BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	Rulemaking 13-12-010 (Filed December 19, 2013)

COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON ALJ FITCH RULING SEEKING COMMENT ON ASSUMPTIONS AND SCENARIOS FOR USE IN THE CAISO'S 2016-17 TRANSMISSION PLANNING PROCESS AND FUTURE COMMISSION PROCEEDINGS

Nancy Rader
Executive Director
California Wind Energy Association
2560 Ninth Street, Suite 213A
Berkeley, CA 94710
Telephone: 510-845-5077 x1
E-mail: nrader@calwea.org

Dariush Shirmohammadi
Technical Director
California Wind Energy Association
2560 Ninth Street, Suite 213A
Berkeley, CA 94710
Telephone: (310) 858-1174
E-mail: Dariush@shirconsultants.com

On behalf of the California Wind Energy Association

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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I. INTRODUCTION & SUMMARY

Pursuant to the February 8, 2016, Ruling of Administrative Law Judge Fitch, the California Wind Energy Association ("CalWEA") provides these comments on Assumptions and Scenarios proposed by California Public Utilities Commission ("Commission") staff for use in the California Independent System Operator's ("CAISO's") 2016-17 Transmission Planning Process (TPP) and future Commission procurement-related proceedings ("Staff Proposals").

In summary, CalWEA recommends the following:

- Consistent with the CAISO tariff, the notion of a "trajectory scenario" should be abandoned in favor of least-regrets transmission planning, which requires multiple distinct and plausible futures that could result from different policy choices and market conditions;
- The cost of the full amount of expected curtailment of excess renewable energy beyond pre-paid curtailment must be included at the PPA price in order to produce economically optimum RPS procurements and scenarios, as we explain in the attached paper, "Curtailment: The Missing Link Toward a More Diverse RPS Portfolio";
- The Default Scenario should include RPS resources based on an optimum mix of energy-only and fully deliverable resources. Similarly, an optimal, rather than arbitrary, level of out-of-state wind should be selected by comparing the value of those resources (including any necessary transmission costs) to in-state RPS resources and included in the Default Scenario;
- A forecast specific to the solar installations expected under the Commission's recent net metering decision should be incorporated in the Default Scenario, and behind-the-meter

resources should be modeled as distribution-level supply resources in all LTPP/TPP study scenarios;

- LTPP modeling should assume that renewables provide only downward operational flexibility services;
- The continued use of the exceedance methodology for capacity valuation is inappropriate given the far greater accuracy of the ELCC methodology and the Commission's progress toward using that methodology; and
- The avoided transmission and distribution loss factors appear to overstate loss-reductions for demand-side resources and should be re-evaluated.

II. COMMENTS ON 2016 PLANNING SCENARIOS

A. Default (and "Trajectory") Scenario

The Staff Proposals state (at p. 5):

> [A]dditional development on specific modeling inputs is needed before a true trajectory scenario can be developed. Instead, we recommend adopting a Default Scenario that can be used to test certain modeling inputs and provide information for the development of a trajectory scenario at a later date.

The notion of a "true trajectory scenario" should be abandoned. It is critical to establish a process now that will ultimately provide the Commission and CAISO with multiple (4 or 5) plausible study scenarios, without favoring any one of them, in order to produce "least-regrets" authorizations for system flexibility resources and transmission upgrades. The CAISO has recently summarized the least-regrets principle as that which "first formulates several alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio followed by selecting for approval those transmission elements that have a high likelihood of being needed and well utilized under multiple scenarios."[1] This premise has already been embraced in the RPS Calculator process, where Energy Division has posited a "guiding principle" that "RPS Calculator portfolios should reflect multiple distinct and plausible

[1] See A.13-10-020, CAISO Testimony in West of Devers CPCN proceeding (10/27/15), quoting the CAISO's 2014-2015 Transmission Plan, at p. 10.

futures that could result from different policy choices and market conditions." [2] It is essential that the LTPP scenarios also reflect this guiding principle.

In addition to the reference to a "true trajectory scenario," several statements in the Staff Proposals (at p. 54) stand in contrast to the least-regrets principle. For example, the suggestion is made that a single portfolio could "trigger new transmission," that the goal is for the Commission to "select a preferred course of action for infrastructure investment enhancements," and that some renewables portfolios would be "speculative" rather than serve as "plausible futures" as envisioned in the RPS Calculator process.

The goal of the LTPP process must be to produce "multiple distinct and plausible futures that could result from different policy choices and market conditions" because this is what the Federal Energy Regulatory Commission ("FERC") effectively required in 2010 in order to approve a "policy driven" transmission plan to support achievement of RPS and other policy goals.[3] In proposing the ability to obtain cost-recovery for policy-driven transmission upgrades, the CAISO pledged to take a comprehensive, holistic approach to transmission planning and approval, rather than the previous project-by-project approach, in order to minimize the risk of stranded transmission investment.[4] FERC accepted these revisions to the CAISO's tariff on the premise that the CAISO will use a "series of engineering sensitivity studies . . . to identify a common set of transmission elements that are needed under the renewable scenarios most likely to occur."[5] The identification of a "common set" of transmission elements is consistent with creating multiple plausible scenarios rather than a single "trajectory" case, plus alternatives, and is fundamental to achieving the goal of minimizing the risk of stranded transmission investments. The same principle applies to determinations of need for other system resources that will be determined in LTPP proceedings.

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[2] See R. 15-02-020, Ruling of Administrative Law Judge Robert Mason (August 28, 2015), including "Staff Paper on Incorporating Land Use and Environmental Information into the RPS Calculator and Developing and Selecting RPS Calculator Portfolios."

[3] *California Independent System Operator Corp.,* 133 FERC ¶ 61,224 (2010).

[4] California Independent System Operator Corporation, Revised Transmission Planning Process Proposal, Filed June 4, 2010 (FERC Docket No. ER10-1401-000).

[5] *California Independent System Operator Corp.,* 133 FERC ¶ 61,224, PP 191-92 (2010).

A case labeled "trajectory" would fundamentally contradict the concept of least-regrets planning, as it is characterized in the CAISO tariff regarding policy-based transmission planning. The existence of a "trajectory scenario" could inappropriately lead CAISO to conduct its policy-based transmission planning around that single scenario and treat all other scenarios as simple sensitivity cases.[6] Such a practice would not be consistent with the concept of least-regrets planning, in which each scenario is accorded equal weight and an independent transmission plan is developed for each scenario, with the transmission elements of each plan that are common to all (or most) plans constituting the "least-regrets" policy-driven plan.

A least-regrets plan is one that will support most any pattern of renewable energy development and avoid favoring any particular development area that may not ultimately be developed (which would lead to stranded transmission investment). Least-regrets upgrades will foster a robust competitive market; upgrades that favor a particular "trajectory" scenario would constrain the market.

B. Behind the Meter (BTM) PV Solar Resources

CalWEA recommends that Energy Division improve its treatment of BTM solar PV resources (BTM resources) in both the level of BTM resources in the default RPS scenario and the modeling of BTM resources.

With regard to the level of BTM resources in the default scenario, a forecast specific to the solar installations expected under the Commission's recent net metering decision should be incorporated.

With regard to the modeling of BTM resources, subsuming the BTM resources within retail load would be totally misleading and unacceptable for grid planning studies (both transmission and distribution). Many grid planning studies involve studying the system at off-peak load conditions wherein the level of BTM generation can sometimes far exceed the relevant retail load, resulting in significant reverse flows on distribution and transmission facilities. Such critical operating conditions cannot be correctly simulated and studied if BTM resources are subsumed in the retail load. Hence, CalWEA emphatically recommends that BTM resources be modeled as distribution-level supply resources in all LTPP/TPP study scenarios.

[6] Such an approach is likely to produce either a plan that works well only for the base case (if the needs of the sensitivity cases are not addressed), or would over-build the system in order to work well also for each of the sensitivity cases.

C. Provision of Operational Flexibility by RPS Resources

LTPP modeling should assume that renewables provide downward operational flexibility services only. The Staff Proposals state (at p. 58-59):

> "Currently gas-fired electric generators are kept online so that the system operators can ramp these resources up or down in order to balance the system's electrical demand and supply. … utilizing zero or low GHG tools to provide operational flexibility (which include flexible operation of RPS generators) would reduce the electric sector's GHGs by 20% relative to using existing "peaker" gas-fired resources for operational flexibility."

Renewable resources can indeed contribute to the reliability of the power system by providing operational flexibility services (including ancillary services). However, CalWEA strongly advises against requiring RPS resources with variable fuel sources, such as wind and solar generators, to provide upward operational flexibility services. We take this position not only due to the high opportunity cost for wind and solar resources that would be involved (i.e., scaling back generation in order to provide upward services), but also because when the need for upward flexibility capacity (normally needed for system reliability) arrives, the renewable resource may not be able to provide the capacity due to lack of availability of its variable fuel source. In fact, the UCS study cited in the Staff Proposals clearly shows that the bulk of the benefits that renewables can provide come from providing *downward* operational flexibility services. Therefore, the modeling should assume that renewables provide downward operational flexibility services only.

III. COMMENTS ON SUPPLY-SIDE PLANNING ASSUMPTIONS

A. RPS Portfolios

The Default Scenario should include RPS resources based on an optimum mix of energy-only and fully deliverable resources. Similarly, an optimal, rather than arbitrary, level of out-of-state wind should be selected by comparing the value of those resources (including any necessary transmission costs) to in-state RPS resources and included in the Default Scenario.

In addition to RPS portfolios being equally weighted, distinct and plausible futures that could result from different policy choices and market conditions, as discussed in section II.A, another "guiding principle" posited by Energy Division staff in the RPS Calculator process is that RPS portfolios should be "designed to facilitate the achievement of RPS goals at the least possible cost"[7] (within the constraints of each assumed scenario). CalWEA strongly agrees with this principle, but the Staff Proposals for the RPS Portfolios are in conflict with it in two ways.

First, the proposed Default Scenario, to be used in the majority of the LTPP/TPP study plans, assumes that all future RPS resources are fully deliverable. This is most perplexing given the effort and resources that have been expended in the RPS Calculator process aimed at developing the ability to compare the cost and value of deliverability status for future RPS resources to energy-only status, and to select the optimum status. Moreover, this capability has been broadly supported by the stakeholders who have been involved in the process. While the Staff Proposals accurately describe the RPS Calculator's capabilities in this regard, it does not explain why it would not use this capability to generate resources for the Default Scenario. The result of the analysis so far show that an energy-only RPS scenario will be less costly and still will produce significant RA capacity given the availability of deliverability capacity on the grid.[8] Hence, CalWEA strongly recommends that the Default Scenario include RPS resources based on an optimum mix of energy-only and fully deliverable resources.

Second, and similarly, selecting 3,000 MW of out-of-state wind resources as a control parameter for one of the LTPP/TPP study scenarios appears to be totally arbitrary. An optimal level of out-of-state wind should be selected by comparing the value of those resources (including any necessary transmission upgrades for consistency with California's RPS requirements) to in-state RPS resources. Further, CalWEA recommends that the optimum level of out-of-state wind resources identified in this fashion be used in the Default Scenario. Under this circumstance, one separate LTPP/TPP study scenario that excludes out-of-state wind resources could be selected.

B. Over-Generation Analysis

CalWEA very much supports the statement that "there is consensus that the Commission should act now to evaluate solutions to over-generation" (Staff Proposals at p. 32). However, the

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[7] Supra note 2.

[8] See R.15-02-020, "Energy Division's Staff Paper on Incorporating Land Use and Environmental Information into the RPS Calculator and Developing and Selecting RPS Calculator Portfolios," August 28, 2015, at p. C2/6. ("Energy Only procurement reduced the overall cost in reference cases.") Based on the location of EO resources, CalWEA expects that several thousand megawatts would be deliverable.

proposed assumption regarding curtailment is nowhere near sufficient to promote the evaluation of solutions.

The Staff Proposals suggest (at p. 32) that 200 GWh of pre-paid curtailment that is available in 2026 should be included as the minimum estimate of available curtailment, even though it was also stated that total available (paid) economic curtailment is forecasted to be 12,600 GWh. The cost of the full amount of expected curtailment of excess renewable energy, beyond pre-paid curtailment, must be included at the PPA price in order to produce economically optimum RPS procurements and scenarios, as we explain in the attached paper, "Curtailment: The Missing Link Toward a More Diverse RPS Portfolio."

As our paper explains, additional steps should be taken by the Commission to fully and appropriately address curtailment-related costs, but modeling the full cost of curtailment is an essential part.

C. Capacity Value of RPS Resources

The Staff Proposals state (at p. 21) that

> The CPUC is actively considering the use of Effective Load Carrying Capability (ELCC) methods of assigning capacity value to wind and solar resources for system related studies. For 2016-17 TPP modeling purposes the current Resource Adequacy exceedance methodology should continue to be utilized to model output levels of variable resources in the power flow (load flow) and stability studies typical of the CAISO's TPP.

The continued use of the exceedance methodology is totally inappropriate for several reasons. First, contrary to the quoted statement, the Commission is already implementing the ELCC method in the Resource Adequacy Track 1 proceeding that is currently underway, and this implementation is many years overdue following a 2011 statutory requirement requiring the ELCC methodology to be used in this context.[9] Second, the Commission has ordered the utilities to use an ELCC assessment in their RPS procurement processes as a comparison to the exceedance methodology,[10] and is clearly in transition to the ELCC methodology judging by a

[9] See R.14-10-010, Assigned Commissioner and Administrative Law Judge's Phase 2 Scoping Memo and Ruling, December 23, 2015.

[10] See D.14-11-042.

recent Commission Ruling.[11] Third, the RPS Calculator that has been developed by the Commission to produce RPS portfolios already incorporates the ELCC method.

Finally, and most importantly, ELCC-based capacity values, particularly for non-dispatchable renewable resources, are widely accepted as a superior gauge of a resource's contribution to the reliable operation of the electric power system.[12] This is due in significant part to the fact that the ELCC methodology actually evaluates the ability of a resource to serve load and, furthermore, is able to show the declining capacity value of the same resource with the increased penetration of other resources with the same output profile.[13]

Given the far greater accuracy of the ELCC methodology and the Commission's progress toward using the ELCC methodology, it would be completely inappropriate to use capacity value figures that are known to be arbitrary and inaccurate. Therefore, CalWEA strongly recommends that ELCC rather than exceedance-based values for RPS resources be used in this round of LTPP/TPP studies.

D. Avoided Transmission and Distribution Losses for Demand-Side Resources

The avoided transmission and distribution loss factors appear to overstate loss-reductions for demand-side resources and should be re-evaluated. The Staff Proposals (at p. 20) present the following table for the assumed reduction in T&D losses due to demand-side resources:

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[11] See R.15-02-020, October 9, 2015, Ruling of ALJ Simon on the use of ELCC for RPS procurement.

[12] See, e.g., M. Milligan and K. Porter, "The Capacity Value of Wind in the United States: Methods and Implementation," *Electricity Journal*, Vol. 19, Issue 2, March 2006. pp 91-99. Elsevier, Inc. (related conference paper available at: http://www.nrel.gov/docs/fy05osti/38062.pdf; and S.H. Madaeni, R. Sioshansi and P. Denholm, "Comparison of Capacity Value Methods for Photovoltaics in the Western United States," NREL (July 2012) (available at: http://www.nrel.gov/docs/fy12osti/54704.pdf).

[13] A. Mills and R. Wiser, *Changes in the Economic Value of Variable Generation at High Penetration Levels: Pilot Case Study of California*, LBNL (June 2012) (available at: http://eetd.lbl.gov/EA/EMP); *Investigating a Higher Renewables Portfolio Standard in California*, Energy and Environmental Economics, Inc. (January 2014) (available at: http://www.ethree.com/public_projects/renewables_portfolio_standard.php); and A. Mills and R. Wiser, *Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels*. LBNL. (March 2014) (available at: http://emp.lbl.gov/sites/all/files/lbnl-6590e.pdf).

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

Given the factors that determine the level of avoided T&D losses due to demand-side resources (T&D losses are lowered nearly quadratically with the reduction in flows in transmission and distribution lines), CalWEA is surprised to see how close the projected average and peak T&D loss-avoidance numbers are. T&D loss-reduction under peak load conditions occurs during very short periods of time. Under non-peak conditions, which constitute most of the year, the T&D loss reduction will be significantly less than that under peak-load conditions. Thus, the average loss reduction should be significantly lower than under peak-load conditions, which calls into question the factors presented in Table 2. The factors should be re-evaluated.

Respectfully submitted,

Nancy Rader
Executive Director
California Wind Energy Association
2560 Ninth Street, Suite 213A
Berkeley, California 94710
Telephone: (510) 845-5077 x1
Email: nrader@calwea.org

On behalf of the California Wind Energy Association

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Curtailment: The Missing Link Toward a More Diverse RPS Portfolio

Nancy Rader, Executive Director
Dariush Shirmohammadi, Technical Director
California Wind Energy Association

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The models being used by the CPUC and the CAISO to project cost-effective 50% RPS resource scenarios for meeting California's 2030 goals consistently show a need for several thousand megawatts of additional wind energy capacity, both in California and across the West.[14] In addition, these models assume that California's fleet of 1980s-vintage wind projects not only continue to operate but increase their energy production, if not capacity.[15] Given the low and still-falling costs of solar energy, a primary driver of the cost-competitiveness of wind energy in these models is the finite capacity of the system to accommodate the output profile of solar: there is only so much demand for power during daytime hours. This concentrated output profile is expected to lead to very significant curtailment of solar energy at high solar penetration levels.[16]

Importantly, however, these models make a critical assumption that may not always track current utility practice: that generators are paid for their curtailed energy at the full contract price.[17] That is, the models assume that the cost to curtail excess renewable generation will be included in the least-cost, best-fit (LCBF) analyses leading to utility procurement decisions, with the result that solar energy becomes less cost-effective and resources with complementary output profiles become more competitive as solar penetration increases. The problem is that curtailment costs are not, in fact, being fully included – if included at all – in utilities' procurement analyses of proposed bids. As a result, solar continues to dominate utility procurements.

Curtailment costs are being overlooked or under-estimated for a number of reasons. First, overgeneration-related curtailments are of little or no concern to the buyer. This is because the CAISO orders curtailment for the purpose of maintaining system reliability when supply is expected to unavoidably exceed demand. 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. So those costs are shifted to the seller and are of no concern to the utility buyer (although the utility should not be counting on obtaining the RECs from projected curtailment periods for RPS compliance purposes).

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[14] For example, E3's Draft Renewable Portfolios for CAISO SB 350 Study presented at a February 8, 2016, CAISO workshop showed a range of 1,500-3,000 MW of incremental California wind, plus an additional 2,000 – 5,000 MW of regional wind (not including wind RECs alone), under various scenarios. See also E3's Update on the 2015 Special Study presented at a June 29, 2015, CPUC-CAISO Webinar.

[15] Statement of E3's Arne Olson in response to a question posed at the February 8th CAISO workshop.

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

[17] *Supra* note 1 (SB 350 Study) at slide 10.

Second, from the seller's perspective, it is not clear whether bidders -- particularly the solar projects that will, by far, be hit the hardest by curtailments -- are factoring in any reliability-based overgeneration curtailment into their pricing. If bidders are factoring anything in, it would almost certainly 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.

Nor is there any accounting in the LCBF RPS procurement process for this curtailment cost-shift to other generators. If curtailment will be borne, on average, by generators and not by the utility or its customers, it's not really an indirect cost of concern to the LCBF evaluation. (Ratepayer groups and utilities might be concerned, however, that, when that curtailment begins to mount, solar project owners will seek to get that curtailment paid for.)

But how much curtailment should be expected by all generators? How can developers accurately predict how much solar energy will be procured by California's utilities as well as all other load-serving entities on the CAISO grid (and as that grid may be expanded)? As importantly, if not more so, bidders would need to factor in the curtailments they will bear as a result of rooftop solar installations, which themselves are expected to bear no curtailment at all, as they are not subject to curtailment by the CAISO. The CPUC's recent net-metering decision, widely viewed as very favorable for rooftop solar installers, will likely produce more than the 10,000 MW of rooftop solar that has been included in recent forecasts. Further, it is difficult to project future levels of demand-response (including midday EV charging) or energy exports that might reduce curtailment.
This situation is a conundrum for any bidders who are thinking about how to factor in future curtailments into their bid prices (even if only the average curtailment they will suffer), since it is virtually impossible to accurately predict curtailment levels over time. And a conservative assumption will result in a losing bid, if other bidders do not project similarly high curtailment levels.

The result is a common-pool resource problem[18] in which everyone has access to a resource and, by using it, additional costs are imposed on other users of the resource. In this case, the grid's limited ability to absorb generation becomes saturated at certain times due to a combination of limited demand and high solar generation, resulting in a curtailment order to all generators. Fixed-output renewable energy generators – again, primarily solar generators – will be in for an unpleasant surprise as unpaid curtailments begin to mount.

To resolve this common-pool problem, two main fixes are needed:[19] ***(1) generators must be paid for overgeneration-related curtailment***, and ***(2) the remaining marginal curtailment that will be imposed on existing and planned generation must be accounted for in the analyses leading to procurement decisions.*** In this way, procurement decisions will take into account the "overuse"

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

[19] These issues could be addressed in the CPUC's implementation of PU Code Section 399.13(a)(8), which was added to statute by SB 350 and states: "In soliciting and procuring eligible renewable energy resources, each retail seller shall consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid."

of the grid, and that overuse will occur only when it is cost-effective to do so – i.e., only when, even with expected overall curtailment, the procured resource is still cost-effective.[20]
There is one problem. To date, the utilities' pro forma PPAs have attempted to assign CAISO-ordered overgeneration-related curtailment costs to the generator; only going forward will the fix described above cause these costs to be felt by the purchasing entities. Therefore, the overgeneration that will be felt by existing generators is not pain that will be felt by the purchaser or its retail customers, and thus does not strictly fit in the LCBF analysis of future procurement options.

There is, however, a way to shift the CAISO-ordered overgeneration-related cost imposed on existing generators to the utility/ratepayer side of the ledger. This shift could occur through another type of curtailment, known as "economic" curtailment, which enables the utility to curtail generators when it makes sense for economic, as opposed to reliability, reasons. Many versions of past utility pro forma PPAs allowed for a limited number of unpaid hours of economic curtailment in order to respond to very low or negative market prices, since utilities would rather not pay the PPA price when they get little or nothing – or even have to pay – to offload the energy onto the grid in return. These contract provisions also enable the use of economic curtailment to back generators down to avoid an overgeneration situation. Moreover, utility contracts also generally allow for unlimited curtailment at the PPA price. In the normal course, one would expect the market price of energy to fall as supply began to exceed demand, which would introduce an incentive for a utility to utilize its economic curtailment rights to reduce supply before the supply-demand imbalance resulted in negative prices being applied to the utility's entire portfolio. But, it's quite possible that utilities would not avail themselves of the opportunity to avoid negative pricing by paying for economic curtailment if engaging in a strategy of foregoing their economic curtailment rights would push the supply-demand imbalance past the "tipping point," forcing the CAISO to declare an overgeneration condition and order curtailments, which the utility is not contractually required to pay for.

If, instead, utilities were required to utilize their economic curtailment rights under their existing contracts in order to avoid overgeneration events, it would (in addition to solving the overgeneration problem) remove the economic incentive to engage in the strategy noted above: namely, it would convert the overgeneration cost to a utility/ratepayer cost, rather than shifting it onto existing generators who could not reasonably have factored in expected levels of reliability-based overgeneration-related curtailment into their original PPA pricing, and who do not control the decision to engage in additional procurement of resources that cause increasing levels of overgeneration (their buyer, along with other buyers, do). Therefore, ***(3) the CPUC should order utilities to utilize their economic curtailment rights under their existing contracts to avoid overgeneration events.***[21]

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

[21] E3 also concludes, in its Western Interconnection Flexibility Assessment (see note 3, supra, at slide 46), that "creating an environment in which renewables can be curtailed routinely on an economic basis is necessary to avoid emergency conditions & reliability events."

Even if utilities don't pay existing generators for economic curtailment to avoid overgen, they should still factor the overall curtailment that is expected to result from their incremental procurements into their LCBF processes to achieve results going forward that are economically rational overall. The common-pool problem requires the problem to be resolved by directing procuring entities to look at the big picture.[22] Presently, stakeholders have very limited visibility into the LCBF processes; therefore, ***(4) the CPUC should require greater transparency and an explanation of how the impact of potential additional procurement on overall curtailment across all existing resources is being factored into the bid-evaluation process.***

Since the utilities likewise cannot perfectly forecast anticipated levels of curtailment, they could use a low- and high-range of curtailments to inform their decision-making. This range would be based on reasonably possible levels of CAISO exports to neighboring BAs, rooftop-solar penetration, demand-response programs, and time-of-use pricing incentives, etc. This analysis should also factor in the low or negative energy values that would be involved in CAISO exports (or sales within an expanded CAISO) of generation that would otherwise be curtailed.
Procurement decisions could be based on a mid-range assumption, or could involve hedging any bets that curtailment levels will be on the low-end of the spectrum by procuring some renewable resources that would most cost-effectively reduce potential curtailments through resource diversity.

In this way, the models – which show that the most cost-effective 2030 50% mix will include substantial amounts of wind energy to complement a solar-dominant portfolio -- will come to fruition in actual utility procurements. Likewise, the state can avoid a common-pool problem that could lead to a dramatic loss of solar energy that would prevent the achievement of 50% goal and hurt all renewable energy generators, but ultimately hit solar projects the hardest.

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