DOCKETED

Docket Number:	17-IEPR-01
Project Title:	General/Scope
TN #:	221757
Document Title:	Comments of the American Wind Energy Association California Caucus on the 2017 Draft IEPR
Description:	N/A
Filer:	System
Organization:	American Wind Energy Association California Caucus
Submitter Role:	Public
Submission Date:	11/13/2017 4:55:50 PM
Docketed Date:	11/13/2017

Comment Received From: Danielle Osborn Mills
Submitted On: 11/13/2017
Docket Number: 17-IEPR-01

Comments of the American Wind Energy Association California Caucus on the 2017 Draft IEPR

Attached please find Comments of the American Wind Energy Association California Caucus on the 2017 Draft IEPR.

Please let me know if you have any questions.

Many thanks,
Danielle Mills

Additional submitted attachment is included below.

November 13, 2017

California Energy Commission
Dockets Office, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

RE: Comments of the American Wind Energy Association California Caucus on the October 23, 2017 Draft IEPR (17-IEPR-01)

Dear Chair Weisenmiller and Energy Commission Staff,

The American Wind Energy California Caucus (AWEA California Caucus or ACC) provides the following comments on the 2017 Draft Integrated Energy Policy Report (Draft IEPR). In these comments, ACC highlights the need for early procurement to capture the fleeting opportunity of the federal Production Tax Credit ("PTC"). As California energy agencies grapple with changes in the retail electricity markets, the State must keep in mind that while customer load is shifting, it is not leaving California. To the contrary, the Draft IEPR forecasts that statewide load will grow.

The RPS will continue to play a critical role in meeting the state's aggressive environmental targets. Utility scale renewables can and should be proactively procured in a way that balances California's current system and minimizes costs for California ratepayers. Realizing these benefits will require near-term coordination among the agencies on both procurement and transmission planning. In the context of the IEPR, the CEC should re-evaluate the rate at which the CEC expects new CCAs will form. The CEC should make recommendations regarding the need to capture the value of federal tax incentives. The CEC should also coordinate with the CPUC and the CAISO on the development of the 2018-2019 Transmission Planning Process ("TPP") to better address regional transmission needs and opportunities. These refinements will put the California's load serving entities (LSEs) on the best path to meeting the longer term RPS targets at least cost for all California ratepayers.

1. RPS Procurement Must Be Aligned with the California Energy Demand Forecast.

The state's three largest investor-owned utilities (IOUs) claim no need for new RPS resources until 2025 at the earliest, in large part due to estimates of customer load-shifting to CCAs, direct access, and distributed resources.[1] For example, PG&E, in its 2017 RPS Plan,

[1] See RPS Plans filed on July 21, 2017 in CPUC RPS Proceeding, R.15-02-020. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M197/K205/197205668.PDF

contends that CCAs and distributed energy resources (DERs) could grow to serve approximately 85% of the IOU retail load over the next decade, and that CCAs and DERs will likely dramatically decrease PG&E's retail sales projections.

Load-shifting is frequently used as a basis for avoiding procurement by IOUs. The CEC plays an important role in framing this debate because the CEC is responsible for developing demand forecasts and making recommendations on statewide energy policy. As noted in Figure 30 of the Draft IEPR, statewide consumption is expected to grow, largely due to increased demand for electric vehicle charging. In light of these load growth assumptions, ACC contends that a more prudent option than deferred renewable energy procurement would be for the energy agencies to ensure that future load growth as predicted by the CEC is met with lowest-cost, and best-fit renewable resources. The obligation to procure renewable energy ought to be assigned to the LSE with existing load to avoid more expensive procurement of renewable energy in the future. For a limited time, low-cost, high capacity-factor wind is available at a significant discount due to declining federal tax incentives. If California does not capture this fleeting opportunity, the longer-term costs of complying with the current RPS (let alone an expanded RPS) will be considerably higher than waiting until the early 2020s to procure additional renewable energy resources. To capture these benefits and allow sufficient time for construction, contracts must be in place before the end of 2018.

To help emphasize the need to capture the benefits of early procurement, the Commission should include an additional recommendation in Chapter 2 (Implementing SB 350) that recommends early procurement of utility scale renewable energy resources that can capture federal tax incentives. The Commission should also include a recommendation in Chapter 6 (Electricity and Natural Gas Demand Forecasts) regarding reliance on CCA load change assumptions. Refinements to the PCIA methodology in R.17-06-026 may change the economics and timing of forming new CCAs. If CCA load assumptions continue to affect the utilities' approaches to procurement, then California should develop more realistic projections of CCA load growth (i.e., projections that consider more than just whether a particular municipality is exploring CCA formation).

For additional information on both the Production Tax Credit timeline and projected load growth to satisfy the RPS, ACC submits its comments filed in the RPS proceeding (R. 15-02-020) into this docket as Attachment A.

2. The CEC Should Encourage Regional Transmission Planning in the Context of the CAISO's Transmission Planning Process.

The AWEA California Caucus encourages the CEC to use the 2017 IEPR, and particularly the Strategic Transmission Plan (Chapter 5), to encourage greater coordination between the CEC, CPUC, the CAISO and other California transmission planners regarding the consideration of higher, more geographically and technologically diverse RPS portfolios in the TPP.

The report notes that transmission congestion forecast, especially within and into California, for 2026 is not enough to justify potential transmission upgrades. While this is true, it may be in large part due to the fact the ISO is not studying 50% renewable scenarios as part of the general TPP. This tends to decrease the amount of congestion that may be observed on the system. Thus, there may be more congestion observed in upcoming TPPs where a full 50% RPS is studied as part of the analysis. The full economic value of transmission under a 50% RPS has not yet been fully examined by the CAISO. Furthermore, congestion relief is not the only benefit transmission capacity expansion can provide. Transmission capacity can also provide the California market with lower cost renewable resources such as wind resources located in New Mexico and Wyoming as the RETI 2.0 outlined.

The Draft IEPR also emphasizes the use of existing transmission. The existing transmission system in the Western Interconnect includes large capacity systems to interconnect the West Coast states and connections to large coal resources in the interior states including Arizona, New Mexico, Nevada and Utah. Unfortunately, these large resources are not located at the best wind resource areas in New Mexico and Wyoming. To access these wind resource areas, a combination of more effective use of existing transmission *plus* new transmission to best use these existing systems is required. The CAISO and other California transmission owners should be encouraged to work together to determine how their existing systems can be best utilized in the future and what additional transmission expansion makes the most sense to access the wind and other renewable resources areas in New Mexico and Wyoming. ACC notes that the use of advanced transmission technologies and transmission right-sizing are good strategies that can be beneficial to delivering more renewables and optimizing the use of disturbed lands.

Regarding regional coordination, the Draft IEPR discusses the Energy Imbalance Market (EIM) and opportunities for a regional grid operator. While the benefits of the EIM are significant, the EIM doesn't significantly help increase the delivery of new renewables to CA, because it is a short-term market and no new renewable generation or transmission will be built to solely due to EIM opportunities. Regional coordination amongst transmission entities should start with the California regional entities and should expand to include other regional entities that may be interested in sharing the benefits and costs of the new regional transmission investments.

The Draft 2017 IEPR does not address the value of accessing out-of-state renewable resources, such as high capacity factor regional wind, that could reduce renewable curtailments in state and provide complementary renewable generation in the evening hours as solar generation declines. ACC suggests that as an important first step toward enhanced regional coordination, new transmission lines can help CAISO access low-cost renewables from the western region. It is important for the appropriate transmission planning processes to take place to ensure sufficient renewables can be delivered from out-of-state resources into California.

AWEA AMERICAN WIND ENERGY ASSOCIATION
CALIFORNIA CAUCUS

The Strategic Transmission Plan primarily focuses on ways the Commission can further develop and refine the RETI 2.0 results.[2] While ACC appreciates the Commission's desire to continue to develop and refine the RETI 2.0 results, the Commission should also be focused on integrating the RETI 2.0 results into the appropriate OATT transmission planning processes, including the CAISO's TPP. We believe more is needed in the near term because regional transmission planning will play an integral role in how the utilities meet their 2030 IRP targets. Currently, the TPP and similar processes by municipal utilities are the primary venue that will enable California utilities to access regional wind renewable resources with high capacity factors and that best compliment California's existing renewable portfolio.

As the Draft IEPR points out, there is likely an abundance of renewable energy technology to meet California's RPS benchmarks, but very few transmission options exist to satisfy demands of the energy market.[3] Proactive, regional transmission planning is necessary to access the high capacity factor wind resources in New Mexico and Wyoming, and the TPP remains a key near-term process for procuring the transmission needed to access these resources.

ACC recommends that the CEC and CPUC direct the CAISO and other California transmission groups to include a policy-driven case that studies at least 1,500 MW of wind from Wyoming and at least 1,500 MW of wind from New Mexico as part of the 2018-2019 TPP. This policy-driven case would allow for formal transmission decisions to be made in the first quarter of 2019 (i.e., in time to capture PTC-eligible resources in these regions). ACC also recommends that the CEC include an additional recommendation in Chapter 5 that the CAISO consider refinements to provide new opportunities for coordination with other balancing authority areas in the TPP to better account for regional transmission planning needs.

AWEA California Caucus appreciates the Commission's consideration of these comments.

/s/ Danielle Osborn Mills

Danielle Osborn Mills
Director
American Wind Energy Association California Caucus
1970 Meadow Oak Lane
Meadow Vista, CA 95722
(916) 320-7584
danielle@renewableenergystrat.com

[2] See for example, recommendations on p. 170.
[3] Draft IEPR at p. 143

AMERICAN WIND ENERGY ASSOCIATION

CALIFORNIA CAUCUS

Attachment A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF THE AMERICAN WIND ENERGY ASSOCIATION CALIFORNIA CAUCUS ON THE RENEWABLE PORTFOLIO STANDARD PROCUREMENT PLANS SUBMITTED BY THE LOAD-SERVING ENTITIES

Danielle Osborn Mills
Director, AWEA California Caucus
Renewable Energy Strategies
1970 Meadow Oak Lane
Meadow Vista, CA 95722
(916) 320-7584
danielle@renewableenergystrat.com

August 18, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

COMMENTS OF THE AMERICAN WIND ENERGY ASSOCIATION CALIFORNIA CAUCUS ON THE RENEWABLE PORTFOLIO STANDARD PROCUREMENT PLANS SUBMITTED BY THE LOAD-SERVING ENTITIES

I. Introduction

The American Wind Energy Association California Caucus (AWEA California Caucus, or ACC) respectfully submits these Comments on the Renewable Portfolio Standard Procurement Plans Submitted by the Load-Serving Entities (LSEs). On August 10, 2017 ACC submitted a motion for party status in R.15-02-020 in accordance with Section 1.4 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure. ACC submits these comments today as a ruling on that motion is still pending.

II. Summary of Recommendation

In these comments, the AWEA California Caucus contends that the RPS plans – collectively – do not sufficiently account for future statewide need, and that further aggregated evaluation by the Commission is necessary to ensure timely and affordable procurement of renewable energy. ACC also asserts that early procurement of utility-scale wind, solar, and storage to capture savings associated with the federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) can serve future forecasted statewide need at lowest cost. Thus, ACC recommends that the Commission identify which LSEs are responsible for procuring renewables to meet future need—according to current load within their respective territories—and encourage near-term procurement of utility-scale renewables to ensure that LSEs achieve their respective RPS targets expeditiously and at lowest cost.

III. 2017 RPS Plans do not accurately assess long-term need consistent with the California Energy Demand Forecast.

ACC is not convinced that each of the CPUC-jurisdictional retail sellers have fully assessed future renewable energy need. We are concerned that such uncertainty may ultimately lead to under-procurement, and thus higher costs for all customers in achievement of RPS requirements.

The state's three largest investor-owned utilities (IOUs) claim no need until 2025 at the earliest,[1] in large part due to estimates of customer load-shifting to community choice aggregators (CCAs), direct access, and distributed resources. For example, PG&E, in its 2017 RPS Plan, contends that CCAs, DA, and DER could grow to serve approximately 85% of the IOU retail load over the next decade, and that CCAs and DERs will likely dramatically decrease PG&E's retail sales projections.[2] This load-shifting is frequently used as a basis for avoiding procurement by IOUs; in this proceeding, PG&E and Sonoma Clean Power served a Notice of

[1]In RPS Plans, filed on July 21, 2017, PG&E and SDG&E claim no RPS need until 2030, and SCE claims no need until 2025.

[2]California Public Utilities Commission, Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework. Energy Division Staff White Paper. May 2017.

Ex Parte Communication for joint meetings to suggest that "it is prudent to avoid having PG&E incur additional costs which may later be subject to debate over cost allocation." Therefore, PG&E expressed that despite its preference for renewable energy, "PG&E wants to stop procuring additional resources to stop adding to its already-long portfolio."[3] At the same time, the State's four largest CCAs have less than 1,000 MW of new resources contracted, and plan to meet remaining need with existing contracts.[4] Similarly, energy service providers (ESPs) claim minimal need.

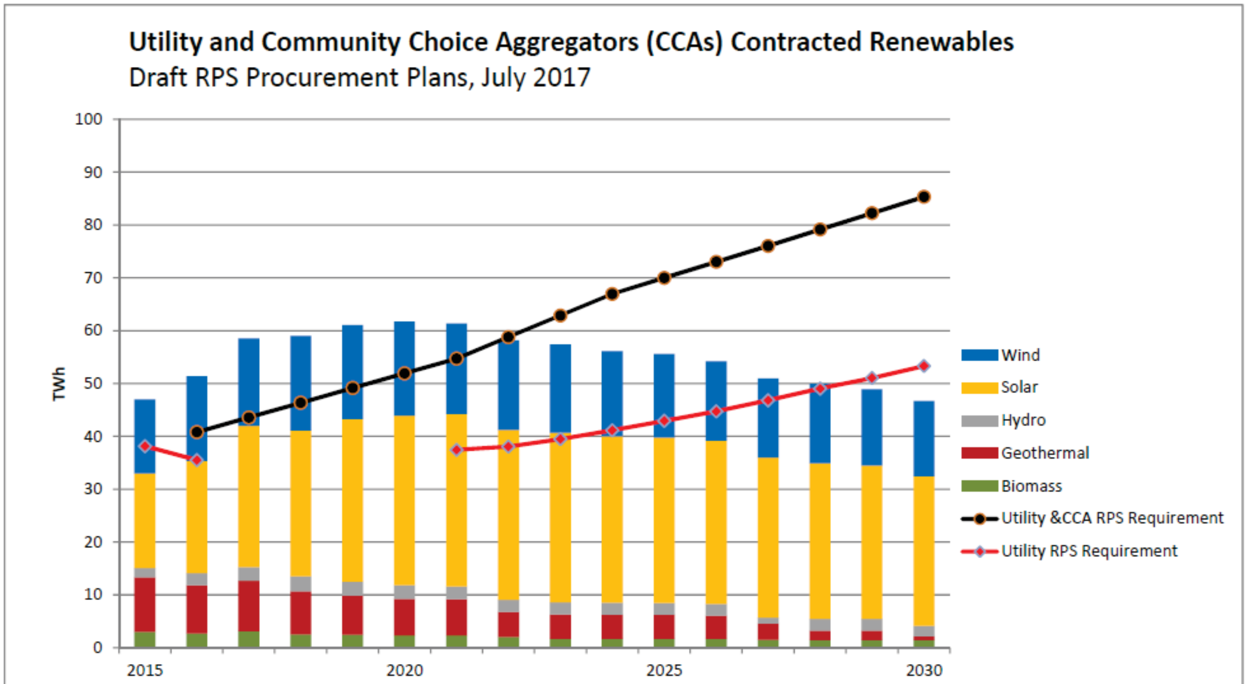
It is curious to ACC that collectively, CPUC-jurisdictional LSEs perceive need for less than 1 GW of new renewable procurement over the next 8 years in light the California Energy Commission's (CEC) Preliminary 2017 California Energy Demand Updated Forecast (Preliminary 2017 CEDU Forecast), which suggests growth of annual sales at 0.32%.[5] This discrepancy suggests that some portion of the California load—beyond that which is served by publicly-owned utilities (POUs)—is not represented in the 2017 RPS plans. Based on an initial analysis of the forecasted RPS requirement of the three major IOUs, the existing CCAs and the forecasted pending CCA load compared to the existing RPS contracts of the three IOUs and four of the state's largest CCAs, ACC projects future need for renewable contracts beginning as early as 2019 for certain LSEs. This analysis is based on extrapolating the actual IOU bundled load plus the existing CCA load for 2016 with the average mid-level annual growth rate from the

[3] Pacific Gas and Electric Company and Sonoma Clean Power Authority Joint Notice of Ex parte Communication with Sandy Goldberg, Advisor to Commissioner Clifford Rechtschaffen – Re.: RPS Program – R.15-02-020. 24 July 2017.

[4] MCE has 11 contracts for new renewable energy, totaling approximately 630 MW. SCPA has entered into contracts with two facilities (~60 MW) that are not yet in commercial operation. Lancaster Energy Choice intends to meet RPS requirement with existing contracts. Peninsula Clean Energy has entered into two new contracts for solar PV, totaling 240 MW.

[5] Preliminary California Energy Demand 2018-2028 Forecast. Annual growth from 2015–2027 for the CED 2017 Preliminary scenarios averages 0.70 percent, 0.32 percent, and -0.02 percent in the high, mid, and low cases, respectively.

CEC forecast, multiplied by the RPS target amounts in 2020, 2024 2027 and 2030 to meet the SB 350 mandate. The IOUs' procurement plans include bundled load forecasts that include their assumptions of "departing load" moving to unformed CCAs. These yet-to-be-formed CCAs have not submitted RPS Procurement Plans since they are not operational—nor is it certain they will become operational let alone in what timeframe. Presumably these pending CCAs do not have contracts for resources, renewable or otherwise. The graph below depicts the aggregate net short position for the combined IOU bundled load plus the CCAs.



Utility & CCA RPS Requirements based on forecasted growth in load, net of behind-the-meter solar and energy efficiency (0.32%/year, per the CEC IEPR preliminary forecast) multiplied by RPS goals.
Utility RPS requirement based on data from IOU Draft RPS Procurement Plans (PG&E, SCE and SDG&E).
Utility &CCA contracted RPS Renewables from Draft RPS Procurement Plans (only includes the four major existing CCAs - MCE, SCPA, Peninsula and SVCE - representing 85% of the existing CCA load).

This analysis does not include the IOU REC banking optimization plans or anticipated REC sales to CCAs since this data is redacted from the public. Banking and IOU assumptions for shifting or departing load appear to be the drivers for the IOUs stated position of no need for renewable procurement to serve their assumed bundled load through 2030. However, the position of the existing and yet-to-be-formed CCAs' load, potentially representing millions of California consumers, is not clear. Also unclear is which LSE is currently responsible for these consumers.

ACC contends that a more prudent option than this deferred procurement would be for the Commission to consider existing load and ensure that future load growth as predicted by the CEC is met with lowest-cost, best fit renewable resources. The obligation to procure renewable energy ought to be assigned to the LSE with existing load to avoid more expensive procurement of renewable energy in the future. For a limited time, low-cost, high capacity-factor wind is available at a significant discount due to declining federal tax incentives; a failure to serve load with this low-cost resource that the Commission has already acknowledged to be a key piece of our 2030 portfolio under the goals of SB 350 and SB 32 would result in increased costs to California ratepayers.

IV. Early procurement will allow California LSEs to satisfy RPS requirements at lowest cost.

A broader understanding of the availability of federal tax credits is necessary to understand the urgency of renewable procurement. ACC points the Commission to the U.S. Energy Information Administration document *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017.*[6] The EIA describes the availability of federal tax credits for certain renewable generation facilities in the following way:

> **"Production Tax Credit (PTC):** New wind, geothermal, and biomass plants receive a \$23/MWh (\$12/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service

[6] U.S. energy Information Administration: Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017. P. 2. https://www.eia.gov/outlooks/aeo/electricity_generation.cfm

if the plants are under construction before the end of 2016. After 2016, wind continues to be eligible for the production tax credit, but at a dollar per kilowatt-hour rate that declines by 20% in 2017, 40% in 2018, 60% in 2019, and expires completely in 2020. Based on documentation released by the Internal Revenue Service (IRS) (see https://www.irs.gov/irb/2016-23_IRB/ar07.html), EIA assumes that wind plants will be able to claim the credit up to four years after beginning construction. As a result, wind plants entering service in 2019 will receive the full credit, and those entering service in 2022 will receive $14/MWh (inflation-adjusted).

Investment Tax Credit (ITC): New solar PV and thermal plants are eligible to receive a 30% investment tax credit on capital expenditures if the plants are under construction before the end of 2019, after which the ITC tapers off for new starts to 26% in 2020, and 22% in 2021. In 2022, the ITC expires for residential systems and declines to 10% for business and utility-scale systems in that year and each year thereafter. All utility-scale plants not placed in service prior to January 1, 2024 receive a 10% ITC regardless of the date construction was commenced. Results in this levelized cost report only include utility-scale solar facilities and do not include distributed solar facilities. In NEMS, EIA assumes that new utility-scale solar PV plants will have a 2-year construction lead time and solar thermal plants a 3-year construction lead time. EIA assumes that all utility-scale solar plants entering service in 2019 receive the full 30% tax credit. PV plants entering service in 2022 receive 26%, whereas solar thermal plants entering service in 2022, having begun construction a year earlier receive 30%."

ACC also points the Commission to an NREL study on the impacts of expiring PTC and ITC credits for wind, geothermal, biomass, solar, and energy storage, *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions,* which anticipates an upward cost curve for wind that will not return to PTC pricing levels until well after 2030, even accounting for baseline technology cost declines.[7] This study also predicts a flat solar PV price curve for the duration of the tax credit sunsets. The following chart illustrates the projected wind and solar Levelized Cost of Energy forward curves in response to the permanent phase out of the PTC and ITC. It should be noted that NREL designed its study prior to IRS documentation referenced above, which extended the window for safe harbor implementation of the PTC from

[7] National Renewable Energy Laboratory. Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions. February 2016. http://www.nrel.gov/docs/fy16osti/65571.pdf

two years to four years, so the timeline of the PTC's impact on increasing the projected wind cost curve can be advanced by two years.

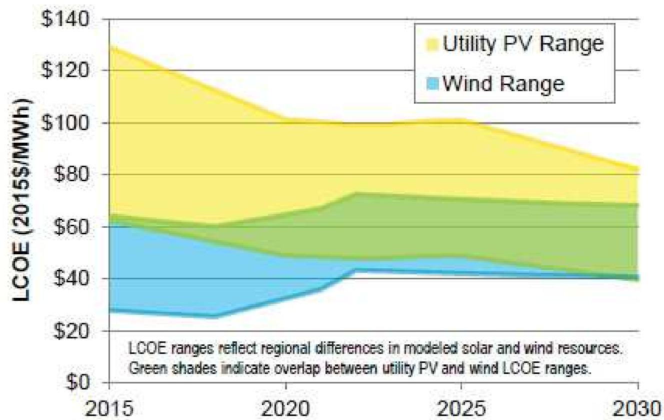


Figure A3. Comparison of estimated utility PV and wind implied LCOEs based on the assumed cost reductions and tax credit schedule from the *Consolidated Appropriates Act of 2016*.

To satisfy this need at lowest-cost and with a commercially mature, reliable, and clean technology, ACC member companies can offer significantly discounted prices due to the availability of the federal PTC for utility-scale wind energy, the benefits of which can be magnified with procurement of high-capacity factor regional wind.

ACC submits an analysis from Energy Strategies as Attachment A, which outlines the potential savings associated with near-term procurement of high capacity-factor regional wind that is eligible for the full value of the PTC by meeting IRS milestones in 2020, compared to projects coming online in 2026, which would not be eligible for the PTC. This analysis demonstrates savings to the tune of $23-25/MWh through early procurement of utility-scale wind energy, and relative savings between 44%-52% for projects coming online in 2020 versus 2026.

TABLE 1: LEVELIZED COST OF ENERGY (2016 $/MWH) AND RELATIVE SAVINGS ACROSS SCENARIOS[9]

COD Year	Scenario 1: Default RESOLVE/RPS Calculator Inputs	Scenario 2: Higher Capacity Factor	Scenario 3: Higher Capacity Factor and Cost Reductions
2020	$31.61	$23.27	$23.27
2026	$56.41	$48.19	$46.07
Delta	*$24.80*	*$24.92*	*$22.80*
Relative savings (%) due to timely procurement	**44%**	**52%**	**49%**

The total approximate value of the PTC over the life of the project was also calculated: For wind with a 44% capacity factor, the net present value of the PTC, over the project life, is $657M for 1,000 MW and $1.97B for 3,000 MW. Regional wind with a 52% capacity factor has higher PTC benefits. The net present value of the PTC, over the project life, for 52% capacity factor wind is $777M for 1,000 MW and $2.33B for 3,000 MW.[8]

In addition to the analysis by Energy Strategies attached to ACC's comments, the Energy Division has preliminarily identified a benefit of early procurement of utility-scale wind, noting that "the ability to procure OOS wind resources prior to the expiration of the PTC significantly improves the economics under all RPS and GHG targets." IRP modeling results continue by stating that "3,000 MW wind procured in 2018 (with the PTC) is approximately $100 MM/yr cheaper than the same resource procured in 2026 (without the PTC) on a levelized basis."[9]

[8] The discount rate for the net present value is the same as the weighted average cost of capital (7.96%) that was used in analyzing the various wind projects studied in this analysis.

[9] Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC. CPUC Energy Division. 19 July 2017. P. 112.

ACC also notes that LSEs can flexibly structure procurement decisions and execute long-term PPAs. If renewable need is not expected to emerge for several years, PPAs can be executed in 2018 to allow financing and construction to continue to bring projects online within the PTC timeframe, but can be structured to start delivery to California LSEs later in the 2020s.

IV. The Commission should tailor statewide RPS procurement to satisfy known demand.

While the IOUs are right to express uncertainty and concern regarding the potential departure of customers to CCAs, planning to satisfy RPS requirements and future demand for electricity is critical and, if and when new CCAs officially form and IOU customers formally depart, IOUs have an obligation to serve load and comply with the RPS.

ACC recommends that the Commission conduct an aggregated analysis of the forecasted demand compared to each LSE's need to identify whether LSEs are collectively as well positioned as they claim in meeting RPS targets and 2030 greenhouse gas targets, considering the potential ratepayer savings associated with early procurement to meet need through PTC- and ITC- eligible resources. Should the aggregated analysis discover a costly gap in procurement, the Commission should require LSEs filing RPS plans to justify their rationale for deferred procurement, providing parties with an opportunity respond.

V. Conclusion

Due to the discrepancy between the need for new generation and procurement planning by CPUC-jurisdictional retail sellers, and the observed benefit of early procurement noted in

---

http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/17/CPUC_IRP_Preliminary_RESOLVE_Results_2017-07-19_final.pdf both the initial modeling results of the IRP and in Attachment A, ACC recommends that the Commission investigate the notion that retail sellers are 'over-procured' to meet 2030 obligations and, instead, urge early and organized procurement now to ensure cost savings for California ratepayers that can extend well into the next decade. It is almost certain that a significant amount of high capacity factor wind will be a key piece of our 2030 portfolio. Early procurement will help load-serving entities capture meaningful PTC benefits, providing a renewable, clean, reliable, and low-cost source of electricity for all customers.

The Commission should not simply accept the claims made by retail sellers, but should instead further investigate renewable need and do what it can to ensure sound decision-making in the near-term to serve future need.

Dated: August 18, 2017

Respectfully submitted,

/s/ Danielle Osborn Mills
Director, AWEA California Caucus
Renewable Energy Strategies
1970 Meadow Oak Lane
Meadow Vista, CA 95722
(916) 320-7584
danielle@renewableenergystrat.com

ATTACHMENT A

MEMO

TO: Danielle Osborn Mills, Director, AWEA California Caucus

FROM: Caitlin Liotiris, Partner, Energy Strategies

DATE: August 18, 2017

SUBJECT: Relative Value of the Full Production Tax Credit for Wind Resources

The AWEA California Caucus (ACC) requested that Energy Strategies perform an assessment of the value of the federal Production Tax Credit (PTC) for wind energy. The PTC is currently scheduled to phase out over the next several years; though, if timely procurement decisions are made, opportunities remain for California's load-serving entities (LSEs) and, ultimately, ratepayers to capture the full benefit of these federal tax credits. Energy Strategies analyzed the impacts on the levelized cost of energy (LCOE) for wind facilities that obtain the full (100%) PTC, compared to wind projects that do not receive these federal tax incentives. To support the assumptions regarding PTC eligibility and the timing of these hypothetical resources, a summary of the relevant Internal Revenue Service (IRS) rules is also included below.

The analysis focused on wind projects that achieve commercial operation in two timeframes: 2020 and 2026. As described below, some wind projects achieving commercial operation in 2020 will be able to capture 100% of the PTC. In contrast, projects reaching commercial operation in 2026 are unlikely to be eligible for federal PTCs. Thus, comparing the costs of wind projects coming online in 2020 and 2026 allows for an assessment of the relative difference in the cost of wind energy with full federal PTCs and without PTCs.[1]

While the PTC began to phase-down by 20% per year at the end of 2016, wind projects under development can still receive 100% of the federal PTC. According to IRS requirements, wind projects that began construction by December 31, 2016 are eligible for the full value of the PTC.[2] Project developers can demonstrate the commencement of construction several ways, including the "physical work test" or the 5% safe harbor (which is frequently accomplished through the purchase of turbines). In order for projects to remain PTC qualified, the project developers must demonstrate the continuous nature of their efforts through the commencement of commercial operations. One straightforward method for demonstrating the continuous nature of efforts on a PTC-eligible wind project is to place the project in service within four years of the year in which construction started (i.e. by the end of 2020 for projects which commenced construction in 2016).[3] Thus, the analysis focuses on a 100% PTC-qualified project which comes online in 2020, as compared to a project commencing operation in 2026, which is not eligible for PTCs.[4]

Several 100% PTC-eligible projects are available to California ratepayers, but will require near-term contracting in order to achieve 100% PTC eligibility. While there is a narrow window in which procurement decisions need to be

[1] 2026 also aligns with the procurement timeframes being evaluated in RESOLVE and would, almost certainly, be past the time wind resources might qualify for reduced PTCs (such as 80%, 60% or 40%).
[2] https://www.irs.gov/irb/2016-23_IRB/ar07.html
[3] See IRS Notices 2013-29, 2013-60, 2014-46, 2015-25, 2016-31 and 2017-4.
[4] Projects coming online after 2020 may still be able to qualify for the full PTC. This will require commencement of construction by December 31, 2016 and demonstrating to the IRS the continuous nature of work from commencement of construction through commercial operation, based on the relevant facts and circumstances.

215 South State Street, Suite 200, SLC, UT 84111
801.355.4365 | energystrat.com

made for wind project developers to qualify for the full PTC in order to meet all necessary IRS eligibility milestones, project developers have flexibility in tailoring contracts to align with LSE needs. For instance, a wind project may be able to enter into a Power Purchase Agreement (PPA) with a utility in the 2018 timeframe, while the PPA may provide for delivery of power at the time the need arises, even if the need does not arise until the early 2020s. While there may be a risk premium added to the PPA price for delivery post-2020, the following analysis demonstrates the significant LCOE cost savings that can be achieved by locking in full federal tax incentives through PPAs executed in time to meet the necessary IRS milestones.

The analysis summarized below illustrates the high-level benefits associated with procuring full-tax benefit eligible wind compared to procuring wind at a time when these tax benefits have expired, demonstrating the economics of the tax and procurement concepts discussed above. The assessment focuses on high-capacity-factor wind from New Mexico and Wyoming. In order to perform this analysis, Energy Strategies utilized version 6.2 of the California Public Utilities Commission (CPUC) Renewable Portfolio Standard (RPS) Calculator[5] with updated assumptions on capital cost and capacity factor taken from the July 2017 RESOLVE documentation of the inputs and assumptions for the CPUC 2017 Integrated Resource Plan (IRP).[6] Specifically, the RPS Calculator's pro forma cash tool was used to calculate the LCOE of wind resources in several scenarios, while using the average capital cost of Wyoming and New Mexico wind from the RESOLVE IRP inputs and assumptions. Although the LCOE values produced by the RPS Calculator may not reflect actual, confidential prices contained in PPAs, the RPS Calculator has been widely vetted in various CPUC proceedings and provides a sound platform for analyzing the *relative change* in the cost of wind energy with and without federal tax incentives.[7]

The analysis considered several scenarios. Each scenario is designed to compare the relative changes in LCOE between a wind project that can achieve commercial operation in 2020, and obtains the full PTCs, and a wind project that achieves commercial operation with no PTCs. The wind project scenarios are described below and summarized in Table 1.

(1) Scenario 1 (Default RESOLVE/RPS Calculator Inputs): This scenario uses the default assumptions from the RPS Calculator, including updated capacity factors and capital cost assumptions from the RESOLVE documentation for inputs and assumptions used in the 2017 CPUC IRP. Capital costs reflect the simple average between Wyoming and New Mexico costs, which were sourced from RESOLVE inputs.
(2) Scenario 2 (Higher Capacity Factor): Scenario 2 uses the same inputs and assumptions as Scenario 1, except that a higher capacity factor (52%) is used to align with the capacity factor of recent a wind project in New Mexico.[8]
(3) Scenario 3 (Higher Capacity Factor and Cost Reductions): Scenario 3 uses the same inputs and assumptions as Scenario 2, except the project that comes online in 2026 has a lower capital cost to reflect potential technological advancements. The capital cost has been reduced from the 2020 value by 7.7%,

---

[5] Version 6.2 of the RPS Calculator was used, because version 6.3 has not been made available on the CPUC's website.
[6] RESOLVE documentation for capital cost and capacity factors used in the analysis is available here: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/17/RESOLVE_CPUC_IRP_Inputs_Assumptions_2017-07-19_redline.pdf
[7] Note that while interconnection costs were assumed for these wind projects, no additional transmission costs were added for any of the wind projects evaluated. While transmission costs would likely be necessary for delivery of significant amounts of regional wind energy, the analysis is focused on isolating the relative value of the PTC. Excluding transmission costs from all projects evaluated allows for a comparison of the relative value of the PTC.
[8] See testimony seeking approval of PPAs for the Sagmore Wind project in New Mexico here: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/NM-Filings-Riley-Hill-NM-Direct.pdf

which is in line with the largest proportional capital cost reductions seen between 2020 and 2030 in the U.S. Department of Energy's Wind Vision analysis.[9]

TABLE 1: SCENARIO SUMMARY

	Commercial Operational Date (COD)	100% PTC Eligible?	Capacity Factor	Capital Cost (2016 $/kW)	Other Financial Assumptions[10]
Scenario 1: Default RESOLVE/RPS Calculator Inputs	2020	YES	44%	Based on RESOLVE (July '17)	Consistent with CPUC documentation for RESOLVE and RPS Calculator 6.2/6.3
	2026	NO			
Scenario 2: Higher Capacity Factor	2020	YES	52%	Based on RESOLVE (July '17)	
	2026	NO			
Scenario 3: Higher Capacity Factor and Cost Reductions	2020	YES	52%	2026 only reduced 7.7% from 2020 RESOLVE value	
	2026	NO			

The relative impact on the LCOEs in each scenario were compared. Table 2 summarizes the results of the assessment. Figures 1 and 2 illustrate the savings that can be achieved by securing the full benefit of the PTC.

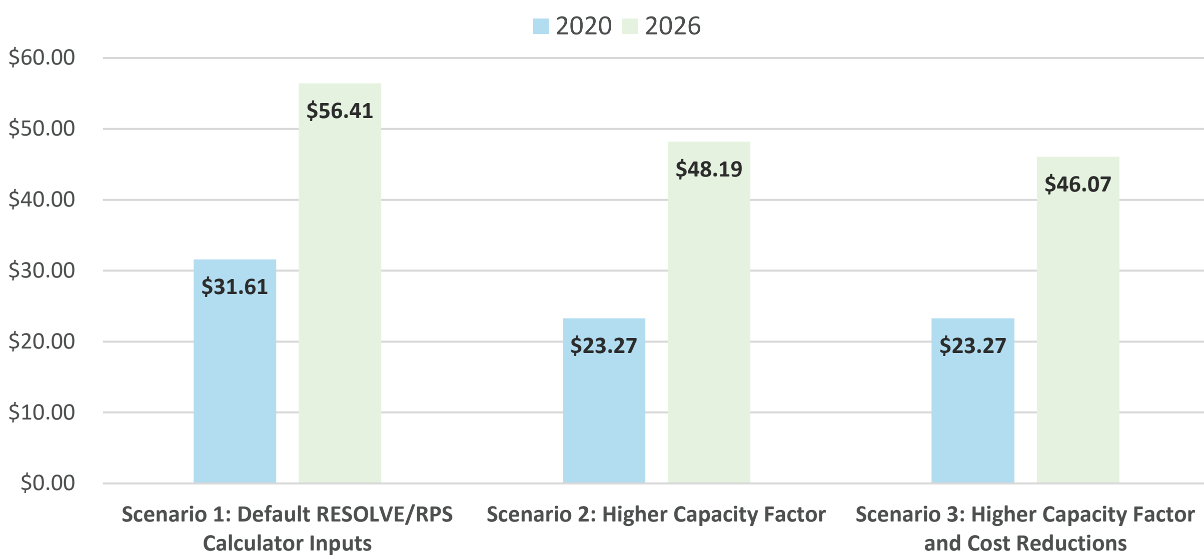
[9] See *Wind Vision: A New Era for Wind Power in the United States*, U.S. Department of Energy, March 12, 2015, Appendix H, Table H-4, available here: https://energy.gov/eere/wind/maps/wind-vision
[10] The RPS Calculator includes functionality to optimize the debt-equity ratio. Because the goal of this assessment was to isolate the relative value of the PTC, the debt-equity ratio for each project was held constant at 50/50.

215 South State Street, Suite 200, SLC, UT 84111
801.355.4365 | energystrat.com

TABLE 2: LEVELIZED COST OF ENERGY (2016 $/MWH) AND RELATIVE SAVINGS ACROSS SCENARIOS[11]

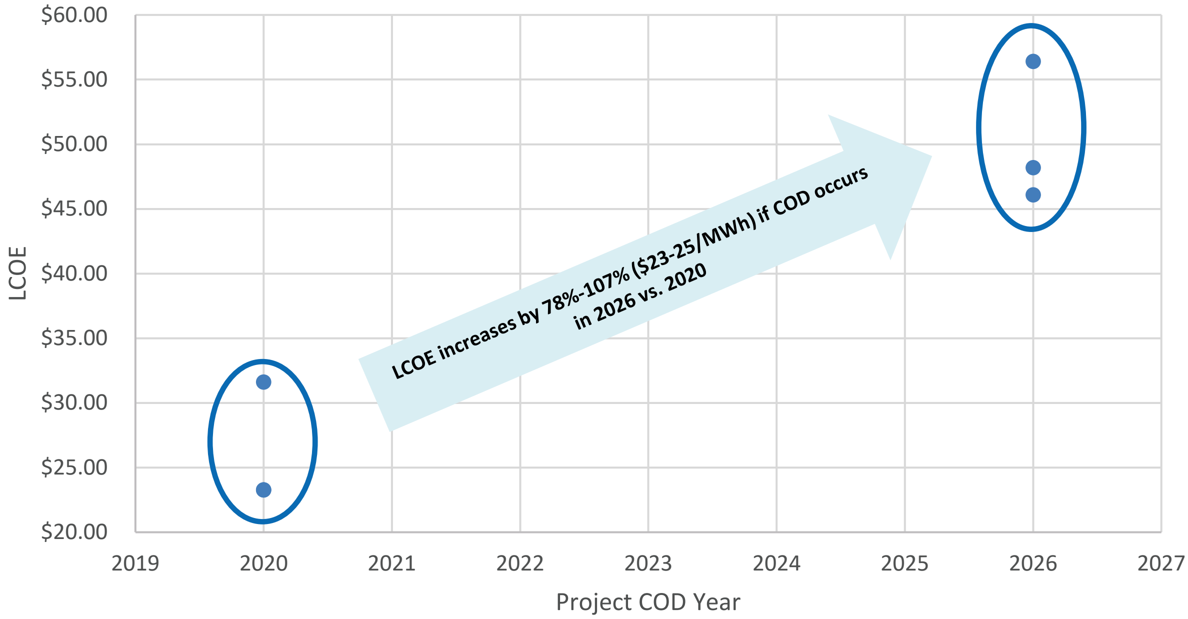
COD Year	Scenario 1: Default RESOLVE/RPS Calculator Inputs	Scenario 2: Higher Capacity Factor	Scenario 3: Higher Capacity Factor and Cost Reductions
2020	$31.61	$23.27	$23.27
2026	$56.41	$48.19	$46.07
Delta	*$24.80*	*$24.92*	*$22.80*
Relative savings (%) due to timely procurement	**44%**	**52%**	**49%**

FIGURE 1: LEVELIZED COST OF ENERGY (2016 $/MWH) COMPARISON



[11] The delta in the LCOE in Table 2 results from comparing LCOEs, as calculated by the RPS Calculator, of the two projects in each scenario. The RPS Calculator calculates LCOE using the net present value of the cash flows and the net present value of the energy and, among various other assumptions, the LCOE is grossed up for taxes. Note that the LCOE from the RPS Calculator may differ from actual PPA prices.

FIGURE 2: LEVELIZED COST OF ENERGY BY COD FOR ALL SCENARIOS (2016 $/MWH)



This analysis demonstrates that the LCOE benefits of obtaining the full PTC, in the scenarios studied, can be between $23-25/MWh or 44-52% lower than the LCOE of wind energy that comes online in 2026. While these values may not be reflective of actual, confidential PPA prices, they demonstrate the relative value of the PTC and the potential for lower cost wind resources that might be achieved with timely procurement decisions.

To put the total approximate value of the PTC into perspective, Energy Strategies assessed the net present value of the PTC for 1,000 MW and 3,000 MW of regional wind. The net present value of the PTC for these wind projects was calculated using a discount rate of approximately 8%.[12] For wind with a 44% capacity factor, the net present value of the PTC, over the project life, is $657M for 1,000 MW and $1.97B for 3,000 MW. Regional wind with a 52% capacity factor has higher PTC benefits. The net present value of the PTC, over the project life, for 52% capacity factor wind is $777M for 1,000 MW and $2.33B for 3,000 MW. Also note that the simple (undiscounted) sum of the PTC for 1,000 MW of regional wind with a 44% capacity factor is $990M and $1.2B for 1,000 MW of wind with a 52% capacity factor.

[12] The discount rate for the net present value is the same as the weighted average cost of capital (7.96%) that was used in analyzing the various wind projects studied in this analysis.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

VERIFICATION

I am a representative of the American Wind Energy Association California Caucus and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to 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 forgoing is true and correct.

Executed on August 18, 2017 at Sacramento, California.

/s/ Danielle Osborn Mills
Director, AWEA California Caucus
Renewable Energy Strategies
1970 Meadow Oak Lane
Meadow Vista, CA 95722
(916) 320-7584
danielle@renewableenergystrat.com