BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE RPS PROCUREMENT PLANS

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In keeping with the schedule established in the *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals,* dated April 5, 2012, the Independent Energy Producers Association (IEP) offers the following comments. IEP will comment only on the Renewables Portfolio Standard (RPS) procurement plans of the three largest investor-owned utilities (IOUs), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

I. INTRODUCTION

Three related points stand out from a review of the IOUs' RPS procurement plans:

- The projects the IOUs have selected have a high rate of failure. SCE, for example, assumes a 40% failure rate for projects with executed contracts that are not yet on-line,[1] and SDG&E assumes the same failure rate for projects that are under development.[2]

- The utilities prefer projects with commercial operation dates (CODs) in 2018 or later, six or more years from now. PG&E, for example, has a "strong preference for deliveries beginning in 2019-2020."[3]
- The pro forma power purchase agreements (PPAs) shift much of the risk associated with the distant CODs to the sellers. Shifting risks to sellers that sellers cannot manage will increase the risk that these projects will fail.

A critical factor for improving implementation of the RPS procurement process is reducing the lengthy time between the initial Request for Proposals (RFO) to final Commission approval of a PPA, a process that can take 18 months or more. This lag has significant effects on the RPS program. For example, the delay means that prices bid initially into the RFO are likely to become stale and can become "out of market" by the time the Commission acts on the PPA. As a result, the Commission is repeatedly faced with comparisons between the price terms of fully negotiated and executed PPAs and bids submitted in new RFOs, bids based on estimates or hopes rather than the costs underlying the seller's contractual obligations. If approval of these PPAs is contested, the result is further delay and increasing "staleness" of the bid. To address this problem, IEP supports an increased emphasis on (a) timely decision-making with the goal of a final decision on a PPA within 120 days of submission, (b) enhancing the emphasis on project viability relative to price in bid evaluation, and (c) allocating risks to the party in the best position to manage the risk.

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[1] SCE's 2012 Plan, p. 4.
[2] SDG&E's 2012 Plan, p. 4.
[3] PG&E's 2012 Plan, p. 54.

IEP particularly urges a greater emphasis on project viability as a means to reduce the high rate of project failure. Project failures harm power markets in several ways. Some projects fail because developers submitted bids that were unrealistically low in competitive solicitations, which allowed these developers to prevail in the RFO but left them with insufficient revenues to successfully bring the project into commercial operation. Projects that win competitive solicitations by using unrealistically low bids, however, can displace bidders that submitted more realistic higher bids. The net result is that unrealistic low bids eliminate projects that might have a better chance of achieving commercial operation. In addition, a pattern of repeated project failures can negatively affect financial markets as the perception of increased risk of failure in California can result in higher costs of financing rates that undermine the economic assumptions of the project developer. For this reason, IEP urges the Commission to require the IOUs to give greater weight, relative to price, to the elements of the Project Viability Calculator in the bid evaluation process.

At the same time, the long lead-times contemplated in the RPS plans create additional risks for project developers. The costs underlying a bid submitted in 2012 can vary considerably from those actually incurred six years later. The economic, legal, and regulatory environment can change, and other elements making up a bid can change in unpredictable ways. Project developers have a number of tools available to manage many of the risks of maintaining bids for six or more years, but there are some significant components that are well beyond the developer's control and that cannot be reasonably managed using the available tools. For these few bid components, additional flexibility must be inserted into the RPS plans and the associated pro forma PPAs.

IEP will elaborate on these general points in the following comments.

II. A GREATER EMPHASIS ON PROJECT VIABILITY IS APPROPRIATE

The utilities' efforts to meet their RPS obligations have been complicated by the high percentage of projects selected in RPS RFOs or though bilateral negotiations that fail to make it to commercial operation. For planning purposes, SCE assumes that only a 60% success rate for projects with executed contracts that have not yet come on line. This high rate of failure unsettles the market, confuses price signals, and leads to a great deal of inefficiency in meeting California's RPS goals.

The utilities propose a number of ways to give greater emphasis to project viability in bid evaluation and to screen out projects that have a high probability of failure. IEP generally supports those efforts:

- PG&E proposes to increase the project development security from $100/kW times the project's expected capacity factor to $300/kW, with no adjustment for the capacity factor. While this is a significant increase, especially for technologies with necessarily low capacity factors, higher project development security will ensure that developers have both adequate financial means to complete the project and an increased incentive to achieve commercial operation.

  With the long lag between when PPAs are executed and when commercial operation begins, a greatly increased project development security ties up considerable capital for a long time. Under the long development times contemplated in PG&E's plan, it might make sense to release a commensurate portion of the project development security when certain milestones are achieved. For example, the project development security could be reduced when interconnection studies are completed, when the construction of interconnection facilities is completed, when permits triggering environmental review (such as the California Energy Commission's certification, permits from the Bureau of Land Management, local Conditional Use Permits or Special Use Permits, and comparable permits for out-of-state projects) are obtained, or at other logical points during the development process.[4]

Starting with relatively high project development security deposits and then reducing the project development security as development proceeds and certain milestones are reached is consistent with a greater emphasis on project viability and also creates a strong financial incentive for the project developer to ensure that development proceeds on schedule.

SDG&E takes the opposite approach and ramps up security requirements from $2.50/MWh multiplied by two times the expected annual generation to $20.00/MWh multiplied by two times the expected generation.[5] This seems backward and counterproductive. As some of the greatest development risks are eliminated (as permits are received and construction milestones reached), the project's development security should likewise be reduced.

- SCE and PG&E propose to require bidders in their 2012 solicitations to have completed at least a Phase I interconnection study in order to be shortlisted. IEP supports these proposals. This requirement should encourage developers to commence the interconnection process well

[4] Not all projects will be sited within the CAISO's control area. Comparable milestones or permits from other states should also be used to qualify a project for reduced project development security.
[5] SDG&E 2012 RPS Solicitation, p. 27.

before submitting a bid in the solicitation, and should enhance project viability in bid selection. Both bidders and the utilities will have a better idea of the costs of interconnection and any network upgrades associated with bidders who have completed the Phase I studies.

On the other hand, IEP is concerned about SCE's further requirement that projects must have completed the Phase II interconnection study before executing the PPA for several reasons. First, the interconnection study process of the California Independent System Operator (CAISO) is still evolving, and it is not certain that Phase II studies will always be completed on time. Second, the CAISO is not currently planning transmission upgrades for projects that do not have a PPA, and a lack of upgrades can affect a project's deliverability. Unless the requirements for the RPS solicitations and PPAs are carefully coordinated with the CAISO's deliverability requirements, the result could be projects that can't get PPAs in competitive RFOs because they can't provide deliverability, and can't get the necessary deliverability because they don't have a PPA. The interaction between the CAISO's transmission planning and interconnection processes and the utilities' RFO requirements must be fully considered and coordinated to eliminate the potential for a "chicken or egg" dilemma.

III. MANAGING RISKS DURING LONG LEAD-TIMES

The long lag between when bids are formulated and submitted in late 2012 or early 2013 and when a project begins making deliveries to the buyer and earning revenues in 2019 or later creates some risk-management challenges for developers. For the most part, developers have access to available tools to manage the risks associated with this lag. However, some risks are so significant and so far out of the developer's control that express provisions should be added to the pro forma PPA to clearly delineate how these categories of risk will be handled. Furthermore, when a risk is beyond the reasonable control of the developer, the risk should be considered in bid evaluation but ultimately be borne by the Buyer who is selecting the bid.

A. Expiration or Extension of the Production Tax Credit and Investment Tax Credit

The federal Investment Tax Credit (ITC) and Production Tax Credit (PTC) have reduced the effective cost of initial capital investments in generating facilities over the last few years. These federal credits are a tremendous benefit to California consumers. However, whether the ITC and PTC will be extended is a controversial political question that is not currently resolved. The extension of these credits is in the hands of Congress and the President, and clearly the outcome is not in any way under the control of the individual developer bidding into an RPS solicitation. PG&E proposes to address the uncertainty about the continuing availability of these federal credits by eliminating the Tax Credit Mitigation Option that it previously made available to renewable developers. The former option allowed developers to seek price adjustments if the ITC/PTC were to expire. PG&E contends that eliminating this option will lead to offers "from developers who are committed and able to fulfill contractual requirements without the guarantee of financing subsidies."[6]

Unfortunately, PG&E's approach will lead only to continuing instability. The lowest bids may come from developers who will gamble that the ITC/PTC will be extended, and if instead the ITC/PTC expire, these developers are likely either to seek a reopener of the price

[6] PG&E's 2012 Plan, pp. 14-15.

term or to abandon the project and terminate the PPA. On the other hand, responsible bidders who make a conservative assumption that the ITC/PTC will expire will find that their bids are too high to make the shortlist for the solicitation. Furthermore, if developers bid a higher price on the assumption that federal tax credits will not be available and they win the bid, they may confront charges that they will accrue windfall profits if the tax credits are continued.

IEP proposes a better solution. Bidders who want to secure the current ITC can plan for a COD before the ITC expires in 2016, but specify a later date for the commencement of the Delivery Term, in keeping with the utilities' general desire for later start dates. These bidder would also accept the risk of obtaining a purchaser for the output of their facilities between the COD and the start of the Delivery Term. Bids from these projects would presumably reflect the current ITC.

On the other hand, other bidders may target their projects' COD for the years after the scheduled end of the ITC in 2016, as the utilities have requested. These bidders have no ability to manage or mitigate the uncertainty concerning congressional action and presidential approval of a continuation of the ITC/PTC. These bidders should be required to submit a primary bid for purposes of bid evaluation and shortlisting that assumes the federal tax credits are not available. In addition, bidders should be required to submit a secondary bid that reflects the price they are willing to take if the federal tax credits are available, even if they are extended in a different form from the present credits. The ultimate price paid for the project's production will depend on whether or not the federal tax credit is available, but the project owner will be contractually obligated to honor its bid—either the primary bid or the secondary bid—regardless of how the ITC/PTC issue is ultimately resolved. Under this approach, developers will have no basis for reopening the price term if the ITC/PTC are not renewed, and conservative developers will not be penalized for submitting bids that do not assume the continuation of the ITC/PTC.

B. Integration Charges Imposed by the CAISO

A second category of potentially significant risks that cannot be managed effectively over the long lag time contemplated in the RPS procurement plans is any charges that the CAISO may impose on renewable generators for the costs of integrating increasing levels of renewable resources into the grid. The CAISO has been studying renewables integration issues for some time, but has not yet come to a conclusion about the extent of those costs or how any such costs should be allocated. Essentially, the CAISO's renewables integration costs are currently unknown and unknowable to developers.

The current pro forma PPAs proposed in the utilities' RPS procurement plans have no provision that describes how integration charges would be allocated. In the absence of any resolution about the extent of integration costs and how any such costs would be allocated, developers are unable to rationally account for potential costs in their bids.

Under these circumstances, IEP proposes to add a non-modifiable standard provision to the pro forma PPAs:

> Unless otherwise specified in this Agreement, any charges imposed on Seller by the CAISO, pursuant to its tariff, to recover costs that the CAISO determines are required to integrate increasing levels of renewable resources into the CAISO-controlled transmission system shall be compensated by Buyer.

The introductory provision allows for individual sellers to negotiate with the buyer to assume more risk or responsibility for specific integration charges or for certain prescribed levels of integration charges, but unless there is an agreement on specific charges, the charges imposed on seller for renewables integration will be borne by buyer.

This allocation also makes sense from a policy perspective. Any renewables integration costs are a product of the policy decision, made by the Legislature and the Governor with strong and consistent support from the Commission, that Californians benefit from a greater supply of renewable energy. Spreading these costs to the benefitting citizens in the form of electricity rates is consistent with the principle that costs should flow to those who benefit from a particular policy. In addition, although termed "renewables" integration costs, any such costs are a function of the variability of demand and the inflexibility of the existing grid, and in that sense it is also appropriate to spread the costs more broadly. Furthermore, this approach does not necessarily undermine the policy goal of sending appropriate price signals for siting new generation. Instead, it assigns cost responsibility to the entity, *i.e.,* the Buyer, that is in the best position to manage these costs when procurement decisions are made. This approach also recognizes the realities underlying renewable development in California today: generation development is driven almost solely by procurement decisions made by load-serving entities because few merchant renewable facilities are being financed and built.

C. Delays and Increased Costs Resulting from Transmission Upgrades

Even if a project is capable of operating as of its commercial operation date, it will be unable to deliver energy in compliance with its PPA if work on the transmission system prevents delivery of the energy it produces.

PG&E proposes to allow sellers to be excused from performing under the PPA due to transmission delays occurring both before and after the start of construction, but PG&E proposes to put a six-month limit on any excused delays and to exclude permitting or transmission delays from the definition of force majeure. SCE seeks the authority to terminate executed PPAs if actual transmission upgrade costs exceed the costs projected in the CAISO's interconnection studies.

These proposals should be rejected. Sellers have no control over the costs or timely construction of transmission expansions or upgrades. PG&E's proposal could punish projects that have met all milestones and stand ready to perform but cannot due to transmission delays. SCE's proposal would terminate a developer's PPA due to costs incurred to upgrade the transmission system far from the point of interconnection, well beyond the developers' control. Transmission-related delays can result from delays of Participant Transmission Owners in siting and constructing new transmission or from CAISO transmission planning practices that determine the what, where, and when to build new transmission. Instead of a six-month limit on these sorts of delays, the PPAs should provide for a day-for-day extension that would excuse performance by the seller until the transmission system is capable of receiving and delivering the energy produced by the project. As opposed to the PG&E recommendation, transmission-related delays should be explicitly integrated into the definition of force majeure that in appropriate circumstances would excuse performance for the duration of the delay.

IV. CHANGES THAT JUSTIFY RELEASING CAPACITY TO THE NEXT SOLICITATION

As described previously, the practice of reopening existing PPAs for further negotiation when certain events have occurred has undermined the stability of renewable energy markets in California. Now that California has several years' experience with the RPS and related solicitations, it makes sense to move away from a model that allows frequent reopeners of existing PPAs toward a model that rewards performance and stabilizes the market.

To further the maturation of the renewable energy markets, to enhance the importance of project viability in bid selection, and to send clear market signals to developers, the Commission should articulate as a matter of policy that advice letters proposing amendments to PPAs must show good cause for amendments and demonstrate that the requested changes are due to circumstances beyond the reasonable control of the developer. Amendments for any of the following changes will trigger Tier 3 review and will face close scrutiny of the reasonableness of the amendments:

- Changes in generation technology (*i.e.,* solar thermal to photovoltaic), other than minor changes (*i.e.,* use of solar panels from a different manufacturer).
- Extension of the COD by more than 18 months.
- A change in the Delivery Point if it triggers a new Phase I interconnection study.
- An increase in Contract Capacity.
- An increase in price.

If a PPA fails to survive the heightened scrutiny of the reasonableness of the amendment, the capacity associated with the PPA should be included in the next available RPS solicitation.

V. COMMENTS ON INDIVIDUAL RPS PROCUREMENT PLANS

A. PG&E

1. *Limits on Baseload Deliveries*

PG&E proposes to limit projects with "baseload delivery profiles" to annual payments equal to 105% of the contract price. Due to time-of-delivery (TOD) factors, projects that can shift deliveries to on-peak periods can receive payments in excess of their contract price. PG&E seeks to ensure that projects with baseload delivery profiles do not unduly shift production to those periods with high TOD factors.

PG&E's proposals are confusing. TOD factors are high for certain periods when the demand for power is high. TOD factors are higher to encourage generators to produce more electricity during those periods. If a plant with a "baseload delivery profile" is able to shift production to times with high TOD factors, it will be providing additional supplies during a period of high demand and responding appropriately to the price signals created by TOD factors. Moreover, the mechanism for limiting annual payments is unclear, since the amount of annual payments will not be known until after the end of the year. Will PG&E expect a refund from companies who exceed the 105% threshold? Will PG&E reduce payments going forward until it can collect the "excess" payments?

IEP respectfully urges the Commission to reject PG&E's proposal.

2. ***Proposed Integration Cost Adder***

An integration cost adder should be part of the bid evaluation. However, the amount of this adder should not be arbitrary; rather, the amount of the adder used for bid evaluation (or the underlying methodology for calculating the integration cost adder) should be transparent and exposed to public scrutiny. The CAISO's ongoing study of renewables integration costs is an example of how integration costs can be addressed publicly and transparently. A comparable study by the Commission or the California Energy Commission would also likely be sufficiently transparent and public. The best available source of information ought to be used for purposes of distinguishing among bidders' integration costs.

PG&E proposes to apply a $7.50/MWh adder for bid evaluation purposes to bids from projects using defined "intermittent" technologies. PG&E's proposed approach assumes that $7.50/MWh is the appropriate amount to account for integration costs. IEP is unaware of any empirical data supporting PG&E's estimate of integration costs. Furthermore, PG&E seems to assume that this adder should apply uniformly to every intermittent renewable resource bid into its solicitations even though integration costs can vary considerably by technology, location, and product design.

IEP respectfully urges the Commission to use verified, Commission-reviewed and adopted integration adders for bid evaluation. PG&E's proposed $7.50/MWh adder was developed in 2008 for modeling purposes and has not been shown to have any relation to integration costs.

B. SCE

1. *Limiting Solicitation to Category 1 Products*

SCE intends to limit its RPS solicitation to products that meet the criteria of Public Utilities Code section 399.16(b)(1)—Category 1 products.[7] Category 1 products may be used without limitation to meet a retail seller's RPS obligations, and for that reason Category 1 products are more valuable. That added value, however, will also likely be reflected in higher prices. Rather than focusing solely on Category 1 products, SCE should consider procuring the most cost-effective portfolio of RPS-eligible resources, a strategy that will minimize the cost to ratepayers of achieving RPS goals.

SCE also asserts that limiting its 2012 solicitation to Category 1 products will "target proposals that are more likely to result in executed contracts." IEP is unaware of any factual basis for this assertion or any indication that proposals to supply Category 2 or 3 products are less likely to result in executed contracts with a retail seller that is willing to entertain offers from resources that provide Category 2 or 3 products.

For these reasons, SCE should be directed to allow all categories of RPS-eligible products to compete in its RPS solicitations.

2. *Termination for Network Upgrade Costs*

SCE's proposed pro forma PPA grants SCE the right to terminate the PPA if any of the interconnection studies for the project estimates that the cost of Network Upgrades to the

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[7] SCE's 2012 Plan, p. 26.

transmission system exceed a specified Network Upgrade Cap. Seller may avoid termination if it agrees to pay the Network Upgrade costs in excess of the Network Upgrade Cap, without reimbursement for the excess costs.

SCE's proposal has several flaws. First, it places the risk that Network Upgrade costs will exceed some pre-specified maximum entirely on the seller. But Network Upgrades benefit the entire system, which is why utilities are required to reimburse generators for the advances they made toward the construction of network upgrades. Moreover, the costs of Network Upgrade costs are determined by the CAISO and the appropriate Participating Transmission Owners, and these costs are outside the control of the developer. Terminating the PPA punishes the seller for events that are entirely beyond its control and for costs associated with transmission infrastructure upgrades that serve the reliability and network needs of all consumers, not only the developer's needs.

Second, the seller buy-down option may have the perverse incentive of leading SCE to negotiate an unreasonably low Network Upgrade Cap, because all costs above that cap will be borne solely by the seller and without reimbursement. Shifting additional upgrade costs to the seller could undermine the viability of the project.

Third, the CAISO has gone to great efforts to revise its approach to interconnection and associated studies so that the Network Upgrades required for an individual project will be minimized. To the extent the CAISO is successful in that effort, a termination provision based on Network Upgrade costs, which reflect infrastructure that brings reliability and system benefits to consumers as a whole, is not needed.

3. ***Proposal to Require Shortlisted Bidders to Refresh Their Price Terms Prior to Determining Successful Bidders***

SCE proposes to negotiate with shortlisted projects to completion based on a set timeline, then allow each seller the opportunity to refresh its price. SCE correctly points out that the negotiation process has taken too long, and the "price refresh" mechanism would allow SCE to take advantage of price drops that may occur during the period of negotiation. SCE suggests that this mechanism will protect against initial bid submittals becoming stale and will help shorten the time between contract execution and Commission approval.

While IEP supports shortening the time between contract execution and Commission approval and other ways to keep bids from becoming stale, SCE's proposal raises a number of concerns. First, this proposal may delay rather than accelerate final approvals. For example, the approach may create incentives for bidders to game the initial bids in order to obtain shortlisted status, only to increase prices when given the opportunity to refresh the price. If this were to occur, it may conflict with efforts to enhance the importance of project viability in bid evaluation. Second, while refreshing bids may provide an opportunity to capture the benefits of declining prices, prices may also increase. The real solution is to accelerate PPA negotiation and approval, and this acceleration should be the primary focus. Third, the refreshed prices may require the revised bids to undergo additional financial due diligence and may trigger additional lender reviews, resulting in a delay rather than an acceleration of the Commission's approval. These concerns lead IEP to recommend additional consideration of the secondary impacts of the "bid refresh" proposal before the Commission adopts it.

4. ***Excess Deliveries***

Section 1.06(c) of SCE's pro forma PPA provides for reduced or no payment for deliveries in excess of threshold amounts. During any hour, if the seller delivers energy in excess of 110% of the contract capacity, then the seller will not be paid for the excess amounts (above 110%) delivered in that hour. SCE argues that this limitation is needed to ensure that the seller has not installed capacity in excess of contract capacity.

IEP has several concerns about this proposed treatment of excess deliveries. First, SCE has curtailment rights in the pro forma PPA to curtail deliveries when power is not needed, *i.e.,* when the CAISO announces a risk of over-generation or indicates system emergencies are imminent. These curtailment rights protect against excess generation that could threaten the operation of the grid. Second, it is difficult for developers to forecast the actual capacity factor for their projects accurately over the course of a 20-year PPA. With changing climate patterns, capacity factors for wind and solar may increase over time. Third, from the state's perspective, production above contracted amounts should not be discouraged, particularly in light of the uncertainties associated with RPS project development and achievement of AB 32 goals. Thus, at a minimum, the Commission should determine a means to continue to compensate generators that are periodically able to increase deliveries above contracted amounts to meet demand.

5. ***Excessive Curtailment Provisions***

SCE seeks the ability to curtail sellers for any reason, without payment, up to a cap of 50 hours for every megawatt of contract capacity. The provision appears to be an error, because taken literally, it would give SCE an unlimited ability to curtail any project over 153 MW **for the entire year!**

IEP assumes that SCE did not intend to propose such a clearly ridiculous provision. SCE should clarify that it (presumably) intended to propose a curtailment cap of 50 hours per year. If SCE's proposal was correctly stated, the Commission should direct SCE to delete this requirement and implement a more reasonable curtailment provision, with a reasonable cap of no more than 50 hours per year.

C. SDG&E

1. *Cap on Network Upgrade Costs*

Like SCE, SDG&E proposes to establish a cap on the costs of upgrades to the transmission system made necessary by the interconnection of a new generating resource. For the reasons stated in connection with SCE's proposal to terminate PPAs for excess network upgrade costs, SDG&E's proposed cap on Network Upgrade costs should be rejected. Completion of the Phase I studies should be a requirement to be short-listed; thus, the utilities will have the best available data about potential interconnection and network upgrade costs for purposes of bid evaluation. Buyers' procurement practices largely determine the need for transmission upgrades and expansions. Therefore, having selected a project, the Buyer should bear the risk that Network Upgrade Costs could exceed the amounts used for purposes of bid evaluation, particularly because Network Upgrades are infrastructure improvements that bring reliability and system benefits to consumers as a whole.

VI. COMMENTS ON THE NEW PROPOSALS

The Assigned Commissioner's Ruling of April 5 presented seven new proposals and asked for the parties' comments on the proposals.

A. Standardized Variables in LCBF Market Valuation

IEP has long been on record as supporting transparency in the bid evaluation process, and the net market valuation formula proposed in the Assigned Commissioner's Ruling can be seen as an effort to improve the transparency of the bid evaluation process. Nevertheless, IEP is concerned that the net market value formula is too simplistic and too inflexible.

One significant omission is that the formula makes no attempt to reflect the reduction in externality costs that are the primary purpose of the RPS program. Even if that omission is explained away by the fact that all MWh from eligible resources provide the same externality benefits, the formula makes no attempt to recognize and reflect the reductions in greenhouse emissions, emissions of air pollutants, risks of fuel- or technology-related outages, and similar benefits of the RPS program that will vary from resource to resource.

Similarly, the formula does not reflect that many of the cost elements have associated benefits that are not accounted for in the formula. For example, the formula includes the costs of Network Upgrades but no recognition that the upgraded transmission system will be more flexible, resilient, and reliable as a result of the investment in Network Upgrades. In addition, as discussed above, the formula assumes that integration costs should be attributed and allocated to the addition of renewable resources to the transmission grid, rather than viewing integration as one aspect of the policy decision to pursue the 33% RPS goal. In addition, the formula seemingly fails to recognize that the CAISO's new "cluster" approach to determining Network Upgrades is not exclusive to renewable generators. Rather, Network Upgrades are designed to reduce congestion, maintain overall grid reliability, and efficiently integrate both renewable and non-renewable generation.

That said, IEP agrees that a refined net market value formula, applied with flexibility, can provide considerably greater transparency to the bid evaluation process.

B. Preliminary Independent Evaluator Report

The Assigned Commissioner's Ruling proposed to institute a preliminary Independent Evaluator's Report on bid solicitation materials that would address clarity of the solicitation materials, the criteria for the least-cost/best-fit (LCBF) analyses, and how the LCBF criteria are used in bid evaluation.

In theory, the preliminary Independent Evaluator's report could provide a valuable critique of the bid evaluation process that could greatly improve both the transparency and effectiveness of bid evaluation. In practice, however, the Independent Evaluators' reports have not provided a critical review of the utilities' conduct of the solicitation, and most Independent Evaluator's reports make it clear that the evaluators do not view their role to include an active, critical assessment of the utility's performance. In addition, significant portions of some Independent Evaluators' reports are redacted and unavailable to the public. Obviously, the goal of greater transparency will be thwarted to the extent the preliminary Independent Evaluator's report is similarly redacted.

C. Use CAISO Transmission Cost Study Estimates in Least Cost Best Fit Evaluations

The Assigned Commissioner's Ruling proposes that utilities should use the transmission cost estimates developed as part of the CAISO's Generator Interconnection Process, rather than the estimates from the utilities' Transmission Ranking Cost Reports (TRCRs).

The TRCRs are preliminary estimates of transmission costs that are much less refined than the cost estimates developed in the various CAISO interconnection studies. IEP agrees that the utilities should use more detailed and up-to-date transmission cost information from the CAISO studies whenever it is available. IEP recommends that as a pre-condition for being shortlisted, bidders will have completed at a minimum their Phase I interconnection studies. The transmission costs from the Phase I studies should then be used for the LCBF analysis. If Phase II studies are available, these data from the Phase II studies could be used for purposes of bid evaluation and shortlisting.

D. Create Two Shortlists Based on Status of Transmission Study

The Assigned Commissioner's Ruling proposed to create two shortlists. The Primary Shortlist would consist of projects that have executed Interconnection Agreements or have obtained Phase 2 interconnection study results from the CAISO. The Provisional Shortlist would consist of all other shortlisted bids. As projects from the Provisional Shortlist obtained their Phase 2 study results, they would migrate to the Primary Shortlist. Only PPAs with projects from the Primary Shortlist could be executed and presented to the Commission for approval.

Currently, shortlisted projects are required to withdraw all other offers of the same product from the same resource from other solicitations. Projects on the Provisional Shortlist have a greatly reduced commitment from the buyer and a greatly reduced chance of obtaining a PPA. Under these circumstances, it is unduly restrictive to force a project on the Provisional Shortlist to, *e.g.,* withdraw its offer from another utility's RPS solicitation.

Moreover, the utility might have an incentive to include a large number of projects on the Provisional Shortlist, to tie up their commercial opportunities and prevent them from negotiating with other buyers. Thus, the Provisional Shortlist could have anticompetitive effects.

E. Shortlists Expire After 12 Months

Currently, the bidding protocols require shortlisted bidders to withdraw their bids from other parties' RFOs and to commit to negotiate exclusively with the utility that shortlisted them for the duration of the process concluding in either Commission approval or denial of the PPA. The proposal that shortlists would expire after 12 months is intended to assure that the utility negotiates diligently and promptly with the shortlisted projects. The goal of requiring the utility to negotiate diligently and promptly with shortlisted projects is laudable, but it raises a number of concerns. For example, it may be that the parties to the negotiation may be fairly close to completion of the PPA when the 12 month period is reached. Would the parties be required to begin anew in the next RFO?

Rather than terminate the shortlist after 12 months, IEP recommends terminating any exclusivity arrangements that prevent developers from bidding their projects into other parties' RFOs. This approach should provide incentive for the parties to negotiate in good faith and complete their transactions as quickly as feasible.

F. Two-Year Procurement Authorization

A two-year authorization of RPS procurement plans, as proposed in the Assigned Commissioner's Ruling, does not vary by much from recent experience. The 2011 RPS procurement plans began their lives as 2010 RPS procurement plans, and the current batch of 2012 procurement plans are unlikely to result in any actual procurement until 2013. A two-year authorization may be a realistic recognition of the time required to prepare and review procurement plans.

The proposal would give the utilities the discretion to conduct annual RPS solicitations. However, annual RPS solicitations, for at least some MWs, should be required. A regular annual solicitation offers a consistent prospect of a PPA to the market. As we have learned, conditions can change significantly from year to year, and an annual solicitation provides the flexibility to respond to changing conditions. Requiring a project with a natural advantage or a revolutionary technology to wait up to two years before it would be considered for a PPA could dampen the innovation and excitement that new projects can bring to the market.

G. Utilize the Commission's RPS Procurement Process to Minimize Transmission Costs

The Assigned Commissioner's Ruling proposes to use the RPS procurement review process to limit the total capacity of PPAs in certain areas to avoid triggering unnecessary reliability or deliverability upgrades. Specifically, the proposal is for the CAISO to net out the amount of PPAs that are already executed in each study area to determine the amount of full capacity deliverability that remains. Second, after the completion of the RPS RFOs, if the total volume of megawatts shortlisted by all the IOUs within a study grid area is within the threshold established by the CAISO, no Commission action will be taken. On the other hand, if the total volume of megawatts shortlisted by all the IOUs in a study area exceeds the threshold, the Commission will apply a rationing procedure using the results of the bid evaluation prioritization methodology.

The Commission should not implement this rationing proposal at this time. The CAISO has undertaken significant modifications to the interconnection process, including developing specific tools for allocating full deliverability, all of which include specific milestone factors and measures of viability. In addition, if the Commission were to require that all successful shortlisted bidders have completed at least a Phase I interconnection study, as IEP recommends, IEP is not convinced there is any need to overlay on these processes an additional mechanism for rationing PPAs. Rather, any such mechanism would likely hinder the utilities' efforts to improve their procurement practices, undermine certainty in the marketplace, and otherwise create a measure of unwarranted regulatory uncertainty.

VII. CONCLUSION

In these comments, IEP has made recommendations intended to promote improved project viability and a lower failure rate for projects, ways to manage the risks associated with the long time between the execution of a PPA and a COD six or more years later, and greater transparency in the solicitation and bid evaluation process. IEP acknowledges that it may have overlooked some issues as it attempted to closely review the over 1500 pages of the IOUs' RPS procurement plans, and IEP may have additional comments in response to the issues raised by other parties. IEP respectfully urges the Commission to consider and adopt the recommendations presented in these comments.

Respectfully submitted this 27th day of June, 2012 at San Francisco, California.

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By */s/ Brian T. Cragg*
Brian T. Cragg

Attorneys for the Independent Energy
Producers Association

VERIFICATION

I am the attorney for the Independent Energy Producers Association in this matter. IEP is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of IEP for that reason. I have read the attached "Comments of the Independent Energy Producers Association on the RPS Procurement Plans," dated June 27, 2012. I am informed and believe, and on that ground allege, that the matters stated in this document are true.

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

Executed on this 27th day of June, 2012, at San Francisco, California.

/s/ Brian T. Cragg
Brian T. Cragg

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