BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON STAFF PROPOSAL ON PROCESS FOR INTEGRATED RESOURCE PLANNING

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On behalf of the California Wind Energy Association

June 28, 2017

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Pursuant to the May 16, 2017, ruling issued by Administrative Law Judge ("ALJ") Julie Fitch ("Ruling") and the June 13, 2017, ruling modifying schedule, the California Wind Energy Association ("CalWEA") submits these comments on the "Proposal for Implementing Integrated Resource Planning at the CPUC: An Energy Division Staff Proposal" ("Staff Proposal"). After an introduction and summary, CalWEA responds to the questions posed in the ruling, followed by more detailed discussion on certain issues.

I. INTRODUCTION & SUMMARY

CalWEA applauds Energy Division staff for producing a very thoughtful draft Integrated Resource Planning ("IRP") process, for guiding the development of the RESOLVE model to support that process, and for seeking input on many additional important questions that will further inform what is a very difficult and complicated endeavor.

While CalWEA generally supports the iterative IRP process that the Staff Paper sets forth, more work is required to ensure that the process will, in the end, be meaningful. Little purpose would be served in developing and conducting an IRP process that does not result in driving actual programs and procurements towards the optimal overall-system portfolio that the Commission will presumably identify in this process. Therefore, most of CalWEA's comments are aimed at improving the chances that an optimal overall portfolio will be achieved – i.e., one that minimizes overall costs while achieving state policy goals.

Toward this end, to the extent that the Commission provides Load-Serving Entities ("LSEs") with the freedom to fashion their own portfolios as they deem appropriate, it will be essential for the Commission to develop and apply cost-allocation methodologies that will hold

LSEs accountable for the total system costs that are caused by their planning and procurement choices, rather than shifting those costs to other LSEs. Cost-responsibility can be achieved with two specific Commission directives:

1. An individual LSE plan should be developed only after explicitly considering the Commission's assessment of the total-cost impact of that plan across the entire footprint of the California Independent System Operator ("CAISO"), based on the assumptions used to generate the Reference System Plan; and

2. Each LSE should pay, on an ongoing basis, for any indirect costs (such as ramping and curtailment costs) that its procurement choices would otherwise impose on other LSEs.

As CalWEA explains in Section III.A, there are various mechanisms for aligning costs to cost-causers through existing CAISO and CPUC policies. In addition, system costs can be reduced through the practices of LSEs; a very important instance of this is economic curtailment – when LSEs instruct generators to curtail production when CAISO market prices go negative, indicating a system-overgeneration condition. To ensure that curtailment costs are fully accounted for in planning and procurement, CalWEA recommends that the Commission require all LSEs to pay for all instructed curtailment based on economic conditions, as well as for emergency overgeneration-related curtailments, and that the costs of actual curtailments be fairly apportioned among LSEs based on the contribution of each LSE to the problem. Similarly, investment costs to make up for curtailed energy and to mitigate curtailment should be fairly allocated based on cost causation. The Commission should make clear in its IRP decision that the incremental costs (or benefits) associated with CCA or ESP plans will accrue to the customers of these LSEs over the long run, although this objective will be achieved in other proceedings. CalWEA also proposes that Energy Division develop an "incremental cost indicator" to help guide LSEs' resource planning and procurement decisions; CalWEA offers a methodology to calculate such indicators in Section III.B.

Lastly, CalWEA strongly recommends that substantially more than 2,000 MW of out-of-state wind energy resources with zero or very low transmission upgrade costs be included in the supply curve, given the latent capacity of the existing grid in the Western Electricity Coordinating Council ("WECC") region. In its previous IRP-like studies, Energy Division has shown that procurement towards the 2030 RPS target is likely to be optimally comprised roughly of half solar and half wind, in part due to the declining capacity value of solar and increasing solar curtailments as solar penetration rises. In view of limited in-state wind development potential, it is therefore critical to the development of an optimal RPS portfolio that the supply curve properly reflect the ability of out-of-state wind to contribute to meeting RPS goals. These issues are discussed in response to Question 17 and in Section III.C.

II. RESPONSES TO QUESTIONS POSED IN THE RULING

1. Guiding principles. Are the guiding principles for IRP articulated in Chapter 1 of the Staff Proposal adequate and appropriate for Commission policy purposes? What changes would you recommend and why?

CalWEA generally supports the stated principles, but makes several important recommendations to clarify and enhance certain principles, as follows.

Guiding Principle #1 – "The structure and design of the IRP process should reduce greenhouse gas emissions and ensure electric grid reliability while meeting the state's other policy goals in a cost-effective manner."

This language is vague, does not specify that the GHG targets will be met, and does not address LSE portfolios that may exceed state targets.[1] Therefore, CalWEA recommends that the principle be modified to read as follows: "The structure and design of the IRP process should ensure that electric-sector GHG emissions targets are met, or exceeded, while ensuring electric grid reliability and achievement of the state's other policy goals at the lowest total system cost."

Guiding Principle #4 – "Filing entities should have the flexibility to respond to changes in technology, electric system needs, and market conditions."

With an important caveat, CalWEA agrees that LSEs should be provided flexibility to respond to the types of changes noted,[2] even though the IRP will be a two-year cycle that will be constantly updated to reflect market, technology and system changes. Further, as the Staff

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[1] The IOUs have exceeded RPS targets in the past and are projected to do so in the future, and many CCAs have been formed in large part because of a desire to exceed RPS targets and GHG goals. These goals should also be addressed in a way that minimizes total system costs and, per our response to Guiding Principle #8, prevents cost-shifting. Therefore, the Commission should also include in its Reference System Plan the resources that will be required to meet any higher RPS or GHG targets of LSEs, and thus should request LSEs to provide to the Commission with their planning targets.

[2] For example, the Commission should make specific note of the fact that the IRP process is based on a high-level resource assessment, particularly when it comes to the selection of resource locations (CREZs) and associated resource quantities. The resource supply curve should therefore not be used to exclude resources in the procurement process that could prove to have superior value in achieving the goals of Guiding Principle #1. We make a recommendation on this point in response to question 17.a below.

Proposal suggests,[3] the LSEs should have the flexibility to use different tools and make different assumptions than the Commission makes in developing the IRP. In providing this flexibility, however, it is essential that the Commission develop and apply cost-allocation methodologies that will ensure that LSEs will be responsible for the total system costs that are caused by their planning and procurement choices – in other words, that LSEs do not shift to other LSEs the costs resulting from their planning and procurement choices. In this way, the Commission's Reference System Plan (RSP) will serve as the Commission's best "advice" to the LSEs without dictating their planning or procurement decisions, while holding LSEs accountable for their procurement decisions. This concept, and its application to LSEs of different types, is discussed further below.

Guiding Principle #7 – "The IRP process should recognize that filing entities have different governing bodies, procurement processes, and statutory obligations, while also ensuring that the content and format of their Plans are consistent and actionable despite those differences."

The Commission should clarify that its IRP is intended to be the Commission's recommendation for achieving the objectives of Guiding Principle #1 for the system overall and for each LSE.[4] As noted above and discussed further below, in providing LSEs with the freedom to fashion their own portfolios as they deem appropriate, it is essential that the Commission also ensure that the LSEs are provided with strong incentives to align their portfolios with the objectives of Guiding Principle #1. That can be achieved with two specific Commission directives:

a) An individual LSE plan should be developed only after explicitly considering the total-cost impact of that plan across the entire CAISO footprint, using the assumptions that the Commission uses to generate the Reference System Plan;[5] and

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[3] E.g., the Staff Proposal states that the Reference System Plan will be a "guide for LSE plan development" and that LSEs will "have the flexibility to use their own models and prepare their own plans accounting for their specific resource and program costs." Staff Proposal at p. 23.

[4] The meaning of "actionable" is ambiguous, as two distinctly different definitions are included in dictionaries. E.g., Google's definitions are, first, "giving sufficient reason to take legal action," and, second, "able to be done or acted on; having practical value." In any case, further elaboration on how LSEs will be held to account, such as we recommend here, is in order.

[5] The Staff Paper appears to require LSEs to develop at least one portfolio that reflects the CPUC's requirements (see step 3 in Figure 2.1), but does not explicitly require LSEs to develop that plan based on the cost impact of that plan across the entire CAISO footprint.

b) Each LSE should pay, on an ongoing basis, for any indirect costs (such as ramping and curtailment costs) that its procurement choices would otherwise impose on other LSEs through various mechanisms discussed below in Section III.A.

Guiding Principle #8 – "Any costs resulting from procurement directed by the IRP process should be allocated in a fair and equitable manner to LSE customers, and there should be no cost shifting between customers of different LSEs."

CalWEA strongly agrees with this principle, and recommends that the statement be expanded so as to be applicable to all procurement, whether "directed" through the IRP process or not. The Commission will not "direct procurement" through the IRP process per se and, to the extent that it does not otherwise direct procurement, as the Staff Proposal seems to envision, the no-cost-shifting principle should still apply. To effectuate that principle, however, it is essential that the IRP process and related policies be designed to avoid cost shifting between customers of different LSEs resulting from procurement that meets, and procurement that exceeds,[6] the goals encompassed in the system IRP. If the Commission does not provide LSEs with clear incentives to minimize total costs (those paid by the LSE and those imposed on other LSEs), it seems very unlikely that the sum of the LSE plans will add up anywhere close to the optimal Reference System Plan. Those incentives should address costs over the long term, since the effects of long-lived resources will be felt over the long-term.

To encompass these objectives, CalWEA recommends that this principle be revised as follows:

> Any costs resulting from LSE procurement, whether or not aligned with the Reference System Plan, should be allocated in a fair and equitable manner to LSE customers, and there should be no cost shifting between customers of different LSEs on a short-term or long-term basis.

The Commission must take the necessary steps to ensure that no cost-shifting occurs by aligning cost-causation with cost-allocation. We discuss this issue further and describe these steps in Section III.A.

[6] An LSE that exceeds RPS goals could, for example, cause curtailment that imposes costs on other LSEs.

2. Disadvantaged communities' objectives. Are the objectives for addressing disadvantaged communities in IRP in Chapter 1 of the Staff Proposal adequate and appropriate in light of the statutory requirements? What changes would you recommend and why? Please make reference to the specific objectives and statutory requirements in your response.

CalWEA has no comments on this question at this time, except to suggest that achievement of any specific DAC goal (e.g., lower emissions in specific areas) should be accounted for as an input to the RESOLVE model and optimized in the IRP process, rather than through post-processing of the IRP results.

3. Overall IRP process. Comment on the overall IRP process proposed in Chapter 2 of the Staff Proposal, beginning with the California Air Resources Board (CARB) establishing greenhouse gas planning targets for the electricity sector and ending with the Commission procurement and policy implementation. What changes would you recommend and why?

a. The IRP process falls short with regard to promoting consistency between the Reference System Plan and LSE Plans

CalWEA generally supports the iterative process that the Staff Paper sets forth, dividing responsibilities between the CPUC and LSEs, where the CPUC identifies an optimal portfolio of new resources in its "Reference System Plan" to serve as a benchmark for LSEs to use in developing their own portfolios and for staff to aggregate those plans into a Preferred System Plan for the Commission to consider for adoption. An important question is begged, however, when the Staff Paper states (at p.22), "If the aggregate portfolio and corresponding short-term actions are reasonably consistent with the Reference System Plan and with state goals, the CPUC approves (or "certifies" in the case of CCAs) the individual LSE Plans." (Emphasis added.) That question is: What happens if the aggregate portfolio is not consistent with the Reference System Plan? Worse yet, what if the LSE plans widely deviate from the RSP? The Staff Paper does not address such scenarios, which we believe will be highly likely unless the Commission provides clear guidance and incentives to LSEs that encourage them to develop plans that contribute to minimizing overall costs across the CAISO system and during the procurement process.

As for guidance, the Staff Paper does not explain how net-short resources identified in its RSP will be translated into individual LSE plans for comparison later with LSE-developed plans. Staff should provide that guidance upfront. For example, will each LSE be expected to assume its pro-rata share of the overall net-short resource mix, such that if the net short includes a 1:3

ratio of resource types A and B, each LSE with a net short should plan on acquiring resources reflecting that same (or close to) 1:3 ratio? Unless this or some other method is developed for this purpose, it is highly unlikely that the resources in the LSE plans will add up to the desired overall resource mix.

If the Commission does not intend to require LSEs to adhere to its guidance in portfolio planning,[7] or to carry that planning through to procurement, or the Commission wishes to reserve such a requirement to extreme situations, then it will be even more critical for the Commission to provide strong incentives for LSEs to minimize cost-shifting by aligning cost-causation with cost-allocation, as we discuss below in Section III.A.

It is conceivable, however, that, even if the Commission provides guidance on LSE-specific plans and provides cost-signals and accountability for indirect costs imposed on other LSEs, many or most LSEs could develop portfolios that either ignore or assume-away long-term indirect costs such that the amalgamation of LSE plans results in a "Preferred" System Portfolio that looks nothing like the Reference System Plan. In that case, the Commission should reserve the right to impose course-corrections and direct LSEs to modify their plans to ensure that the overall portfolio will achieve the state's policy goals and not veer seriously off-course, raising costs for all consumers. If the Commission believes that it needs additional authority to accomplish that, it should seek that authority from the legislature.

b. Separate track for lumpy collective investments

CalWEA agrees that any collective investments in lumpy assets, such as bulk storage or major transmission upgrades to bring in out-of-state resources, cannot be readily handled with this IRP tool and process, and that it is appropriate to consider any capital-intensive, long-lead-time resources in a separate track. We note, however, that the Staff Paper should refer (on p. 23) to "transmission to access out-of-state RPS resources" rather than simply "out-of-state wind." More importantly, as we discuss elsewhere in these comments, it is essential that substantially

[7] This seems to be the implication from the Staff Paper at p. 74, which states only that individual plans should "discuss the extent to which the plans adhere to the Reference System Plan portfolio resource balance, and to the extent they do not, explain why there are differences." The staff paper seems to contemplate that the Commission would modify or supplement an LSE plan only if there are resource gaps, and even then suggests that it does not have the power to order certain types of LSEs to procure specific resources.

more than 2,000 MW of out-of-state wind with zero or very low transmission upgrade costs be included in the supply curve, given the latent capacity of the existing grid in the WECC region.

4. <u>2017-2018 IRP process</u>. Do you support the Staff Proposal's characterization of the purpose and outcomes of the first round of IRP in 2017-2018? Why or why not?

Yes, CalWEA agrees that emphasis for this first round, 2017-18, should be on generating a single optimal 20-year portfolio to meet SB 350 goals (least-cost under a variety of different possible future conditions), developing IRP filing guidance, and establishing a formal process for filing and reviewing LSE plans, and defining the relationship between IRP and procurement with respect to other resource programs and proceedings at the CPUC.

5. <u>Electric sector 2030 GHG emissions targets</u>. Do you support using the CARB Scoping Plan as the starting point for setting the electric sector GHG emissions target or range for 2030? Why or why not?

CalWEA has no comments on this question at this time.

6. <u>LSE-specific GHG emissions targets</u>.

CalWEA has no comments on this question at this time.

7. <u>Modeling in 2017-2018</u>.

a. Do you support use of the RESOLVE modeling approach for development of a Reference System Plan in 2017-2018? Why or why not?

Yes, CalWEA supports the use of RESOLVE for developing the RSP for 2017-2018 because, to the best of CalWEA's understanding, there are no capacity expansion models comparable to RESOLVE at this time in the electric industry and, in any case, we support the use of this model at least for the first IRP cycle.

b. If you prefer an alternative approach, describe it in detail.

CalWEA recommends that the Commission search for publicly available comparable models and, if any are found, develop criteria for consistency with RESOLVE (including consistency with modeling capability and practices), as well as the ability to efficiently perform stochastic capacity expansion planning, for selection of complementary or replacement models in future IRP cycles.

8. **<u>GHG emissions scenarios to be modeled</u>.**

a. Are the four GHG emissions levels for the electric sector recommended to be analyzed by staff the appropriate ones? Why or why not?

b. What alternative targets do you recommend and why?

CalWEA has no comments on this question at this time.

9. **<u>Modeling Assumptions</u>. Do you have any specific changes to recommend to the modeling assumptions detailed in Chapter 4 and Appendix B of the Staff Proposal and the associated spreadsheet Scenario Tool? What are they and why? Indicate a publicly-available source of your recommended assumptions.**

Except when modeling out-of-state resources, as spelled out in our response to Question 17, CalWEA generally supports the modeling assumptions presented in Chapter 4 of the Staff Proposal. In that regard, and as it pertains to selecting "possible future conditions," each of which leads to the development of a different Reference System Plan, CalWEA believes that, for the sake of consistency and in view of the fact that the IRP will be repeated biennially, it would be efficient if the number of these future conditions are limited to those that are least speculative and conform most closely to the conditions that are likely to take place and also are expected to have a notable impact on the IRP results.

With regard to the assumptions made by LSEs in their IRP processes, it is critical that each LSE develop its own plan only after developing and considering a basecase plan using the assumptions that the Commission uses to generate the Reference System Plan -- if not developed using the Commission's RESOLVE model itself, assessing the total-cost impact of that plan across the entire CAISO footprint. Any assumptions that do not fully align with those made by the Commission should not be used in the LSE basecase unless the LSE can demonstrate that its assumption is superior to that of the Commission's. (For example, one LSE's electric vehicle charging infrastructure and demonstrated EV adoption rate could be superior to the state average.) Unless such LSE assumptions are based on confidential data, the assumptions should be shared with the public before it is ruled upon by the Commission (e.g., within the process that the parties are engaged in here). See Section III.A for further discussion of this point.

CalWEA agrees with the proposed treatment of lumpy investments, such as large storage resources, a volume of out-of-state wind resources that requires a large transmission investment, or a large geothermal plant that is approved outside of the standard IRP process and through a separate track, particularly given our understanding of the limitations of the current state-of-the-art in capacity expansion models. However, the exact process and outcome of such separate processes deserves significantly more clarification and discussions. Further, if any such lumpy investment becomes part of the Reference System Plan in any IRP cycle, extensive explanation of the justification should be provided, including a clear showing that the overall cost of the Reference System Plan will be lower with the lumpy investment.

Finally, CalWEA's understanding is that an artificial and hard limit of 2,000 MW (based on our examination of the RESOLVE spreadsheet) or 5,000 MW (based on our discussion with Energy Division staff) is enforced on the net energy exports out of the CAISO BA. We are not sure whether this hard constraint ever becomes active in the production simulation runs, but this method of dealing with energy exports would be arbitrary and would potentially lead to incorrect and sub-optimal results. CalWEA instead proposes that the following principles be used when determining both the export limit as well as the hourly level of net energy exports during the production simulation modeling in RESOLVE:

- There are no institutional, regulatory, or technical barriers to exporting energy out of the CAISO BA. If there are any limits, they are economic limits resulting from neighboring BAs' valuation of energy from the CAISO BA (due to cost of the energy, the wheeling-out cost, or the neighboring BA's own minimum generation limits or other operating considerations). If there is to be any limit set for net exergy exports, that limit should be established using WECC-wide production simulation studies with consideration for these factors.[8] We expect that such a limit will vary seasonally depending on overall operating conditions in the WECC system.

- During the production simulation studies embodied in RESOLVE, the cost of wheeling out should be considered in determining the level of exports from the CAISO BA; and

- During the production simulation runs embodied in RESOLVE, the cost of energy exports from the CAISO BA should be clearly accounted for from the perspective of the ratepayers in the CAISO BA. This cost should be equal to the PPA payment made by LSEs (i.e., their customers) for the energy being exported less

[8] As stated in CalWEA's January 13, 2017, informal comments in this proceeding, these limits could be reasonably established by performing a WECC-wide study with proper hurdle rates for inter-BA transactions to determine maximum expected export values from California to neighboring BAs. One such value should be established for each study year and interpolation could be used to determine the maximum expected export value for non-study years. The maximum expected export values, thus determined, would then become export limits for the IRP studies.

any payment received by the CAISO BA from the neighboring BA for the exported energy.[9]

Accounting for the above principles is critical for properly determining whether the production simulation studies allow the export of extra energy during overgeneration periods in the CAISO BA or simply curtail such extra energy. This step is critical in determining the optimum level of new RPS resources in the Reference System Plan and individual LSE plans.

10. **Modeling outputs and metrics.** Are the modeling outputs and metrics in Chapter 4 of the Staff Proposal reasonable? What changes would you suggest and why? Be as specific as possible about how to quantify your recommended metrics.

As referenced in our responses to several of the questions below, CalWEA proposes that an "incremental cost indicator" for the incremental addition of each type of RPS resource be calculated and included as an output of the Reference System Plan. Section III.B of these CalWEA comments offers a methodology to calculate such incremental cost indicators.

11. **Sensitivities.** Are the sensitivities defined in Chapter 4 of the Staff Proposal reasonable? What changes would you suggest and why?

CalWEA has no comments on this question at this time.

12. **Futures.** Are the alternative futures proposed to be modeled in Chapter 4 of the Staff Proposal the appropriate ones? What changes would you suggest and why?

CalWEA has no comments on this question at this time.

13. **Costs. Is the cost analysis summarized in the Staff Proposal appropriate and sufficient for the Commission to assess tradeoffs among alternative futures and choose the appropriate level of GHG emissions reductions in the electric sector by 2030 for which to plan? Explain.**

CalWEA has no comments on this question at this time.

14. **Risks.**

a. **Are there any other risks or criteria that should be considered in the portfolio analysis described in the Staff Proposal?**

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[9] Accounting for the PPA payments associated with exported energy would be similar to accounting for the PPA payment for curtailed energy and allows a proper comparison to be made between exporting versus curtailing energy. The LSE's PPA price to be used for this calculation should be the average PPA price for all RPS resources for that LSE.

b. How should the risks associated with not achieving the State goals listed in Table 4.4 of the Staff Proposal be defined and quantified? Propose an appropriate and feasible methodology and explain how the cost of reducing each risk can be quantified.

With regard to a potential lack of "diversity and balance" in the portfolio for the Reference System Plan, as long as the assumptions and data in the underlying model – such as having a sufficient supply of out-of-state wind resources – are sound, there should be no need to qualitatively review (and, by inference of the question, adjust) the model results. In other words, the focus should be on ensuring that inputs to the IRP process and associated models capture as much of the expected uncertainties and risks as possible, not on changing the IRP outputs based on nebulous perceptions of the risks.

For example, the words "diverse and balanced" in Public Utilities Code 454.51(a) should be read in the context of the rest of the sentence: "Identify a diverse and balanced portfolio of resources <u>needed to ensure</u> a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner." Thus, a "diverse and balanced portfolio" is in service to the ends stated – reliability and optimal, cost-effective integration of renewables. The purpose of IRP is to determine the least-cost portfolio within the constraints of meeting established reliability standards and of meeting GHG planning targets for the electric sector. To the extent that a more diverse and balanced portfolio will achieve these ends more cost-effectively than a less diverse portfolio, the IRP process should identify an optimal, diverse mix based on inputs and assumptions that embody the risks that need to be managed. Any criteria that attempts to judge whether there is any "overdependence" on a single technology should be translated to proper input data and assumption and fed to the IRP models, not to subvert the primary goals of achieving GHG goals at least-cost while maintaining reliability.

In summary, to avoid subjective determinations and tampering with the output of the IRP process based on concerns with diversity, the Commission should try to capture all factors that can be used to quantify risks up front in the data (e.g., through a supply/demand relationship in technology costs).[10] If, even with such factors, Energy Division is still concerned that the portfolio is insufficiently diverse and subject to technology-cost or other risks, then it can

[10] Ideally, a range of technology costs would be used in a stochastic IRP model, which the Commission should strive for in later IRP cycles.

conduct a "check" on the IRP results in a post-processing sensitivity run that forces-in greater diversity. If greater diversity is possible without significantly increasing cost or GHG emissions, and without reducing reliability, then the Commission could adopt that portfolio since greater diversity may be preferable, <u>all else equal.</u> Otherwise, if greater diversity (however measured) does not provide benefits expressed by the legislature in the statute, it is not clear what purpose would be served by portfolio diversity per se.

Finally, we note that the Commission should be more concerned with actually achieving the optimal resource mix shown in the Reference System Plan, both in LSE plans and their procurements. The risk of the optimal mix failing to be realized will be high unless the prospect for cost-shifting by LSEs in their RPS procurements is identified and corrected in the IRP and procurement processes and later during actual system operations. CalWEA proposes methods for preventing such cost-shifting in Section III.A, below. Simply qualitatively modifying the RSP's resource mix in a post-processing exercise will do nothing to reduce the risk of LSE's actually producing an improperly balanced, higher-total-cost portfolio.

15. <u>Disadvantaged communities definition</u>. Is it appropriate to use communities scoring at or above the 75th percentage in the California Environmental Protection Agency's CalEnviroScreen 3.0 Tool as the definition of "disadvantaged" for IRP analysis purposes? Why or why not? Are there any other analyses that could better inform the development of metrics to account for the costs and benefits of prioritizing disadvantaged communities?

CalWEA has no comments on this question at this time.

16. <u>Demand-side resources</u>.

CalWEA has no comments on this question at this time.

17. <u>Supply-side resources</u>.

a. Is the treatment of these resources in the staff's recommended approach reasonable? What changes would you suggest and why?

The treatment of the availability of out-of-state ("OOS") resources, particularly OOS wind resources, is not reasonable because the supply curve does not, or does not sufficiently, recognize the various ways that OOS wind resources can currently -- or could, with policy changes that could reasonably occur -- contribute to meeting California's RPS goals without major transmission upgrades and within the current RPS statutory framework:

i. **Resources in OOS CREZs that could be directly interconnected to the existing CAISO grid (which extends beyond California's boundaries) should be treated as in-state CREZs.** Resources from these CREZs readily qualify as Product Content Category 1 ("PCC 1") resources under the RPS statute. For the purpose of IRP, resources in these CREZs should be modeled exactly the same as California CREZs for building the supply curve, e.g., no transmission delivery (wheeling) costs.

ii. **At least 2,500 MW of OOS wind resources should be assumed by 2024 without any transmission upgrades.** Resources within the WECC that are not directly interconnected to the existing CAISO grid can deliver directly to the CAISO through a dynamic transfer agreement[11] with the CAISO and the project's host transmission provider. Such resources qualify under PCC 1. Based on the RETI 2.0 Western States Outreach Project and a WECC case-study, it would be reasonable to assume that this amount of wind energy could be accessed by 2024 through dynamic transfer arrangements with the CAISO (with or without an expanded CAISO) across the WECC footprint without any transmission upgrades in view of scheduled coal-plant retirements. This is discussed below in section III.C.[12]

iii. **Low-cost, advanced grid technologies[13] could enable another 2,500 MW by 2024.** These technologies can be used to overcome WECC grid constraints found only under highly constrained operating conditions that are rarely, if ever, seen in actual operations. With or without coal plant retirements, the combination of advanced grid technologies has enormous potential to facilitate direct deliveries of Western wind resources to California at low-cost. Conservatively, CalWEA believes that the use of these technologies can readily double the 2,500 MW of wind capacity that could qualify for PCC 1 using firm transmission capacity and dynamic scheduling, enabling a total of 5,000 MW.

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[11] Such arrangements put the project under direct CAISO control similar to projects that are physically located within the CAISO's balancing area.

[12] As an example, LADWP's divestiture from the Navajo coal plant in 2016 has freed up nearly 500 MW of firm transmission capacity into California from the Southwest area that could be used by LADWP or be transferred, subject to proper compensation, to CAISO-member LSEs. Once the entire plant retires, transmission capacities from the Southwest into California will further clear up, allowing more firm transmission to become available for scheduling RPS resources, e.g., New Mexico wind, into California.

[13] Until recently, transmission planners and operators have mainly had costly and long-lead-time solutions to address transmission constraints, such as the addition of new transmission facilities. As a result, many renewable resource projects have proven uneconomical. Several new technologies, among them Smart Wires' Power Guardian technology, offers a new approach to address many types of transmission constraints at a substantially lower cost, with substantially lower environmental impacts, and with much shorter deployment timelines. This technology was recently identified by the CAISO and SDG&E as a promising tool to manage the reliability risk associated with the delay of the in-service date of the Sycamore to Penasquitos 230-kv line. See "Pacific DC Intertie Upgrade and Mission-Old Town Flow Control Upgrade; Expedited Approval Consideration" (April 25, 2017).

iv. **Resources that could be delivered with conditional firm transmission service further justify the above figures.** Resources within the WECC that are not directly interconnected to the existing CAISO grid but can deliver directly to the CAISO through a dynamic transfer agreement with the CAISO and the project's host transmission provider using conditional firm transmission service would qualify under PCC 1 with an enabling CAISO protocol clarification.[14] While this potential is very substantial, it has not been specifically quantified and therefore at this time it can be used to undergird the 5,000-MW estimate made above.[15]

v. **Limited potential new transmission infrastructure in the WECC further justify the above figures.** Resources in the previous two categories (relying on dynamic transfer) could connect to the WECC grid with very limited new transmission infrastructure. While RETI 2.0 was not a regulatory process, the draft RETI 2.0 report includes a potentially valuable "schedule" of potential transmission upgrades along with the associated cost range for the new renewables capacity accessed by each of those potential upgrades.[16] This information could be used to provide transmission upgrade costs for the relatively low-cost lines that could interconnect OOS wind resource areas with the WECC grid by the mid-2020s (conservatively) for use in conjunction with dynamic scheduling and firm or conditional firm transmission service. Such lines, with costs well under $1 million per MW, could connect several thousand megawatts of wind energy capacity, according to the draft RETI 2.0 report. While this potential is very substantial, it has not been specifically quantified and therefore at this time it can be used to undergird the specific estimates made in the above categories. Alternatively, the RETI 2.0 report identified wind resources along with their specific transmission costs, which could be added to the IRP model's supply curve.

vi. **Resources that could qualify under PCC 2 or PCC 3.** "Firmed and shaped" PCC 2 products can fulfill up to 25% of RPS compliance, and PCC 3 renewable energy credits ("RECs") can fulfill up to 10% of RPS compliance) (both categories not to exceed 25% of RPS compliance). Given the net short of approximately 2,500 GWh (more explanation on the net short amount below), or about 9,500 MW, roughly 8 GWh, or 2,350 MW, could be procured from OOS resources that qualify under PCC 2 or PCC 3.

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[14] Based on CAISO protocols, dynamic scheduling depends on firm transmission capacity from the location of the resource to the CAISO-controlled grid. Conditional-firm transmission service allows transmission service to be treated as firm during specified time periods or system conditions. The modification in CAISO protocols would allow dynamic scheduling with conditional firm transmission service for those time periods when the transmission service is deemed as firm.

[15] This is discussed below in section III.C.

[16] See RETI 2.0 Final Plenary Report, Table 2-4, p. 46. Available at: http://docketpublic.energy.ca.gov/publicdocuments/15-reti-02/tn216198_20170223t095548_reti_20_final_plenary_report.pdf.

California has some, if not full, control over the aforementioned unquantified or not fully quantified options. Given the quality and quantity of wind resources outside of California and within the WECC, the potential could be quite substantial. The issue, for developing the IRP Reference Plan in 2018, is defining a reasonably conservative quantity of resources for the supply curve, given the multiple pathways listed above and as further discussed in Section III.C, to be used in developing the IRP's reference and sensitivity portfolios.

CalWEA submits that a minimum of 5,000 MW of OOS wind resources, beyond the RPS resources in OOS CREZs that could be directly interconnected to the existing CAISO-controlled grid, can be reasonably assumed to have zero or near-zero transmission upgrade costs based on the categories and discussion above. The supply curve should be augmented accordingly – with more than half of the resources located in New Mexico, one-third in Wyoming, and the rest in the Northwest[17] – and refined for later IRP cycles, to reflect the full potential of the existing grid to transmit OOS RPS resources, particularly wind energy, into California at a relatively low cost.

In its previous IRP-like studies, Energy Division has shown that procurement towards the 2030 RPS target is likely to be optimally comprised roughly of half solar and half wind, in part due to the declining capacity value of solar and increasing solar curtailments as solar penetration rises.[18] Given Energy Division's estimated "net short" of approximately 9,500 MW of non-rooftop-PV RPS resources (the difference between RPS resources needed to meet the 50% RPS target in 2030 and RPS resources already planned or operating),[19] at least 4,000 MW of wind is likely to be needed to achieve a cost-effective 50% RPS portfolio. However, other estimates of RPS net short are substantially higher,[20] as may be reflected in sensitivities. It is therefore

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[17] The retirement of the Navajo and Four Corners coal power plants in Arizona and New Mexico and development of major collector lines which are going forward independently, such as Sunzia Southwest Transmission Project (http://www.sunzia.net/), would increase import capacity from the New Mexico area. The retirement of IPP Coal Plant would boost import capacity from the Wyoming area. Recent and planned increases in the capacity of Pacific DC and AC lines should allow more imports from the Pacific Northwest.

[18] See presentation by Forest Kaser (CPUC) to RETI 2.0 Workshop, April 18, 2016, cited in the RETI 2.0 Final Plenary Report (see note 16 *supra*) at p. 28.

[19] CalWEA calculated this net short quantity using the RESOLVE Scenario Spreadsheet ("RESOLVE_Scenario_Tool_2017-05-16.xsls").

[20] For example, the California Pathways Study, available on the E3 website at: https://ethree.com/public_projects/energy_principals_study.php, shows a net short of 24,000 MW.

essential that the supply curve properly reflect the ability of OOS wind to contribute to meeting RPS goals.

With regard to in-state resources, most of the best remaining wind resource areas within California are unavailable due to county and federal land-use restrictions or outright wind prohibitions.[21] Thus, CalWEA estimates the long-term potential for new wind development to be, at most, 2,000 MW in all of California,[22] which may be less competitive than out-of-state wind resources. (Note also that there are at least 700 MW of existing wind projects in high-quality wind resource areas that do not have long-term RPS contracts and could be repowered; these resources should be included in the model's supply curve as CalWEA has previously requested.[23] Their continued operation absent new long-term contracts should not be assumed.)

Lastly, CalWEA recommends that the Commission note that the resource supply curve is not intended to preclude development areas or supersede land-use decisions and should not be interpreted as limiting or endorsing procurements in particular areas.

b. What additional information, other than modeling, might materially affect these resources? Provide specific sources of publicly available information, what question(s) the additional information would help address, and why you think the information should be used.

c. What market, regulatory, or other barriers could prevent or impede an optimal level of procurement for each resource area and type of LSE, and what solutions would you recommend to address the identified barriers? Explain your answer clearly and provide quantitative support using publicly available information wherever feasible.

Generators have a right to meaningful conditional firm transmission service at reasonable rates under FERC Order No. 890.[24] As we discussed in response to Question 17, and in Section

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[21] See "The (Limited) Wind Energy Potential in California," CalWEA presentation at March 16, 2016, Energy Commission workshop, available at http://www.calwea.org/public-filing/limited-wind-potential-california-31616-reti-20-workshop.

[22] Reflecting this bleak outlook is the fact that only 768 MW of active in-state wind development projects are currently in the CAISO queue (up to and including Queue Cluster 9).

[23] See CalWEA's March 29, 2016 comments in the RPS proceeding, R.15-02-020, on Staff Paper on Draft 2016 RPS Portfolios for Generation and Transmission Planning, at p. 4.

[24] See FERC Order No. 890; Bracewell LLP, "FERC Approves Settlement of Conditional Firm Transmission Service Dispute" (January 31, 2011). Available at:

III.C below, given limited constraints on the WECC grid, combined with advanced grid technologies, considerable potential exists for transmitting wind energy across existing transmission lines in the West without major transmission additions/upgrades. However, the ability of generators to obtain this service from the various transmission owners across the West without a lengthy and potentially contentious process is not clear. A proactive effort by this Commission and/or the Energy Commission, working together with Western states and others, could facilitate the use of conditional firm service.

18. Short-term investments, actions, or procurement. Has staff identified the correct areas for analysis to determine the need for short-term investment or procurement activities, including: bulk storage, out of state wind, and geothermal resources? What changes or additions would you recommend and why?

CalWEA has no comments on this question at this time.

19. Transportation electrification.

a. Do you support the Staff Proposal's approach to characterizing transportation electrification and the uncertainties and impacts associated with it? Explain.
b. What tools and/or data could be used to assess how electric vehicle deployment could maximize benefits to disadvantaged communities?

CalWEA has no comments on this question at this time.

20. Reference System Plan development.

a. What methodology should staff use to develop a recommendation for the portfolio to include in the Reference System Plan?
b. If you recommend a scorecard-style approach, what weight should be given to each state goal in Table 4.4 of the Staff Proposal?
c. Are there any additional criteria, apart from the goals listed in Table 4.4 of the Staff Proposal, that staff should also include? If so, why?
d. Are there any additional questions or studies that staff should address in the Reference System Plan? If so, describe each question or study and explain why you think it should be included, considering the limited time and resources available.

Our responses to questions 3, 4, 9 and 14 broadly address CalWEA's position on these questions as well.

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http://www.energylegalblog.com/blog/2011/01/31/ferc-approves-settlement-conditional-firm-transmission-service-dispute.

21. **<u>LSE filing process</u>**. Do you support the approach to LSE IRP filing outlined in Chapter 5 of the Staff Proposal? Why or why not?

CalWEA has no comments on this question at this time.

22. **<u>General LSE filing requirements</u>**

a. Are there any additional general requirements that the Commission should require LSEs to include in their IRPs?

As we discussed in response to Question 1 (with regard to Guiding Principle #8) and as we recommend in Section III.A, to promote the conformance of LSE plans with the Reference System Plan, the Commission should require that each LSE develop an RPS portfolio that is optimized based on its operational cost impact on the entire CAISO BA, not just the LSE's own system, and by employing the same assumptions and methods used by Energy Division in developing the Reference System Plan.[25] If the LSE uses other assumptions and methods to develop its Preferred LSE Plan, the RSP-based plan will provide a critical reference point that will enable the LSE's governing body to understand how the Commission's optimal portfolio-based recommendation differs from the LSE staff's recommendation, and the indirect system costs that the LSE may expect to pay on an ongoing basis as a result of its procurement choices.[26] Indeed, it is possible to estimate the expected lifetime cost of the Preferred LSE Plan and the RSP-based plan to enable a direct comparison of the expected costs for each.[27] This analysis should be performed using incremental cost indicators that should be produced in connection with the RSP, which identify the total cost impact of adding incremental amounts of various RPS resource types. We discuss in Section III.B how these indicators can be generated.

b. Are any of the general requirements proposed by staff infeasible to provide? If so, explain what barriers make providing the information infeasible, what the risks of not requiring the information might be for both bundled and unbundled customers, and how that risk could be mitigated in another, more feasible way.

CalWEA has no comments on this question at this time.

[25] To develop this RSP-based plan, LSEs could use the same RESOLVE model used by the Commission.

[26] Various cost-alignment mechanisms are discussed in Section III.A.

[27] As noted in Section III.B, incremental cost indicators would estimate the systemwide life cycle cost of a specific RPS resource technology. An LSE can simply estimate the systemwide life cycle cost of any RPS portfolio by multiplying the MW size of each RPS resource type by its cost indicator and summing these costs for the entire portfolio.

23. Technical LSE filing requirements.

a. Are there any additional technical requirements that the Commission should require LSEs to include in their LSE Plans? Describe in detail.
b. Are there any staff-recommended technical requirements that should be omitted or consolidated? Specify.
c. Are any of the technical requirements proposed by staff infeasible to provide? If so, explain the barriers that make providing the information infeasible, the risks of not requiring the information (for bundled and unbundled customers) and how the risks could be mitigated in another, more feasible way.

LSEs should file the expected lifetime cost impact of their LSE plan based on the incremental cost indicators referenced in CalWEA's response to Question 22 and described in detail in Section III.B.

24. LSE IRP Filing Template. Describe any changes you recommend to the Staff-recommended template in Appendix C and explain why.

CalWEA has no comments on this question at this time.

25. Standard and Alternative IRPs. Do you support the staff proposal for standard and alternative IRP filings? What changes would you suggest, either to the overall approach or to the specific requirements for each, and why?

While CalWEA understands the Commission's desire to avoid imposing burdens on smaller LSEs, we believe that these smaller LSEs should be able to readily develop their plan using the incremental cost indicators in such a way that is generally consistent with the Commission's RSP. Furthermore, these LSEs should also report on the total cost of their Alternative Plan as part of their reporting responsibility.

26. For individual LSEs:

a. Do you support the staff recommendation for the type of IRP you should file? Why or why not?
b. If you have an alternative recommendation, please describe it in detail.

CalWEA has no comments on this question at this time.

27. Individual LSE load determination. How should the Commission determine what load to assign to each LSE for IRP filing purposes? Describe your preferred method in detail, such that it can be readily reproduced using publicly available information.

CalWEA has no comments on this question at this time.

28. **<u>For individual LSEs</u>:**

a. What load should you be assigned for 2017-2018 IRP purposes?
b. Describe in detail the methodology associated with your proposed load obligation.

29. **<u>Marginal GHG abatement cost/planning price</u>:** Is it appropriate and feasible for the Commission to use the results of the IRP analysis to inform the inputs for certain cost-effectiveness analysis, such as in the Integrated Distributed Energy Resource proceeding evaluation of the societal cost test for demand-side resources? Why or why not?

Given that the IRP addresses the cost impact of potential transmission and distribution investments at a very high level, CalWEA believes that, particularly for comparison purposes, the incremental cost indicators referenced in our response to Question 22 and described in more detail in Section III.C can be used to evaluate the cost impact of distributed resources which can, in turn, be used in developing long term policies and strategies regarding such resources.

30. **<u>Relationship between IRPs and procurement</u>.**

a. Describe your reaction to the Staff Proposal's characterization of how IRP development and approval will lead to actual resource procurement in the next few years.
b. Are there any alternative approaches to IRP-based procurement that the Commission should consider? If so, describe the approach in detail and explain which specific problems it would address with reference to the statutory requirements for IRP, while not conflicting with other Commission non-IRP statutory requirements. What existing rules should the Commission consider studying to improve the ability of the IRP process to achieve its goals (e.g., Renewable Energy Credit banks, Renewables Portfolio Standard content categories, etc.)? What approaches or methodologies should the Commission consider using to study the costs and benefits of your proposals?
c. How should the Commission ensure that LSEs comply with their approved IRPs? Describe your preferred approach in detail, with reference to the IRP statutory requirements.

Please see our responses to questions 1, 3 and related comments in Section III.A.

31. **<u>Relationship between IRPs and bundled procurement plans</u>.**

a. Does the Staff Proposal appropriately characterize the relationship? What changes would you recommend to the approach and why?

b. What interactions between the IRP process and the bundled procurement practices and policies should be considered in future IRP cycles? Identify specific bundled plan requirements that may need to be changed to facilitate coordination with IRP in the future.

As CalWEA has noted in its response to a number of questions and in Section III.A, the main connection between the RSP and individual LSE procurement plans should be the use of incremental cost indicators developed as part of the RSP to estimate the total lifetime cost of an LSE procurement plan either during the LSE's IRP or actual procurement process. The success of such an approach, of course, is contingent on the LSE being made responsible for paying for any cost shift stemming from its resource selection onto other LSEs as articulated in Section III.A.

32. <u>Disadvantaged communities impacts in procurement</u>.

a. Do you support the Staff Proposal's approach to assessment of the impacts of procurement on disadvantaged communities? What changes would you recommend and why?
b. What specific quantitative and/or qualitative showings should LSEs be required to provide to demonstrate how disadvantaged communities were considered in the development of their IRPs?
c. How should the Commission utilize the information provided by the LSEs to assess the impacts of procurement on disadvantaged communities?

CalWEA has no comments on this question at this time.

33. <u>Cost allocation and cost recovery</u>.

a. Is the Staff Proposal approach to these issues workable? What changes would you recommend and why?
b. How important is it for the Commission to allocate responsibility for deficiencies in the aggregate portfolio (of all LSE plans) to individual LSEs?
c. How should the Commission address the situation where one LSE's IRP is identifiably the cause of a gap in meeting the Reference System Plan GHG target for the electric sector (e.g., if one LSE does not appropriately factor the GHG Planning Price into its IRP)?
d. How should the Commission assign responsibility for procurement of system or flexibility resources when an overall deficiency is identified?

Please see our responses to questions 1, 3 and related comments in Section III.A.

34. Alignment of IRP process with other Commission resource proceedings.

a. Are there obvious opportunities for alignment across Commission proceedings that the staff should consider in developing a process alignment workplan?
b. What would be the benefits to coordinating proceedings to align based on these opportunities?
c. Identify any barriers to coordination.

CalWEA strongly supports the Staff Paper's suggestion (at p. 65) that the IRP process should be used to recommend changes to existing policies that are anticipated to produce quantities of any resources that are not aligned with the Reference System Plan. The Reference System Plan, not the Preferred System Plan, should be used to make such determinations because the aggregation of LSE plans may (as discussed elsewhere) diverge significantly from the system-optimal Reference System Plan. The essential purpose of IRP is to compare resources on a consistent basis and "turn the ship" towards those that will best meet the objectives in Guiding Principle #1.

35. Preferred System Plan. Is the Staff Proposal's recommendation to utilize a Commission-approved Preferred System Plan as the basis for input into the IEPR and TPP processes appropriate and workable? What changes would you recommend and why?

In general, CalWEA believes that the Reference System Plan, which considers costs and benefits across the entire CAISO footprint, is better aligned with the CAISO policy-based TPP process. As a result, the Reference System Plan (and its associated resource portfolio), and not the Preferred System Plan, should be used by the CAISO for developing its policy-based TPP upgrade plan. The development of TPP upgrades based on the Reference System Plan should also further encourage LSEs to develop resource plans that better line up with the Reference System Plan, which is intended to minimize costs over the entire CAISO BA.

36. Alignment with CEC's Integrated Energy Policy Report (IEPR) and California Independent System Operator's (CAISO's) Transmission Planning Process (TPP).

a. Do you support the Staff Proposal approach to coordination with the IEPR and TPP processes? What changes would you recommend and why?
b. Are there specific outputs from the IRP process that should be included in California's long-term planning processes that were not previously outputs from the long-term procurement planning process? Describe the outputs and the benefits of including them.

c. Are there previous outputs from long-term procurement planning that are not anticipated to be included in IRP but which may be necessary? Describe the outputs and the benefits of including them.

Please note our response to Question 35.

37. Regional Planning. How should the IRP process and analysis take into account the potential for CAISO regionalization?

CalWEA has no comments on this question at this time.

III. CALWEA'S ADDITIONAL COMMENTS

A. For IRP to Achieve Its Stated Goals, the Commission Must Align Cost-Causation with Cost-Allocation

1. Overview

If the goal of the IRP process is to develop an optimal overall-system portfolio based on its evaluation of all competing policy goals and potential supply-side and demand-side resources, then – assuming that the Commission's evaluation is accurate and sound, and all LSEs use the same assumptions and methodology in producing their individual plans – the sum of the LSE plans and actual procurement should together match the procurement projected in the optimal portfolio as closely as possible in order to achieve optimal results.

To the extent that the Commission provides LSEs with the freedom to fashion their own portfolios as they deem appropriate, however, it is essential that the Commission also ensure that the LSEs are provided with strong incentives to align their portfolios with the objectives of Guiding Principle #1. As noted above, that cost-responsibility can be achieved with two specific Commission directives:

a) An individual LSE plan should be developed only after explicitly considering the Commission's assessment of the total-cost impact of that plan across the entire CAISO footprint. The Staff Paper appears to require LSEs to develop at least one portfolio that reflects all of the CPUC's assumptions and methodologies (see step 3 in Figure 2.1), however, the Commission should make this expectation explicit; and

b) Each LSE should pay, on an ongoing basis, for any indirect costs (such as ramping and curtailment costs) that its procurement choices would otherwise impose on other LSEs through various cost-alignment mechanisms discussed below.

As an example, assume that a CCA believes that it will achieve an electric vehicle ("EV") adoption rate and customer charging behavior that is significantly more aggressive and favorable than what the agencies have assumed in the RSP, and therefore the CCA assumes that there will be no overgeneration associated with a generation portfolio that relies heavily on distributed solar resources. The LSE (and its customers) should be held responsible for any resulting increased system costs (e.g., curtailment and grid-integration costs) associated with the LSE's procurement decisions.

2. Mechanisms for aligning costs with cost-causers

There are various ways in which the Commission, together with the CAISO, can and must ensure that cost-causers will pay for the indirect costs of their procurement, in order to achieve its policy objectives:

- **Directly, via the CAISO** – For example, when the CAISO curtails resources to maintain system reliability due to overgeneration conditions, it curtails all generating resources uniformly. Therefore, the generators that are contributing to the overgeneration problem by producing during these periods will suffer the most curtailment. Thus, LSEs that have procured a portfolio of resources (both demand- and supply-side) that contribute to overgeneration will suffer the resulting consequence. Similarly, the costs of the new short-term (five-minute) Flexible Ramping Product market (which addresses the CAISO's need to maintain power balance in real time) will be allocated by CAISO to loads and generators that deviate from their schedules. CAISO is in the process of properly allocating the cost of other services (e.g., Primary Frequency Response) that are procured directly by the CAISO.

- **Directly, via the CPUC** – With guidance from the CAISO, the Commission determines, in its Resource Adequacy ("RA") proceeding, the amount of flexible resource capacity that should be procured to ensure that the system has sufficient ramping capacity to meet the CAISO's operational needs. However, until flexible RA needs (and costs) are allocated to each LSE based on its individual contribution to net load ramp, flexible capacity costs will not be aligned with cost causation. The Commission has so far neglected to accomplish cost-causation-based allocation,[28] despite the fact that cost-causation data is available from the CAISO. This must be remedied.

- **Indirectly, via the CPUC** – In addition to portfolio balance, system costs can be reduced through the practices of LSEs. A very important instance of this is economic curtailment – when LSEs instruct generators to curtail production when CAISO market prices go negative, signaling a system-overgeneration condition (among other conditions). Curtailing production keeps the CAISO from having to curtail on an emergency basis to maintain system reliability, and also keeps prices in positive territory for the benefit of all generators who are not curtailed. For reasons explained in Section III.A.4 below, CalWEA recommends that the

[28] See Decision 16-06-045 in R.14-10-010 (June 23, 2016).

Commission require all LSEs to pay for all instructed curtailment based on economic conditions, as well as for emergency overgeneration-related curtailments. This uniform requirement is necessary both to ensure that curtailment costs are fully accounted for in planning and procurement, and to facilitate generator financing, particularly as curtailment costs mount.

Even if all of the above mechanisms are fully implemented, however, an additional mechanism will be required to fully capture indirect costs, as discussed next.

3. Methodology for aligning remaining costs to cost-causers

a. Principles

As discussed above, many indirect costs can be addressed by the CAISO and CPUC; however, there may be additional, mostly curtailment-related costs, that will not be captured. Unless these costs are properly calculated, allocated and recovered from the LSEs whose procurement decisions caused them, the resulting RPS resource mix for the entire CAISO BA could grossly deviate from the guiding principles of the IRP program as envisioned in SB 350 and in the Staff Paper. The Commission must therefore act on the following three principles:

1. Require that each LSE develop its LSE plan and the associated LSE resource portfolio in such a way that it is optimized based on the operational cost impact on the entire CAISO BA, not just the LSE's own system. This goal can generally be achieved by employing the same assumptions and methods used by Energy Division in developing the Reference System Plan. If the LSE uses other assumptions and methods to develop its Preferred LSE Plan, the RSP-based plan will serve as a reference point for the LSE's governing body regarding how the Commission's recommendation differs from the LSE staff's recommendations. The incremental cost indicators noted in response to questions 10 and 22 can be used to calculate the system cost difference between the two plans, which can then be used in the evaluation by the LSE's governing body.

2. Individual LSE RPS resource procurement decisions should likewise be made in consideration of the total cost that the associated procurement will cause, in the Commission's estimation, on the CAISO system for the life of the procurements. To the extent that an LSE's procurement decision is made based on models that deviate from the IRP model, these RPS procurement models should use the cost for the entire CAISO BA along with LSE's investment cost as its objective function. This will provide the LSE with the Commission's estimate of what the LSE should expect to pay in indirect-cost assessments over the life of the procurement.

3. Individual LSEs should be made responsible for any operating costs resulting from their procurement decisions not captured by the mechanisms discussed in Section III.A.2 on an ongoing basis for the life of the procured RPS resources.

The largest such cost category will be curtailment costs, whose cost components are as follows:

- **Economic curtailment costs --** Assuming that economic curtailment costs are paid for directly by LSEs, as discussed and recommended in Section III.A.4 below, those costs may not be incurred equitably across LSEs. In the event that a subset of LSEs undertakes most of the economic curtailment, which benefits all ratepayers, the costs of such curtailment should be fairly apportioned to all LSEs based on their impact on the need for the curtailment.

- **Investments made to make up for the curtailed energy** – i.e., the cost of any additional cost-effective RPS resources that LSEs will need to procure to make up for the energy lost due to curtailment so that RPS targets can be met. Whether the decision to procure such resources is made by individual LSEs, or on an aggregate basis for all LSEs (e.g., a lumpy out-of-state wind and transmission investment), the cost of these resources should be properly shared by those who cause them.

- **Investments made to mitigate curtailment** – i.e., the cost of any new procurement or investment made to cost-effectively reduce the level of curtailments. For example, procurement of energy storage resources (or applicable portion thereof) specifically targeted to address RPS energy curtailment, or the added cost to purchase higher-cost RPS resources that help mitigate curtailment cost. Whether the decision to procure such resources is made by individual LSEs, or on an aggregate basis for all LSEs, the cost of these resources should be proportionately shared by those who cause them.

With regard to all three principles, when CAISO curtails RPS resources, it does so on a pro-rata basis, without regard to resource vintages or their associated LSE's contribution to curtailment. For example, while the introduction of a new solar resource can marginally increase RPS energy curtailment by the equivalent of 50% or more of that new resource's production, the solar resource itself is curtailed only on average along with all other resources operating on the CAISO system, amounting to a small fraction of the marginal curtailment caused by the solar resource.[29] The result is that the curtailment costs caused by an LSE's procurement decision are largely shifted to all other resources operating on the system. To ensure that the LSE accounts

[29] See, e.g., E3's Investigating a Higher Renewables Portfolio Standard in California (January 2014), at p. 15, which found marginal curtailment for solar PV to be 65% in a solar-heavy 50% RPS scenario. Similar results were found in E3's January 2016 Western Interconnection Flexibility Assessment, where almost 9% of all renewables are shown to be curtailed on average in a high-solar case (slide 30). See also E3's Update on the 2015 Special Study presented at a June 29, 2015, CPUC-CAISO Webinar.

for the full cost of its procurement decision, the CPUC should ensure that the shifted costs are accounted for and allocated back to the LSE.[30] In the following section, we propose an allocation formula that is intended to correctly allocate curtailment-related costs to the cost-causer.

b. Allocation of curtailment-cost components

Of the above three curtailment-cost components, the latter two investment costs could be readily allocated to an LSE (LSE_i) based on the following simple formula at the time that these costs are incurred:

> LSE_i share of the curtailment investment cost = (LSE_i actual curtailment share / Sum of all LSEs' actual curtailment shares) x total curtailment investment cost
>
> where LSE_i's actual curtailment share is calculated as the sum of the product of LSE_i's existing RPS resources (of all types) multiplied by average curtailment for each existing RPS resource type, plus the product of new RPS resources of all types being procured in the next cycle multiplied by the expected marginal curtailment for those types of RPS resources. This simple formula will ensure that there is no cost shift among LSEs when it comes to curtailment-related investment costs. This allocation should occur for all cost-justified procurement decisions made by individual LSEs, or on an aggregate basis for LSEs during each procurement cycle.

Addressing costs shifted due to the economic curtailment costs borne unequally across LSEs is more complex. We propose the following algorithm for addressing such cost shifts:

> Step 1) For every hour of operation when curtailment took place, each LSE should report the total curtailed energy and the total payments made for the curtailed energy. This information would be used to determine average curtailment payments per MWh of curtailed energy for each LSE.
>
> Step 2) For every hour of operation when curtailment took place, a marginal curtailment-related payment should be paid by each LSE that experienced curtailment into a common fund. This payment is calculated by multiplying that LSE's average curtailment payment per MWh (calculated in Step 1) by the total of vintage incremental[31] curtailment in MWhs for the RPS procured resources post-IRP – all pre-IRP RPS resources are assumed to have the average curtailment in MWh.

[30] Note that some of the LSE's own resources will be impacted by its marginal procurements, which should also be taken into account.

[31] "Vintage incremental" curtailment refers to RPS resource-specific incremental curtailment figures for each RPS procurement cycle that occurs after the IRP process has been initiated. For example, it is expected that RPS resources procured in the 2022 procurement cycle will have higher incremental curtailment impacts than those RPS resources procured in the 2018 procurement cycle.

Step 3) For each hour of operation when curtailment took place, the common funds for marginal curtailment collected in Step 2 would be distributed to LSEs who experienced curtailment. Payment to each LSE will be based on the ratio of the total proposed payment for curtailed energy for that LSE divided by the total proposed payment for all curtailed energy across all LSEs.

The above process could be performed confidentially by the CAISO or CPUC.

4. All curtailment costs should be absorbed by the LSEs

It is our understanding that the RESOLVE model makes a critical assumption that may not always track the current practices of all LSEs: that generators will be paid for their curtailed energy at the full contract price.[32] That is, the model assumes, in developing the Reference System Plan, that the cost to curtail excess renewable generation will be factored into the procurement process, with the result that solar energy becomes less cost-effective and resources with complementary output profiles become more competitive as solar penetration increases. The problem is that curtailment costs are not necessarily being fully included – if included at all – in LSEs' procurement analyses of proposed bids. Thus, LSE procurement is unlikely to match the procurement assumed in planning analyses.

For the reasons explained below, in order for curtailment costs to be fully reflected in procurement costs, it is essential that the power purchase agreements (PPAs) of all LSEs provide that the LSE-buyer will pay for all of the seller's renewable energy curtailment, both economic[33] and reliability overgeneration-related curtailments.[34] Further, the IOUs (if not all LSEs) should be required to use their economic curtailment rights to avoid negative pricing conditions signaling overgeneration conditions. As described in the previous section, if curtailment costs are not evenly incurred by all Commission-jurisdictional LSEs, the costs of curtailment should be fairly re-apportioned among those LSEs.

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[32] See, e.g., E3's Draft Renewable Portfolios for CAISO SB 350 Study presented at a February 8, 2016, CAISO workshop, at slide 10. The slide describes the cost analysis in the RESOLVE model, stating, "Renewables are compensated for curtailed energy at full PPA price."

[33] Economic curtailment is when LSEs instruct generators to curtail production when CAISO market prices go negative, signaling system overgeneration conditions.

[34] The CAISO orders curtailment on an emergency basis for the purpose of maintaining system reliability when supply is expected to unavoidably exceed demand.

Curtailment costs are being overlooked or under-estimated for a number of reasons.[35] First, overgeneration-related curtailments are of little or no concern to the LSE-buyer because they do not pay for them. 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.[36] So those costs are shifted to the seller and are of no concern to the buyer.[37]

Second, while it is in the interest of ratepayers for LSEs to pay the full PPA price for curtailment that an LSE orders to avoid negative pricing (economic curtailment), it is not clear that this is the practice of all LSEs. In its 2016 RPS Procurement Plan, SCE explained very clearly why payment for economic curtailment is in the interest of ratepayers:

> In instances where SCE has either exceeded the curtailment cap [representing pre-paid economic curtailment] or only has "take-or-pay" economic curtailment rights to begin with, if SCE were not to curtail deliveries in excess of any schedules awarded at positive prices, customers would pay the contract price for that excess delivered energy *and* incur the costs associated with negative pricing in such intervals. SCE's economic bids will therefore serve to further limit customer exposure to negative prices both day-ahead and in real-time, even if SCE ultimately pays the contract price for curtailed energy.[38]

This logic should extend to the practices of all LSEs, but it is far from clear that such economic curtailment is common practice. For example, SCE has stated only that it "will retain the right to curtail at its discretion" (paying for those curtailments).[39] SCE does not commit to using economic curtailment rights as a matter of practice. The Commission should require the IOUs, if not all LSEs, to use their economic curtailment rights to avoid negative pricing and to

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[35] For further elaboration on these issues, see, in this proceeding, Comments of the California Wind Energy Association on Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements (March 21, 2016), Attachment: "Curtailment: The Missing Link Toward a More Diverse RPS Portfolio." Also see, in R.15-02-020, Joint Parties' Motion to Amend ALJ Ruling (June 1, 2016).

[36] See, e.g., definition of "Curtailment Order" in PG&E's pro forma RPS contract. Absent information to the contrary, it is reasonable to assume that CCAs and ESPs likewise do not pay for overgeneration-related curtailments.

[37] However, the utility and other LSEs should not be counting on obtaining the RECs from projected curtailment periods for RPS compliance purposes.

[38] SCE 2016 RPS Procurement Plan, Volume 1, Public Version, at p. 42.

[39] *Id*.

pay all generators (those already contracted, where those rights exist, and those to be contracted) for CAISO-directed, reliability-related generation reductions due to overgeneration conditions.

With regard to renewable energy sellers, they are not in a position to factor curtailment costs into their bids. First, bidders lack the ability to make even a reasonable estimate of overgeneration and have no control over many factors that will bear on overgeneration. For example, bidders are not able to predict how much solar energy will be procured by all LSEs on the CAISO grid, the growth of rooftop solar installations,[40] load growth or future levels of demand-response (such as midday electric-vehicle charging), or energy exports that might reduce curtailment. Second, a conservative assumption will result in a losing bid, if other bidders do not project similarly high curtailment levels. Finally, to the extent that a resource contributes to overgeneration-related reliability curtailment, that curtailment will be spread over many resources. Therefore, if bidders are factoring any curtailment into their bids, it would likely be no more than the bidder's individual share of the average curtailment level expected under the CAISO's practice of uniformly curtailing generators during overgeneration conditions, not the total curtailment that all generators (both existing and planned) will suffer as a result of the bidder's marginal contribution to the need for curtailment.

Hence, bidders are unlikely to factor their marginal reliability-related curtailment costs into their offers. Requiring buyers to pay for economic and overgeneration-related reliability curtailments will compensate sellers for curtailment that they are not in a position to accurately anticipate, and will encourage buyers to fully consider these reliability-related curtailment costs in their procurement decisions.

5. System costs that occur due to sub-optimal portfolios should be subject to recovery from the customers of the LSEs making the procurement decisions

With regard to the Investor-Owned Utilities ("IOUs"), whose procurement plans and actual procurements must be approved by the Commission, the Commission could decide whether to adopt any differing assumptions made by an IOU in developing its Preferred Plan,

[40] 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.

and allow any excess costs or benefits to flow through to IOU customers, or whether to adopt the plan conditioned on such costs being absorbed by shareholders.

With regard to CCAs and ESPs, their customers will incur the direct and indirect costs associated with their procurement choices (assuming that the Commission takes the cost-alignment steps outlined above). However, the Commission must ensure that the incremental costs (or benefits) associated with CCA or ESP plans (as compared to what would result based on the Commission's adopted assumptions and methodology) accrue to these LSEs over the long run.

To the extent that an LSE's customers subsequently decide to take service from another LSE (leaving an IOU and joining a CCA, or returning from a CCA to an IOU), the departing customers' share of the incremental costs should continue to be recovered from those customers. While the various mechanisms for assigning these costs -- such as CCA bonds, shareholder penalties, or direct charges to former ESP or CCA customers -- are outside of the scope of this proceeding, the Commission should make clear in its IRP decision that system costs that occur due to sub-optimal portfolios will be subject to recovery from the customers of the LSEs making the procurement decisions, with the goal of preventing cost-shifting to other customers.

B. Calculating Incremental Cost Indicators

In response to Question 10, above, CalWEA referenced the application of "incremental cost indicators" that can be used to estimate the overall cost impact of adding additional capacity of a specific RPS resource type – similar to the system-wide marginal GHG abatement cost. The incremental cost indicators, which can be calculated as an output of the Reference System Plan, will have two components:

- The incremental fixed-cost indicator (amount of capacity and estimated cost) refers to the cost of new resources (RPS, conventional or storage) that would be needed in an optimal portfolio to address integration needs, mitigate curtailments and make up for lost energy due to curtailment as a result of procuring a particular RPS resource type. The fixed-cost indicators would be expressed as the amount of capacity cost (and estimated fixed cost) that is needed for each MW of RPS resource of each type that is procured.[41]

[41] The cost figure will also inform those LSEs that wish to exceed their RPS requirements of the associated integration costs.

- The incremental variable (operating) cost indicator refers to the cost associated with procuring RPS resources of each type.[42] The operating-cost indicator would be expressed as the variable CAISO-wide cost caused for each MW of a specific RPS resource technology that is procured.

These fixed and variable integration cost indicators for each RPS technology type could be estimated by repeating the reference study and adding a certain amount (say, 1,000 MW) of an RPS technology type to the optimal portfolio and determining the resulting incremental fixed and variable integration costs.[43] All cost indicators so calculated would remain constant for each IRP cycle.

C. Detail on Potential Transmission of Wind Energy on Existing WECC Grid

In response to Question 17, above, we noted that a 2015 WECC case study demonstrates that it is reasonable to expect very limited curtailment, if any, for approximately 3,500 MW of wind energy and 1,800 MW of solar to be accessed through dynamic transfer arrangements with the CAISO (or via an expanded CAISO) across the WECC footprint without any transmission upgrades in view of scheduled coal-plant retirements. In this section, we document and explain that potential.

According to the RETI 2.0 Western States Outreach Project Report (WSOP),[44] there are 3,000 MW of coal units coming offline in the West by 2019, and another 4,000 MW by 2025, creating the ability to "repurpose" for renewables a significant amount of transmission capacity previously used for coal. While it is not clear how much of that 7,000-MW of firm-transmission capability would be available for deliveries to California, it would be reasonable to assume that a

[42] These costs would include the added fuel and O&M costs from existing and new non-RPS resources (conventional generation and storage resources), added A/S (e.g., regulation) procurement cost by the system operator, multi-hour and sub-hourly ramping capacity procurement costs by the system operator due to the addition of each type of RPS resource. For accounting purposes, some of these cost categories (such as generator O&M cost) can be treated as "capital cost."

[43] It is unlikely that these cost indicators can be accurately produced using shadow prices from the production simulation runs for mathematical reasons as these models will produce a portfolio that is close to, but not exactly, the mathematical optimum. Therefore, the shadow prices (derivatives of the total cost for each RPS technology type) are likely to be mathematically anomalous.

[44] RETI 2.0 Western States Outreach Project Report (revised November 2, 2016), p. 20. Available at: http://www.energy.ca.gov/reti/reti2/documents/index.html.

significant portion – at least one-third (approximately 2,500 MW) -- would be available for use in combination with dynamic transfers[45] in the years leading up to 2024.

A 2015 WECC case study, "PC-21: Coal Retirement,"[46] showed that little or no congestion occurs with coal-plant retirements and significant renewable energy additions across the WECC footprint. (See PC-21 slide reproduced below.) Specifically, the following can be gleaned from the PC-21 case study:[47]

- The retirement of over 6,000 MW of coal units that are already scheduled to occur by 2024 will enable approximately 3,500 MW of wind energy and 1,800 MW of solar to be accessed through dynamic transfer (DT) arrangements with the CAISO (or via an expanded CAISO) <u>without any transmission upgrades</u>.[48]

The wind (and potentially solar) supply curve for the IRP study should reflect the WECC transmission that becomes available due to coal plant retirements and the ability to dynamically transfer renewables into the CAISO (or directly interconnect these renewables in an expanded CAISO).

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[45] Within the past two years, four contracts totaling over 700 MW of OOS wind energy have been signed with two California utilities that will utilize dynamic scheduling and out-of-state transmission service using existing transmission lines. See October 27, 2015, SCE Advice Letter 3299-E (Broadview Energy contracts for 324 MW), and February 9, 2016, SCE Advice Letter 3360-E (El Cabo contract for 298 MW). In addition, SMUD has signed a contract for 200 MW from the Broadview project.

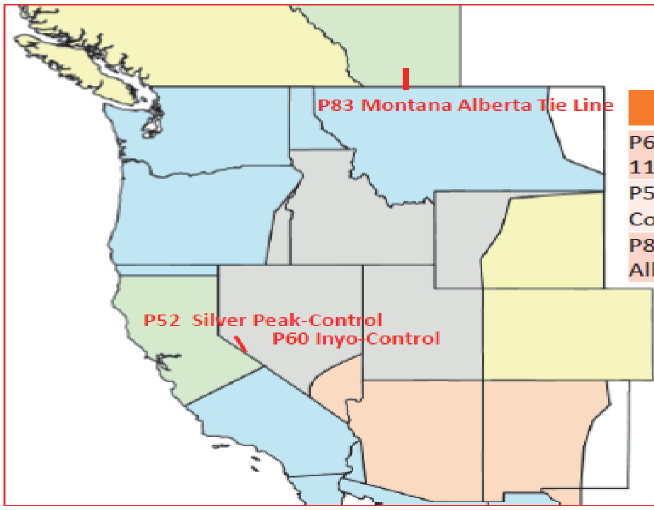
[46] "WECC Reliability Study Requests" (October 28, 2015, presentation). Available at: http://westernenergyboard.org/wp-content/uploads/2015/10/10-29-15_CREPC-SPSC-WIRAB_woertz_WECC_reliability_study_requests.pdf.

[47] The following MW figures were calculated from the TWh figures in the WECC slides. The figures assume the following capacity factors: 45% for wind, 25% for solar, and 85% for coal.

[48] This result can be inferred by scaling down the assumed 16,626 MW of coal retirements in PC-21 by the amount of coal retirements announced at the time of the study (which total 6,157 MW by 2024). Because congestion was found to be very limited under PC-21 assumptions, it is reasonable to assume that scaling down the assumptions by 63% would produce no congestion. This transmission capacity can be utilized for the purpose of dynamically scheduling resources into the CAISO.

11

PC-21 Heavily Utilized Paths



Path	75%	90%	99%
P60 Inyo-Control 115 kV Tie	38%	25%	18%
P52 Silver Peak-Control 55 kV	34%	23%	0%
P83 Montana Alberta Tie Line	20%	11%	7%

WESTERN ELECTRICITY COORDINATING COUNCIL

Source: WECC (see footnote 46).

To elaborate on conditional firm service: currently, the CAISO and WECC require firm transmission service in order to use dynamic scheduling. However, there is no reason why a CAISO and WECC protocol amendment could not enable dynamic scheduling using conditional-firm service, which would allow the direct delivery of far more OOS wind resources with very limited curtailment. The RETI 2.0 WSOP Report noted that financiers of renewable generation projects have historically been disinclined to have a facility's output curtailed in instances when transmission service would not be available under conditional firm service.[49] Overcoming this barrier is likely to be mainly an educational and contractual challenge (as compared to getting land-use permits and raising capital for new transmission lines or getting six states to agree on CAISO governance), since the risk of curtailment under conditional firm service can be strictly bounded in both amount and timing -- critical factors in project finance because it allows potential losses to be quantified. Conditional firm service could enable far more than the 3,500

[49] *Supra* note 44 (WSOP) at p. 9.

MW of wind that could be transmitted with firm transmission service, given that WECC transmission lines, even if reserved, are unused much of the time.[50]

IV. CONCLUSION

CalWEA appreciates this opportunity to contribute to the development of this important process. We urge the Commission to make the necessary changes to ensure that this considerable effort fosters the realization of an optimal overall-system portfolio.

Respectfully submitted,

/s/ Nancy Rader

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On behalf of the California Wind Energy Association

June 28, 2017

[50] See the 2013 WECC Path Rating catalog (later editions are not publicly available). Available at: https://www.wecc.biz/Reliability/TAS_PathReports_Combined_FINAL.pdf.

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 Staff Proposal on Process for Integrated Resource Planning" 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 28, 2017, at Berkeley, California.

/s/ *Nancy Rader*
Nancy Rader
Executive Director
California Wind Energy Association