

Attachment K - Detailed Least Cost Best Fit Evaluation Criteria

Template: IOU Written Description of RPS Bid Evaluation and Selection Process and Criteria (“LCBF Written Report”)

I. Introduction

A. Note relevant language in statute and CPUC decisions approving LCBF process and requiring LCBF Reports.

Response

Decision D.03-06-071 and D.04-07-029 adopted criteria for the rank ordering and selection of least cost, best fit renewable resources for use in RPS solicitations. Furthermore, D.05-07-039 directed the IOUs to make their bid evaluation process transparent to their Procurement Review Groups and the CPUC.

In addition, D.06-05-039 required “each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility’s evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected.”

D.06-05-039 also required each IOU to hire an independent evaluator (IE) “to separately evaluate and report on the IOU’s entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The Independent Evaluator’s preliminary report should be provided with the IOU’s short list, and a final report with the AL for approval of selected bids.”

The Scoping Memo for R.06-05-027, issued August 21, 2006, required that the IOUs submit their first written report describing their bid evaluation criteria and selection process on September 29, 2006, and that IOUs resubmit the report with their short lists (including more information, such as bid analysis, as necessary). Additionally, in the RPS Transparency Workshop held on December 15, 2006, the CPUC’s Energy Division staff proposed, pursuant to D.06-05-039, a template to be used for future evaluation criteria and selection reports (“LCBF Written Report”).

D.06-05-039 further required that each IOU include certain elements, subject to confidential treatment of protected information, in each report. These elements include bid-specific price information, the evaluation and scoring of each bid, and the decision rationale with respect to each bid, both selected and rejected.

B. Goals of bid evaluation and selection criteria and processes

Response

The goal of the bid evaluation, selection criteria, and selection processes is to produce a short list of offers for negotiations which ultimately result in energy procurement of 1-2% of PG&E's load.

II. Bid Evaluation and Selection Criteria

A. Description of Criteria

1. List and discuss the quantitative and qualitative criteria used to evaluate and select bids. This section should include a full discussion of the following:

- a. Market valuation (i.e. price)
 - include treatment of integration costs
 - include treatment of dispatchability/curtailability benefits
 - exclude treatment of transmission cost adders (discussed below)
- b. Portfolio fit
- c. Credit and collateral requirements
- d. Project Viability
 - Project status
 - Transmission availability
 - Technology viability
 - Developer experience
- e. Transmission Cost Adders
 - Discuss how much detailed transmission cost information the IOU requires for each project
 - Discuss whether cost adders are always imputed for projects in transmission-constrained areas, or whether and how costs for alternative commercial transactions (ie. swapping, remarketing) are substituted.
- f. Impact of quantitative and qualitative factors on the LCBF ranking process

Response

The selection methodology is based upon the mathematics of a strict partial ordering. This is a mathematically rigorous, unbiased ranking approach which makes minimal *a priori* assumptions about the data. It is explained further below. The inputs to the partial ordering are the results of the different offer attributes: market value, portfolio fit, credit and finance, project status, technology viability and participant experience, RPS goals, and transmission adder.

The final shortlist will yield the offers that can provide the "least cost-best fit" renewable energy for PG&E's customers.

Evaluation Using Partial Ordering

Overview

PG&E will use the mathematical concept of a strict partial ordering to determine quantitatively which offers are better than others. One of the basic assumptions in this method is that attributes are not to be weighted in any way to produce a single numerical score. The best offers will be shortlisted and pursued for negotiations. (Ineligible offers are not considered in the Partial Ordering.)

Evaluation Methodology

PG&E will obtain numerical values for the following attributes:

1. Market Valuation, excluding Transmission Adder (in \$/MWh)
2. Portfolio Fit (score of 1, 2, 3, 4, or 5)
3. Credit (score of 1, 2, 3, 4, or 5)
4. Project Viability (score of 1, 2, 3, 4, or 5)
5. RPS Goals (score of 1, 2, 3, 4, or 5)
6. Transmission Adder (in \$/MWh)

In each case, except Transmission Adder, a larger (more positive) number is to be considered better—all else being equal—than a smaller (less positive) number.

PG&E will apply the Partial Ordering method in the following order:

1. The Market Valuation will be computed for each Offer. Similarly, the Portfolio Fit will be calculated for each Offer. Then, each of the scores for Credit, Project Viability, and RPS Goals will be assessed and collected.
2. The values and scores for the attributes above will be used to construct a Strict Partial Ordering among the offers. In a Strict Partial Ordering, certain offers will “dominate” other offers (see below) when the dominating offer is better in at least one attribute, but is not worse in any attribute. The offers will then be separated by transmission cluster.
3. Next, the Transmission Adder is introduced. The Transmission Adder is added at this stage because the resulting ranking prior to this step determines the allocation of existing transmission and any costs associated with transmission upgrades based on the Transmission Ranking Cost Report (TRCR). Alternatively, if an alternative commercial arrangement has a lower cost than the value from the TRCR, then that value is used instead. Ultimately the lower of the two values is applied to the Market Valuation result from before.
4. The values and scores for the attributes above, with Market Valuation being

adjusted for the Transmission Adder, will be used to construct a Strict Partial Ordering among the offers. In a Strict Partial Ordering, certain offers will “dominate” other offers (see below) when the dominating offer is better in at least one attribute, but is not worse in any attribute.

5. Offers will be grouped into three categories: Superior, Inferior, and Indeterminate. The concept of dominance will be used to ensure a level of consistency in this classification. No Inferior Offer may dominate any Indeterminate or Superior Offers, and No Indeterminate Offer may dominate any Superior Offers. Superior Offers will be strongly considered for inclusion on the shortlist. Indeterminate Offers will be further reviewed to determine which offers belong on the shortlist and which do not.

Strict Partial Ordering

Measurement Error

If two offers are very close in a particular attribute, it may not be reasonable to consider the one that is slightly better as being significantly better. Some sort of tolerance will be used to account for attribute values that are very close. PG&E has established a nonnegative *tolerance* value for each applicable attribute.

Dominance Relationship Shows Preferences

One offer may be preferable over another offer when considering one attribute, but the situation may reverse itself if a different attribute is considered. This means that these two offers are not well-ordered and one cannot—on the basis of the attribute scores alone—determine which offer is the best ultimate choice for PG&E and its customers. Despite there being situations where no clear preference exists between two given offers, there is typically enough information in the attribute values to cull out the offers that are not in the top tier.

The Strict Partial Ordering concept avoids making any arbitrary assumptions about the relative importance of two separate attributes.

Market Valuation

Overview

Market valuation considers how an offer’s costs compares to its benefits, from a market perspective. Costs include fixed and variable components representing all anticipated significant relevant costs, including Transmission and Integration cost adders and debt equivalency. Benefits include energy, capacity, and ancillary services. Costs and Benefits are each quantified and expressed in terms of present value (January 1, 2007

dollars) per MWh. Market Value is Benefits minus Costs. Offers are classified into three types: 1) forwards; 2) dispatchables; and 3) buyout options. How benefits and costs are calculated varies for each of the three types of offers.

Only the offer type affects how the offer is valued and not whether an offer is for a power purchase agreement (PPA) or purchase and sales agreement (PSA). Buyout options are a distinct type. The forward type includes Baseload product, Peaking product, As-Available product, product Combination I (Peaking plus As-Available) and product Combination II (Peaking plus firm products). Offers of “sites for development” are not discussed here.

Market Value

Market Value is Benefits minus Costs, and is expressed in terms of present value per MWh (2007 dollars and 2007 MWh). For each offer type, below is a description of how Benefits, Costs, and Market Value are calculated.

Forwards

Benefits include energy, capacity, and ancillary services. Benefits are measured in units of present value per MWh (2007 dollars and 2007 MWh).

Energy benefit, for each hour of delivery, is quantity of energy delivery for each hour times the forward energy price for that hour. For Peaking and Baseload products, the quantity of energy delivery for each hour is determined by the performance requirements of the offer. For As-Available products, the quantity of energy delivery for each hour is determined by the hourly generation profile of the offer. Combination products will be considered accordingly. For each calendar year, hourly energy benefit is summed across hours of delivery. Annual energy benefit is then discounted to units of present value per MWh (2007 dollars and 2007 MWh), and summed across years.

Capacity benefit, for year of availability, is quantity of qualifying capacity multiplied by capacity value (in nominal dollars per kW-year), divided by 8760. Annual capacity benefit is then discounted to units of present value per MWh (2007 dollars and 2007 MWh), and summed across years. For Peaking and Baseload products, the quantity of qualifying capacity is determined by the performance requirements of the offer. For As-Available products, pursuant to D. 05-10-042 (section 7.7), the quantity of qualifying capacity is determined by the annual average of the hourly (noon to 6 pm only) generation profile of the offer. Combination products will be considered accordingly.

For offers whose location would contribute to PG&E’s satisfaction of its Local Capacity Requirement as specified by CAISO and adopted by the CPUC, the capacity value attributable to the offer shall be valued at a premium relative to the value of capacity which satisfied only system needs.

Ancillary services benefit is assumed to be zero for offers classified as the type forwards.

Cost is determined by PG&E's payments for each offer, plus debt equivalence, plus Transmission and Integration cost adders. Debt equivalence only applies to PPA offers and is described in a separate section below. Transmission and Integration cost adders are determined by methodology specified by statute and regulation. PG&E's payments for each offer are determined by the offer's pricing multiplied by the appropriate Time of Delivery (TOD) factors, as specified in the RPS Solicitation Protocol. Cost is measured in units of present value per MWh (2007 dollars and 2007 MWh). In the case of PSA offers, PG&E's payments for each offer are replaced by the revenue requirements, fixed and variable operations and maintenance costs, and ownership costs.

Dispatchables

Benefits include energy, capacity, and ancillary services. Benefits are measured in units of present value per MWh (2007 dollars and 2007 MWh).

Energy benefit for an offer classified as type dispatchable are calculated as daily exercise European options using the Black option pricing model. Additional details depend on the nature of the particular characteristics of a specific offer.

Capacity benefit for an offer classified as type dispatchable is calculated the same way as described above for type forwards. The quantity of qualifying capacity is determined by the performance requirements of the offer, and the nature of the particular characteristics of a specific offer.

Ancillary services benefit for an offer classified as type dispatchable depends on the nature of the particular characteristics of a specific offer.

Cost for an offer classified as type dispatchable is calculated the same way as described above for type forwards, except that PG&E's payments for each offer are determined by the offer's pricing multiplied by the appropriate Time Of Availability (TOA) factors. Cost is measured in units of present value per MWh (2007 dollars and 2007 MWh).

Buyout Options

Market Value for the buyout option is calculated as *MarketValuePPA* plus *OptionValue*. Each of these components is described below.

MarketValuePPA is Benefit minus Cost, where Benefit and Cost are calculated for the period prior to option exercise date. Benefit and Cost are calculated as described above, for type forwards or dispatchables, as appropriate for each offer.

OptionValue is the possible incremental value associated with ownership. Such value derives from a project life that extends beyond the term of the PPA. Such value may also be affected by different costs for ownership compared to costs for the PPA; for example, costs for the PPA include debt equivalency. The benefits for ownership and PPA are

assumed to be the same during the delivery periods in which the PPA is in effect. If the expected life of the facility is the same as the terms of PPA, then the incremental ownership value is zero. In the 2006 RPS solicitation, twenty years of expected life is assumed.

OptionValue is calculated as an option value. It is the present value per MWh (2007 dollars and 2007 MWh) of the expected value of the payout function

$$\max \{0, \text{IncrementalBenefitsFromOwnership} - \text{IncrementalCostsFromOwnership} - \text{Buyout Price} \}$$

The Black option pricing model is used to compute the value of *OptionValue*. Required inputs include strike price, price of the underlying, volatility, and expiry. Each of these inputs is described below.

Strike price is in units of dollars, present valued to the date when the buyout option may be exercised. The strike is *BuyoutPrice* plus *IncrementalCostsFromOwnership*, net any portion of *IncrementalBenefitsFromOwnership* that has no uncertainty represented; for example, capacity benefit has no uncertainty represented. *BuyoutPrice* denotes the present value (to valuation day) of the stream of annual revenue requirements associated with the buyout payment to the Participant. *IncrementalCostsFromOwnership* denotes the present value (to the date when the decision must be made to exercise or not the buyout option) of the incremental costs associated with ownership, compared to the costs associated with the PPA for the delivery periods after the decision must be made to exercise or not the buyout option. Elements of *IncrementalCostsFromOwnership* include fixed and variable costs for operations and maintenance (incremental to such costs for the PPA) and ownership costs.

Price of the underlying is the expected present value (in the year the buyout option may be exercised) of the portion of *IncrementalBenefitsFromOwnership* that has uncertainty represented. This includes the energy benefit for delivery periods during the project life beyond the term of the PPA.

Volatility is the volatility associated with the portion of *IncrementalBenefitsFromOwnership* that has uncertainty represented. This includes the volatility of the energy benefit for delivery periods during the project life beyond the term of the PPA.

Expiry is the difference between project on-line time and the time the decision must be made to exercise or not the buyout option.

Integration Costs

Integration costs are defined as the costs and values of integrating a generation project into a system-wide electrical supply. The primary categories of integration costs are regulation, load following, and shadow capacity. Pursuant to D. 04-07-029, and unless provided further guidance from the California Public Utilities Commission and/or the California Energy Commission, PG&E will assume that integration costs are zero.

Debt Equivalence

Debt equivalence is the imputation of debt-like characteristics to contracts or financial instruments not classified as debt for financial reporting purposes under Generally Accepted Accounting Principles. Credit rating agencies attribute debt equivalence to long-term operating contracts such as PPAs or leases in order to accurately assess a firm's credit risk profile. Because of this increased credit risk, the utility's cost of debt and equity may be higher and may eventually lead to higher borrowing costs. In Decision 04-12-048, the CPUC recognized that these additional costs should be quantified and added to the overall cost in evaluating PPA contracts. The methodology for determining these additional costs are straightforward and specified in this decision. These costs are not used in the evaluation of PSA Offers. In the case of Buyout Offers, the monthly fixed payments (referenced below), are provided by the Participant.

Portfolio Fit

PG&E will compare the "fit" between the Project's online date and generation profile with PG&E's portfolio needs on an hourly, seasonal, and annual basis. An Offer that provides energy when PG&E has a short energy position will be preferred to an Offer that provides energy during periods when PG&E has a long energy position. Offers with dispatchability are generally more valuable than offers without that flexibility. It is intended that Portfolio Fit be complementary to Market Valuation.

Credit

Overview

The Credit component of the evaluation will determine the Participant's capability to perform all of its financial and financing obligations under the Agreements, and the Participant's ability to provide collateral to secure its obligations under the applicable Agreement. In evaluating Offers, PG&E will consider the Participant's financial strength as determined by PG&E as well as the form and amount of acceptable security that Participant offers in accordance with the requirements in Section VII. In its evaluation, PG&E will also consider PG&E's overall credit concentration with the Participant, including any of Participant's affiliates.

The Credit assessment will result in a score on a scale from 1 to 5 points with 5 being highest and 1 the lowest. This protocol will apply for shortlisting of offers for the PPA.

Methodology

PG&E will evaluate offers per the terms of Section XI.C of the 2007 Solicitation Protocol.

Participants offering a sale under a PPA or PSA are required to post security in a form and amount acceptable to PG&E, as described further below, during the following periods:

(1) between the date on which the Agreement is executed and a date that is within thirty (30) days following the Agreement’s CPUC Approval, as defined in the Form Agreement, in the amount of \$3/kW in the form of a Letter of Credit or cash;

(2) between the date that is within thirty (30) days following CPUC Approval and the generating facility’s Commercial Operation Date, as such terms are defined in the Agreements, in the amount of:

(a) in the case of Dispatchable Products: \$20/kW; or

(b) in the case of all other Products: \$20/kW multiplied by the greater of either: (i) the Capacity Factor; or (ii) 0.5;

in the form of Letter of Credit or cash (as used herein, security provided in this Section (1) and (2) are collectively “Project Development Security”); and

(3) from the Commercial Operation Date of the facility until the end of the Delivery Term, as such term is defined in the Agreements, in the form of cash, Letter of Credit, or guaranty acceptable to PG&E, in the amounts indicated in the Performance Assurances Standards table below (as used herein, “Delivery Term Security”).

The Delivery Term Security will be based upon the maximum potential revenue from the Project during the Delivery Term. Participants must be able to demonstrate their financial ability to provide such security. If the amount of the Project Development Security, or Delivery Term Security offered by Participant in its Offer is below the applicable amount indicated in the *Table* below, PG&E may not give any value to Participant’s offer of Credit when evaluating the Offer.

Table: Performance Assurance Standards

10 Yr Contract	15 Yr Contract	20 Yr Contract
Project Development Security: \$3/kW with an increase to a total of the amount calculated in (2) above;	Project Development Security : \$3/kW with an increase to a total of the amount calculated in (2) above;	Project Development Security: \$3/kW with an increase to a total of the amount calculated in (2) above;
Delivery Term Security: 6 months revenue	Delivery Term Security: 9 months revenue	Delivery Term Security: 12 months revenue

Project Viability

Project Viability will be evaluated based on a combined score from the Project Status criteria and the Technology Viability and Participant Experience criteria. The Project Viability assessment will result in a score from 1 to 5 points with 5 being the highest and 1 the lowest. This protocol applies to Purchase Power Agreements, Purchase and Sale Agreements and Sites for Development.

Project Status

Overview

PG&E will assess the stage of development of each project. Those in operation or advanced development (e.g., permits received, equipment purchased, sites and easements obtained, transmission studies completed, design/construction status) will score higher than those in early stages of development. The Project Status assessment will result in a score from 1 to 5 points with 5 being the highest and 1 the lowest. This protocol applies to Purchase Power Agreements, Purchase and Sale Agreements and Sites for Development.

Methodology

Project Status will be assessed primarily based on information provided in the offer (2007 RPS Solicitation Protocol Section VIII.C). The Participant's Project Status claims may be verified using publicly available or PG&E data.

Each project, including transmission to the point of interconnection, will be assessed on each of the following attributes. Each attribute has a unique set of criteria that will be used to inform the outcome. Evidence of completion of specific criteria will contribute favorably to the offer's score.

1. Land/Easements
 - a. Status of site control and easements
 - b. Land Use/Zoning
 - c. GIS Mapping
2. Permitting/Environmental
 - a. Status of applications and permits
 - b. Air Quality
 - c. Water Quality
 - d. Habitat and Species
 - e. Hazardous Materials/Waste
 - f. Sensitive Receptors, Environmental Justice, Socioeconomic
 - g. Cultural Resources
 - h. Permit feasibility
3. Design/Construction
 - a. Status of feasibility study, design, EPC contractor, construction
4. Equipment Acquisition
 - a. Status of ordering and delivery of major components
5. Grid Interconnection

- a. Status of System Impact Study (SIS) and/or Facility Study (FS)
- b. Identification of grid upgrades

Technology Viability and Participant Experience

Overview

PG&E will assess the probability that the project will operate as proposed based on the resource risk, state of commercialization of the technology, and Participant's experience. The Technology Viability and Participant Experience assessment will result in a score of 1 to 5 points with 5 being the highest and 1 the lowest. The evaluation is designed to place greater weight on proven resource areas, established technology in wide commercial use, and bidder operating experience specific to the particular technology. This reflects PG&E's interest in reducing technology risks to its customers.

Methodology

Technology Viability will be determined primarily based on the information provided in the offer (see RPS Solicitation Protocol Section VIII.C), which will be compared to external benchmarks for the technology. The Participant's experience claims will be verified using publicly available or PG&E data.

Each project will be scored based on the following attributes:

- Resources Risk
 - o Whether Resource availability and sustainability have been proven
- Technology Feasibility and Commercialization Risk
 - o Technology still in R&D stage, or
 - o Emerging technology (in demonstration phase or in early commercialization), or,
 - o Established technology in wide commercial use
- Participant Experience Risk
 - o Bidder has submitted no qualification or experience information, or
 - o Bidder has little or no experience with specific technology, however has significant experience with other renewable or conventional power generation, or
 - o Bidder has experience developing/operating facilities of this technology type, or
 - o Bidder has experience developing/operating facilities utilizing the same equipment.

RPS Goals

Overview

PG&E will assess the offer's consistency with and contribution to California's goals for the RPS program and the offer's support of PG&E's supplier diversity goals (collectively

“RPS Goals”). The RPS Goals assessment will result in a score of 1 to 5 points with 5 being the highest and 1 the lowest.

Methodology

Support of RPS Goals will be determined primarily based on the information provided in the offer (see RPS Solicitation Protocol Section VIII.C).

Each project will be scored based on its support of the following attributes:

- Non-quantitative factors identified in CPUC Decision 04-07-029
 - o Benefits to low income or minority communities, Environmental Stewardship, Local Reliability, and Resource Diversity benefits
- Legislative Findings and Declaration that increasing California’s reliance on renewable energy may do each of the following:
 - o increase the diversity, reliability, public health and environmental benefits of the energy mix;
 - o promote stable electricity prices;
 - o protect public health;
 - o improve environmental quality;
 - o stimulate sustainable economic development;
 - o create new employment opportunities;
 - o reduce reliance on imported fuels;
 - o ameliorate air quality problems;
 - o improve public health by reducing the burning of fossil fuels;
 - o provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.
- Impact of the project on California’s water quality and use and the relationship to the CPUC’s Water Action Plan adopted on December 15, 2005. To the extent a project uses water on site, its proposed use of water will be reviewed for consistency with the CPUC’s recommended water conservation practices and goals.
- In Executive Order S-06-06, signed on April 25, 2006, Governor Schwarzenegger described the benefits of biomass resources in electricity production and established a goal that the state would meet 20% of its renewable energy needs with electricity produced from biomass. The Participant is encouraged to describe in its Offer how its ERR facility, if applicable, can support that 20% goal.
- In support of PG&E’s supplier diversity goals, the good faith efforts of Participants to subcontract with Women-, Minority-, and Disabled Veteran-owned Business Enterprises (WMDVBES) and if a Participant is a WBE, MBE, or DVBE are factors that will be considered in the bid evaluation process.

Transmission Adder

Overview

The transmission adder is meant to adjust offer prices for the cost of bringing the power from the generating facility to PG&E's network. Once offers have been ranked on all evaluation criteria except for Transmission Adders, the ability to deliver the power to PG&E's customers will be examined. Available capacity (if any) will be first assigned to the top ranked bids at a given network location, or cluster. Projects will then be assigned a cost adder if applicable. PG&E will use the lesser of the Transmission Adder developed from the Transmission Ranking Cost Report (TRCR) or alternative commercial arrangements in determining the market value of bids and selecting the shortlist. The pertinent cost information from the TRCR is included in the Solicitation Protocol. The clusters are for bid evaluation only. Resource projects do not have to physically connect to a cluster.

Methodology for TRCR Adder

After the initial ranking of offers on all scoring factors other than transmission, the team calculating the transmission adder will receive a download of data for each offer. The data shall be grouped by transmission cluster and sorted by points, from highest to lowest.

PG&E will assign each Offer an estimated amount of transmission network upgrade costs, if applicable, using the Transmission Ranking Cost Table X.1 in the 2007 RPS Solicitation Protocol. Within each of twenty-two transmission clusters, PG&E has identified various levels of possible additional transmission capacity, in megawatts, and the related costs, in dollars, of providing that capacity. These megawatts and dollars in the table are divided between "Peak & Shoulder" and "Night" periods (note that the dollars for "Baseload & As-Available" columns are simply the sum of the other two sets of columns minus any common transmission facilities).

Within each of the twenty-two transmission clusters, and within each period (Peak & Shoulder and Night), starting with the highest scoring Offer, each Offer will be assigned a pro-rata share of the cost. This share will be based on the Offer's maximum MW as a percentage of the maximum MW of potential generation assigned to each transmission level based on the initial ranking provided. Offers whose MWs fall into two levels will be assigned a pro-rated cost based on the amount of the Offer's MWs in each level. For purposes of determining the level to which a project's MWs are assigned, only the highest scoring Offer from each Project above it in the cluster ranking will be considered. This was done to prevent the allocation of transmission capacity to multiple offers of a single project.

PG&E may accept the electricity at a CAISO delivery point or another delivery point outside of PG&E's service territory and avoid the cost of congestion through the use of typical commercial

arrangements. Examples of such arrangements include remarketing of the delivered energy, utility swaps, use of transmission adjustment bids and obtaining transmission as it becomes available. PG&E will continue to utilize the TRCR values to assess the cost of transporting the energy to its load center, but PG&E will also consider the cost of alternative commercial arrangements and choose the most cost-effective option using least-cost best-fit principles. Ultimately, who pays for the cost of transmission is negotiable, subject to PG&E's ability to recover the cost.

If a Project were located outside the CAISO-controlled grid and is offering delivery outside the CAISO grid, the Participant is asked to provide a premium it would charge to deliver the energy onto or to an intertie with the CAISO grid. Such a premium could be expected to include the cost of wheeling and related charges through the host utility and any intervening utilities. Following the application of such a premium, the resulting transmission cost adder would be based on the transmission ranking cost at the cluster closest to the point where its power would enter PG&E's territory (*e.g.* for power coming in from the Pacific NW, the cluster would be Round Mountain). However, as noted above, PG&E will also consider possible commercial arrangements that might be more economical than physically transmitting the power to the PG&E grid and will choose the most cost-effective option using least-cost best-fit principles.

A Present Value Revenue Requirement (PVRR) will be calculated from the Transmission Ranking Cost table X.1 for each. This PVRR captures from a ratepayer perspective the risk and cost to construct and maintain transmission upgrades to accommodate the generation from the renewable resource.

This PVRR of the costs of the Network Upgrades will be converted into a present value per MWh (2007 \$ and 2007 MWh) by dividing the PVRR by the Discounted MWh. These present value per MWh (2007 \$ and 2007 MWh) values, one for each Offer, will be returned to the database for a recalculation of the Market Valuation points.

If a large population of offers is received in a given area, it is possible that alternative commercial arrangements may not be feasible. In this case, and if the interconnection studies have not yet been completed, the default is the Transmission Adders from the TRCR.

B. Criteria Weightings

1. If a weighting system is used, please describe how each LCBF component is assigned a quantitative or qualitative weighting compared to other components. Discuss the rationale for the weightings.

PG&E does not apply a weighting system in the evaluation and selection of offers.

2. If a weighting system is not used, please describe how the LCBF evaluation criteria are used to rank bids.

As described above, PG&E applies a Partial Ordering method.

3. Discuss how the IOU LCBF methodology evaluates project commercial operation date relative to transmission upgrades required for the project.

The LCBF process discussed above does not prescribe a specific course of action. However, in the course of due diligence during the review of offers, PG&E may request supplemental information from bidders to clarify areas of question and reassess project characteristics as applicable.

4. Discuss how the LCBF methodology takes into account bids that may be more expensive, but have a high likelihood of resulting in viable projects.

The LCBF process considers all offers on all criteria, not just price. All offers are scored in each of the criteria and ranked as described above.

PG&E notes that the LCBF process is a screening tool that helps with an initial selection of projects. It is only upon shortlisting that substantive discussions with bidders can begin.

C. Evaluation of utility-owned, turnkey, buyouts, and utility-affiliate projects

1. Describe how utility-owned projects are evaluated against PPAs.

PG&E has not bid any utility-owned projects into its solicitation.

2. Describe how turnkey projects are evaluated against PPAs.

All else being equal, a turnkey project would be compared to a PPA based on an all-in Net Value, defined as Market Value after adjustment for Transmission Adders, in \$/MWh. The cost of ownership, measured as a present value of revenue requirements, would be recalculated to be based in \$/MWh. The project with the higher Net Value would be considered better than the one with the lower Net Value, but it is possible that both could move forward.

3. Describe how buyout projects are evaluated against PPAs.

Buyout projects are discussed above.

4. Describe how utility-affiliate projects are evaluated against non-affiliate projects

PG&E does not have an affiliate that develops renewable energy projects. If PG&E establishes such an affiliate in the future, there will be detailed protocols to address such an evaluation in order to ensure fairness to all bidders in the process.

III. Bid Evaluation and Selection Process

A. What is the process by which bids are received and evaluated, selected or rejected for shortlist inclusion, and further evaluated once on the shortlist?

When bids are received and opened, a processing team reviews each offer to identify and summarize key characteristics, and to note any major areas of missing or unclear information. PG&E has set up evaluation teams for each of the evaluation criteria, as described above. Each team reviews the entire population of offers in its evaluation area in order to ensure consistency in scoring across offers. A lead person for each offer ensures that the scores for that offer make sense across evaluation teams. If there are any additional information needs from a bidder, the PG&E lead makes such requests. Responses are taken into account prior to ranking offers.

An evaluation committee oversees the integrity of the evaluation process and makes a shortlist recommendation to the steering committee. The steering committee has the authority to approve the shortlist and additionally to rule on issues of eligibility. Following shortlisting, the steering committee approves the priority of negotiations. Offers and their respective valuations are updated as new information becomes available in the course of negotiations.

B. What is the typical amount of time required for each part of the process?

From RFO issuance until bid receipt is 10 weeks. From bid receipt until shortlisting is 8 weeks. Negotiations can take from 2 to 6 months, or longer, depending on the complexity of the transaction and the number of issues of difference between the seller and the IOU. From contract execution until CPUC Approval is 3 to 6 months.

C. How is the size of the shortlist determined?

The shortlist is sized to create a population of offers large enough to satisfy PG&E's procurement target of 1-2% of load. PG&E takes into account that certain offers may withdraw and that negotiations with certain others may not result in executed contracts.

D. Are rejected bidders told why they were rejected? If so, what is the process?

PG&E notifies rejected bidders by email and by phone. The emails do not specify the reason, but PG&E is available to discuss the reason for rejection.

E. Describe involvement of the Independent Evaluator.

The IE reviews the evaluation criteria, detailed protocols, and the market valuation and portfolio fit models prior to bid opening. The IE provides feedback on potential areas for improvement. The IE is present at bid opening and receives a hard copy and electronic copy of all bid documents. The IE monitors all email

communications with bidders. PG&E uses email exclusively to make supplemental information requests, and all responses are provided to the IE upon receipt. The IE may submit additional questions that are not raised by the PG&E team. The IE participates in all meetings of PG&E's RPS steering committee and in all PRG meetings related to the PG&E's RPS solicitation. The IE performs an independent evaluation of the offers. If any substantive differences exist between the IE's evaluation and the utility's evaluation, the IE discusses these areas with the utility to determine the reason and to correct the difference.

F. Describe involvement of the Procurement Review Group.

PG&E presents its initial summary of results to the PRG about two-three weeks after bid receipt. Key project characteristics are discussed. The PRG raises questions and provides initial feedback. PG&E returns to the PRG with a recommended shortlist about seven weeks after bid receipt. PG&E solicits and incorporates the PRG's feedback into the final shortlist about eight weeks after bid receipt.

G. Discuss whether and how feedback on the solicitation process is requested from bidders (both successful and unsuccessful) after the solicitation is complete.

Although PG&E does not have an established process in terms of requesting feedback from all bidders, PG&E is open to providing/receiving feedback, and would consider holding a post-solicitation workshop in order to allow all bidders to express concerns and provide/receive feedback.