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 LEAST-COST BEST-FIT REFORM FOR RENEWABLES PORTFOLIO STANDARD PROCUREMENT

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On behalf of the California Wind Energy Association

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I. INTRODUCTION AND SUMMARY

Pursuant to the June 22, 2016, ruling of Administrative Law Judge Anne Simon ("Ruling"), the California Wind Energy Association ("CalWEA") respectfully submits these comments on issues related to reform of the Least-Cost Best-Fit ("LCBF") bid evaluation process under the Renewables Portfolio Standard ("RPS") program. Our comments respond to the questions posed to all parties in the Ruling' s attached *Energy Division Staff Paper on Least-Cost Best-Fit Reform* ("Staff Paper").

To summarize the primary points we make in answer to the staff questions:

- The staff' s proposed Work Plan should prioritize consideration of curtailment issues in time for the 2016 RFOs, even if it means delaying those RFOs until Q2 2017;
- Using public forward capacity price curves for assigning capacity value to bids will enable developers to pay for full capacity deliverability (FCD) status only when it improves the net value of the projects they bid;
- TOD factors can, theoretically, serve the purpose of valuing capacity and energy for bid-evaluation and payment purposes, but in practice it is very difficult. Instead, the utilities should consider projected energy and capacity values separately in LCBF criteria, and any capacity payments should be separately made;
- Time-differentiated energy values should be applied, as appropriate, in the bid-evaluation process, reflecting expected low or negative energy prices in the hours in which overgeneration is projected to occur;
- For most renewables, TOD factors are not materially effective or efficient in incentivizing renewable energy facilities to shift the timing of their production, since

their energy source is free and uncontrollable. If TOD factors are used as the basis for energy payments, they should reflect the value-profile used in bid evaluation;

- The Commission' s focus on energy-only ("EO") deliverability status within the LCBF process (and more broadly) is worthy, and long overdue, for many reasons. Any preference for FCDS resources can no longer be justified;
- In most cases, there is no direct or predictable relationship between EO or FCDS status and financial, curtailment or reliability risks, and therefore the questions posed along these lines are not relevant to whether a project has EO or FCDS status;
- To facilitate the development of EO projects, the Commission should: (a) most importantly, ensure that RA capacity value is properly assessed; (b) work with the CAISO to assess expected transmission-related curtailments for all CREZs; (c) work with CAISO to facilitate awarding the utilities with RA credit for their portfolio of EO contracts; and (d) for the long-term, encourage the CAISO to revisit its deliverability methodology to ensure consistency with the Commission' s reliability standards;
- With CAISO estimates of the level of potential curtailment from different renewable development areas, transmission-related curtailments could be estimated in the LCBF analysis for both EO and FCDS projects; and
- If and when FCD status becomes more valuable down the road, and after many EO resources have come on line, it would be useful for CAISO protocols to allow projects to upgrade to FCD status.

II. THE DRAFT WORK PLAN SHOULD PRIORITIZE CONSIDERATION OF CURTAILMENT COSTS

The Staff Paper suggests only implicitly what the primary objective of LCBF reform should be: to adjust the LCBF process as necessary such that the result of the investor-owned utilities' ("IOU") LCBF procurement is an optimal RPS portfolio – i.e., one that minimizes total costs to ratepayers. The Commission should prioritize the LCBF reform topics that are likely to make the greatest contribution to that goal. In a Joint Motion filed earlier in this proceeding with regard to the Procurement Plan ruling, CalWEA and other parties flagged the importance of addressing the cost impacts associated with energy curtailments.[1] That filing is appended to these comments. As the Joint Motion explained in detail, if curtailment issues are not properly addressed in the LCBF process (as well as in contract terms and resource management), the result is likely to be an unbalanced portfolio that shifts costs to other market participants or raises

[1] *See* R.15-02-020, Motion of the California Biomass Energy Alliance, California Wind Energy Association, Calpine Corporation, Geothermal Energy Association and Ormat Nevada, Inc., to Amend Assigned Commissioner and Assigned Administrative Law Judge' s Ruling Identifying Issues And Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans (June 1, 2016) (attached).

overall costs, rather than the more optimal resource mixes that have been produced by the Commission's RPS Calculator and other studies that take curtailment costs into account.

Energy curtailments will likely have a far greater impact on optimal procurement outcomes than most of the issues listed in the Work Plan contained in Table 1 of the Staff Paper, especially given low current capacity values that will naturally reduce the importance of capacity price and deliverability status issues. While "curtailment costs" are not explicitly called out in the Work Plan as they deserve to be, these costs should arise nevertheless in connection with the Work Plan topic of time-of-delivery ("TOD") factors, since curtailment should be reflected in very low or negative projected energy values that are used to rank bids in the LCBF process. CalWEA addresses curtailment costs in the TOD-related questions below, and strongly encourages the Commission to place a priority on curtailment/TOD issues in this process.

Indeed, the Work Plan should be revised such that a high priority is placed on the TOD-curtailment issue and a decision is made on the issue before the next RFOs are issued. Otherwise, the RFO results will continue to be suboptimal and foster increased risk of more curtailments. It should be possible to issue a decision on TODs and curtailments by the end of 2016, enabling reformed RFOs to be issued before the end of Q2 2017.

III. RESPONSES TO QUESTIONS POSED IN THE STAFF PAPER

A. Questions Relating to Capacity Valuation

Question 3: Benefits and risks to ratepayers and to RPS program outcomes of relying on public forward capacity price curves

What are the benefits and risks to ratepayers and to RPS program outcomes of relying on public forward capacity price curves for assigning capacity value to bids in utilities' LCBF methodologies? What approaches could be used to maximize the benefits and minimize the risks?

CalWEA Response:

As discussed in section (e) of our response to Question 4, below, there are relatively few feasible opportunities under the CAISO's generation interconnection protocols for developers to assure full capacity deliverability (FCD) status, which is needed to obtain RA capacity value in the LCBF process and any associated capacity payments under RPS contracts. Moreover, the need for system capacity is presently very low. Nevertheless, in order to make an efficient choice, the developer must know the value of the RA capacity to the IOUs in addition to the cost of the upgrades. This knowledge will prevent developers from making inefficient interconnection choices that would lead to costly transmission upgrades to the detriment of ratepayers. Therefore, one benefit of relying on public forward capacity price curves for assigning capacity value to bids in the utilities' LCBF methodologies is that it will enable developers to optimize the net value of the projects that they bid, which, in turn, will improve the RPS program results and benefit ratepayers accordingly.

Another benefit, as also discussed in section (e) of our response to Question 4, is that these public forward capacity price curves can be used to inform investment decisions made in the (public) LTPP and CAISO TPP processes. Consistent values should be used in all venues, including the RPS LCBF process and the RA program.

Some may argue that the “risk” in creating transparency and consistency around forward capacity price curves is providing a target value for bidders to use in fashioning their bids. In a very competitive market, such as exists in California, this risk is unfounded, as competition, rather than value estimates, will drive bid prices. Moreover, in the case of renewable energy procurement, bidders are competing to provide the primary product, RPS energy, on an overall net market value basis, and capacity is an ancillary product that provides only one of the many inputs in the NMV calculation. Thus, providing an estimate of capacity value will not compromise the competitiveness of the solicitation, but it will inform some bidders as to whether securing FCD status would be worthwhile.

B. <u>Questions Relating to Time-of-Delivery Factors</u>

Question 4. Function and Purpose of TOD Factors

TOD factors were initially approved by the Commission in part to provide an estimate of the capacity value of an offer in an RPS solicitation. Do TOD factors still serve this, or another useful function? Identify the specific RPS program goals that may be served by TOD factors and clearly articulate how TOD factors do or do not help achieve them. Explain how TOD factors may, or may not, overlap with other elements of utility LCBF methodologies, including capacity value calculations. Clearly distinguish between the function of TOD factors used to rank bids through in LCBF criteria and TOD factors included in contracts and used as the basis for payments.

CalWEA Response:

TOD factors can, theoretically, serve the purpose of valuing capacity and energy for bid-evaluation and payment purposes, but in practice it is very difficult to develop TOD factors that objectively and transparently reflect both energy and capacity values. Instead, therefore, the utilities should consider projected energy and capacity values separately in LCBF criteria, and any capacity payments should be made separately. TOD factors, or an alternate method of developing time-differentiated energy values, should be applied, as appropriate, to energy values in the bid-evaluation process; these values should reflect expected energy curtailments. Finally, time-differentiated energy payments serve little purpose in optimizing renewable energy operations since most renewable fuels cannot be controlled. If TOD factors are used as the basis for energy payments, they should reflect the value-profile used in bid evaluation. To inform these decisions, the utilities should provide bidders with specific information about the values they are ascribing for energy and RA capacity. We elaborate below.

(a) Energy and capacity values should be considered separately in LCBF bid evaluation.

In the past, in their LCBF bid-evaluation processes for at least some of their RFO cycles, the utilities have used separate sets of TOD factors for projects with full capacity deliverability status (FCDS) and those with energy-only (EO) status, as granted by the CAISO. However, differentiating TODs by deliverability status serves no purpose. First, an FCDS project delivers the same energy at the same time and subject to the same congestion management protocols as an otherwise identical EO project located next door providing the same shape of deliveries. Second, the RA capacity benefit is already separately valued through the capacity component of the “Net Market Value” (NMV) formula adopted by the Commission in its decision on the 2012 RPS procurement plans. As noted by SCE in its 2014 procurement plan when it appropriately proposed to eliminate its dual factors, “SCE already differentiates between FCDS and EO project proposals by crediting FCDS proposals with capacity benefits in its LCBF valuation.” SCE also explained how its dual TOD factors have created “unnecessary complexity and uncertainty for both sellers and SCE with respect to expected contract payments.”[2]

[2] SCE 2014 RPS Procurement Plan, Volume 1, June 4, 2014, at p. 19.

For these reasons, TOD factors should not be used to value capacity in the LCBF bid-evaluation process. Capacity value should be reflected in the capacity component of the NMV formula, and the capacity price assumption driving that valuation should be made known to bidders, as discussed below.

(b) If LSEs believe there is a need to provide compensation for the capacity component of the product, then contracts should provide separate capacity payments for FCDS projects.

TOD factors -- whether they reflect capacity value or not -- serve little purpose as the basis for differentiated energy payments with respect to projects whose fuel source is free and uncontrollable, as discussed below in response to Question 5. While capacity payments could be made accurately on a per-kWh basis using a very complex rate structure, it would be more straightforward and consistent with current RA capacity policy (a monthly RA requirement on LSEs) to simply make capacity payments to FCDS projects on a per-kW-month basis, similar to what is practiced with conventional resources. Thus, if LSEs believe that there is a need to separately compensate a renewable project for the capacity that it provides, then paying for capacity value in a per-kW-month payment (combined with project availability requirements) is the most straightforward way to provide that benefit. Developers with FCDS projects can then adjust their energy price accordingly as long as the expected capacity payment is known (this point is discussed below).

(c) TOD factors, or an alternate method of developing time-differentiated energy values, should be applied, as appropriate, to energy values in the bid-evaluation process; these values should reflect expected energy curtailments.

The NMV formula contains an energy-value component that should reflect forecasted time-of-delivery values, finely differentiated across locations, seasons, days and hours, for uniform application to each bidder' s expected delivery profile. Thus, this forecast should reflect times during which energy curtailment is expected, evidenced by low or negative energy prices (reflecting the need to pay other resources not to generate) in the hours in which overgeneration is projected to occur. To fully capture curtailment costs, it is critical that the energy-value forecast reflect all resources that are expected to be on the system over the term of the bid being considered, including additional renewable resources that are expected to be needed to meet RPS requirements as well as projected behind-the-meter solar resources that will significantly impact the curtailment of other resources on the system. Thus, it would be appropriate for the utilities to use the latest adopted LTPP portfolios, with behind-the-meter solar resources explicitly modeled, as the basis for their forward-price curves.

The Commission should adopt specific protocols for the utilities' development of price curves, or adopt specific price curves for their use. In any case, the forecasted energy values (at least on a relative basis) should be made known to bidders to inform their decisions in choosing specific technologies to deploy (the obvious example being PV fixed-tilt vs. tracking technology, although wind turbines also have varying production profiles). While the operational changes that a project operator can make are very limited once the project is built, providing signals about the values being ascribed will enable developers to optimize the projects that they bid (which, in turn, will benefit ratepayers).

(d) Any time-differentiated energy payments should mirror the time-differentiated energy values used in bid analysis.

If, despite their limited value in influencing renewable energy operations as discussed in answer to Question 5, TOD factors are nevertheless used as the basis for contractual energy payments, those factors should closely represent what should be finely differentiated forecasted energy values used in the LCBF analysis. To the extent that differentiating energy payments is worthwhile, the only reason for doing so would be to increase the probability of obtaining energy deliveries at the times assumed in the LCBF bid analysis. Thus, the TOD factors used to determine actual payments must match the relative finely differentiated forecasted energy values used in the LCBF analysis. Further, using different profiles would skew the actual cost-competitiveness of selected bidders (for example, if the TOD factor used for payments is higher than the relative energy value for the same time period in the LCBF analysis, the discrepancy will unnecessarily depress the NMV of the bid). Unlike the time-of-use periods being discussed in a separate proceeding, where simplicity is important to promote customer understanding and responsiveness, TOD factors used in making energy payments should, if they are used at all, be as finely differentiated as those used in the LCBF analysis.

(e) Utilities should be required to make transparent the value they will assign to projects with FCD status, which should match the capacity payment, if applicable.

While the ability of renewable energy developers to respond to capacity-value signals is currently limited, the utilities should be required to make transparent the value they will assign to projects with FCD status to inform those developers who are in a position to respond. The only benefit that a generator obtains from deliverability status is the ability for a portion of its capacity to be counted (according to the CPUC's NQC rules) toward a utility's RA capacity requirement, and to be credited for that value in the LCBF bid-evaluation process. As noted above, the generator receives virtually no preferential dispatch treatment or other grid benefits due to FCD status. Therefore, the only factor in the developer's calculation as to whether to obtain FCD status, if applicable (which can be extremely costly due to the associated deliverability transmission upgrade) is the benefit it will obtain in the LSEs' bid evaluation processes for that status.

Currently, the overwhelming majority of renewable energy project developers select "Option A" under the CAISO's Generator Interconnection and Deliverability Allocation Procedures ("GIDAP") protocols,[3] which provides developers with the possibility of obtaining deliverability status at no cost. This opportunity derives from the deliverable capacity that is available via existing transmission facilities or pending reliability or policy upgrades. Because deliverability upgrades are in most cases extremely costly, very few developers select Option B in the GIDAP process, which guarantees FCD status. Therefore, knowing the value that the utilities will award for having FCD status is unlikely to change developers' decisions whether to select Option A or B in most cases. Nevertheless, because this value could make a difference in some cases, and for the important purpose of informing decisions regarding policy-based upgrades made in the LTPP and CAISO TPP processes, the utilities should publicly disclose the capacity values that they would ascribe to projects with FCD status, and associated capacity payments. (And, as with any TOD energy factors and payments, these values should match, as discussed above.) This will enable FCD status to be obtained from renewable resources only when it is cost-effective to do so, and will allow decisions on policy-based deliverability transmission upgrades to be properly made based on a comparison of the cost and value of such

[3] GIDAP is addressed in Appendix DD of the CAISO Tariff.

upgrades. The utilities could provide this information in a "look-up" table that indicates values for different project types and locations.

Question 5: Role of TODs in Incenting Production

One function of TOD factors could be to provide a market signal to incent production at times that it has the greatest expected value to the grid. How effective are TOD factors at incentivizing renewable energy resources to shift the timing of their production? Please provide quantitative estimates of how different TOD factors might affect the timing of energy production by different RPS-eligible resources. For each estimate provided, specify the resource type and ensure that that the effect is both physically plausible for that resource type and economically feasible given a reasonable estimate of the costs that enable the shift to occur (such as storage).

CalWEA Response:

For most renewables, TOD factors are not materially effective or efficient in incentivizing renewable energy facilities to shift the timing of their production, since their energy source is free and uncontrollable. As noted above, developers can be most responsive in delivering production during the most valuable times if clear signals are provided at the outset, in the RFO. With the exception of biomass, renewable resources make large capital investments to capture free fuel, and (to be most competitive) must recoup those capital costs by generating electricity whenever possible. Variable renewable resources (wind and solar) will generally conduct maintenance during the ample times when the "fuel" is unavailable. Therefore, differentiated TOD payments serve little, if any, purpose in influencing their production. On the other hand, flat (no) TOD payment factors provide greater revenue certainty and thus will reduce the risks that affect financing costs. This is particularly true for wind generators whose long-term generation profile is less predictable than solar generation.

In contrast, there is a greater rationale for using TOD factors for making energy payments to geothermal and biomass power plants. Given the very high capital costs of geothermal plants, they will seek to run as much of the time as possible. Given high capacity factors, TOD factors would incentivize maintenance scheduling during low-capacity/energy-value periods. Biomass plants, with their higher and potentially variable fuel costs, can be more responsive to time-differentiated payments.

As long as all bids are evaluated with the same forecasted energy values, and those values are mimicked in any TOD factors used for energy payments, there should be no inequity in using flat payments for variable generators and time-differentiated payments for baseload or flexible generators.

To the extent that renewable resource production is paired with storage, those storage services can be separately addressed in the same manner as they are evaluated and contracted for now, with a separate capacity payment for the storage component. Alternatively, paired projects could be evaluated in the same manner as renewable resources (as recommended above), with the improved output profile garnering greater value for shifting production away from less-valuable and towards more-valuable periods.

Similarly, any ancillary services from the renewable resource, or its storage component, should be separately valued and compensated. Note that, under CalWEA's proposed curtailment plan, all renewables would be available to provide downward flexibility at the contract price. Providing upward flexibility is totally impractical for renewables given the high opportunity cost of lost free fuel (and potentially tax credits).

C. <u>Questions Relating to Valuation of Energy-Only Deliverability Status</u>

Introduction to CalWEA Responses:

The Commission's focus on energy-only ("EO") deliverability status within the LCBF process (and more broadly) is worthy, and long overdue, for many reasons. Energy Division Staff identified many of these reasons almost two years ago in conjunction with the evolution of the RPS Calculator.[4] Staff explained that it makes sense to consider projects without full deliverability status given the low near-term market value of RA capacity (which decreases the value of a resource being fully deliverable in the near term), the fact that the cost of the transmission upgrades required to achieve deliverability may exceed the value of the capacity benefit, and the lower expected capacity value of solar after 2020. We note the following additional reasons:

- The RPS is an energy, not a capacity, requirement, thus there is no justification for requiring all RPS resources to be deliverable. The RPS statute, in the context of legitimate excuses for non-compliance, requires consideration of the delivery of

[4] See R.11-05-005, Administrative Law Judge DeAngelis's *Ruling (1) Issuing an Energy Division Proposal on the Renewables Portfolio Standards Calculator, (2) Entering the Proposal into the Record, and (3) Setting a Comment and Workshop Schedule* (October 10, 2014), at Attachment p. 22.

renewables under the CAISO's *operational* protocols, not its interconnection protocols.[5] Accordingly, the Commission has, on more than one occasion, specifically rejected utility proposals to disallow energy-only bids.[6]

- Any need for new capacity in the CAISO Balancing Authority Area will likely be for local or flexible capacity. Renewable resources generally do not provide, or are not cost-effective sources of, local or flexible capacity.
- As we explain and discuss below, the methodology used by the CAISO to determine deliverability status is extremely conservative, which frequently results in the identification of excessive network upgrades for deliverability. Thus, RA capacity comes at a very high price to ratepayers, particularly as compared to RA resources located in load centers that avoid the need for transmission upgrades.
- It is commonly assumed that a CREZ resource must be deliverable to ensure lack of curtailment from that CREZ. Given the methodology that CAISO uses to study deliverability, however, there is no fundamental correlation between deliverability and transmission-related curtailment from a CREZ. In fact, commercial studies conducted for renewable projects often show that lack of deliverability for a renewable project does not result in any expected transmission-congestion-related curtailments of those projects.[7]

These reasons add up to a compelling rationale for the Commission to ensure that FCDS and EO resources are evaluated properly in the LCBF process. In response to the Staff Paper's observation that, historically, the proportion of projects requesting interconnection with EO status has been very small and that no IOUs have PPAs approved through the Commission's RPS program with EO resources, CalWEA notes that the Sunrise Powerlink and the Tehachapi Renewables Transmission Project ("TRTP") created a significant amount of FCDS capacity which renewable energy projects have been able to utilize free of charge. In addition, the IOUs have historically shown a clear preference for FCDS projects and discouraged EO projects. However, for the reasons above, this preference can no longer be justified.

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[5] P.U. Code Sec. 399.15(b)(5)(A).

[6] For example, in Commission Decision 13-11-024 conditionally accepting the utilities' 2013 RPS plans, the Commission reiterated that the utilities must accept bids from energy-only projects and rejected SCE's proposal to require sellers with energy-only projects to bear the risk of negative CAISO market prices (but accepted SCE's proposal to apply a congestion adder to energy-only projects).

[7] As indicative of these studies, see A. 07-06-031 (SCE's CPCN application for the TRTP), Testimony of Dr. Ajit Kulkarni on Behalf of the City of Chino Hills (March 20, 2013) at p. 24, finding no significant curtailment under an aggressive renewable energy scenario in the absence of deliverability upgrades.

Question 7: Effects of EO projects on financial, reliability or RPS-compliance-related risks.

How would an increase in energy-only projects affect financial, reliability, or RPS-compliance related risks, including risks to existing, online projects? Do the risks differ for projects at different stages in the development cycle (e.g., online projects, projects under development, future projects)? Describe each identified risk and how an increase in energy-only projects would increase or decrease that risk.

CalWEA Response:

This question suggests that there is a relationship between EO/FCDS status, curtailment and reliability, but that is generally not the case. In most cases, there is no direct or predictable relationship between EO or FCDS status and financial, curtailment or reliability risks, and therefore these questions are not relevant to whether a project has EO or FCDS status (with one exception noted below).

Regarding reliability, the CAISO interconnection process requires all projects, including those interconnecting with EO status, to go through a reliability study process (separate from the deliverability study process) and to fund upgrades identified as necessary to safely and reliably interconnect the project to the CAISO (or a utility) system and to remedy all reliability impacts, including transmission/distribution facility overloads, operational voltage criteria violations, and all short-circuit or stability problems. Thus, EO projects do not affect system reliability.

Regarding transmission-related curtailments, which could conceivably create RPS-compliance-related risks and financial risks for developers, CAISO's deliverability methodology is not aimed at determining and mitigating transmission congestion that could cause curtailments. Deliverability of generation from a proposed project, as currently determined by the CAISO, and whether the renewable generation will be curtailed due to transmission congestion, are not directly correlated. This is because the single scenario assuming double-contingency-based dispatch used for the CAISO's peak-load deliverability study has no resemblance to the actual commitment/dispatch conditions that are likely to occur in actual CAISO operations.[8] That is, the constraints found under deliverability studies do not necessarily represent the same constraints that would occur under more realistic operational conditions,

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[8] Specifically, resource dispatch is governed by the CAISO's Market Redesign and Technology Upgrade ("MRTU") algorithms.

which are not simulated by the deliverability study. Thus, except for radial or semi-radial sub-transmission lines,[9] deliverability status is not a forecast of potential curtailment (or lack thereof). As a result, renewable generation from an EO resource can have zero transmission-related congestion curtailments, while renewable generation from an FCDS resource might experience transmission-congestion-related curtailments. For that reason, financing companies generally require curtailment studies to be performed by developers before they provide project financing regardless of the deliverability status of a project.

Illustrating the point that energy-only status is not a predictor of curtailment is the CAISO' s 2015 Special Study. That study, which evaluated the ability of the CAISO' s transmission system to absorb a portfolio of RPS resources with EO deliverability status,[10] was based on the level of curtailment that would be seen under expected operating conditions. As noted in the Staff Paper and in subsequent CAISO reports,[11] the Special Study found that the CAISO system has the potential to absorb over 22,000 MW of EO resources, widely dispersed across the state, without transmission-congestion-related curtailments. That potential represents far more than the roughly 4,500 MW to 8,700 MW of California renewable resources shown to be needed on the CAISO system in order to achieve 50% renewables in 2030 under a variety of scenarios.[12] Additionally, by virtue of the current significant availability of FCDS capacity, thanks to the TRTP and Sunrise projects and other deliverability upgrades already built or approved, over 5,000 MW of RPS projects could obtain FCDS status through the CAISO' s current GIDAP process without additional cost.[13] (See discussion of GIDAP procedures in our response to Question 4, part e.)

Thus, there appears to be little transmission-related curtailment risk that could affect RPS compliance or cause significant financial risks for developers selecting EO status in the 2030

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[9] In the case of projects interconnecting at radial or semi-radial sub-transmission lines, EO status could result in curtailments; however, this problem is usually addressed in the course of addressing reliability issues.

[10] See footnote 37 in the Staff Paper.

[11] See Renewable Energy Transmission Initiative 2.0, presentation of Neil Millar, CAISO, at the Joint Agency Workshop, "Update on Existing Transmission Capability for Renewable Resources" (May 2, 2016).

[12] See Energy+Environmental Economics (E3), "Senate Bill 350 Study, Volume IV: Renewable Energy Portfolio Analysis" (July 8, 2016) at Table 23. Available at http://www.caiso.com/Documents/SB350Study-Volume4RenewableEnergyPortfolioAnalysis.pdf.

[13] See note 11, supra (Millar, RETI 2.0).

timeframe. This provides considerable "breathing room" with which to plan transmission upgrades that would be useful or necessary in the post-2030-timeframe.

Question 8: Actions to facilitate development of EO projects or mitigate risks.

Are there any actions, such as changes to policies or business practices, that the Commission, utilities, or entities (such as the California Independent System Operator) could take to facilitate the development of energy-only projects or mitigate the financial, reliability, or RPS-compliance risks posed by energy-only projects? Please describe any suggested action in detail and explain how it will facilitate the development of energy-only projects or mitigate risks associated with an increase in energy-only projects.

CalWEA Response:

Yes, several actions could facilitate the development of EO projects. As discussed below, the Commission should: (a) most importantly, ensure that RA capacity value is properly assessed, which will also facilitate appropriate transmission planning by the CAISO; (b) work with the CAISO to assess expected transmission-related curtailments for all CREZs; (c) work with CAISO to facilitate awarding the utilities with RA credit for their portfolio of EO contracts; and (d) for the long-term, encourage the CAISO to revisit its deliverability methodology to ensure consistency with the Commission' s reliability standards.

a. The Commission should ensure that RA capacity value is properly assessed, which will facilitate appropriate transmission planning by the CAISO.

At a recent RETI 2.0 workshop, CAISO Executive Director of Infrastructure Development, Neil Millar, presented the fact that the CAISO grid has over 22,000 MW of available transmission capacity for in-state, energy-only renewable resources (involving very little or no curtailment) – as well as over 5,000 MW of available FCDS capacity that could be conferred on renewables. At the workshop, Mr. Millar stated that the "critical question" is whether California wants to obtain capacity value from renewables. The Commission could answer that question by recognizing, as Energy Division staff have already done (discussed above), that the value of system capacity is currently low and is likely to remain low for many years, and then declaring that the utilities should not seek to obtain RA capacity value from renewable resources. However, if the Commission ensures that capacity value is properly and transparently evaluated, as discussed in answer to Question 9, below, it will be able to rely on the

LCBF process to determine when RA capacity value is obtained. This is the most important thing that the Commission can do to encourage EO bids.

If the capacity values used by the utilities are consistent with those used in the RPS Calculator – as the Staff Paper appropriately suggests they should be, then the combination of FCDS and EO resources in the multiple portfolios generated by the RPS Calculator can be relied upon by the CAISO in its transmission planning process in generating a "least-regrets" transmission plan.

b. The Commission could work with the CAISO to assess transmission-related curtailments in congested areas to inform developers and the LCBF process

As specified above, the transmission system has been shown to have considerable capacity to absorb renewable resources with EO status with little or no curtailment, as well as FCDS status to confer upon additional renewables. However, adding renewable resources to the grid once the EO capability in each transmission area is used or in already-congested areas of the sub-transmission system (regardless of their deliverability status) without expanding the transmission system raises the possibility that transmission congestion could induce meaningful quantities of renewable energy curtailments. In some instances, these curtailments could have a major impact on the economic viability of particular resource areas. Therefore, "transmission-related curtailments" (as opposed to "EO-related curtailments") should, if not available from the 2015 Special Study results,[14] be evaluated in follow-up CAISO studies and used in the RPS Calculator to produce estimates of the level of curtailments for each credible resource area, regardless of EO or FC status, with the results factored into the LCBF process. This information would provide developers with valuable information and could potentially open up areas where high resource or low environmental mitigation costs could offset the cost of expected curtailments.

The curtailment level of a CREZ, and the transmission costs to fully or partially mitigate that curtailment, could be estimated using CAISO' s TEAM methodology, which is used for Economic Transmission Planning. The RPS Calculator can then use the same framework that it

[14] As part of the 2015 Special Study that identified the ability to absorb over 20,000 MW of EO resources across numerous CREZs, the CAISO must have seen other CREZs where added resource would cause curtailment. This information could be used to provide an indication of the level of curtailment that would be seen from these CREZs that could be used to calculate "transmission-curtailment adders" for specific CREZs.

intends to use for assessing a CREZ' s deliverability for assessing a CREZ' s curtailment. In other words, for every CREZ, the cost of transmission-congestion-related curtailments should be compared to the cost of the transmission upgrade needed to alleviate such curtailment. If the cost of curtailment is higher than the cost of the transmission upgrade, the CREZ should be included with the cost of the transmission upgrade. On the other hand, if the cost of transmission-congestion-related curtailment from a CREZ is less than the cost of the required transmission upgrade, then the CREZ should be represented with transmission-congestion-related curtailment but without the transmission upgrade. Any resource areas that have been modeled with curtailments, but were still found to be cost-effective, should be accommodated in the procurement process. As additional development occurs, ongoing studies should be performed by the CAISO to determine whether economic and/or policy upgrades are warranted to capture anticipated levels of curtailment.

c. The Commission should facilitate awarding the utilities with RA credit for their portfolio of EO contracts.

Existing or new EO-designated projects, by choice or otherwise, can prove to be fully or partially deliverable when deliverability capacity is available from existing transmission facilities or confirmed transmission upgrades. Clearly, despite their EO status, these projects will have value in the aggregate in improving system reliability; ignoring that value only increases ratepayer costs. CAISO already has protocols in place for such projects to ask for and receive full or partial deliverability status and, in the process, offer added RA capacity to their load-serving entities. However, many EO projects may not be aware of that potential. The Commission should work with CAISO to identify such EO projects and educate them about the possibility of ex-post deliverability status. However, since existing PPAs for such projects normally provide no incentive for the project to seek this ex-post deliverability status, at such time as system RA capacity is needed, the Commission should direct load serving entities to offer to pay developers for the cost of the deliverability study in order to obtain the associated RA credit.

d. The Commission could encourage the CAISO to revisit its deliverability methodology.

While the current low value of RA capacity is very unlikely to warrant paying for FCDS status, certainly by developers of variable renewables, when the value of RA capacity rises, it is still likely to be low in relation to the high cost of FCDS upgrades due to the CAISO's methodology for conferring deliverability status on a generator. The CAISO deliverability methodology is based on a super-stressed, worse-case scenario that is not relevant to actual system operations (including unrealistically high capacity factors for renewable energy generation, assumptions of base generation dispatch that are not supported by actual system operation, and an N-2 outage condition). The frequent result is upgrade bills for interconnecting generators seeking deliverability status in the $10s of millions, which is almost always unaffordable and thus projects that should be able to offer RA capacity are deprived of that ability. Therefore, for long-term purposes, the Commission should engage the CAISO on the origins of its deliverability methodology and on the CPUC's expectations for the standard that an RA product has to meet.

The CAISO's methodology contrasts with the basis for the Commission's RA program, which is designed to acquire adequate system resources to meet a peak demand forecast expected to be reached on a once-in-two-years basis (i.e., in an average year), with a 15% to 17% reserve margin.[15] While the Commission's RA decisions have contemplated the need for resources to be deliverable, the CAISO's deliverability methodology is significantly more conservative than even the Commission's methodology for establishing the *Local RA* procurement obligations for LSEs.[16]

Hence, the Commission should re-evaluate with the CAISO the standard that deliverable products should meet, and align the standard with the basis for the CPUC's RA program, which presume far less stringent conditions than under the CAISO's deliverability methodology.

Question 9: Utilities LCBF methodologies.

Do utilities' most recent LCBF methodologies accurately weight the likely costs and benefits to ratepayers of energy-only projects relative to full capacity deliverability projects? If any of the utilities' LCBF methodologies do not

[15] Decision 04-10-035, at p. 18.

[16] See Decision 06-06-064, at pp. 16-22.

accurately weight the likely costs and benefits of energy-only projects, please identify the methodology, describe the problem, and how the methodology should be changed to improve the problem.

CalWEA Response:

Assuming that the utilities accurately assess the value of RA capacity provided by renewable energy bids, then the current LCBF methodologies will accurately reflect the only benefit of FCD status, which is the ability to obtain RA capacity credit for the resource. The associated costs will be reflected in the developers' bid price (as well as the deliverability network upgrade cost that would be borne by the ratepayers). However, as discussed in our response to Question 4 (part e), in order to discourage generators from seeking uneconomic deliverability status in the first place, the utilities must make transparent the values they will assign to projects with FCD status.

The assumption that the utilities accurately assess the value of RA capacity is not necessarily the case at present, however, as the value of capacity has often been overestimated in the past due to inflation of both factors: the value of capacity, and the fraction of that capacity that is delivered by variable renewable resources. With regard to the former, the Ruling's requirement that the utilities develop a joint proposal for a standardized methodology and set of inputs and assumptions for estimating future capacity prices is encouraging.[17] The Commission should ensure that the capacity values used in the utilities' ANMV equation are not inflated and prohibit any unquantified preferences for FCD status.

With regard to the latter (the fraction of capacity value that is delivered by variable renewable resources), it will be necessary for all of the utilities to use the ELCC methodology, which the Commission has yet to require, despite the fact that Commission has recognized that the ELCC approach "is a more reliable and accurate measure" of renewable energy capacity value than the methodology currently in use, and that the inaccuracies of the current approach "are magnified as renewable penetration increases."[18]

There is an additional potential cost to <u>both</u> EO and FCDS bids (see our response to Question 7, above), which is the cost of transmission-related curtailments. With CAISO estimates of the level of potential curtailment from different renewable development areas, as

[17] Staff Paper at p.1.

[18] See R.15-02-020, ALJ Ruling Accepting Into the Record Revised Energy Division Staff Paper on the Use of ELCC for RPS Procurement and Setting Schedule (March 9, 2016) at Attachment A, p. 2-3.

discussed above in response to Question 8, these curtailments could be estimated in the LCBF analysis. The Adjusted Net Market Value calculation approved by the Commission in Decision 11-04-030 provides that the IOUs are permitted to include a congestion adder in the quantitative portion of the LCBF evaluation. Unfortunately, SCE' s 2015 RPS procurement plan applies an incremental congestion cost adder to all CAISO projects that select EO status, despite the lack of correlation between congestion and deliverability status, and on an average basis rather than specific to transmission areas.[19]

Question 10: Barriers to developing EO projects.

What are the most significant barriers to developing renewable energy projects with energy-only deliverability status and winning bids in the RPS program?

CalWEA Response:

The most significant (and really only) barrier would be overestimating the value of RA capacity (see our responses to Questions 4 and 9) and any unquantified (and unjustified) preferences for FCDS projects.

Question 11. Determining the value of FCDS status.

What information would be likely to improve a renewable energy project development team's ability to confidently determine whether the value of FCDS status is worth the cost of obtaining it? What types of analysis or studies would be needed to generate the required information? Describe the types of analysis, including any modeling tools, data inputs, and assumptions, that would helpful.

CalWEA Response:

As discussed in our response to Questions 4 (part e) and 9 above, the only thing that the bidder needs in order to determine whether acquiring (and paying for) FCDS status is worth the cost is to know what value the utilities will ascribe to that status. Secondarily, it would be useful for developers to know the level of curtailment that might be expected from various CREZs around the state, for both EO and FCDS projects, as discussed in our response to Question 8 (b), above.

[19] *See* SCE 2015 RPS Procurement Plan, Volume II, at p. 5.

Question 12: Bidding to convert to FCDS status.

Would enabling owners of energy-only resources to bid the cost of the transmission upgrade required to convert their projects to full capacity deliverability status be a reasonable approach for mitigating the potential risk that an increase in energy-only resources could lead to a decline in system-wide resource adequacy?

CalWEA Response:

As discussed in the preamble to this section, and as explained in our response to Question 8 (part a), as long as RA capacity value is properly assessed and made transparent to bidders, renewable resources will provide RA capacity to the extent that it can be done cost-effectively. Otherwise, RA capacity can and should be provided more cost-effectively by other system resources, such as existing gas-fired capacity, bulk storage and demand-response. Also, as noted in our response to Question 8 (part c), EO resources are likely, collectively, to reduce the need for system-RA.

However, if and when FCD status becomes more valuable down the road, after many EO resources have come on line (and hopefully when the CAISO's deliverability methodology is assured to be consistent with the Commission's reliability standards as discussed in our response to Question 8, part d), it would be useful for CAISO protocols to allow projects to upgrade to FCD status.

Question 13: Ability to convert to FCDS status.

Do current policies and practices permit a project owner to convert an existing project with energy-only deliverability status to a full capacity project in order to offer that project as a capacity resource? If no, what changes would be required to enable such an action? If yes, what policy or market practices would facilitate the ability of project owners to undertake such an action?

CalWEA Response:

While the CAISO tariff does not currently permit an EO resource to upgrade to FCD status (except for the possible tenuous award of “free” deliverable capacity under GIDAP protocols), other ISOs do, and it should be possible at CAISO as well. Therefore, CAISO should allow EO projects to re-enter the interconnection queue in order to receive FCD status via new network deliverability upgrades.

Question 14: RA accounting changes to support economically optimal level of EO projects.

What changes, if any, to resource adequacy accounting would best support an economically optimal level of energy-only project procurement? (Note that some issues relevant to the consideration of energy-only projects in LCBF reform are also relevant to the Commission's resource adequacy (RA) proceeding. Parties' views on this question will be useful in considering LCBF reform, but are not part of the record of the RA proceeding.)

CalWEA Response:

As we noted in our response to Question 8 (part a), if the capacity values used by the utilities are consistent with those used in the RPS Calculator, then the combination of FCDS and EO resources in the portfolios generated by the RPS Calculator can be relied upon by the CAISO in its transmission planning process. Similarly, RA valuation in the Commission' s RA proceeding (specifically, the capacity value that is delivered by variable renewable resources, which should be measured using the ELCC methodology) and the RPS LCBF process should be aligned so that the value that is ascribed to RPS bids matches what is later recognized in the RA process.

As we noted in our response to Question 8 (part c), the Commission should also consider awarding the utilities with RA credit for their portfolio of EO contracts.

Respectfully submitted,

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July 22, 2016

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 Least-Cost Best-Fit Reform For Renewables Portfolio Standard Procurement" 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 22, 2016, at Berkeley, California.

/s/ Nancy Rader

Nancy Rader
Executive Director, California Wind Energy Association

ATTACHMENT

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)

MOTION OF THE CALIFORNIA BIOMASS ENERGY ALLIANCE, CALIFORNIA WIND ENERGY ASSOCIATION, CALPINE CORPORATION, GEOTHERMAL ENERGY ASSOCIATION AND ORMAT NEVADA, INC., TO AMEND ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE'S RULING IDENTIFYING ISSUES AND SCHEDULE OF REVIEW FOR 2016 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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June 1, 2016

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)

MOTION OF THE CALIFORNIA BIOMASS ENERGY ALLIANCE, CALIFORNIA WIND ENERGY ASSOCIATION, CALPINE CORPORATION, GEOTHERMAL ENERGY ASSOCIATION AND ORMAT NEVADA, INC., TO AMEND ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE'S RULING IDENTIFYING ISSUES AND SCHEDULE OF REVIEW FOR 2016 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

I. INTRODUCTION

The Assigned Commissioner and Administrative Law Judge Mason' s May 17, 2016, Ruling Identifying Issues and Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans ("Ruling"), among other things, instructed the three investor-owned utilities ("IOUs") to "continue to report on observations and issues related to economic curtailment as well as any actions and analysis." (Ruling at p. 16.) Pursuant to the Commission' s Rule of Practices and Procedure 11.1, the California Biomass Energy Alliance, California Wind Energy Association, Calpine Corporation, Geothermal Energy Association and Ormat Nevada, Inc. ("Joint Parties") respectfully submit this motion to modify the Ruling to direct the utilities to specifically address: (1) how they propose to address the projected direct and indirect costs of energy curtailments in the least-cost, best-fit bid evaluation process, and (2) how they plan to make use of their contractual economic curtailment rights with respect to potential overgeneration conditions. Full consideration of these issues is necessary in the 2016 procurement cycle to ensure that the utilities acquire a least-total-cost portfolio, avoid shifting substantial costs onto other market participants, and foster timely compliance with the

Renewables Portfolio Standard ("RPS") policy.[1] Properly addressing what is a common-pool problem may require the Commission and the IOUs to rethink how the utilities handle economic and overgeneration-related curtailments.

II. ARGUMENT

A. Achieving a Least-Total-Cost Portfolio Requires Accounting for All Curtailment Costs in Procurement Decisions

CPUC and CAISO planning models show that the concentrated daytime output profile of solar photovoltaic projects is expected to lead to very significant curtailment of solar energy over the next decade, a timeframe obviously encompassed in LCBF bid analysis.[2] Curtailment is an explicit cost component of the CPUC' s RPS Calculator, which is used to project cost-effective 50% RPS resource portfolios for meeting California' s 2030 Renewables Portfolio Standard ("RPS") goals. This model make a critical assumption that may not track current utility practice: that generators are paid for their curtailed energy at the full contract price.[3] That is, the model assumes that the cost to curtail excess renewable generation will be included in the least-cost, best-fit (LCBF) analyses leading to utility procurement decisions, with the result that solar energy becomes less cost-effective and resources with output profiles that are complementary to solar become more competitive as solar penetration increases. However, it is not at all clear that curtailment costs are, in fact, being fully included – if included at all – in utilities' analyses of proposed bids. As a result, utility procurements may not be leading to a least-cost RPS portfolio.

Curtailment costs may be overlooked or under-estimated for two primary reasons. First, overgeneration-related curtailments are not necessarily of concern to the purchasing utility. This is because if normal operating practices, including the dispatch of economic curtailment bids from renewable resources, fail to maintain system reliability when supply is expected to exceed

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[1] In the event that curtailment is included as one of many issues to be addressed in an anticipated ruling addressing least-cost, best-fit reform in this proceeding, the Joint Parties stress that curtailment requires more immediate attention.

[2] See, e.g., Draft 2016 RPS Portfolios, RETI 2.0 Plenary Group Meeting, slide 12 (3/18/16) (CPUC presentation by Forest Kaser); and E3' s Draft Renewable Portfolios for CAISO SB 350 Study presented at a February 8, 2016, CAISO Public Workshop.

[3] *Id.* (E3 study at slide 10).

demand, CAISO will implement reliability-related curtailment of renewable resources. The investor-owned utilities' pro forma power purchase agreements (PPAs) – and therefore presumably most, if not all, of their signed contracts – generally provide that the utilities will not pay for any reliability-related curtailments ordered by the CAISO, including curtailments resulting from overgeneration.[4] In this way, the utilities would shift curtailment costs to the seller.

Second, it is unlikely that bidders are fully factoring reliability-related curtailment into their pricing. While nobody may be able to accurately predict curtailment due to overgeneration over the long term, bidders lack access to much of the data needed to make even a reasonable estimate. For example, bidders will not be able to predict how much solar energy will be procured by California's utilities as well as all other load-serving entities on the CAISO grid, the growth of rooftop solar installations, [5] load growth or future levels of demand-response (such as midday electric-vehicle charging) or energy exports that might reduce curtailment. Furthermore, a conservative assumption will result in a losing bid, if other bidders do not project similarly high curtailment levels. Finally, as discussed below, most of the curtailment caused by the bidder will affect other operating generators.

B. The LCBF Process Should Consider Costs Imposed on Other Market Participants

Reliability-related curtailments affect not only the marginal renewable supplier but other suppliers as well because reliability-related curtailments are indiscriminate, e.g., they do not differentiate between generation from new solar generators who may have tipped the market into overgeneration conditions and existing solar generators who may be curtailed only as the result of new solar resources entering the market. In fact, studies show that, while the marginal

[4] See definition of "Curtailment Order" in PG&E's pro forma RPS contract and the definition of "Curtailed Product" in SCE's pro forma RPS contract.

[5] Though solar rooftops will cause curtailment, they will not suffer any curtailment because behind-the-meter resources are not subject to curtailment by the CAISO. Thus, the curtailment caused by rooftop solar will fall largely on wholesale solar projects.

curtailment caused by a bidder might be equivalent to 65% of its generation, overall average curtailment at that point would be 9% of overall renewable energy production.[6]

Thus, even if a bidder were to factor in some estimated amount of curtailment that it might suffer over its lifetime, it would not factor in the total curtailment that all generators (both online and contracted) would suffer because of the bidder's marginal contribution to the need for curtailment. Thus, the bidder effectively shifts costs to other market participants, largely other solar generators that would otherwise produce power during times of curtailment. These costs, as far as the Joint Parties can tell, are not being considered in the LCBF bid evaluation process. Moreover, it is not clear whether the utilities are factoring in reduced production from generators (primarily, but not exclusively, solar generators) in their own portfolios resulting from their additional solar procurements and resulting curtailments, let alone reduced production in the portfolios of the other utilities.

C. Fully Accounting for Curtailment Costs Will Foster Timely RPS Compliance

As discussed above, renewable energy curtailments are expected to be very significant if solar procurements dominate the 50% RPS portfolio. These curtailments (on the order of 9% of all renewables) could affect the ability of the IOUs to comply with the RPS policy. By the same token, fully anticipating and accounting for curtailments (and avoiding them when it is cost-effective to do so) will foster timely RPS compliance.

D. Rethinking How The Utilities Handle Overgeneration-Related Curtailments May Be Necessary

The situation described above represents a common-pool resource problem[7] in which everyone has access to a resource and, by using it, additional costs are imposed on other users of the resource. In this case, the grid's limited ability to absorb generation becomes exhausted at certain times due to a combination of limited demand and high solar generation, resulting in a

[6] Marginal curtailment for solar PV was found to be 65% in a solar-heavy 50% RPS scenario in E3's Investigating a Higher Renewables Portfolio Standard in California (January 2014), at p. 15; similar results were found in E3's more recent Western Interconnection Flexibility Assessment, where almost 9% of all renewables are shown to be curtailed on average in a high-solar case (slide 30). Also see note 2, *supra,* CPUC presentation slide 9.

[7] More specifically, the grid can be thought of as an open-access resource.

curtailment order to all generators. In their procurement plan filings, the IOUs should address this common-pool problem.

In the view of the Joint Parties, addressing the problem will require that procurement decisions take into account the potential "overuse" of the grid, such that procurement that exacerbates overgeneration will occur only when it is cost-effective in a global sense, including its impact on the curtailment of other resources.[8] This will require the utilities to account and pay for all curtailed power associated with congestion and overgeneration.[9] Three specific fixes are needed:

(1) generators should be paid for reliability-related curtailment;

(2) impacts of additional procurement on the curtailment of existing and planned generation must be accounted for in the analyses leading to procurement decisions; and

(3) the utilities should utilize their economic curtailment rights under their existing contracts (under which generators are paid for economic curtailments) to avoid reliability-related curtailment.

Many versions of past utility pro forma PPAs allowed for a limited number of unpaid hours of economic curtailment in order to respond to very low or negative market prices, since utilities would rather not pay the PPA price when they get little or nothing – or even have to pay – to offload the energy onto the grid in return. These contract provisions also enable the use of economic curtailment to back generators down to avoid an overgeneration situation. Moreover, utility contracts also generally allow for unlimited curtailment if the seller is paid at the PPA price. In the normal course, one would expect the market price of energy to fall as supply began to exceed demand, which would introduce an incentive for a utility to utilize its economic curtailment rights to reduce supply before the supply-demand imbalance resulted in negative prices being applied to the utility' s entire portfolio. Nevertheless, it' s quite possible that utilities

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[8] Alternatively, the utilities could assign increasing, but reasonable levels of unpaid overgeneration-related reliability curtailments to each group of annual procurements (with the balance of curtailments paid). This would require selective curtailments, however, which would require the CAISO to give curtailment instructions to specific Scheduling Coordinators or generators, rather than the current practice of curtailing all generators uniformly.

[9] E3 similarly concludes, in its Western Interconnection Flexibility Assessment (see note 6, *supra*, at slide 46), that "creating an environment in which renewables can be curtailed routinely on an economic basis is necessary to avoid emergency conditions & reliability events."

would not avail themselves of the opportunity to avoid negative pricing by paying for economic curtailment. This might occur if engaging in a strategy of foregoing the utilities' economic curtailment rights would push the supply-demand imbalance past the "tipping point," forcing the CAISO to implement reliability-related curtailment.

If, instead, utilities were required to utilize their economic curtailment rights under their existing contracts to avoid overgeneration events, it would (in addition to solving the overgeneration problem) remove the economic incentive to engage in the strategy noted above. Namely, it would convert the overgeneration cost to a utility/ratepayer cost, rather than shifting it onto existing generators who could not reasonably have factored expected levels of reliability-related curtailment into their original PPA pricing. Moreover, an existing generator does not control the decision to engage in additional procurement of resources that cause increasing levels of reliability-related curtailment (their buyer does, along with other buyers).

Even if utilities don't pay existing generators for economic curtailment to avoid overgeneration, they should still factor the overall curtailment that is expected to result from their incremental procurements into their LCBF processes to achieve results going forward that are economically rational overall. The common-pool problem requires the problem to be resolved by looking at the big picture.[10] The CPUC should require greater transparency and an explanation of how the utilities are factoring in the impact of potential additional procurement on overall curtailment across all existing resources into the bid-evaluation process.

Since the utilities likewise cannot perfectly forecast anticipated levels of curtailment, they could use a low- and high-range of curtailments to inform their decision-making. This range could be based on reasonably possible levels of CAISO exports to neighboring BAs, rooftop-solar penetration, demand-response programs, and time-of-use pricing incentives, etc. This analysis should also factor in the low or negative energy values that would be involved in CAISO exports (or sales within an expanded CAISO) of generation that would otherwise be

[10] To the extent that Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs) do not employ this type of LCBF process and continue to purchase solar without paying to avoid curtailments, the investor-owned utilities (IOUs) should be able to charge them for the higher direct costs that they incur to avoid overgeneration curtailments pursuant to PU Code Sec. 454.51.

curtailed. Procurement decisions could be based on a mid-range assumption, or could involve hedging any bets that curtailment levels will be on the low-end of the spectrum by procuring some renewable resources that would most cost-effectively reduce potential curtailments through resource diversity.

In this way, the various planning models, which demonstrate that more diverse 50% RPS resource mixes are more cost-effective, will come to fruition in actual utility procurements. Likewise, the state can avoid a common-pool problem that could lead to a dramatic loss of solar energy that would prevent the achievement of 50% goal and hurt all renewable energy generators, but ultimately hit solar projects the hardest.

E. CONCLUSION

For the foregoing reasons, the Joint Parties respectfully request that the Commission grant the Motion to direct the utilities to address specifically: (1) how they propose to address the projected direct and indirect costs of energy curtailments in the least-cost, best-fit bid evaluation process, and (2) how they plan to make use of their contractual economic curtailment rights with respect to potential overgeneration conditions. Including this information in the draft procurement plans will enable other parties to comment on the utilities' proposals in this regard, and enable the Commission to make any needed adjustments in the plans.

Respectfully submitted,

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June 1, 2016

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 "Motion of the California Biomass Energy Alliance, California Wind Energy Association, Calpine Corporation, Geothermal Energy Association and Ormat Nevada, Inc., to Amend Assigned Commissioner and Assigned Administrative Law Judge' s Ruling Identifying Issues And Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans" are true of my own knowledge, except as to the matters which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on June 1, 2016, at Berkeley, California.

/s/ *Nancy Rader*

Nancy Rader
Executive Director
California Wind Energy Association