Rulemaking 10-05-006

Exhibit No.: _____

Date: August 4, 2011

Witness: William A. Monsen

TESTIMONY OF WILLIAM A. MONSEN ON BEHALF OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION IN TRACK III OF THE LONG-TERM PROCUREMENT PLANNING PROCEEDING CONCERNING BID EVALUATION

Table of Contents

1. Introduction and Summary

Q. Please state your name and business address.

A. My name is William A. Monsen. I am a Principal and Executive Vice-President at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. Please describe your professional background.

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including California, New England, Wisconsin, and Nevada. Prior to joining MRW, I worked at Pacific Gas and Electric Company (PG&E). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison. Additional information about my qualifications is provided in Attachment A.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of the Independent Energy Producers Association (IEP).

Q. What is IEP's interest in this proceeding?

A. IEP represents the interests of independent power producers (IPPs). IEP members collectively own and operate approximately one-third of California's installed generating capacity, which includes renewable products derived from biomass, geothermal, small hydro, solar, and wind; highly efficient cogeneration; and gas-fired merchant facilities.

Q. What is the purpose of your testimony?

A. My testimony addresses refinements to the bid evaluation process, particularly weighing competing bids between utility-owned generation (UOG) and power purchase agreements (PPAs). As bidders into the utilities' competitive Requests for Offers (RFOs), IEP members have an interest in increasing the transparency of the bid evaluation process and ensuring that their bids to sell power to the California utilities are evaluated in a fair manner.[1]

Q. Is this issue within the scope of this proceeding?

A. Yes. This is one of the Track III issues that are being addressed concurrently with Track I.[2]

Q. Please summarize your recommendations regarding the bid evaluation process.

A. My recommendations are as follows:

[1] In general, IEP does not support IOU-owned generation. Instead, IEP believes that if utility holding companies want to develop and own generation in the California power market, they should do so via an unregulated subsidiary.

[2] Administrative Law Judge's Ruling Revising System Track I Schedule. R.10-05-006, March 10, 2011, page 5.

1. Information on the bid evaluation process and bid evaluation parameters should be available to all bidders prior to bid preparation;
2. IPP contract terms should not be capped and must be appropriately considered in the bid evaluations;
3. Bidders should be able to bid existing units into RFOs without exclusion;
4. Utilities should be required to include all project development costs in their bids;
5. The cost of ratepayer risk associated with UOG and IPP projects should be incorporated in the bid evaluation process;
6. My proposed bid evaluation methodology should be used as a model for the IOUs' bid evaluations; and
7. The Energy Division's proposal to restrict contracting with once-through cooling plants should be rejected.

2. Competitive RFOs Should be Non-Discriminatory

Q. Are there different types of UOG projects?

A. Yes. There are a number of different types of project constructs that ultimately result in utility-owned generation. These include Purchase and Sale Agreement (PSA) offers (where the potential counterparty is responsible for developing, permitting, constructing, testing, and completing the facility, which is then handed over to the investor-owned utility (IOU)), Engineering, Procurement, and Construction (EPC) offers (in which the IOU develops and permits the facility, while the potential counterparty is responsible for constructing the facility), and utility development offers (in which the IOU develops, permits, and constructs the facility). There are also hybrids of these three basic types of

projects. For the purposes of this testimony, I refer to all of these potential projects as UOG projects.

Q. Are proposals for UOG and IPP projects compared side-by-side in bid evaluations?

A. They can be. If a utility submits a proposal for a UOG project in response to its own RFO, the UOG project is evaluated alongside IPP project bids. All three IOUs have stated that they will consider pursuing UOG projects in the future.[3] In response to IEP's data requests, PG&E and San Diego Gas & Electric Company (SDG&E) have both indicated that they will consider submitting UOG bids in the competitive solicitations for long-term energy and capacity for the 2011 through 2020 planning horizon.[4] Southern California Edison (SCE) states that "UOG projects should be proposed only when competitive processes cannot deliver the products that the utility needs to serve its customers in a cost-effective manner,"[5] that it is not appropriate to evaluate UOG and IPP projects on the same basis, and that it has no current plans to pursue UOG projects.[6] However, SCE will not rule out pursuing UOG projects if they "provide significant value" to ratepayers.[7]

Q. Do utility and IPP projects evaluated in competitive solicitations currently compete on equal footing?

A. No, they do not. UOG projects often receive explicit or implicit advantages in the bid evaluation process relative to bids for PPAs with projects owned or operated by IPPs.

[3] PG&E response to IEP data request 5 Question 1, SCE response to IEP data request 6 Question 3, and SDG&E response to IEP data request 6 Question 1, as presented in Attachment B, Attachment C, and Attachment D, respectively.
[4] PG&E response to IEP data request 5 Question 1 and SDG&E response to IEP data request 6 Question 1, as presented in Attachment B and Attachment D, respectively.
[5] SCE Track III testimony in R.10-05-006, July 1, 2011, p. 16.
[6] SCE response to IEP data request 6 Question 3, as presented in Attachment C.
[7] SCE response to IEP data request 6 Question 3, as presented in Attachment C.

Q. What are some of the implicit and explicit advantages that UOG projects receive in bid evaluation?

A. My testimony focuses on the following advantages, which are explained further below:

1. IOUs may have greater access to information regarding the timing and type of needs the IOU has than do IPPs.
2. IOUs can amortize the costs of UOG projects over a longer term than can IPPs. As a result, IOUs may be improperly evaluating the actual cost of IPP projects and over-stating the costs of IPP projects relative to UOG projects.
3. Through their RFOs, the IOUs often preclude potentially competitive existing generation projects from bidding, which reduces competition for UOG projects.
4. IOUs may be able to exclude some project development costs from their bids by recovering these costs outside of the RFO process.
5. It appears that IOUs are able to exclude from their bids much of the risk associated with the inherent uncertainty in costs and performance of power plant projects while IPPs must internalize some or all of those uncertainties into their project bids.

Q. Why does it matter that utility and IPP projects presently do not compete on equal footing?

A. IPPs and the financing institutions that support them (e.g., banks, private equity) have limited opportunities to enter the California energy markets. The perception that there is not a competitive level playing field hinders planning and undermines the investment of resources (e.g., time, personnel, development capital) by these entities that is needed to

identify and develop the best sites for new construction. Ultimately, this results in less attractive projects and, as a result, higher costs for ratepayers.

In addition, to the extent that UOG projects are selected in place of lower cost or better-fitting IPP projects on account of biases in the bid evaluation process, this also increases ratepayer costs.

Q. What changes are needed to make competitive RFOs non-discriminatory?

A. Several aspects of bid evaluation need to be changed in order to make competitive RFOs non-discriminatory. This section of the testimony focuses on the following five changes:

1. Information on the bid evaluation process and bid evaluation parameters should be available to all bidders prior to bid preparation so that bidders can incorporate that information into the formulation of their bids;
2. IPP contract terms should not be capped and must be appropriately considered in the bid evaluations;
3. Bidders should be able to bid existing units into RFOs without exclusion;
4. Utilities should be required to include all project development costs in their bids; and
5. The cost of risks associated with UOG and IPP projects should be incorporated in the bid evaluation process.

The subsequent chapter presents an approach to bid evaluation that begins to incorporate these proposals.

Q. Are these proposals relevant to all utility RFOs?

A. These proposals are relevant to all utility RFOs into which the utilities are eligible to bid.[8]

A. Information on the bid evaluation process and bid evaluation parameters should be made available to all bidders

Q. What information on the bid evaluation process is currently available to IPPs?

A. The utilities currently provide limited information to IPPs on the bid evaluation process, generally restricted to the categories of parameters considered. IPPs are not provided with information on how each parameter is assessed or weighed relative to other parameters. IPPs are also not provided with the underlying assumptions that the utilities (and the Independent Evaluator (IE)) plan to use for bid evaluation, including forward energy and capacity price curves that are to be used in bid evaluation and the utilities' supply and demand forecasts.

Q. Would providing this information to IPPs result in better project/bid submittals?

A. It should. For example, the relative value of the bid evaluation factors determines the results of the bid evaluation process, starting with the short-listing of projects. If bidders had a better understanding of the relative value of the bid evaluation factors (which should reflect the relative value that the utilities place on different power project attributes), the IPPs could plan and propose projects more suited to the needs of the utilities, thereby improving competition and helping ensure that the projects selected truly are the "best fit" in light of the utility needs and specifications.

[8] The proposed bid evaluation framework can be used even if no bids for UOG projects are submitted; however, some of the factors in the bid evaluation framework would not be relevant if only IPP projects bid into a particular solicitation.

Q. Would providing this information to IPPs result in higher bid prices?

A. It is unlikely that providing these data to IPPs would result in higher bid prices. On the contrary, providing more information on the bid evaluation process reduces the uncertainties for potential bidders, which reduces bidding costs and could motivate more developers to make the substantial investment required to submit a bid. A larger pool of bidders and greater transparency both work to increase the efficiency and competitiveness of the bidding process, to minimize speculative, non-viable bids, and to reduce ratepayer costs.

Q. Do economic studies support your belief that providing this information to IPPs would not result in higher bid prices?

A. Yes. Frayer, Neeman, and Wittenstein of London Economics International have studied this issue extensively from both empirical and theoretical standpoints. They explain:

> Leaving theory aside for the moment, conventional thinking in the utility sector has typically resulted in very limited information disclosure by the utility running the RFP. Utilities tend to be protective of the various methods, inputs, forecasts and projections they use internally to develop their market valuation, which then guides the bid evaluation process. Utilities may fear that their forecasting and analytical approach, if made public, could be discredited. They may also worry they would be at a disadvantage should they find themselves competing directly with a bidder in the future under a different context (as these are "repeated" markets with various dimensions, a supplier can become a buyer in the future). Finally, there is a general concern that bidders may use information provided to take advantage of the utility soliciting offers by pricing in a non-competitive manner. For example, if a utility publishes their own opportunity cost for securing supplies through other means, bidders may target that opportunity cost when they make their offer, instead of their own expectations and marginal costs. This concern would only be valid if there is truly an insufficient level of competition. If there is sufficient competition, suppliers will bid based on their marginal cost (which may not necessarily be their physical production cost, but should represent their marginal opportunity cost), even if they know the buyer's reference purchase price, because they can do no better by bidding below their costs (why take on a commitment that is unprofitable?) or bidding above their costs (they may risk not being selected at all because of more

> competitive bids from other suppliers)…. **In fact, both theory and experience from competitive solicitations involving the gas and oil sectors in the energy industry suggests [sic] that additional information about the soliciting entity's views on the economic value of the product being sought could be helpful in motivating competition amongst the bidders.**[9]

Q. Have the recent all-source and renewable RFOs been competitive?

A. Yes. The number and capacity of projects bid in recent RFOs have far exceeded the amount of capacity and energy the IOUs were seeking to procure. For example, PG&E received 48 offers totaling almost 13,000 MW in response to its 2008 long-term RFO, far exceeding the 800-1,200 MW that it sought to procure.[10] Similarly, SCE received 29 offers for nearly 9,000 MW of capacity in response to its 2006 RFO for 1,500 MW of new capacity,[11] and SDG&E received bids "with a MW total well above the RFO's 250 MW goal" in its 2008 Peaker RFO.[12]

Q. How does providing more information to bidders in competitive RFOs result in lower bid prices?

A. As explained by Frayer, Neeman, and Wittenstein, providing more information has two effects, known as the publicity effect and the weighting effect, both of which encourage more competition and reduce bid prices:

> If the revelation of "new" information by the utility (the buyer) reduces private information held by certain suppliers, it will encourage more intense competition and increase the expected returns for the buyer (this is known as the publicity effect in auction theory). Moreover, if the buyer's revelation of information on expected market value of the product being procured is a substitute for the supplier's pre-

[9] Frayer, Neeman, and Wittenstein. "Applications of Information Policy Principles from Auction Theory in the Deregulated Electricity Market." Presented at the 32nd International Association for Energy Economics (IAEE) International Conference in June 2009, pages 3-4 (emphasis added), as presented in Attachment E.
[10] PG&E testimony in A.09-09-021, September 30, 2009, pages 1 and 5, as presented in Attachment F.
[11] SCE application in A.08-04-011, April 4, 2008, pages 2-3, as presented in Attachment G.
[12] SDG&E Application for Expedited Approval of the Miramar Energy Facility II Project in A.08-06-017, June 16, 2008, p. 5, as presented in Attachment H.

existing private information on the value of the product, then it also motivates competition and reduces bidders' (suppliers') profits to the benefit of the buyer(s) (this is referred to as the weighting effect).[13]

Q. Have Frayer, Neeman, and Wittenstein evaluated any of the California IOUs' RFO processes?

A. Yes, they evaluated RFOs from all three of California's IOUs and found their information sharing to be significantly lacking. For instance, with regard to SDG&E they note:

> Because of the subject nature of the [least-cost/best-fit] criteria and its application by SDG&E, there was not a lot of concrete guidance for bidders in terms of how the project evaluation would play out. Although some qualitative analysis is probably inevitable in a complex RFO such as this, the subjectivity of qualitative analysis can lead to some bidder apprehension, and could likely cause some bidders to drop out of the process even before it started…[This] type of uncertainty created by vague and subjective bid evaluation parameters is likely to create dynamic, longer term effects that discourage new investors from seeking to participate…In business terms, this lack of information is a very significant initial investment hurdle to overcome.[14]

Q. What sorts of information do they recommend be disclosed and how?

A. They recommend that utilities disclose assumptions about underlying drivers, such as forecasts of fuel prices, supply, and demand. They explain the benefits of these disclosures as follows:

> Utilities, as the solicitors in these procurements, have an opportunity to better the results of their procurements by actively managing what information is provided to potential bidders in order to displace private information on future market value and encourage more bidders to participate, and more aggressive bidding by suppliers with reduced risk premiums. We do not intend to suggest that utilities release their actual reference levels for future electricity prices. Rather, we argue that it is important that they release their assumptions about underlying drivers, like fuel price outlooks, and supply and demand forecasts. In doing so, they would allow bidders to develop views congruent with the soliciting utilities' expectations, or at the minimum direct bidders to credible public sources for this information. Bidders need to get information simultaneously and sufficiently ahead of any financial bid

[13] Frayer, et al. page 6, as presented in Attachment E.
[14] Frayer, et al. page 13, as presented in Attachment E.

> submission, so that they can absorb it and reflect it in their proposal. The release of such information could also have longer-term positive effects, in that it may serve as a launch pad for attracting new players to future competitive solicitations. Furthermore, a more concrete and documented bid evaluation process, released for public consumption, would also be helpful in encouraging new participants and potentially lower risk premiums in future RFPs.[15]

Q. Do other experts agree with Frayer, et al?

A. Yes. Other experts have also highlighted the benefits of providing information to bidders that may help them prepare better bids. For example, Dr. Susan Tierney and Dr. Todd Schatzki of the Analysis Group prepared a White Paper on electricity supply procurement policies and practices for the National Association of Regulatory Utility Commissioners in July 2008 as part of a dialogue with the Federal Energy Regulatory Commission on competitive power procurement policies and practices.[16] They reviewed existing competitive procurement practices, developed criteria for evaluating procurements, and identified lessons learned and best practices.[17] They found as follows:

> [In] order to submit offers that best reflect the utility's needs and system conditions, potential bidders need access to accurate and sufficiently comprehensive information on product specifications, model contract terms, credit and collateral requirements, relevant transmission constraints, costs to integrate generators into the transmission system, evaluation criteria, and other relevant factors.[18]

For example, Tierney and Schatzki point out:

> [Utility] RFP documents should assist bidders by identifying to the extent possible such things as: any favored delivery points given the existing configuration of loads and generation in the network; locational information about a benchmark resource; or information about likely integration costs.[19]

---

[15] Frayer, et al. pages 16-17, as presented in Attachment E.
[16] Susan Tierney and Todd Schatzki. "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices." The Analysis Group. July 2008, as presented in Attachment I.
[17] Tierney and Schatzki, page i, as presented in Attachment I.
[18] Tierney and Schatzki, page 15, as presented in Attachment I.
[19] Tierney and Schatzki, page 42, as presented in Attachment I.

In addition, where simulation models are used as part of the evaluation process, Tierney and Schatzki recommend:

> To the extent possible, utilities should aim to provide bidders with information about input assumptions used in these models, such as demand forecasts and key parameters of other system resources. This will allow suppliers to shape their competitive offers to be more attractive than other offers.[20]

These findings are consistent with the findings of Frayer et al.

Q. Has the Commission found in the past that it is important for bid evaluation criteria to be transparent?

A. Yes. For example, in a previous LTPP decision, the Commission stated:

> [The] evaluation criteria used in competitive solicitations must be clear, transparent, and available to potential bidders early enough in the procurement process to permit potential bidders to tailor their projects to fit the utility's actual needs…When the utility functions as both buyer and seller, it is particularly critical to ensure that the bid evaluation is fair and transparent. In the absence of a fair and transparent evaluation process, it is unlikely that ratepayers will benefit fully either from competition or from the utilities' participation in a hybrid market.[21]

Q. Do project developers agree that lack of transparency increases their bid costs?

A. Yes. For example, the Large-scale Solar Association (LSA), which represents the developers of utility-scale solar energy projects, addressed this issue in June 2011 comments to Commission Draft Resolution E-4405, focusing on the Commission approval portion of the bid evaluation process: "LSA emphasizes that the PPA approval process must be fully transparent to ensure efficient [Renewable Portfolio Standard

[20] Tierney and Schatzki, page 29, as presented in Attachment I.
[21] D.07-12-052 in R.06-02-013, p. 155.

(RPS)]-eligible project development."[22] LSA further elaborated on the cost increases to ratepayers that result from the lack of transparency in the PPA approval process:

> If developers are to identify viable projects, they need to understand the criteria that the Commission will employ in reviewing RPS PPAs…The Draft Resolution focuses only on contract price and its relationship to prevailing market conditions, with no explanation as to how or whether Staff weighed that contract price against the other [least-cost/best-fit (LCBF)] factors when arriving at its recommendation that the Commission reject the PPA. As such, developers are left to guess whether and how the LCBF may have been reformulated. The result of this lack of transparency is that developers will be unable to ascertain how the Commission will review projects in the future. Absent this understanding, developers are severely hindered from developing projects that will obtain Commission approval. Expending resources developing projects that never come to fruition, and negotiating with the utilities PPAs that are ultimately rejected, increases ratepayer costs. Thus, it is imperative that there be complete transparency in the Commission's PPA approval process.[23]

Q. Would additional transparency in bid evaluation tend to elicit proposals that better align to utility needs?

A. Yes. As noted above, greater transparency in bid evaluation including the relative weights of the various factors used in bid evaluation will help bidders plan, design, and bid projects more closely aligned to the utilities' needs.

Q. What information should the IOUs provide to prospective bidders?

A. The IOUs should provide the underlying assumptions they plan to use in their bid evaluations, comparable to the Required Assumptions established for the Common Value Portfolio for the bundled LTPP filings in this proceeding.[24] Providing these assumptions

[22] Comments of the Large-scale Solar Association on Draft Resolution Number E-4405. Filed with the CPUC Energy Division. June 13, 2011, p. 2, as presented in Attachment J.
[23] Ibid, as presented in Attachment J.
[24] Administrative Law Judge's Ruling Requesting Post-Workshop Comments, Updating Standardized Planning Assumptions, and Providing Lawrence Berkeley Report on Modeling Issues in R.10-05-006, December 23, 2010, Appendix B, pp. 3-6.

would help bidders understand the bases upon which their proposals will be considered. This would allow bidders to tailor bids to maximize their value to ratepayers. As discussed above, it would also improve the quality and quantity of bids received in these solicitations.

Q. What sorts of assumptions should SCE and SDG&E provide?

A. It is my understanding that SCE and SDG&E rely on production cost modeling as part of their bid evaluation processes. If this is the case, they should provide their modeling assumptions to prospective bidders, so that bidders could, in theory, build their own production cost model databases to mimic the IOUs' bid evaluation models and identify the projects that would be valued most highly by the IOUs.

Q. What sorts of assumptions should PG&E provide?

A. It is my understanding that PG&E does not use production cost modeling to evaluate bids. Instead, PG&E relies in part on forward capacity and energy price curves to evaluate bids. If this is the case, PG&E's forward curves are among the primary underlying assumptions that PG&E uses for bid evaluation, and these curves should be provided to bidders along with PG&E's remaining assumptions. If PG&E were not to disclose its forward curves and other assumptions, then bidders would have little or no information upon which to base proposals to PG&E and, as a result, PG&E's ratepayers would lose the benefits of transparency discussed above.

B. IPP contract terms should not be capped and must be appropriately considered in the bid evaluations

Q. In the previous round of IOU long-term RFOs, did the IOUs cap the terms of PPAs for conventional (i.e., non-renewable) resources?

A. SCE's 2006 RFO for New Generation (New Gen RFO) and PG&E's 2008 Long-Term RFO (LTRFO) both set a maximum contract term of 10 years for new resources, with most existing resources ineligible to bid.[25] In contrast, SDG&E's 2009 RFO for Demand Response and Supply Resources provided a 20-year term for tolling agreements with new resources located within its service territory and a 10-year term for existing resources and for new resources located outside of its service territory.[26]

Q. Could a non-renewable project with an expiring PPA participate in either the PG&E LTRFO or the SCE New Gen RFO?

A. In general, no. Aside from the special cases of qualifying facilities and repowered facilities, PG&E and SCE accepted PPA bids only for new conventional generation.[27] Most existing non-renewable generation facilities were therefore ineligible to bid into the long-term RFOs. Of the three IOUs, SDG&E alone allowed existing conventional resources to bid for long-term contracts.[28]

[25] PG&E All Source Long-Term Request For Offers, issued April 1, 2008, page 12 and SCE New Gen Request For Offers, issued August 14, 2006, pp. 5, 9, as presented in Attachment K and Attachment L, respectively.
[26] SDG&E Request for Offers for Demand Response and Supply Resources, June 9, 2009, pp. 1-4, as presented in Attachment M.
[27] PG&E All Source Long-Term Request For Offers, issued April 1, 2008, pages 6-7 and SCE New Gen Request For Offers, issued August 14, 2006, page 5, as presented in Attachment K and Attachment L, respectively.
[28] SDG&E Request for Offers for Demand Response and Supply Resources, June 9, 2009, Products 5 and 6, pp. 3-4, as presented in Attachment M.

Q. If these restrictions on contract term and eligibility continue, is it correct that most new non-renewable power plants would be unable to enter into a long-term contract with a California IOU for more than 10 years of the plant's life?

A. Yes. If PG&E and SCE continue to exclude existing non-renewable generators from participating in their long-term RFOs, most developers of new non-renewable power plants will be eligible for at most a 10-year PPA. If SDG&E keeps the rules from its last long-term RFO, power plants inside SDG&E's service territory will be eligible to bid for PPA terms of up to 20 years, and existing plants will be eligible to bid into SDG&E's RFO for PPA terms of up to 10 years.[29] However, SDG&E's service territory and capacity needs are a small part of the California marketplace, so under current rules most power plants will be limited to PPAs of at most 10 years.

Q. Are bids for utility self-builds and purchase and sale agreements (PSAs) evaluated based on capital recovery over a 10-year period?

A. No. UOG projects are generally evaluated based on capital recovery over the project life. For example, the Oakley PSA was evaluated based on annual revenue requirements assuming a 30-year plant life.[30]

Q. How does this create a disadvantage for IPPs bidding to sell via PPAs?

A. IPPs proposing PPAs need to incorporate most or all of the project's capital recovery over the initial PPA bid (which in most cases is 10 years),[31] whereas bids for utility self-

[29] SDG&E Request for Offers for Demand Response and Supply Resources, June 9, 2009, p. 2, as presented in Attachment M.

[30] PG&E Prepared Testimony for Approval of 2008 Long-Term Request for Offer Results and For Adoption of Cost Recovery and Ratemaking Mechanisms in A.09-09-021, September 30, 2009, page 9-13, as presented in Attachment F.

builds would be evaluated based on capital recovery over a period of 30 years or more. Since payments made 11-30 years in the future can be discounted significantly in present value calculations used in bid evaluations, deferring these capacity payments effectively reduces the bid prices for utility builds and PSAs. Since IPPs seeking PPAs are not able to defer these payments, this puts IPP PPA bids at a disadvantage.

Q. Couldn't the IPP obtain financing over a period longer than that of its PPA?

A. It might be possible for a very limited portion of the overall financing package to extend beyond the PPA period. However, entities financing power projects past the end of the initial PPA would see significant risks associated with this so-called "merchant tail." The perception of greater risk results in an increase in financing costs. Of course, the cost of financing the "merchant tail" would be less if it were clear that there were short-term markets that provided a reasonable expectation of capital cost recovery.

Q. What recommendations do you have to eliminate this disadvantage for IPP bids?

A. The maximum PPA term should be extended to cover a larger portion of the capital cost-recovery period used for UOG projects, such as the 20-year term provided by SDG&E in its most recent RFO for projects located within SDG&E's service territory. This would likely reduce the cost of power from PPAs by enabling IPPs to spread capital cost recovery over a longer period.[32]

[31] This is particularly true when the value of capacity in short-term capacity markets is too low to ensure significant capital recovery in the post-PPA years.

[32] The benefit from extending the PPA term is most pronounced during periods where short-term capacity markets are too weak to ensure significant capital recovery in the post-PPA years.

Q. Even if IPPs are allowed to bid for PPAs that are longer than 10 years, would that necessarily level the playing field between IPPs and utility self-build projects being bid into RFOs?

A. No. If IPP bids are restricted to terms of less than 30 years or if IPPs decide to bid for terms of less than 30 years, the IOUs should take into account this difference in bid terms between UOG and IPP projects in their bid evaluations.

Q. How does the difference in bid terms come into play in the bid evaluation?

A. For an IPP project, ratepayers are obligated to purchase power from the IPP plant only during the term of the PPA (e.g., up to 10 years). On the other hand, ratepayers are obligated to pay for power from a UOG plant over its expected life of 30 years or more. The bid evaluation process must properly consider the ramifications of the different terms of these obligations.

Q. How have the IOUs attempted to evaluate projects with different lives in the past?

A. IEP submitted a data request to each of the IOUs asking how they compared 10-year or shorter PPA offers with longer-term bids in their last long-term all-source RFO for energy and capacity. SCE did not provide a useful response.[33] SDG&E stated that this situation did not arise in its last RFO but, if it had, that SDG&E would have applied unspecified "end effects" in order to evaluate the bids over an equal time period.[34] The most detailed response came from PG&E, which explained that it compared projects with different lives by estimating the levelized cost of power over the life of each

[33] SCE response to IEP data request 5 question 1, as presented in Attachment N.
[34] SDG&E response to IEP data request 5 question 1, as presented in Attachment O.

agreement in order to control for different project lives.[35] For example, for a 10-year PPA, PG&E estimated the present value of net costs[36] associated with the project over the 10-year contract term and then divided by the present value of capacity provided over the 10-year period to arrive at a levelized cost of power (on a $/kW-year basis). Similarly, PG&E estimated the present value of net costs associated with a UOG project over the project's life and divided by the present value of capacity provided over the project's life.

Q. Are there problems with PG&E's approach?

A. Yes. Calculating the levelized cost of power over the life of the PPA instead of the resource life misstates the net cost that the IOU incurs associated with that particular resource decision. While it is true that the IOU must pay for power from the IPP for the first 10 years of the analysis, once the PPA terminates, the IPP plant will almost certainly remain in the CAISO market with its capacity available to the IOU at the resource adequacy price and its energy available to the IOU at the market price of power. In other words, the IOU would NOT continue to purchase power from the IPP at its contract rate for years 11-30 but would instead purchase energy and capacity at short-run market prices.

[35] PG&E response to IEP data request 4 question 1, as presented in Attachment P.

[36] Net costs are the difference between the cost of the resource and the value of the products received from the resource. Note that in the case of long-term procurement when there is excess capacity, net costs can be positive (i.e., the cost of generation can exceed the short-run value of generation).

Q. How would you suggest correcting this improper levelization?

A. To appropriately account for the fact that the IPP project continues to provide power after the term of the PPA, it is necessary to extend the period of levelization for IPP contracts over the entire useful life of the IPP plant, typically 30 years.

Q. How significant is this error in PG&E's levelized cost calculation?

A. The significance of this error will depend on the particulars of the proposals being evaluated. If all projects have the same duration (e.g., 10 years), then the error is not important. However, if a UOG project has an assumed life of 30 years and an IPP PPA has a term of only 10 years, then the error can be significant. Using hypothetical but reasonable assumptions, I calculated that correcting for this error would reduce the levelized cost of a sample IPP bid by about a third. Such a reduction in the levelized cost used for bid evaluation could be decisive in whether or not a project makes the short list.

Q. Does your suggested approach ignore the fact that the IOU would ultimately procure power from another IPP after termination of the initial IPP's PPA?

A. No. Since SCE and PG&E have elected not to solicit long-term offers from existing non-renewable resources, the IPP plant is forced into the short-run energy and resource adequacy markets after the end of the PPA and is not able to continue selling power to the IOUs under a long-term PPA. Therefore, ratepayers only bear net costs related to the specific PPA being considered over the term of the PPA, with the net costs from the IPP plant falling to zero after expiry of the PPA (since the IOU is assumed to purchase power

from the short-term markets). The IOU's decisions related to other resources are immaterial when evaluating the bid of a specific IPP.[37]

Q. Is your proposal consistent with SDG&E's approach?

A. This is not clear. As noted above, SDG&E's description of its approach for evaluating assets of different lives was to rely on an end effects adjustment. However, SDG&E did not explain this adjustment. Therefore, without additional information on how SDG&E would calculate and apply end effects, I cannot comment on SDG&E's approach.

C. Bidders should be able to bid existing units without exclusion into RFOs

Q. Does the Commission have a policy on whether existing plants should be eligible to bid into utility RFOs?

A. The decision adopting the utilities' prior long-term procurement plans specifically stated, "the IOUs are authorized to procure existing resources (in addition to the authorized new generation)."[38]

Q. Have California IOUs allowed existing plants to bid into their long-term RFOs?

A. As discussed above, only SDG&E has issued an RFO that allowed existing non-renewable large-scale resources to bid for contracts of up to 10 years.[39] RFOs issued by

[37] It should be noted that if the existing IPP had the option to bid into a follow-on solicitation for a long-term PPA, then the IPP might have net costs after the end of the initial PPA period that should be reflected in the economic analysis.
[38] D.07-12-052 in R.06-02-013, p. 103.

PG&E and SCE that have been open to such existing resources have all provided contract terms of less than five years (i.e., short- or intermediate-term RFOs).[40] Long-term RFOs issued by PG&E and SCE (i.e., for contracts with a 10-year term) have restricted offers for non-renewable large-scale generation to new generation or repowers of existing generation.[41]

Q. What are the consequences of not allowing existing conventional resources to bid in long-term utility RFOs?

A. Not allowing existing conventional power plants to bid into long-term RFOs essentially precludes plant owners from entering into long-term power sales contracts after their initial PPAs expire.[42] The inability to enter into additional long-term contracts requires plant owners to amortize most or all of their capital costs in their initial PPAs. This increases long-run PPA prices.

Q. Are there policy benefits to excluding existing conventional resources from bidding?

A. Excluding existing conventional resources from bidding results in the development of additional gas-fired capacity. Encouraging new capacity could be a policy goal in a time

---

[39] SDG&E Request for Offers for Demand Response and Supply Resources, June 9, 2009, p-1, as presented in Attachment M. Products 5 and 6 provide contracts of 10 years for existing resources located within or outside of SDG&E's service territory, respectively.

[40] For example, PG&E's most recent Intermediate-Term Request for Offers Solicitation issued July 2010 accepted offers for existing or new resources for contract terms of up to three years or five summers (pages 3-4) , as presented in Attachment Q.

[41] For example, PG&E's most recent All Source Long-Term Request for Offers Solicitation issued April 2008 accepted offers from renewable resources, new distributed generation, qualifying facilities, repowers, and new conventional generation, but not existing conventional generation (pages 6-7) and SCE's New Gen Request For Offers, issued August 14, 2006 accepted offers from new conventional generation, repowers, and qualifying facilities, but not existing conventional generation (pages 5-7). See Attachment K and Attachment L

[42] Some plants could conceivably be entered into long-term contracts with non-IOU power purchasers or with SDG&E, but there are limited opportunities for such transactions since PG&E and SCE purchase the bulk of the state's power.

of capacity shortage when new resources are needed to ensure reliability. However, based on the Commission's preferred planning assumptions in this proceeding, there is currently a surplus of capacity serving California.[43]

On the other hand, allowing existing resources to bid into long-term RFOs can provide policy benefits. By entering into long-term PPAs with existing resources during times of excess capacity, the IOUs could lock in lower prices for consumers in the future. Allowing existing resources to bid for long-term PPAs would also discourage the development of new capacity in times of excess capacity, since more expensive new capacity would likely not win an RFO if sufficient lower-cost existing capacity were available. This would avoid the cost and environmental burden of unnecessary development.

Q. If existing non-renewable resources are allowed to bid into an RFO, should those bids be penalized relative to bids from new resources?

A. No. Existing resources and new resources should both be evaluated based on their attributes, such as cost, heat rate, and environmental impact. These attributes may differ between new plants and existing plants, but they also differ among new plants and among existing plants. Some existing plants (especially plants that are only 10 years old) may have higher efficiencies and lower environmental impacts than some new plants, so there is no *a priori* reason to impose a bid evaluation penalty on existing plants. Instead, each

[43] Track I Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator Corporation in California Public Utilities Commission proceeding R.10-05-006, July 1, 2011, Slide 35.

plant should be evaluated on its own merits according to the criteria described later in this testimony.

D. Utilities should be required to include all project development costs in their bids

Q. Do IPPs include project development costs in their bids?

A. The sole source of revenue for independent developers is project revenue, so IPPs must try to incorporate all project scoping and development costs in their bids. They must also attempt to recover their corporate overhead expenses and all other expenses through the revenue they receive from power sales.

Q. What happens if an IPP is unsuccessful in its efforts to recover these costs through project revenues?

A. If an IPP is unsuccessful in such efforts (e.g., market conditions do not allow pricing to recover these costs), then the IPP's earnings will be reduced, resulting in lower profits or greater losses.

Q. Do utilities have expenses for power project development?

A. Yes. For example, PG&E received funds in its last general rate case (GRC) for a Strategic Renewables Investment group to be responsible for "executing strategic investments" and acquisitions of renewable energy projects.[44] PG&E has also had (and

[44] PG&E requested $10 million for a Strategic Renewables Investments group in its 2011 GRC (A.09-12-020 PG&E-05 p. 6-37, as presented in Attachment R). As part of the settlement agreement that was adopted by the Commission, PG&E was awarded $2 million for this purpose. D.11-05-018, Attachment 1, page 1-7.

may currently have[45]) a Renewable Resource Development group to conduct project screenings of greenfield renewable development opportunities involving "preliminary due diligence review, preliminary land siting, economic and project feasibility, and interconnection feasibility studies"[46] and "all other development activities that may occur before project construction."[47]

Q. Do IOUs include these costs in their bids?

A. It is unlikely. The IOUs should not include in their bids any expense that is recoverable through GRC funding or other ratepayer funding so as not to charge ratepayers twice for the same expense.

Q. Approximately how large are the project development costs that utilities can exclude from their project bids by using GRC funding?

A. PG&E estimated that costs to evaluate and perform initial project screenings amount to "tens to hundreds of thousands of dollars per project" and that for renewable projects "it will be necessary to screen a number of projects to arrive at [a] small percentage of these projects that will ultimately be constructed."[48] PG&E estimated its annual costs at $37 million per year for these activities.[49]

[45] PG&E was denied the funding requested for this group in the settlement adopted in D.11-05-018. I do not know whether the group is continuing using other funds. D.11-05-018, Attachment 1, page 1-7.
[46] PG&E testimony in A.09-12-020, Exhibit-005 page 6-37, as presented in Attachment R.
[47] PG&E testimony in A.09-12-020, Exhibit-005 page 6-34, as presented in Attachment R.
[48] PG&E testimony in A.09-12-020, Exhibit-005 pages 6-37 – 6-38, as presented in Attachment R.
[49] PG&E testimony in A.09-12-020, Exhibit-005 page 6-37, as presented in Attachment R.

Q. Should these costs be included in the evaluation of UOG bids?

A. Yes. To compare UOG projects with IPP projects on an equal footing, these costs should be included when evaluating UOG projects.

Q. Aside from project development expenses, are there other kinds of corporate overhead expenses that should be included in the evaluation of UOG projects?

A. Yes. A utility's management must provide some manner of oversight over its project development activities. While this is not necessarily a full-time effort by senior management, these key employees must divert some attention from other utility activities to manage project development and acquisition activities, so a *pro rata* allocation of management time should be included when evaluating UOG projects. In addition, bid evaluations of UOG projects should include a *pro rata* share of the IOUs' Administrative and General expenses and fixed building and office costs.

Q. Do you have an estimate of the magnitude of these overhead expenses?

A. Yes. Based on PG&E's most recent GRC application, I estimate that PG&E's overhead expenses related to project development activities are about $8 million per year.[50]

Q. How should these costs be treated in bid evaluation?

A. If a utility has a project development team and the utility's costs associated with that team are recovered through general rates, then all of the team's costs, including costs for

[50] Calculated as a *pro rata* share of Power Gen A&G costs ($6 million) plus the revenue requirement associated with a *pro rata* share of Weighted Average Plant ($2 million), based on data obtained from A.09-12-020 Exhibit 2, Table 7-14 and 9-1 and Appendix, A-10 and A-24 and Exhibit 5, Table 6-1. See Attachment R and Attachment S.

investigating projects that are ultimately not built, should be estimated by the bid evaluators and included as an adder to the UOG project's costs. Similarly, all overhead costs associated with project development and bid development should be estimated by the bid evaluators and included as an adder to the UOG project's costs. Only when a fair estimate of the *pro rata* portion of these overhead costs is included in the bid evaluation is it possible to compare UOG and IPP bids.

Q. If the bid adder changes the selection of winning proposals such that the UOG project is rejected and an IPP project is selected, would this result in higher overall costs for ratepayers?

A. It is possible that ratepayer costs would be higher, since ratepayers would need to pay for the IOU's project development costs that are recovered through general rates even though the UOG project is not selected. This can be remedied by not allowing recovery of IOU project development costs through general rates. Instead, project development costs and associated overhead costs should be recovered through UOG bids.

Q. Is this recommendation consistent with prior Commission policy?

A. Yes. When SCE asked for ratepayer funding of a Project Development Division, the Commission stated:

> [We] find it necessary to subject SCE to the same cost recovery risks as faced by independent producers. Independent producers' development costs associated with unsuccessful projects are not recoverable from ratepayers. It is a matter of

fairness that SCE assume that same risk, if it chooses to participate [in project development].[51]

E. The uncertainty in UOG and IPP project costs must be considered in the bid evaluation

Q. Is there uncertainty in the future cost to ratepayers from a UOG project?

A. There can be, depending on how the project's costs are recovered in rates. If an IOU is able to fully recover its installed costs, operating and maintenance (O&M) costs, fuel costs, and future capital additions regardless of the IOU's estimates for these values and the plant's operational characteristics submitted as part of the UOG bid, then there is significant uncertainty in the future cost to ratepayers of the UOG project.

Q. Is there uncertainty in the future cost to ratepayers from an IPP project?

A. There might be, although typically that uncertainty will be less than for a UOG project. The level of uncertainty in costs from an IPP project depends on the amount of time between submission of bids and final contract approval as well as specific terms and conditions of the PPA under which the IPP operates. It is my understanding that PPAs typically are not cost-of-service agreements, meaning that the uncertainty in costs for a project selling pursuant to a PPA is less than that typically seen in UOG projects.

Q. Given these potential differences in uncertainty associated with power costs from UOG and IPP projects, is it appropriate to consider these uncertainties when comparing UOG and IPP projects in a competitive solicitation?

A. Yes.

[51] D.06-05-016, p. 52.

Q. Is there a theoretical basis for considering risk as part of a bid price?

A. Yes. There is substantial theoretical support for considering risk as part of a bid price. Consider, for example, the following publications:

- In a 2008 *Electricity Journal* article, Dr. C.K. Woo compared tolling agreements to renewable energy contracts. In the paper he discussed how a contract's financial risk should be incorporated into the decision-making process and concluded that a contract's value-at-risk should be computed for this purpose.[52]

- In a 1993 *Electricity Journal* article, Susan Morse and Meg Meal discussed how utility incentives and other strategies should be used to provide an even playing field for power purchases *vis a vis* utility builds. They identified several principles to guide the regulatory framework, including the need for all risks associated with the utility build option to be included in the utility build price: "When a utility-build option is competing against purchase options, certainly all the risks associated with the build option should be included in the utility's own 'bid price,' including the incremental cost of accessing capital markets and issuing new debt and equity to finance plant construction. In addition, for a true apple-to-apples comparison between buy and build, the utility must be held to the same pricing, performance and scheduling

[52] C. K. Woo. "Should a Lower Discount Rate be Used for Evaluating a Tolling Agreement than Used for a Renewable Energy Contract?" *Electricity Journal*. Volume 9, Issue 21. November 2008, p. 40, as presented in Attachment T.

standards to which the [non-utility generator (NUG)] is held, over a time frame equivalent to the term of the NUG contract."[53]

- In the 2008 paper by The Analysis Group cited above, Dr. Tierney and Dr. Schatzki identified key criteria for evaluating offers. These include "[shifts] in risks among the utility, the seller and retail customers associated with various provisions in the contract, such as fuel price indices, availability penalties, collateral requirements of the utility and supplier, [and other] non-price policy factors and considerations (e.g., environmental impacts, development risk for a new project, the utility's fuel or portfolio diversity, etc.)."[54] Furthermore, they note that a "successful evaluation should attempt to account for these costs and risks, assign weights that appropriately reflect the value proposition (and risks) to customers, make comparable evaluations across all offers (including self-build and affiliate offers), and complete evaluations in a timely and efficient fashion to provide proper incentives for bidders."[55]

Q. Is there precedent for considering risk as part of a bid price?

A. Yes. For example, as part of PG&E's proposed reorganization during its bankruptcy proceeding, the Federal Energy Regulatory Commission required PG&E's proposed generation spinoff ("Gen") to "benchmark the PSA's non-price contractual terms against the comparison group. This included analyzing the assignment of responsibilities and

[53] Susan Morse and Meg Meal. "Balancing Incentives in a Competitive Marketplace." *Electricity Journal*. August/September 1993, pp 30-31, as presented in Attachment U.
[54] Tierney and Schatzki, p. 28, as presented in Attachment I.
[55] Tierney and Schatzki, p. 28, as presented in Attachment I.

risks and the consequences of non-performance by the parties. Gen compared the non-price terms of its PSA with those of typical, arms-length bilateral sales agreements. The terms evaluated included availability risk (a measure of reliability), fuel price risk, dispatch control, hydrologic risk, and Diablo Canyon facility security risk."[56]

Q. How can the risks of IPP and UOG bids be considered on the same footing?

A. The risks to ratepayers from all bids should be explicitly considered by evaluating the potential risk of each bid element. For example, if the O&M price embedded in an IPP bid is a fixed price with a pre-specified escalation rate, it will have no ratepayer risk (i.e., uncertainty) associated with it, since the IPP absorbs any variation in costs relative to the bid. However, if increases in O&M costs relative to the costs used in evaluating a project proposal are passed through to ratepayers, as is often the case with UOG projects, then the bid evaluation process must consider the potential for O&M cost increases. As described in more detail below, whenever this is the case, the utility and the independent evaluator should add to the O&M cost for the UOG bid an adder to reflect the risk to ratepayers of such a cost increase.[57] This adder is needed to more accurately assess the true expected costs to ratepayers of projects for which they bear the risk of cost increases.[58]

[56] C. K. Woo. "Benchmarking The Price Reasonableness Of A Long-Term Electricity Contract" *Energy Law Journal*, Volume 25 (2004), p. 373, as presented in Attachment V.

[57] If an IOU enters into a long-term service agreement or other type of hedging agreement that assigns a project's cost overruns to a third party, the UOG project should not be assigned the adder associated with the risk covered by that agreement. However, the Commission should require the IOU to file annual compliance reports to ensure that this agreement (or an equivalent agreement) remains in place throughout the life of the project.

[58] "[The energy price] is the sum of a baseline price and a risk premium." C. K. Woo. "Cross hedging and forward-contract pricing of electricity?" *Energy Economics* 23 (2001) p. 1, as presented in Attachment W.

Q. Aside from the potential for higher expected costs associated with a project using cost-of-service ratemaking, are there other risks that this ratemaking structure places on ratepayers?

A. Yes. Aside from the potential for higher expected costs, UOG projects can have much greater variance in their costs relative to an IPP project. If a UOG project uses cost-of-service ratemaking for cost recovery and an IPP's fixed costs and operating characteristics are fully specified in the project's PPA, then there is significantly greater uncertainty in the UOG project's costs than the IPP's project costs.

Q. Should this be of concern to ratepayers?

A. Yes. If two projects have the same expected value for net cost but one has greater ratepayer risk and one has lower ratepayer risk, the project with lower ratepayer risk is clearly preferable from a ratepayer perspective. If risk were not considered, this preference would not be apparent. Similarly, if the bid evaluation only examines the expected value of costs, it is possible that proposals with lower expected values for net costs but with higher risk factors may be deemed superior to slightly higher-priced projects with lower risk factors, even though ratepayers might prefer the higher-cost but less risky project.

Q. Is it possible that costs from the UOG project will be less than expected in bid evaluation?

A. This is possible. However, based on the information I reviewed in response to data requests and other information regarding historical non-fuel O&M costs for UOG projects, this has not typically been the case.[59]

Q. How should the IOUs establish the likely distribution of costs associated with UOG and IPP proposals?

A. The utilities should identify the potential change in ratepayer costs associated with each specific proposal over the life of the project's obligation to the IOU. Ranges of possible values and the probabilities for specific values within these ranges should be set based on historic variability of these parameters. For example, the historic variability of natural gas prices can be used to establish probability weights for different gas price scenarios to be used in the analysis for projects for which ratepayers bear natural gas price risk. Other uncertain variables include installed costs, future capital additions, fixed and variable O&M, forced and maintenance outage rates, plant capacity, plant efficiency, and plant life. I discuss this approach in greater detail below.

[59] For example, see PG&E's updated costs for its Gateway project after installing dry cooling and updating other costs in PG&E's Advice Letter 2928-E (presented in Attachment Y) and data files for Fabrizio, Rose, and Wolfram. "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." *American Economic Review*, 2007, Vol. 97 (September): 1250-1277. Available at http://faculty.haas.berkeley.edu/wolfram/ (Calculations described below.)

Q. What do you propose if the Commission does not choose to adopt your proposal for explicitly incorporating risk into the evaluation of projects?

A. If the Commission does not adopt my proposal to require the explicit consideration of cost and performance risk when evaluating UOG projects, I have two alternate proposals.

1. The Commission could require the IOU's shareholders to accept the risks associated with potential changes to the cost and operating characteristics of their self-build projects, just as an IPP must generally do. Transferring risk of UOG cost overruns to IOU shareholders would also result in greater comparability of UOG and IPP projects, since they would have similar risk profiles for ratepayers.

2. Alternatively, the Commission could require utility bids to include hedging and contracting measures that shield ratepayers from risks to the same extent that IPP bids do.[60] This is the recommendation of Tierney and Schatzki, who identify, as a key safeguard against improper self-dealing, the requirement of "comparable forms of risk mitigation in utility and non-utility offers, such as comparable treatment of offer 'refreshing' and hedging of various types of risks, including development and construction risk, power plant performance risk, fuel price risk, and risks tied to changes in law or regulation, such as costs of mitigating carbon emissions."[61] This approach would also place the risks of IPP and UOG bids on equal footing, though it could result in higher transaction and risk mitigation costs and be administratively burdensome.

[60] Certain UOG contracts already have these protections in place.
[61] Tierney and Schatzki, p. viii, as presented in Attachment I.

Q. How would the first alternative be reflected in a UOG bid?

A. Under the first alternative, the IOU would agree to stand by its proposal and to not request any after-the-fact adjustments to the costs of its plant as proposed. In this case, the cost of risk would not be reflected in the UOG bid, since ratepayers would not bear this risk. The Commission may consider using as a model for this approach the ratemaking treatment of cost-overrun risk for the Contra Costa Generating Station (Oakley plant) provided in the February 2010 Partial Settlement Agreement in A.09-09-021.[62]

Q. How would the second alternative be reflected in a UOG bid?

A. Under the second alternative, the IOU would explicitly procure hedges for construction costs, O&M costs, plant efficiency, plant availability, and plant capacity and document that it has included these hedging costs in its bid proposal. The Commission already requires the IOUs to procure hedges to protect ratepayers against unexpected cost increases up to the Commission-approved Customer Risk Tolerance factor.[63]

[62] For example, with regard to O&M costs increases, the settlement states: "PG&E has agreed to fix operations and maintenance ("O&M") rates for CCGS through January 1, 2022, based upon the O&M forecast used in the bid evaluation to evaluate and ultimately select the Project as a winner in the 2008 LTRFO solicitation. The Project is expected to be operational in the 2014, resulting in a fixed revenue stream for at least the first 8 years of operations. Thus, if actual O&M costs are greater than forecast, PG&E cannot recover its excess costs in rates…There are a few limited opportunities where PG&E can propose to adjust its O&M rates via an expedited advice letter process in the first eight years (i.e., until 2022): (1) delays in closing; (2) increased O&M caused by governmental agency requirements or changes in permitting assumptions; (3) changes in operating profile from the maximums assumed in forecast (i.e., 333 starts/year and 4329 operating hours/year); and (4) on a one time basis, PG&E may update its forecast of Long Term Service Agreement ("LTSA") costs to reflect the terms and conditions in the executed contract." Motion for Approval of Partial Settlement Agreement Between and among Pacific Gas And Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, The Coalition Of California Utility Employees, And California Unions For Reliable Energy in A.09-09-021, filed February 17, 2010, p. 5, as presented in Attachment X.

[63] D.07-12-052 in R.06-02-013, December 20, 2007, pp. 173-178.

Q. What if a UOG project does not provide adequate proof that it has hedged its project's cost and operational characteristics to a level consistent with an IPP?

A. Under this circumstance, the UOG project should be considered non-conforming and face possible disqualification from the RFO unless the IOU is willing to require shareholders to bear the residual risk.

3. Proposed Bid Evaluation Framework

Q. How should the bid evaluation process be structured?

A. I recommend that a bid evaluation algorithm be established and made known to bidders, including the parameters to be considered, the method for quantifying each parameter, information needed for this quantification process, and the weighting factor for each parameter. The algorithm should consider all relevant project parameters, including project risks. In cases where information will need to be updated prior to the bid evaluations, such as with regard to gas price forecasts, the utilities should establish and make known the methodology for updating the forecast based on publicly available information.

Q. What categories of project parameters should be included in the bid evaluation process?

A. The categories that should be considered are the present value of net financial benefit, which should consider the financial benefits, financial costs, and financial risks of a project; project viability, based on the Project Viability Calculator; environmental characteristics; and other qualitative parameters that should influence bid evaluation.

Q. Do you have recommendations for weighting factors for each of these elements?

A. Yes. A complete bid evaluation algorithm, including weighting factors, is provided as Appendix A to this testimony.

Q. Over what time period should these net present value calculations be performed?

A. The calculations should cover the time period set by the longest-term bid submitted in the RFO. Shorter bids should be extended for the purposes of the bid evaluation to cover this longer term. As discussed above, IPPs with PPA terms shorter than the life of a UOG project would have their net costs (i.e., project costs less project benefits) evaluated over the same timeframe as the UOG projects.

A. Financial Characteristics

Q. What specific elements should be considered in the calculation of the net present value of financial benefit?

A. The following elements should be considered:[64]

- Financial Benefits: Locational market value of energy (by time of delivery), market value of capacity, market value of ancillary services (including the value of Automatic Generation Control), value of optionality, and local Resource Adequacy benefit;

- Financial Costs: Capacity costs, variable O&M costs, fixed O&M costs, transmission upgrade and interconnection costs, greenhouse gas costs, hedging

[64] Some of these factors might not be applicable to all proposals. For example, IPP bids do not need to separately identify their hedging costs and fuel transportation costs, since these costs are included in the PPA price or absorbed by project developers.

costs, fuel storage and transportation/contracting costs, and project development costs (including associated overhead costs);[65] and

- Financial Risks: Operational risks that reduce market values (i.e., potential changes to availability, ramp rates, life of project, etc.), operational risks that increase costs (i.e., potential changes to heat rate, O&M costs, etc.), fuel price uncertainty, risk of higher transmission costs, risk of higher construction and financing costs, risk of unanticipated capital expenditures over the plant's lifetime, risk from fuel availability exposure (such as with hydroelectric power), risk from greenhouse gas cost exposure, and congestion risk.

Q. Have you developed adders to account for the difference in risk profiles between UOG and IPP projects?

A. I have estimated three sets of adders to address some of the incremental uncertainty in ratepayer costs for UOG projects relative to PPAs. The three adders relate to (1) actual installed cost relative to the cost initially proposed for the project, (2) changes in heat rate relative to the project's initial heat rate, and (3) changes in O&M costs relative to the project's initial estimates.

Q. Do these adders apply equally to both fossil-fired and renewable generation projects?

A. Given the difficulty in obtaining data, these adders were developed based only on data for utility-owned gas-fired plants. However, until more data that are specific to renewable

[65] As noted above, these costs do not need to be separately identified for IPP bids.

projects are available, the installed cost and O&M adders can be applied equally to fossil-fired and renewable generation projects. The heat rate adder should be applied only to gas-fired plants. There may be additional risk factors associated with renewable plants not incorporated by the installed cost and O&M adders. These should be evaluated when more data related to utility-owned renewable projects are available.

Q. Are there additional uncertainties in UOG project costs and performance other than those for which you developed risk adders?

A. Yes. However, I was only able to obtain publicly available data for the three factors that I examined. I suspect that the IOUs might have data that could quantify the uncertainty in the factors that I don't address here, and I recommend that the Energy Division obtain the necessary data from the IOUs or from other sources to calculate appropriate adders to account for these risk factors. These factors include:

- Operational risks that reduce market values (availability, longer-than-expected ramp rates, life of project, etc.);
- Fuel price uncertainty;
- Risk of higher transmission costs;
- Risk of unanticipated capital expenditures over the plant's lifetime;
- Price risk from indexed priced offers;
- Risk from fuel availability exposure (mainly with hydro);
- Risk from greenhouse gas cost exposure; and
- Congestion risk.

Q. Have you developed similar factors to account for the uncertainty in IPP project costs?

A. No. I have assumed that the capacity, heat rates, and non-fuel O&M costs for IPP projects are fully specified in their PPAs, meaning that there should be little or no uncertainty in

these factors. If a PPA were structured to assign some of these risks to ratepayers, adders would need to be assigned to the appropriate cost elements to reflect this risk.

Q. How did you derive the adder for changes in capital costs?

A. Based on the IOUs' recent experience with UOG projects, I determined the capacity-weighted average percentage difference between the IOUs' initial installed cost estimates and the ultimate installed costs of their gas-fired generation.[66] Based on these data, I estimated that a UOG project (either one that is acquired from an IPP or one that is developed by the IOU) should be assigned a 9% adder relative to its initial cost estimate if ratepayers are to bear the risk for capital cost overruns.

Q. How did you derive the adder for changes in heat rates?

A. I developed a distribution of changes in heat rate for utility-owned gas-fired generation over the course of the plants' lives compared to the plants' Year One heat rates based on information from an extensive database of cost and operating characteristics of utility-owned generation.[67] Using this distribution, I simulated the expected variation in heat rate for a UOG plant over its lifetime.[68] Based on this Monte Carlo simulation,[69] I estimated

[66] For PG&E's Gateway project, I used their estimated cost of the project after installation of dry cooling as proposed in PG&E's Advice Letter 2928-E (presented in Attachment X).

[67] Data files for Fabrizio, Rose, and Wolfram. "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." *American Economic Review*, 2007, Vol. 97 (September): 1250-1277. Available at http://faculty.haas.berkeley.edu/wolfram/. Database filtered to include only natural gas-fired plants of at least 150 MW in states that did not deregulate and only those plants with at least three data points. Year One data represents the first year of data available in the database (which covers 1981-1999 only) and not necessarily the plant's first year of operations, and the data extends for at most only 19 years, not the entire plant lifetime. This likely underestimates the degradation of heat rate over the plant's lifetime.

[68] I assumed that the variations from Year One heat rates observed in this dataset represent approximately the distribution of heat rates over a plant's lifetime. This likely underestimates the degradation of heat rate over the plant's lifetime, since the dataset covers only 19 years.

[69] I performed the simulation by applying all the percent variations from Year One heat rates to a starting-value heat rate of 7,000 Btu/kWh and having the model choose one of these potential heat rates during each

that a UOG plant would have an average heat rate that is 5.5% higher than the heat rate that the plant has when it comes online.[70]

Q. How should this adder be applied?

A. If ratepayers would be at risk for the higher costs associated with heat rate degradation, the expected heat rate increase must be incorporated in the bid evaluation. This can be done as a 5.5% heat rate adder or as a heat rate forecast that reflects anticipated degradation resulting in a 5.5% increase in the levelized heat rate over the bid evaluation period. If the utility provides a heat rate forecast showing degradation over time, the 5.5% adder should be adjusted so that the degradation included in the heat rate forecast plus the additional heat rate adder sum to a 5.5% increase in the levelized heat rate over the bid evaluation period.

Q. How did you derive the adder for O&M costs?

A. Using the database of historic utility generation costs and operating characteristics discussed above, I used a regression analysis to disaggregate fixed and variable O&M costs from the database's values of total non-fuel O&M costs. From this initial analysis, I estimated that an average value for variable O&M would be about $3/MWh in 2010 dollars.[71] Subtracting this amount from the plant-specific total O&M amount allowed me

---

of 500,000 independent trials. To be consistent with technical feasibility, I excluded all heat rates below 6,500 Btu/kWh from this selection.

[70] The 5.5% is calculated by comparing the mean heat rate from the 500,000 trials (7,387 Btu/kWh) to the assumed starting-value heat rate (7,000 Btu/kWh).

[71] The database did not disaggregate fixed and variable O&M costs. Thus, I assumed that variable O&M costs were not uncertain and that all uncertainty was in fixed O&M. With a database that disaggregated fixed and variable O&M costs, I would not need to make this simplifying assumption.

to estimate fixed O&M by plant for gas-fired UOG projects.[72] From these new data, I derived percentage changes in fixed O&M for each plant compared to the plant's Year One fixed O&M costs and then used the distribution of changes to fixed O&M costs to simulate the expected fixed O&M costs for a UOG plant over its lifetime. Based on these simulations, I found that the expected fixed O&M cost was 83% higher than the starting O&M cost value.[73] An 83% fixed O&M adder should therefore be added to UOG proposals that put ratepayers at risk for direct pass-through of unexpected increases in fixed O&M costs.[74]

Q. Do these adders account for the greater potential variation in financial costs and benefits associated with UOG projects when compared to IPP projects?

A. It would not be unreasonable to increase the adders to account for this greater risk faced by ratepayers. However, in order to provide conservative estimates for these adders, I have calibrated them only to correct the project bids to better approximate expected ratepayer costs. I have not made any adjustments to reflect the greater uncertainty that ratepayers face with a UOG project on account of the greater potential variation in ratepayer costs.

[72] In cases where subtracting the $3/MWh variable O&M cost yielded a negative residual non-fuel O&M amount for three or more data points for a particular plant, I assumed that the reported non-fuel O&M costs for that plant represent fixed costs only and did not subtract from the reported value any variable O&M amount. In cases where subtracting the $3/MWh variable O&M cost generally yielded positive residual values with isolated negative values, I assumed that the reported values generally included $3/MWh variable O&M costs and eliminated the negative values from the dataset.

[73] Please see footnotes 67 and 68 for more information on the data source, how the data were filtered, and the conservative assumptions used in developing the selection values for the Monte Carlo analysis. The 83% adder is calculated by comparing the mean fixed O&M cost from the 500,000 trials ($18/kW-year) to the starting-value fixed O&M cost ($10/kW-year).

[74] If the UOG proposal includes a guaranteed level of non-fuel O&M costs, then the adder should not be applied during bid evaluation.

Q. How do you propose these adders be applied to UOG project bids to reflect the fact that changes in UOG costs relative to bid estimates are passed through to ratepayers?

A. In the absence of specific, transparent data regarding changes in UOG installed costs, non-fuel O&M costs, and heat rates relative to costs and operating characteristics originally proposed by the IOU when it submitted its project for evaluation, I estimate that capital costs should be increased by 9%, fixed O&M costs should be increased by 83%, and heat rates should be increased by 5.5% for each project that assigns to ratepayers the risk for cost increases associated with these parameters. Projects should be assigned only those adders that are associated with parameters for which ratepayers would bear the risk of unplanned changes in these parameters.[75]

Q. Should these adders be applied to all UOG bids for the IOUs?

A. Yes. I recommend that these adders apply to UOG projects proposed by any of the IOUs.[76]

Q. Why should the same adders be applied to UOG projects for all three IOUs?

A. The heat rate and O&M adders were derived based on information for a wide range of utility projects. Thus, they represent industry-wide trends. The capital cost adder was derived based on aggregated information from the three IOUs. This increases the sample size for the adder. Given the small number of plants that the IOUs have developed in the

[75] Of course, these estimates might change if I were to have access to a full complement of cost and performance data for UOG projects.

[76] It might be appropriate to include adders for IPP projects based on the uncertainty in IPP project costs and performance if ratepayers would be at risk for the cost increases.

recent past, it would be unreasonable to use IOU-specific cost adders based on individual companies' past performance.

Q. Do you recommend that the IOUs use these specific adders in their evaluation of UOG proposals in their RFOs?

A. These adders are a proxy for an actual simulation of the future expected value for costs associated with UOG projects. If the Commission adopts my recommendation that the IOUs reflect uncertainty in the evaluation of UOG and IPP projects, then I believe that the Energy Division should assemble a working group to develop a set of adders based on the best available information. These adders should account for the three risk elements for which I have estimated adders as well as for additional risk factors, such as those listed earlier in my testimony. However, such an effort might take a significant amount of time and effort. If that proves to be the case, then I recommend using the adders I developed for evaluation of UOG projects in the interim.

B. Non-Financial Characteristics

Q. What environmental characteristics should be considered in the bid evaluation algorithm?

A. The environmental score should consider the following elements:

- Cumulative pollution exposure to criteria pollutants within one mile and six miles of the facility;
- Local community outreach plans;

- Quantities and potential costs to IOU and to society associated with project environmental characteristics that were not included in the energy valuation, including environmental costs that have been mitigated using the best-available control technology;
- Whether the project is on a brownfield or a greenfield site; and
- Renewable benefits (when considering renewable projects).

Q. What qualitative parameters should be considered?

A. The qualitative score should provide or deduct points for the following parameters:

- Start date consistent with IOU preference; and
- Conformance with RFO terms and conditions (i.e., score reduction for modifications that shift costs/risk to ratepayers).

C. Project Selection

Q. How should a short list of projects be selected?

A. The IOUs should calculate the total score for each project based on the algorithm in Appendix A. Projects with the highest total scores from the bid evaluation process should be selected for the short list. Projects should be added to the list in rank order until the list includes no less than 200% of the needed capacity and energy.[77]

[77] For example, if the need is 500 MW, the IOU should have a short list that initially includes at least 1,000 MW of projects.

Q. Why do you recommend making the shortlist larger than the need identified in the RFO?

A. It is important to have a sufficient number of projects on the shortlist to allow the IOU the opportunity to reject proposals during negotiations without putting the overall solicitation in jeopardy. However, too large a short-list could be administratively burdensome to the utilities and would extend the bid evaluation period.

Q. Once a short list of projects is selected, how should the least-cost/best-fit projects be determined?

A. All of the short-listed projects should be evaluated on a portfolio basis to evaluate the least-cost/best-fit option. A model could be used to fully examine all portfolios of plants that meet the energy, capacity, and reliability requirements of the bid and the system. Such a model should evaluate the revenue requirement per MWh of sales associated with each of these portfolios.[78] It should also examine the robustness of each potential portfolio under a wide range of uncertain assumptions, such as fuel prices, uncertainty in actual UOG costs and performance relative to bid values, inflation, technological change, and other uncertain assumptions that would affect ratepayer costs. By developing the least-cost/best-fit portfolio under a wide range of assumptions, the modeling will explicitly examine important issues such as the benefits of fuel diversity, the importance

[78]It is my understanding that the IOUs each have different approaches for determining the overall least-cost/best-fit portfolio, even though the IOUs were only willing to disclose the broad outlines of their different approaches. The approach described above is one possible way to determine the least-cost/best-fit portfolio.

of longer (or shorter) contract terms depending on future assumptions regarding technological changes,[79] and levels of risk in customer costs.

To ensure that IPP and UOG projects are treated equally within this modeling, the utilities should be required to provide all modeling assumptions to their Procurement Review Groups prior to the release of the RFOs. For modeling assumptions that will need to be updated, they should provide an updating process, specifying the index that will be used to calculate the updated values and the timing of the update.

D. Repowers and Expansions

Q. Under your proposed evaluation procedure, how would project repowers and expansions be evaluated?

A. Project repowers/expansions would be evaluated using the framework developed above. The financial costs of these projects would be assessed by considering the costs to the IOU for purchasing the output from the proposed project, and the financial benefits would be assessed by considering the market value of the repowered/expanded project (i.e., the market value of capacity, energy, and other benefits of the new project).[80]

[79] Longer contracts can be advantageous because they provide greater cost certainty and allow capital costs to be amortized over a longer period. However, they also lock the IOU into a particular technology that may become outdated and keep the IOU under contract even if a plant's capacity is no longer needed. Shorter contracts provide the opportunity to transition more quickly to a new, lower-cost technology and to move away from unneeded plants to better match demand. A diversified portfolio therefore includes contracts with a range of terms. In order to prevent a weak market position, a strong portfolio is also structured so that contract expiration dates are staggered.

[80] This is a conservative estimate of the net market value of the repowered/expanded project. It could be argued that, absent a PPA for the repowered project, the existing project would shut down, which would result in a higher market price for energy and capacity.

4. Other Issues

Q. Are there other issues that you would like to address in this testimony?

A. Yes. There is one other Track III issue I would like to address: the Energy Division's proposal to limit the duration of PPAs with existing power plants that use once-through cooling (OTC).

Q. What is the Energy Division's proposal regarding contract terms with OTC plants?

A. The Energy Division proposes to limit the duration of any new PPAs with OTC plants to one year or less and to disallow new contracts with OTC facilities that extend beyond the plant's OTC compliance date unless one of the following conditions holds:

1. The State Water Resources Control Board finds that the facility is fully compliant with the OTC requirements of the Clean Water Act;
2. The PPAs are for the express purpose of enabling the repowering of the OTC facilities, the contracts do not result in the OTC system to be operational beyond the facility's compliance date, and the Commission authorizes the procurement of new capacity in this proceeding; or
3. The facility elects to comply with the OTC policy by means of Track 2 (reducing water intake or installing screens or other technologies to reduce impingement mortality and entrainment).[81]

[81] Administrative Law Judge's Ruling Denying Motion for Reconsideration and Motion Regarding Track 1 Schedule and Addressing Rules Track III *Issues* in R.10-05-006, June 10, 2011. Appendix A. http://docs.cpuc.ca.gov/efile/RULINGS/136997.pdf

Q. Is this a reasonable proposal?

A. No. The Energy Division has not justified why contracting with OTC plants should be restricted prior to the plants' compliance dates, which in many cases are not until the end of 2017 or 2020.[82] Restricting such contracting could increase ratepayer costs by reducing available capacity on the market and restricting the utilities' ability to enter into multi-year resource adequacy contracts. The facilities will be required to comply with OTC requirements regardless of the Commission's action, so there is no policy advantage to limiting contracting with these resources, just increased ratepayer costs. As such, the proposal should be rejected.

5. Conclusion

Q. Please summarize your recommendations.

A. My recommendations are as follows:

1. Information on the bid evaluation process and bid evaluation parameters should be available to all bidders prior to bid preparation;
2. IPP contract terms should not be capped and must be appropriately considered in the bid evaluations;
3. Bidders should be able to bid existing units into RFOs without exclusion;
4. Utilities should be required to include all project development costs in their bids;

[82] The compliance date for Encina, Contra Costa, Pittsburg, and Moss Landing is December 31, 2017. The compliance date for Huntington Beach, Redondo, Alamitos, Mandalay, and Ormond Beach is December 31, 2020. State Water Resources Control Board. *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*. October 1, 2010, Attachment 1, pp 13-14, as presented in Attachment Z. Also available at: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf

5. The cost of ratepayer risk associated with UOG and IPP projects should be incorporated in the bid evaluation process;
6. My proposed bid evaluation methodology should be used as a model for the IOUs' bid evaluations; and
7. The Energy Division's proposal to restrict contracting with once-through cooling plants should be rejected.

Q. Does this conclude your testimony?

A. Yes.

Appendix A

Structure of Bid Evaluation Algorithm: Project-Specific Analysis

Project Score = 60% * Present Value of Financial Benefit + 25% * Project Viability + 10% * Environmental Characteristics + 5% * Qualitative Parameters

Elements Considered Within Each Category

1. Present Value of Financial Benefit
    - Financial Benefits
        - Locational market value of energy (by time of delivery)
        - Market value of capacity
        - Market value of ancillary services (including the value of Automatic Generation Control)
        - Value of optionality
        - Local Resource Adequacy benefit
    - Financial Costs
        - Capacity costs
        - Variable O&M costs
        - Fixed O&M costs
        - Transmission upgrade and interconnection costs
        - Greenhouse gas costs
        - Hedging costs
        - Fuel storage and transportation/contracting costs
        - Project development costs (including associated overhead)
    - Financial Risks[83]
        - Operational risks that increase costs (e.g., heat rate, O&M costs)
        - Operational risks that reduce market values (e.g., potential changes to availability, longer-than-expected ramp rates, shorter project life)
        - Fuel price uncertainty
        - Risk of higher transmission costs
        - Risk of higher construction and financing costs
        - Risk of unanticipated capital expenditures over the plant's lifetime
        - Price risk from indexed priced offers
        - Risk from fuel availability exposure (mainly with hydro)

[83] The risk of heat rate degradation, O&M cost increases, and construction and financing cost increases should be incorporated using the risk adders discussed in this testimony or updated values provided by the Energy Division. I recommend that the Energy Division assemble a working group to recommend appropriate adders to account for the remaining risk factors.

    - Risk from greenhouse gas cost exposure
    - Congestion risk
2. Project Viability *(use Project Viability calculator)*
3. Environmental Characteristics (equal weighting for each factor)
    - Cumulative pollution exposure to criteria pollutants within one mile and six miles of the facility
    - Local community outreach plans
    - Quantities and potential costs to IOU and to society associated with project environmental characteristics that were not included in the energy valuation, including environmental costs that have been mitigated using the best-available control technology
    - Whether the project is on a brownfield or a greenfield site
    - Renewable benefits (when considering renewable projects)
4. Qualitative Parameters (equal weighting for each factor)
    - Start date consistent with IOU preference
    - Conformance with RFO terms and conditions (score reduction for modifications that shift costs/risk to ratepayers)

Scoring and Ranking Process for Project-Specific Analysis

Each project is to be scored within each of the four categories on a scale of 1-100. The category scores are then to be weighted and combined into a final project score as follows:

Table 1: Final Project Scoring

	Weight	Example 1	Example 2
PV of Financial Benefit	60%	80	95
Project Viability	25%	75	60
Environmental Characteristics	10%	50	85
Qualitative Parameters	5%	20	95
Final Project Score		**73**	**85**

For this scoring system, high scores are superior to low scores.

1. To obtain the category score for **Present Value of Financial Benefit**, the present value of costs and risks are subtracted from the present value of benefits to obtain a single present value of net financial benefits for each project. The minimum and maximum of the present values assessed for the project bids should be used to develop a range, and each project should be assessed a category score based on its position within this range: the highest present value receiving a category score of 100, the lowest present value receiving a category score of 0, and intermediate present values receiving scores based on their positions within this range (Table 2).

Table 2: Category Scoring for Present Value of Financial Benefits

[A]: Ranked Present Values (PVs)	*[B]: Normalized PVs [A]-$80,000*[84]	*[C]: Category Score [B[/$720,000*[85]
$80,000	$0	**0%**
$150,000	$70,000	**10%**
$500,000	$420,000	**58%**
$600,000	$520,000	**72%**
$800,000	$720,000	**100%**

2. To obtain the category score for **Project Viability**, each project should be assessed a preliminary score of between zero and 100 using the Commission's RPS Project Viability Calculator.[86] These scores should then be adjusted based on their positions within the range of project scores in the same manner as done for the Present Value of Financial Benefits scoring (Table 3).

[84] Subtract off the minimum present value.
[85] Divide by the maximum normalized present value
[86] Presented in Attachment AA and also available at http://www.cpuc.ca.gov/NR/rdonlyres/7B9EE608-CE16-4EAB-BEDC-616F526214EE/0/Final_RPS_Project_Viability_Calculator.xls

Table 3: Category Scoring for Project Viability

[A]: Ranked Scores from Viability Calculator	*[B]: Normalized Scores [A]-65*	*[C]: Category Score [B[/30*
65	0	**0%**
70	5	**17%**
80	15	**50%**
90	25	**83%**
95	30	**100%**

3. To obtain the category score for **Environmental Characteristics**, each project should be assessed a preliminary score of between zero and 100 for each of the five categories shown. These scores should then be averaged together (with equal weighting) to obtain the final project score for each category (Table 4).

Table 4: Category Scoring for Environmental Characteristics

	Example 1 Renewable on Pristine Site	*Example 2 Efficient Conventional Plant*	*Example 3 Less Efficient Conventional Plant*
Pollution Exposure	100	75	0
Outreach Plans	70	50	20
Environmental Characteristics	80	60	0
Brownfield vs. Greenfield	0	100	100
Renewable Benefit	100	0	0
Final Score	70	57	24

Preliminary scores for Cumulative Pollution Exposure should be assessed by comparing the expected exposure to the National Ambient Air Quality Standard (NAAQS) for each criteria pollutant within one mile of the plant and within six miles of the plant.[87] The exposure values for each criteria pollutant for both of these distances should be averaged together (all with equal weighting). These preliminary scores should then be adjusted based on their positions within the range of project scores to obtain a score between 0 and 100 (with the higher score associated with greater pollution exposure), as done to obtain the category scores for PV of Financial Benefit and Project Viability. To adjust the scores so that higher scores are associated with lower pollution exposure, each score should then be replaced with 100-the score (i.e., 60 becomes 40, 80 becomes 20, 100 becomes zero, etc.). This process is illustrated in Table 5 for four sample bids.

[87] These standards, which are developed by the U.S. Environmental Protection Agency, are summarized at http://www.epa.gov/air/criteria.html (presented in Attachment AB). The Primary Standards should be used for this assessment.

Table 5: Subcategory Scoring for Cumulative Pollution Exposure

[A]: Exposures as % of NAAQS for Each Pollutant, Averaged	*[B]: Normalized Scores [A]-30*	*[C]: Preliminary Subcategory Score [B]/69*	*[D]: Subcategory Score 100-[C]*
30	0	0%	**100**
50	20	29%	**71**
80	50	72%	**28**
99	69	100%	**0**

Preliminary scores for Local Community Outreach Plans should be assessed based on the comprehensiveness of the plans and the resources dedicated to implementation. These preliminary scores should then be adjusted based on their positions within the range of project scores to obtain a subcategory score between 0 and 100 (higher score for better plans), as done to obtain the category scores for PV of Financial Benefit and Project Viability.

Preliminary scores for Quantities and Costs associated with the Project's Environmental Characteristics should be assessed based on the specific environmental characteristics of each plant. These preliminary scores should then be adjusted based on their positions within the range of project scores to obtain a subcategory score between 0 and 100 (higher score for lower costs), as done to obtain the category scores for PV of Financial Benefit and Project Viability.

For the Brownfield vs. Greenfield category, projects proposed on brownfield sites should receive a score of 100 and projects proposed on undisturbed sites should receive a score of zero. Intermediary scores can be assigned to projects proposed on semi-disturbed land or disturbed land that serves as habitat for threatened or endangered species.

For the Renewable Benefit category, renewable projects should receive a score of 100 and non-renewable projects should receive a score of zero.

4. To obtain the category score for **Qualitative Parameters**, each project should be assessed a preliminary score of zero or 100 for each of the two categories. Projects with start dates consistent with the IOU's preference should receive a score of 100; other projects should receive a score of zero for this subcategory. Projects that conform to RFO terms and conditions should receive a score of 100; other projects should receive a score of zero for this subcategory if their proposed modifications shift cost or risk to ratepayers. (If several projects propose modifications that shift varying amounts of cost or risk to ratepayers, intermediary values between zero and 100 can be used to differentiate these projects.) These scores should then be averaged together (with equal weighting) to obtain the final project score for each category.

Portfolio Analysis

All of the short-listed projects should be evaluated on a portfolio basis to evaluate the least-cost/best-fit options. A model could be used to fully examine all portfolios of plants that meet the energy, capacity, and reliability requirements of the bid and the system. The IOU should examine each portfolio under a wide range of uncertainties to determine the robustness of the plan under different conditions. The model should evaluate the revenue requirement per MWh of sales associated with each of these portfolios.