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 TENASKA SOLAR VENTURES ON THE ASSIGNED COMMISSIONER'S RULING

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I. INTRODUCTION

Tenaska Solar Ventures ("Tenaska") submits these comments pursuant to the April 5, 2012 Assigned Commissioner's Ruling ("ACR"). The ACR invited comment by the parties to this proceeding on a number of new proposals to modify the existing Renewables Portfolio Standard ("RPS") procurement and review process.

The substance of Tenaska's comments in Section II below is intended to reflect the following principles. (i) A number of the proposals set forth in the ACR make sense, as they should improve the efficiency and fairness (both to project developers and ratepayers) of the sometimes cumbersome process whereby the State's major investor-owned utilities ("IOUs") try to identify the most cost-effective renewables projects for ultimate procurement via power purchase agreements ("PPAs"). (ii) However, several of these proposed reforms appear to be doing nothing more than replacing one set of criteria that present significant technical challenges in terms of teasing out the relevant data needed to effectively compare competing projects with a set of different, but equally challenging, criteria. If a proposed process reform does not promise to make a real, positive difference in terms of facilitating the identification of the respective costs and benefits of a set of renewables projects that are in competition for IOU PPAs in a relevant and real manner, that reform should not be adopted. (iii) By contrast, if a proposed reform shows some promise of moving the effort to identify the best RPS projects forward in a constructive manner, but maintains some unhelpful criteria from previous RPS procurement cycles, that proposed reform should be modified in order to eliminate the unhelpful parts.

Tenaska would encourage the Commission to apply these principles to its evaluation of the proposed process reforms. In so doing, the Commission will hopefully recognize which of these proposed reforms should move forward, which should be eliminated and which should be amended or revised. Applying these principles reveals that the Commission should:

- Require standardized variables in the least-cost, best fit ("LCBF") market valuation;
- Adopt the Preliminary Independent Evaluator Report ("PIER") proposal;
- Employ the California Independent System Operator ("CAISO") transmission cost study estimates in LCBF evaluations, but also:
    - Require a completed CAISO Phase I study to participate in the RPS solicitation,
    - Attribute ratepayer-funded upgrade costs to benefitting projects, and
    - Ensure that network upgrade costs are not double counted for project expansions;
- Create two shortlists based on the status of the CAISO transmission study, and require a project with a completed CAISO Phase II study to be placed on the Primary Shortlist;
- Approve the proposal to create a 12-month expiration date for short lists, but clarify that parties must negotiate in good faith;
- Reject the creation of a two-year procurement process; and
- Minimize transmission costs by limiting the total capacity of RPS-eligible projects in certain areas based on interconnection agreements as opposed to power purchase agreements (PPAs).

Following these recommendations will enable the Commission to achieve its real goal here, which is to improve and streamline the process whereby the IOUs identify and procure new RPS resources that are both viable and comport with LCBF valuation.

II. COMMENTS ON THE ACR'S PROPOSALS

A. The Commission Should Require Standardized Variables in the LCBF Market Valuation.

The proposed Net Market Value ("NMV") equation is a reasonably accurate tool for assessing the costs and benefits that a proposed RPS project would create for ratepayers, and it should be adopted. The proposed equation reflects bid evaluation factors that all three utilities already employ to assess projects.[1] Further, the use of standardized variables will assist the utilities and Commission in objectively discerning credible, cost-effective projects from speculative projects with hidden costs for ratepayers. Such hidden costs can include unforeseen investments required to overcome congestion, to deliver energy to load and to integrate variable resources.

Tenaska believes that such costs should be considered in bid evaluation and ranking and generally supports the use of the proposed NMV equation going forward. That said, two IOU comments in this proceeding raise a number of subsidiary issues that require Commission clarification.

Firstly, contrary to comments made by Southern California Edison ("SCE") and Pacific Gas and Electric Company ("PG&E"), fairness, market certainty and transparency require that if the Commission intends to approve an equation that incorporates a specific set of factors to be used in comparing projects, these should be the *only* factors that utilities are allowed to consider

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1 SDG&E RPS Plan, at 27; SCE Comments, at 2; PG&E RPS Plan, at 64.

in evaluating projects.[2] In other words, the IOUs should not be given the option to include non-Commission-sanctioned variables in their analysis.

Secondly, it is vitally important to project viability and a healthy renewables market that the use of integration costs in bid evaluation not start the Commission down the road of pushing such costs onto developers. PG&E and SCE emphasize the importance of including integration costs in bid evaluation.[3] SCE goes so far as to list balancing reserves, frequency regulation, and flexible ramping as examples of products and ancillary services needed to integrate variable generators.[4] Tenaska agrees that California should include integration costs as a factor in comparing one project to another for purposes of determining which project/s an IOU should procure. Including such costs as a competitive factor in comparing projects will have the beneficial effect of providing developers with an incentive to locate projects in the most cost-effective areas for ratepayers.

However, the inclusion of such costs in the bid evaluation process should be sufficient by itself to encourage proper project location. Such costs should *not* be imposed on top of the significant other costs that a renewable project developer must shoulder in order to bring a project to market. Imposing such additional costs, which must ultimately be borne by ratepayers one way or another, will only make it more difficult for renewable project developers to finance their projects, which, in turn, will have an adverse impact on California's ability to meet its aggressive RPS goals in a timely manner. Accordingly, the Commission should safeguard against the use of the integration cost factor in the NMV equation for purposes of evaluating

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2 SCE Comments, at 2; PG&E RPS Plan, at 64-65.
3 SCE Comments, at 2-3; PG&E RPS Plan, at 65.
4 SCE Comments, at 3.

competing projects as an implicit or explicit justification for pushing such costs onto renewable energy developers.

B. The Commission Should Adopt the Preliminary Independent Evaluator Report Proposal.

The ACR proposes to include a portion of the PIER within the IOUs' proposed RPS procurement plans.[5] Under this proposal, the RPS plans would not only include the bid solicitation materials and LCBF methodology components of a utility's solicitation, but would also incorporate the IE's analysis of the *"reasonableness, accuracy, strengths, weaknesses, and fairness"* of those components.[6] This proposal would allow stakeholders to see an upfront assessment of the utilities' bid evaluation methodologies. A bifurcated PIER would increase the transparency of those methodologies, especially for the valuation of RA capacity, and would result in better-informed comments on the RPS plans. The utilities point out the proposal could result in duplicative efforts by the IE, unnecessary delays and bid gaming.[7] However, adjustments in the RPS solicitation schedule can resolve concerns about delays, and existing safeguards are sufficient to combat bid gaming. The benefits of upfront transparency outweigh the potential administrative burdens, and the proposal should be adopted.

C. The Commission Should Adopt the Proposal to Use CAISO Transmission Cost Study Estimates in LCBF Evaluations.

An accurate assessment of the costs that a project will impose on ratepayers is essential to the cost-effective achievement of the RPS goals. The Commission's proposal to use CAISO study data when available will increase the accuracy of transmission upgrade cost assessments. The CAISO study provides specific, project-level costs for the interconnection, distribution and

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5 ACR, at 18-19.

6 *Id.* at 19.

7 SDG&E RPS Plan, at pages 28-29; SCE Comments, at 4-5;

transmission facilities that a project will require to mitigate adverse impacts on system reliability and/or guarantee deliverability. All three of the IOUs already rely on such CAISO studies to some extent, and requiring their use, when available, in the LCBF analyses is a natural extension of established practice.[8]

Tenaska generally supports this proposed reform, but we believe the Commission should take even more decisive steps to solidify the proper consideration of transmission costs in connection with the cost-effective procurement of renewables. First, it should adopt PG&E's proposal to require a completed CAISO Phase I study in order to participate in the 2012 RPS solicitation.[9] Requiring a *completed* Phase I study will ensure that the IOUs' RPS solicitations only consider legitimate projects that are sufficiently mature that the project proponents are in a financial position to post the significant study deposits mandated by the CAISO's interconnection study process. Further, the Commission's adoption of this proposal will guarantee that the IOUs will have accurate estimates of a project's transmission costs. After all, the very purpose of a CAISO Phase 1 study is to identify with a reasonable degree of certainty the total system upgrade costs that a particular new generation project will trigger.[10]

Second, the Commission should adopt the SCE proposal to attribute ratepayer costs to projects that will benefit from transmission upgrades built through the CAISO Transmission Planning Process ("TPP").[11] As SCE explains, "[f]or Queue Cluster 5 and beyond, generators have the option to obtain Full Capacity Deliverability Status without having to fund (on a reimbursable basis) certain deliverability network upgrades."[12] Once the Federal Energy

8 SDG&E RPS Plan, at 30; SCE Comments at 5; PG&E RPS Plan, at 70.
9 PG&E RPS Plan, at 71.
10 *See* CAISO Tariff, Appendix Y § 6.4.
11 SCE Comments, at 6.
12 *Id.*

Regulatory Commission ("FERC") approves the tariff revisions that were recently approved by the CAISO Board and filed with FERC,[13] utility customers will directly fund the cost of all transmission system upgrades that are approved through the TPP. Assigning these costs to the projects that will benefit from the upgrades will result in a more accurate representation of a project's total cost to ratepayers, thereby ensuring the most cost-effective procurement.

Moreover, by not assigning such costs to projects that benefit from the upgrades, the Commission would be ignoring the arguably most important distinguishing cost item in a highly competitive pricing environment. Such an outcome would be to the detriment of projects that are already located in areas specifically selected for their low anticipated upgrade costs. After all, the objective of the ACR's changes is to reduce costs, and the Commission cannot achieve that objective by ignoring ratepayer-funded upgrade costs for bid evaluation purposes.

Third, projects that have executed CAISO Large Generator Interconnection Agreements ("LGIAs") should not be assigned upgrade costs for planned expansions if a project's existing LGIA already contemplates the expansion. Contrary to this, SDG&E states that "[p]rojects with existing interconnections should not have any upgrade costs assigned, *unless the project is a repower or expansion of existing facilities* or otherwise requires modifications to an existing interconnection to meet new standards."[14] SDG&E's statement appears to propose that a project expansion should be assigned upgrade costs even if those anticipated upgrade costs resulting from the project expansion are already included as part of an executed LGIA covering an earlier phase of a project. SDG&E's proposal should be disregarded. Many projects that have completed the interconnection study process have included planned expansions in their CAISO-

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13 See, *Tariff Amendment to Integrate Transmission Planning and Generator Interconnection Procedures* (TPP-GIP tariff amendment), FERC Docket No. ER12-1855, filed May 25, 2012.

14 SDG&E RPS Plan, at 30.

approved LGIAs. This means that the interconnection, distribution and transmission facilities that were identified as being needed to accommodate an initial phase of a given project are already built to accommodate the planned expansion of that project at a later date. Assigning upgrade costs to a project expansion that is *already included* in an executed LGIA would double count a project's transmission-related costs, which would put it at a distinctly unfair disadvantage and ignore the already-negotiated costs and capacity within an executed contract that is the objective of CAISO's entire generator interconnection process.

D. The Commission Should Create Two Shortlists Based on the Status of the CAISO Transmission Study.

The Commission notes that the creation of two shortlists, and the requirement for a project to complete a Phase II study or execute interconnection agreements before being placed on the Primary Shortlist (presumably during the two-month bid evaluation process associated with that year's RPS solicitation and not some extended date in the future), will work to improve the accuracy of cost-benefit analyses and allow the IOUs and the Commission to perform those analyses earlier in the solicitation.[15] However, there is a third advantage to the proposal that should not be overlooked. Since the CAISO interconnection process requires a project to expend "considerable time and financial resources,"[16] the Primary Shortlist will act as an early lever to eject speculative projects from utility solicitations, thereby increasing the efficiency of the procurement process. The requirement to incur the Phase II study costs prior to being on the Primary Shortlist will ensure that only legitimate and credible projects from responsible and committed developers will proceed through the RPS solicitation process and contracting. For all these reasons, this proposal should be adopted.

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[15] ACR, at 20-21.
[16] PG&E RPS Plan, at 73.

SCE's counterproposal should be rejected because it fails to provide the level of certainty regarding costs and ratepayer value that the Commission's proposal provides. SCE proposes that all potential sellers be required to have completed a Phase I study.[17] It then proposes to "only execute a PPA once the project obtains the Phase II study" results, including the final estimate of required upgrades.[18] Under SCE's proposal, a project could still be included in a utility's shortlist without having obtained Phase II study results. The difference between the SCE and Commission proposals, therefore, is that under SCE's approach, the Commission would have to wait to obtain clarity regarding a project's total costs until months later than under the Commission's approach. SCE's approach also fails to reduce uncertainty, since CAISO-determined upgrade costs can change greatly between the Phase I and Phase II studies, and such costs, when known, could be prohibitive to that project. The Commission's approach shines a brighter light on the actual costs and value that a project provides to ratepayers by focusing attention on the Phase II study results – a much more accurate measure of project value – within the procurement process.

E. The Commission Should Approve the Expiration of Shortlists after 12 Months with Clarifications.

It is to be expected that prices for renewable energy projects will change over the course of time. Under the Commission's proposed reform, if a project that has completed its CAISO Phase II study and is on a shortlist for its energy output to be procured by an IOU, both the IOU and the developer should enter into good faith contract negotiations and strive to complete them within a year. This reform will help prevent developers' bid prices from becoming stale and can provide heightened certainty for the IOUs, developers and ratepayers. The establishment of a

17 SCE Comments, at 7.
18 *Id.*

shortlist with a 12-month duration is a reasonable balance between the risk that prices will change and the incentives for the counterparties to delay, based on their respective perception of the direction in which the market is headed. However, to avoid this potential for delay based on perceptions (accurate or not) of where the market may be heading, the Commission needs to clarify this proposed reform to make it abundantly clear to the IOUs, and successful bidders in RPS procurement solicitations, that it expects all counterparties to negotiations leading to PPAs to negotiate in good faith for the full 12-month period. Also, as SDG&E notes in its comments,[19] a 12-month shortlist will allow provisionally shortlisted bidders with whom the IOU has not initiated negotiations to be released from the shortlist sooner, which will enable them to re-bid their projects the following year. Enabling re-bidding in this manner will provide the added benefit of allowing projects to obtain CAISO Phase II study results in time for the next solicitation's Primary Shortlist.

F. The Commission Should Not Authorize the IOUs to Procure Resources pursuant to their 2012 RPS Procurement Plans over a Two-Year (or Longer) Period.

Tenaska does not support the proposal for two-year procurement authorization. Not all projects that submit winning bids into the IOUs' RPS procurement solicitations are viable, and extending the procurement cycle to two years would breathe unnecessary additional life into such unviable projects while viable projects incur carrying costs. Moreover, as was noted above, prices for renewable energy projects will change over the course of time, and stretching the RPS procurement cycle over a period of two years or longer will only contribute to greater price uncertainty, to the significant potential detriment of ratepayers.

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[19] SDG&E RPS Plan, at 34.

SDG&E, SCE and PG&E all support this proposed reform, primarily on the ground that it would enhance the efficiency of their procurement processes.[20] However, SDG&E concedes that given the uncertainty of the market, a two-year procurement cycle could result in the need for the IOU to procure additional resources in a year when it was not conducting an RPS solicitation and could increase the risk of IOU procurement being benchmarked to outdated data.[21]

Finally, we note that this proposed reform seems to be at odds with the proposed reform calling for the expiration of shortlists after 12 months. If the RPS procurement cycle is two years or longer, it would seem that there will be a 12-month shortlist only once every two years. The Commission already acknowledges the fact that a significant number of the entities that have successfully negotiated PPAs with the IOUs are unlikely to be able to develop their projects and has taken this fact into account in its projections of the amount of renewable energy resources that the IOUs need to procure. A two-year RPS procurement cycle will definitely exacerbate the problem of over-shooting the mark and is likely to provide a perverse incentive to the IOUs to sign up even more unviable projects, thereby putting the Commission's laudable goal of seeking to meet the 33% RPS by 2020 at greater risk than it needs to be.

G. Utilizing the Commission's RPS Procurement Process to Minimize Transmission Costs is Valuable in Principle; However, the Details of this Proposal, as Set Forth in the ACR, Will Require Substantial Revisions if the Goal of the Proposal Is to Be Achieved in a Just and Reasonable Manner.

The proposal to minimize costly transmission upgrades resulting from RPS procurement is a good idea in general; however, this proposal needs to be modified in a number of important respects. Specifically, Tenaska agrees that an identification of needed system upgrades in order to assure the full deliverability of the energy from a given (presumably highly ranked) project

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[20] SDG&E RPS Plan, at 34-35; SCE Comments, at 9; PG&E RPS Plan, at 68-69.
[21] SDG&E RPS Plan, at 35.

should no longer be based on the CAISO's large interconnection queue volume (in particular, the pre-Cluster Five queues). The ACR is correct in noting that the "interplay" between the large CAISO queue volume and the *de facto* requirement that RPS projects provide RA capacity has had the effect of delaying the execution of PPAs and, consequently, the financing of such projects.

However, the specific proposal that the ACR sets forth in order to minimize the need for costly network deliverability upgrades, namely, to utilize a MW cap to limit the total capacity of executable PPAs in certain areas so as to avoid triggering unnecessary upgrades, fails to provide an effective solution to the problem it seeks to address and is in need of revision. The Commission's proposal aims to limit the PPAs executed in congested areas to those of high value and viability. However, the proposal uses the wrong gauge of project viability and decouples the existing problem (transmission capacity) from the proposed solution (*i.e.*, reliance on PPAs).

The execution of a PPA is not correlated to the amount of capacity that can be added to the transmission system without costly upgrades. That is, transmission system capacity is the limiting factor to avoid costly upgrades; therefore, any limit should be based on a transmission-system-related criterion (*i.e.,* the existence of executed LGIAs) and not on an uncorrelated commercial criterion (*i.e.*, total PPA MW). The Commission is well aware that a significant number of RPS projects with executed PPAs have not been built. This has led to a situation in which the IOUs have been compelled to overshoot the mark in terms of signing up RPS projects, because they know, as does the Commission and Commission staff, that a certain percentage of these projects will not come to fruition.

This has led, in turn, to the novel – and troubling – circumstance that a utility resource procurement process overseen by the Commission has acquired a significant aura of uncertainty, both in identifying where the RPS projects with the highest likelihood of being built will be located and what configuration of transmission upgrades is likely to be needed to in order to allow the output of those most likely projects to be deliverable to load in the most cost-effective manner. If the Commission is serious about effectively addressing and resolving this conundrum (an effort that the ACR is clearly intended to accomplish), it should look to the most factual and certain criterion for gauging the likelihood of project success.

A much better – and more factual – criterion for evaluating the likelihood of project success than what the ACR proposes is the existence of an executed LGIA between the prospective project and the CAISO. In order to have such an LGIA in place, the project proponent must have made a very substantial financial commitment in order to have undergone all of the required interconnection studies and, as well, to have completed the complex technical negotiations that inevitably precede the execution of an LGIA. By the time of LGIA execution, one knows the specific upgrade costs of a project and, if those costs are low, by definition, all parties also know that costly upgrades have been avoided.

The commitment on the part of a project developer that is needed to bring a project to the point of having an executed LGIA demonstrates a high degree of seriousness on the part of the developer. Moreover, the existence of an executed Full Capacity Deliverability Status LGIA demonstrates that the project in question will be able to fully deliver the needed RA capacity that the project is designed to provide, which, as the ACR correctly notes, is a *de facto* requirement that RPS projects need to meet. Tenaska would also note that the actual costs (as well as the ultimate feasibility) of interconnecting projects that already have executed LGIAs are, by definition, more certain than the costs of interconnecting projects that do not have executed LGIAs (although such projects may have executed PPAs).

The Commission needs to recognize this critical difference and to modify its proposal to minimize the costs of the deliverability network upgrades resulting from RPS procurement in a manner that *generally* recognizes not only the higher value of projects with executed LGIAs, but that also *specifically* acknowledges the higher value of projects with executed LGIAs when determining a cap on MW levels in certain areas to avoid costly upgrades. Some specific suggested modifications to several steps of the process proposed at pages 27-29 of the ACR, which would be consistent with the Commission's larger policy points noted above, are set forth below (shown with strike-outs and underlines from the text on pages 27-28 in the ACR).

1. The CAISO, after determining - based on engineering studies - the amount of deliverability for new generation projects that the grid can support in each study area without requiring additional high-cost DNU, will net out the amount of LGIA megawatts for all LGIAs that were executed on or before December 31, 2012, and the CAISO will assume that such projects already have full capacity deliverability. After the megawatt amount of executed LGIAs is netted out, the CAISO will net out the megawatt amount of executed power purchase agreements ~~that are already executed~~ in each study area only if such projects have a valid LGIA in the CAISO process, whether executed or not, based on information to be provided by the Commission. The amount of full capacity deliverability megawatts that remains after this two-stage netting will be considered available in the annual RPS procurement process. The result is that the IOUs will clearly know how many megawatts are available to contract in a specific area: executed LGIA megawatts without PPAs plus remaining megawatts after the two-stage netting.

[. . .]

5. Projects on an IOU's shortlist with LGIAs that were executed on or before

December 31, 2012, shall be exempted from the Commission's rationing procedure. Such projects will thus be entitled to their contractual rights, *i.e.*, the amount of full capacity deliverability megawatts that is the subject of their executed LGIAs. Pursuant to the rationing procedure, the Commission's Staff will utilize the rankings performed by the IOUs based on need, project viability, and project value, and will prioritize the best ranked projects among the three IOUs until the available deliverability is fully accounted for. The Commission's Energy Division Director will then communicate the results to the CAISO so CAISO can validate that the selected subset of megawatts is fully deliverable. The Commission's Energy Division Director will then communicate the validated results to the IOUs and will direct them to limit execution of power purchase agreements according to the rationed thresholds; provided, however, that any such best-ranked project that already has an LGIA executed on or before December 31, 2012, shall be exempted from the rationed thresholds and will be entitled to a power purchase agreement for the full amount of capacity deliverability megawatts that is the subject of contractual rights via its executed LGIA.

[…]

The foregoing suggested edits reflect the principle that in the evaluation of whether a given project will or will not require significant delivery network upgrades, the prime determinant of the available capacity on a given line should be the total megawatts of capacity that would be using that line based on executed LGIAs, and should *not* be the total megawatts of capacity that would be using that line based on executed PPAs.

III. CONCLUSION

For all the foregoing reasons, Tenaska urges the Commission to take action on the seven proposals to modify the existing RPS procurement and review process in accordance with the substance of the foregoing comments.

Respectfully submitted,

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Counsel to Tenaska Solar Ventures

June 27, 2012

VERIFICATION

I am the attorney for Tenaska Solar Ventures (Tenaska Solar) in this matter. Tenaska Solar is absent from the County of Alameda, 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 Tenaska Solar for that reason. I have read the attached **COMMENTS OF TENASKA SOLAR VENTURES ON THE ASSIGNED COMMISSIONER'S RULING.** 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 this 27th day of June, 2012, at Oakland, California.

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