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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The Independent Energy Producers Association (IEP) offers the following comments on the draft Renewable Portfolio Standard (RPS) Procurement Plans of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), in response to request of the *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2013 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on a New Proposal* (ACR), issued on May 10, 2013. IEP has no comments at this time on the other RPS Procurement Plans.

I. BID EVALUATION MUST PROPERLY WEIGH THE BENEFITS OF RENEWABLE RESOURCES AND THE COSTS OF INTEGRATION

One of the continuing issues raised in connection with the utilities' RPS Procurement Plans, most recently in Decision (D.) 12-11-016, is how to properly account for costs of integrating renewable resources, especially variable energy resources like wind and solar, into the grid. In D.12-11-016, the Commission declined to adopt a non-zero integration cost adder. IEP and others parties argued that integration cost adders must be developed in a public forum and be subject to public review and comment. The Commission agreed and barred the use of non-zero integration cost adders.[1]

Two years later, the Commission again is faced with proposals for non-zero integration cost adders and the issue of how best to address the integration costs of renewables in bid evaluation. IEP believes that it is time to address and resolve this matter.

A consideration of integration costs is appropriate at this time because under the Commission-adopted Least-Cost/Best-Fit procurement criteria, it is not clear that the existing RPS bid evaluation methodology properly recognizes and values the full benefits and costs of existing RPS resources. For example, it is not clear that existing RPS resources are fully valued in terms of their operational experience, viability, negligible impacts on electric grid, and similar characteristics, nor is it clear that new RPS resources designed to mitigate the costs of their integration into the electric grid are properly valued. Existing renewable resources offer several advantages to load-serving entities (LSEs) with an RPS procurement obligation that can help lower overall RPS costs. First, existing resources have their interconnections completed and will not create additional integration costs or a need for network upgrades. Second, existing resources are not subject to the risk of permitting delay, interconnection delay, or construction delays. Third, because of the resources' historical operating experience, existing resources can offer a more dependable and less risky operations profile. These factors ought to be considered in RPS bid evaluation.

The issue of integration costs is a complicated one that requires a consideration of customers' responsibilities, past utility procurement practices, and the flexibility of various generation technologies. As the Commission ruled in D.12-11-016, the integration cost adder should be developed in a public process and with public review and comment. SCE and PG&E

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[1] D.12-11-016, p. 29.

continue to express their dissatisfaction with the Commission's instruction to use an integration cost of zero in evaluation of bids in RPS solicitations.[2] IEP supports the use of an appropriate integration cost adder in bid evaluation, but the factors used to calculate the integration cost adder ought to be empirically based and publicly vetted. While the Commission should continue to resist calls for it to authorize an arbitrary non-zero integration cost adder, the Commission should commence public proceedings to determine the appropriate adder or methodology to derive an adder. This process should be completed before the next RPS RFOs.

In spite of the fact that the utilities have been directed for some time to conduct RPS procurement within the least-cost/best-fit framework, some parties continue to argue that generators ought to face a retroactive, post-contract risk for integration costs. Generators are not well positioned to address this unknown and unknowable risk, particularly in light of the state's desire for RPS resources to enter into fixed price arrangements on a long-term basis as a hedge against the volatility of market prices. Until variable energy resources can receive credit for addressing yet-to-be defined integration costs, the load that selects the resources is in the best position to predict, assess, and pay for integration costs and charges.

II. CURTAILMENT

Curtailment risk rests at the heart of the commercial viability of the contracts. Curtailment is properly addressed in bilateral negotiations between the Buyer and the Seller. When the Commission addressed the issue of curtailments in D.11-04-030, it allowed the utilities considerable flexibility in fashioning curtailment provisions, but required the provision to "be financeable (e.g., reasonably bound the developer risk, such as by a maximum number of curtailment hours or other device)."[3] PG&E proposes to require a seller to offer its energy as

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[2] SCE RPS Procurement Plan, pp. 34-35; PG&E RPS Procurement Plan, p. 6.
[3] D.11-04-030, p. 18, fn.22.

"curtailable at any time at Buyer's discretion."[4] An unlimited curtailment right, as PG&E proposes, raises three immediate concerns. First, any compensation offered should include compensation for the loss of Production Tax Credits, which may be a significant factor in the price of the renewable energy. Second, because no Renewable Energy Credits (RECs) are created with renewable generation is curtailed, a utility's right to curtail, whether unlimited or not, should be exercised very judiciously. Third, an open-ended and unlimited curtailment right may complicate developers' ability to finance their projects, since forecasting revenues becomes more difficult as the potential curtailable hours increase. It seems highly unlikely that PG&E will actually need to curtail renewable generators for 8760 hour per year, and a more moderate level of curtailment would meet the needs of both PG&E and the entities financing renewable energy projects.

SCE proposes an approach that includes a negotiated cap on uncompensated curtailments, payments for curtailments in excess of the cap, and a recapture of energy associated with compensated curtailments at the end of the contract term.[5] SCE's general approach provides a basis for a negotiated, mutually agreeable level of uncompensated curtailment and bounds the curtailment risk so that the PPA remains financeable. In spite of this assessment of SCE's general approach, IEP remains concerned that SCE's pro forma contract does not replicate the stated intention. The pro forma contract is less than clear about how curtailments will be imposed. SCE should be directed to clarify its goal and objectives related to curtailment, and to demonstrate how the pro forma contract conforms to the Commission's position on curtailment. RPS developers need clarity about exactly how and when SCE proposes to compensate the Seller for economic curtailment in excess of the proposed curtailment cap, particularly in the situation

[4] PG&E Procurement Plan. Appendix 7, p. 31.
[5] SCE's RPS Procurement Plan, pp. 44-45.

when the demand for curtailment is driven by the decisions of SCE serving as the resource's Scheduling Coordinator, the Participating Transmission Owner or the California Independent System Operator (CAISO).

SCE recognizes that curtailments could mean that "SCE and other load-serving entitles could be significantly impacted in meeting their RPS goals," and that "curtailments could affect the ability of owners of operating renewable projects to maintain adequate revenue to service their debt, and may create a chilling effect on future financing of projects under development."[6] SCE describes some of the efforts it has taken to reduce curtailments, like aggregating several large wind projects into a "physical scheduling plant" to mitigate the effects of curtailment. Efforts to reduce curtailments should be encouraged, because ultimately no one benefits from curtailments.

Finally, the Commission should be aware that curtailment needs are a function of the utility's resource selection and procurement practices. If the need for curtailment is deemed large enough to justify requests for unlimited or high levels of curtailment, this need is likely a reflection that the Least-Cost/Best-Fit approach to procurement is not working particularly well or has not been implemented properly.

III. TIME OF DELIVERY PERIODS AND FACTORS

SCE and PG&E propose to revise the time of delivery (TOD) factors, and SDG&E proposes to redefine the hours of the delivery periods. These proposals lead to several comments.

First, the Commission should consider how changes to the TOD times and factors will affect existing contracts and related documents. Some existing contracts specify the TOD periods and factors to be applied for deliveries under the contract, and those provisions should be

[6] SCE's Procurement Plan, p. 17.

respected. Other agreements may include an assumption that the then-effective TOD periods and factors would continue, and incorporating revised TOD factors could undermine the contracting parties' mutual intent. For this reason, the Commission should observe the general principle that changes to TOD factors and periods should apply only prospectively.

Second, the development of revised TOD factors and hours should be done through a public process, and not by using "internal forecasts for the value of capacity and energy,"[7] the basis for SCE's revisions. TOD factors can be critical to project design and contract viability. Using the wrong TOD factors could have far-reaching impacts for RPS procurement and efforts to reduce integration costs.

Third, to the extent that the Commission determines that revising the TOD factors in the absence of a public process is reasonable, the Commission should consider how the new TOD factors will affect market behavior. For example, the TOD factors will impact the extent to which storage capabilities are directly integrated into renewable project development. Currently, the Commission is considering a sizable set-aside for storage resources to assist in the integration of renewable resources (among other reasons). This program will be implemented separately from the RPS program, although it is recognized that RPS resources may be in the best position to make efficient use of storage due to the intermittent nature of wind and solar energy. If the promotion of storage is the Commission's goal, then the TOD factors should be set to maximize the differential between off-peak and on-peak prices. On the other hand, flattening the TOD factors may create incentives for the development of baseload renewable resources that will lower the impact of renewable resources on the overall system.

IEP recognizes that many elements must be weighed in the revisions of TOD factors and periods, and these examples are intended to illustrate the range of potential incentives

[7] SCE's RPS Procurement Plan, p. 16.

that could be created by different TOD factors. Overall, the TOD factors are critical to driving certain resource outcomes, and they should be applied on a going-forward basis. Existing contracts should be held harmless to changing TOD factors (recognizing that the Buyer and Seller may mutually agree to contractual changes as practical and needed).

IV. EXCESSIVE SECURITY REQUIREMENTS

PG&E requires sellers to post New Resource Project Security of $300/kW from 30 days after the Commission's approval of the PPA until the date Delivery Term Security is posted.[8] This amount is excessive and unnecessary to ensure performance by the seller. By contrast, SCE's Development Security for intermittent renewable resources is $60/kW.[9] There is no reason why PG&E's development security requirement should be five times higher than SCE's and no suggestion that PG&E's sellers present a risk that is five times greater than the risk presented by SCE's sellers. Furthermore, developers are already incurring significant additional costs associated with the CAISO's initiative to increase security requirements for Interconnection Agreements and CAISO queue management.

The Commission should direct PG&E to reduce its security requirement to $60/kW.

V. EXCLUSIVITY

The utilities require renewable generators to drop out of other RPS solicitations once the project has been shortlisted, or selected for further negotiation. This requirement is apparently intended to prevent generators from playing off one utility against another. If so, the restriction is no longer needed. RPS solicitations are highly competitive, and utilities shortlist many more resources than they intend to sign to PPAs. This provision could leave viable, cost-

[8] PG&E RPS Procurement Plan, Appendix 7, p. 33.
[9] SCE RPS Procurement Plan, pro forma PPA, § 3.06(a).

effective projects without a PPA if one utility shortlisted the project but ultimately did not sign a PPA for reasons that may have nothing to do with the value or competitiveness of the project.

VI. AVAILABILITY OF FEDERAL TAX CREDITS AND PROCUREMENT SCHEDULES

To the extent practicable, RPS procurement should be managed to maximize developers' access to federal tax credits (*e.g.,* the Production Tax Credit (PTC) and Investment Tax Credit (ITC)) available for the development of renewable resources. Use of federal tax credits lowers consumer costs, but their future availability is not certain. Expediting procurement to realize these benefits may be prudent even if the procurement positions the utilities to exceed the current RPS goals. In this sense, the RPS procurement goals set for 2017 and 2020 could be considered as a floor rather than a ceiling to maximize the availability of federal funding for the benefit of California ratepayers. SCE sets a good example by scheduling RPS procurement to take full advantage of available federal funding before the ITC expires in 2016. IEP supports this approach. While annual procurements are no longer required, RPS procurement should continue to be conducted in an aggressive manner to capture the benefits of the federal tax credits before they are terminated.

VII. CONCLUSION

IEP respectfully urges the Commission to consider these comments as it deliberates on the utilities' RPS procurement plans.

Respectfully submitted this 12th day of July, 2013 at San Francisco, California.

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By *_/s/ Brian T. Cragg_*
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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 July 12, 2013. 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 12th day of July, 2013, at San Francisco, California.

/s/ Brian T. Cragg
Brian T. Cragg

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