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VIA E-MAIL
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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 11-RPS-01
And Docket No. 02-REN-1038
RPS Proceeding
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Comments of Pacific Gas and Electric Company on the Lead Commissioner Draft *RPS Eligibility Guidebook* and *Renewable Energy Program Overall Program Guidebook*

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the Lead Commissioner Drafts of the Renewables Portfolio Standard ("RPS") Eligibility Guidebook (5th Ed.) (the "Draft Eligibility Guidebook") and the Renewable Energy Program overall Program Guidebook (4th Ed.) (the "Draft Overall Guidebook") (together, the "Draft Guidebooks"), both of which were issued in April 2012 and are on the agenda for discussion at the California Energy Commission's ("Commission") Business Meeting scheduled for May 9, 2012.

I. INTRODUCTION

PG&E's comments focus on the following seven substantive issues with the Draft Eligibility Guidebook: (1) the burdensome and costly RPS eligibility criteria for surplus generation from net metered customers under Assembly Bill ("AB") 920; (2) the lack of consistency with the statutory definitions of certain "out-of-state" facilities; (3) the need for regulatory certainty once precertifications for RPS eligibility have been approved; (4) the need to distinguish between sub-categories of RPS-eligible hydroelectric facilities; (5) the need to better define what "significant" change in the use of fuel at a multifuel facility requires amendment of an RPS certification; (6) the need to change the Commission's RPS reporting deadline from June 1 to July 1 of each year for the prior year's generation; and (7) the need for clarification of the process for re-certifying renewable QF facilities that previously filed a CEC-RPS-2 form.

Additionally, the Appendix to this letter provides a list of technical or clarifying edits that PG&E recommends to each of the Draft Guidebooks.

II. SUBSTANTIVE COMMENTS ON THE DRAFT ELIGIBILITY GUIDEBOOK

A. The Standards for Receiving RPS Credit from Surplus Net Metering Pursuant to AB 920 Are Too Burdensome and Expensive.

In order to count RECs procured under the AB 920 program for RPS compliance, the Draft Eligibility Guidebook requires net metered facilities to be RPS certified and the generation to be tracked in and reported to WREGIS after October 1, 2012 with a meter having an independently verified rating of 2 percent or higher. *See* Draft Eligibility Guidebook at pp. 72, 77. *Cf.*, *id.* at p. 81 (suggesting that RECs must be tracked in WREGIS without regard to date). In addition, the guidebook requires customers with small facilities (less than 20 kW) to use an aggregator for RPS certification and WREGIS reporting. *Id.* at p. 81. Unfortunately, PG&E expects these standards to be too burdensome and expensive for customers to implement, and therefore it is likely that net metered customers will not be able to sell their Renewable Energy Credits ("RECs") pursuant to AB 920. In particular, PG&E expects that any requirement to use an aggregation service will mean a payment to the aggregator that will far exceed any AB 920 compensation the customer is likely to receive.

As PG&E commented on the last draft revision of the Eligibility Guidebook, for the small amount of RECs expected from the AB 920 program, a more feasible and reasonable approach would be to allow RPS credit from net metering surplus generators to occur without WREGIS tracking. To prevent double counting from these net surplus generators, the Commission can require each such facility owner to attest they will not report any net surplus generation to any renewable energy tracking system during the RPS certification process. Thus, the only generation these facilities will be permitted to report to a tracking system will be the generation that is not compensated under AB 920.

The Commission should not implement AB 920 in a way that is commercially infeasible. The current draft Guidebook effectively and impermissibly nullifies the Legislature's goal of allowing net metering customers to receive compensation for the renewable value of their net surplus generation.

B. The Group of Facilities Subject to "Out-of-State" Requirements Must Be Limited to Those That Do Not Interconnect to a California Balancing Authority Area.

The Draft Eligibility Guidebook attempts to incorporate the geographic distinctions in the RPS legislation by generally replacing the phrase "out of state facilities" with "facilities with the first point of interconnection outside California." *See, e.g.*, pp. 16, 22, 57-67, 86, App. B (various forms). The revised terminology still does not fully capture the nuanced distinctions in the legislation and must be further revised.

The statutory definition of a "renewable electrical generation facility" creates three classes of facilities, each with its own conditions. These distinctions are primarily geographic in nature, but not entirely. The first class of facilities is those that are either located (1) "in the state" or (2) "near the border of the state with the first point of connection to the transmission network of a balancing authority area primarily located within the state." Pub. Res. Code § 25741(a)(2)(A). This definition of balancing authority areas in the second category of this first class tracks closely the definition of a California balancing authority found in Public Utility Code Section 399.12(d), and both sections should therefore be read as referring to the same group of balancing authority areas.[1/] It is clear from these statutory definitions that facilities in this first class may or may not be located in California and may or may not have a point of interconnection within the boundaries of California, given that CAISO, a California balancing authority, has metered boundaries that extend outside the physical border of the state.

The second statutory class of facilities includes those that have their "first point of interconnection to the transmission network outside the state, within the Western Electricity Coordinating Council (WECC) service area" and meet other stated conditions. Pub. Res. Code § 25741(a)(2)(B). Note that a facility located near the border of California with a first point of interconnection to a California balancing authority at a location outside of California would fall within *both* the first and second classes.

Finally, the third statutory class of facilities are those located "outside the United States." *Id.* at § 25741(a)(3).

In order to qualify as RPS-eligible, a facility must meet all requirements for *either* class 1 *or* class 2. *See id.* at § 25741(a)(2) ("The facility satisfies *one* of the following requirements . . .") (emphasis added). Accordingly, a facility that falls within both classes need not meet the more stringent conditions for the class 2 facilities. However, if the same facility is also located outside the United States (e.g., in Mexico), then it must nonetheless also meet the further conditions for a class 3 facility.

With this backdrop, it is clear that the Draft Eligibility Guidebook is overbroad when it repeatedly describes class 2 facilities as those "with the first point of interconnection outside of

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1/ "California balancing authority" is a balancing authority with control over a balancing authority area primarily located in this state and operating for retail sellers and local publicly owned electric utilities subject to the requirements of this article and includes the Independent System Operator (ISO) and a local publicly owned electric utility operating a transmission grid that is not under the operational control of the ISO. A California balancing authority is responsible for the operation of the transmission grid within its metered boundaries which may not be limited by the political boundaries of the State of California." Cal. Pub. Util. Code § 399.12(d). *See also* Draft Overall Guidebook at 21 (incorporating the same definition of a California balancing authority and noting further that "[a] California balancing authority is "primarily located in this state" if more than 50 percent of its load is physically located within the geographical boundaries of California." The CPUC has decided that five balancing authorities currently meet the statutory definition of a "California balancing authority": California Independent System Operator (CAISO), Balancing Authority of Northern California (formerly SMUD), Imperial Irrigation District, LADWP, and Turlock Irrigation District. CPUC Decision ("D.")11-12-052 at p. 20.

California." *See, e.g.,* Draft Eligibility Guidebook at pp. 16, 22, 57-67, 86, App. B (various forms). Rather, the Draft Eligibility Guidebook must adhere to the structure of Section 25741(a) by describing class 2 facilities more narrowly as: "Facilities with a first point of connection to the transmission network outside the state and within the WECC service area, but not including a facility located near the border of California that has a first point of interconnection with a California balancing authority as defined in the Renewable Energy Program Overall Guidebook." For ease of reference, the guidebook should simply define this second class of facilities as "Out-of-State, Non-CBA Facilities." This more precisely defined term should replace all references in the Draft Eligibility Guidebook and the draft forms to "facilities with a first point of interconnection outside California," except where that phrase refers only to out-of-country (class 3) facilities.

C. The Commission Should Provide Regulatory Certainty by Applying the Requirements of the Guidebook and Law in Effect at the Time of Precertification for Purposes of Subsequent Certification Requests.

The Draft Eligibility Guidebook states in several places that even where a facility has been precertified, a facility must nonetheless meet the requirements of the RPS Eligibility Guidebook that are in effect at the time the Commission receives a subsequent application for certification for the same facility. *See* Draft Eligibility Guidebook at pp. 15, 76, 87. The Commission should provide additional regulatory certainty to the renewables market by instead allowing facilities that are precertified to apply for final RPS certification based upon the rules in place at the time the facility first sought precertification.

Renewables developers in today's market face major uncertainties as they seek to bring their products to the market. These uncertainties include the competition for a PPA, the uncertainty of tax credit extensions, the cycles of the financial markets, and the major potential for delay and increased project costs from interconnection studies and unforeseen environmental impacts that must be mitigated during project construction. All of these uncertainties tend to operate as barriers to entry and success for renewable projects, thereby reducing the available supply of RPS-eligible products and increasing the cost of meeting RPS requirements for California's energy consumers. In light of these circumstances, the Commission should seek every reasonable opportunity to provide a greater level of regulatory certainty to the renewables market.

It appears that offering to "lock in" the regulatory rules at the time of precertification is one way in which the Commission could offer greater certainty to the market while remaining consistent with its statutory responsibilities. Moreover, holding developers to the certification rules at the time they first apply for precertification is fair. It is based upon the rules in effect at that time that developers invest substantial resources in initiating the permitting, financing, PPA negotiation, and ultimately the construction process. To require developers to invest such massive sums of money, only to deny them certification because of changes many years into the future that could not have been foreseen at the time of precertification, is an unjust and highly inefficient outcome.

D. The Guidebook Does Not Sufficiently Differentiate "Conduit" Hydroelectric Facilities from Those Facilities Operated as Part of a Water Supply or Conveyance System.

The Draft Eligibility Guidebook, like the RPS statute itself, distinguishes between "conduit hydroelectric facilities," which are RPS-eligible up to 30 MW, and "existing hydroelectric generation unit[s] that [are] operated as part of a water supply or conveyance system," which are RPS-eligible up to 40 MW. *See* Draft Eligibility Guidebook at p. 30. A conduit facility is one that uses the hydroelectric potential of man-made conduits that are operated to distribute water "for a beneficial use." Draft Overall Guidebook at p. 22. A "water supply or conveyance system" may include the distribution of water through man-made conduits primarily for "agricultural, municipal or industrial consumption" although "not primarily for the generation of electricity." *Id.* at p 34.

Because "beneficial use" in the context of conduit hydroelectric facilities may include domestic and irrigation use, it appears that the same hydroelectric systems may qualify as either a conduit hydroelectric facility or one operated as part of a water supply or conveyance system. However, the guidebooks do not adequately describe what types of facilities qualify for the 40 MW eligibility, and which are limited to the 30 MW eligibility. The guidebooks should be revised to explicitly describe the relationship and any overlap between these two types of facilities.

E. The Commission Should Clarify What "Significant" Change in Fuel Amount Would Require Amending an RPS Certification.

When discussing applications for certification of multifuel facilities, the Draft Eligibility Guidebook provides that "[a]ny significant change in the fuel amounts should be reported to the Energy Commission through an amended application for certification, or precertification." Draft Eligibility Guidebook at p. 46. In another part of the Guidebook, the Commission appears to define the threshold of significance as an "[i]ncrease in the amount of nonrenewable fuel used annually beyond the allowable amount, or a change that exceeds 10 percent of the total annual energy input." *Id.*at p. 89.

PG&E is concerned that language could be read to require an amendment to an RPS certification for a multifuel facility utilizing biogas every time the volume of biogas provided to a facility may temporarily fall below the average volume stated in the application or change by more than 10% of the total energy input into the facility. First, there is no indication of the period of time over which the change should be measured. Deliveries of biogas could change dramatically from day-to-day and even month-to-month depending on availability of supply, storage, and transmission. It could be administratively burdensome, if not infeasible, to seek certification changes with each such daily, weekly, or monthly change. Second, it is unclear whether the change is one that is projected and prospective, or if an amendment to certification should only be sought after-the-fact for past changes.

In order to make this language operationally feasible, PG&E recommends that certifications state the maximum expected renewable fuel deliveries under particular contracts and that any actual exceedance of the certified amount over a calendar year will trigger the need for an amendment to the certification. Reductions in renewable fuel volumes should not trigger amendments to certifications, but rather will be tracked in WREGIS when creating the RECs based upon actual renewable fuel use at a multifuel facility.

F. RPS Reports to the Commission Should Not Be Due Until July 1 of Each Year.

The Draft Eligibility Guidebook proposes that LSEs report RPS-eligible procurement for the prior calendar year and/or RPS compliance period to the Commission by June 1 (except for 2011 reporting, which is on hold pending the issuance of the next edition of the Eligibility Guidebook). *See* Draft Eligibility Guidebook at p. 107. PG&E has previously proposed that the Commission's annual procurement report due date be moved to July 1 of each year.[2/] The reason for this is that the June 1 reporting date does not provide sufficient time to receive, reconcile, correct and retire all WREGIS certificates for the prior year. Since WREGIS Certificates are issued 90 days after the end of each generation month,[3/] certificates for the last month of the prior year are not available as a practical matter until early April of the following year. Moreover, since WREGIS creates certificates only once per month, the first opportunity to make any necessary corrections to newly issued certificates is in the month following issuance.[4/] Therefore, any corrected certificates for generation occurring at the end of the prior year will not be practically available until early May at the earliest. In some more complicated circumstances, corrections have taken an additional month – until June - to resolve. Only after any necessary corrections are made can the certificates be transferred from the counterparty to PG&E.[5/]

Based on this timeline, PG&E may not receive some of its WREGIS certificates for the prior year until June of the following year. PG&E then must review the certificates and verify that they are consistent with settlements between the parties. Finally, PG&E will retire the certificates within WREGIS for purposes of RPS compliance. PG&E's recommended July 1 reporting deadline is the earliest that will allow up to two certificate creation cycles to occur for corrections, which PG&E believes will be adequate to cover most circumstances.

2/ Letter from Mark Krausse, PG&E, to Melissa Jones, CEC, dated May 16, 2011.

3/ WREGIS Operating Rules, WREGIS (December 2010) ("WREGIS Operating Rules"), Sec. 12.2, pg. 37 (available at http://www.wregis.org/uploads/files/851/WREGIS%20Operating%20Rules%20v%2012%209%2010.pdf).

4/ *See* WREGIS Operating Rules, Sec. 9.4.2., pg. 30 (noting that adjustments to certificates "will be reflected in the next certificate issuance cycle"); *Id.* at Sec. 12.2., pg. 37 (certificates are issued once per month).

5/ *See* WREGIS Operating Rules, Sec. 9.4.2., pg. 30 ("Adjustments . . . shall take place in the Account/sub account to which the Generating Unit is assigned.").

G. The Commission Should Clarify The Process for Submitting a New Certification Application for a Facility Previously Certified Using the CEC-RPS-2 Form.

The Draft Eligibility Guidebook states that a "utility may count only the amount of generation under contract with the facility identified in the utility [CEC-RPS-2 form] certification that occurs after the termination date of the contract if the facility operator, or agent thereof, submits an application for certification to the Energy Commission using a CEC-RPS-1 form before October 1, 2012." Draft Eligibility Guidebook at p. 79. PG&E is confused by the reference to the October 1, 2012 deadline in this statement. Does this require that renewable QF facilities that had been previously certified using a CEC-RPS-2 form must submit a new form by October 1 even if the contracts under which their output is procured do not expire or terminate until far into the future? PG&E submits that a more reasonable approach is reflected on pages 82-83 of the Draft Eligibility Guidebook, which requires a facility operator or its agent to submit a CEC-RPS-1 form "[o]nce the contract expires or is voluntarily renegotiated." The Commission should resolve the apparent inconsistency between these two statements by removing the reference to "October 1, 2012" in the former.

III. CONCLUSION

PG&E appreciates the opportunity to provide comments on the Draft Guidebooks. In these comments, PG&E urges the Commission to: (1) reduce the burdensome and costly RPS eligibility criteria for surplus generation from net metered customers; (2) revise the descriptions of certain "out-of-state" facilities to adhere more closely to the statutory provisions; (3) lock in the eligibility rules for precertified facilities at the time of precertification to provide greater regulatory certainty and reduce RPS program costs to customers; (4) distinguish more clearly between conduit hydroelectric facilities and those that use water supply or conveyance systems; (5) clarify what "significant" change in the use of fuel at a multifuel facility requires amendment of an RPS certification; (6) change the Commission's RPS reporting deadline from June 1 to July 1 of each year for the prior year's generation; and (7) clarify that a renewable QF facility previously certified with a CEC-RPS-2 form need only re-apply for certification using a CEC-RPS-1 form once the original contract expires or is voluntarily renegotiated.

Best regards,

/s/

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cc: Valerie Winn, PG&E
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Appendix: PG&E Recommendations for Technical and Clarifying Edits to the Draft Guidebooks

I. Technical/Clarifying Edits to the Draft Eligibility Guidebook

Issue Area	Page Reference(s)	Recommended Edit	Notes
Description of RECs	ii, 72-74	~~Tradable~~ Unbundled Renewable Energy Credits	SB 2(1X) uses the term "unbundled" to refer to RECs that are procured and traded separately from the underlying energy. *See* Pub. Util. Code § 399.16(b)(3). The prior use of the phrase "Tradable Renewable Energy Credit" should be discontinued, since it refers specifically to a CPUC-defined product that is not applicable to the post-January 1, 2012 RPS program.
RPS Statutory Goals	1, 3, 10	"These laws ~~require~~ set a goal for retail sellers of electricity and local publicly owned electric utilities (POUs) ~~to~~ of increas~~e~~ing the amount of renewable energy they procure until 33 percent of their retail sales are served with renewable energy by December 31, 2020."	As implemented by the CPUC in D.11-12-020 (issued December 1, 2011), SB 2(1X) does not require retail sellers to demonstrate actual deliveries of RPS-eligible products equal to 33% of retail sales in 2020. Rather, retail sellers must procure sufficient RPS-eligible products to meet the 2017-2020 compliance period requirement, which allows higher procurement

			in 2017-2019 to make up for less than 33% in 2020. *See* D.11-12-020 at pg. 24 (Ordering Paragraph 3).
Changed Requirements	2, fn. 5.	~~In the meantime, many requirements remain unchanged in this guidebook even though they are changed or new in the law.~~	PG&E finds the intended meaning of this statement to be unclear, and it may suggest that the guidebook is inconsistent with law.
RPS Statutory Goals	3	"SB X1-2 increases the RPS procurement goal from 20 percent by 2010 to 33 percent by 2020 . . . ."	As implemented by the CPUC in D.11-12-020 (issued December 1, 2011), SB 2(1X) does not require retail sellers to demonstrate actual deliveries of RPS-eligible products equal to 33% of retail sales in 2020. Rather, retail sellers must procure sufficient RPS-eligible products to meet the 2017-2020 compliance period requirement, which allows higher procurement in 2017-2019 to make up for less than 33% in 2020. *See* D.11-12-020 at pg. 24 (Ordering Paragraph 3).
RPS Statutory Goals	10	"SB X1-2 directs the CPUC to oversee retail sellers' procurement of eligible renewable energy resources and to assess retail sellers' compliance with procurement quantity requirements over initial three compliance periods, ending ~~with 33 percent eligible renewable energy resource procurement by~~	As implemented by the CPUC in D.11-12-020 (issued December 1, 2011), SB 2(1X) does not require retail sellers to demonstrate actual deliveries of RPS-eligible products equal to 33% of retail sales in 2020. Rather, retail sellers must procure sufficient RPS-eligible products to meet

		December 31, 2020, and annually thereafter."	the 2017-2020 compliance period requirement, which allows higher procurement in 2017-2019 to make up for less than 33% in 2020. *See* D.11-12-020 at pg. 24 (Ordering Paragraph 3).
Typographical Error	12, fn. 39	"Resolution No. 12-0328-3, as adopted or ~~sub~~ subsequently amended . . . "	
Description of Product Content Category Requirements in SB X1-2.	18	"~~For the first compliance period, r~~Retail sellers must procure at least 50 percent for the first compliance period, 65 percent for the second period, and 75 percent thereafter of all procurement credited towards each respective compliance period from Portfolio Content Category Number 1~~the eligible renewable energy resource electricity~~ products associated with contracts executed after June 1, 2010~~, from Portfolio Content Category Number 1~~. ~~Retail sellers shall not procure~~ No more than 25 percent for the first compliance period, 15 percent for the second compliance period, and 10 percent thereafter of all procurement credited towards each respective compliance period may come from Portfolio	Clarifying edits intended to track the statutory language in Section 399.16(c) more accurately and clearly.

		Content Category Number 3 ~~the eligible renewable energy resource electricity~~ products associated with contracts executed after June 1, 2010~~, from Portfolio Content Category Number 3~~."	
Statutory Eligibility Criteria	21, fn. 59	"Public Resources Code Section 25741, Subdivision (a). *See also* Public Utilities Code Section 399.12, Subdivision (e)."	Both of these sections must be read in conjunction to determine the RPS eligibility of a resource.
De Minimis Quantity	49	"All of the generation from multifuel facilities using a de minimis quantity of nonrenewable fuels or energy resources in the same generation process as the renewable fuel or resource . . . "	Missing "de minimis"
CEQA Thresholds	64	With regard to Transmission System Safety and Nuisance: "2 miles~~, although if the transmission line interconnection extends into California, the facility would be considered in state and an environmental review pursuant to the California Environmental Quality Act would be required~~."	This criterion fails to recognize that if a project interconnects to a California balancing authority, the environmental review thresholds for out-of-state would not apply to it. Moreover, CEQA review may not be required of in-state projects if the project does not trigger CEQA or is exempt from it.
Confidentiality	66	"All data submitted are generally expected to be public, subject to exceptions to public disclosure consistent with the California Public	Information that is exempt from disclosure under the CPRA should not be disclosed by the Commission. *See* Draft

		Records Act.”	Overall Guidebook at 11.
Eligibility Date	80	“All eligible generation produced in and following the month of the eligibility date and properly tracked in the WREGIS system will be considered RPS-eligible generation.”	Appears to be the unstated intent of the paragraph.
Limited Certifications	83	“A facility receiving a limited certification will be eligible for the RPS only for the duration (as may be amended consistent with Public Utilities Code Section 399.16(d)) of the contract or ownership agreement originally executed prior to June 1, 2010 . . .”	Note that Pub. Util. Code § 399.16(d) allows grandfathered contracts to be amended to extend the term of the contract so long as the original contract had a term of at least 15 years.
RPS Reporting	107	“Although SB X1-2 established multiyear compliance periods, the Energy Commission requires retail sellers and POUs to report monthly the net deposit of WREGIS certificates into a compliance entity’s WREGIS accounts during ~~procurement that was retired or claimed in~~ the previous calendar year, as described below.”	LSEs need not retire RECs until the end of a compliance period, and it is unclear what the Commission means by “claimed” in this sentence. An LSE has no obligation to retire or use for compliance any RECs until the end of the compliance period.

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II. Technical/Clarifying Edits to the Draft Overall Guidebook

Issue Area	**Page Reference(s)**	**Recommended Edit**	**Notes**
RPS Statutory Goals	1	"These laws ~~require~~ set a goal for retail sellers of electricity and local publicly owned electric utilities ~~to~~ of increas~~e~~ing the amount of renewable energy they procure each year until 33 percent of their retail sales are served with eligible renewable energy resources by December 31, 2020."	As implemented by the CPUC in D.11-12-020 (issued December 1, 2011), SB 2(1X) does not require retail sellers to demonstrate actual deliveries of RPS-eligible products equal to 33% of retail sales in 2020. Rather, retail sellers must procure sufficient RPS-eligible products to meet the 2017-2020 compliance period requirement, which allows higher procurement in 2017-2019 to make up for less than 33% in 2020. *See* D.11-12-020 at pg. 24 (Ordering Paragraph 3).
Definition of "distributed generation facility"	23	"***Distributed generation facility*** **–** a small-scale electricity generation facility that is interconnected to a distribution or transmission network operating at 115kV or less and is generally 20 MW or smaller. Distributed generation facilities may serve on-site load or off-site load or both."	The definition of distributed generation should not depend upon the LSE service territory. Since each of the large IOUs has different definitions for the voltage of its distribution system, the Commission should simply adopt 115kV, the highest of the three distribution systems, as the cut-off for defining distributed generation facilities.
RPS Statutory Goals	32	In definition of the Renewables Portfolio Standard: "Under the RPS,	As implemented by the CPUC in D.11-12-020 (issued December 1,

		a retail seller or local publicly owned electric utility must demonstrate reasonable progress toward procuring i~~ncrease its total procurement of eligible renewable energy resources so that~~ 33 percent of its retail sales ~~are procured~~ from eligible renewable energy resources ~~no later than~~ by December 31, 2020."	2011), SB 2(1X) does not require retail sellers to demonstrate actual deliveries of RPS-eligible products equal to 33% of retail sales in 2020. Rather, retail sellers must procure sufficient RPS-eligible products to meet the 2017-2020 compliance period requirement, which allows higher procurement in 2017-2019 to make up for less than 33% in 2020. *See* D.11-12-020 at pg. 24 (Ordering Paragraph 3).