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 2014 RPS PROCUREMENT PLANS AND RELATED QUESTIONS IN ASSIGNED COMMISSIONER'S RULING

Nancy Rader
Executive Director
California Wind Energy Association
2560 Ninth Street, Suite 213A
Berkeley, California 94710
Telephone: (510) 845-5077
Email: nrader@calwea.org

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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 2014 Renewables Portfolio Standard Procurement Plans* ("ACR"), and the April 16, 2014, 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 2014 Renewables Portfolio Standard ("RPS") Procurement Plans (the "2014 Plans") and on the specific topics raised in the ACR for comment by the parties.

CalWEA has reviewed portions of the 2014 Plans, including portions of 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. Require PG&E to include proposed revisions to its solicitation protocol and *pro forma* PPA in RPS plan updates;
2. Direct PG&E to compensate sellers for the after-tax value of Production Tax Credits ("PTCs") for energy that would have been generated but for the buyer-directed curtailment;

3. Direct SCE to restore its obligation to compensate sellers for the after-tax value of PTCs for energy that would have been generated but for buyer-directed curtailment; and

4. Require SDG&E and the other utilities to clarify that automated curtailment instructions will be deemed buyer-directed economic curtailment.

In addition, CalWEA offers comments on all three of the specific topic areas and related questions identified in the ACR, and recommends that the Commission should:

1. Direct the utilities to use a resource adequacy value of zero in their 2014 least-cost, best-fit ("LCBF") bid evaluations;

2. Direct the utilities to use Commission-approved capacity values based on an effective load carrying capacity ("ELCC") methodology at such time that resource adequacy has a positive value;

3. Direct PG&E and SDG&E to use a single set of time-of-delivery factors, as SCE proposes to do;

4. Refrain from pursuing any sort of threshold bidding requirement related to the environmental permitting process; and

5. Adopt an integration cost methodology for application in the 2014 RFO cycle, following a workshop to consider a CalWEA proposal set forth in these comments and any other proposals.

Each of these recommendations is addressed in greater detail below.

II. COMMENTS ON RPS PLANS

A. PG&E's 2014 RPS Procurement Plan

1. The Commission Should Require PG&E To Include Proposed Revisions To Its Solicitation Protocol and *Pro Forma* PPA In RPS Plan Updates

In its 2014 Plan, PG&E states:

> Given the dynamic nature of the renewables industry, market, and regulatory environment, PG&E may make modifications to the 2014 Solicitation Protocol and 2014 RPS Form PPA as market conditions evolve prior to solicitation issuance in order to minimize operational challenges, maximize the value of projects to

> PG&E customers, and minimize any potential future contract disputes.[1]

PG&E's proposal to make such modifications "prior to solicitation issuance" is inconsistent with the Commission's statutory obligation to review and approve RPS procurement plans. Therefore, the Commission should require PG&E to include any proposed revisions to its solicitation protocol or *pro forma* PPA in its RPS plan updates filed with the Commission.

The Commission has a statutory obligation to review and approve the IOUs' RPS Procurement Plans, which include the *pro forma* PPAs.[2] 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 solicitation protocol and *pro forma* PPA that it intends to use in its solicitation with the rest of the updates to its 2014 RPS 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 2014 RPS Plans.

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 2014 RPS 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 from 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 2014 RPS Plans, including the *pro forma* PPAs, the Commission should require PG&E to include any proposed revisions to its solicitation protocol or *pro forma* PPA in its RPS plan updates filed with the Commission.

[1] PG&E June 4, 2014 Draft 2014 RPS Plan at 70.
[2] Cal. Pub. Util. Code § 399.13.

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

In Decision 13-11-024, the Commission rejected PG&E's proposal to require unlimited compensated buyer-directed curtailment in the *pro forma* PPA, while allowing for the subject to be further negotiated in the context of individual PPA discussions.[3] In its 2014 RPS Plan, PG&E proposes to reintroduce unlimited compensated buyer-directed curtailment, while allowing bidders to "offer less than full operational flexibility," although PG&E warns that any limitations will be reflected in its valuation of the offer.[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 PTCs to "price-in" the financial effects of lost PTCs, even though PG&E may end up not needing to exercise its buyer-directed curtailment rights. CalWEA acknowledges that the Commission has previously considered whether sellers should be compensated for lost PTCs when economically curtailed;[5] however, the current class of highly-flexible, buyer-directed economic curtailment proposals differs materially from that previously considered by the Commission and warrants reconsideration of this issue.

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 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 compensated buyer-directed curtailment would disproportionately impact projects relying on PTCs 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

[3] D. 13-11-024 at 38-40.
[4] PG&E June 4, 2014 Draft 2014 RPS Plan at 71-72.
[5] D. 11-04-030 at 20.

"price it in" when setting a bid price results in higher costs for IOU customers.[6] 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 has rejected similar requests by CalWEA in prior RPS procurement plan proceedings.[7] 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.[8] It was in this context that the Commission determined not to require compensation for lost PTCs, noting that "it is reasonable for sellers to bear some of the curtailment risk."[9] However, each of PG&E, SCE, and SDG&E now propose that the buyer can unilaterally direct the seller to curtail for any reason.[10] While the Commission may have found it reasonable for sellers to bear some portion of the curtailment risk 5% of the time, CalWEA submits that it is not reasonable for sellers to bear the risk of lost PTCs 100% of the time, particularly where the "risk" is whether the buyer elects to exercise its unilateral rights. The current circumstances are materially different than those previously considered by the Commission.

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

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[6] *See* Reply Comments of The Utility Reform Network on the 2010 RPS Procurement Plans (January 26, 2010) at 2; Proposed Decision at 13.
[7] D. 13-11-024 at 40; D. 11-04-030 at 20.
[8] D. 11-04-030 at 20.
[9] *Id.*
[10] PG&E June 4, 2014 Draft 2014 RPS Plan at 71-72; SCE Written Plan at 46-47; SDG&E 2014 RPS Plan at 29-31.

B. SCE's 2014 RPS Procurement Plan

1. The Commission Should Direct SCE To Restore Its Obligation To Compensate Sellers For The After-Tax Value Of PTCs For Energy That Would Have Been Generated But For The Buyer-Directed Curtailment

In its 2014 RPS Plan, SCE proposes to remove from its *pro forma* PPA several provisions relating to federal tax credits.[11] One of these provisions is former Section 4.01(d) of the *pro forma* PPA, which required SCE to compensate sellers with PTC-eligible projects for the PTCs that the sellers were unable to obtain due to buyer-directed economic curtailment. Presumably, SCE's view is that this provision is not likely to be applicable given the timing of the solicitation resulting from its 2014 RPS Plan and the current status of the federal PTC. However, proposed legislation has been introduced that would extend the deadline for start of construction of PTC-eligible projects to December 31, 2015.[12] Thus, there may be projects participating in SCE's next solicitation that would still be PTC-eligible.

Therefore, the Commission should require SCE to restore the provisions of its *pro forma* PPA that require SCE to compensate sellers for the after-tax value of PTCs that are not received by sellers due to buyer-directed economic curtailment.

C. SDG&E's 2014 RPS Procurement Plan

1. The Commission Should Require SDG&E And The Other IOUs To Clarify That Automated Curtailment Instructions Will Be Deemed Buyer-Directed Economic Curtailment

In its 2014 RPS Plan, SDG&E expresses concern that recent changes in CAISO market design have increased SDG&E's exposure to negative price risk, and, in response, SDG&E proposes that (1) buyer should have unlimited compensated buyer-directed economic curtailment rights, and (2) sellers should be required to install equipment on their projects that will allow automated receipt and implementation of curtailment instructions, including the automated dispatch system ("ADS") and application programming interface ("API").[13] With respect to the first proposal, the Commission has already considered, and rejected, requests for unlimited

[11] SCE Written Plan at 51-52.
[12] *See Final Summary of Expire Act as reported* at ¶50 (available at http://www.finance.senate.gov/legislation/details/?id=67094f10-5056-a032-52ff-257830e0a938).
[13] SDG&E 2014 RPS Plan at 29-31.

buyer-directed economic curtailment rights and should do so again here.[14] With respect to the second proposal, the Commission has previously established the principle that buyer-directed economic curtailment must be bounded, while non-economic curtailment should not be limited.[15] SDG&E's proposal to require installation of equipment that would receive and implement automated curtailments blurs the line between economic and non-economic curtailment by causing curtailments to be implemented without providing a reason for the curtailment. To ensure that the required distinction between economic and non-economic curtailment is observed, the Commission should require SDG&E and the other IOUs to revise their *pro forma* PPAs to make it clear that automated curtailment instructions will be considered buyer-directed economic curtailment for which seller will be compensated.

In its prior decisions addressing curtailment, the Commission has drawn a distinction between economic curtailment and non-economic curtailment.[16] These decisions have established the clear principle that any "economic curtailment provision must be . . . financeable (e.g., reasonably bound the developer risk, such as by a maximum number of curtailment hours or other device)"[17] while these limits would "not apply to non-economic curtailment (e.g., for system reliability, safety, stability)."[18] The Commission has also further clarified this principle, noting that the limits on economic curtailment apply "even when that economic curtailment is initiated by an entity other than [the buyer] (such as the CAISO)" because "the curtailment instruction may be the result of [the buyer's] actions or omissions."[19]

SDG&E's proposal to require automated receipt and implementation of curtailment instructions would make it difficult to enforce the required distinction between economic curtailment and non-economic curtailment. The automated system proposed by SDG&E would cause the project to be curtailed in response to an electronic signal. There would be no accompanying explanation of the reason for the curtailment and, thus, no basis for sellers to determine whether the curtailment is appropriate. However, since this automated instruction would originate from the buyer, the instruction should be deemed a buyer-directed economic curtailment, unless there is a separate basis for non-economic curtailment (e.g., for system

[14] D. 13-11-024 at 38-40.
[15] *See e.g.*, D. 11-04-030 at 16-20.
[16] *Id.*
[17] D. 11-04-030 at n. 22.
[18] *Id.* at n. 24.
[19] *Id.* at 19-20.

reliability, safety, stability). In a case where there is a separate basis for asserting that the curtailment is actually a non-economic curtailment, then the buyer should be able to provide this curtailment instruction via a non-automated notice to Seller along with an explanation of the basis for the curtailment.

To ensure that the required distinction between economic curtailment and non-economic curtailment is maintained, the Commission should require SDG&E and the other IOUs to revise their *pro forma* PPAs to make it clear that automated curtailment instructions will be considered buyer-directed economic curtailment for which seller will be compensated.

III. COMMENTS ON SPECIFIC TOPICS RAISED IN THE ACR

A. Capacity Valuation

CalWEA strongly agrees with the ACR that the LCBF process is vitally important because this is where the indirect costs and benefits associated with competitive bids are evaluated. The least-cost, best-fit ("LCBF") process is the core concept that has guided California's RPS policy since its adoption in 2002. The RPS was never about the lowest bid price alone, but about total overall value, factoring in direct and indirect costs and benefits along with the bid price.

CalWEA further agrees with the ACR's suggestion (at p. 20) that LCBF capacity valuations should be consistent with system capacity needs, as forecasted in the Commission's most recently adopted Long-Term Procurement Plan ("LTPP"). "Syncing up" the RPS with the LTPP process in this way is one of the most important means by which the Commission can "link its silos" with the goal of promoting consistency among the Commission's decisions and actions and linking-up its planning and procurement functions. Such consistency will, in turn, promote overall portfolio efficiency and lower costs for consumers.

Thus, in response to the ACR's question, given the present condition that the Commission has not identified a need for system capacity until at least 2030, CalWEA sees no justification for including a positive value for system resource adequacy ("RA") capacity in the 2014 RPS procurement cycle. Thus, the Commission should direct the utilities to use a zero RA value in their 2014 LCBF bid evaluations. Because a dual set of time-of-delivery ("TOD") values for "full capacity deliverability status" ("FCDS") and "energy-only" ("EO") projects (as defined in the CAISO tariff) is another way of paying for capacity value, the Commission should support SCE's proposal to use a single set of TOD factors, and should direct the other utilities to do the same. Finally, for later use when a need for system capacity arises, the Commission should ensure that the capacity value of the various renewable resources is properly assessed by requiring the IOUs to use Commission-approved values for renewable energy capacity using the effective load carrying capacity ("ELCC") methodology.

We elaborate on these issues below.

1. The Commission Should Direct The Utilities To Use A Zero RA Value In Their 2014 LCBF Bid Evaluations

Historically, the IOUs have been permitted to develop their own internal forward price curves for purposes of assigning a value to the system capacity provided by FCDS projects and separate TOD factors to provide additional incentives for these projects, both of which have been used in the LCBF evaluation of bids in the RPS procurement process. While the system capacity values used by the IOUs are often non-transparent, it has become clear that the values ascribed to capacity in recent years do not reflect the large oversupply of "generic" system capacity and greatly exceed reported median RA prices.[20] As a result, RPS procurements have been biased in favor of procuring more expensive resources based on their ability to provide system capacity for which there is no need.

As the ACR states, the adopted 2014 LTPP assumptions show no need for system resource adequacy capacity until 2030 at the earliest.[21] Thus, while there is a need for local and flexible capacity (which will simultaneously provide system capacity), there is no need to procure additional generic system capacity from renewables or any other resource. Because there is no need to procure additional system capacity, the Commission should direct the utilities to use a zero RA value for all bids (both EO and FCDS) in the "adjusted net market value" ("ANMV") calculation portion of the LCBF evaluation.[22] (The same ANMV calculation should

[20] E.g., in the 2013 RPS procurement cycle, then-recent median RA prices were a small fraction of the values used by SDG&E. *See*, in this proceeding, CalWEA's July 12, 2013, Comments on Draft 2013 RPS Procurement Plans, at p. 18.

[21] The 2014 LTPP Trajectory Scenario shows the planning reserve margin at 15% or higher through 2030. Summary Load and Resources Tables by Scenario can be found at this link: http://www.cpuc.ca.gov/NR/rdonlyres/65FB0FED-7463-4E17-9E3D-B2D38A589675/0/SummaryLoadandResourceScenariosinExcelv2.xls.

[22] Transmission adders based on the estimated reliability network upgrade costs (energy-only) or reliability network upgrade and delivery network upgrade costs (fully deliverable) should continue to be

also be invoked in the general procurement process to ensure that proper and consistent credit is being given for any RA resource that is bid.) Any provisions of the *pro forma* PPAs that require the seller to obtain FCDS or penalize seller for a failure to obtain that status should be removed.

The Commission can leave the door open for the parties to the PPA to negotiate appropriate terms for the seller to enable the project to provide additional system capacity in the future, should capacity become needed before the end of the term of the PPA. In fact, the CAISO allows generators to seek and attain FCDS at a later time if transmission capacity is available (this is the most desirable form of FCDS – obtaining that status without triggering transmission upgrades). These resources would also remain eligible to sell their system capacity in competition with other RA capacity suppliers in other RFOs.

Underscoring the need to reflect the current oversupply of system capacity in the RPS procurement process is the fact that the CAISO's deliverability study methodology (used to support FCDS) is extremely conservative,[23] which frequently results in the identification of excessive delivery network upgrades with excessive costs. Thus, RA capacity comes at a very high price to ratepayers.

2. The Commission Should Direct All IOUs to Use a Single Set of TOD Factors

CalWEA supports SCE's proposal to use a single set of time-of-delivery (TOD) factors[24] and encourages the Commission to direct the other two IOUs to follow suit. A fully deliverable project delivers the same energy at the same time and subject to the same congestion management protocols as an otherwise identical energy-only project located next door providing the same shape of deliveries. Because the RA benefit is already valued through the capacity component of the ANMV calculation (although that value presently should be zero), assigning higher TOD values to a deliverable project rewards deliverable projects twice for a single attribute – RA capacity. As noted by SCE (at p. 19), "SCE already differentiates between FCDS and EO project proposals by crediting FCDS proposals with capacity benefits in its LCBF

calculated for the ANMV because the incremental cost of the delivery network upgrades associated with the fully deliverable project will continue to be incremental indirect costs of procurement.

[23] The CAISO's deliverability methodology is based on a super-stressed, worse-case scenario including simultaneous, unrealistically high capacity factors for renewable energy generation, assumptions of base generation dispatch that are not supported by experience, an N-2 outage condition, and no benefits from Special Protection System actions associated with new projects.

[24] SCE 2014 RPS Procurement Plan, Volume 1, June 4, 2014, at p. 18.

valuation." SCE further explains how its dual TOD factors have created "unnecessary complexity and uncertainty for both sellers and SCE with respect to expected contract payments." PG&E also separately credits projects for their capacity value and also uses dual sets of TOD factors,[25] which also rewards a project twice for the same attribute and perpetuates the "unnecessary complexity and uncertainty" referenced by SCE. As for SDG&E, its procurement plan proposes to apply a TOD factor of 1.0 in its executed PPAs, but simultaneously asserts that unspecified "TOD factors will continue to be updated for valuation purposes and will be used in the LCBF analysis,"[26] which will replicate the shortcomings of PG&E's approach to the extent that SDG&E's LCBF analysis employs two sets of TOD factors. The Commission must remedy this situation by directing all of the utilities to use a single set of TOD factors, consistent with SCE's proposal.

3. RA Values in the LCBF Evaluation Should Be Based on the ELCC Methodology

The Commission should ensure that the capacity values used in the LCBF bid evaluation process for the various renewable resources are properly assessed by requiring the IOUs to use Commission-approved capacity values based on an effective load carrying capacity methodology. Should the Commission adopt a zero capacity value for the 2014 RPS procurement cycle, such ELCC-based capacity values would not be needed in 2014 and there would be plenty of time to vet and adopt them for the 2015 RPS procurement cycle (assuming a need for capacity arises in that timeframe). If a zero capacity value is not adopted for 2014, however, then the Commission should direct the utilities to use the ELCC values already in use at the Commission for application in 2014 RPS bid evaluations. It is very important to do so, given that ELCC values can be forward-looking, reflecting the projected resource portfolio that the IOUs will be adding to with their 2014 procurements. An ELCC analysis will reflect the changing relative value of resources as their and other resources' penetration levels change on an energy basis. The utilities' LCBF analysis must reflect these rapidly changing ELCC values in order to fairly evaluate competing technologies and to prevent overpayment for RPS resources.

These issues are further explained below.

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[25] PG&E 2014 RPS Procurement Plan, Appendix H, June 4, 2014, at Table VII.2.
[26] SDG&E 2014 RPS Procurement Plan, Attachment A, June 6, 2014, at pp. 27-28.

a. Assessing Capacity Value Using the ELCC Methodology Is Necessary to Accurately Conduct Least-Cost, Best-Fit Bid Evaluations

Several recent studies confirm the phenomenon that the system capacity value of any fixed-profile resource declines with increased penetration. These studies include 2012 and 2014 studies by Lawrence Berkeley National Laboratory[27,28] ("LBNL"), a 2014 study by Energy and Environmental Economics, Inc. performed for California's five major utilities ("E3 Five-Utility Study"),[29] and others.[30] The phenomenon is pronounced with solar resources due to the concentration of its production during certain, relatively limited, hours of the year. However, SCE uses the CPUC's current RA counting values to evaluate the capacity value of renewables in its RPS bid evaluations,[31] values that are based on the "exceedance" methodology adopted by the Commission several years ago. The exceedance methodology does not capture the phenomenon of declining capacity value with penetration; thus it can produce values that are outdated, grossly inaccurate, and much higher than the actual RA value of the resource. PG&E bases the value of capacity "on the projected monthly quantity of qualifying capacity" but does not specify the methodology used.[32] SDG&E notes that it will incorporate ELCC values into its LCBF analysis once ELCC values are adopted in Rulemaking 11-10-023, but is silent on the methodology it currently uses.[33]

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[27] Andrew Mills and Ryan Wiser, *Changes in the Economic Value of Variable Generation at High Penetration Levels: Pilot Case Study of California*, LBNL (June 2012). Available at: http://eetd.lbl.gov/EA/EMP.

[28] Andrew Mills and Ryan Wiser, *Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels*. LBNL. (March 2014) Available at http://emp.lbl.gov/sites/all/files/lbnl-6590e.pdf.

[29] *Investigating a Higher Renewables Portfolio Standard in California*, Energy and Environmental Economics, Inc. (January 2014). Available at http://www.ethree.com/public_projects/renewables_portfolio_standard.php.

[30] *See, e.g.,* J. Jorgenson, P. Denholm, and M. Mehos, *Estimating the Value of Utility-Scale Solar Technologies in California Under a 40% Renewable Portfolio Standard.* NREL. (May 2014.) Available at: http://www.nrel.gov/docs/fy14osti/61685.pdf.

[31] *See, e.g.,* Southern California Edison Company's (U-338-E) 2014 Renewables Portfolio Standard Procurement Plan, Volume 2 (June 4, 2014), at PDF-page 517.

[32] PG&E 2014 Renewables Portfolio Standard Procurement Plan, Appendix H - 2014 Solicitation Protocol (June 4, 2014), at PDF-page 25.

[33] SDG&E 2014 RPS Procurement Plan, Attachment A, June 6, 2014, at pp. 41-42.

The Commission's compliance-year 2014 RA (exceedance-based) values for solar exceed 80% of nameplate capacity during summer months.[34] With about 8,000 MW of solar resources expected to be operating on the CAISO system by 2020, California will be at approximately 7% solar penetration on an energy basis at that time.[35] (These figures do not include behind-the-meter solar, which would significantly raise these figures.) A 2012 study[36] by E3 for the CAISO indicates that, at the 8,000 MW penetration level under a projected 2020 resource mix, the average solar ELCC value would decline to approximately 30% (as shown in the graphic below).[37]

While the RA and ELCC values are not perfectly comparable, they are indicative of the dramatic difference between ELCC values for solar resources – which capture the phenomenon of declining capacity value with penetration – and the exceedance methodology, which does not. The graphic below, from a 2014 LBNL study, likewise illustrates the diminishing value of adding large penetrations of a single resource, as well as how the relative value of resources can change as penetration increases on an energy basis. In light of significantly changing capacity values with technology penetration, it is critically important for the IOUs to use updated capacity values that reflect procurement that has already occurred. More accurate and updated capacity values are needed for fairness to bidders, to prevent ratepayers from paying for a perceived value they are not actually receiving, and to reduce the total costs associated with the RPS as required by statute.

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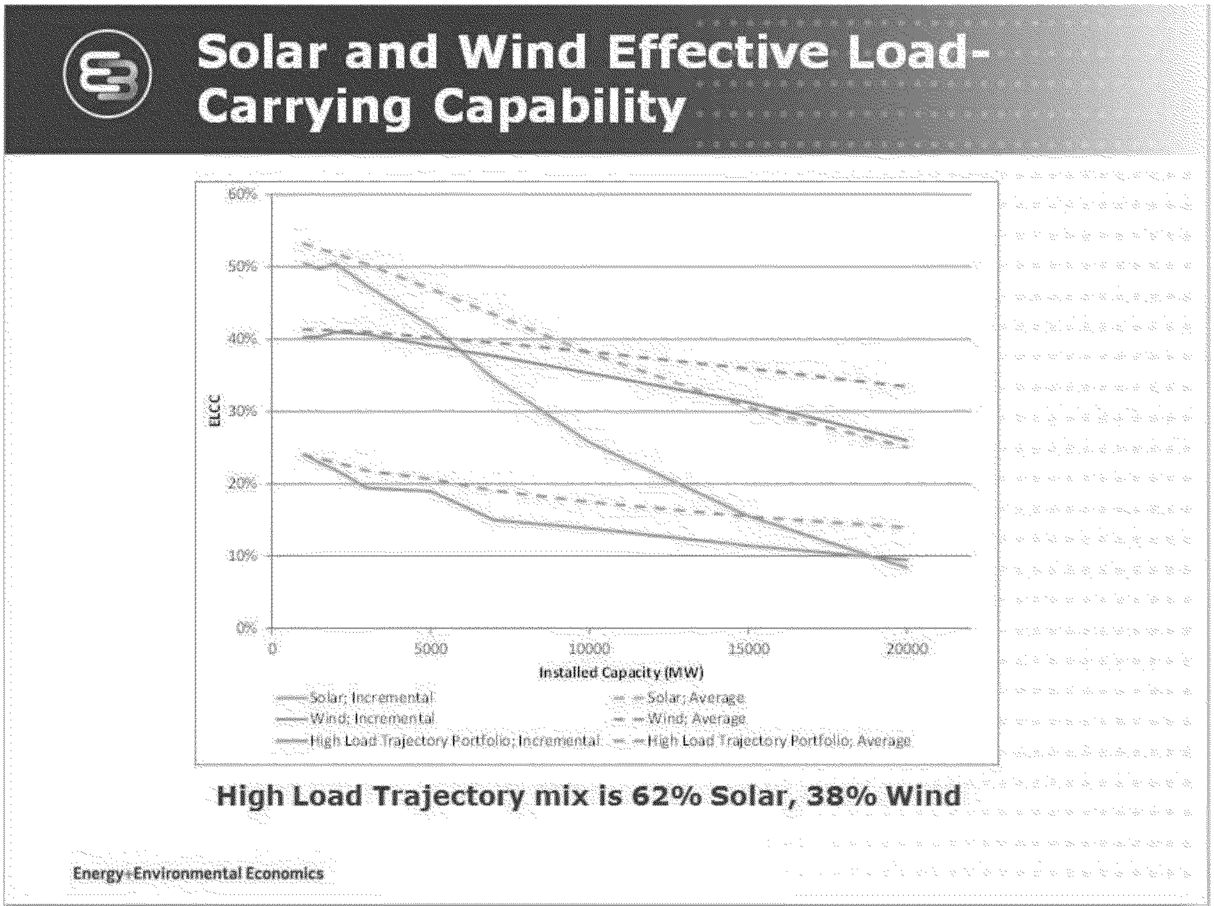
[34] The current methodology is described beginning at the bottom of p. 15 at http://www.cpuc.ca.gov/NR/rdonlyres/2526B26C-BEEA-46FE-904F-A99D2F042FD8/0/AdoptedQCmethodologymanualfromD1006036APPENDIXB.doc. The default values for 2014 are posted here: http://www.cpuc.ca.gov/NR/rdonlyres/C334EAC0-2090-41B3-884C-F115076C60FC/0/2014TechnologyFactors.xls.

[35] Based on the CPUC's RPS Projects Status Table (http://www.cpuc.ca.gov/PUC/energy/Renewables/); California Energy Commission, *California Energy Demand 2010-2020 Adopted Forecast* at Table 5 (available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF); "2013 Annual Report on Market Issues and Performance" CAISO (April 2014); and assuming 25% solar capacity factor.

[36] E3, "Needs Modeling Summary" (Presentation to the CAISO) (May 7, 2012).

[37] Although E3's ELCC value is an annual figure, it represents the capacity contribution of a resource over all the hours in the year where the loss of load probability (LOLP) is meaningfully different from zero. For California, the highest LOLPs are concentrated during the summer months, so it is reasonable to compare the annual ELCC figure to the summer NQC values.



Source: E3, 2012.

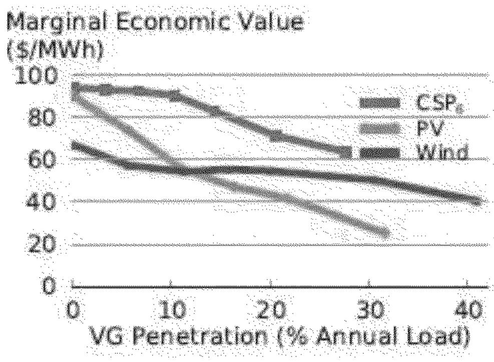


Figure 1: Marginal economic value of wind, PV, and CSP with thermal storage found in the Reference scenario of the valuation report.

Source: LBNL, 2014.

Stated differently, the CPUC needs to forge a better linkage between planning and procurement. The E3 Five-Utility Study and CalWEA's analysis of that study[38] both emphasize the importance of a carefully balanced renewable energy mix in reducing the total overall cost of renewable energy, including grid-integration costs. While studies of the type conducted by E3 for the utilities will be important for long-term planning, accurate capacity values are an essential cost-signal along the way to steer utilities towards that appropriately balanced, least-total-cost path. Capacity values that remain artificially high for solar resources will over-value capacity during summer midday periods relative to delivery during other times, which effectively under-values the relative capacity value of baseload, intermittent baseload, and flexible resources. Without a course correction, ratepayers will continue to pay too much for capacity during summer midday periods when it is needed less and less.

b. ELCC-Based Capacity Values are Readily Available for Application in the 2014 Bidding Cycle

The Commission has used ELCC values in several other proceedings using a modeling tool developed by E3.[39] ELCC is an established methodology, and the E3 model (first developed for the CAISO and adapted for use at the CPUC) uses standard techniques. Energy Division RPS staff is expected to release very soon an updated RPS Calculator, also developed by E3, that will include a matrix of resource-specific ELCC values reflecting various penetration levels of both wind and solar. CalWEA understands that this matrix will enable annual ELCC values to be estimated for each resource type, based on resource-specific penetration levels in 2015 and future years.

Unless a capacity value of zero is adopted for the 2014 RPS bidding cycle, as discussed above, the Commission should direct the utilities to employ E3's ELCC values in their 2014 RPS bid evaluation processes because they are certain to be far more accurate than the current

[38] "Investigating the Investigation of a Higher Renewables Portfolio Standard in California: A Review of the Five-Utility E3 Study," CalWEA (April 2014). Available at: http://bit.ly/1kwt7YS.

[39] *See, e.g.,* CPUC, "California Net Energy Metering Ratepayer Impacts Evaluation" (October 2013). The CPUC has also used E3's RECAP ELCC values in calculating the potential for local distributed PV installations (see http://www.cpuc.ca.gov/NR/rdonlyres/5F2B76C0-043D-46CA-8C41-1F67E3116999/0/Jan31_CPUC_RenewableDGTechnicalPotentialWorkshopSlides.pdf). The Energy Commission has used these values to develop its time-dependent valuation factors for its building standards (see http://www.energy.ca.gov/title24/2016standards/prerulemaking/documents/2014-04-29_workshop/presentations/Brian_Horii-Eric_Cutter_2017_TDV_Updates.pdf).

exceedence-based RA values that at least one utility is using. While CalWEA would have no objection to Energy Division hosting a workshop on the E3 methodology and values and/or seeking parties' comment on them (in time for the 2014 procurement cycle), we do not believe this is necessary. Currently, much of the utilities' respective LCBF evaluations are non-transparent. In contrast, much is publicly known about the ELCC methodology generally, it has been endorsed by the North American Electric Reliability Corporation,[40] and E3's ELCC values are already being used in various CPUC programs. The Commission should direct the utilities to use the same values that will be used in its RPS calculator, as they are the most accurate capacity values now available and will support the goals of least-cost, best-fit procurement and reducing total RPS procurement costs.

At the very least, the Commission should direct the utilities to run their LCBF analyses using the E3 ELCC values in addition to the capacity values they otherwise use, providing both sets of results to the Commission, and should authorize the utilities to shortlist projects based on the analysis using ELCC-based capacity values.

B. Project Development Requirements

The ACR requests comment on whether to add an additional requirement related to project development. Specifically, the ACR proposes that a project could be required to have, at a minimum, the Initial Study portion of its environmental review under the California Environmental Quality Act (CEQA) and/or National Environmental Quality Act (NEPA) completed before a project may be bid into an IOU's annual RPS Solicitation.

The purpose behind the proposed screen (whether for an RFO or bilateral transaction) is not stated, thus it is not clear whether the Commission's interest is in ensuring that projects have made a certain level of progress towards project development or something else. We will not address here another possibility -- the notion that the Commission would attempt to evaluate the environmental merits of proposed projects (*per se* or as it relates to the viability of proposed projects), because that idea was recently addressed and roundly condemned by most parties in separate comments in this proceeding.[41]

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[40] NERC Integration of Variable Generation Task Force, "Accommodating High Levels of Variable Generation" (April 2009), at 36-42. This report is available on the NERC website at http://www.nerc.com/files/IVGTF_Report_041609.pdf.

[41] *See, e.g.,* the comments of CalWEA, SCE, PG&E, SDG&E, UCS, LSA, IEP, and CEERT on Administrative Law Judge's Ruling Issuing Staff Proposal to Reform Procurement Review Process for

Assuming that the interest is in ensuring project progress, the proposal is not necessary because the utilities' power-purchase agreements already contain a series of milestones related to making progress in the land-use permitting process. If these milestones are not met, the seller faces the risk of contract cancellation. Developers are required to obtain all required permits by the project's commercial operation date, and are subject to default and payment of damages in the event they fail.[42] While these milestones are not routinely enforced by the utilities, the Commission should encourage the utilities to do so. For example, if a utility seeks to amend a contract under which a milestone has been missed, the Commission should reject the amendment. The Commission should pursue this approach before restricting participation in RFOs to those that have crossed some initial threshold in the permitting process.

Moreover, a permitting threshold is likely to be arbitrary and not necessarily practical or meaningful. For example, the ACR's suggestion that a project may be required to have prepared its "initial study" under CEQA or NEPA is problematic because, under the CEQA Guidelines, if the lead agency determines that a project may have significant impacts, it can skip the Initial Study phase and proceed to conducting an Environmental Impact Report.[43] In these cases, no Initial Study will be prepared, and it would be impossible for a bidder to demonstrate compliance with the Commission's proposed permitting screen. Further, an Initial Study is just that – initial, and preliminary. It indicates very little about the actual potential impacts that might be found upon conducting on-site studies. Land areas are often marked, based on computer models or sparse, outdated information, as containing sensitive species or habitat but such conditions often are not found when surveyed. Moreover, potential impacts may be avoided through careful siting, or be fully or partially mitigated. If it were easy to evaluate a site based on a screening study, the permitting process would not be as thorough, lengthy and expensive as it is.

The next step in the process that might be contemplated as a threshold requirement is the preparation of an EIR.[44] The EIR is a much more significant undertaking, however, and

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the Renewables Portfolio Standard Program, Setting Comment Dates, and Entering Staff Proposal Into the Record in this proceeding (April 8, 2014).

[42] See e.g., Pacific Gas and Electric Company 2013 pro forma RPS PPA §§ 3.9(a)(iii), 5.1(b)(iii), and 5.2.

[43] Oftentimes, even when impacts are thought not to be significant, a lead agency will assume significance for the purpose of avoiding arguments over a no-significant-impact determination, and proceed to evaluate and mitigate any impacts in the EIR.

[44] In some cases, the permitting agency requires the preparation of a less burdensome "mitigated negative declaration" instead, which is uncommon for greenfield projects.

generally requires site-specific studies of various kinds that require at least one year, and in many cases several years, to conduct. Given the significant expense of conducting these studies (hundreds of thousands of dollars or more), developers often cannot support them without the assurance that, if the studies produce the expected results, the costs will be recovered through a PPA. Therefore, the EIR is not an appropriate threshold requirement, as it would substantially reduce the number of bidders participating in an RFO. Should the studies conducted show greater impacts than expected to an extent that the power purchase price cannot be met, the utility can and should cancel the contract.

In summary, CalWEA strongly discourages the Commission from pursuing any sort of threshold bidding requirement related to the environmental permitting process. If the purpose behind this proposal is something other than what our response above has assumed, CalWEA would be pleased to engage in further discussion.

C. Renewable Integration Adder

The ACR (at p. 21) poses various questions related to a "renewable integration adder." Before answering these questions, below, CalWEA responds by presenting a proposed methodology for estimating such an adder. More specifically, CalWEA presents a methodology to support the integration cost component of the "Adjusted Net Market Value" (ANMV) formula adopted by the Commission in its decision on the 2012 RPS procurement plans, for use in the utilities' LCBF bid evaluation processes.[45] (We suggest the word "component" be used, rather than "adder.") As set forth by the Commission:

ANMV = (E + C + S) – (P + T + G + **I**), where

E	=	Energy value
C	=	Capacity value
S	=	Ancillary Services value
P	=	Post-TOD PPA price
T	=	Transmission cost adder
G	=	Congestion cost adder
I	=	**Integration cost adder**

[45] CPUC D. 12-11-016, at p. 24 (November 14, 2012).

1. CalWEA Proposal for the Integration Cost Component in LCBF Bid Evaluations

The proposal builds upon a CalWEA proposal submitted over 18 months ago in this docket,[46] reflecting the evolution of Commission and CAISO policy since that time. While not all of the data required is yet available, the methodology is based upon information that is now or will (or should) soon become available from the CAISO and the CPUC. CalWEA recommends that the Commission hold a workshop in the very near future to discuss this proposal, and any others, so that integration costs may be applied in the 2014 bidding cycle.

The integration cost methodology should represent all of the "indirect costs associated with … the ongoing electrical corporation expenses resulting from integrating and operating eligible renewable energy resources," as required under the RPS statute.[47] This proposal achieves that goal, including short-term, medium-term and long-term integration-cost components. The short-run cost component reflects the additional short-term capacity payments to resources that are needed to balance for renewables during real-time system dispatch. The medium-term cost component reflects the cost of obtaining flexible capacity from existing sources in the form of capacity payments to such resources on a monthly and annual basis. The long-term cost component reflects any long-term, capacity-related costs of new (specifically, flexible) resources that must be procured, or the capacity-related costs of existing (flexible) resources which must be kept in operation, solely to integrate renewables. Together, these costs comprise the extra costs that utilities would incur, directly or indirectly, as a result of procuring renewable resources. The costs must then be allocated among the renewable technologies based on cost-causation principles.

CalWEA discusses each of these components below, offering straightforward methodologies to calculate their costs and to assign those costs among the various renewable technologies. For the long-term cost, we offer two methodologies, one reflecting the 33% RPS procurement goal for 2020 and a separate concept reflecting post-33% / 2020 renewables

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[46] See, in this docket, CalWEA Comments on the Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals (November 20, 2012).

[47] *See* Public Utilities Code Section 399.14(a)(4)(A)(i). CalWEA notes that pending legislation (SB 1139) would reconstitute this section; however, we believe that, should the legislation be adopted, the rephrasing would not change the meaning of the existing statute or the responsiveness of this proposed methodology.

procurement that would be more closely linked with portfolio planning. Obviously, the Commission can take more time to consider the methodology employed for post-33% goals, but the former methodology can be readily employed for the 2014 bidding cycle.

a. Short-term integration-cost component

The short-run integration-cost component reflects the additional short-term capacity payments to resources that are needed to balance for renewables during real-time dispatch periods. These costs will be a portion of total costs related to the CAISO's procurement of Flexible Ramping Product (FRP), which address the CAISO's need to maintain power balance in its real-time markets (RTM).[48] While FRP initiative is still being finalized through a CAISO stakeholder process, the CAISO has already provided proxy costs for FRP based on the costs associated with its Flexible Ramping Constraint (FRC) in its RTM. The FRC was implemented in January 2012 to ensure that CAISO has adequate ramping capability within each hour to address short-term variability from load and all variable sources, including existing renewables. The CAISO also has developed a methodology to allocate FRC costs to load, to supply sources (both conventional and renewable), and to the fixed ramps in self-schedules. The CAISO intends to use this same method to allocate the procurement of the FRP costs. Once implemented, the FRP will replace the FRC.

The CAISO proposes to initially allocate the costs for the FRP based upon movements that require changes in real-time dispatch of resources. For load, this would be changes in observed loads every 10 minutes. The movement for generation would be the change in uninstructed imbalance energy (UIE) every 10 minutes. Movement for fixed ramps in self-schedules would be calculated based upon the change in MWh deemed delivered every 10 minutes. Using this approach, the CAISO allocated the $5.7 million in FRC costs for the first quarter of 2012 as follows:[49]

[48] Information on the CAISO's Flexible Ramping Product is available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx. The FRP is currently being modified to align with FERC Order No. 764 market design changes and the CAISO's new Energy Imbalance Market and is expected to be adopted by the CAISO board in December 2014.

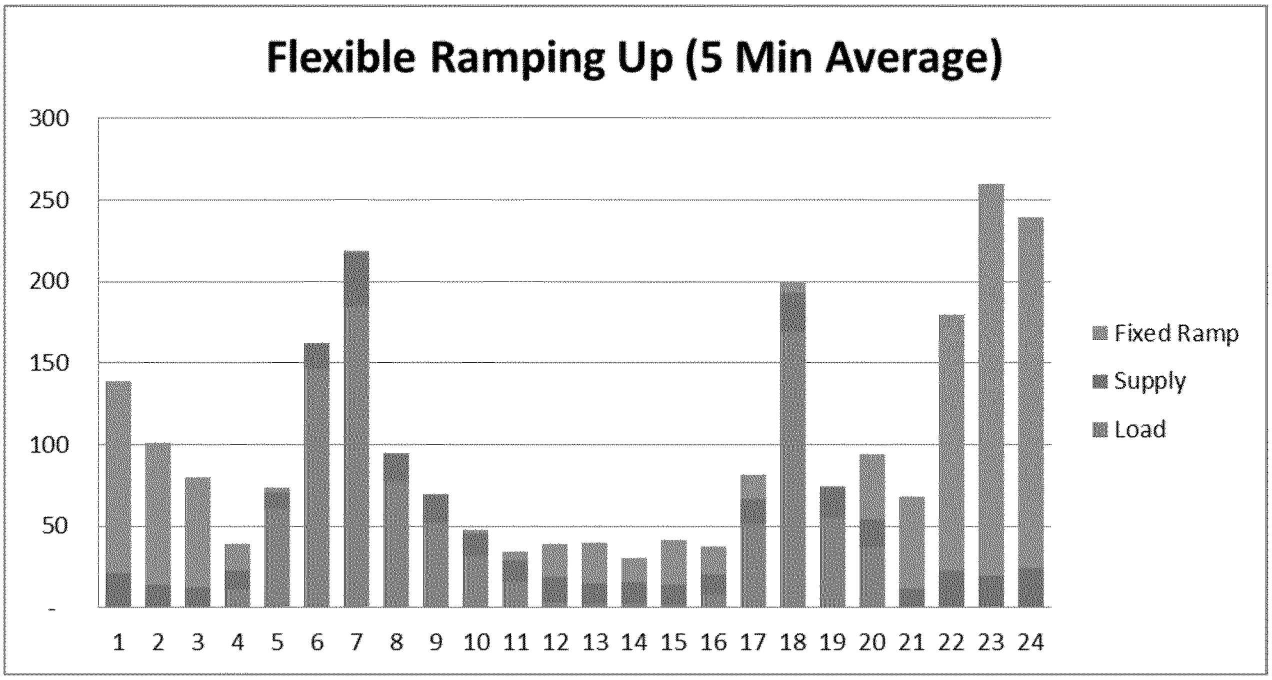
[49] These Q1 2012 figures, presented previously by CalWEA, are illustrative. The CAISO's figures for all of 2012 and 2013, if not Q1 and Q2 2014, should now be available.

Table 1: Flexible Ramping Constraint Costs – First Quarter of 2012 *($ millions)*

Source	FRC Cost (1Q 2012)	Allocation Method
Load	$3.26	Observed 10-minute load changes
Supply	$1.04	10-minute change in UIE
Fixed Ramps	$1.17	10-minute change in MWhs delivered
Total	$5.47	

Source: CAISO, "Flexible Ramping Products - Revised Draft Final Proposal" (dated August 9, 2012, hereafter "*FRP Proposal*"), at 42, reporting on the FRC data from January 1 through March 31, 2012. The CAISO provided CalWEA with the workpapers for this allocation.

Thus, in this time period, the FRC costs attributable to all supply sources amounted to a little over $1.0 million in the first quarter of 2012, or about 19% of total FRC costs. The following figure shows how the flexible ramping-up requirements (in MW) are distributed over the hours of the day.



Source: CAISO, *FRP Proposal,* at 37.

CalWEA has extended the CAISO's allocation method to assign supply-related FRC costs to specific supply sources on the basis of each source's contribution to 10-minute changes in uninstructed imbalance energy, based on the data on 10-minute changes in UIE by supply source in the CAISO's workpapers. The resulting allocations are shown in **Table 2** below, and the final column expresses the FRC costs in $ per MWh of output from each type of supply during the first quarter of 2012.

Table 2: Allocation of FRC Costs to Specific Supply Sources – First Quarter of 2012

Supply Resource	FRC Costs *($ million)*	Generation (GWh)	FRC Costs *($/MWh)*
Wind	0.227	1,760	0.13
Hydro	0.244	3,648	0.07
Solar	0.065	167	0.39
Gas	0.417	23,543	0.02
Baseload*	0.083	9,164	0.01
Total	1.037	38,282	0.03

* *Baseload resources include geothermal, biomass/biogas, and nuclear.*

Table 2 is illustrative, based on just one quarter of data on FRC costs. To provide more accurate values, these figures would need to be updated to include all data now available, which will also reflect any updates in the approach that CAISO uses to allocate these costs among different sources of supply. Nonetheless, CalWEA presents this allocation to show that actual cost data on the short-term integration cost for renewables – ramping within the hour – is available from the CAISO. Moreover, this data can be further parsed and allocated to specific supply sources, particularly the different types of solar.

b. Medium-term integration-cost component

The CAISO and the CPUC have relatively recently recognized the importance of flexible capacity, due in part to the substantial expected additions of variable renewable energy resources to the system and in recognition of the fact that many system-capacity resources, many of which have flexible capability, were not offering that flexibility to the system operator. In late 2012, the CAISO launched its Flexible Resource Adequacy Criteria and Must-Offer Obligation (FRACMOO) initiative with two main goals:[50] 1) provide an incentive for existing flexible resources to offer their flexible capacity for use by the system operator; and 2) ensure that, once existing and planned flexible resources have been made available, new sources of flexible capacity are identified and procured by CAISO-member LSEs (mainly Commission-

[50] For information on the FRACMOO initiative, see http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

jurisdictional LSEs).

As discussed below in relation to long-term costs, given that there is no envisioned need for new flexible or other capacity in the foreseeable future for the purpose of integrating renewables, the principal outcome of the FRACMOO process in the near future will be to provide incentives for existing RA resources to offer their flexible capacity for use by the system operator. Designating some of the existing RA capacity as flexible RA capacity may or may not entail additional payments to such resources, depending upon the utilities' contract terms for their existing resources. However, any added expenditures would constitute the total medium-term component of the integration cost. The utilities would need to report these costs to the Commission (and to the parties, at least in average terms), so they may be included in the calculation of the integration cost.

The next step -- determining and assigning this medium-term integration cost to specific renewable technologies -- should be straightforward due to the work that the CAISO has put into its FRACMOO proposal to assign ramping costs to various primary sources of system variability (load, and solar and wind resources) based on cost causation principles.[51] The CAISO has assigned these costs as shown in table below. Thus, once the CPUC-jurisdictional LSEs' annual or monthly RA procurement process is complete, the added cost of procuring flexible RA capacity versus "generic" system RA capacity will be readily known to the Commission. This added cost could then be readily assigned to various renewable technologies using the allocation factors that CAISO has developed for every month of 2015 (and 2016) and is expected to update on an annual and monthly basis once its FRACMOO studies are complete. As the first flexible RA capacity procurement process is not expected to be completed until Q3, 2014, data for this component of the integration cost value may not be available in time for use in the 2014 RPS RFO cycle, in which case the value may be temporarily assessed at zero.

[51] *See*, in CPUC R. 11-10-023, "Final 2014 Flexible Capacity Needs Assessment Report of the California Independent System Operator Corporation," Table 2 - Contribution to Maximum 3-hour Continuous Net-Load Ramp. May 1, 2014.

Table 2: Contribution to Maximum 3-hour Continuous Net-Load Ramp[13]

	Average of Load contribution 2015	Average of solar contribution 2015	Average of Wind contribution 2015	Average of Load contribution 2016	Average of solar contribution 2016	Average of Wind contribution 2016
January	79%	17%	4%	79%	17%	4%
February	71%	27%	3%	71%	27%	3%
March	64%	25%	10%	64%	25%	10%
April	62%	30%	8%	62%	30%	8%
May	53%	35%	12%	53%	35%	12%
June	96%	-8%	13%	96%	-8%	13%
July	111%	-28%	18%	112%	-29%	17%
August	99%	-6%	7%	99%	-5%	7%
September	51%	52%	-3%	51%	52%	-3%
October	62%	32%	6%	65%	28%	8%
November	61%	38%	1%	59%	40%	1%
December	68%	31%	1%	67%	31%	1%

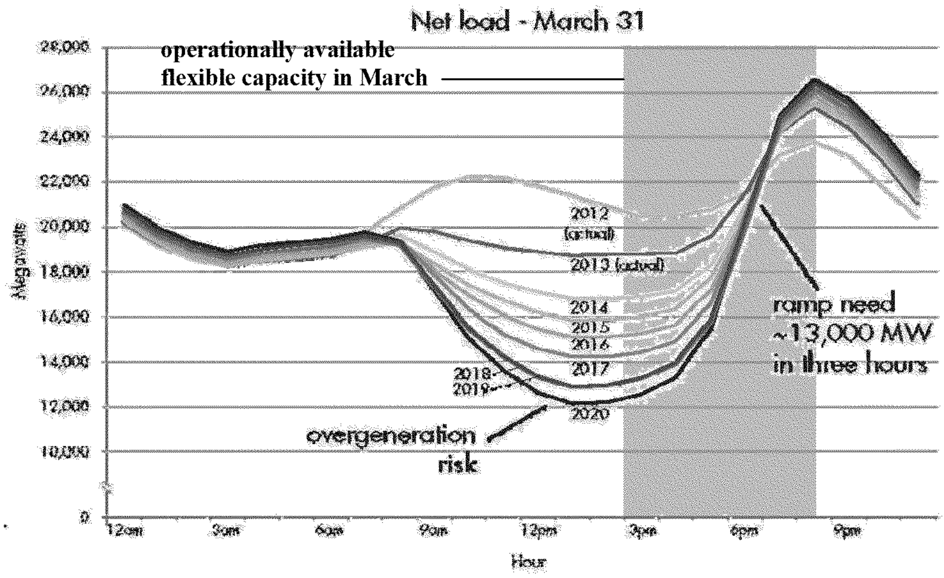
c. Long-term integration-cost component

The long-term component of the integration cost is potentially the largest component of the total integration cost, thus it is critical that it be properly quantified. However, for purposes of procurement aimed at achieving the 33% renewable energy target in 2020 (as discussed below), the issue becomes moot due to the lack of identified need for any additional capacity necessary to integrate this level of renewables. For levels of renewable energy beyond 33% in 2020, we offer a planning-related approach for consideration. These two time-periods are discussed below.

When a need for new sources of RA capacity has been established (solely for flexible resources), whether generation or non-generation resources, the long-term integration capacity cost can be readily estimated based on the capital cost of these new resources and assigned to various technologies based on the same allocation formulae developed and used for allocating the medium-term integration capacity cost among different renewable technologies.

i. Long-term costs associated with the 33% RPS target

The 33% renewable energy target has been the subject of numerous studies, none of which has yet shown that any new capacity is necessary to integrate this level of renewable energy on the system, at least through 2020.[52] Most recently, as the ACR notes (p. 20), the adopted 2014 LTPP assumptions show no need for system RA capacity until 2030 at the earliest.[53] Similarly, as the graphic below indicates, CAISO data show that there is substantially more than enough flexible capacity physically in operation today to address the need for system flexibility in 2020. (All 28,000 MW of Effective Flexible Capacity is operationally available to address the 13,000-MW ramping need in 2020.) Moreover, much of the local capacity that will be procured to replace the San Onofre nuclear plant can be expected to be flexible. Thus, it is very reasonable to assume that no additional system or flexible capacity will be required in the 2020 timeframe; therefore, the long-term component of the integration cost value is expected to be zero for the foreseeable future.



Source: CalWEA graphic, based on CAISO materials: the "Duck Chart" from CAISO "Fast Facts," 10/2013, and the light-green bar from CAISO 3/22/2013 presentation, which represents all available and dispatchable Effective Flexible Capacity (EFC) in March.

However, when a need for new sources of flexible RA capacity is established, sometime after 2020, the long-term integration capacity cost can be readily estimated based on the capital cost of these new sources of flexibility and assigned to various technologies based on the same

[52] *See, e.g.,* the August 3, 2011, settlement agreement in the 2010 LTPP proceeding (R.10-05-006), agreeing that further analysis is needed before any renewable integration resource need determination is made.

[53] This is shown in the assumptions adopted for the 2014 LTPP process. Through 2030, the planning reserve margin is shown to be at least 15% or higher in the Trajectory case. *See* http://www.cpuc.ca.gov/NR/rdonlyres/65FB0FED-7463-4E17-9E3D-B2D38A589675/0/SummaryLoadandResourceScenariosinExcelv2.xls.

allocation formulae developed and used for allocating the medium-term integration capacity cost among different renewable technologies.

ii. Long-term integration costs associated with renewables beyond 33% -- a proxy approach

For renewable energy levels appreciably beyond 33% in 2020, a recent study by the research consulting firm E3,[54] which was commissioned by California's five largest investor and publically owned utilities (SCE, PG&E, SDG&E, LADWP and SMUD), provides an approach that should be considered for determining the long-term capacity component of the integration cost value. This methodology would be well-suited for use in conjunction with long-term portfolio planning, which would reasonably be employed in support of cost-consciously achieving higher renewable energy penetration levels.

The E3 study indicated that it is readily possible to reliably integrate renewable resources at 40% or 50% levels in California while incurring some integration costs. The study presented the integration costs in the form of the amount of overgeneration/curtailment that would be expected to occur in the process of safely and reliably operating the grid, under a number of possible resource portfolio mixes and with the application of various overgeneration/curtailment solutions. E3 then quantifies the cost of the remaining curtailed generation. E3 also reports the contribution to the overgeneration/curtailment problem by each renewable technology. Based on this data,[55] the contribution of each renewable generation technology to overall long-term integration costs can be estimated based on various projected renewable energy portfolio mixes.

If this type of planning approach is used to develop a preferred procurement roadmap for utility achievement of higher levels of renewable energy (based on costs and possibly other factors), it would be sensible to use the integration costs associated with the roadmap in the procurement processes that are conducted along the way. As adjustments are made in the roadmap over time, so can the integration costs be adjusted.

Given that, per the discussion above, no capacity additions are needed to achieve 33% RPS levels in 2020, the Commission has time to explore this post-33% / 2020 methodological

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[54] *Investigating a Higher Renewables Portfolio Standard in California*, Energy and Environmental Economics (January 2014). Available at http://www.ethree.com/public_projects/renewables_portfolio_standard.php.
[55] See E3 Tables 2, 27, 28 and 33.

approach.

2. Responses to ACR Renewable Integration Adder Questions

Having set forth the above proposed methodology for the integration cost adder, CalWEA can now respond to the specific questions set forth in the ACR in the context of its proposal.

> **ACR Question 1:** *Many parties, in various venues, have expressed interest in the development of an integration adder. Staff understands this concept to mean an addition to the criteria utilities use to select contracts that would reflect the impact a resource has on the transmission system. In simple terms, using this criterion, if designed appropriately, a rampable and dispatchable resource would score better than a baseload resource that does not ramp well, which would, in turn, score better than an intermittent resource that requires firming and shaping. Please explain ...*
>
> *a. If this definition matches your understanding and why or why not?*
>
> Although we would use different terms, yes. As we have envisioned how an integration cost value would be developed, a resource that is rampable and dispatchable would be assessed a zero integration cost (and may receive a capacity or ancillary value credit in the ANMV formula), which would compare favorably to non-rampable, non-dispatchable resources which would be assigned integration costs.
>
> *b. If not, what is your definition of an integration adder?*
>
> n/a
>
> *c. Do you believe an integration adder is needed at this time? Why or why not?*
>
> Yes, CalWEA believes that the integration cost component of the ANMV formula is needed. First, the RPS statute has required it since 2002. Second, it is now readily possible to calculate (although the mid-term value may not be available until the 2015 bidding cycle), as we have explained. Third, assumptions are being made that the integration cost value could be large enough to change bidding outcomes, particularly between variable and baseload renewable resources. For example, the Senate Floor analysis for SB 1139, which would mandate the procurement of 500 MW of geothermal resources, cites "failure to account for the integration costs of some renewables in competitive procurement causing geothermal to look more expensive when it may not be" as one of the "dynamics working against geothermal."[56] Such assumptions, and the Commission's failure to update its integration cost methodology, are driving attempts such as these to make an end-run around the LCBF process.

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[56] *See* http://leginfo.ca.gov/pub/13-14/bill/sen/sb_1101-1150/sb_1139_cfa_20140424_163251_sen_comm.html.

ACR Question 2: *As reflected in the first question above, the definition of a renewable integration adder is not clearly understood. Given this ambiguity, what is your interpretation of how an integration adder would be used? Please consider the follow sub-questions:*

a. What form should any integration adders take? For example, should they be incorporated into the value side or cost side of the least cost best fit equation, and why?

As noted above, there is already a place (an appropriate one) for the integration cost within the Commission's adopted ANMV formula (see above).

b. Is an integration adder a single static value, a value that changes over time, or many values that change over time? How frequently should it be updated?

The value will change over time, although gradually. For achievement of the 33% RPS in 2020, the values can readily be updated based on the methodology we have proposed, using the most recent FRP and FRACMOO cost figures on a $/MWh basis for each technology and applying them as the adder. These costs could be made more accurate by simulating costs for future years, but this will be more challenging and time-consuming. At least for the Commission's immediate purposes for the 2014 RFO, using actual recent values should be sufficient.

For post-33% / 2020 values, additional consideration is necessary for the interval at which the long-term values should be updated; however, we envision that the integration cost will be calculated over a period of time and averaged for use in the LCBF procurement process.

c. With what granularity should such adders be calculated and applied, in terms of resource types and locations? E.g., for how many (and which) distinct categories of resources, and for how many (and which) distinct geographic locations?

The methodology proposed above would enable as much granularity as may be desired. For now, each distinct type of resource/technology should be evaluated. In the future, sources of flexibility need could be grouped in as many geographic areas as are sufficiently distinct from one another. The Commission should not allow the "perfect to be the enemy of the good" and proceed in 2014 with values that can readily be calculated using the data at hand.

d. How far out in time should we project (e.g., model) system operation when calculating adders for any "current" vintage of resource additions? E.g., 10 years out, 20 years out, for one target year, or for a multi-year time horizon? Should this depend on contract length?

See our reply to question 2b, above. The adder should apply to all projected procurement under each proposed contract.

e. *Should an integration adder take into consideration only the cost of integrating renewables or should it also consider the positive attributes of intermittent renewable generation such as the ability to potentially hedge against rising natural gas prices? If so, how?*

By mandating a certain level of renewable energy, the RPS policy itself takes into account the positive attributes of renewables (intermittent and not) in relation to natural gas. As we noted above, as stated in the RPS statute, the integration adder is intended to reflect the "indirect costs associated with … the ongoing electrical corporation expenses resulting from integrating and operating eligible renewable energy resources."

ACR Question 3. *With respect to questions above, what is the framework you recommend for calculating an integration adder? Please be explicit and provide a quantitative example.*

See CalWEA's proposal above.

ACR Question 4. *The Commission's Long-term Procurement Plan (LTPP) proceeding is currently considering the use of stochastic based probability models to forecast the need for flexible capacity ten years into the future (i.e., by 2024). Modeling results from stakeholders that submit testimony in this proceeding may determine that there is a need for resources that can provide flexible capacity within the LTPP's study horizon. Should an integration adder be derived from these flexibility studies? Please consider the following sub-questions when providing an answer:*

a. *Results from these studies may be several years away. Is it appropriate for the Commission to wait until LTPP studies are completed to develop a new integration adder? If not, provide an alternative realistic approach for analysis with a roadmap for implementation.*

No, the Commission should not wait until the 2014 LTPP studies are available before adopting an integration cost methodology. As shown above, it is highly unlikely that a need for new flexible capacity will be demonstrated for renewable resources procured for purposes of achieving the 33% RPS in 2020. For the longer term, however, the Commission should begin planning now to conduct the type of probabilistic study conducted by E3 to explore the integration costs associated with higher target levels of renewable energy.

b. *Should the Commission develop an interim integration adder and update the adder once the results of the LTPP flexibility studies are known? If so, what interim approach do you recommend and why is this approach valid?*

Per the framework presented above, while the short-term integration costs can be readily calculated based on CAISO's experience with FRC and FRP, the "medium-term" integration costs will likely not be known in time for the 2014 bidding cycle and we propose that a zero value be used for the medium-term integration cost in the interim. With regard to the long-term cost component of the integration cost value, we propose a zero value for procurements aimed at achieving 33% renewables levels in 2020.

c. *Publicly available studies are available that attempt to define and project the value of an integration adder. Should the Commission adopt an integration adder based on these studies rather than utilize results from the upcoming flexibility studies? Why or why not?*

The Commission should not use "proxy" integration adders derived from studies of other utilities or control areas, which reflect different system operating protocols and which do not reflect the significant portfolio of flexible resources that are available to the CAISO to manage system operating needs – in particular, California's significant hydro resources and it large fleet of gas-fired capacity.

ACR Question 5. *Should an integration adder reflect the actual impact of a resource, even if new infrastructure is not needed to integrate the resource, or only reflect incremental increases in infrastructure needs? In other words, if there is no need identified for new flexible resources, should the adder still be set at zero? Please explain your answer.*

As presented in our proposal, two out of the three components of the integration cost do not involve the addition of new resources but do reflect new payments to existing sources of flexible capacity that the system operator is expected to incur in order to address the variability of renewable resources, among other variability needs. Hence, the integration cost cannot be assumed to be zero, even if there are no new capacity additions.

IV. CONCLUSION

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

Respectfully submitted,

Nancy Rader
Executive Director
California Wind Energy Association
2560 Ninth Street, Suite 213A
Berkeley, California 94710
Telephone: (510) 845-5077
Email: nrader@calwea.org

July 2, 2014

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 2014 RPS Procurement Plans and Related Questions in Assigned Commissioner's Ruling* 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 2, 2014 at Berkeley, California.

Nancy Rader

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Nancy Rader

Executive Director, California Wind Energy Association