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**VIA E-MAIL DOCKET@ENERGY.CA.GOV**



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

Re: Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities: PG&E Comments on Pre-Rulemaking Draft Amendments

## I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the issues covered in the July 11, 2014 California Energy Commission ("CEC") pre-rulemaking workshop on enforcement procedures for the Renewables Portfolio Standard ("RPS") for Local Publicly Owned Electric Utilities ("POU"). Specifically, PG&E comments on the proposed amendments and questions posed in Attachment A (the "Workshop Report") to the workshop notice.

In the following comments, PG&E requests that the implementation of Senate Bill 591 follow its legislative intent and that PG&E is concerned the alternatives and exemptions suggested in the CEC Workshop Report do not do so. Additionally, PG&E requests that the amendments to the definitions of RPS products, definition of "resale", contract amendments, and dynamic transfers for the POUs be consistent with rules for all retail sellers and with what is already defined by the California Public Utilities Commission ("CPUC").

## II. SENATE BILL 591 SHOULD BE STRICTLY IMPLEMENTED

Although Senate Bill ("SB") 591 appears narrowly drafted to apply only to the Merced Irrigation District ("MID"), PG&E provides comments on the CEC's implementation of the bill to ensure that all load-serving entities ("LSEs") in California contribute equitably, to the greatest extent possible, in the effort to achieve the State's RPS and greenhouse gas emission reduction goals. These goals require that any statutory exemptions provided to specific LSEs be implemented strictly according to the expressed intent of the Legislature and not be broadened through administrative action.

PG&E is concerned that some of the alternatives discussed in the Workshop Report may not be consistent with the language of SB 591 and may impermissibly expand the statutory exemption. First, the Workshop Report allows for the possibility that MID's eligibility for the exemption only involves a theoretical comparison of the output of the New Exchequer hydroelectric facility with Merced ID's retail load, while the legislation specifically requires MID to actually receive and use the New Exchequer output to serve its own load. Second, the Workshop Report considers a seven-year averaging period to establish eligibility, while the statute specifies an annual requirement. Third, the Workshop Report considers expanding the legislative language to consider only the retail sales not met by New Exchequer when establishing MID's RPS requirements, in contravention of other provisions in the RPS statute which point to different approaches. Finally, the Workshop Report considers exempting MID from the portfolio balance requirements, even though nothing in SB 591 refers to or allows such an exemption.

### A. MID Must "Receive" New Exchequer Output in Order to Qualify for the SB 591 Exemption.

Under SB 591, if MID "*receives* greater than 50 percent of its *annual retail sales*" from New Exchequer, it need only meet an RPS target in the applicable compliance period that is the least of three measures: (1) the RPS requirement applicable to other POUs; (2) the portion of MID's retail sales not "*supplied*" by New Exchequer; or (3) the volume of RPS procurement associated with an adopted cost limitation provision.[1/] Thus, the statute makes clear that MID must actually *receive* the generation from New Exchequer and *supply* that same generation to its own retail customers in order to qualify for the exemption.

The Workshop Report is not, however, consistent with the legislation insofar as it suggests that MID does not have to use the New Exchequer output to meet its retail sales. It leaves open the possibility that MID may qualify for the exemption even if it sells the New Exchequer output to another LSE and procures other electricity to serve its own customers. Such an outcome would not be consistent with the clear language or intent of the legislation. The Senate enacted SB 591 based upon the proponents' arguments that the New Exchequer output "is forecasted to be enough in many years to meet all of MID's energy customers' needs. However, under existing law, it appears MID will be required to purchase additional and unneeded power that is no friendlier to the environment that what we will already be producing."[2/] Given this understanding, an administrative implementation of the law that now allows MID to qualify for the exemption even while it purchases substitute power, including potentially greenhouse gas emitting fossil-fueled generation, would not only contradict the plain language of the statute, but would also be entirely contrary to the intent of the Legislature.

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1/ *See* Cal. Pub. Util. Code § 399.30(k) (emphasis added).
2/ August 27, 2013 Senate Floor Analysis of SB 591, p.5 (available at http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_0551-0600/sb_591_cfa_20130827_151851_sen_floor.html).

**B. MID Must Demonstrate the 50% Requirement Each Year in Order to Qualify for the Exemption.**

The Workshop Report asks whether MID should be able to average the generation produced by New Exchequer over multiple years in order to determine whether it met the 50% threshold to qualify for the exemption.[3/] It refers to the seven-year averaging period established by the Commission when implementing a statutory RPS exemption for the City and County of San Francisco ("CCSF").[4/]

Here, again, the legislation expressly answers the question when it states that MID must demonstrate that it has served 50% or more of its "*annual*" retail sales with New Exchequer output.[5/] Thus, it is clear that MID must demonstrate in each year of a multi-year RPS compliance period that it has met the 50% threshold; otherwise it does not qualify for the exemption. It is important to note that the CCSF exemption, found at Section 399.30(j), does not contain the same reference to "annual," but states more generally that CCSF must receive 67% of its "electricity resources," without specifying a time period. This distinction allows the CEC to interpret the CCSF exemption as allowing a multi-year averaging period, but the Legislature has not granted that same latitude to the CEC in the case of the MID exemption.

**C. Regardless of Whether MID Qualifies for the Exemption, the Commission Must Consider the Generally-Applicable RPS Requirement Based on Total Retail Sales.**

The Workshop Report asks whether, in the case that MID qualifies for the statutory exemption, its RPS target should be based on its total retail sales or its remaining retail sales not met by the New Exchequer output.[6/] As noted in Subsection A, above, if MID qualifies for the exemption, the statute requires its RPS requirement to be calculated as the lesser of three volumes. One of those volumes is "the procurement requirements of subdivision (c)" of Section 399.30.[7/] The procurement requirement of Section 399.30(c), which is the generally applicable procurement requirement for all POUs, clearly requires consideration of total retail sales, and not some portion of retail sales not met by large hydroelectric facilities. Accordingly, the CEC should calculate MID's RPS target pursuant to the generally applicable rules of Section 399.30(c), using total retail sales, and then compare that requirement against (1) the portion of retail sales not met by New Exchequer and (2) the volume of RPS procurement allowed by a properly-adopted cost limitation. The least of these will establish MID's RPS requirement for a given compliance period, if MID is eligible for the statutory exemption.

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3/ Workshop Report at 2.
4/ *Ibid.*
5/ Cal. Pub. Util. Code § 399.30(k)(1).
6/ Workshop Report at 2.
7/ Cal. Pub. Util. Code § 399.30(k)(4).

**D. The Portfolio Balance Requirements Apply to MID's RPS Obligation.**

Nothing in the language of the MID statutory exemption refers to the portfolio balance requirements or suggests that they do not apply to MID's remaining RPS obligation if it qualifies for the exemption.

Section 399.30(k) states simply that MID's remaining RPS procurement obligation must be met by procurement of "eligible renewable energy resources." This language is identical to that used in Section 399.30(a), which applies to all POUs. Further, Section 399.30(c)(3) states without any vagueness or ambiguity that "[a] local publicly owned electric utility shall adopt procurement requirements consistent with [the portfolio balance requirements]." If the Legislature had intended to exempt the MID from the portfolio balance requirements, it would have made that exemption clear and specific given the otherwise broad application of Section 399.30(c)(3) to all POUs.

In implementing the CCSF exemption found at Section 399.30(j), the CEC determined that the portfolio balance requirements do not apply to CCSF because: (1) "section 399.30(j) can be viewed as a stand-alone requirement;" (2) "because section 399.30(j) does not include an express provision to meet the PCC allocation requirements;" and (3) because CCSF would be unable to appropriately plan to meet the portfolio balance requirements given uncertainty about hydroelectric generation and demand.[8/] At the time, PG&E argued that none of these rationales justify ignoring the plain reading of the statute,[9/] and PG&E now urges the CEC to take the opportunity of this amendment to properly implement the statute by applying the portfolio balance requirements to both CCSF and MID.

However, even assuming that the CEC does not change its approach to the CCSF exemption, it is important to note the different language in the CCSF and MID statutory provisions. The CCSF exemption allows CCSF to use "eligible renewable energy resources, *including renewable energy credits*" to meet its remaining RPS obligation.[10/] The reference here to "renewable energy credits" is the only potential statutory basis the CEC could have relied upon in exempting CCSF from the portfolio balance requirements, and that language is absent from the MID statutory exemption. Accordingly, even if the CEC correctly interpreted the CCSF exemption, the same reasoning cannot be applied to the MID exemption.

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8/ Initial Statement of Reasons for the *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities* at 22.

9/ *See* Comments of Pacific Gas and Electric Company on the Proposed Regulations Establishing Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities, filed April 15, 2013 in Docket 13-RPS-01, at pp. 6-7.

10/ Cal. Pub. Util. Code § 399.30(j).

## III. PORTFOLIO CONTENT CATEGORY FOR POU-OWNED OR PROCURED DG SYSTEM

The Workshop Report asks whether there are circumstances when it would be appropriate to classify electricity generation from either a POU-owned, or from a customer-owned or third party-owned distributed generation ("DG") system as Portfolio Content Category ("PCC") 1. The Workshop Report also asks whether it would matter if the electricity generation was immediately sold to a POU customer, rather than transmitted to the POU's distribution system. This could occur, for example, where the POU-owned DG system was located behind the meter ("BTM") on the customer's site.

In the interest of ensuring consistent definitions for RPS products that apply throughout California, both to avoid conveying unintended regulatory advantages to certain load-serving entities and to reduce the complexity and cost of participating in the California renewables market, it is important to note that the California Public Utilities Commission ("CPUC") has already promulgated rules for retail sellers regarding the treatment of on-site, BTM use of electricity from an RPS-certified DG facility. In its Decision regarding the portfolio content category requirements of the RPS statute, the CPUC states that, "the sale of [Renewable Energy Credits ("REC")] associated with the on-site use of electricity from an RPS-certified DG facility is different from the sale by the system owner of both energy and RECs to a retail seller."[11/] The CPUC supported this outcome in the following discussion: "In considering the role of such unbundled RECs [aka, PCC 3], it is important to recognize that the on-site consumption of the electricity from the DG system has already produced an RPS benefit: it reduces the total retail sales of the interconnected utility, and thus reduces the amount of RPS-eligible procurement the utility requires."[12/] The CPUC therefore concluded that "conferring an additional value on the unbundled RECs by considering them to meet the 'first point of interconnection to distribution system' criterion is not warranted by any statutory language or Commission decision."[13/] PG&E's provides below responses to the specific questions on this topic set forth in the Workshop Report.

### A. Are there circumstances where 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?

Under CPUC regulations, a utility-owned DG system which transmits generation to the utility's distribution system is considered PCC 1. Therefore, a consistent application is necessary where a POU-owned DG system transmitting electricity to the POU's distribution system should

11/ CPUC Decision ("D.")11-12-052 at 35 (available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156060.PDF).
12/ *Ibid.*
13/ *Id.* at 35-36.

also be PCC 1. PG&E has no comments on the circumstance in which the electricity generation from a BTM DG system owned by a POU was immediately sold to a POU customer, as PG&E does not currently own any facilities with such an arrangement.

**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?**

In order to maintain consistency in RPS product definitions between CPUC- and CEC-regulated entities, the CEC should not 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.[14/]

**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 onsite electrical load and claim the procurement as PCC 1?**

No, such a transaction would not comport with section 3203 (a)(1) of the Commission's regulations precluding such a sell back.

**D. If the customer installed the DG system to offset the customer's on-site load, and the system is operated for this purpose, is the system's electricity generation available to be procured by a POU?**

If the customer is under a net energy metering arrangement with the POU, then the net surplus electricity amount, if any, at the end of the customer's true-up period, would be available to be procured by a POU. Generation under a net energy metering transaction would differ significantly from generation exported from a central station facility. A central station facility would need multiple meters to facilitate measuring on an hourly or sub-hourly basis the portion of the plant's electricity generation being transmitted to grid and the portion meeting onsite load. Therefore, in such a transaction with a central station facility, the netting would occur throughout each hour of each day, while under a net energy metering arrangement, the netting would occur once per year.

14/ *See* CPUC D.11-12-052 at 35 (concluding same).

**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?**

Such an arrangement would significantly reduce a customer's benefits under a net energy metering program, since the procurement price of the bundled electricity would likely be less than the customer's retail rates. In addition, such a transaction would not be possible with the metering arrangement currently used for net energy metering arrangements. Additional revenue quality meters would need to be installed to measure the generation of the customer-owned DG system.

## IV. DEFINITION OF "RETAIL SALES"

PG&E has no comments at this time on this section of the Workshop Report.

## V. DEFINITION OF "RESALE"

**A. Is the guidance posted on the CEC's website regarding the definition of "resale" sufficient or is additional guidance needed, and if so in what areas and why?**

The CEC's website states: "A purchase is considered a "resale" if the POU is buying the electricity product from another California RPS-obligated utility." PG&E believes this definition should be clarified to be consistent with the CPUC's adopted definition of a resale and should not be limited to transactions between utilities. The CPUC describes a "resale" as the circumstance in which, "a retail seller could buy part or all of the procurement acquired through a contract for RPS procurement entered into by another entity and claim it purchased procurement for RPS compliance in the same portfolio content category as would have been used for the original procurement."[15/] Furthermore, the CEC's definition of a resale may be both over- and under-inclusive. It may be under-inclusive because a resale may not be limited to transactions between "California RPS-obligated utilities." Marketers and utilities outside of California may also participate in RPS transactions. It may be over-inclusive because not all transactions between "California RPS-obligated utilities" may constitute "resales." For example, a "resale" rule should not apply to a transaction in which a California utility has developed RPS-eligible generation and is selling that generation directly and in real time to another utility. For all these reasons, PG&E recommends that the CEC adopt the CPUC's definition of resale cited above.

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15/ *Id.* at 52.

## VI. CONTRACT AMENDMENTS AND EXCESS PROCUREMENT

The Workshop Report asks whether the Commission's regulations should be clarified regarding the term of amended contracts for purposes of calculating and subtracting excess procurement. Section 3206 (a)(1)(A) of the Commission's regulations requires that electricity products procured under contracts of less than 10 years in duration be subtracted from the calculation of excess procurement, unless the electricity product is deemed "count in full." However, the regulations do not currently address how the term of the contract is calculated when the original contract term is amended.

Similar to the CEC's RPS enforcement regulations, the CPUC's decisions implementing the RPS statute do not directly address how the term of a PCC 1 contract is calculated when the original contract term is amended.[16/] In the interest of fairness and consistency across all load serving entities, PG&E suggests that the CEC and the CPUC first reach a common understanding on this matter, and to the extent possible pursue such clarifications jointly or at the same time.

## VII. DYNAMIC TRANSFER AGREEMENTS

The Workshop Report asks whether the CEC's regulations need to distinguish between two types of dynamic transfer agreements. It also asks whether the CEC should require hourly verification of deliveries under dynamic scheduling agreements in order for those deliveries to qualify as PCC 1.[17/]

As the Workshop Report itself notes, the statutory requirement for eligibility of dynamically transferred output to qualify as PCC 1 is that the eligible renewable energy resource generating the output has, "an agreement to dynamically transfer electricity to a California balancing authority [("CBA")]."[18/] Thus, the CEC's current regulation that requires POUs to submit a dynamic transfer agreement in order to verify the PCC 1 eligibility of these resources is entirely consistent, and, in fact, required, by the statute, and it should not be altered to require more burdensome reporting and verification requirements. Similarly, the CPUC has held that RPS products, "scheduled into a California balancing authority pursuant to a dynamic transfer

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16/ While the CPUC Decision on this point is clear that "short-term" contracts (those of less than 10 years in duration) are not eligible to be banked, it does not address a circumstance in which a contract that was originally short-term has been amended to have a total duration of 10 or more years. *See* CPUC D.12-06-038 at 63 ("It is clear that the instruction that the Commission 'shall deduct the total amount of procurement associated with contracts of less than 10 years in duration' prevents procurement from short term contracts signed later than June 1, 2010 from being counted as excess procurement."). The CEC should treat separately "grandfathered" contracts that were executed prior to June 1, 2010 and continue to meet the criteria set forth at Section 399.16(d) of the California Public Utilities Code. The CPUC has determined that because such contracts are required to "count in full" under the statute, they are eligible for banking even if they are short-term. *Id*. at 63, fn. 84 (noting that "procurement from contracts signed prior to June 1, 2010 may count without limitation as excess procurement").

17/ Workshop Report at 6.

18/ Cal. Pub. Util. Code § 399.16(b)(1)(B).

agreement between the balancing authority where the generation facility is interconnected and the California balancing authority into which the generation is scheduled" qualify for PCC 1 treatment, assuming no unbundling of the RECs and that the generator is RPS-eligible.[19/]

The Legislature made the determination that resources with a dynamic transfer agreement into a CBA should qualify for PCC 1 treatment, without further conditioning the eligibility on verification of hourly deliveries. In fact, the Legislature made clear that dynamic transfers are a special category by separating them from other out-of-state generation that is scheduled into a CBA and must be verified on an hourly basis.[20/] The CEC's proposal to require hourly verification of dynamically scheduled output would conflate these two separate categories of PCC 1 products and would ignore the special and separate treatment accorded by the Legislature to dynamic transfers. The CEC should not amend its regulation regarding dynamic transfers.

## VIII. CONCLUSION

PG&E appreciates the opportunity to comment on the pre-rulemaking amendments to the RPS regulations for Local POUs. Please contact me if you have any questions or wish to discuss matters further.

Sincerely,

/s/

Madeline R. Silva

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19/ CPUC Decision 11-12-052 at 71 (Conclusion of Law 15).

20/ *Compare* Cal. Pub. Util. Code § 399.16(b)(1)(A) (hourly verification required for out-of-state generation) *with* Cal. Pub. Util. Code § 399.16(b)(1)(B) (no requirement of hourly verification for dynamic transfers).