BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

COMMENTS OF THE
CALIFORNIA WIND ENERGY ASSOCIATION
ON DRAFT 2015 RPS PROCUREMENT PLANS AND
RELATED QUESTIONS IN ASSIGNED COMMISSIONER'S RULING

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August 31, 2015

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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 Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewables Portfolio Standard Procurement Plans* ("ACR"), and the June 30, 2015, email from Administrative Law Judge Mason revising the schedule for the procurement plans, the California Wind Energy Association ("CalWEA") respectfully submits these comments on the investor-owned utilities' ("IOU") draft 2015 Renewables Portfolio Standard ("RPS") Procurement Plans (the "2015 Plans"), and responds to some of the specific topics and questions raised in the ACR.

CalWEA has reviewed portions of the 2015 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:

- Reject SCE's proposal to require sellers to execute an exclusivity agreement with respect to shortlisted projects, with the exception of standard offer contracts; and
- Direct the utilities to revise their PPAs to permit projects with shared facilities, including shared transformers, and projects using low-side metering.

CalWEA also responds to some objectionable recommendations made by SCE regarding the ACR's directive to plan for a 40% RPS requirement on the topics of customer-side renewable distributed generation and the accounting of curtailed energy towards RPS goals. Finally, CalWEA responds to specific topics raised in the ACR pertaining to the least-cost, best-fit ("LCBF") methodologies and related planning processes and recommends that the Commission should:

- Direct the utilities to enhance their LCBF methodologies to anticipate higher renewable energy penetration levels and evaluate energy value consistent with the RPS Calculator; and

- Direct the utilities to ensure that there is no double-counting of costs between the integration cost adder and other NMV components.

Each of these recommendations and responses is addressed below.

II. COMMENTS ON PRO FORMA CONTRACT ISSUES

1. The Commission Should Reject SCE's Proposal To Require Sellers To Execute An Exclusivity Agreement With Respect To Shortlisted Projects, With The Exception of Standard Offer Contracts in Certain Circumstances

SCE proposes to add a requirement that sellers execute an exclusivity agreement with respect to shortlisted projects.[1] SCE makes this proposal even as it recognizes the Commission's rejection of this requirement in D.13-11-024 and D.14-11-042 and its finding that shortlist exclusivity is an "unnecessary restriction on the market based on the current level of competition."[2]

SCE argues that the level of competition is not relevant to its view of the main reason for requiring exclusivity arrangements after shortlisting: the expense of negotiating many PPAs that may not be signed. SCE made this same argument last year, which was rejected by the Commission. As the Commission's D.14-11-042 stated, "SCE may be correct that exclusivity will reduce transaction costs but we continue to find it an unnecessary restriction on the market based on the current level of competition."[3] This market condition has not changed. Moreover,

[1] *See* PDF-p. 71 of SCE's Procurement Plan, Volume 1.

[2] *Ibid.*

[3] D.14-11-042 at p. 35.

the expense of negotiating a PPA that may not be signed is not unique to SCE, as this is a risk that has always been borne by every shortlisted developer.

However, SCE's proposal that sellers who utilize the standard contract option (i.e., execution of SCE's 2015 pro forma with no further negotiations) should be subject to an exclusivity requirement would be reasonable if SCE commits to enter into a standard contract with the short-listed project. Upon shortlisting and acceptance of the offer, the parties would proceed to execution of the PPA, so the seller should not need a right to continue to negotiate with other buyers.

2. The Commission Should Direct the Utilities to Revise PPAs to Permit Projects With Shared Facilities, Including But Not Limited To Shared Transformers, And Projects Using Low-Side Metering

In response to the utilities' Renewable Auction Mechanism ("RAM") 6 Advice Letters, CalWEA protested the provisions of the utilities' pro forma PPAs that prohibited projects from utilizing shared transformers (and, in SDG&E's case, any shared facilities at all) or the use of low-side metering.[4] Ultimately, CalWEA's protest was denied without prejudice because Energy Division found that the issue was too complex for resolution in the advice letter process and should be addressed instead in a formal proceeding.[5] The Commission's review of the utilities' 2015 RPS Procurement Plans presents an opportunity for these issues to be addressed in a formal proceeding.

While the pro forma PPA presented in SCE's 2015 RPS Procurement Plan does not include the shared facilities language found in the RAM 6 pro forma PPA, SCE has previously explained that this shared facilities language is based on prior consent agreements through which SCE agreed to permit projects to share facilities where the PPA did not expressly address the topic.[6] Thus, a developer bidding a project with shared facilities into SCE's 2015 solicitation would reasonably expect SCE to propose shared facilities language that is similar to what was included in the RAM 6 pro forma PPA. Similarly, while PG&E did not include a pro forma PPA in its 2015 RPS Procurement Plan, the pro forma PPA in PG&E's 2014 RPS Procurement Plan

[4] Protest of California Wind Energy Association to Southern California Edison Company Advice Letter 3195-E, Pacific Gas and Electric Company Advice Letter 4605-E, and San Diego Gas & Electric Company Advice Letter 2717-E, April 8, 2015.

[5] *See e.g.*, Advice Letter 4605-E Disposition Letter dated June 17, 2015.

[6] *See* Advice Letter 3003-E at pp. 7-8; Resolution E-4655 at 20.

included the same restrictions on shared transformers and low-side metering that are found in PG&E's RAM 6 pro forma PPA. Thus, a developer planning to bid in future PG&E RPS solicitations would reasonably expect that these restrictions would be applied.

The Commission should direct the utilities to revise their PPAs to permit projects with shared facilities, including shared transformers, and projects using low-side metering because the current restrictions are not required for CAISO compliance and will result in unnecessary costs that may make the projects uncompetitive in the RPS solicitation and impair repowering efforts. The CAISO tariff already allows projects to utilize shared facilities, including shared transformers, and to employ low-side metering, subject to CAISO approval.[7] Thus, the restrictions imposed by the utilities are not necessary for CAISO compliance. In addition, the Commission should authorize the utilities to offer amendments to existing PPAs, including PPAs executed under the RAM program, to allow the projects subject to those PPAs to utilize shared transformers and low-side metering.[8]

While the restrictions on shared transformers are not necessary, they are expensive, and these unnecessary costs may make the projects uncompetitive in the RPS solicitation and impair repowering efforts. There are many existing projects that were developed before the formation of the CAISO and utilize interconnection arrangements that were based on the local utility's interconnection rules in effect at the time, which permitted the use of shared transformers and the use of low-side metering. Requiring these existing resources, developed under a different paradigm, to comply with new restrictions on shared transformers and low-side metering will impose significant costs, which may make these projects uncompetitive in the RPS solicitation process or make repowering efforts uneconomic. Additionally, requiring the construction of new facilities to eliminate decades-long sharing arrangements may impose new environmental impacts, which erodes one of the major benefits of existing and repowered projects – the ability to contribute to RPS goals without imposing new environmental impacts.

To provide context for these concerns, we provide an example based on an affected wind project of a CalWEA member company (one of many affected projects). The project is an

[7] CAISO tariff §10.2.10.

[8] Commission precedent supports this approach. In Resolution E-4655, the Commission authorized SCE to offer amendments to its RAM 3 and RAM 4 PPAs to conform the guaranteed resource adequacy provisions in those PPAs to the newly adopted guaranteed resource adequacy provisions, with the amendments to be approved via Tier 2 advice letter. Resolution E-4655 at 17-19.

approximately 30-year old 15-MW wind farm in the Palm Springs area. The project shares a 33/115 kV step-up transformer with two other projects, with the first project utilizing a dedicated feeder line and the other two unrelated projects utilizing a second dedicated feeder line. The CAISO tariff would permit these projects to be metered on the low-side of the transformer on the separate feeder lines, subject to CAISO approval of the metering arrangement, as the projects have been metered historically, but the restrictive PPA provisions proposed by the utilities would not permit this arrangement. Instead, CalWEA's member would be required to pay for an expansion of the substation and the installation of an additional step-up transformer, with an expected cost in excess of $2 million. This cost would not be driven by compliance with interconnection requirements or the CAISO tariff; instead, this cost would be incurred purely for the opportunity to bid the project in an RPS solicitation. If the project were selected, the incremental cost would be reflected in a PPA rate that would be $6-$9/MWh higher, which would be passed on to ratepayers without any corresponding benefit.

In most cases, these incremental costs will significantly harm the ability of projects with shared facilities to successfully compete in RPS solicitations at all. In addition, the requirement to install new interconnection facilities adds a level of uncertainty that will increase the risk that will be associated with these facilities in the utilities' project viability calculators. The likely result is that older resources will be prevented from repowering, and existing facilities will be prevented from completing their useful economic life prior to repowering.

In the RAM 6 advice letter review process, the utilities expressed concerns that transformers and low-side metering could lead to inaccurate metering, penalties assessed to the utilities for inaccurate meter data, WREGIS certificate disallowance, and confidentiality concerns. However, as described further below, CalWEA believes that these concerns are misplaced and do not justify the costs that would be imposed to comply with the utilities' restrictions.

a. Metering accuracy

The utilities have suggested that low-side metering with shared transformers is inaccurate.[9] The CAISO Business Practice Manual (BPM) for Metering Section 5.1.1 explains

[9] *See e.g.*, Reply of Southern California Edison Company ("SCE") to the Protests/Comments of: (1) Large-Scale Solar Association ("LSA"); (2) Independent Energy Producers Association ("IEP"); and (3) California Wind Energy Association ("CalWEA") to Advice 3195-E, April 15, 2015, at pp. 5-6.

that the meter readings must be adjusted for (1) line losses, (2) transformer losses (if applicable), and (3) distribution system losses or credits (if applicable) in order to reflect the amount delivered to the point of delivery at the CAISO Controlled Grid. Thus, even if all projects had dedicated transformers and high-side metering, there would still be metering inaccuracies due to the need to estimate line losses for the generator tie-line and the application of average distribution system losses that fail to consider project-specific attributes. Permitting the use of low-side metering with shared transformers would introduce another category of losses to be estimated, but this can occur "only if the CAISO is satisfied that adequate accuracy and security of Revenue Quality Meter Data obtained can be assured." If the CAISO is comfortable that a particular shared-transformer metering scheme can assure "adequate accuracy and security" of the meter data, then the terms of the PPAs should not be used to prevent this approach. Otherwise, additional cost will be imposed for no meaningful benefit.

b. Penalties for inaccurate meter data

The utilities have suggested that they may be liable for penalties as the Scheduling Coordinator if metering data is inaccurate.[10] As described above, the CAISO Tariff permits low-side metering and shared transformers with CAISO approval. Thus, any shared-transformer metering scheme, including any resulting inaccuracy, would already be approved by the CAISO, so there would be no basis for assessing a penalty based on metering inaccuracy resulting from the use of a shared transformer. Indeed, the CAISO Tariff requires generators to enter into Meter Service Agreements (MSA), and Section 3.2.3 of the CAISO's pro forma MSA (found in CAISO Tariff App B.6) requires the generator to "use the CAISO approved Transformer and Line Loss Correction Factor referred to in the CAISO Tariff and in the applicable Business Practice Manual." If the utilities are concerned about a penalty being assessed on some other basis (e.g., a damaged meter, failure to comply with the LGIA, etc.), then that risk already exists whether shared transformers are permitted or not.

c. WREGIS disallowance

[10] *See e.g.*, PG&E's Reply to the California Wind Energy Associations' Protest of Advice Letter 4605-E and to the Large-Scale Solar Association's Protest of SCE's Advice Letter 3195-E requesting approval of the RAM 6 Protocol and PPA, April 15, 2015, at p. 2.

The utilities have suggested that they may be at risk for having RECs from the facility disallowed by WREGIS.[11] The WREGIS Operating Rules classify generators based on their size, contracts, and whether the generation is reported to the Balancing Authority on a unit-specific basis. (WREGIS Operating Rules Section 9.1). Any generator that has its generation reported on a unit-specific basis is always included in Class A, which requires that generation data be reported from a revenue-quality meter output measuring, or adjusted to reflect, the energy delivered into the transmission grid at the high side of the transformer. (WREGIS Operating Rules Section 9.3.1). This is the same standard used in the CAISO BPM for Metering (see "Metering Accuracy" section above). Thus, the CAISO-required metering meets the standard specified by WREGIS. In addition, the CAISO offers Qualified Reporting Entity (QRE) services to generators in the CAISO Balancing Authority, whereby the CAISO reports generation to WREGIS as a QRE, because the CAISO already has a comprehensive metering program in place.

d. Confidentiality

The utilities have suggested that the use of low-side metering with shared transformers could result in the Scheduling Coordinator for one project deriving the meter data for another project and then using that derived meter data to develop gaming strategies.[12] As has been discussed above, it appears that this concern is misplaced. First, this assumes that the Scheduling Coordinator for the project has sufficient data to derive the other projects' meter data, which may not be the case if there are more than two projects sharing the transformer or if the CAISO-approved metering scheme uses estimated losses based solely on the project's own meter. Second, most renewable energy projects are under contracts with Commission-regulated investor owned utilities acting as the Scheduling Coordinator, so there is very little incentive for these entities to engage in gaming behavior. Third, most renewable energy projects are bid into the market at or near-zero dollars because there is no variable cost, which is already well-known.

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[11] *See e.g.*, Reply of Southern California Edison Company ("SCE") to the Protests/Comments of: (1) Large-Scale Solar Association ("LSA"); (2) Independent Energy Producers Association ("IEP"); and (3) California Wind Energy Association ("CalWEA") to Advice 3195-E, April 15, 2015, at pp. 5-6.

[12] *See e.g.*, PG&E's Reply to the California Wind Energy Associations' Protest of Advice Letter 4605-E and to the Large-Scale Solar Association's Protest of SCE's Advice Letter 3195-E requesting approval of the RAM 6 Protocol and PPA, April 15, 2015, at p. 2.

Fourth, the CAISO is extremely committed to identifying, investigating, and eliminating anti-competitive behavior (see e.g., CAISO Tariff App P describing the CAISO's Department of Market Monitoring; CAISO Tariff Section 37 describing CAISO's Rules of Conduct; CAISO Tariff Section 39 describing CAISO's Market Power Mitigation tools). Finally, and most importantly, the use of low-side metering with shared transformers requires CAISO approval, and the CAISO is unlikely to approve a metering scheme if it is concerned that the scheme can be used for gaming.

Given that the proposed restrictions on shared facilities and low-side metering will result in unnecessary increased costs, the Commission should direct the utilities to revise their PPAs to permit projects with shared facilities, including shared transformers, and projects using low-side metering. In addition, the Commission should authorize the utilities to offer amendments to existing PPAs, including PPAs executed under the RAM program, to allow the projects subject to those PPAs to utilize shared transformers and low-side metering.[13]

III. COMMENTS ON SCE's 40% RPS PLANNING

1. The Policy Changes That SCE Proposes With Regard To A 40% RPS Requirement Are Misplaced And Not Responsive To The ACR

In responding to the Assigned Commissioner's Ruling, SCE advises against the Commission's adoption of a 40% RPS until the Legislature acts and, SCE hopes, makes several specific policy changes.[14] As the ACR did not request comment on policy issues, SCE's suggestions are misplaced. However, because these issues have been raised, CalWEA briefly responds to two of the most objectionable SCE proposals.

a. Counting customer-side renewable distributed generation in the RPS

SCE suggests that current metering requirements that apply to RPS-eligible energy production be relaxed for behind-the-mater distributed generation (DG) systems and, presumably, that SCE be allowed (via legislation) to estimate DG output and count it towards its RPS requirements.[15] There are many serious flaws in this proposal, among them the following.

[13] As documented in footnote 8, Commission precedent supports this approach.

[14] SCE 2015 Procurement Plan, Volume 1 at PDF-p. 18.

[15] SCE 2015 Procurement Plan, Volume 1 at PDF-p. 20.

First, SCE does not claim that it cannot meet a 40% RPS target without counting customer-side renewables, thus this proposal bears no relation to the ACR's directive to plan for a 40% target. Moreover, counting behind-the-meter renewables towards the utilities' RPS requirements would reduce the total amount of renewables on the system. Currently, customer-side renewables add to the wholesale renewables that are acquired to meet RPS requirements. Counting customer-side renewables towards the RPS without adjusting the RPS target would effectively reduce the total amount of renewable energy on the system. The Pathways study conducted for the State of California shows that California will need both a 50-60% RPS and rooftop solar to meet a 40% greenhouse-gas reduction target by 2030.[16]

Second, the proposal to relax metering requirements is misguided. The WREGIS accounting system for renewable energy credits (RECs) was developed with the primary objective of ensuring the credibility of the renewable energy production represented by the RECs, to instill public confidence that the RECs, representing the environmental attributes of the electric generation from a renewable resource, are real. This objective should not be undermined by loosening metering requirements.

Finally, crediting customer-side renewables towards the utilities' RPS requirements would risk consumer deception and double-counting. The REC accounting system ensures that each kilowatt-hour of renewable energy is counted once and only once for purposes of regulatory compliance or marketing claims. Under consumer protection guidelines issued by the Federal Trade Commission, consumers cannot be sold "renewable power" unless the associated RECs are included as part of the sale. If consumers purchasing, for example, rooftop solar are sold "solar energy" and that energy is also counted towards the utilities' RPS requirements, the renewable energy has been double-counted. Such a practice would not only risk deceiving consumers but also threatens the integrity of the entire REC market, according to FTC principles.[17]

b. Counting curtailed energy

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[16] *See* https://ethree.com/public_projects/energy_principals_study.php.

[17] *See, e.g.,* February 5, 2015, Federal Trade Commission letter to Green Mountain Power, available at: https://www.ftc.gov/system/files/documents/public_statements/624571/150205gmpletter.pdf.

SCE recommends that paid curtailed energy be eligible to count towards RPS targets on or after January 1, 2021.[18] Crediting towards the RPS renewable energy that was never generated is a very bad idea for at least two reasons. First, non-existent renewable energy does not displace fossil fuels and thus does not deliver the greenhouse-gas (GHG) reduction and other benefits that the RPS policy is intended to achieve. Second, crediting curtailed energy would undermine the incentive that the utilities have to minimize curtailment and could lead to rampant curtailment. As noted in section IV.1 below, several studies have shown that significant curtailment will occur if the utilities procure primarily solar resources, and that curtailment can be cost-effectively avoided through more diverse resource procurements. If curtailment could be counted towards RPS compliance, it would be the cheapest way to comply, but it would not deliver the GHG-reduction that the state is counting on to achieve its GHG-reduction goals.

IV. COMMENTS ON ACR LCBF DIRECTIVES

1. The Commission Should Direct The Utilities To Enhance Their LCBF Methodologies To Anticipate Higher Renewable Energy Penetration Levels And Evaluate Energy Value Consistent With The RPS Calculator

The ACR, at p. 10, asks the utilities to "explicitly and specifically address, both qualitatively and quantitatively, to the extent possible, how the buyer intends to increase the diversity in its portfolio overall, to address issues of grid integration, potential for overgeneration and ratepayer value." This directive reflects the now well-established understanding that a lack of diversity in renewable resource procurement can lead to significant overgeneration, raising RPS costs.[19] However, to cost-effectively achieve higher RPS targets, a longer-term view must be taken when procuring resources, which is not reflected in the utilities' procurement plans. This longer-term view should be consistent with the Commission's planning for transmission and system reliability resources which, in turn, will be informed by RPS planning portfolios produced by the Commission's RPS Calculator. This has several implications for the utilities' LCBF processes, as discussed below.

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[18] SCE 2015 Procurement Plan, Volume 1 at PDF-p. 23.

[19] See, e.g., Energy and Environmental Economics, Inc., *Investigating a Higher Renewables Portfolio Standard in California* (January 2014); CalWEA, "Investigating the Investigation of a Higher Renewables Portfolio Standard in California: A Review of the Five-Utility E3 Study," (April 2014); and several recent papers by LBNL, including "Integrating Solar PV in Utility System Operations" (March 2014).

a. The Commission should direct the utilities to use LCBF values that are reasonably consistent with the values used in the RPS Calculator

The level of redaction in the utilities' procurement plans makes it impossible for market participants to know whether the values proposed to be used are consistent with those being used in the RPS Calculator. The RPS Calculator will be used to generate renewable resource portfolios for purposes of studying needed planning transmission and system reliability resources, and would include expected overgeneration for the optimized basecase RPS portfolio for the 2016 LTPP. If actual procurements are not aligned with this planning, at least for a base-case assessment, the Commission risks planning for a different resource mix than what actually materializes. Therefore, the Commission should direct the utilities to use values that are reasonably consistent with those to be used in the RPS Calculator to generate planning portfolios for the 2016 LTPP in Q4 of this year,[20] at least to generate a basecase shortlist. Any significant deviations from this basecase shortlist should be justified in terms of assuring that the differences will not cause inconsistencies with system planning efforts. In addition, any deviations should inform possible changes in the RPS Calculator methodology to ensure that procurement and planning efforts are harmonized.

In particular, the Commission should direct SCE and SDG&E to use the Effective Load Carrying Capacity (ELCC) methodology in calculating resource adequacy (RA) values. These utilities propose to use the exceedance methodology to calculate RA quantities, and also to report Proposal rankings based on RA quantities using an ELCC method, consistent with D.14-11-04.[21] The Commission should now direct the use of ELCC in calculating RA values, however, given the significant advantages of ELCC, its required use for RA purposes,[22] and the need to align the RPS Calculator with LCBF bid evaluations.

b. The Commission should direct the utilities to develop optimum renewable energy portfolios for purposes of LCBF evaluation, particularly if higher RPS levels are established by the Commission or the Legislature

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[20] April 13, 2015, ALJ Ruling Requesting Post-Workshop Comments, Attachment A, Table 2.

[21] SCE RPS Procurement Plan, Volume 2 at p. 4; SDG&E RPS Procurement Plan, Appendix 9, p. 4. (PG&E apparently proposes to use ELCC only, although this was not entirely clear to CalWEA.)

[22] *See* PU Code Section 399.26(d).

CalWEA's understanding is that, currently, the utilities' LCBF procurement processes do not evaluate a proposed project's expected impact on the full RPS portfolio that is ultimately anticipated. (Today, that would be a 33% RPS portfolio, but it may be established at a higher level, either by this Commission or by the Legislature, prior to the issuance of the 2015 RFO.) Rather, the project is evaluated on the basis of its net market value today, using market-value projections that may not take into account larger RPS portfolios that are expected in the future.

As shown in recent studies,[23] however, the value of a proposed project can be dramatically affected by the other RPS projects in operation at higher RPS levels – in particular, it could suffer significant curtailment that is not captured with the NMV assessment, leading to potentially large inaccuracies in the relative value of the offered project. Therefore, the LCBF process should take into account the anticipated RPS portfolio. Presently, that portfolio should be a 33% RPS portfolio, but the evaluation should be consistent with any higher targets that may be adopted.

This adjustment could be implemented by developing a basecase portfolio that incorporates the longer-term projected RPS goals and then reflecting, in the NMV process, the expected impact of adding an RPS resource to that portfolio. The basecase portfolio would be that which is expected to meet the RPS net short of all retail sellers. To ensure consistency between procurement and planning, as discussed above, the forecasted RPS portfolio should be one produced by the RPS Calculator.[24]

The substantial benefit of this approach is that resources would be evaluated based on the impact of the resource on the 33%, 40% or 50% portfolio, not just the market value of the marginal resource. Specifically, it would better capture the overgeneration impact of proposed resources down the road. At present, there is no indication in SCE's or SDG&E's procurement plan filings that curtailment costs are quantitatively considered in LCBF at all, let alone impacts

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[23] See *supra* note 19, as well as the Integration Cost Study (see note 28, *infra*) and initial RPS Calculator results.

[24] However, even the Calculator's methodology does not presently build an optimum renewables portfolio based on the target year and level, but rather adds renewables to the portfolio incrementally. Thus, concomitant changes are also required in the Calculator's methodology.

down the road. [25] SCE indicates that curtailment is considered qualitatively, to the extent that it is not captured in the quantitative evaluation.[26] SDG&E states that it "does not have a robust set of data to analyze curtailment and its impacts at this juncture."[27]

CalWEA recognizes that considering the long-term resource portfolio in the NMV process could represent a significant departure from current practice that may not be implementable in time for the 2015 RFOs. However, as has been demonstrated, these impacts are significant and warrant further investigation and discussion, in the context of both procurement and planning.

c. The Commission should direct the utilities to carefully consider energy value in the LCBF process

As noted in footnote 23 of the ACR, an ALJ ruling in the LTPP proceeding directed the IOUs to run simulation modeling to refine the interim renewable integration cost adder by developing California-specific variable component values. The resulting study included an interesting finding: that "energy value" -- the reduction in total costs resulting from incremental renewable generation displacing other generation sources -- dwarfs the size of the integration cost adder. The integration costs for either wind or solar generation offset only about 8% of the energy value.[28] Because the energy value of wind and solar (and possibly other renewable resources, which were not studied) differ significantly from one another, it is important that the relative differences in that value be accurately represented in the LCBF evaluation, as reflected in the forecasted value of renewable energy, and, for reasons discussed above, be consistent with the values in the RPS Calculator.

The energy value of a renewable resource is based on the cost of generation that is displaced by renewable energy production. Energy value may be reduced by renewable energy curtailment. When system load is low, particularly compared to total renewable generation, the energy value will be depressed and can potentially become negative if some generation resources

[25] PG&E's Procurement Plan acknowledges increased likelihood of curtailment at higher penetration levels of renewables. See, e.g., PG&E's Table 6-2. However, CalWEA was unable to determine the extent to which PG&E considers this phenomenon during procurement.

[26] SCE Procurement Plan, Volume 2, PDF-page 573.

[27] SDG&E Procurement Plan at p. 43.

[28] See SCE's May 29, 2015, Report on Renewable Integration Cost Study, Table III-4, and slide 23 of the associated June 12, 2015, E3 presentation on Marginal Integration Cost Calculations.

must be curtailed to accommodate the incremental generation from the renewable resource. Renewable energy produced at times when generation prices are low or negative result in low energy values for that resource. Because different types of renewable resources have significantly different generation profiles and thus produce significantly different energy values, the Commission should direct the utilities to ensure that their LCBF methodologies capture these differences in energy value in ways that are consistent with those produced by the RPS Calculator. This could be done by using methods similar to those used in the integration cost study for the LTPP proceeding.

2. The Commission Should Direct The Utilities to Ensure That There Is No Double-Counting Of Costs Between The Integration Cost Adder And Other NMV Components

The integration cost (IC) adder is being concurrently developed in the LTPP proceeding for use in the RPS LCBF evaluations (as well as in the RPS Calculator, whose results will flow into the LTPP studies). However, as indicated in a presentation on the development of the IC adder, some of the IC values may be duplicated in the NMV calculation. Specifically, in generating the IC adder, energy value and integration costs are both captured in total production cost savings, with integration costs "taking back" some of the energy value of renewables. As noted in the presentation,[29] these components are very closely linked, and methods of determining integration costs that are more sophisticated than the stack model used in the RPS Calculator (and flowing into the IC adder in the SCE Report) "might already capture some or all of the integration costs." This is a critical point, as the methods used by the utilities to determine energy value may have already captured those same costs. If so, then the IC adder as applied to the LCBF NMV calculation would double-count these values. Therefore, the Commission should require each utility to demonstrate that the application of the IC adder will not duplicate values in its energy value analysis.[30]

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[29] Slide 7 of E3's June 12, 2015, presentation on the IC adder, "Marginal Integration Cost Calculations."

[30] In the LTPP IC adder process, in response to the expressed concerns of CalWEA and other parties, PG&E, in its July 6, 2015, Reply Comments in R.13-12-010, agreed that double-counting should not occur and explained why its integration cost adder can be used without double counting. SCE did not, in CalWEA's view, provide a sufficient response. SDG&E did not respond.

V. CONCLUSION

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

Respectfully submitted,

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August 31, 2015

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 2015 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 August 31, 2015, at Berkeley, California.

Nancy Rader

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Nancy Rader
Executive Director, California Wind Energy Association