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 CALIFORNIA WIND ENERGY ASSOCIATION ON ASSIGNED COMMISSIONER RULING PROPOSALS AND DRAFT 2012 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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I. INTRODUCTION

Pursuant to the California Public Utilities Commission's ("CPUC" or "Commission") Rules of Practice and Procedure and 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* ("ACR"), the California Wind Energy Association ("CalWEA") respectfully submits these comments on the proposals presented in the ACR and the investor-owned utilities' ("IOU") draft 2012 Renewables Portfolio Standard ("RPS") Procurement Plans (the "2012 Plans").

CalWEA has reviewed the ACR and provides comments below on the proposals described in the ACR. In addition, CalWEA has reviewed the 2012 Plans, including the proposed *pro forma* power purchase agreements ("PPA"), submitted by Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") and recommends that the Commission should:

1. Reject PG&E's proposal to permit unpaid curtailment in response to any warning, forecast, or anticipated overgeneration conditions;

2. Reject PG&E's proposed integration-cost bid adder because it does not satisfy the Commission's requirements for procedural protections;

3. Reject PG&E's proposed increase in development security requirements because it creates an artificial barrier to project development;

4. Reject PG&E's proposed elimination of the ITC and PTC risk mitigation provisions because it encourages higher-risk projects;

5. Direct SCE to modify its proposed curtailment provisions to comply with Decision 11-04-030;

6. Require SCE to modify the resource adequacy ("RA") provisions of its *pro forma* PPA and direct the other IOUs to adopt the provisions as modified;

7. Reject SCE's proposal to require bidders to have a completed Phase II Interconnection Study prior to execution of a PPA;

8. Clarify that shortlisted bidders will not be required to grant exclusive negotiating rights if SCE implements its proposal to require bidders to refresh pricing; and

9. Require SDG&E to seek a modification of the CPUC Approval non-modifiable standard term and condition ("STC") rather than introducing new terms in its *pro forma* PPA.

Each of these recommendations is addressed in greater detail below.

II. COMMENTS ON ACR PROPOSALS

A. Standardized Variables in LCBF Evaluation

The ACR proposes to standardize the calculation of net market value for use in the least-cost, best-fit ("LCBF") evaluation as the following E+C+S – (P+T+G+I), where E is energy value, C is capacity value, S is ancillary services value, P is post-time of delivery PPA price, T is the cost of network upgrades, G is congestion costs, and I is integration costs. The ACR further proposes that these inputs and calculations should be reviewed and verified for reasonableness by the Independent Evaluator ("IE") and publicly disclosed to the greatest extent possible.[1]

CalWEA supports the ACR's proposal to standardize the variables. While the IOUs may have differences in the specific inputs that they use, the basic elements of the costs and benefits associated with bids should be common across the IOUs. Along these lines, CalWEA notes that PG&E's 2012 Plan proposes to use Portfolio Adjusted Value ("PAV") in lieu of the net market valuation used by SCE and SDG&E.[2] PG&E's PAV will adjust net market value to reflect PG&E's preference for projects in its territory,[3] make evolving adjustments for changes in RA markets, and adjust for portfolio needs, uncertainty regarding project output, tenor, transmission costs, integration costs,[4] and number of hours of curtailment.[5] None of these adjustments are described with sufficient clarity to enable a bidder to understand how the adjustments will be applied to a given bid or what the magnitude of the adjustment may be. Moreover, many of these adjustments should already be captured in the existing components of net market value, such as locational value. In addition, PG&E's proposal to revise over the time the manner in which the adjustments are made conflicts with the requirement for the Commission to review the RPS procurement plan. Accordingly, PG&E's proposal to use PAV should be rejected.

CalWEA also supports the ACR's statement that the inputs in the LCBF should be publicly disclosed to the greatest extent possible. For the LCBF process to be meaningful, it must be transparent. To the extent that the LCBF evaluation captures the costs and benefits to

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[1] ACR § 7.1.
[2] PG&E Renewable Energy Procurement Plan at 62.
[3] Note that locational adjustments should already be reflected in the energy value of bids. To the extent that PG&E is stating that it would take a lower net market value project within its territory over a higher net market value project outside its territory, PG&E's proposal should also be rejected because it would be expected to raise the cost of RPS procurement.
[4] See Section III.A.2 below.
[5] PG&E Renewable Energy Procurement Plan at 62-63.

the IOU, public disclosure enables bidders to customize their bids (and the underlying projects) to provide the IOUs and their ratepayers with the highest value product possible. This is particularly critical with respect to the quantification of transmission cost adders and RA capacity valuation because Full Capacity Deliverability Status ("FCDS") and the associated capability to provide RA capacity represent an incremental product that has a separate decision point (i.e., a project can be offered Energy-Only ("EO") without RA capacity and avoid Delivery Network Upgrade ("DNU") costs, or offered FCDS with RA capacity and incur DNU costs). To the extent that SCE's proposal to allow third-party RA capacity supplies is approved, and hopefully extended to the other IOUs,[6] this same access to transparent RA capacity valuation and transmission upgrade cost adders will be critical to ensuring that third-party substitution is efficiently applied. For example, a developer should be able to determine that the IOUs will assume the developer's project of *x* megawatts will provide *y* megawatts of RA capacity, which the IOUs will value at *z* dollars per megawatt-year. Likewise, a developer with a Phase I Interconnection Study from the CAISO that specifies *x* million dollars in Delivery Network Upgrade costs should have access to sufficient detail about an IOU's LCBF process to be able to determine that the transmission cost adder the IOU will assign to the developer's offer will be *y* dollars per megawatt-hour. By making this information available to the market prior to the submission of offers, the Commission will enable developers to present offers with higher net value to ratepayers and make efficient decisions about whether to pursue FCDS interconnection. Accordingly, the Commission should continue to pursue as much public disclosure of LCBF inputs as possible.

[6] *See* related discussion of the SCE RA proposal in Section III.B.2 below.

B. Preliminary Independent Evaluator Report

The ACR proposes to require a preliminary IE report to be filed at the same time as the RPS Procurement Plans. This IE report would address the clarity of the solicitation materials with regards to, but not limited to, procurement targets and objectives, LCBF criteria, and how the LCBF criteria will be used to evaluate bids.[7]

CalWEA supports this proposal. As described above, bidders need a clear understanding of how their bids will be valued by the IOUs so that the bidders can provide bids that offer the maximum value to the IOUs. In its comments on this proposal, SDG&E expressed concern that bidders would use this information for "gaming purposes."[8] CalWEA submits that SDG&E's concerns about gaming are misplaced. The LCBF evaluation is supposed to represent the net value of a given bid to a given IOU. To the extent that disclosure of the LCBF inputs or calculations enables a bidder to tailor its bid in a manner that results in a higher net value in the LCBF analysis, the bidder has succeeded only in providing the IOU with a higher value product. Thus, the Commission should encourage public disclosure of LCBF inputs and calculations.

C. Use CAISO Transmission Cost Study Estimates in LCBF Evaluation

The ACR proposes that the IOUs should use CAISO interconnection study cost data in lieu of the Transmission Ranking Cost Report ("TRCR") where available.[9]

CalWEA has no comment on this proposal.

D. Create Two Shortlists Based on Status of Transmission Study

The ACR proposes that, after the IOUs generate their initial shortlist, the shortlist should be split into a Primary Shortlist and a Provisional Shortlist, where only projects with a Phase II Interconnection Study can be placed on the Primary Shortlist.[10]

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[7] ACR § 7.2.
[8] SDG&E 2012 Draft Renewable Procurement Plan at 28.
[9] ACR § 7.3.

CalWEA opposes this proposal. By creating two shortlists and moving projects between the two shortlists, the Commission would be creating an iterative process that could impede the negotiating process. For example, an IOU could start negotiations with a project on the Primary Shortlist, but then it may need to suspend negotiations because a higher-value project originally on the Provisional Shortlist receives its Phase II Interconnection Study and is moved to the Primary Shortlist.

E. Shortlists Expire After 12 Months

The ACR proposes that the IOUs should be required to execute a PPA with shortlisted bids within 12 months after the shortlist is submitted to the Commission. The ACR further proposes that, if no PPA is executed in this timeline, the IOU cannot execute a bilateral contract with the project, and the project must be bid into the next RPS solicitation.[11]

CalWEA opposes this proposal. The proposed 12-month limit presents an arbitrary restriction on the negotiating process. For example, as PG&E notes in its comments on this proposal,[12] there may not be another solicitation upon the conclusion of the 12-month period. The IOUs and shortlisted bidders should not be prevented from continuing to negotiate simply because a given amount of time has elapsed. Moreover, restricting a project that has been shortlisted from subsequently entering into a bilateral agreement, while allowing a project that was never shortlisted to do so, appears to penalize the bidder for having been shortlisted. However, CalWEA agrees that any contracts submitted more than 12 months after submission of the shortlist should be compared to more current price benchmarks to the extent available.

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[10] ACR § 7.4.
[11] ACR § 7.5.
[12] PG&E Renewable Energy Procurement Plan at 68.

In addition, CalWEA supports SDG&E's request for the Commission to require parties to negotiate the PPA in good faith.[13]

F. Two-Year Procurement Authorization

The ACR proposes that the IOUs be required to file RPS Procurement Plans every two years instead of annually. The IOU would then be required to file a Tier 3 advice letter in the off-year explaining whether it will be holding a solicitation in that year and any changes to its previously filed plan.[14]

CalWEA supports this proposal, provided that the Commission clarifies that the IOUs are required to identify any changes to the solicitation materials and *pro forma* PPA (including filing redlines) in the Tier 3 advice letter that the IOUs are required to file in the off year.

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

The ACR proposes to use the Commission's RPS procurement process to limit the amount of PPA capacity executed in given areas of the transmission system. Under the ACR proposal, the CAISO will identify the available capacity in different areas of the grid, and then the IOUs will provide the Commission with their shortlists. If the capacity associated with shortlisted bids in a given area collectively exceeds the available capacity identified by the CAISO for such area, then the Commission will allocate that scarce transmission capacity to the best-ranked shortlisted projects. The remaining shortlisted projects must be bid into the next solicitation.[15]

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[13] SDG&E 2012 Draft Renewable Procurement Plan at 33.
[14] ACR § 7.6.
[15] ACR § 7.7.

1. CalWEA Opposes This Proposal Because The Commission Should Let The Market Determine Which Entities Obtain PPAs

CalWEA opposes this proposal because it requires Commission staff to pick winners and losers rather than allowing the market to determine which projects obtain PPAs. The rationing process proposed in the ACR would effectively re-write the Federal Energy Regulatory Commission-jurisdictional interconnection process by allowing the Commission staff to determine which projects are permitted to interconnect. Moreover, the rationing process likely will not be sufficient to limit project development in constrained areas to the capacity identified by the CAISO because the Commission regulates only the PPAs entered into by the IOUs. To the extent that projects under contract to publicly-owned utilities interconnect to a constrained area, the rationing performed by the Commission may prove to be insufficient to avoid triggering additional DNUs.

Instead of administratively determining which projects will be allocated transmission capacity, the Commission should allow projects to compete on an economic basis. For example, if a given project triggers incremental DNUs, but is nonetheless able to offer a bid that is competitive with other projects that do not trigger incremental DNUs, then that project should still have an opportunity to enter into a PPA. Likewise, if a project avoids triggering incremental DNUs because it is interconnecting as an EO project, that project should be permitted to obtain a PPA so long as its bid is competitive with other options available to the IOU.[16]

In addition, allowing bidders to provide RA from third party suppliers, as previously advocated by CalWEA and now proposed in SCE's 2012 Plan,[17] will allow the market to address

[16] Note that both PG&E and SCE encourage the Commission to recognize that EO projects should not be subject to the rationing process described in the ACR. PG&E Renewable Energy Procurement Plan at 76; SCE Comments on Assigned Commissioner's April 5, 2012 Ruling Requesting Comment on New Proposals Related to Renewables Portfolio Standard Procurement Plans at 12. CalWEA agrees.

[17] *See* additional discussion of SCE's RA proposal in Section III.B.2 below.

the "problematic" DNU described in the ACR.[18] The third-party supply option removes the de facto requirement for a developer to provide RA capacity from its project. Instead, if costly, long-lead-time DNUs are identified, the developer has the option to pursue EO interconnection in lieu of FCDS interconnection and provide RA capacity from a third party. Thus, the third party supply option introduces more efficient transmission expansion by allowing a more direct trade-off between the cost of incremental DNUs and the value of the RA capacity it enables. Accordingly, the Commission should direct the IOUs to allow third party supply of RA capacity, as further described in Section III.B.2 below, and allow the market to determine which entities obtain PPAs.

2. If The Commission Is Not Persuaded At This Time To Abandon This Proposal, The Commission Should Defer Consideration Of This Proposal Until After It Considers Additional Evidence Relating To The CAISO's Deliverability Assessment Methodology

While allowing bidders to provide RA capacity from third party suppliers will allow bidders to prevent the "problematic" DNUs from impeding development of their projects, this solution does not address the underlying cause for identification of costly, long-lead-time DNUs. As CalWEA has previously stated, the CAISO currently designs DNUs to meet extremely rare system conditions – essentially, operating conditions that might arise once every several thousand years – and assuming that renewable generators are operating at their full capacity, even though the RA capacity that projects are eligible to provide will be less (in some cases, much less) than full capacity.[19] Accordingly, CalWEA has recommended that to facilitate a long-term solution to the high cost of FCDS interconnection and to address significant

[18] The ACR describes the "problematic" DNU as the situation where "developers of potentially desirable generation projects are impeded from obtaining power purchase agreements and even project financing because the large interconnection queue volume and the de facto requirement to provide RA capacity are tying their deliverability status to costly, long lead-time [DNUs] many of which may never be built." ACR at 26.

[19] *See e.g.*, *Comments of the California Wind Energy Association on Phase 1 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (January 13, 2012), R. 11-10-023.

transmission constraints, the Commission should encourage the CAISO to (1) revise the methodology and assumptions used in its interconnection study processes to reflect more reasonable system conditions, and (2) address major transmission constraints in its transmission planning process, where FERC has authorized the CAISO to plan for "policy-driven upgrades" to promote the achievement of state policy goals.

In support of its assertions that the CAISO should revise the methodology and assumptions used in its interconnection study processes to reflect more reasonable system conditions, CalWEA has commissioned an independent review of the CAISO's deliverability assessment methodology. However, the timing for completion of this review is such that CalWEA will not be able to present the conclusions to the Commission in accordance with the current procedural schedule.

Because the ACR proposal to use the Commission's RPS procurement process to limit the amount of PPA capacity executed in given areas of the transmission system is heavily dependent on assumptions about the available existing capacity on the system and the likelihood of triggering incremental DNUs, if the Commission is not persuaded by the reasoning above that this proposal should be abandoned, the Commission should defer consideration of this proposal until after it has reviewed the results of the deliverability assessment methodology review.

III. COMMENTS ON SPECIFIC RPS PLAN ISSUES

A. PG&E's 2012 RPS Procurement Plan

1. The Commission Should Reject PG&E's Proposal To Permit Unpaid Curtailment In Response To Any Warning, Forecast, Or Anticipated Overgeneration

In its 2012 Plan, PG&E proposes to modify the definition of "Curtailment Order" in its draft 2012 *pro forma* PPA to include any warning, forecast, or anticipated overgeneration conditions.[20] This revision would result in PG&E having the right to curtail the project, without compensation to the seller, in the event there is a warning, forecast, or anticipated overgeneration condition. However, the CAISO currently manages anticipated overgeneration by requesting market bids to mitigate the expected condition and does not issue mandatory curtailment instructions until there is an actual overgeneration condition. Thus, PG&E's proposal would inappropriately result in the seller being curtailed without payment for conditions that are expected to be resolved economically. Therefore, the Commission should reject PG&E's proposal.

In Decision 11-04-030, the Commission concluded that "it is reasonable for the *pro forma* contract of each IOU to include provisions for economic curtailment."[21] However, the Commission also drew a distinction between economic curtailment, which must "reasonably bound the developer risk, such as by a maximum number of curtailment hours or other device," and "non-economic curtailment (e.g., for system reliability, safety, stability)."[22] Here, PG&E's proposal to include any warning, forecast, or anticipated overgeneration conditions within the definition of Curtailment Order is inappropriate because the term Curtailment Order is used in PG&E's *pro forma* PPA to describe non-economic curtailment for which the seller is not

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[20] PG&E Renewable Energy Procurement Plan at 60.
[21] D. 11-04-030 at 17.
[22] *Id.* at n. 22, 24.

compensated, but the CAISO manages such conditions economically. CAISO Operating Procedure 2390 (Overgeneration) provides that, if there is a forecast overgeneration condition, the CAISO will "[s]end a Market Notification via the Market Messaging system (MNS), and . . . [r]equest decremental Energy bids to mitigate the Overgeneration" prior to the CAISO's Hour-Ahead Scheduling Process.[23] The CAISO does not issue mandatory curtailments based on a warning, forecast, or anticipated overgeneration condition; rather, mandatory curtailments are not used until actual overgeneration conditions occur in real time.[24]

Because anticipated overgeneration conditions are subject to market responses, PG&E should be required to use the economic curtailment provisions of its *pro forma* PPA, which provide PG&E with the right to curtail projects a minimum of 250 hours per year, to address these conditions. PG&E should not be permitted to curtail the seller without compensation in order to provide a market response. Accordingly, the Commission should reject PG&E's proposal to modify the definition of "Curtailment Order" in its draft 2012 *pro forma* PPA to include any warning, forecast, or anticipated overgeneration conditions.

2. The Commission Should Reject PG&E's Proposed Integration Cost Adder Because It Does Not Satisfy The Procedural Protections Required By The Commission

PG&E proposes to apply an integration cost adder of approximately $8.50/MWh in 2013 dollars to resources that are considered intermittent.[25] PG&E further intends to apply lower integration cost adders to resources with some reduced levels of intermittency on a "case-by-case basis."[26] However, PG&E's proposal does not provide the public review and comment and other procedural protections that the Commission has repeatedly stated are necessary before a non-zero

[23] CAISO Operating Procedure 2390 § 3.1.1.
[24] *Id.* § 3.1.2.
[25] PG&E Renewable Energy Procurement Plan at 16.
[26] *Id.*

integration cost adder can be applied to RPS procurement.[27] Accordingly, the Commission should reject PG&E's proposed integration cost bid adders.

This is not the first time the IOUs have requested authority to establish non-zero integration cost bid adders. The Commission first directed the IOUs to apply an integration bid cost adder of $0/MWh in Decision 04-07-029 based on the results of a CEC integration cost study published in 2004.[28] Subsequently, SCE sought authority to establish a non-zero integration cost bid adder, and the Commission denied SCE's request.[29] Then, SDG&E requested authority to include a non-zero integration cost bid adder in its 2008 RPS solicitation, which the Commission again denied, noting that the Commission is "not inclined to permit an IOU to develop an arguably important element of its LCBF assessment subject only to PRG review without the opportunity for public input."[30] In the 2010 RPS Procurement Plans, both SCE and SDG&E again proposed to apply non-zero integration cost bid adders. The Commission again rejected the proposals, agreeing that "an adder should only be used if it is developed in a public forum and, in addition, with Commission supervision."[31]

PG&E has not presented any evidence that warrants a departure from the Commission's prior holdings that any non-zero integration cost bid adder must be developed with public input and subject to Commission supervision. PG&E arrives at its proposed $8.50/MWh adder based on an assumption used in portfolio modeling for the 2010 Long Term Procurement Plan ("LTPP") proceeding.[32] However, this modeling assumption was not developed with public input; rather, it was developed independently by consulting firm E3 for use in greenhouse gas

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[27] *See e.g.*, D. 08-02-008 at 44.
[28] D. 04-07-029 at 12-14.
[29] D. 07-02-011 at 56.
[30] D. 08-02-008 at 44.
[31] D. 11-04-030 at 23.
[32] PG&E Renewable Energy Procurement Plan at 15.

modeling in Rulemaking 06-04-009 and adopted for modeling purposes in the LTPP proceeding only "in the absence of more rigorous analysis of California-specific integration costs."[33] Thus, the "opportunity for public input" the Commission found essential in Decision 08-02-008 is noticeably absent here. As a result, the Commission should reject PG&E's proposed integration cost bid adder.

Moreover, even if the level of the proposed integration cost adder were appropriate, the Commission should still reject PG&E's proposal because it fails to transparently describe how the integration cost bid adder would be applied. As noted above, PG&E proposes to apply the integration cost bid adder to intermittent resources, but will apply lower integration cost bid adders to resources with some reduced levels of intermittency on a "case-by-case basis."[34] This opaque description fails to establish any relationship between the integration cost bid adder and the operational characteristics of the projects to which it will be applied. In the absence of such a description, developers are unable to adjust the products they develop and offer to the IOUs to provide maximum value. For example, the developer of an intermittent resource may be able to invest in additional equipment to mitigate the effects of intermittency to which the IOU seeks to apply the integration cost bid adder (e.g., battery storage). However, without an understanding of whether the increase in the bid price that is required to fund the additional equipment will be offset by a reduction in the integration cost adder applied to the bid, the developer is unable to tailor its bid to the IOU's needs. Instead, the developer is left guessing, which introduces inefficiencies in RPS procurement. Accordingly, the Commission should reject PG&E's integration cost bid adder proposal.

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[33] *See* February 10, 2011 Administrative Law Judge's Ruling Modifying System Track I Schedule and Setting Pre-Hearing Conference, Attachment 2, "Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans", R. 10-05-006, at n. 18.
[34] PG&E Renewable Energy Procurement Plan at 16.

3. The Commission Should Reject PG&E's Proposed Increase in Required Development Security Because It Creates An Artificial Barrier to Project Development

PG&E's 2012 Plan proposes to increase the development security required to be posted by the seller to $300/kW of contract capacity.[35] This amount is *six times* the amount required in the 2011 solicitation.[36] PG&E attempts to justify this increase as necessary to "ensure that Sellers have a strong incentive to meet their obligations under the PPA, including the contract price, and in order to ensure that if they cannot, customers will be sufficiently protected."[37] However, PG&E fails to describe why the $50/kW it used in the previous solicitation is now insufficient to provide the desired incentives, or any basis for the $300/kW value it is now proposing.

Increased development security requirements have no relationship to the actual characteristics of the project, such as land costs, expected transmission upgrade costs, or the cost of generating equipment, but the increased requirements do directly increase the cost to develop a project. PG&E requires this development security to be posted early in the project development cycle, when a developer's capital structure consists primarily of comparatively expensive sponsor equity, and the cost of the development security diverts resources from the actual project development efforts. Moreover, this bloated security requirement must remain in place until 2019, which is the earliest on-line date PG&E proposes to accept in this solicitation. As a result, the ever-increasing development security requirements create an artificial barrier to project development. All of these factors end up raising the renewable energy costs ultimately paid by ratepayers. Accordingly, the Commission should reject PG&E's proposed increase in development security requirements.

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[35] *Id.* at 14.
[36] *Id.*
[37] *Id.* at 57-58.

4. The Commission Should Reject PG&E's Proposal To Eliminate The PTC/ITC Risk Mitigation Provisions Of PG&E's pro forma PPA Because It Encourages Higher Risk Projects

PG&E also proposes to eliminate for 2012 the provisions in its prior *pro forma* PPAs that mitigated the seller's risk associated with a failure of the PTC or ITC to be extended, if and to the extent that such failure affected the seller's ability to claim the applicable tax credit.[38] PG&E asserts that the deletion of these provisions is intended to "mitigate potential viability concerns" and that "[b]y eliminating this option, PG&E expects to receive offers from developers who are committed and able to fulfill contractual requirements without the guarantee of financing subsidies."[39] Contrary to PG&E's assertion, the elimination of ITC/PTC risk mitigation provisions is likely to have an adverse effect on project viability by increasing the risk associated with those projects that are selected.

PG&E's prior *pro forma* PPA provided that the seller could extend its guaranteed milestones if the applicable tax credit had not been extended by a specified date, and ultimately the seller could terminate the PPA if the tax credit still had not been extended by a later specified date and PG&E was not willing to pay the higher contract price required to compensate for the absence of the tax credit. These provisions leveled the playing field by allowing all developers to bid based on common assumptions about the availability of tax credits, with the ability for the parties to adjust the price or for the seller to be relieved of its obligations in the event the assumption proved false.

Eliminating these provisions will require each developer to decide whether to assume the risk that the tax credit will not be extended. Given that PG&E is seeking projects with an on-line date in 2019 or later and that the PTC is set to expire in 2012 (or 2013 for certain technologies)

[38] *Id.* at 14-15.
[39] *Id.*

and the ITC is set to expire in 2016, none of the projects bidding into PG&E's 2012 solicitation is be expected to be eligible for the tax credits. Thus, the seller will either have to take the low-risk approach and submit a high bid price that acknowledges that tax credits are not currently available for PG&E's preferred on-line dates, or the seller will have to take the high-risk approach and submit a lower bid price that assumes that the tax credit is extended. Indeed, the risk associated with assuming the tax credits are extended is even further magnified by the six-fold increase in development security described above, which magnifies the harm incurred by the developer if its assumption proves false.

All else being equal, the LCBF evaluation will lead PG&E to select the project that bids the lower price, which is also the higher risk project because it likely will not be able to perform its obligations unless the tax credits are extended. In other words, instead of "receiv[ing] offers from developers who are committed and able to fulfill contractual requirements without the guarantee of financing subsidies," PG&E may be receiving offers from developers who are willing to bear the increased risk associated with betting on the future availability of financing subsidies. Thus, the Commission should reject PG&E's proposed elimination of the ITC and PTC risk mitigation provisions.

B. SCE's 2012 RPS Procurement Plan

1. The Commission Should Direct SCE To Modify Its Proposed Curtailment Provisions To Comply With Decision 11-04-030

In its original 2010 RPS Procurement Plan, SCE proposed that it would have unlimited economic curtailment rights.[40] Subsequently, SCE revised the curtailment provisions in its plan a few times, ultimately settling on an economic curtailment proposal that allowed SCE to

[40] D. 11-04-030 at 16.

economically curtail based on CAISO prices up to a negotiated cap on the number of hours of curtailment (without compensation to the seller), and SCE could economically curtail based on CAISO prices in excess of the cap on hours (provided that SCE would compensate the seller for economic curtailment in excess of the cap).[41] The Commission accepted this revised proposal in Decision 11-04-030.

In its 2012 Plan, SCE proposes to "streamline" the economic curtailment structure approved in Decision 11-04-030:

> Specifically, the 2012 language allows SCE to curtail sellers for any reason, without payment, up to a megawatt hour curtailment cap (i.e., 50 hours for every megawatt hour of contract capacity). SCE can curtail in excess of the cap with payment to the seller for the amount of energy that could have been delivered, absent the curtailment, thus, maintaining revenue certainty for the project in order to facilitate financing of the project.[42]

While this description suggests that the new proposal is straight-forward, close review of the contractual provisions in SCE's draft *pro forma* PPA reveals that SCE's new economic curtailment proposal is much more complex. Specifically, SCE's draft *pro forma* PPA provides that SCE will pay the seller only for those curtailments directed by SCE that are not the result of a "Notice from SCE that Seller has been instructed by the CAISO or Transmission Provider to curtail energy deliveries" or a "Notice that Seller has been given a curtailment order or similar instruction in order to respond to an Emergency."[43] The draft *pro forma* PPA also provides that SCE will the CAISO scheduling coordinator for the project. Read together, these provisions are

[41] *Id.*
[42] SCE 2012 Written Plan at p. 30.
[43] SCE draft 2012 *pro forma* PPA §§ 3.12(g) and 4.01(c), and Exhibit A §§ 58 and 64. In greater detail, Section 4.01(c) provides that SCE will pay Seller for CNPP in excess of the Curtailment Cap, where "CNPP" is defined in relevant part as "energy that could have been delivered to the Delivery Point by Seller but which was not delivered . . . due to Seller's curtailment in accordance with Section 3.12(g)(iii)." Section 3.12(g)(iii) requires Seller to curtail in response to a Curtailment Order from SCE, where "Curtailment Order" is defined in relevant part as an order from SCE to curtail "for any reason except as set forth in Sections 3.12(g)(i)-(ii)." Sections 3.12(g)(i)-(ii) require Seller to curtail if SCE instructs Seller to curtail based on an instruction from CAISO or Transmission Provider to curtail or based on an instruction provided in order to respond to an Emergency.

susceptible to an argument that the seller would not be compensated for any curtailment resulting from any instruction from the CAISO, even if such curtailment instruction is the result of SCE's actions or omissions as the scheduling coordinator, such as a failure to submit a bid for the project, submission of a bid for the project that fails to clear the applicable CAISO market, or initiation of any other action that indicates to the CAISO a willingness to curtail or reduce generation from the project based on economic considerations.

This type of economic curtailment "loophole" was addressed by the Commission Decision 11-04-030. In its 2010 RPS Procurement Plan, PG&E proposed that it could curtail projects up to five percent of the project's expected annual generation per year, with PG&E paying the seller the full contract price for curtailed energy, but PG&E would not pay for curtailment instructions provided by the CAISO or any other entity.[44] The Commission acknowledged that "the curtailment instruction may be the result of PG&E actions or omissions" and that PG&E's "approach to economic curtailments would thereby effectively not be limited to five percent of expected annual output."[45] Accordingly, the Commission required PG&E to modify its PPA to "pay a seller for curtailment even when that economic curtailment is initiated by an entity other than PG&E (such as the CAISO)."[46]

Here, SCE proposes a payment excuse that is even broader than that proposed by PG&E, and rejected by the Commission, in Decision 11-04-030. While PG&E proposed that it would not pay for curtailment instructions that it did not deliver, SCE proposes that it will not pay for curtailment instructions it delivers itself if such curtailment instruction is provided to the seller based upon delivery of a similar instruction by the CAISO. In rejecting PG&E's proposal, the Commission has already recognized that such an approach to economic curtailment can

[44] D. 11-04-030 at 16.
[45] *Id.* at 20.
[46] *Id.* at 19.

effectively unravel any apparent limitations on economic curtailment. Accordingly, the Commission should require SCE to modify its economic curtailment proposal to clarify that SCE will compensate the seller for all economic curtailment in excess of the curtailment cap even when the curtailment is initiated by an entity other than SCE (such as the CAISO).

2. The Commission Should Require SCE To Modify The Resource Adequacy Provisions Of Its pro forma PPA And Direct The Other IOUs To Adopt The Provisions As Modified

SCE's 2012 Plan includes several revisions to its historical approach to procuring RA capacity from renewable projects. Specifically, SCE proposes that bidders will be able to bid projects as either Energy-Only ("EO") interconnections or Full Capacity Deliverability Status ("FCDS") interconnections (including specification of the date by which FCDS will be obtained), and, separately, bidders will also have the ability to designate the specific amount of RA capacity that the seller will provide for each month during the contract term, not to exceed the expected Net Qualifying Capacity that would be associated with the project if it were to obtain a FCDS interconnection.[47] In addition, the seller may provide this RA capacity from sources other than the project.[48] To the extent that the seller fails to provide the fixed RA capacity, it will either have to provide replacement RA capacity to SCE, or pay liquidated damages to SCE, with the specific option documented in the PPA.[49]

CalWEA commends SCE for proposing a progressive approach to procuring RA capacity within the RPS program. As CalWEA has previously explained in this proceeding and in the Commission's RA proceeding, Rulemaking 11-10-023, a rigid approach to procuring RA that requires all resource to obtain FCDS interconnection prior to COD can lead to inefficient

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[47] SCE 2012 Written Plan at 28.
[48] *Id.*
[49] SCE draft 2012 *pro forma* PPA § 3.02.

expansion of the transmission system and inefficient procurement of RA capacity.[50] In contrast, a structure in which RA capacity can be provided by a third party in lieu of requiring the seller to obtain FCDS can avoid the "problematic" DNUs described in the ACR while enhancing rational procurement of RA capacity. However, to capture the benefits of this structure, it is imperative that the LCBF valuation of transmission network upgrade costs and RA capacity be transparent to the marketplace, so that bidders are able to determine whether the ability to provide RA capacity will create enough value to compensate for the increased cost of a FCDS interconnection.

While SCE's proposal represents a large improvement, the Commission should require SCE to further refine its proposal. First, the Commission should require SCE to clarify that projects bid with FCDS interconnection and committing all of their capacity to SCE are not required to provide fixed amounts of RA and be subject to replacement obligations or liquidated damages. Instead, these projects, which conform to SCE's preferred approach, should continue to be subject to the current RA provisions, which require that the seller provide SCE with all RA capacity that is available from the project, whatever that may be and as it may change throughout the term of the PPA. This would preserve existing practice for projects with FCDS, where the buyer receives all RA capacity associated with the project, whether it increases or decreases over time.

Second, the Commission should require SCE to clarify that the replacement obligation and liquidated damages provisions are not mutually exclusive for projects that commit to a fixed quantity of RA capacity. Instead, these projects should have the right to provide replacement RA capacity for any shortfall. Then, to the extent that the seller fails to provide the required

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[50] *See e.g.*, *Motion of the California Wind Energy Association Regarding 2012 Renewables Portfolio Standard Procurement Plans* (December 8, 2011), R. 11-05-005.

replacement RA capacity, the seller would be subject to liquidated damages for such shortfall. Both the replacement RA capacity obligation and the liquidated damages are intended to compensate SCE for a shortfall relative to the guaranteed RA capacity. Thus, the seller should have the ability to cure a shortfall through either option.

As noted above, SCE's proposal to allow RA capacity to be provided by a third party in lieu of requiring the seller to obtain FCDS can avoid the "problematic" DNUs described in the ACR while enhancing rational procurement of RA capacity. Accordingly, the Commission should require PG&E and SDG&E to amend their 2012 Plans to incorporate the RA capacity provisions proposed by SCE, as modified in accordance with CalWEA's recommendations above.

3. The Commission Should Reject SCE's Proposal To Require Bidders To Have A Completed Phase II Interconnection Study Prior To Execution Of A PPA

SCE proposes to require bidders in its solicitation to have "at least a Phase I Interconnection Study (as demonstrated by a completed System Impact Study, Facilities Study, a Phase I or Phase II Interconnection Study, documentation showing that the project has passed fast Track Screens, or a signed Interconnection Agreement)" to be shortlisted, and bidders must have a completed "Phase II Interconnection Study (or equivalent or better)" before SCE will execute a PPA.[51] CalWEA understands that requiring a completed Phase I Interconnection Study (or equivalent or better)[52] in order for a bid to be shortlisted simplifies bid evaluation by increasing the quality and uniformity of transmission cost information. However, requiring a completed Phase II Interconnection Study (or equivalent or better) for execution of a PPA

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[51] SCE 2012 Written Plan at 27.

[52] The Commission should require the IOUs to clarify that existing qualifying facilities ("QFs") already meet these criteria. Existing QFs are able to transition from their original QF-based interconnection arrangements to contemporary interconnection arrangements through the QF conversion process, which does not require the projects to enter the transmission interconnection queue.

unnecessarily constrains the PPA negotiation and execution process. If all bids are required to have completed Phase I Interconnection Studies (or equivalent or better), then SCE will already have a meaningful transmission cost estimate on which to make its shortlisting decision. While the Phase II Interconnection Study may result in different estimated transmission costs, SCE's draft 2012 *pro forma* PPA already contains a provision that addresses increases in transmission costs. Thus, there is no need to delay PPA negotiations and execution until the Phase II Interconnect Study is completed. Accordingly, the Commission should reject SCE's proposal to require bidders to have a completed Phase II Interconnection Study prior to execution of the PPA.

4. If SCE Implements Its Proposal To Require Shortlisted Bidders To Refresh Pricing, The Commission Should Clarify That Shortlisted Bidders Will Not Be Required To Grant Exclusive Negotiating Rights

In its 2012 Plan, SCE notes that it is "considering" a revised solicitation structure in which it will negotiate PPAs to completion with shortlisted bidders, then request that the shortlisted bidders refresh their pricing, and then SCE would execute PPAs with a subset of the shortlisted bidders that offer the most attractive refreshed bids.[53] SCE asserts that this approach provides benefits to its customers because prices may fall during this time period.[54] If SCE implements this revised structure, the Commission should clarify that shortlisted bidders will not be required to grant exclusive negotiating rights.

In Decision 04-07-029, the Commission adopted the current solicitation process whereby bidders are allowed to bid into multiple solicitations, provided that the IOUs can request that the bidder grant the applicable IOU exclusive negotiating rights within five days after being shortlisted, and the applicable IOU can cease negotiating with any bidder that refuses to provide

[53] SCE 2012 Written Plan at 29.
[54] *Id.*

such exclusive rights.[55] The Commission determined that "[t]his approach provides a reasonable balance between bidder interests in submitting multiple bids and utility interests in having binding bids before proceeding to negotiations."[56] SCE's current proposal, however, would not require binding bids before proceeding to negotiation. Instead, bidders would not provide binding bids until after completion of PPA negotiations when SCE requests refreshed pricing. Thus, bidders would not know whether their bids have actually been accepted until after PPA negotiations are complete. Given the lag between the original shortlist notification and the completion of PPA negotiations, requiring bidders to maintain exclusive negotiations would not be reasonable.

As the Commission explained in Decision 06-05-039, "[c]ompetition is diminished to the extent potential buyers and sellers face barriers to making trades, and is increased to the extent unreasonable barriers are removed."[57] Because SCE's proposal to require bidders to refresh pricing after negotiation of the PPA would require bidders to forego other opportunities before knowing whether they had been selected by SCE and diminish competition, the Commission should clarify that shortlisted bidders will not be required to grant exclusive negotiating rights if SCE implements its proposal.

C. SDG&E's 2012 RPS Procurement Plan

1. The Commission Should Require SDG&E To Seek A Revision To The Non-Modifiable Definition of CPUC Approval Rather Than Introducing A Separate CPUC Approval Condition Precedent

SDG&E proposes to modify its 2012 *pro forma* PPA to include a new condition precedent requiring that Buyer will obtain CPUC Content Category Approval prior to a

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[55] D. 04-07-029 at 8.
[56] *Id.*
[57] D. 06-05-039 at 54.

negotiated date.[58] "CPUC Content Category Approval" is defined in relevant part as a final and non-appealable order of the CPUC without unacceptable conditions that finds that procurement pursuant to the PPA is procurement that meets the portfolio content category identified by the parties in the PPA.[59] Presumably, SDG&E is seeking to introduce this new provision to increase the regulatory certainty that it will be able to apply procurement from the PPA to the portfolio content category for which it was intended.

CalWEA does not object to the concept behind SDG&E's proposal to condition effectiveness of the PPA on receipt of advance approval from the Commission of the applicable portfolio content category. However, there is already a non-modifiable STC for "CPUC Approval" that must be included in all of the IOUs' PPAs.[60] This STC already requires a final and non-appealable order of the CPUC without unacceptable conditions that approves the PPA in its entirety, including payments to be made by the buyer (subject to Commission review of the administration of the PPA), and finds that procurement under the PPA is procurement from an eligible renewable energy resources for purposes of determining buyer's compliance with its RPS obligations.[61] SDG&E's proposed CPUC Content Category Approval provisions essentially seek to modify the content of the existing CPUC Approval STC. Accordingly, the Commission should require SDG&E to seek a modification of the CPUC Approval STC rather than introducing new conditions tied to CPUC approvals.

[58] SDG&E draft 2012 *pro forma* PPA § 2.3(a).
[59] *Id.* at § 1.1.
[60] *See* D. 07-11-025 Att. A.
[61] *See e.g.*, SDG&E draft 2012 *pro forma* PPA § 1.1.

IV. CONCLUSION

For the foregoing reasons, the Commission should adopt the recommendations set forth in these comments.

Respectfully submitted,

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June 27, 2012

VERIFICATION

I, Nancy Rader, am the Executive Director of the California Wind Energy Association. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the foregoing copy of *Comments of the California Wind Energy Association on Assigned Commissioner Ruling Proposals and Draft 2012 Renewables Portfolio Standard Procurement Plans* are true of my own knowledge, except as to the matters which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on June 27, 2012 at Berkeley, California.

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Nancy Rader

Executive Director, California Wind Energy Association