly Resource Adequacy showing in accordance with the CAISO Tariff or CPUC decision. Previously the language only referred to 90 days before the applicable event.	These modifications help ensure that PG&E receives sufficient notice of project outages so that PG&E is better positioned to claim the RA benefit from the projects and to avoid being subject to availability penalties if the RA notification time rules change.
Global		References to imbalance or imbalance charge changed to "Imbalance Energy."	The term "Imbalance Energy" more accurately captures the costs that PG&E, acting as Scheduling Coordinator, will incur if the amount of Energy scheduled to the CAISO differs from the amounts actually delivered onto the CAISO.
1.42 and 1.43	Definition of "Commercial Operation Date"	Adds requirement that Seller provide a copy of the Full Capacity Deliverability Study Finding as a requirement for the Commercial Operation Date.	The new language better reflects the CAISO Tariff requirements applicable to Electric System, which includes Network Upgrades, and supplements Section 3.4(a) (i) (A), which requires that the Project obtain and maintain Full Capacity Deliverability Status throughout the delivery term.

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
1.57	Definition of "Curtailment Order"	Subsection (iii) adds "any warning, forecast or anticipated overgeneration" to the list of CAISO orders that will qualify as a Curtailment Order.	The CAISO may direct, order, or notify PG&E, as Scheduling Coordinator, to curtail generating facilities within PG&E's control in anticipation of overgeneration on the transmission system rather than waiting until the overgeneration actually occurs.
1.107	Definition of "Force Majeure"	Adds defined terms "Permitting Delay" and "Transmission Delay" to exclusions from Force Majeure.	These changes supplement Section 3.9(c) (iii) (A) and (B), which distinguishes Transmission Delay, Permitting Delay, and Force Majeure.
1.118, 1.119	Definition of "Generator Interconnection Agreement" and "Generator Interconnection Process"	Replaces "LGIA," "LGIP," "SGIA," and "SGIP."	This provision has been updated to conform to current CAISO tariff.
3.1(e)(ii)[(B)][(C)](I) [applicable to an As-Available Product]	Guaranteed Energy Production cure provision	Added language to clarify that if Seller has paid liquidated damages or met the 90% generation production requirement to cure a GEP Failure, then the Contract Year to which the remedy applies would be valued as having the greater of 80% of Contract Quantity or the actual Delivered Energy amount when calculating the next following rolling two Contract Year Performance Measurement Period.	Clarification to alleviate concerns expressed by a number of developers that the language did not sufficiently reflect the benefit of the remedy provided by the GEP Cure.
3.1(e)(ii)[(B)][(C)](III) [applicable to an As-Available Product]	Guaranteed Energy Production cure provision	Added "Cure Payment Period" definition to clarify timing for payment of the GEP Cure.	Clarification to the timing of the GEP Cure and consequences of failing to make timely payment.
3.1(f)(ii) [Baseload only]	Contract Capacity/Declared Contract Capacity/Net Rated Output	Added a phrase to clarify that Capacity Test used to determine the Net Rated Output Capacity of a Project may only be conducted one time per Contract Year.	Clarification to timing and use of Capacity Test.

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
3.1(h)(i)	Interconnection Facilities. Seller Obligations	Deleted language that states that Electric System Upgrades must be for the Contract Capacity "during the times at which such delivery is anticipated under the Agreement."	Makes the Electric System Upgrade obligations more consistent with the CAISO's Reliability Network Upgrade and Delivery Network Upgrade requirements.
Old Section 3.1(h)(ii) [Old Section 3.1(h)(iii) renumbered to new 3.1(h)(ii)]	Limited Operation	Removed the provision entirely.	Given PG&E's compliance position, PG&E does not anticipate needing to require a generator to begin deliveries without the necessary Electric System Upgrades or Interconnection Facilities in place.
3.1(i)(ii)	Performance Excuses. Buyer Excuses	Added language stating that Buyer is only excused from receiving Product during a Buyer Curtailment Period.	Clarifies that Buyer is still obligated to pay for the Deemed Delivered Energy so long as Seller complies with the Buyer Curtailment Order.
3.1(j)	Greenhouse Gas Emissions Reporting	Reiterates that Buyer is not responsible for Seller's emissions compliance obligations.	In light of AB32 and other emissions reductions programs, PG&E would like to confirm that the GHG reporting requirements in the Agreement are completely separate from Sellers' obligation to comply with all Laws, rules, and regulations to which Seller or the Project is subject.
3.1(l)(ii)	Access to Data and Installation and Maintenance of Weather Station	Modifies use of publicly available information, when Seller data is not provided. Buyer will use the information for scheduling, not settlement purposes.	Corrects an error in the form.
3.1(l)(iv)(D) [As-Available only]	Installation, Maintenance and Repair	Modifies the examples of alternate form of communication that may be used while Seller's telecommunications system is down and allows for other methods that are mutually agreeable.	Provides more flexibility to PG&E and Sellers in order to provide data necessary for accurate forecasting in the event that Seller's telecommunications system is not functioning.

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
3.1(m) Removed old Section 3.1(m)(ii)	Prevailing Wage	Removed obsolete reference to Section 399.14(h) of the CPUC Code regarding the Seller's obligation to pay prevailing wages	The CPUC Code provisions no longer exist and were not replaced with a successor provision.
3.7(b)	Planned Outages	Notice of Planned Outages to be provided by July instead of August of the prior year. Also requires that updates to the Planned Outage schedule must be provided within two (2) Business Days of the CAISO deadline for Planned Outages, if the date is later than 14 days prior to the outage, as previously required in the Agreement.	Change to allow sufficient time for PG&E to include planned outages in year-ahead RA showing
3.9(c)(iii)(B)(I) and (II)	Guaranteed Project Milestones	Provides Seller with a six month delay in meeting either Guaranteed Project Milestone, if the Electric System Upgrades cannot be completed by the Guaranteed Commercial Operation Date for reasons that are not due to Force Majeure, not caused by Seller and Seller works diligently to resolve. Similar modifications have been made to the Permitting Delay provision regarding the cause of delay and exclusion from Force Majeure.	PG&E recognizes that even though Seller may be able to enter into an Interconnection Agreement with a PTO and the CAISO, limited delays may arise after construction start that prevents the timely completion of the necessary upgrades or interconnection. PG&E believes that it is reasonable to provide a limited delay without the payment of liquidated damages. PG&E seeks to provide generators with some latitude with respect to Permitting and Transmission Delays and to distinguish clearly between those delays and Force Majeure events.
3.9(c)(iii)(B)(III)	Guaranteed Project Milestones	Adds a prohibition on Seller declaring a Force Majeure Event for any event that may have qualified as a Transmission Delay or Permitting Delay.	Complements the new language provided in Transmission Delay and Permitting Delay as explained above.

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
4.1(b)(iii)	Deemed Delivered Energy Price	Modification of note allowing Seller to indicate additional Buyer Curtailment Period hours and the Contract Price applicable to such hours.	To provide Seller the opportunity to specify an acceptable number of hours in incremental blocks of 250 hours with incremental pricing
Old Section [4.3[[4.4]	TOD Factors and Monthly TOD Payment	Removed "rounded" factors from table of TOD Factors.	This was an error in the 2011 Form.
4.4(c) [Baseload Only]	TOD Factors, Monthly TOD Payments, and Annual TOD Payment Adjustment	Added a provision to limit the total amount that PG&E pays Baseload generators per Contract Year to 105%. If PG&E has paid more than 105% due to TOD factor adjustments, then the Seller will need to reimburse PG&E for such excess payment.	Because our valuation is dependent on the generation profile, this section was revised to hold generators to a profile that closely matches the profile on which the decision to execute the transaction was made.
4.4 [As Available Only]	Excess Delivered and Deemed Delivered Energy	Added language to clarify timing for payment or netting of payment owed by Seller to PG&E in the event that the Seller produces more than 120% of the Contract Quantity in a Contract Year.	Clarifies timing of payment obligations and PG&E's right to net payment if Seller fails to make timely payment.
4.5(b)	CAISO Charges	Clarifies that Buyer's obligation to pay for CAISO costs and charges and Imbalance Energy is only in Buyer's capacity as Scheduling Coordinator and is "subject to," not excepted from, Seller's obligations in Section 4.5(a) and the Forecasting Penalty provision in Section 4.5(c).	Revised to more accurately reflect PG&E's intent.
4.5(c)(ii) [Baseload Only]	Payment Calculation for As-Available Forecasting Penalty	Added reference to TOD Factor.	Clarification that forecasting penalties are based on TOD-adjusted contract price.

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
Definitions: "1.89 Eligible LC Bank," "1.147 Letter of Credit," 1.151 "Maximum Issuing Amount," "1.227 Transfer." and Section 8.5	Letter of Credit	PG&E now limits the amount of any particular letter of credit to the lesser of 60% of the amount of total collateral to be posted or twenty-five million dollars ($25,000,000.00) and alerts Sellers that if the Letter of Credit is going to be issued by a U.S. branch of a foreign commercial bank, PG&E may require additional changes to the form of Letter of Credit. PG&E has also modified the credit rating requirement from A/A2 to A-/A3	PG&E has revised the definition for Letter of Credit to better address PG&E's need to limit ongoing credit exposure to counterparties and banks and to avoid concentration of credit from these parties, on a portfolio basis. PG&E has also lowered the issuing bank's credit rating requirement to A-/A3. This is consistent with Southern California Edison and SDG&E's approach in their RPS solicitation power purchase agreements.
10.10	Insurance	In Section 10.10(i)(iii), PG&E has updated the contact information for Exigis, which is the third party vendor that PG&E uses to record and monitor insurance documents. PG&E removed a redundant reference to coverage for hazardous materials found in Section 10.10(b)(iii).	The change to Exigis was an administrative update. The change to the hazardous material provision corrected a duplicative requirement.
New Section 10.15 [Old Section 10.15 "Counterparts" renumbered to 10.16]	Mobile Sierra	Moved language from the "General" provision to its own section. Changed standard of review at FERC from "just and reasonable" to "public interest."	Consistent with the standard of review included in RAM and the PG&E's PV PPA forms of agreement.
Removed Old Section 10.16	Discussion Concerning Buyer Purchase of Project	Removed the provision in its entirety	Consistent with PG&E's 2012 RPS Plan, PG&E is not actively seeking ownership opportunities at this time.

APPENDIX 5: Changes in the 2012 RPS PPA Compared to Form RPS PPA Filed with CPUC on May 11, 2011

PPA Section	Description of Section	Change	Purpose of Change
Removed Old Section 11.1	Termination Events Related to [Production Tax Credits][Energy Investment Tax Credits]	The provision has been removed in its entirety.	Based on current federal legislation both tax credits will have lapsed by 2019, which is the preferred date by which PG&E seeks to begin purchasing renewable energy from projects bidding into the next RPS solicitation.
Appendix VIII	Notification Requirements for Available Capacity and Prolonged Outages	Updated notification instructions for PG&E website and fixed formatting and errors	This is an administrative update.
Appendix XVI	Buyer Curtailment Orders	Modified operational requirements for Buyer Curtailment Orders for both As-Available and Baseload Products	Operating characteristics that must be considered when calling a Buyer Curtailment are now linked to the operational considerations used by the CAISO for dispatch.