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April 8, 2010 **VIA ELECTRONIC FILING**

Mr. Gary Collord
Air Pollution Specialist, Energy Section
CALIFORNIA AIR RESOURCES BOARD
1001 I Street
Sacramento, CA 95812-2828

Re: Pacific Gas and Electric Company's Comments on the California Air Resources Board's Preliminary Draft Regulation for the California Renewable Electricity Standard

Dear Mr. Collord:

Pacific Gas and Electric Company ("PG&E") welcomes the opportunity to provide these comments on the California Air Resources Board's ("ARB") March 2010 *California Renewable Electricity Standard Preliminary Draft Regulation ("PDR*").

I. INTRODUCTION

PG&E continues to urge the ARB to work toward a Renewable Electricity Standard ("RES") that provides flexibility to ensure a 33% mandate is achievable at a reasonable cost to customers. Given the very short timeline allowed by the Governor's executive order, PG&E appreciates the progress ARB staff has made in collaboration with the staff of the California Public Utilities Commission ("CPUC"), the California Energy Commission ("CEC"), and the California Independent System Operator ("CAISO"). However, PG&E remains concerned that without increased flexibility in the implementation rules, the RES standard will be difficult to achieve and will place an undue burden on customers. As in past comments in this proceeding, PG&E's comments on the PDR seek primarily to ensure that the final RES will fulfill five key principles:

1. **Expand eligible sources** to include unbundled Renewable Energy Credits ("RECs") from anywhere within the western interconnection, without limitation or delivery requirements, and to capture the significant greenhouse gas ("GHG") reduction potential of small hydropower resources in British Columbia.

2. **Adopt appropriate compliance flexibility mechanisms** so that the RES remains feasible and equitable, including: (a) realistic interim annual compliance targets that, at a minimum, mirror the "stair step" approach in proposed 33% legislation; (b) clear standards to be applied during the periodic regulation reviews; and (c) harmonization of RPS and RES compliance reporting requirements.

3. **Ensure universal application of the RES requirements** to all California load-serving entities ("LSE"), without exemptions for new market entrants that allow entities to avoid the RES regulation by shifting load away from a regulated party and by ensuring that all regulated parties can procure RES-eligible electricity from the same resources.

4. **Maintain the cost-effectiveness of the RES program** by assessing during the periodic regulation reviews whether GHG reductions can be achieved more cost-effectively through alternative AB 32 scoping plan measures or in other industrial sectors, and by delaying compliance where factors outside the control of a regulated party make compliance infeasible or unreasonably expensive.

5. **Delineate enforcement responsibilities** between the ARB and other state agencies like the CPUC to ensure that regulated parties are not subject to double penalties for overlapping renewable energy procurement requirements.

Building upon PG&E's comments on the initial Concept Outline, these comments on the PDR provide more specific suggestions in each of these areas and recommend specific regulatory language to address many of PG&E's concerns. The comments also address a number of other issues outside the primary substantive focus areas noted above, including: clarification regarding the ability to use RECs to satisfy both the RPS and RES programs; clarification that ARB does not intend to impose cumulative deficits where a regulated party does not achieve a target; recommendations on harmonizing procedures at ARB and CPUC for the protection of market-sensitive information; and clarification regarding the RES formula included in the PDR.

II. SPECIFIC COMMENTS ON THE PDR

A. The RES Compliance Targets Should Be Enforced on an Annual Basis and Should Be No More Aggressive Than Targets Proposed in the Legislature.

Section 97003 of the PDR sets forth compliance intervals and REC procurement requirements for each interval that are expressed as percentages of retail sales for each regulated party. It appears that the PDR is structured so that if REC procurement in one year of a compliance interval is below the applicable REC percentage, the REC procurement in another year of the same compliance interval could make up for the earlier or later deficit.

While PG&E appreciates the flexibility that the compliance interval concept offers and believes that such flexibility is crucial to the success of the RES, PG&E recommends that the existing annual compliance requirements and banking mechanisms found in the RPS program be adopted for the RES. Use of the existing RPS mechanisms would help to further CARB's goal of harmonizing the two programs, and it would reduce potential volatility in the market produced by regulated parties seeking to purchase all of their compliance requirements in short-term deals at the end of a multi-year compliance period.

PG&E further recommends that ARB adopt less aggressive compliance milestones than those identified in the PDR. Having faced many obstacles in the course of seeking to achieve the 20% RPS mandate, PG&E is intimately familiar with the myriad issues that stand in the way of compliance with a higher mandate. For this reason, PG&E asks that the PDR be modified to provide interim compliance targets no more aggressive than those set forth in the March 4, 2010 amended version of Senate Bill 722. These include the following milestones: 20% by December 31, 2013; 25% by December 31, 2016; and 33% by December 31, 2020.[1/] While both the SB 722 milestones and the PDR milestones reach 33% by 2020, PG&E believes the compliance milestones set forth in SB 722 are more realistic, and should allow for renewables development to accelerate over time as transmission, interconnection, permitting, financing, and other siting obstacles are gradually overcome. However, it is important to view these interim milestones as subject to modification based on the ARB's periodic review of the regulation under Section 97011 of the PDR.

Many process reforms are underway to streamline permitting of facilities and to develop sufficient transmission to access renewables. However, those reforms need time to be put into practice and to produce results. The current and significant efforts underway to achieve 20% renewables can be leveraged, but the sheer magnitude of the challenge to reach 33%, coupled with the uncertainty surrounding which new transmission lines will be built, call for the establishment of more realistic compliance targets than those contained in the PDR.

Accordingly, PG&E recommends that Table 1 of Section 97003 be modified as follows:

Compliance Year	REC Percentage (% of retail sales by December 31 of each of the applicable compliance years)
2013, 2014, 2015	20
2016, 2017, 2018, 2019	25
2020 and subsequent years	33

1/ *See* SB 722, as amended in Assembly on March 4, 2010, Section 18 (proposing to repeal the existing Pub. Util. Code § 399.15 and replace it with a new § 399.15, including new compliance milestones at (b)(1)(A)-(D)) (available at http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0701-0750/sb_722_bill_20100304_amended_asm_v95.pdf).

B. Regulation Review Provisions Are Appropriate and Necessary, Although Standards for Modifying the Initial Compliance Schedule Should Be Clarified.

Section 97011 of the PDR sets forth a process to conduct three implementation reviews of the RES program. PG&E supports the provisions for implementation reviews and notes in particular that if the compliance milestones recommended by PG&E in Section II.A above are adopted, the timing of the implementation reviews will allow for early identification of barriers to achievement of the RPS goals and development and possible implementation of recommendations on how to address those barriers. Moreover, the review process should allow ARB to consider the cost-effectiveness of the RES in an ongoing manner and make adjustments should they be necessary.

Early review can provide greater regulatory certainty to the market and regulated parties about their compliance obligations. For example, parties will need to take early and consistent actions to meet increasing targets. Any obstacles that delay the development of new facilities that are needed to meet increasing goals will have the effect of pushing regulated parties to pursue other short-term alternatives to achieve compliance. However, if targets were to be postponed because of the delays in the development of new facilities, parties would be able to avoid procuring the short-term alternative if sufficient notice of the target delays is provided. The notice can help to minimize the potential for unreasonable regulatory implementation costs to customers.

The regulation reviews should also be an opportunity for ARB to seek public comment on whether GHG reductions could be achieved at a lower cost through other energy sector measures or in other economic sectors. This discussion will be more concrete after several years of RES implementation when ARB and the parties have more data regarding RES compliance costs and resulting GHG reductions compared to the costs and reductions resulting from other AB 32 measures. If warranted, ARB should use the opportunity of the regulation review to move GHG reductions slated to come from the RES proceeding to alternative measures. This will ensure that ARB fulfills AB 32's requirement that adopted measures minimize costs and maximize the total benefits.[2/]

In drafting the regulation review provisions, ARB should add a new subsection to make clear its intent, stated initially in the Concept Outline for the RES, to limit the liability of regulated parties where they are prevented from complying with the RES because of circumstances outside of their control. This would provide regulatory certainty by making ARB's process and standards for conducting periodic reviews of the RES more transparent. Additionally, providing a clearer standard will allow parties to plan for and participate in these reviews more effectively. PG&E recommends that the PDR be revised to specifically require that the RES compliance targets be deferred and/or reduced as to all applicable regulated entities

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[2/] Cal. H&S Code § 38562(b)(1), (b)(5).

if as a result of any periodic review, or at any other time, ARB determines that any of the following is true:

(1) Transmission, interconnection, financing, and/or permitting constraints outside the exclusive control of any or all regulated entities has/have prevented the delivery or development of necessary volumes of RPS-eligible electricity to enable cost-effective compliance with the RES;

(2) Any other unforeseen or unanticipated factor outside the control of any or all regulated entities has made timely compliance with the RES infeasible or unreasonably expensive for retail customers when considering the feasibility and cost of alternative sources of GHG reductions.

Including such criteria would better harmonize the RES with the existing RPS program, which is one of ARB's stated goals for development of the regulation. In the RPS Program, both statutory and regulatory criteria allow the CPUC to delay compliance deadlines due to transmission, permitting, and financing constraints that are outside the direct control of the LSE, so long as the LSE has taken all reasonable steps within its control to plan for or to overcome these obstacles.[3/] The compliance delay language that was included in the 33% bill passed by the California Legislature but vetoed by the Governor (for other reasons) may provide a model for the RES regulation, and it is worth noting that the same language has been included in SB 722, the 33% bill now pending in the Legislature.[4/]

[3/] *See* Cal. Pub. Util Code § 399.14(a)(2)(C(ii); CPUC Decision ("D.")03-07-071, at pp. 50-51 (providing four grounds for delaying RPS compliance deadlines, including seller non-performance due to factors beyond the control of the regulated party); D.03-06-071, at p. 53; D.03-12-065, at p. 8 (allowing modification of RPS compliance requirements if an LSE demonstrates lack of effective competition, that deferral promotes ratepayer or program interests, or other good cause).

[4/] *See* Senate Bill 14, as enrolled on September 15, 2009 (subsequently vetoed by Governor Schwarzenegger) (available at http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_14_bill_20090915_enrolled.pdf), which would have amended Public Utilities Code Section 399.15(b) to provide in relevant part as follows:

> (4) The commission may only allow a retail seller for a maximum of two years per request to delay compliance with a renewables portfolio standard procurement requirement established pursuant to subparagraph (B) or (C) of paragraph (1), if it finds that the retail seller has demonstrated that either of the following conditions will prevent timely compliance:
>
> (A) There is inadequate transmission capacity to allow for sufficient electricity to be delivered from proposed eligible renewable energy resource projects using the current operational protocols of the Independent System Operator (ISO). The commission shall consult with the ISO in making its findings relative to the existence of this condition. In making its findings relative to the existence of this condition with respect to a retail seller that owns transmission lines, the commission shall consider both of the following:

Additionally, the RES regulation should explicitly address situations in which decisions by sister state agencies, including the CPUC, make attainment of the RES by an LSE infeasible. For example, the RES should recognize the link between the ability of a CPUC-jurisdictional LSE to attain the RES target and the CPUC's approvals or disapprovals of that LSE's third-party power purchase agreements or utility-owned generation proposals. To the extent that the CPUC concludes that the cost of renewable procurement has become unreasonable and, on that basis, denies an LSE the ability to recover the costs of executed renewable PPAs or utility-owned development proposals, ARB's periodic review must necessarily excuse, or at least defer, some or all of the LSE's RES obligation. The failure to explicitly link CPUC rate recovery jurisdiction and the RES obligation could subject an IOU to penalties under the RES for noncompliance even though it would have attained the targets but for CPUC denial of competitively-bid contracts and ownership proposals.

(i) Whether the retail seller has undertaken all reasonable measures to develop and construct new transmission lines or upgrades to existing lines in a timely fashion.

(ii) Whether the retail seller has taken all reasonable operational measures, as verified by the ISO, to maximize deliveries of electricity from eligible renewable energy resources in advance of transmission availability.

(B) Unanticipated permitting, interconnection, or other delays for procured eligible renewable energy resource projects, or there is an insufficient supply of delivered electricity from eligible renewable energy resources available to the retail seller. In making this finding, the commission shall consider whether the retail seller has prudently managed portfolio risks, relied on sufficient viable projects, sought to develop its own eligible renewable energy resources, and procured an appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to compensate for foreseeable delays or insufficient supply.

(5) Prior to granting a delay pursuant to paragraph (4), the commission shall require a retail seller to demonstrate that it has presented evidence that it has made material progress in reducing its compliance deficit and has taken all reasonable measures consistent with this article to procure cost-effective distributed generation and renewable energy credits consistent with the restrictions in paragraph (6) of subdivision (a) of Section 399.21.

(6) The commission may not approve any request to delay a compliance obligation for which it has already granted a delay unless a retail seller presents evidence that it has made material progress in reducing its compliance deficiency and has identified and taken all reasonable actions under its control to pursue additional options to comply with the delayed interim procurement obligation and remove impediments that are related to its delay.

(7) The commission may not authorize any delay in achieving the 33 percent by December 31, 2020, renewables portfolio standard procurement requirement of subparagraph (D) of paragraph (1).

(8) If a retail seller fails to procure sufficient eligible renewable energy resources to comply with a renewables portfolio standard procurement requirement and fails to obtain an order from the commission authorizing a compliance delay pursuant to paragraph (4), the commission shall exercise its authority pursuant to Section 2113.

C. Fundamental Fairness and Good Public Policy Require That All Regulated Parties Be Able to Procure RECs from the Same Eligible Resources.

Under the proposed definitions of "eligible renewable energy resources" and "RES Qualifying POU Resource," as well as the eligibility requirement in Section 97004(c), the PDR would allow only publicly-owned utilities ("POUs"), to use deliveries from certain facilities that are not certified eligible under RPS program to be used for RES compliance up to a cap of 20% of retail sales. The ARB comment in the PDR notes that the intent is to allow POUs to use deliveries under existing contracts, mostly large hydropower, for RES compliance until those contracts expire.[5/]

Such disparate treatment between the POUs and all other regulated parties is fundamentally unfair, and the record in this proceeding provides no policy rationale for allowing such unequal treatment. Instead, the PDR could lead to the absurd outcome that two different regulated parties could hold contracts with the same facility but only one regulated party, a POU, could count the output it received from the facility, while the second party, an IOU, would have to go to the market to buy additional renewable energy. This would likely result in the IOU's customers having to pay more for compliance with the RES.

PG&E recommends that the PDR be modified to allow all parties to count the same types of resources, up to any limits promulgated in the PDR. Such equitable treatment will ensure that some customers do not unfairly bear a larger portion of the costs to meet the State's aggressive renewables requirements.[6/]

D. ARB Should Not Set Limits on the Use of Out-Of-State or Undelivered RECs.

The PDR notes that ARB is considering two options with regard to the procurement of unbundled RECs for purposes of RES compliance. The first option would allow the unlimited use of unbundled and undelivered RECs,[7/] consistent with the letter and spirit of the Governor's Executive Order instituting this rulemaking.[8/] The second option ARB is considering is to apply the CPUC's recent decision allowing the limited use of unbundled RECs in the RPS Program.[9/]

5/ PDR at p. 6.

6/ If, despite the patent inequity of doing so, ARB allows only POUs to receive credits from large hydropower, it should at a minimum exclude their ability to count owned resources since the rationale of crediting resources that were contracted in reliance on self-imposed POU rules does not apply to those facilities.

7/ *See* PDR at pg. 5.

8/ Executive Order S-21-09, Sept. 15, 2009, at Ordering Paragraph 5 (directing ARB to include in its 33% regulation "resources and facilities located throughout the Western Interconnection").

9/ *See* D.10-03-021 (March 16, 2010).

The CPUC's approach not only requires delivery of RECs into California,[10/] but would also unlawfully revise the CEC's well-established definition of delivery to re-categorize certain types of bundled purchases that are firmed and shaped for delivery into California as unbundled RECs.[11/] Moreover, the CPUC RECs Decision would limit only the three largest IOUs in the state to procuring no more than 25% of their RPS compliance targets through the purchase of unbundled RECs (as redefined by the decision),[12/] ignoring statutory requirements that all LSEs under the jurisdiction of the CPUC, including community choice aggregators and electric service providers, be subject to the same terms and conditions for RPS compliance.[13/]

The limits on the use of RECs embodied in the CPUC's decision should not be adopted by the ARB for use in the RES. First, the CPUC RECs Decision could reduce the incentives for development of new renewable resources across the West. Second, because the arbitrary limits on out-of-state procurement may limit the ability to develop renewable resources where they are most efficient, the CPUC REC decision could lead to higher costs.[14/] ARB can, and should, provide a model for the use of RECs in a 33% regulation that incents the development of renewable facilities throughout the West and that achieves 33% at the lowest cost to

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10/ This requirement stems from the RPS Statute. *See* Pub. Util. Code §§ 399.13(a); 399.12(b), (c). Because ARB is promulgating the RES pursuant to its authority under AB 32, and not the RPS Program, ARB is not required to include the RPS Program's delivery requirement.

11/ *Compare* D.10-03-021 at pp. 97-98 (Ordering Paragraphs ("OP") 6 and 7) (declaring, despite the CEC's jurisdiction over certifying RPS eligibility and delivery, that only purchases of out-of-state energy where the energy is dynamically scheduled into the California grid will be considered "bundled transactions" for purposes of applying the REC Decision) *with* Cal. Pub. Res. Code § 25741(a) (granting CEC jurisdiction over RPS delivery requirements) *and* CEC, *Guidebook on Renewables Portfolio Standard Eligibilty*, 3rd Ed. (Jan. 2008) (available at http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF), pp. 23-26 (defining delivery to include firming and shaping structures).

12/ *Id.* at p. 101 (OP 17).

13/ The CPUC is required by statute to ensure that all RPS-obligated LSEs are subject to the same requirements that are applicable to the three largest IOUs under any programs or rules adopted by the CPUC to implement the RPS program. *See* Pub. Util. Code §§ 365.1(c), 380(e), and 399.12(g)(2)-(3).

14/ *See* Ernest Orlando Lawrence Berkeley National Laboratory, *Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative*, Feb. 2010, at pp. 52-53 (available at http://eetd.lbl.gov/EA/EMP/reports/lbnl-3077e.pdf) (using Western Renewable Energy Zone model and data to conclude that costs to implement a WECC-wide 33% target can be reduced by $8 billion through the unrestricted use of unbundled RECs, which translates into an average renewable energy cost reduction of $6/MWh). *See also* CPUC, *33% Implementation Analysis Preliminary Results*, June 2009 at pp. 19, 24 (noting that meeting 33% in a high out-of-state delivered case reduces costs of the RPS Program by 3.1% compared to a 33% reference case. Although unbundled RECs were not included in the high out-of-state reference case, that scenario did assume that firming and shaping delivery arrangements would be unlimited. The CPUC RECs decision renders that assumption invalid since it reclassifies shaping and firming deals as REC-only and subjects them to a cap); *id.* at p. 58 (noting that the already lowest relative cost of the high out-of-state case would be lower still if it incorporated tradable RECs with no delivery requirement); *id.* at p. 61 (Table 15) (notes that a focus on "Least-Cost Renewables" requires prioritizing procurement of out-of-state renewables facilitated through tradable RECs with no delivery requirement).

Californians. Option 1 in the PDR meets these goals and should be the approach taken in the RES regulation.

PG&E would support the limited adoption in the RES of other aspects of the CPUC RECs decision, including those governing the trading and banking of RECs. In this regard, PG&E notes that ARB's discussion of the REC concept, which would allow for trading of RECs for a period of up to three years from their WREGIS creation date,[15/] is not consistent with the CPUC's REC decision, which allows trading for only three calendar years following the generation of the REC, inclusive of the year of generation.[16/]

E. The Broadest Array of Renewable Resources Should Be Used to Meet the RES

Given the limited time to achieve the ambitious 33% RES goal, ARB has correctly focused on maximizing the flexibility of the regulation while preserving its GHG reduction goals. In particular, PG&E supports ARB's comments at the March 18, 2010 workshop that GHG is a global pollutant, and that therefore a real reduction in GHG related to electricity production anywhere should be treated equal to a reduction in GHG in California. As noted above in relation to the discussion on unbundled RECs, access to out-of-state renewable resources through a variety of delivery structures and through unbundled, undelivered RECs should be encouraged. In addition, PG&E encourages ARB to consider expanding its eligibility requirements to incentivize the development of significant potential sources of GHG-free, run-of-the-river ("ROR") hydroelectric power in British Columbia ("BC").

Current restrictions in the RPS law amount to a practical prohibition on the eligibility of BC hydropower resources, despite the very significant GHG reduction benefits these facilities could offer. PG&E has identified as part of a CPUC-authorized feasibility study and compliance report that BC has the potential for up to 6,150 MWs of ROR hydropower generation by 2016, and 4,480 MWs of ROR generation beyond 2016.[17/] This equates to the potential for 24,700 GWh/year of ROR generation in 2016,[18/] which would produce annual GHG benefits from displaced fossil-fueled generation of about 12.3 million metric tons of carbon dioxide.[19/] At a time when California is pursuing all feasible and cost-effective GHG reductions pursuant to AB 32, such substantial potential reductions should not be excluded from the RES.

15/ *See* PDR at p. 7.

16/ D.10-03-021 at p. 99 (OP 10).

17/ Letter from Janet C. Loduca to Sean Gallagher and Dana Appling, June 20, 2008, at p. 2 (Attached as Appendix 1).

18/ *Id.*

19/ ARB's GHG Benefit Determination for Renewable Sources, dated February 1, 2010, finds the potential GHG benefit of small hydropower to be 1,100 lbs. CO2e/MWh. *See* pg. 4. To derive potential GHG reduction benefits from BC hydropower, PG&E therefore used the following equation: 24,700 (GWh potential in BC in 2016) * 1,000 (convert to MWh) * 1,100 (lbs CO2 per MWh) / 2204.6 (lbs to metric tons) = 12,324,231.

This is particularly true where the energy can be generated in compliance with stringent environmental and land-use requirements. A typical ROR hydropower project in British Columbia requires more than 50 permits, licenses, approvals and reviews from 14 regulatory bodies, including federal, provincial, local, and First Nations authorities. Accordingly, PG&E supports expanding eligibility for small ROR hydropower resources in BC so long as the resource is in compliance with each governing jurisdiction's environmental requirements.

Beyond the clear GHG reduction benefits of developing BC's hydropower resources, there are a number of other policy-based reasons for expanding RES eligibility to these generators. First, the expansion of eligibility will open the market to increased competition and allow California's electricity customers to benefit from the development of the most efficient and least-cost resources. Second, increased eligibility will relieve pressure to develop in-state projects that may impact critical habitat. Finally, BC hydropower resources would be most reliable and operate at their highest capacity in the summer when California is at its peak load.

To incentivize the development of these BC hydropower resources, and to make clear that unbundled RECs do not have to be delivered into California for RES compliance, PG&E recommends that the definition of "eligible renewable energy resources" at Section 97002(a)(5) be modified as follows:

"Eligible renewable energy resources" *means any of the following: (1) an eligible renewable energy resource, as defined in Public Utilities Code Section 399.12(c) as of the date of adoption by ARB of this article;*[20/] *(2) any hydroelectric generation facility of 50 megawatts or less that is located within the Western Electricity Coordinating Council but outside of the United States, provided that the facility has obtained the approvals required to demonstrate compliance with the environmental and other land use regulations of the governing jurisdiction;*[21/] *or (3) is otherwise recognized as a RES Qualifying Resource as provided in this article.*[22/]

[20]/ Note that the reference to Public Utilities Code Section 399.12(c) rather than to the PDR's reference to Section 399.13 removes the need to exclude from the reference the need for delivery. Neither Public Utilities Code Section 399.12(c), nor its reference to Public Resources Code Section 25741, includes any requirements of delivery for a facility to be an "eligible renewable energy resource." This simplifies the PDR's definition. PG&E also recommends that ARB include a date (e.g., the date of RES adoption) whenever incorporating other statutes by reference, to ensure clarity.

[21]/ In order to fully carry out the expansion of eligible resources to out-of-country hydropower facilities, Section 97006 of the PDR should be modified to include a new subsection allowing a regulated party to file an application with the Executive Officer to certify and verify the eligibility of the hydro resources.

[22]/ PG&E has modified the reference to a "RES Qualifying POU Resource" to remove the reference to "POU" on the assumption that the RES will be modified to allow all regulated parties to use the same eligible resources, consistent with the discussion in Section III, above.

F. Enforcement Regimes between the RES and RPS Programs Should be Harmonized

PG&E's opening comments on the RES Concept Outline noted that PG&E supports the proposed coordination between CARB and the energy agencies to reduce administrative burdens by using the same compliance information submitted by LSEs to the energy agencies for purposes of the RPS to determine compliance with the RES.[23/] However, PG&E cautioned against creating overlapping enforcement regimes that could subject regulated entities to enforcement penalties from multiple agencies for failure to procure the same renewable energy. The purpose of this section is to propose more specific regulatory language for consideration in the development of the RES.

Because the CPUC is already charged with enforcing the RPS standard of 20% of retail sales by 2010 (with flexible compliance mechanisms), CARB should exercise its discretion to defer to the CPUC enforcement of any CPUC-jurisdictional LSE's failure to meet the volume of RES procurement that would be equivalent to the RPS requirement. Because the CPUC does not have similar enforcement jurisdiction with regard to the publicly-owned utilities, CARB would necessarily enforce the RES as to all volumes of procurement against those entities.

This clear delineation of enforcement responsibilities is necessary given the overlapping and intertwined nature of the RES and the RPS programs. Advance exercise of enforcement discretion would help to avoid unfair and administratively burdensome outcomes, such as a situation in which an IOU or other CPUC-jurisdictional entity has met RPS Program criteria for a delay in a specific compliance milestone due to factors outside the control of the regulated party, and yet even after having been granted such a delay and establishing a renewables procurement plan based on the delay, the regulated party finds itself subject to an enforcement proceeding at ARB under the RES. Overlapping enforcement jurisdiction could also lead multiple state agencies to expend the same scarce enforcement resources investigating the same set of underlying facts. In the most extreme case, exercise of overlapping criminal enforcement authorities could unconstitutionally subject a regulated party to double jeopardy.

Finally, it is worth noting that under the proposed RES, a CPUC-jurisdictional entity may bear fines from both the CPUC and the ARB for the same underlying violation (ie., failure to procure 20% or more of RPS- and RES-eligible electricity in a given compliance year), while a similarly-situated POU would face only a penalty under the RES. To further harmonize the RPS and RES so that all LSEs are treated equitably, the RES should "net out" any fine imposed by the CPUC on a regulated party for the same facts underlying an RES violation when the ARB decides on the amount of a penalty to seek.

To accomplish the delineation of enforcement responsibilities and the harmonization of the RPS and RES programs described above, PG&E recommends adding the following italicized language, or language to similar effect, in Section 97008 of the PDR:

[23/] PG&E Opening Comments, November 20, 2009, at pg. 7.

<u>Exercise of Enforcement Discretion</u>.

c. Notwithstanding subsections (a) and (b) of this Section, ARB shall exercise its enforcement discretion to decline to prosecute any violation of this article where the regulated party and the violation meet all of the following requirements:

> *1. The regulated party is also subject to the requirements of California's Renewables Portfolio Standard ("RPS") Program (Article 16 of the California Public Utilities Code);*
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> *2. The regulated party is subject to the enforcement jurisdiction of the California Public Utilities Commission ("CPUC") for failure to comply with the RPS Program; and*
>
> *3. The facts underlying a potential violation of this article arise from the failure to procure or develop qualifying renewable energy that is also necessary for said regulated party to meet any requirement under the RPS; <u>provided further</u> that ARB shall defer to the CPUC regarding any determination by the CPUC that a violation falling within the scope of this section should be excused because compliance is infeasible or outside the reasonable control of said entity, and ARB shall on that basis decline to further prosecute any such failure pursuant to this Regulation.*

d. ARB shall further exercise its enforcement discretion to reduce any fine it seeks or has imposed against a regulated party where the regulated party meets the criteria in subsections (c)(1) and (c)(2) above and where the CPUC has imposed or seeks a fine against said regulated party on the basis of the same facts that underlie a violation of this article. The amount of the reduction of the ARB fine under this subsection (d) shall be equal to the fine levied or sought by the CPUC.

e. A regulated party may raise this section as an affirmative defense to an enforcement action brought by ARB pursuant to this article.

To further implement this coordinated enforcement approach, PG&E recommends the CPUC and CARB separately negotiate an inter-agency agreement that assures both agencies that their jurisdictional authority is clearly delineated and that appropriate enforcement of both the RES and RPS requirements will occur.

G. Any Exemption for Small LSEs Should Be Limited to Existing IOUs and POUs.

Section 97001(b) of the PDR establishes a partial exemption from RES requirements for small regulated parties. The Question and Answer document accompanying the PDR explains that the intent of this provision is to provide "a compliance exemption threshold for the smallest IOUs and POUs."[24/] However, the effect of the PDR's language is broader, applying to community choice aggregators ("CCAs") and electric service providers ("ESPs") that have less than 200,000 MWh in load. PG&E generally opposes exemptions for any LSE and notes that any such exemption conflicts with the Governor's order that the RES apply to "*all* California load serving entities."[25/] However, to the extent any small party exemption is included in the final RES, it should be strictly limited to *existing* IOUs and POUs, should not apply to any new LSE, and should not apply to CCAs and ESPs. This focus on existing IOUs and POUs would more closely align the RES with staff's concern that such existing utilities will have less flexibility to re-orient procurement toward RES-eligible resources. New LSEs, including entrants to the market like CCAs and ESPs, however, will have adequate notice of RES obligations and will have the opportunity to structure their business models to account for these requirements. Exempting any entities from the regulation, and particularly exempting new market entrants, is fundamentally unfair to the customers of other regulated parties who must pay RES compliance costs that are not borne by others in the state. These exemptions can also create "leakage" in which entities seek to avoid RES regulation costs, and thereby reduce RES GHG reductions, by joining new, disaggregated LSEs that are exempt from the requirements.

H. RECs Must Be Available for Simultaneous Use in the RPS and RES Programs

Section 97004(b) of the PDR would prohibit RECs from being used "to meet the requirements of any federal, state or local program." PG&E agrees that the RES should prohibit double counting of RECs, but this language should be modified to make clear that the same RECs can be used for RPS and RES compliance.

I. The PDR Should Clarify That No Cumulative Deficits Will Apply.

Section 97005(b)(1)(A) of the PDR states that in the process of developing an annual RES Progress Report, "[w]here a REC obligation was not met, the report shall document the MWh shortfall and demonstrate how the [regulated party] will make up the shortfall within the succeeding compliance period." PG&E believes that the intent of this provision is simply to note that under the compliance interval requirements included in Section 97003, a regulated party could procure less than the RES target in one year of the interval and make up the shortfall through over-procurement in a subsequent or earlier year of the interval. However, at a minimum, the reference to "REC obligation" in the quoted sentence above should be changed to "REC procurement target" to make clear that ARB is not referring to shortfalls between compliance intervals. It is PG&E's understanding from earlier workshops that ARB does not intend to require any deficit in one compliance interval to be carried forward into a future compliance interval, and the RES regulation should make that intent clear. Additionally, to the extent ARB adopts the annual compliance requirements recommended in Section II.A, above,

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24/ Questions and Answers on the PDR, March 11, 2010, at p. 3.

25/ E.O. S-21-09, Ordering Paragraph 2 (emphasis added).

ARB should make clear that it does not intend for any deficits to be carried forward from year to year.

J. Compliance Reporting and Protections for Market-Sensitive Information Should be Harmonized between the RES and RPS Programs

Section 97005(b)(1)(B) of the PDR requires certain CPUC-jurisdictional regulated parties to submit RES Procurement Plans by August 1 of each year, including a project status development report. Because the requirements for these plans track very closely the RPS Procurement Plans that CPUC-jurisdictional entities already prepare for the RPS Program, the RES regulation should explicitly allow the RES and RPS procurement plans to be combined in a single document. This will reduce the administrative burden on both regulated parties and the state agencies.

The elements of the RES Progress Report and RES Procurement Plan required pursuant to Section 97005(b)(1) will contain highly confidential, market-sensitive information regarding the parties' net short positions in the market for renewable energy, parties' strategy for near-term RES-eligible contracting or development, and potentially confidential information provided by developers concerning the status of site control, permitting, and financing. Additionally, as part of its Regulation Review, PG&E anticipates that ARB will request market-sensitive information concerning the prices regulated parties paid for renewable energy. All of these types of information have been found to be confidential pursuant to heavily-litigated proceedings before the CPUC. The confidentiality of such information is based on the ability of the information to: (1) distort the market for renewable energy; (2) place regulated parties at a competitive disadvantage if publicly released; (3) breach a legal obligation and expectation of confidentiality between a regulated party and an unregulated third party; and/or (4) provide leverage to market participants that will result in artificially high prices and rates for energy.[26/] In balancing its legal obligations to disclose information whenever possible with legitimate concerns about the market sensitivity of certain information provided by regulated entities, the CPUC has created a mechanism through which non-market participants, and independent reviewing representatives of market participants, can receive market sensitive information once the parties have signed an appropriate non-disclosure agreement or an appropriate protective order has been entered.[27/] This much-contested balancing of interests must be preserved when the same or similar information is provided to ARB pursuant to its RES authority.

The PDR states that confidential information submitted pursuant to the RES will be handled in accordance with ARB's regulations implementing the California Public Records Act.[28/] To a great extent, protection under these regulations is predicated upon the extent to

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26/ *See, e.g.*, D.06-06-066, as modified by D.07-05-032 (the landmark CPUC confidentiality decisions); CPUC General Order 66-C (establishing confidentiality protection for categories of information not specifically covered by Appendix 1 to D.06-06-066).

27/ *See* D.06-12-030 at pp. 50-53.

28/ *See* PDR at p. 10.

which such information is a "trade secret" under applicable law.[29/] However, the CPUC has made clear that "market sensitive" information is different and not co-extensive with "trade secrets."[30/]

The CPUC has recognized that its obligations to protect market-sensitive information under Public Utilities Code Section 454.5(g) may lead it to treat information differently than other agencies, like the CEC, who are not subject to that statute.[31/] The CPUC addressed this potentially different treatment by creating provisions in a model protective order that allows market-sensitive information to be given to the CEC once an appropriate Interagency Information Request and Confidentiality Agreement is in place.[32/] The CEC would agree to maintain the CPUC's confidentiality designations.[33/] A similar Interagency Confidentiality Agreement should be developed between ARB and the CPUC to provide for the exchange of market-sensitive information subject to the same protections that information currently receives at the CPUC.

With respect to market-sensitive information provided by regulated parties directly to ARB, ARB should clarify in the RES that such information is not "emission data" that is required to be made public under its regulations,[34/] and that it is not data that is relevant to any existing federal law and therefore will not be shared as a matter of ordinary business with any federal government agency.[35/] Additionally, ARB should explicitly find that where a regulated party makes a prima facie showing that information meets the CPUC's definition of market-sensitive information, the information will be deemed "data . . . used to . . . produce . . . an article of trade . . . and that the disclosure of the data would result in harmful effects on [the regulated parties' or their counter-parties'] competitive position,"[36/] and that therefore any such market-sensitive information shall carry a presumption that disclosure is "prohibited by law."[37/] Such a presumption should only be overcome after a specific showing by a requesting party that the information is either already public or does not in fact meet the CPUC's definition of market-sensitive.

[29/] *See, e.g.*, 17 Cal. Code. Regs. § 91010.

[30/] D.06-06-066 at pp. 46-50.

[31/] *Id.* at p. 74.

[32/] D.08-04-023, at App. D, pp. 11-12.

[33/] *Id.* at p. 12.

[34/] *See* 17 Cal. Code Regs. §§ 91010, 91011.

[35/] *Cf. id.* at § 91010.

[36/] 17 Cal. Code Regs. § 91022(c)(6).

[37/] *Id.* at § 91010.

K. The RES Formula Should Be Modified

PG&E notes that the formula provided at Section 97005(d) of the PDR appears to calculate the applicable RES compliance target in kWh, and not a regulated party's "annual RES progress" as stated in that section. The formula should be modified if the intent is to provide the actual status of an entity's RES procurement.

III. CONCLUSION

Thank you for the opportunity to submit these comments. PG&E is happy to discuss any of these issues with ARB in more depth and looks forward to continuing to work with ARB and all of the stakeholders to help tackle the challenge of global climate change through the successful implementation of the RES.

Very truly yours,

/s/

M. Grady Mathai-Jackson

cc: Mary Nichols, Chairman, ARB
James Goldstene, Executive Officer, ARB
Richard Corey, Chief, Stationary Source Division, ARB
Kevin Kennedy, Chief, Office of Climate Change, ARB
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June 20, 2008

Mr. Sean Gallagher
California Public Utilities Commission
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102-3298

Ms. Dana Appling
Executive Director
Division of Ratepayer Advocates
505 Van Ness Avenue
San Francisco, CA 94102-3298

Dear Mr. Gallagher and Ms. Appling:

In Decision (D.) 07-03-013 in the *Application of Pacific Gas and Electric Company (PG&E) for Recovery of Generation Feasibility Study Costs Associated with the Evaluation of Wind-Generated and Other Renewable Electric Power in British Columbia* (A.06-08-011), approved on March 1, 2007, the CPUC orders PG&E, upon completion of Phase 1, to provide "an explanation of the decision to continue with Phase 2 or to discontinue the BC Renewable Study."

Pursuant to D.07-03-013, below is PG&E's explanation of its decision to pursue Phase 2 of the BC Renewable Study.

PG&E would be glad to answer any questions you have related to this report. If you have any questions, you may contact Alice Harron at (415) 973-3662.

Sincerely,

/s/

Janet C. Loduca
Director
Energy Proceedings

Pacific Gas and Electric Company
BC Renewable Study Phase 1

On March 1, 2007, the California Public Utilities Commission ("CPUC") approved D.07-03-013, which grants Pacific Gas and Electric Company ("PG&E") the authority to recover up to $14 million for external consultants to study the feasibility of obtaining renewable power from various regions in British Columbia ("BC") and the potential to transmit this power to PG&E's service area.[1] The potential for a power purchase agreement ("PPA") with BC Hydro and/or Powerex and the transmission line from BC to California ("CA") will be called the Project for the purposes of this paper.

Under the CPUC Application (A.) 06-08-011 and Decision (D.) 07-03-013, the BC Renewable Study is divided into two phases. The purpose of Phase 1 is to study the feasibility of: (a) obtaining economic, commercially viable renewable generation from BC; and (b) building a transmission line from BC to CA. Phase 2 consists of generation procurement and transmission development activities.

In D.07-03-013, the CPUC orders PG&E, upon completion of Phase 1, to provide "an explanation of the decision to continue with Phase 2 or to discontinue the BC Renewable Study."[2] The purpose of this paper is to explain PG&E's decision to pursue Phase 2.

During Phase 1 (between March 2007 and May 2008), PG&E:

a. estimated the amount and cost of future generation resources (see Part I, "Generation Resources");
b. studied the feasibility of building a transmission line from BC to CA (see Part II, "BC-CA Transmission Line Feasibility");
c. considered the costs and benefits of various ownership alternatives for the transmission line (see Part III, "Cost and Benefits of Various Transmission Ownership Alternatives and Regulatory Arrangements");
d. reviewed potential commercial arrangements (see Part IV, "Commercial Structure Assessment");
e. evaluated commercial viability, including the potential for executing a letter agreement (see Part V, "Commercial Viability");
f. reviewed BC's regulatory climate (see Part VI, "Regulatory Environment in BC");
g. assessed CA's regulatory and legal impediments (see Part VII, "CA Regulatory and Policy Impact on Project");
h. studied wind integration ability (see Part VIII, "Ability to Integrate Resources"); and
i. compared the Project with other potential renewable sources (see Part IX, "Economic Analysis").[3]

[1] From inception through April 30, 2008, PG&E has spent $3.8 million on external consultant costs which have been recorded in the British Columbia Renewable Study Balancing Account. Once all invoices have been received, PG&E forecasts $5.2 million to complete Phase 1.
[2] D.07-03-013, Ordering Paragraph (OP) 4.
[3] Source reflects an evaluation that includes cost of generation and the transmission line to transport to a load center in CA.

There is a strong complementary relationship between the seasonal demands of summer-peaking CA and winter-peaking BC. This relationship provides a foundation for mutual benefit. Developing new renewable generation resources in BC and strengthening transmission links in the region will support BC's self-sufficiency policy as well as help meet BC and CA's environmental and energy objectives.

Given the vast amount of potential renewable resources in BC, the strong feasibility of building a transmission line, good indicators of commercial viability, and the results of economic analyses, PG&E has decided to proceed to Phase 2 of this Project, including pursuit of discussions with Powerex and transmission development activities. PG&E will institute some action items for Phase 2, including monitoring progress to determine whether to continue the Project during Phase 2. (See Part X, "Decision".)

I. Generation Resources

Amount of Potential Renewable Generation

British Columbia has a large amount of potential renewable generation that is well in excess of its own needs to serve its forecasted load. The table below illustrates the amount of renewable generation potentially available in BC by 2016. This estimate represents an aggregated range of identified potential, which takes into account environmental and permitting issues. It does not, however, identify any particular project or express an opinion regarding any particular project's ability to meet the requirements of environmental and other provincial permitting processes.

Generation Source	Amount that Could Be Available by 2016		Amount of Potential Energy by 2016		Net Capacity Factor	Potential Beyond 2016
Units	**MW**		**(GWh/Yr)**		**%**	**MW**
Run-of-River Hydro	3,100	6,150	12,500	24,700	46%	4,480
Wind	4,400	10,300	11,500	26,900	30%	1,500
Biomass	700	700	5,200	5,200	85%	820
Geothermal	100	100	800	800	90%	600
Totals	**8,300**	**17,250**	**30,000**	**57,600**	--	**7,400**

Methodology

PG&E's consultant, Global Energy Concepts ("GEC") conducted an in-depth analysis of the potential wind, small run of river ("ROR") hydro, biomass and geothermal renewable generation.

GEC developed wind energy capacity and energy production estimates. It assessed and evaluated past studies and commissioned creation of improved wind resource maps. GEC performed regional field assessments and developed regional estimates of generating potential. GEC incorporated wind resource estimates to calculate energy potential and developed regional cost estimates.

Numerous independent power producers' ("IPP") ROR hydro power projects are in various stages of investigation and development in BC. GEC and its subcontractor R.W. Beck took two approaches to understand the extent of new ROR hydro development. First, GEC's team compiled an inventory of current permitting activities for hydro projects. Then, GEC's team contacted IPPs and their consultants to obtain information regarding their development plans.

To estimate biomass development, GEC's team reviewed available BC biomass assessment reports. GEC's team also held extensive conversations with key BC biomass developers, BC forestry government officials, and the Council of Forest Industries (a trade organization representing BC's forest industries) to obtain the most current and in depth understanding of issues surrounding biomass generation. Based on compilation of current information, GEC's team created possible future development scenarios regarding fuel type, quantity, combustion technology, and performance parameters to derive its independent estimate of future development potential.

To estimate geothermal development potential in BC, GEC subcontracted with GeothermEx (one of the largest and most experienced geothermal energy consulting companies in the Western Hemisphere). GeothermEx supports and monitors geothermal development activities within BC as part of its regular business activities.

Because current detailed geothermal resource analysis reports are not available for BC, the estimates for potential geothermal generation development are based on GeothermEx's experience and first hand knowledge of BC. In conducting the work, GeothermEx also consulted with geothermal project developers that have historically been active in BC to obtain additional information.

II. BC-CA Transmission Line Feasibility

PG&E's objective in Phase 1 is to confirm whether there are one or more feasible corridors for locating high-capacity electric transmission lines, and to develop sufficient cost and schedule information to support the decision-making process as to whether to proceed with Phase 2. These transmission corridors would need to accommodate a new high-capacity electric transmission line between BC and Central CA, which could consist of either an inland alternating current ("AC") or direct current ("DC") line, or a coastal submarine DC line.

An overland transmission line from British Columbia to California is technically (engineering and construction) and environmentally feasible. Developing a new transmission line through Washington and Oregon would encounter some land use and environmental challenges, but these would be within a manageable level. Routing a transmission line through northern California, while feasible, may involve significant environmental mitigation.

From a technical perspective, the submarine cable option does not meet the project objectives to meet 2016/2017 on-line date nor is it capable of transmitting 1,500 MW. Additionally, the existing worldwide manufacturing and installation capability for submarine cable is not sufficient to support the project. In addition, the submarine cable option is more expensive on an installed $/MW basis than the overland option.

III. Cost and Benefits of Various Transmission Ownership Alternatives and Regulatory Arrangements[4]

Decision 07-03-013 requires PG&E as part of its BC Renewables Study to review the costs and benefits of various ownership alternatives and regulatory arrangements for the transmission line from BC to CA.[5, 6] In 2007, in accordance with the Western Electricity Coordinating Council ("WECC") procedures, PG&E conducted a Regional Planning process that included substantial stakeholder outreach regarding the planning of the transmission project, and PG&E filed a final report on the process with WECC. PG&E also initiated the first of a three-phase WECC Project Path Rating Review process. The objective of the WECC Phase 1 effort is to determine: (1) a preliminary plan of service including intermediate terminations and transformation facilities, and (2) the non-simultaneous ratings of the various line segments in the preliminary plan of service. This activity is well underway, and PG&E expects that WECC Phase 2 efforts will begin later this year.[7] All of these activities have been overseen by a Steering Team comprised of the five transmission-owning utilities whose service footprints could be traversed by the proposed transmission line.[8]

PG&E is also participating in a Transmission Coordination Working Group ("TCWG"), established in January 2008 to coordinate the planning study efforts for eight transmission projects in the Pacific Northwest.[9] The proposed transmission line from BC to CA is one of these eight projects.

Because transmission line development is in its formative stages, it is still early to definitively address issues of costs and benefits, the role that any regional transmission organization might have in the operation and control of the line, and/or tariff structure. PG&E is an active member of the Steering Team, and is working through these issues with them. There has yet to be a final determination regarding the transmission line's configuration, or ultimate location of its interconnection points.

Nevertheless, PG&E can offer observations on the implications of various ownership alternatives and regulatory arrangements. Preliminarily, no ownership alternative has been shown to make building a transmission line infeasible. Under a multiple-owner scenario, geographically relevant project owners/partners could provide expertise and other benefits to siting a transmission line through multiple states. To the extent that any portion of the line would be included in the California Independent System Operator ("CAISO") Controlled Grid, access to that portion of the line would be governed by the CAISO Tariff. As to portions of the line not operated and controlled by a regional transmission organization, and assuming that the line owner(s) is a FERC jurisdictional utility, access to the line would be governed by the terms of an Open Access

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4 See Section II above ("BC-CA Transmission Line Feasibility") for a discussion of transmission costs and hurdles to the development of alternative routes which allow delivery of energy into California.

5 Decision 07-03-013, OP 2.b.

6 Note that as to transmission costs, PG&E filed for and obtained cost recovery for transmission development activities from FERC. 123 FERC ¶ 61,067 (issued April 21, 2008).

7 Relevant materials are posted at http://www.pge.com/canada/.

8 Current Steering Team members are: PG&E, Portland General Electric, PacifiCorp, Avista, and the British Columbia Transmission Corporation.

9 TCWG materials are posted at http://www.nwpp.org/tcwg/.

Transmission Tariff ("OATT").[10] The owner of such portions of the line would, as a Transmission Provider, offer non-discriminatory access to others under the terms of an OATT.

IV. Commercial Structure Assessment

PG&E reviewed the following potential contractual structures to facilitate the purchase and transport of renewable generation from BC to CA:

1) PG&E to contract directly with Canadian IPPs to obtain generation and transport to the US/Canadian border;
2) PG&E to form a Canadian joint venture company with an entity such as BC Hydro and/or Powerex with the joint venture company contracting with developers to obtain generation within BC and transport to the US/Canadian border;
3) PG&E to acquire and manage generation assets in BC for transport to the US/Canadian border; and
4) PG&E to contract directly with an entity such as BC Hydro and/or Powerex to obtain generation and transport to the US/Canadian border.

PG&E reviewed each potential transaction structure in the context of obtaining benefits to the parties to the transaction as well as the ability to transact under that structure.

Based on that review, PG&E believes that the fourth alternative of contracting directly with an entity such as BC Hydro and/or Powerex through a power purchase agreement to deliver an all-in product at the US/Canadian border is the most viable option to obtain renewable generation. PG&E would transport from the US/Canadian border to CA.

V. Commercial Viability

Pilot/ Letter Agreement

PG&E's application (A.06-08-011) proposed a pilot to help demonstrate the feasibility of procuring, firming, and transmitting renewable energy from BC to CA. Through discussions as part of this feasibility study, Powerex and PG&E have determined that a non-binding Letter Agreement is the appropriate mechanism under which to pursue additional discussions about the feasibility of reaching a possible future commercial arrangement between PG&E and Powerex, including further evaluation of the benefits to the respective parties and jurisdictions.

The Letter Agreement, while non-binding, covers a much greater scope of the Project than the pilot transaction. Having the agreement to work though issues for the full scope of the Project as opposed to a small trial transaction provides a foundation for continuing to Phase 2 of the Project.

[10] FERC adopted terms of and conditions for jurisdictional utilities' pro forma OATTs in Order Nos. 888, 889, and 890.

The Letter Agreement delineates the commitments of PG&E and Powerex to explore and evaluate structures for possible future commercial arrangements between PG&E and Powerex for sale of renewable energy that is in the interest of both jurisdictions.

Standard Firming Product

Decision 07-03-013 requires PG&E to pursue a standard firming service from BC.[11] At the time of the decision, PG&E was just beginning discussions with various BC entities regarding aspects of the Project. PG&E explored the possibility of an unbundled firming/shaping service. However, it became apparent that an "all-in" contract for purchase of renewable power at the US/Canadian border was the most desirable approach.

VI. Regulatory Environment in BC

BC's electricity industry comprises a mix of private and government-owned companies. (Government-owned companies are known as Crown Corporations.) BC Hydro, a Crown Corporation,[12] serves roughly 90 per cent of the Province. BC Hydro is also the buyer for virtually all of the electricity generated by IPPs in BC.

BC Hydro's position as a Crown Corporation means the Province's electricity industry is tightly linked with the public policy objectives of the provincial government.

The Energy Plan,[13] released in February 2007 by the BC Government, set a clear direction for the BC electricity sector, emphasizing environmental protection, conservation, and energy security—the last point being made manifest through a requirement for provincial self-sufficiency. In May 2007, the Premier of British Columbia and the Governor of California signed a Memorandum of Understanding that commits the two jurisdictions to adopt policies to create more renewable energy development and transmission. In September 2007, the Premier's Technology Council recommended that BC target exporting renewable generation by 2020.

VII. CA Regulatory and Policy Impact on Project

CA regulations concerning the eligibility of generation from out-of-country renewable energy resources to meet CA's Renewable Portfolio Standard ("RPS") requirements have an enormous impact on the commercial viability of the Project. While 2016 is eight years away, PG&E will describe how some of CA's current rules affect the commercial viability of the Project. Some of these rules must be modified for the Project to succeed.

The key obstacle to project success that must be modified by legislation is the definition of new small hydro generation. So long as BC small hydro generation requires balancing and shaping, the non-RPS eligibility of BC ROR hydro affects not only

[11] Decision 07-03-013, OP 2.d.
[12] The Province of British Columbia owns BC Hydro and BC Transmission Corporation ("BCTC") ("Crown Corporations."). Each entity has its own Board. The Province as shareholder appoints members of each of the Boards. Powerex is a wholly owned subsidiary of BC Hydro.
[13] The BC Energy Plan: A Vision for Clean Energy Leadership

counting the generation towards RPS goals but also potentially affects the Project's economics under current and future State Green House Gas ("GHG") rules.

As described below, RPS eligibility affects the cost for GHG compliance under both AB 32 and SB 1368. Shaping and banking non-RPS-eligible projects could lead to (1) added costs for retiring GHG emission allowances for system energy at default emission rate; and (2) not using system energy to bank and shape.

Renewable Portfolio Standard (RPS) Eligibility

Facilities located outside of the United States, such as those that would be part of the proposed Project, must satisfy these three criteria:

1. Out of Country Eligibility;
2. Resource Eligibility; and
3. Delivery Eligibility.

1. Out of Country Eligibility

To be certified by the California Energy Commission (CEC) as RPS eligible, a renewable energy generator located outside of the United States must be shown to be "… developed and operated in a manner that is as protective of the environment as a similar facility located in the State."[14] In this case, the developer must show that the laws, ordinances, rules, and statutes (LORS) governing the generation facility in BC will protect the environment to the same extent that the relevant LORS in CA would govern a similar facility located in CA.[15]

While the eligibility of any particular out-of-country facility will not be known until it is submitted for RPS certification, PG&E believes that BC laws, regulations and protocols for the types of generation it reviewed, (e.g., wind, biomass) are as protective of the environment as those of California. All indications are that the CEC should find that the applicable BC LORS will result in the development and operation of a project that is as protective of the environment as an equivalent CA development and approve BC projects as out-of-country compliant for RPS eligibility.

2. Resource Eligibility

Based upon PG&E's initial research, BC ROR hydro facilities would not be qualified as RPS eligible resources. Under California legislation, hydro generation facilities are RPS-eligible if they meet all of the following criteria:

- Do not cause a change in volume or timing of stream flow;
- Are less than or equal to 30 MW; and

[14] Public Resources (Pub. Res.) Code section 25471(b)(2)(B)(v).
[15] Guidebook p. 40, "3. Instructions for additional Required Information for Out-of-State Facilities."

- Do not cause an adverse impact on instream beneficial uses.[16]

BC ROR Hydro facilities will not meet any of these criteria.[17] However, it may be argued that a different streamflow requirement and an increase in the maximum capacity limit may be warranted due to different circumstances in BC, and that the disqualifying impact on instream beneficial uses should be limited to significant adverse impacts to allow reasonable hydroelectric development to be RPS-eligible. Thus far, PG&E's consultants have found that ROR projects do not have major impacts on the overall environment of the watershed. Because the current standards for the eligibility of hydroelectric generation are the consensus result of a coalition effort, new efforts to qualify hydroelectric generation in BC for the RPS must be closely coordinated with these identified stakeholders.

3. Delivery Eligibility

Renewable energy generation must be delivered to CA before it can fulfill RPS requirements. Under State statute and the CEC's implementation rules, the out-of-state eligible renewable resource generation may be banked and shaped into firm deliveries at a time other than generation. The later delivery, bundled with the green attributes of the renewable generation, will be RPS eligible.

<u>GHG Emissions</u>

The fact that new BC small hydro is currently not RPS eligible and will need to be banked and shaped by system energy during certain periods may create a potential GHG emissions compliance cost issue under AB 32. System energy used to bank and shape small hydro may be assigned a default GHG emissions rate, because the deliveries will not be considered renewable. PG&E or the seller may incur AB 32 compliance costs to acquire and retire "GHG emissions allowances" equivalent to the default emissions assigned to the transaction during the periods when system energy is used to bank and shape the small hydro.

In addition, SB 1368 may create restrictions on the ability of new BC small hydro to use system energy for banking and shaping. Small hydro is not RPS eligible and therefore system energy used to bank and shape it may be considered baseload energy that is subject to SB 1368's restrictions, potentially precluding the use of the new BC small hydro as part of the Project.

If, due to legislative amendment, new BC small hydro did become RPS eligible and was banked and shaped, the delivered energy would be considered renewable. PG&E would not need to retire allowances at the default emissions rate for these deliveries. PG&E could use system energy to shape BC small hydro under SB 1368 as well.

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[16] CEC regulations state that an adverse impact on the instream beneficial uses may be found if the facility causes an adverse change in the chemical, physical, or biological characteristics of water. CEC RPS Eligibility Guidebook, Third Edition (Guidebook), p. 34, "8. Capacity."

[17] There may be a certain amount of potential BC ROR hydro facilities that are less than 30 MW but not the majority of projects.

Separately, preliminary indications are that the economics of out-of-state biomass and geothermal generation can be improved if it can be banked and shaped. However, the CPUC's separate GHG emissions performance standard rules under SB 1368 do not allow substitute energy to be delivered in place of baseload generation, such as biomass-fired and geothermal generation. While such banking and shaping of biomass and geothermal baseload resources would be beneficial for the BC Project, the magnitude of such benefits is within the uncertainty of the overall Project economic analysis.

<u>CPUC Non-Modifiable Standard Terms and Conditions</u>

The CPUC Standard Terms and Conditions decision requires that all RPS PPAs be governed by California law (D.07-11-025). This requirement is included in a non-modifiable standard term. As noted above, PG&E believes that a transaction with an entity such as BC Hydro and/or Powerex is the most viable option. Both BC Hydro and Powerex have the ability to agree to CA law on issues relating to the PPA. However, this issue may raise potentially significant concerns and will be further discussed in Phase 2.

VIII. Ability to Integrate Resources

The very preliminary conclusion is that it appears that it could be technically feasible to integrate and shape volumes of wind used in the economic analysis. However, further study is needed to identify potential operational constraints on the BC Hydro system. Costs associated with such integration need further analysis and discussion with BC Hydro. BC Hydro will be conducting a much more in-depth wind integration study scheduled to be completed by the end of 2008. PG&E will update information for its analysis during Phase 2.

IX. Economic Analysis

The primary conclusion of this economic analysis is that BC potential renewable generation is within the range of other options on a delivered cost basis to CA. The following assumptions can readily change the attractiveness of the Project relative to other renewable alternatives:

- Cost of renewable generation alternatives to California;
- BC Hydro's ability and cost to shape;
- Transmission capital cost;
- Amount of MW available in alternate regions; and
- Various government incentive extensions.

The economics of British Columbia renewables should continue to be reevaluated as the price and availability of resources and the cost of delivery become more certain.

X. Decision

Given the vast amount of renewable resources in BC, the strong feasibility of building the transmission line, good indication of commercial viability (including ability to firm and shape), and the results of the economic analysis, PG&E has decided to proceed to Phase 2 to pursue discussions with Powerex and to conduct preliminary transmission development work.[18]

Action Items for Phase 2

PG&E will take the following actions during Phase 2:

1) Establish milestones to determine whether to pursue the Project throughout Phase 2. Examples are:
   a) Demonstrate progress of discussions with Powerex;
   b) Monitor and review BCTC transmission planning efforts and BC Hydro calls for energy;
   c) Refresh economic analysis periodically (up through earlier of execution of PPA or termination of Project) with updated information; and
   d) Target execution of PPA with Powerex by 2010.
2) Work with CA policymakers on RPS eligibility for small hydro;
3) Continue to consult with CPUC on Project's progress; and
4) Continue consultant contracts to monitor regulatory matters, provide technical support (e.g., resource cost, wind integration) and support economic analysis.

[18] As noted above, PG&E filed for and obtained cost recovery for transmission development activities from FERC. 123 FERC Section 61,067 (issued April 21, 2008).