July 28, 2014

VIA Electronic Mail – docket@energy.ca.gov, RPS33@energy.ca.gov

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 14-RPS-01
1516 Ninth Street
Sacramento, CA 95814-5512

RE: Docket No. 14-RPS-01, Amendments to Regulations Specifying Enforcement Procedures for the RPS for POUs

Ms. Chisholm:

The Alliance for Solar Choice (TASC) would like to thank you for the opportunity to provide comments following the July 11th workshop where stakeholders discussed Pre-Rulemaking Draft Amendments to Regulations for Enforcement Procedures for the Renewables Portfolio Standard for Local Publically Owned Electric Utilities.[1] (Regulations).

TASC is a leading solar advocacy organization promoting policies to support the development of a robust rooftop solar industry across the country. Founded by the largest rooftop companies in the nation, TASC represents the vast majority of the market. Its members include: Demeter Power, SolarCity, Solar Universe, Sungevity, Sunrun, and Verengo.

I. Comments

As explained in these comments, TASC supports modifying the Energy Commission's existing regulations to allow renewable energy credits (RECs) generated by RPS-certified, distributed generation (DG) facilities located behind the customer meter to be classified as Portfolio Content Category (PCC) 1 under Public Utilities Code Sec. 399.16(b)(1) and section 3203 of the Regulations. Doing so will give compliance entities an additional compliance tool with which to achieve current RPS goals, thereby reducing compliance costs, and also facilitate compliance with future increases in renewable procurement that will be necessary to meet California's greenhouse gas emission reduction goals.

[1] Cal. Code of Reg., Title 20, Division 2, Chapter 13, Sections 3200-3208 and Chapter 2, Article 4, Section 1240.

Moreover, allowing RECs from customer-owned generation to assist in meeting California's current and future RPS goals will harmonize the RPS program with the state's interest in creating a sustainable market for distributed generation which has been facilitated via a number of state policies such as the California Solar Initiative, including the New Solar Homes Partnership, and the Governor's 12,000 MW distributed generation target. Continued growth in customer-side DG will also support the state's goal that all new construction be zero net energy buildings by 2020.[2] RECs produced by customer-side DG can form an important part of such a self-sustaining market, a point noted by the California Public Utilities Commission over seven years ago in Decision No. 07-01-018 wherein the Commission determined that customers should retain the RECs produced by their system:

> Allowing solar DG system owners to retain the RECs produced by their facilities is also consistent with the long-term goal of transitioning the solar industry away from ratepayer incentives to a self-sustaining model in which no such incentives are necessary. To the extent that RECs may prove to have any value, whether explicitly or implicitly as discussed above, they could supplement and eventually, in combination with other elements of economic value, replace altogether ratepayer incentives as these incentives are phased out.[3]

Additionally, from a public policy standpoint, it is unequivocal that DG systems deployed on the customer side of the meter fulfill all of the objectives the RPS was intended to achieve. These resources are located in-state, are clearly delivering energy to end use customers in California and thus provide the full spectrum of economics development, environmental, reliability and hedging benefits that motivate the RPS program.[4] The characterization of the RECs associated with customer-side facilities as PCC 3 dramatically reduces the value of these resources, both in economic terms, given the dramatically lower value associated with PCC 3 RECs in the compliance market, and in terms of their ability to facilitate utility achievement of RPS goals at reduced costs by increasing viable compliance options.

Mitigating RPS compliance costs is an issue that will be of critical importance for policymakers to consider; particularly to the extent the state contemplates increasing the RPS goals from their current levels, which will be required to achieve the states 2050 GHG emissions goals. The Air Resources Board's recently updated AB 32 Scoping Plan recognizes that meeting California's goal to reduce GHG emissions to 80% of 1990 levels by 2050 will require the widespread electrification of the state's transportation, building, and industrial sectors.[5]

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[2] See http://www.californiaznehomes.com/.

[3] D.07-01-018 at p. 19.

[4] See Public Utilities Code Sec. 399.11.

[5] ARB, *First Update to the Climate Change Scoping Plan: Building on the Framework,* May 2014, at 36-37. Available at http://www.arb.ca.gov/cc/scopingplan/2013_update/draft_proposed_first_update.pdf (Updated

ARB's findings are supported by independent research by Lawrence Berkeley National Laboratory demonstrating that sustained action beyond even the policy measures currently under consideration will be necessary to meet California's long-term climate change goals; other recent academic research on the topic reaches similar conclusions.[6] In sum, these reports clearly demonstrate that in order to reach California's long-term climate goals far greater amounts of renewable energy will need to be procured. The only way these long-term goals can be met in a cost-effective fashion is in partnership with those energy consumers who are making investments in customer-sited DG. ARB's recently updated Scoping Plan recognizes this fact noting, "…we have to coordinate and align public investments in ways that most effectively leverage private resources."[7] Categorizing RECs generated by customer-side DG as PCC 1 procurement is just the type of leveraging necessary to significantly expand the supply of new renewable generation that would be readily available to meet both current and future RPS requirements, thus lowering the cost of reaching the state's long-term climate goals.

Furthermore, as state and local incentive programs wind down, scheduled reductions in the ITC come into effect, rate design changes are implemented and NEM caps are reached, unnecessarily limiting the value of customer-side DG RECs through PCC 3 categorization appears at cross purposes with the desire to ensure the market for distributed renewable generation systems continues to grow sustainably.[8]

Harnessing customer investment in distributed generation to meet state RPS goals is common in a number of states. For example, Colorado, Massachusetts, New Jersey, Maryland, Ohio, Delaware and Pennsylvania are states that do not place limits or otherwise institute differentiated policies that adversely affect the value or ability of RECs associated with customer-side of the meter DG facilities to fully participate and contribute to their respective

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Scoping Plan).

[6] See, Estimating Policy-Driven Greenhouse Gas Emissions Trajectories in California: The California Greenhouse Gas Inventory Spreadsheet (GHGIS) Model," Lawrence Berkeley National Laboratory, October 2013. Available at http://eetd.lbl.gov/publications/estimating-policy-driven-greenhouse-g, and see, e.g., Greenblatt, J., et al. 2011. California's Energy Future, The view to 2050: Summary report. California Council on Science and Technology (CCST). Available at: https://www.ccst.us/publications/2011/2011energy.pdf. Williams, J. H., et al. 2011. "The Technology Path to Deep Greenhouse Gas Emissions cuts by 2050: The pivotal role of electricity." Science Express 335 (6064): 53–59. Available at: http://www.sciencemag.org/content/335/6064/53. Wei, M., et al. 2013. "Deep carbon reductions in California require electrification and integration across economic sectors." Environmental Research Letters 7: 1–9. Available at: http://iopscience.iop.org/1748-9326/8/1/014038/.

[7] See Updated Scoping Plan at p. ES5.

[8] See Public Utilities Code Sec. 2827.1(b)(1) which requires the Public Utilities Commission development of a tariff which will "ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

RPS programs. In fact, in a number of cases, DG RECs specifically associated with solar facilities hold enhanced status within those programs. California appears unique in establishing a rule that effectively relegates customer side of the meter generation and the RECs produced by these systems to second-class status within state RPS programs.

In addition to the policy reasons discussed above, there is no legal prohibition against utilizing customer-side RECs for RPS compliance within PCC 1. Sec. 399.16(b)(1) states in relevant part:

"(1) Eligible renewable energy resource electricity products that meet either of the following criteria: (A) Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area…"

Customer-side facilities clearly meet the requirement within statute of having their first point of interconnection on distribution facilities used to serve end users within California.[9] Thus customer-side DG facilities meet the threshold requirement of the statute to be considered in PCC 1. We agree with prior commenters in Docket No. 13-RPS-01 that facilities that meet this requirement should have their RECs counted within PCC 1.

Additionally, there is a distinction that could be made to the term "unbundled RECs" as used in section 399.16(b)(3), which established PCC 3 as consisting of "eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under the criteria of paragraph (1) or (2)." TASC believes that the CEC could reasonably determine that "unbundled renewable energy credits" for purposes of portfolio content category designation, could be defined as any REC sold separately from energy produced on a **wholesale** basis by an RPS eligible facility. Defining unbundled RECs in terms of wholesale energy would ensure the intent of the portfolio content categories is preserved, namely to prevent California utilities from meeting the entirety of the RPS goals with unbundled RECs such that none of the energy benefits from PCC 1 actually flow to California customers. Under this approach, RECs from customer side DG facilities would fall under PCC 1, as the energy from these facilities necessarily flows to California utility customers and therefor is never sold on a wholesale basis. Because the energy is, by definition used to serve end use load, this energy and these systems provide all of the associated benefits of a bundled transaction, irrespective of who purchase the RECs subsequent to the energy being produced.

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[9] See, also, Comments of the Sacramento Municipal Utility District (SMUD) on the Proposed Regulations CEC-300-2013-02-SD *Enforcement Procedures for the Renewable Portfolio Standard for Local Publicly Owned Utilities*, Docket No. 13-RPS-01, filed April 17, 2013, pp. 7-8.

The statutory language itself strongly suggests that establishing such distinctions is well within the Commission's authority. The phrase, "…that do not qualify under the criteria of paragraph (1) or (2)", indicates that in the Legislature's view, there may be circumstances where unbundled RECs would fall under PCC 1 or 2. The inclusion of the "that do no qualify" language implies that the Commission has the discretion to determine which unbundled RECs do not qualify under the criteria of PCC 1 and PCC 2.

Based on the above discussion, there is a clear statutory and policy basis for the Commission categorizing RECs produced by customer-side DG as PCC 1.

We now address the particular questions posed in Attachment A contained in the Notice of Staff Workshop:

a. Are there circumstances when it would not be appropriate to classify electricity generation from a POU owned DG system as PCC 1? Would it matter if the electricity generation was immediately sold to a POU customer, rather than transmitted to the POU's distribution system? This could occur where the POU owned DG systems was located on the customer's site.

Whether the DG system is contractually delivering energy to the utility or to the customer should be irrelevant to the determination as to whether or not DG RECs are deemed PCC 1 or PCC 3. The key determinant should be whether or not the generating facility meets the requirements of 399.16(b)(1)(A). As discussed above, we believe facilities connected at the distribution level serving end use load meet the requirements of statute. That said, the approach described in the question under which the utility owns the solar system and then sells the output from a generator sited at the customer premises to that customer on a retail basis is unambiguously a bundled transaction, indistinct from if the utility were procuring renewable energy on a wholesale basis from a utility scale project and then selling the energy from that facility to its retail customers. However, this approach appears in TASC's view to needlessly complicate the contractual structures required to deploy distributed resources and enable them to contribute to the RPS as PCC 1 procurement. It would be far simpler from a contractual standpoint to simply deem energy and RECs produced by customer side DG facilities as PCC 1 rather than forcing the market to pursue these workarounds at significant cost and to no practical advantage.

b. Under what circumstances, if at all, would it be appropriate to classify electricity generation from a customer-owned or third party-owned DG system as PCC 1, when that electricity generation is used to meet the customer's on-site load?

TASC believes that in all circumstances where the energy is used exclusively for onsite consumption, the associated RECs should be deemed PCC 1. As noted above, as commenters noted in the past, Public Utilities Code Sec. 399.16(b)(1) does not require that these RECs be deemed as something other than PCC 1 and there appears to be no practical or policy benefit to categorizing these resources as anything but PCC 1. In fact, categorizing them in other categories will stymie the ability of stakeholders to harness customer interest in DG resources to meet state climate change goals and contrary to clearly articulated state policy seeking to support customer-sited DG.

c. Would it be appropriate for a POU to procure all of the bundled electricity generated by a customer-owned DG system and then immediately sell back to the customer all of the commodity electricity to serve the customer's on-site electrical load and claim the procurement as PCC 1? Could such a transaction comport with section 3203 (a)(1) of the Energy Commission's regulations that precludes a POU from buying a bundled electricity product and then reselling the underlying electricity from the bundled product back to generator from which the electricity product was purchased?

As with question (a) above, this appears to be a workaround that would enable a facility that is electrically identical to one that is deployed under NEM, to be deemed PCC 1 under the existing set of rules. Also as in the case of (a) above, the fact that this particular workaround exists underscores the impractical nature of the existing PCC 3 designation and highlights the benefit of simplifying this process by designating energy and RECs associated with onsite facilities as PCC 1. The output from two facilities, one participating in NEM and another, identical facility participating under a buy-all/sell-all agreement, as described in this example, are accorded different statuses under the RPS program, despite the physically identical nature of the facilities and power-flows. While such a workaround may have some appeal given existing regulation, it is unnecessary given the flexibility in Sec. 399.16 to allow for RECs produced by customer-side DG to be categorized as PCC 1. TASC is also very concerned about the potential tax, interconnection and other implications of such a buy-all/sell-approach when compared to the relatively straightforward and well-understood interconnection and compensation framework under NEM.

Regarding the prohibition on selling back to the generator, in TASC's view the example provided here could be viewed as distinct from the circumstance that we believe was intended to be addressed by section 3203(a)(1) insofar as the energy sold back to the customer is used to meet the customer-generators retail electrical needs by that customer-generator in their "role" as a retail customer of the utility. This is different from the circumstances the regulation is attempting to guard against, in which the utility, through a purchase and sell-back arrangement from a wholesale generator, is seeking to engage in a REC-only transaction, thinly veiled through the purchase-sell back arrangement. The key distinction here being that in customer-generator scenario, the energy is being sold to and consumed by an end-use customer, not being sold to a wholesale generator for resale in the wholesale market.

d. If the customer installed the DG system to offset the customer's on-site load, and the system is being operated for this purpose, is the system's electricity generation available to be procured by a POU? How would the generation under such a transaction compare with generation from a central station facility that uses a portion of the facility's generation to satisfy on-site load, and sells the facility's net surplus generation to a utility via a power purchase agreement? An example of a central station facility could be a biomass facility that uses a portion of the facility's electricity generation to meet the on-site electrical load of related timber milling operations. How would your response differ, if at all, if a third party owned and installed the system?

Regarding the first question, the answer is "no." If the energy is used onsite, then that energy is not available to be purchased on a wholesale basis by the utility. The use of the energy to meet onsite load, whether that load is associated with a retail customer or is used to meet station load, means that the energy cannot be sold to the utility on a wholesale basis for resale. These outcomes appear to be mutually exclusive. As provided in the examples above, one could envision contractual approaches where all of the energy is purchased on a wholesale basis by the utility, with the amount needed to serve onsite needs immediately sold back to the customer-generator on a retail basis. These approaches are unnecessarily complex and highlight the advantages of categorizing RECs produced by customer-side DG as PCC 1. The response to this question/scenario is the same no matter who owns the onsite generating system in the example.

e. How, if at all, would the net-energy metering provisions of PUC section 2827 be implicated if a POU were to procure all of the bundled electricity generated by a customer owned DG system and then immediately sell back to the customer all of the commodity electricity to serve the customer's on-site electrical load?

Quite simply, this would not be a NEM transaction so PUC section 2827 is not implicated. The transaction envisioned in the question is a "buy-all, sell-all" approach, which implicates a number of significant issues when compared to NEM including ITC eligibility, potential tax liability as well as the interconnection standard under which the generator may have to interconnect.

II. Conclusion

TASC appreciates the opportunity to comment on whether generation from RPS-certified DG facilities, including customer-owned generation located behind the customer meter, should be classified as PCC 1 under Public Utilities Code Sec. 399.16(b)(1) and section 3203 of the Regulations. For the foregoing reasons, TASC supports the Energy Commission modifying its existing regulations to allow RECs produced by RPS eligible, customer side of the meter DG facilities to be classified as PCC 1. We believe such a categorization is consistent with state law and that there are strong public policy rationales for doing so at this time.

Respectfully submitted this July 25, 2014 at San Francisco, California.

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