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 DRAFT INTEGRATED RESOURCE PLANS OF THE LOAD-SERVING ENTITIES

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On behalf of the California Wind Energy Association

September 12, 2018

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Pursuant to the May 14, 2018, Amended Scoping Memo and Ruling of Assigned Commissioner Randolph and Administrative Law Judge Fitch, the California Wind Energy Association ("CalWEA") submits these comments on the draft integrated resource plans ("IRPs") of the individual load-serving entities ("LSEs").

Given the overwhelming task of reviewing so many IRPs, these comments are based on CalWEA's limited review of a sampling of the public versions of the plans, focusing primarily on those of the community choice aggregators ("CCAs"). Based on that review, we raise general concerns about the plans, and the Commission's own Reference System Plan ("RSP") on which those plans are based, and offer recommendations for addressing these concerns.

A. The Commission Should Require Each LSE to Explain Specifically How It Intends to Meet Its Near-Term RPS Obligations; If a Convincing Case Cannot Be Made, the Commission Should Inform LSEs of the Options Available To Meet These Obligations and the Consequences of Failing To Do So

LSEs state in their draft plans that they intend to comply with the state's Renewables Portfolio Standard ("RPS") requirements, including (1) the new requirement that, beginning in 2021, at least 65 percent of RPS procurement for each compliance period be from contracts of 10 years or more in duration or from LSE-owned resources,[1] and (2) the requirement that at least 75

[1] PU Code Section 399.13(b).

percent of eligible renewable energy resource electricity products meet the requirements of Product Content Category ("PCC") 1.[2] However, although a few CCAs acknowledged the long-term contracting requirement[3] and at least one flagged financial status as a challenge,[4] the IRPs of many (if not most) CCAs and ESPs do not address the long-term contracting requirement or there is no detail regarding how, particularly for newly formed or forming CCAs, they expect to be able to establish sufficient creditworthiness to enable them to accomplish these related requirements within two or three years of formation.[5] In one case, an ESP appears to contemplate not meeting the long-term contracting requirement.[6] If even a handful of LSEs prove unable to sign long-term contracts in the near-term, California may not achieve its near-term RPS goals.

As renewable energy trade groups collectively indicated in comments on the Commission's "Green Book,"[7] a main concern with CCAs presently is that they do not possess the same level of creditworthiness as the utilities and there is uncertainty surrounding when and whether most CCAs, which are relatively new, will obtain the level of creditworthiness needed to procure new or repowered renewable resources.[8] A lack of creditworthiness impedes financing

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[2] PU Code Section 399.16(c)(1). PCC 1 products are generally from new or repowered resources that require long-term contracts to enable capital investment. PCC 2 and PCC 3 products tend to be short-term contracts with existing, often out-of-state, projects.

[3] Valley Clean Energy Draft IRP at p. 27; Redwood Coast at pp. 3-4; Silicon Valley at p. 2; Solana Energy Alliance at p. 4.

[4] Valley Clean Energy Draft IRP at p. 27.

[5] See, e.g., the IRPs of Monterey Bay, San Jacinto Power, Rancho Mirage, Pico Rivera (PRIME), Lancaster Choice, Pioneer, Silicon Valley, MCE and Sonoma Clean Power.

[6] See Direct Energy at pp. 10, 13 and 14 ("The majority of DEB's RPS contracts are currently short-term in nature, so changes to DEB's portfolio may be occurring in the coming years." "DEB feels that having short-term contracts and not locking in existing resources for an extended period is a prudent strategy in this dynamic market." "Greater consideration will be made for signing long-term contracts to meet future RPS obligations.")

[7] Comments of the California Wind Energy Association, Independent Energy Producers Association, California Biomass Energy Alliance, Large-scale Solar Association, American Wind Energy Association's California Caucus, Geothermal Resources Council, and the California Low Carbon Fuel & Energy Coalition on the May 2018 draft paper, "California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market" (a.k.a. the "Green Book") (June 8, 2018).

[8] Only one CCA, eight-year-old MCE, has achieved a credit rating, having been awarded a Baa2 rating from Moody's a few months ago. Moody's noted that, among other factors, having to pay

of capital-intensive renewable energy facilities. Further, and related, the CCAs' RPS compliance has, to date, relied heavily on short-term purchases of existing out-of-state resources and on the front-end of new projects built under long-term utility contracts. [9] In stark contrast, starting in 2021, LSEs will be required to procure 65 percent of their RPS resources under long-term contracts. In adopting this requirement, the Legislature appropriately recognized that long-term contracts will be required to truly make a difference in decarbonization (sometimes referred to as "additionality") because long-term contracts foster new renewable energy projects and the major capital investments necessary to maintain existing renewable energy projects. The draft Green Book's Table 2 ominously shows that the "Annual RPS Positions" (percent of portfolio that is RPS compliant) of all but one operational CCA is forecasted to decrease significantly between 2017 and 2018, with many falling well below the 2020 RPS goal of 33%.

While some or all CCAs could ultimately develop the financial strength necessary to shoulder – and even exceed – the state's ambitious climate change goals, it is not at all clear that all, or even most, of the CCAs scheduled to become operational over the next few years will establish sufficient creditworthiness in time to foster the long-term contracting necessary to support new renewables development in the near-term, given the multi-year development lead times that renewable energy projects require. One CCA states that it will not even begin entering into long-term PPA agreements until 2021.[10] Moreover, a stable and sustained market in long-term contracts is necessary to keep existing renewable resources operational in the face of exceedingly low wholesale market prices. As discussed in section B, below, the Reference System Plan assumes that a substantial amount of existing renewable energy capacity – predominantly wind, geothermal and biomass – will remain on line until 2030. But this is a

higher "transition fees" (i.e., an increase in the PCIA) could lead to a credit downgrade. *See California Energy Markets*, "Marin Clean Energy Assigned Moody's Credit Rating," p. 10. (May 18, 2018.)

[9] While several CCAs have recently signed a number of contracts with renewable energy developers, the reality is that Lancaster Choice Energy and Sonoma Clean Power obtained no energy from renewable energy projects constructed to meet their demand in their first two and three years of operation, respectively, and MCE obtained approximately five percent or less of its energy from renewable energy projects constructed to meet its demand in its fourth, fifth and six years of operation. *See* "Correction to Comments of Sempra Services in Response to Questions Regarding Customer Choice Workshop" (January 8, 2018).

[10] EBCE IRP at p. 9.

tenuous assumption, given the operating costs of these resources and, in the case of wind energy projects, the need to repower an aging fleet with modern wind turbines.

For those CCAs and ESPs that cannot make a convincing case that they will be able to meet all of their RPS requirements in the near-term, the Commission should inform each CCA's governing body and each ESP of the options available to meet these obligations and the consequences of failing to do so, including the potential levy of penalties.[11] One option for quickly meeting the long-term contracting requirement that is available to CCAs and other retail sellers is the use of a procurement entity. California Public Utilities Code Section 399.13(f) provides that the Commission "may authorize a procurement entity to enter into contracts on behalf of customers of a retail seller for electricity products from eligible renewable energy resources to satisfy the retail seller's renewables portfolio standard procurement requirements." This procurement entity is then able to "recover reasonable administrative and procurement costs through the retail rates of end-use customers that are served by the procurement entity."[12] To facilitate RPS compliance by CCAs, the Commission should invite all interested persons to submit proposals to serve as a procurement entity on behalf of CCA customers and provide this information to CCA governing bodies and ESPs as an option for meeting their RPS requirements in the near-term. If the procurement entity can be established and commence procurement in 2019, CCA ratepayers and ESP customers will also benefit from capturing imminently declining federal tax credits.

B. In Developing the Preferred System Plan, the Commission Should Correct the Flaws in the Reference System Plan that have Resulted in Draft IRPs that Underestimate Needed Resources and Resource Diversity

As CalWEA pointed out in the lead-up to the adoption of the Reference System Plan, two important, faulty assumptions likely resulted in substantially under-estimating both the volume of wholesale renewable energy that needs to be procured to achieve the state's greenhouse gas

[11] *See* D. 18-05-026 at p. 9 ("Long-term procurement is at the core of RPS program and a central legislative mandate, and the current enforcement scheme is carefully designed to promote long-term procurement. Lower (differential) penalties for not meeting the long-term procurement goals would undermine the core mandate of the RPS program.").

[12] Cal. Pub. Util. Code §399.13(f)(2).

("GHG") and RPS goals and to achieve the optimal amount of resource diversity that should be reflected in that procurement.

First, the assumed behind-the-meter ("BTM") solar levels were far too high – nearly 16 GW by 2030 (which has grown to nearly 20 GW in the latest analysis) – a result of the assumption that current Net Energy Metering ("NEM") rates will continue indefinitely. The RESOLVE modeling results showed that reducing BTM solar to 9 GW would save ratepayers $682 million/year in the 42 MMT case,[13] but even this figure (which still does not reflect optimal levels) reflected only BTM-solar installation costs, not total ratepayer impacts. If 16 GW were realized under current NEM rates, it would result in a cost shift on the order of <u>$4 billion annually by 2030</u>.[14] A more reasonable BTM estimate would be many fewer gigawatts than the 16 GW assumed, resulting in a greater need for wholesale renewable energy than is currently reflected in the RSP.

Second, the RSP was based incorrectly on the assumption that existing, mostly pre-RPS, renewable resources operating outside of long-term contracts will continue to operate until 2030.[15] But most existing, pre-RPS resources will need to be re-contracted or replaced in order to maintain the assumed baseline level of renewable resources. In the case of wind energy, over 1,000 MW of these projects would be 40 years old in 2030, and, given the cost to keep these projects operating, the assumption that these resources will continue to operate based on short-term CAISO market prices is highly questionable. The assumption is even more dubious when applied to a much larger quantity of existing biomass and geothermal resources, whose operating costs are substantially higher than those of existing wind resources.[16] The overly optimistic assumption that the current, very diverse baseline of renewable resources (see Figure 1) will

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[13] September 19, 2017, *Ruling Seeking Comment on the Proposed Reference System Plan and Related Commission Policy Actions* Ruling, Attachment A, PDF-page 202.

[14] CalWEA estimate, based on data provided to CalWEA by the three investor-owned utilities. CalWEA strongly encourages the Commission to make its own assessments of ratepayer impact when contemplating BTM-solar levels.

[15] In assuming that only 200 MW of California wind will be available to it, EBCE, for example, appears to have ignored the availability of up to 1,000 MW of existing pre-RPS wind energy resources that need to be repowered.

[16] Calpine demonstrated in its October 26, 2017, Comments on the Proposed Reference System Plan that existing geothermal would be cost-effective in the 2030 portfolio – although apparently not in the interim, presumably due to relatively high operating costs.

persist regardless of going-forward purchases led to a solar-dominated plan that almost certainly skewed downward the estimated need for non-solar resources in going-forward procurement.[17]

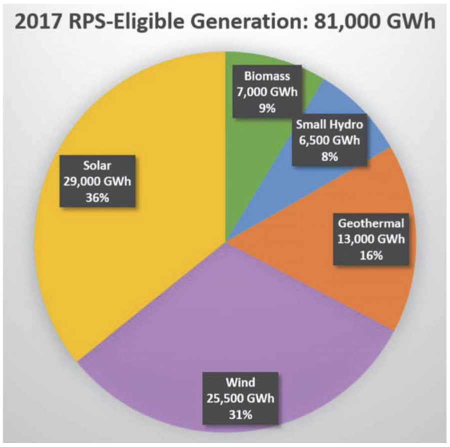

Figure 1. The current overall portfolio is very diverse, but many non-solar resources are without long-term contracts.
Source: Tracking Progress, California Energy Commission (July 2018).
(Data is statewide.)

Unsurprisingly, therefore, the draft IRPs of some ESPs and CCAs indicate heavy reliance on solar resources in going-forward procurement[18] and overall procurement will be insufficient to meet load or RPS requirements if the assumed high levels of BTM solar do not materialize. Moreover, based on representative CCA IRPs[19] that reflect high levels of procurement from large hydro projects, the overall effect of the CCAs' procurement seems to be that much of California's current resource diversity will be replaced with NW hydropower, which may not be

[17] The recommended portfolio of additional resources to meet the 42 MMT GHG planning target in the RSP included approximately 9 GW of new utility-scale solar, 1,100 MW of in-state wind; and 2,000 MW of battery storage in addition to existing baseline resources whose continued operations were assumed.

[18] For example, the Conforming/Preferred portfolio of the Clean Power Alliance of Southern California ("CPA") through 2028 consists of approximately 90% solar (Table 2). Direct Energy's portfolio includes 85% solar "because it's the lowest cost." EBCE's portfolio is dominated by solar and large hydro resources (Table 2). Valley Clean Energy ("VCE") indicates (p. 18) that, if it has the opportunity, lower cost renewable energy supplies than shown in its plan "would most likely be considered and contracted for." Solana Energy Alliance states (at p. 4) that its "IRP team decided on adding the lowest cost utility scale solar resources for SEA's conforming portfolio" (which also serves as its preferred portfolio).

[19] See note 22 *infra.*

dependably available due to lack of firm transmission capacity or in dry years as discussed below in section C.

In modeling the Preferred System Plan, therefore, the Commission should place in the supply curve all existing renewable resources that do not have contracts running through 2030 (with existing wind taking the form of potentially repowered projects). This exercise is likely to show that (a) the retention of existing/repowered wind resources would be cost-effective (particularly if procured in the near-term while tax credits are still available), and (b) some existing non-solar renewable resources are likely to decline, leading to a need for additional wind resources and/or more storage. Conducting this analysis this year is important to enable and encourage LSEs to capture the full value of wind energy tax credits with contracts signed in 2019,[20] and solar/storage tax credits in the near term.

C. The Commission and LSEs Should Address Cost and Reliability Issues Associated with LSE Proposals to Rely Heavily on Northwest Hydropower

With at least one notable exception,[21] most of the CCAs' draft plans propose to rely substantially on Northwest ("NW") hydropower to meet load as well as their required and aspirational GHG targets.[22,23] Although some CCAs perfunctorily note the existence of hydro-

[20] IRS guidance enables PTC-qualified wind turbines to count towards the 2016 "begin construction" date that enables 100% capture of the PTC; after that date, a facility using these turbines must be placed into service within four calendar years, i.e., the end of 2020. In this way, contracts with projects using PTC-qualified turbines that are signed in 2019 can potentially allow capture of 100% of the PTC for projects that can be constructed in 2020. 80% of the PTC could be captured for projects that come on line by the end of 2021.

[21] Peninsula Clean Energy's draft IRP is a relatively detailed and thoughtful document. Importantly, PCE's planned portfolio does not include large hydro, and increasingly seeks to meet its load with a diversity of renewables on an hourly basis, while recognizing (p.10) that challenges remain with regard to matching resources and load.

[22] For example, the following CCAs include these amounts of large hydropower in their plans for 2030: Sonoma Clean Power – 415 MW; MCE – 250 MW; San Jose – 629 MW; SVCE – 775 MW; CPSF – 395 MW; EBCE – 1,240 MW; CPA – 70 MW; Pioneer – 37 MW (total: 3,811 MW).

[23] This discussion sets aside the fact that purchases of large hydropower are unlikely to make any positive difference in overall GHG emissions and may have negative GHG impacts, calling into question whether these resources should qualify as "GHG free" at all. See CalWEA's opening and reply comments (April 20, 2018, and April 30, 2018, respectively) on the Commission's Ruling Seeking Comment on Greenhouse Gas Emissions Accounting Methods and Addressing Updated Greenhouse Gas Benchmarks in this proceeding.

related risks in their cookie-cutter plans,[24] it is not at all clear that most CCAs planning to rely on hydropower have seriously contemplated the various challenges related to the availability of that resource that may affect their long-term plans, both individually and collectively and, in turn, how grid reliability may be affected. For example, EBCE's IRP, which shows large hydro accounting for about a third to a half of its portfolio through 2030, contains no details related to procuring this resource,[25] and, further, states that it "does not expect to encounter material risks in procuring its Conforming (Preferred) Portfolio."[26] Similarly, the draft IRPs of Silicon Valley Clean Energy, Sonoma Clean Power and MCE do not mention the risks associated with their planned reliance on hydropower.[27]

The Commission and the CCAs should not underestimate the risk of over-reliance on NW hydropower. The Pacific Northwest relies on its hydropower plants for about two-thirds of its electricity use.[28] In a bad water year, it can find itself "with generating capacity for our peak hours, but without enough water (fuel) to provide the total electricity needed over the whole year."[29] In addition, production from reservoir-hydropower facilities is bounded by many complex constraints including regulatory obligations to contracted purchasers, environmental

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[24] The draft IRPs of San Jacinto (at p. 8), Rancho Mirage (at p. 7), Pico Rivera (PRIME) (at p. 8), and Lancaster (at p. 8) contain virtually the same statement of risk: "the potential for reduced availability of large hydro-electric energy due to draught [sic] or increasing demand."

[25] "With respect to achieving EBCE's remaining carbon-free procurement goals, 75% of EBCE's 2030 above-RPS clean energy targets are assumed to be met via long-term large hydro PPAs. The remainder of EBCE's clean energy target is assumed to be met via short-[t]erm large hydro contracts." (EBCE Draft IRP, p. 9.) Similarly, with regard to ensuring the reliability of its portfolio, details are sparse: "EBCE is assumed to purchase resource adequacy capacity to serve 1.15 times its monthly maximum load." (EBCE Draft IRP, p. 7.) Likewise, VCE "assumes that the price premium for carbon-free energy will remain similar to today's levels also during the 2022-2030 timeframe." (VCE Draft IRP at p. 14). In its August 31, 2018, response to PG&E's first data request, VCE states that it "used the 'large hydro' category as a placeholder for GHG-free energy expected to be procured in the 2018-2030 period."

[26] EBCE Draft IRP, p. 11.

[27] SVCE's default option consists of 50% large hydroelectric; SCP's 2030 portfolio includes 415 MW of large hydropower, and MCE's 2030 portfolio is comprised of 20% large hydropower, most of which is currently under short-term contracts (see MCE Table 3).

[28] See, e.g., BPA's "Guide to Tools and Principles for a Dry Year Strategy" (2006). (Available at https://www.bpa.gov/p/Generation/Dry-Year/DryYear/11-2006_Final_Dry_Year_Tools_and_Principles.pdf.)

[29] *Id.* at p.1.

requirements, and operational constraints of the generation equipment. In addition, NW hydropower plants are used to balance hourly variability. To address dry-year risks, the Bonneville Power Administration ("BPA") has developed general guidelines for handling dry-year challenges.[30] The long-standing beneficiaries of BPA hydropower can be expected to jealously guard their interests as they have in the past; therefore, it is reasonable to assume that CCA energy contracts will not be high on their priority list during dry years. Even simply modeling these challenges will be very difficult.[31]

The CCAs' long-term plans could, collectively, result in California becoming overly reliant on NW hydropower resources, while losing the diversity of its current resource mix as discussed above. This dependence could present operational risks to the CAISO system, particularly given the lack of available firm transmission capacity required to import such hydropower when needed for system reliability, such as meeting system-ramp needs. The Commission should ensure that the CCAs address these challenges in their final IRPs. The Commission should also consider these challenges in developing its Preferred System Plan.

If the CCAs intend to use hydropower imports to provide system or flexible resource adequacy ("RA") capacity, the CCAs must obtain firm power purchase contracts and firm transmission rights on the California-Oregon Intertie ("COI"). In addition, the CAISO should be able to control these resources, particularly if needed to meet system ramp needs, which will require dynamic scheduling. All of the firm transmission capacity rights for the 4,800 MW of capacity on the COI is, however, held by California municipal and investor-owned utilities. Unless virtually all of these rights are relinquished and transferred to the CCAs – which are collectively proposing to use much, if not all, of that capacity[32] – the CCAs will not be able to secure firm transmission rights for their imported hydropower, short of upgrading the COI.

To the extent that hydropower resources are aimed at energy use alone, the CAISO currently has various existing mechanisms to ensure that it has sufficient energy in the event that

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[30] *Ibid.* This document is intended to guide BPA "through future critical periods marked by abnormal conditions such as drought, volatile market prices, and/or significant reductions in the availability of power to BPA."

[31] National Renewable Energy Laboratory, *Hydropower Modeling Challenges* (NREL/TP-5D00-68231) (April 2017). Available at https://www.nrel.gov/docs/fy17osti/68231.pdf.

[32] See note 22 *supra.* From our review, just eight of the CCAs alone propose to procure 3,811 MW of large hydropower capacity.

NW hydro is unavailable, or LSEs can secure replacement resources themselves. However, if CCAs are collectively over-relying on NW hydro, and/or the Northwest has a dry year or an extended drought, the CAISO's current capabilities could be over-taxed. The Commission and the CAISO should anticipate the potential need for greater reliability reserves in the very near future when more CCAs are operational and relying heavily on NW hydro, especially as California's gas plants and existing, pre-RPS renewable energy facilities may retire.

The Clean Net Short ("CNS") GHG accounting methodology gives LSEs an incentive to ensure that their hydropower resources follow load, because hydro that is not used to meet demand will not earn GHG-free credit. However, using hydropower as a load-following resource will require LSEs to schedule deliveries with firm transmission rights from specific hydropower resources to their specific loads on an hourly basis (or 15-minute-basis when that becomes available). This is typically significantly costlier than purchasing hydropower in blocks, and is uncertain, as discussed above, in the face of limited firm transmission rights and drought, particularly an extended drought. The Commission should require CCAs to demonstrate that they have considered the costs and transmission rights associated with using large hydropower for load-following purposes and the dry-year risks associated with these "GHG-free" resources.

D. Many IRPs Appear to Be Too Vague to Support a Meaningful Preferred System Plan; Alternative Methods Will Be Needed to Minimize Indirect System Costs

Beyond the lack of specificity mentioned above, the public versions of some ESP and CCA plans – conforming, preferred or otherwise – lack meaningful, concrete information as to what LSEs actually plan to procure, and when, and some do not conform to the Commission's Reference System Plan. For example, Direct Energy's portfolio includes 85% solar "because it's the lowest cost" (p. 9). Valley Clean Energy ("VCE") indicates (p. 18) that, if it has the opportunity, lower-cost renewable energy supplies than shown in its plan "would most likely be considered and contracted for."[33] Similarly, the objective of EBCE's IRP analysis (p. 5) is to "determine the least-cost set of resources to serve its loads over the IRP procurement horizon"

[33] VCE also states (at p.7) that the objective of its IRP is to "provide guidance for VCE's Board, executive management and the public regarding the relative power supply cost impact of various long term resource options … and to ensure that these options are strategically aligned with VCE's short and long term vision." VCE explains (at p. 4) that "the choice of resource path is uncertain" and its "resource plan may therefore be adjusted according to market developments over the next several years."

and Sonoma Clean Power (at p. 4) states its IRP objectives as demonstrating that it has a resource plan to meet its CEC 2017 IEPR load forecast through 2030 and that its resource plan meets the 2030 GHG Emissions Benchmark – neither CCA mentions the objectives of minimizing total system costs or conforming to the RSP's optimized portfolio. One ESP claims that its small size may require divergence with the RSP.[34]

One of the primary purposes of integrated resource planning is to determine whether system resources, such as storage, will be needed and whether procurement of those resources should be ordered by the Commission to ensure reliability. Given the ambiguity of many of the plans and their lack of conformance with the RSP, however, it is difficult to imagine how Energy Division will be able to assemble these plans into an aggregated Preferred System Plan that will be at all predictive for the purpose of guiding system-wide planning. It is far from clear that the sum of LSE portfolios will add up to the RSP (including the diverse resources in the baseline) or any facsimile; instead, the sum of the plans (if realized) could trigger significant system costs or jeopardize system reliability.

This lamentable situation underscores a proposal that CalWEA made earlier in this proceeding: that, until the Commission is prepared to direct the procurement of each LSE to conform to the overall optimal portfolio, each LSE should be held accountable to pay for the total system costs that are caused by its planning and procurement choices, rather than shifting those costs to other LSEs. Cost-responsibility can be achieved in three specific ways:

1. Individual LSE plans 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 CAISO, based on the assumptions used to generate the Reference System Plan;

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; and

3. To ensure that curtailment costs are fully accounted for in planning and procurement, the Commission should require all LSEs to pay for all instructed curtailment based on economic conditions, as well as for emergency overgeneration-related curtailments, and fairly apportion the costs of actual curtailment among LSEs based on the contribution of each LSE to the problem.

[34] Just Energy Solutions Draft IRP at p. 6.

CalWEA discussed these issues in detail in Section III of its June 28, 2017, Comments on Staff's Proposal on the Process for Integrated Resource Planning.

Respectfully submitted,

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September 12, 2018

VERIFICATION

I, Nancy Rader, am the Executive Director of the California Wind Energy Association. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the foregoing copy of "Comments of the California Wind Energy Association on Draft Integrated Resource Plans of the Load-Serving Entities" 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 September 12, 2018, at Berkeley, California.

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