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 DRAFT 2013 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, 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"), and the May 23, 2013, email from Administrative Law Judge DeAngelis revising the schedule for this proceeding, the California Wind Energy Association ("CalWEA") respectfully submits these comments on the investor-owned utilities' ("IOU") draft 2013 Renewables Portfolio Standard ("RPS") Procurement Plans (the "2013 Plans").

CalWEA has reviewed the 2013 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 revise its pro forma PPA without disclosing those revisions to the Commission in RPS plan updates;

2. Direct PG&E to compensate the seller for the after-tax value of production tax credits ("PTC") for energy that would have been generated but for the buyer-directed curtailment;

3. Reject PG&E's proposal to require sellers to bear all integration-related charges;

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

5. Reject SCE's resource adequacy ("RA") liquidated damages proposal and direct all of the IOUs to allow RA to be provided by a source other than the project subject to the PPA;

6. Reject SCE's proposal to require sellers to reimburse SCE for negative market prices if the project is operating with energy-only ("EO") status;

7. Clarify that shortlisted bidders will not be required to grant exclusive negotiating rights;

8. Adopt SCE's proposal for development of integration cost adders through workshops;

9. Reject SCE's proposal to exclude projects located within an IOU service territory and having a capacity of 20 MW or less from the RPS solicitation;

10. Reject SDG&E's proposed capacity valuations and require all of the IOUs to provide transparent and reasonable capacity valuations; and

11. Reject SDG&E's proposal to reduce the price paid for delivered energy during a given time-of-delivery ("TOD") period that exceeds 115% of the energy originally expected in that TOD period.

Each of these recommendations is addressed in greater detail below.

II. COMMENTS ON RPS PLANS

A. PG&E's 2013 RPS Procurement Plan

1. The Commission Should Reject PG&E's Proposal To Revise Its pro forma PPA Without Disclosing Those Revisions To The Commission In RPS Plan Updates

PG&E proposes that "it should be understood that the RPS Form PPA is a living document that will continue evolving throughout the pendency of the RPS Plan proceeding."[1] PG&E further asserts that "[b]ecause the RPS Form PPA is constantly changing, PG&E does not intend to submit revised versions of the PPA in future phases of the 2013 RPS planning cycle, but the next RPS Plan that PG&E files in a subsequent planning cycle will update the RPS Form PPA to include intervening changes."[2] PG&E's proposal is inconsistent with the Commission's statutory obligation to review and approve RPS procurement plans, and therefore the Commission should reject it.

The Commission has a statutory obligation to review and approve the IOUs' RPS Procurement Plans, which include the pro forma PPAs.[3] While the pro forma PPAs may need to be revised over time due to changes in market and regulatory conditions, as PG&E suggests, this does not relieve PG&E of its obligation to present the pro forma PPA to the Commission nor the Commission of its obligation to review and approve that pro forma PPA. Thus, PG&E should be required to include any updates to the pro forma PPA that it intends to use in its solicitation with the rest of the updates to its 2013 Plan that are submitted to the Commission for review and approval. This public process also ensures that other interested stakeholders are afforded the opportunity to review and comment on the revisions to ensure that the Commission has a balanced set of viewpoints to consider in its own review of the 2013 Plans.

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[1] PG&E June 28, 2013 Draft 2013 RPS Plan at 79.
[2] *Id.*
[3] Cal. Pub. Util. Code § 399.13.

To the extent that there are terms of that pro forma PPA that must be revised by PG&E to reflect changes in market and regulatory conditions between the time the 2013 Plan is approved and the completion of negotiations between a given seller and PG&E, those changes to the pro forma can be reviewed by the Commission, along with all of the other negotiated deviations form the pro forma PPA, in connection with the Commission's review and disposition of PG&E's Tier 3 Advice Letter filing of the executed PPA.

Because the Commission has a statutory obligation to review and approve the 2013 Plans, including the pro forma PPAs, the Commission should reject PG&E's proposal to be allowed to update the pro forma PPA without including those revisions in its filing of updates to the 2013 Plan.

2. The Commission Should Direct PG&E To Compensate Sellers For The After-Tax Value Of PTC For Energy That Would Have Been Generated But For The Buyer-Directed Curtailment

In its 2013 Plan, PG&E proposes to modify its pro forma PPA to provide for unlimited buyer-directed curtailment.[4] This proposal would disproportionately affect renewable energy projects that rely on the PTC and unnecessarily increase PG&E's costs of RPS procurement by causing projects that rely on PTC to "price-in" the financial effects of lost PTC, even though PG&E may end up not needing to exercise its buyer-directed curtailment rights. Accordingly, the Commission should direct PG&E to compensate the seller for the after-tax value of PTC for energy that would have been generated but for the buyer-directed curtailment.

Renewable energy projects typically utilize PTCs, which are available for actual production over time on a volumetric basis, or the investment tax credit ("ITC"), which is independent of production volumes or timing. For a seller that is claiming PTCs, a curtailment order would preclude the seller from claiming PTCs with respect to the generation that the

[4] PG&E June 28, 2013 Draft 2013 RPS Plan at 80.

project could have produced but for the curtailment order, whereas the tax benefits available to a seller claiming the ITC are unaffected by a curtailment order. Thus, PG&E's proposal for unlimited buyer-directed curtailment would disproportionately impact projects relying on PTC unless PG&E pays the seller the TOD-adjusted contract price for the energy the project could have produced as well as the value (on an after-tax basis) of the PTCs associated with the energy the project could have produced.

In addition, as The Utility Reform Network ("TURN") and others have previously explained in Rulemaking 08-08-009, the predecessor to this proceeding, requiring the seller to "price it in" when setting a bid price results in higher costs for IOU customers. [5] Here, if a project relying on the PTC were selected, the IOU's ratepayers would be required to bear the cost of the developer's assumption about the extent to which PG&E might exercise its economic curtailment option, irrespective of the actual economic curtailment occurring during the term of the PPA. To avoid this unnecessary cost, the Commission should direct PG&E to compensate the seller for the after-tax value of PTC for energy that would have been generated but for the buyer-directed curtailment.

CalWEA acknowledges that the Commission rejected a similar request by CalWEA during the 2011 RPS procurement plan proceeding.[6] However, the current circumstances are much different than the last time the Commission considered this request. In its 2011 RPS procurement plan, PG&E proposed that buyer-directed curtailment would be limited to 5% of the expected annual energy output from the project.[7] It was in this context that the Commission determined not to require compensation for lost PTCs, noting that "it is reasonable for sellers to

[5] *See* Reply Comments of The Utility Reform Network on the 2010 RPS Procurement Plans (January 26, 2010) at 2; Proposed Decision at 13.
[6] D. 11-04-030 at 20.
[7] *Id.*

bear some of the curtailment risk."[8] However, PG&E has proposed to increase the limit on buyer-directed curtailment from 5% of expected output to 100% of actual output. This is a substantial difference that increases roughly 20-fold the potential impacts.

Accordingly, CalWEA requests that the Commission direct PG&E to compensate the seller for the after-tax value of PTC for energy that would have been generated but for the buyer-directed curtailment to avoid the disproportionate impacts and unnecessary cost increases described above.

3. The Commission Should Reject PG&E's Proposal To Require Sellers To Bear All Integration-Related Charges

PG&E notes repeatedly throughout its 2013 Plan that it "has not proposed an integration cost adder in its 2013 RPS Solicitation Protocol only because it was prohibited from doing so in D.12-11-016" and that it "will use existing tools (e.g., PPA modifications and new terms or conditions in future PPAs) to attempt to address integration cost allocation and customer impacts."[9] As described in greater detail in Section II.B.5 below, CalWEA fully agrees that the time has come to develop appropriate integration cost adders for use in LCBF evaluation of RPS bids. However, the Commission should reject PG&E's threat that "[i]f the Commission does not adopt a reasonable integration cost adder for use in the evaluation of the 2013 RPS Solicitation bids, PG&E intends to require sellers as part of specific PPA negotiations to bear all integration-related charges that are attributable to the resource's output."[10] Because these costs are not predictable, financiers must assume the worst and price it into the bid. The result will be higher costs for ratepayers, as compared to utilities absorbing the actual costs that materialize. Accordingly, the Commission should reject PG&E's proposal.

[8] *Id.*
[9] *See e.g.*, PG&E June 28, 2013 Draft 2013 RPS Plan at 6, 21, 53, 92, and 107.
[10] *Id.* at 92.

B. SCE's 2013 RPS Procurement Plan

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

In its initial 2010 RPS Procurement Plan, SCE proposed that it would have unlimited economic curtailment rights.[11] Subsequently, in response to concerns raised by CalWEA and other stakeholders that such a provision would increase bid prices and jeopardize project financing, SCE revised the curtailment provisions in its plan a few times, ultimately settling on an economic curtailment proposal that allowed SCE to 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).[12] The Commission accepted this revised proposal in Decision 11-04-030.

In its 2013 Plan, SCE proposes to "streamline" the economic curtailment structure approved in Decision 11-04-030:

> The proposed language provides for the following: (1) up to a megawatthour ("MWh") curtailment cap (i.e., 50 hours for every megawatt of contract capacity), SCE may curtail sellers for any reason, without payment; (2) SCE may curtail in excess of the cap, with payment to the seller for the amount of energy that could have been delivered absent the curtailment; (3) SCE may elect to receive all generated energy curtailed over the cap that SCE pays for but does not receive, at the end of the contract term, subject to a two-year limitation; (4) SCE must pay for energy SCE curtails during on-peak hours; and (5) SCE maintains its ability to curtail due to emergencies, instructions from the CAISO, or instructions from the transmission or sub-transmission provider, as was included in SCE's 2011 *Pro Forma*.[13]

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[11] D. 11-04-030 at 16.
[12] *Id.*
[13] SCE Written Plan at 44.

Close review of the contractual provisions in SCE's draft *pro forma* PPA, however, reveals that SCE's new economic curtailment proposal is much more complex than SCE's description suggests. 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."[14] The draft *pro forma* PPA also provides that SCE will be the CAISO scheduling coordinator for the project. Read together, these provisions are 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.[15] The Commission

[14] SCE draft 2013 *pro forma* PPA §§ 3.12(g) and 4.01(c), and Exhibit A §§ 60 and 66. 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.

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

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."[16] 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)."[17]

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 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 Reject SCE's Resource Adequacy Liquidated Damages Proposal And Direct All Of The IOUs To Allow RA To Be Provided By A Source Other Than The Project Subject To The PPA

SCE's 2013 Plan includes a departure from its historical approach to procuring RA capacity from renewable projects. Specifically, SCE proposes a new provision under which sellers that propose a full capacity deliverability status ("FCDS") project must pay SCE liquidated damages if the amount of net qualifying capacity ("NQC") assigned to the project by

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[16] *Id.* at 20.
[17] *Id.* at 19.

the CAISO is less than the qualifying capacity ("QC") of the project.[18] The Commission should reject this proposed revision to the RA provisions of SCE's pro forma PPA.

Pursuant to Section 40.4 of the CAISO tariff, the CAISO will determine a project's QC using criteria provided by the Commission. As SCE notes, a project's NQC may be reduced to a value less than the QC based on deliverability studies that assess the availability of transmission capacity on the CAISO system.[19] SCE asserts that it values bids offering FCDS based on the amount of RA it is expected to provide, and that if the NQC (and thus the amount of RA available from the project) is reduced, then SCE would be paying for a benefit that it never received.[20]

However, SCE's proposal ignores the reality that the reduction in NQC resulting from deliverability studies is entirely outside the seller's control. The seller can request FCDS in the interconnection process, and cause the construction of the transmission system upgrades identified in its interconnection studies, but the seller has no role in transmission system planning once it is interconnected. Thus, the seller has no mechanism to mitigate the risk that its NQC may be reduced in the future. In contrast, SCE, as a participating transmission owner, has a much greater opportunity to expand the grid to avoid a decrease in NQC of the project (or SCE's entire portfolio of projects in the affected area). Accordingly, the Commission should reject SCE's proposal to assess liquidated damages to the seller for reductions in NQC.

In addition, the Commission should direct SCE, and the other IOUs, to revise the RA provisions of the pro forma PPAs to allow the seller to provide RA from a source other than the project subject to the PPA. 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

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[18] SCE Written Plan at 43.
[19] *Id.*
[20] *Id.*

requires all resources to obtain FCDS interconnection prior to COD can lead to inefficient expansion of the transmission system (based on cost or timeline) and inefficient procurement of RA capacity.[21] 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" delivery network upgrades ("DNUs") described previously in this proceeding[22] while enhancing rational procurement of RA capacity. However, to capture the benefits of this structure, it is imperative that the LCBF valuation of DNU 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.[23]

Specifically, the Commission should require the IOUs to permit projects to bid (1) EO, (2) EO with third-party RA supply, or (3) FCDS or Partial Capacity Deliverability Status ("PCDS"). Projects that bid EO with third-party RA supply should be required to specify a guaranteed amount of RA that will be supplied. To the extent that the seller fails to provide the required RA capacity, the seller would be subject to liquidated damages for such shortfall.[24] For projects that bid with FCDS or PCDS interconnection, the project would continue to be subject to the current RA provisions, which require that the seller provide the IOU 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 (or PCDS), where the buyer receives all RA capacity associated with the project, whether it increases or decreases over time.

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[21] *See e.g.*, *Motion of the California Wind Energy Association Regarding 2012 Renewables Portfolio Standard Procurement Plans* (December 8, 2011), R. 11-05-005.
[22] *See* discussion on pages 9-10.
[23] *See* Section II.C.1 below for further discussion of this point.
[24] Note that this is similar to the proposal that SCE made in its initial draft 2012 RPS Procurement Plan before it decided it would not hold a 2012 RPS solicitation.

As noted above, allowing RA capacity to be provided by a third party in lieu of requiring the seller to obtain FCDS can avoid the "problematic" DNUs described previously in this proceeding while enhancing rational procurement of RA capacity. Accordingly, the Commission should require the IOUs to amend their 2013 Plans to incorporate the RA capacity provisions described above.

3. The Commission Should Reject SCE's Proposal To Require Sellers To Reimburse SCE For Negative Market Prices If The Project Is Operating With Energy-Only Status

SCE proposes revisions to its pro forma PPA to require projects interconnected as EO resources (including projects that elected FCDS) during the period prior to completion of required delivery network upgrades) to bear the risk that market prices will be negative.[25] SCE asserts that these revisions are necessary to appropriately allocate congestion risk to such projects.[26] The Commission should reject this proposal because it exposes the seller to unquantifiable and unmanageable revenue risk that could substantially raise financing costs and adversely affect financeability of the PPA.

SCE's assertion that projects operating with EO status must bear negative market price risk in order to appropriately allocate congestion risk is wrong for several reasons. First, SCE likely overstates the extent of the risk. As CalWEA has previously stated, the CAISO currently designs DNUs to meet extremely rare system conditions – more stringent than system reliability studies, and assumes, among other unreasonably conservative assumptions, that renewable generators are operating at very high capacity, even though the RA capacity that projects are eligible to provide will be less (in some cases, much less) than the studied capacity.[27] Given that

[25] SCE Written Plan at 45-46.
[26] *Id.*
[27] *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.

these DNUs are designed to mitigate transmission limitations under extreme conditions, the lack of the DNUs does not mean that the system will become congested.

Second, SCE can mitigate its perceived risk of incremental congestion from EO projects in the bid selection stage through the application of its LCBF methodology without a need to modify the pro forma PPA. The Adjusted Net Market Value calculation approved by the Commission in Decision 11-04-030 provides that the IOUs are permitted to include a congestion adder in the quantitative portion of the LCBF evaluation. To the extent that SCE believes that EO projects cause SCE to incur incremental congestion risk, SCE can reflect this incremental congestion risk through the development of congestion adders for EO projects. Indeed, this is the approach that SCE proposed in its 2012 RPS procurement plan before it decided that it would not hold a 2012 RPS solicitation.[28]

Finally, and most importantly, SCE's new proposal results in an inappropriate allocation of risk to the seller because it would effectively operate as an unquantifiable and unmanageable curtailment provision, which could raise financing costs and adversely impact financeability of the PPA. SCE's pro forma PPA provides that the seller is paid based on metered generation. To the extent the market price is negative and the seller is required to reimburse SCE for this price, the seller must compare the cost of reimbursing SCE against the revenue for metered amounts under the PPA. Anytime the absolute value of the negative market price exceeds the PPA price, the seller will have to self-curtail to avoid a net loss associated with the generation. Because the seller, and its lenders, cannot predict with any particular level of assurance when the market price will be negative, or by how much, this risk is effectively unbounded, which runs afoul of the Commission's direction in Decision 11-04-030 for the IOUs to develop economic curtailment

[28] *See* SCE 2012 Written Plan (May 23, 2012), R. 11-05-005, at 28.

provisions that "reasonably bound the developer risk."[29] Moreover, given the CAISO's unduly conservative methodology for DNUs, forcing developers to select FCDS status to avoid this unbounded negative market price risk could dramatically, and unnecessarily, raise transmission costs.

Accordingly, the Commission should reject SCE's proposal to require projects interconnected with EO status to bear the risk that market prices will be negative.

4. The Commission Should Clarify That Shortlisted Bidders Will Not Be Required To Grant Exclusive Negotiating Rights

In its 2013 Plan, SCE notes that it intends to implement 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.[30] SCE asserts that this approach provides benefits to its customers because it alleviates the risk of stale pricing.[31] PG&E also reserves the right to delay its decision on whether to contract with shortlisted bidders, noting that "whether or not PG&E executes PPAs arising out of the 2013 RPS Solicitation is dependent on whether PG&E and the shortlisted bidders can reach mutual agreement on specific and definitive terms, some of which may differ significantly from those in the RPS Form PPA. PG&E reserves the right not to execute any PPA."[32] Similarly, SDG&E proposes that it "will consider any proposal by shortlisted counterparties to reduce the price for shortlisted projects."[33] Because all of the IOUs propose to reconsider offers from shortlisted bidders during, or at the end of, the

[29] D. 11-04-030 at 18.
[30] SCE 2012 Written Plan at 41-42.
[31] *Id.*
[32] PG&E June 28, 2013 Draft 2013 RPS Plan at n. 44.
[33] SDG&E 2013 Request for Offers at 22.

negotiation process, 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 such exclusive rights.[34] 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."[35] The IOUs' current proposals, however, no longer require binding bids before proceeding to negotiation. Instead, bidders are expected to refresh elements of their bids – explicitly pricing in the case of SCE, implicitly pricing in the case of SDG&E, and new terms not included in the pro forma PPA in the case of PG&E. Thus, bidders would not actually know whether their bids have truly 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."[36] Because the IOUs' proposals would require bidders to forego other opportunities before knowing whether their bids had truly been selected and thus diminish competition, the Commission should clarify that shortlisted bidders will not be required to grant exclusive negotiating rights.

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[34] D. 04-07-029 at 8.
[35] *Id.*
[36] D. 06-05-039 at 54.

5. The Commission Should Adopt SCE's Proposal For Development Of Integration Cost Adders Through Workshops

In its 2013 Plan, SCE proposes that the Commission should set a date by which the IOUs would propose integration cost adders, which would then be subject to public comment and workshops.[37] CalWEA agrees that the use of workshops to develop the integration cost adder is an appropriate approach and encourages the Commission to adopt this proposal with the clarification that integration cost adders can be proposed by any party to the proceeding, not just the IOUs.

On several occasions, the Commission has rejected various proposals from the IOUs to implement non-zero integration cost 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.[38] Subsequently, SCE sought authority to establish a non-zero integration cost bid adder, and the Commission denied SCE's request.[39] 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."[40] 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."[41] Most recently, the Commission rejected PG&E's proposed $8.50/MWh integration cost adder in Decision 12-

[37] SCE Written Plan at 34-35.
[38] D. 04-07-029 at 12-14.
[39] D. 07-02-011 at 56.
[40] D. 08-02-008 at 44.
[41] D. 11-04-030 at 23.

11-016, again noting that the integration cost adder must be developed through a public process.[42]

However, as reflected in SCE's 2013 Plan and the comments of several parties (including CalWEA) filed in response to the *Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals and Establishing a Schedule for Comments on Proposals* ("2nd ACR") issued in this proceeding on October 5, 2012, there is a need to start the process of developing a non-zero integration cost adder.[43] In response to the 2nd ACR, CalWEA presented a quantitative proposal for an integration cost adder using actual, current data from the CAISO's markets.[44] The CalWEA proposal is based on recent data on the load following costs which renewable generation causes the CAISO to incur. CalWEA recognizes that its proposal uses a limited, three-month set of data from January-March 2012 reflecting the costs of the CAISO's Flexible Ramping Constraint ("FRC"), that data from additional months is needed, and that the CAISO is continuing to refine its methodology for allocating FRC costs between load and various types of supply sources.

CalWEA supports SCE's proposal for workshops on an integration cost adder, and would be happy to present the details of its integration cost adder proposal at such a workshop, hopefully using additional FRC data from additional months in 2012. CalWEA also asks the Commission to encourage the CAISO to make such data available to stakeholders as soon as possible.

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[42] D. 12-11-016 at 28-29.

[43] *See* Reply Comments of California Wind Energy Association on Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals (December 12, 2012), R. 11-05-005, at 12-17.

[44] *See* Comments of California Wind Energy Association on Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals (November 20, 2012), R. 11-05-005, at 25-34.

6. The Commission Should Reject SCE's Proposal To Exclude Projects Located Within An IOU Service Territory And Having A Capacity Of 20 MW Or Less From The RPS Solicitation;

In its 2013 Plan, SCE proposes that its 2013 RPS Solicitation will prohibit bids from projects located within one of the IOU service territories if the project has a capacity of 20 MW or less.[45] SCE asserts that this approach is appropriate because these projects are eligible to participate in a variety of other procurement programs for small renewable resources.[46] However, SCE's claim likely overstates the availability of other procurement opportunities. There is only one remaining Renewable Auction Mechanism ("RAM") solicitation authorized by the Commission, RAM 5, which is scheduled to close in June 2014. SCE intends to seek only 20 MW of wind-powered generation in RAM 5, which provides an extremely limited opportunity for wind-powered generating projects with capacity greater than 3 MW and less than 20 MW to compete for a PPA. Accordingly, the Commission should reject SCE's proposal to exclude projects located within an IOU service territory and having a capacity of 20 MW or less from the RPS solicitation.

C. SDG&E's 2013 RPS Procurement Plan

1. The Commission Should Reject SDG&E's Proposed Capacity Valuations And Require All Of The IOUs To Provide Transparent And Reasonable Capacity Valuations

In its 2013 Plan, SDG&E discloses that it intends to use proxy capacity prices of (1) $120/kW-year for projects providing "local" RA, (2) the CAISO Capacity Procurement Mechanism ("CPM") rate (currently $67.50/kW-year and already set to increase to $70.88/kW-year early next year) for projects providing "Imperial Valley Area" RA, and (3) the CPUC

[45] SCE Written Plan at 40-41.
[46] *Id.*

penalty rate for failure to meet RA requirements for projects providing "system" RA.[47] In stark contrast to these rates, Energy Division and Policy and Planning Division have highlighted the current "large oversupply of generic system capacity" and reported recent median RA prices of $1.65/kW-month ($19.80/kW-year) for CAISO system RA and $2.50/kW-month ($30.00/kW-year) for SP26 local RA, which are a small fraction of the proxies proposed by SDG&E.[48] In addition, Decision 12-12-010 adopted, after stakeholder participation, the standardized planning assumptions and scenarios to be used in the 2012 Long-Term Procurement Planning ("LTPP") proceeding for forecasting system reliability needs for California's electricity grid, including a "base case" that indicates that system supply will exceed system demand throughout the entire planning horizon – i.e., there is excess system capacity through 2034.[49] Given the current low prices for RA capacity and the forecast of excess RA capacity in the 2012 LTPP proceeding, the Commission should reject SDG&E's proposed capacity valuations and require all of the IOUs to provide a transparent and reasonable capacity value for use in the LCBF evaluation of bids in the 2013 RPS solicitations.

The calculation of the market value of capacity should be transparent. The IOUs should be applying a specific metric to each type of renewable technology to derive the expected RA capacity available from the project, and then multiplying that RA capacity by an RA capacity market price to determine the capacity value, which can then be discounted to present value. Each IOU should include in its RPS solicitation materials the IOU's assumptions for RA capacity by resource type, its forward price curve for RA capacity pricing, and its discount rate.

[47] SDG&E 2013 RPS Procurement Plan at 38-39.
[48] CPUC Energy Division & Policy and Planning Division, Briefing Paper: A Review of Current Issues with Long-Term Resource Adequacy (February 20, 2013) at 5, 16.
[49] D. 12-12-010 at Att. A, p. 21.

Then, all stakeholders will have the information necessary to calculate the value to a given IOU of RA capacity that could be provided by a given project.

With a specific quantitative value for the capacity available from its project, a developer can make much more efficient decisions about whether to incur the costs associated with providing RA capacity, which also leads to more efficient expansion of the transmission system. As CalWEA has previously explained in this proceeding, projects are required to request during the interconnection process either FCDS, PCDS, or EO. The first two options (FCDS and PCDS) include the associated capability to provide RA capacity by funding Delivery Network Upgrade ("DNU") costs, while the third option (EO) precludes the ability to provide RA capacity but also avoids the construction of DNUs. The choice between FCDS, PCDS, and EO represents a separate decision point where the developer must choose whether to offer an incremental product to the IOU (i.e., a project can be offered as EO without RA capacity and avoid DNU costs, or offered as PCDS/FCDS with RA capacity and incur DNU costs). In some cases, the cost for these upgrades is significantly higher than the value of RA capacity that the upgrades create. To make an efficient choice, the developer must know the value of the RA capacity to the IOUs in addition to the cost of the DNUs. This knowledge not only improves the RA procurement process but also prevents developers from making inefficient interconnection choices that would lead to costly transmission upgrades to the detriment of the ratepayers.

Accordingly, the Commission should direct all of the IOUs to provide transparent and reasonable capacity valuations.

2. The Commission Should Reject SDG&E's Proposal To Reduce The Price Paid For Delivered Energy During A Given TOD Period That Exceeds 115% Of The Energy Originally Expected In That TOD Period

In its 2013 Plan, SDG&E proposes to reduce the price paid for delivered energy during a given TOD period that exceeds 115% of the energy originally expected in that TOD period.[50] In the context of a wind-powered generator, this proposal is unreasonable. While a wind generation profile is reliable, on average, for 20 years, it is not predictive for any given day or hour. To the extent that SDG&E is concerned that bidders will submit one delivery profile and then deliver something entirely different,[51] there are better ways to address these gaming concerns. For example, SDG&E could require bidders to provide their meteorological data to support the submitted profile, or, if SDG&E considers a profile to be out of the ordinary, it could substitute a generic profile from the wind region for purposes of the LCBF bid evaluation. Uniformly penalizing any seller for deviation from the original profile is not necessary. Thus, the Commission should reject SDG&E's proposal.

[50] SDG&E 2013 pro forma PPA § 4.2(a)(iii).
[51] SDG&E 2013 RPS Procurement Plan at 38.

III. CONCLUSION

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

Respectfully submitted,

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July 12, 2013

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 Draft 2013 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 July 12, 2013 at Berkeley, California.

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Nancy Rader

Executive Director, California Wind Energy Association