STATE OF CALIFORNIA

ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

June 18, 2007

Advice Letter 2979-E

Rose de la Torre
Pacific Gas & Electric
77 Beale Street, Room 1088
Mail Code B10C
San Francisco, CA 94105

Subject: Demonstration Project to Convert Dairy Waste for Renewable Natural Gas Electric Energy Production

Dear Ms. de la Torre:

Advice Letter 2979-E is effective May 24, 2007. A copy of the advice letter and resolution are returned herewith for your records.

Sincerely,

Sean H. Gallagher, Director
Energy Division

REGULATORY RELATIONS
Tariffs Section
M Brown
R Dela Torre
B Lam
D Poster
M Hughes

JUN 21 2007

Return to ______ Records File ______

cc to ______

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulatory Relations

77 Beale Street, Room 1087
San Francisco, CA 94105

Mailing Address
Mail Code B10C
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177

415.973.4977
Internal: 223.4977
Fax: 415.973.7226
Internet: BKC7@pge.com

February 2, 2007

Advice 2979-E
(Pacific Gas and Electric Company ID U39 E)

Public Utilities Commission of the State of California

Subject: **Demonstration Project to Convert Dairy Waste for Renewable Natural Gas Electric Energy Production**

Pacific Gas and Electric Company ("PG&E") hereby submits a contract ("Contract") with BioEnergy, LLC, for approval by this Commission (California Public Utilities Commission or "CPUC"). If approved, the contract would require PG&E to purchase "digester gas" or "biogas", produced by the digestion of agricultural, food or dairy wastes (organic waste) by anaerobic bacteria or other processes and converted into pipeline-quality methane, as set forth in the contract.[1]

Approval of this gas purchase contract will allow PG&E to demonstrate the conversion of a form of organic waste into a renewable source of pipeline-quality methane or "biogas" that can be used to generate energy at a power plant. When converted to pipeline-quality methane (which is also known as natural gas) the biogas can be used instead of fossil fuel to generate electricity. A positive ruling will further enhance the CPUC's goal of acknowledging the unique benefits that biopower provides in meeting global greenhouse gas emission reduction targets.[2]

Approval of the Contract will also initiate an opportunity for the California Energy Commission ("CEC") to certify the eligibility of a generation facility that uses a hybrid fuel source that includes biogas and to verify the methodology for

[1] The term "digester gas" is defined by the California Energy Commission to mean "gas from the anaerobic digestion of organic wastes." *Overall Program Guidebook* April 2006, CEC-300-2006-008-F, at 17. The term "biogas" is defined by the Contracts as "methane, carbon dioxide and associated non-combustible gases in a gaseous state produced by anaerobic digestion, fermentation, or gasification of organic matter."
[2] See August 21, 2006, "Assigned Commissioner Scoping Memo and Ruling" issued in R.06-05-027, p. 10-12.

converting digester gas into RPS-eligible electricity that was proposed in the Staff Draft Renewable Portfolio Standard ("RPS") Eligibility Guidebook.[3]

By enabling a demonstration project with growth potential, the biogas Contract also complements PG&E's emerging renewables technology program, described in PG&E's 2006 Long-Term Procurement Plan.[4] In both cases, PG&E's payments under the Contract will provide the revenue stream necessary to enable the digester gas resource to develop to full commercial scale.

The purchase of pipeline quality biogas under this Contract is a significant opportunity for PG&E to assist in the conversion of a burdensome nuisance, cow manure, into a combustible fuel and thereby assist in the destruction of greenhouse gases. By approving this contract, the Commission would authorize PG&E to lend its demand for natural gas to facilitate the development of new sources of energy in the State of California, foster reductions in greenhouse gas emissions, and provide other air emissions benefits in U.S. Environmental Protection Agency ("EPA") Non-Attainment Areas.

I. INTRODUCTION

California is a significant dairy producer in the United States, with over 1.7 million dairy cows in the state. The 3.6 million bone dry tons of manure produced by those cows each year can be converted into biogas, which consists of methane, carbon dioxide, and associated non-combustible gases in a gaseous state produced by anaerobic digestion, fermentation, or gasification of organic matter. Additionally, California has significant quantities of agricultural and food wastes that can also be converted into biogas.

The anaerobic digestion or bacterial decomposition of manure in an oxygen-starved environment is a natural process that occurs unaided in many California dairies. Typically, the biogas is released into the atmosphere, but biogas can be produced through a controlled process. Anaerobic digesters allow the dairies to capture the biogas and convert it into BioMethane, a process which generates greenhouse gas (GHG) reduction credits so long as the BioMethane is combusted. Dairies can flare the BioMethane, combust it on-site in a generator and feed it into the electric transmission grid, or scrub and inject it into the gas transmission pipelines. Proximity to gas and electric transmission lines, size of the dairy farm, and on-site energy needs, among other things, help determine whether the BioMethane is converted into electricity or converted into pipeline-quality gas and then subsequently combusted off-site. The CEC has determined

---

[3] The Staff Draft RPS Eligibility Guidebook was published for public comment in December 2006. PG&E and other parties commented on this, and other Renewables Guidebooks at the CEC's workshop on January 10 and through written comments filed with the CEC on January 22. These comments are provided in Appendix C to this advice letter.

[4] R.06-02-013, PG&E's 2006 Long Term Procurement Plan, filed December 11, 2006, vol. 2, chapter 1, p. I-18 to I-29.

that "digester gas", which is another term for BioMethane, is a renewable fuel. Thus, RPS-eligible electricity may be created directly by the dairy, a middleman, or by a generating facility that purchases the pipeline-quality BioMethane for electric generation.

II. THE DEMONSTRATION PROJECT CONTRACT

The counterparty to this Contract is a developer of "cow power" projects and has experience in installing the anaerobic digesters and scrubbing equipment, as well as building the compression equipment necessary to elevate the BioMethane to pipeline-quality gas. However, the developer/manufacturer has never built a full scale facility on a dairy where the gas is created, scrubbed, compressed and injected as pipeline quality natural gas into a transmission pipeline. The biogas Contract submitted for Commission approval in this Advice Letter has the potential to foster development of a new renewable energy source; it will use its own facilities and processes to create BioMethane. At this stage of biogas resource development, it is important for producers to have a buyer for their products while efficiencies are being identified and improvements are made. This project will provide valuable information about the feasibility of future biogas projects and hopefully provide guidance for more commercial deployment of the most successful techniques. PG&E anticipates deliveries under the Contract may begin as early as May 2007.

The counterparty, BioEnergy, LLC, is a developer of biogas projects that partners with a nationally-recognized provider of gas scrubbing technology that is used for a number of industrial applications.

Under the Contract, PG&E will procure a product consisting of the BioMethane and the environmental attributes necessary to count the resultant electrical generation toward California's RPS requirements. The delivered BioMethane must meet PG&E's tariffed gas quality guidelines. In particular, the heat content of the BioMethane from the biogas producer will be metered to verify that it falls within PG&E's minimum and maximum range when the gas enters PG&E's gas transmission system.

III. SIGNIFICANCE OF DEMONSTRATION PROJECT CONTRACTS FOR RPS PROCUREMENT

Consistent with the direction provided in the CEC Staff's Draft, PG&E proposes to nominate delivery of the biogas to one of PG&E's electric generation facilities which will be certified as "RPS-eligible" per CEC guidelines. Delivery of the biogas to the facility will occur just like any other nomination of gas pursuant to PG&E's gas system tariffs. For the reasons given above, the CEC should adopt a procedure that relies on recorded gas consumption times actual electricity output, instead of the forecasted heat rate, to calculate RPS-eligible MWh. The use of biogas as proposed will demonstrate how seamlessly a renewable energy resource can be integrated into California's electric generation system and how easily documented its contribution can be documented using publicly available data.[5]

IV. BENEFITS FOR PG&E'S CUSTOMERS

Approval of this Contract should provide many benefits for PG&E's customers, including:

- Creating demand for a renewable fuel that can be used to produce RPS-eligible electric energy, depending on CEC certification;

- Providing a predictable source of renewable gas that satisfies a portion of PG&E's overall electric portfolio gas needs;

- Providing significant reductions of greenhouse gas by capturing and destroying methane, a greenhouse gas that has approximately 21 times the climate change impact as carbon dioxide.[6]

- Providing some implicit value as a hedge against natural gas price fluctuations because the cost of the BioMethane is fixed (in $/MMBtu) over the contract term. However, because the BioMethane is provided on an as-available basis, the hedge is not as effective as would be a baseload gas contract.

- Providing an option for PG&E to purchase Additional Environmental Attributes (AEAs)[7] in the form of emission credits. The AEAs are recognized attributes -- that may be recognized at some point in California to result from the disposition of the fuel source other than its combustion in order to produce electricity -- such as the sequestration of methane.[8]

---

[5] The electricity generated by a facility per volumetric unit of gas depends on the heat content of the gas, which is measured at or near the generating facility. The heat content of the gas delivered by PG&E's gas department is governed by PG&E's gas Rule 2 – Description of Service, Section 3 and is measured at meter where such gas enters PG&E's gas transmission system. PG&E is billed for biogas on an energy basis (not on a volumetric basis).

[6] The conversion process to BioMethane results in an actual reduction in CO2 emissions because CO2 is absorbed from the atmosphere as part of the conversion *process.*

[7] AEAs are defined in the biogas contract as any environmental attributes created by the production of Biogas other than those defined in the standard Environmental Attributes definition. These include, but are not limited to sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases.

V. PRG FEEDBACK

PG&E provided its PRG with a report on this technology and the potential projects on July 19, 2006 and September 25, 2006.

VI. REQUEST FOR COMMISSION APPROVAL

PG&E requests that the Commission approve this Contract by resolution no later than April 5, 2007. Upon certification by the CEC that the biogas sold under the Contract qualifies as “digester gas”, PG&E will provide a copy of the certification to the Director of the Energy Division and confirm that it will report RPS energy deliveries consistent with the methodology described in this Advice Letter, unless modified by the CEC or this Commission, in which case the approved methodology will be used.

In support of this request, certain confidential information is being submitted under the confidentiality protections of Section 583 of the Public Utilities Code and General Order 66-C. Pursuant to the Administrative Law Judge’s Ruling Clarifying Interim Procedures For Complying with Decision 06-06-066, issued August 22, 2006 in Rulemaking 05-06-040, a separate Declaration of Confidential Treatment regarding the confidential information is being filed concurrently herewith.

PG&E requests that the Commission issue a resolution no later than April 5, 2007 that:

1. Approves this Contract in its entirety, including payments to be made by PG&E, subject to CPUC review of PG&E's administration of the agreement.

2. Finds that electricity generated through the use of the biogas procured under this Agreement is produced by an eligible renewable energy resource for purposes of determining PG&E’s compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 et seq.), Decision (D.)03-06-071, or other applicable law, subject to CEC certification that the use of digester gas to generate electricity creates an eligible renewable energy resource as defined by Section 399.12 of the Public Utilities Code.

3. Finds that electricity generated through the use of the biogas procured under this Agreement constitutes incremental procurement or procurement for baseline replenishment by PG&E from eligible renewable energy resources for purposes of determining PG&E’s compliance with any obligation to increase its total procurement of eligible renewable energy resources that it may have pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 et seq.), D.03-06-071, or other applicable law,

subject to CEC certification that the use of digester gas to generate electricity creates an eligible renewable energy resource as defined by Section 399.12 of the Public Utilities Code.

4. Finds that payments made under the Contract and any indirect costs of renewables procurement identified in Section 399.15(a)(2) shall be recovered in full over the life of the contracts in the Energy Resource Recovery Account as a utility fuel cost.

5. Finds that the cost associated with this Contract between PG&E and Sellers are reasonable and in the public interest.

Protests

Anyone wishing to protest this filing may do so by sending a letter by February 22, 2007 which is **20** days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

CPUC Energy Division
Attention: Tariff Unit, 4th Floor
505 Van Ness Avenue
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: mas@cpuc.ca.gov and jnj@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4005 and Honesto Gatchalian, Energy Division, at the address shown above.

The protest also should be sent via U.S. mail (and by facsimile and electronically, if possible) to PG&E at the address shown below on the same date it is mailed or delivered to the Commission.

Pacific Gas and Electric Company
Attention: Brian Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-Mail: PGETariffs@pge.com

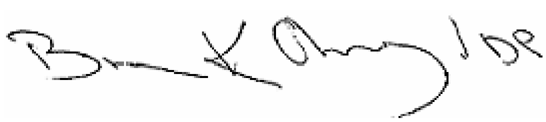
Effective Date:

PG&E requests that this advice filing become effective on **April 5, 2007.**

Notice:

In accordance with General Order 96-A, Section III, Paragraph G, a copy of this advice letter excluding the confidential appendices and the confidentiality declaration are being sent electronically and via U.S. mail to parties shown on the attached list and the service list for R.01-10-024, R.06-02-012, and R.06-05-027. Non-market participants who are members of PG&E's Procurement Review Group and have signed appropriate Non-Disclosure Certificates will also receive the advice letter and accompanying confidential attachments by overnight mail. Address changes should be directed to Rose De La Torre (415) 973-4716. Advice letter filings can also be accessed electronically at:

http://www.pge.com/tariffs



Vice President - Regulatory Relations

cc: Service List R.06-05-027
Service List R.06-02-012
Service List R.01-10-024
Paul Douglas -- Energy Division
Eugene Cadanesso – Energy Division

Attachments

Limited Access to Confidential Material:

The portions of this advice letter so marked Confidential Protected Material are submitted under the confidentiality protection of Section 583 of the Public Utilities Code and General Order 66-C. Pursuant to the Administrative Law Judge's Ruling Clarifying Interim Procedures For Complying with Decision 06-06-066, issued August 22, 2006 in Rulemaking 05-06-040, a separate Declaration of Confidential Treatment regarding the confidential information is filed concurrently herewith.

Confidential Attachments:

Appendix A – Power Purchase Agreements

Appendix B – Contract Analysis

Public Attachments:

Appendix C – Letter from PG&E to CEC setting forth methodology for determining RPS-eligible energy produced using BioGas

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. Pacific Gas and Electric Company (ID39E)

Utility type:	Contact Person: David Poster
☒ ELC ☒ GAS	Phone #: (415) 973- 1082
☐ PLC ☐ HEAT ☐ WATER	E-mail: dxpu@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **2979-E**

Subject of AL: Demonstration Project to Convert Dairy Waste for Renewable Natural Gas Electric Energy Production

Keywords (choose from CPUC listing): RPS

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☒ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A_

Summarize differences between the AL and the prior withdrawn or rejected AL:

Resolution Required? ☒ Yes ☐ No

Requested effective date: **04-5-07** No. of tariff sheets: 0

Estimated system annual revenue effect: (%):N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
mas@cpuc.ca.gov and jnj@cpuc.ca.gov

Utility Info (including e-mail)
Attn: Brian K. Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

DECLARATION OF HAROLD O. LA FLASH
SEEKING CONFIDENTIAL TREATMENT
FOR CERTAIN DATA AND INFORMATION CONTAINED
IN ADVICE LETTER 2979-E
(PACIFIC GAS AND ELECTRIC COMPANY ID U 39 E)

I, Harold O. La Flash, declare:

1. I am presently employed by Pacific Gas and Electric Company (PG&E) and have been an employee for more than 25 years. My current title is Director, Renewable Energy Policy & Planning within PG&E's Energy Procurement Department. In this position, my responsibilities include planning for and attracting renewable energy resource developers. In previous positions I have also had responsibilities for buying natural gas. In carrying out current and past responsibilities, I have acquired knowledge of PG&E's contracts with numerous counterparties, I have also gained knowledge of the operations of such sellers in general and, based on my experience in dealing with facility and contract owners, I am familiar with the types of data and information about their contracts and operations that such parties would consider confidential and proprietary.

2. Based on my knowledge and experience, and in accordance with the "Administrative Law Judge's Ruling Clarifying Interim Procedures For Complying With Decision 06-06-066," issued August 22, 2006, I make this declaration seeking confidential treatment of certain data and information contained in PG&E's "Demonstration Project to Convert Dairy Waste for Renewable Natural Gas Electric Energy Production," Advice 2979-E, submitted on February 2, 2007. By this Advice Letter PG&E is seeking this Commission's approval of a power purchase agreement (PPA) to purchase gas produced by the anaerobic

conversion of agricultural, food or dairy wastes (Dairy Waste) or other processes as set forth in the agreements.

3. The data and information for which PG&E is seeking confidential treatment fall into the following general categories:

- Contract price.
- Specific credit or collateral requirements.

4. The categories above either correspond to a category of protected, confidential information specified in Appendix 1 of the Commission's recent confidentiality decision, D.06-06-066 (Confidentiality Matrix), or should be kept confidential because it concerns information the Seller considers confidential and proprietary. I am informed and believe that such information qualifies for confidential treatment pursuant to this Commission's General Order No. 66-C.

5. The PPA is protected from public disclosure, as provided by category VII.B. of the Confidentiality Matrix, which governs "Contracts and power purchase agreements between utilities and non-affiliated third parties (except RPS)" and category I.4 of the Confidentiality Matrix, "Long-term fuel (gas) buying and hedging plans."

6. PG&E will comply with the limitations on confidentiality described in the Confidentiality Matrix for the type of data specified in category VII.B.

7. This information is not already public.

8. The data has been summarized in accordance with the Confidentiality Matrix as explained in paragraph 6 of this declaration

9. If the Commission orders disclosure of the Sellers' confidential data that is included in the Advice Letter, PG&E may be hampered in future contract negotiations. Sellers

may be more reluctant to negotiate agreements directly with PG&E if they know their confidential, proprietary information must be made public as part of the Commission approval process. Such a circumstance could limit PG&E's ability to obtain customer benefits through direct negotiations with facility owners.

10. To my knowledge, the Sellers' operating and cost data information is not already public.

11. The data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

12. I am informed and believe that Sellers' information qualifies for confidential treatment pursuant to paragraphs 2.2 and 2.8 of General Order No. 66-C.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on February 2, 2007, at San Francisco, California.

Harold O. La Flash

HAROLD O. LA FLASH

Appendix C

Letter from PG&E to CEC Setting Forth Methodology for Determining RPS-Eligible Energy Produced Using BioGas

Docket No. 02-REN-1038
Docket No. 03-RPS-1078
Filed: January 22, 2007

Post-Workshop Comments of Pacific Gas and Electric Company re: The California Energy Commission Staff Drafts of Revised Renewables Portfolio Standard Guidebooks

TABLE OF CONTENTS

Page

I. INTRODUCTION AND OVERVIEW 1

A. Banking and Shaping Should Access the Greatest Potential Supply While Avoiding Market Distortions 1

B. The Conversion of Eligible Biogas to RPS-eligible Electricity. 2

C. Revisions to Eligibility of Small Hydro Conduit Facilities. 2

D. The RPS Solicitation Results and Pricing and Negotiation Information Required in Support of the SEP Process Merit Automatic Confidential Treatment 2

II. REPONSE TO QUESTIONS FOR PUBLIC INPUT 2

A. Renewables Portfolio Standard Eligibility Guidebook 2

1. New facilities seeking RPS and SEP eligibility may not require a 'new or increased appropriation of water' under Water Code Section 1200 et seq. 2

2. Regarding RPS-eligible gas injection into the gas transmission pipeline 3

3. A process for the Energy Commission to certify tradable RECs 6

B. Existing Renewable Facilities Program Guidebook 6

1. power purchase contract with an electrical corporation originally entered into prior to September 24, 1996 6

2. Whether any of the information below, requested for purposes of determining target prices, should or should not be confidential 7

3. A methodology to determine the annual average capacity price component for each facility 8

4. Information on the 'market value' of the facility 8

III. COMMENTS ON RENEWABLES PORTFOLIO STANDARD ELIGIBILITY GUIDEBOOK 9

A. Digester Gas 9

B. Small Hydroelectric and Conduit Hydroelectric (pp.16-20) 10

1. Reference to December 31, 2005 must be removed from eligibility criteria of conduit hydroelectric resources (p.17). 10

C. Hybrid Systems – "Conversion of RPS – eligible Fuel from Natural Gas Pipeline" (pp. 26-26) 11

TABLE OF CONTENTS
(continued)

Page

1. Requirement to Certify "Hybrid System" Plant as RPS-Eligible should be Explicit. ... 11
2. Conversion Methodology Should be Revised to Apply Ratio of RPS-Eligible Fuel to the Output of the RPS-Eligible Plant. ... 11
3. Requirement that Biogas must be injected at a point within California should be stricken ... 12
4. PG&E offers the following comments on the five biogas implementation issues on p. 26: ... 12

D. Delivery Requirements (p.29) ... 13

1. Requirements Should be Edited for Consistency ... 13
2. The commercial structure of the banking function should be clarified and should not be limited to the control area of the generating facility. ... 14
3. NERC Tag Information Should be Revised to Reflect Banking and Shaping. ... 14
4. Annual True-Ups Between Eligible Generation and Deliveries from Control Area Are Based Upon the Correct Interval. ... 15
5. The use of Calendar Year for Annual Banking Without True-Ups May Result in Stranded Deliveries. ... 17
6. Minor Technical Amendment Needed to Recognize Retail Seller's Role ... 17

E. Certification (p.33) ... 17

1. The CEC should clearly state that all generation by a pre-certified renewable energy facility that is delivered to a retail seller prior to final CEC certification of RPS eligibility will count toward the retail seller's RPS obligation when the generator receives CEC its RPS certification ... 18

F. Renewing Certification and Pre-Certification (p.36) ... 18

1. The CEC Should Avoid Unnecessarily Changing Eligibility Criteria for Certified Projects. ... 18
2. Recertification Should be Retroactive to the Date of Expiration of Certification, in Case of Delay ... 19

G. Supplemental Instructions for Out-of State Facilities (p.43) ... 19

TABLE OF CONTENTS
(continued)

Page

H. Supplemental Information – Repowered Facilities (pp.46-48) 20

IV. COMMENTS ON NEW RENEWABLE FACILITIES PROGRAM GUIDEBOOK 20

A. Introduction -- Apprise Sellers of Maximum Potential Grant (p.1) 20

B. Program overview 21

1. Approval by CPUC is limited to IOU contracts. (p.4) 21

2. SEPs Are Now Available For Cumulative Above-Market Costs Over Duration of Contract (p.5). 21

3. Confidentiality of Price and Other Contract Terms Should be Subject to Blanket Protection. (p.5) 21

C. Multiple Awards 23

D. Award Determination - p. 14 23

V. COMMENTS ON EXISTING RENEWABLE FACILITIES PROGRAM GUIDEBOOK 24

A. The Commission Should Exercise its Discretion to Preserve Existing Deliveries. 24

B. Continued Incidental Use of Fossil Fuel Should Not Jeopardize Eligibility Because Fuel Use Restrictions Were Intended to Address the Renewable Category of Fuel. 24

C. Conclusion 25

I. INTRODUCTION AND OVERVIEW

On December 18, 2006, the Renewables Committee of this Commission (California Energy Commission or "CEC") issued its "Notice of Committee Workshop on Guideline Revisions for the Renewable Energy Program and RPS Implementation" and circulated the Staff's draft changes to the CEC's five Renewables Portfolio Standard (RPS) implementation guidebooks for public comment. The Renewables Committee heard comments at the January 10, 2007 workshop and invited parties to provide written responses no later than January 22.

At the workshop, Pacific Gas and Electric Company (PG&E) expressed its appreciation of the timeliness and thoroughness of the CEC staff's draft revisions to implement the RPS legislation of 2006. Along with codifying the acceleration of the 20% RPS goal to 2010, Senate Bill (SB) 107 enlarged the range of renewable resource facilities that are eligible to meet the RPS, SB 1250 clarified the eligibility of biomass facilities for public financial support, and Assembly Bill (AB) 2189 assured that increased capacity from efficiency improvements would not disqualify currently eligible small hydro facilities. Accordingly, the goal of expanding eligibility should be a paramount consideration in the Commission's revisions to its RPS Guidebooks, particularly on issues subject to the Commission's exercise of discretion, so that retail sellers such as PG&E have the broadest range of potential renewable resources with which to meet their RPS procurement goals.

A. Banking and Shaping Should Access the Greatest Potential Supply While Avoiding Market Distortions.

The primary vehicle for substantial new procurement opportunity is the adoption of a new definition of "delivery", which allows the generation from an eligible resource to count so long as it is consumed in California, even if the use occurs at a time other than when the power was generated. The CEC staff's proposal for annual true ups of generation and deliveries will allow retail sellers to access maximum annual procurement from renewable resources with intermittent or seasonal generation patterns without incurring uneconomic transmission costs.

While this proposal appropriately facilitates the inter-temporal nature of banking and shaping, the commercial dimension of these transactions should also be addressed to avoid uneconomic or unnecessary constraints. To make full use of the commercial arrangements by which banking and shaping may be documented, PG&E recommends revisions to recognize that the generation may be banked and shaped in various control areas, so long as the amount of claimed RPS-eligible electricity does not exceed the generation metered at the eligible renewable generating facility or the amount delivered into California. The flexibility to "deposit" and "withdraw" from different control areas will ensure that power will flow where it is needed during the interval between generation and consumption, maximizing supply and avoiding any unnecessary incremental costs for the delivered electricity.

B. The Conversion of Eligible Biogas to RPS-eligible Electricity.

In response to inquiries by PG&E, the CEC staff has drafted a procedure by which the digester gas can be nominated to a specific plant for use in the production of RPS-eligible electricity. The Staff Draft has addressed practically all of the issues involved in the conversion of the energy in the biogas to electricity in an objective, quantitative manner. However, there is a slight inconsistency in the calculation which calls for the use of the generating facility's heat rate, which is not considered to be public information. Below, PG&E describes the proportional methodology which is actually implicit in the staff's draft for calculating the amount of RPS-eligible electricity to be generated by using RPS-eligible digester gas.

C. Revisions to Eligibility of Small Hydro Conduit Facilities.

The overlay of the 2006 amendments regarding the eligibility of out of state resources upon the already complex eligibility rules for small hydro facilities appears to have created guidelines in conflict with the statutes. PG&E suggests a technical correction to the eligibility criteria for conduit hydro facilities.

D. The RPS Solicitation Results and Pricing and Negotiation Information Required in Support of the SEP Process Merit Automatic Confidential Treatment.

The New Renewables Facilities Program Guidebook sets out the procedure by which the CEC will consider applications for supplemental energy payments (SEPs). Among other things, it requires the investor-owned utilities (IOUs) to provide the results of their RPS solicitations to the CEC within 30 days of the CPUC's publication of the MPR, regardless of whether any seller has indicated intent to seek SEP payments. The seller and the IOU are required to disclose pricing information, including the initial and final bid plus an explanation of how the difference was derived, in support of an individual SEP application. Clearly this information is *prima facie* market sensitive information. The Guidebook should provide automatic confidentiality protection of this information, instead of simply indicating that the IOUs and applicants may seek a confidentiality determination by the CEC's executive director.

While these are the areas of most importance to PG&E, we have also responded to the questions posed for public input and offer comments on the RPS Eligibility Guidebook, New Renewable Facilities Program Guidebook, and Existing Renewable Facilities Program Guidebook. We encourage the CEC to revise its Guidebooks to provide a broader range of resources for renewable energy resource procurement and would welcome the opportunity to or provide additional information, if needed.

II. REPONSE TO QUESTIONS FOR PUBLIC INPUT

A. Renewables Portfolio Standard Eligibility Guidebook

1. New facilities seeking RPS and SEP eligibility may not require a 'new or increased appropriation of water' under Water Code Section 1200 et seq. New facilities

seeking RPS eligibility may not require a 'new or increased appropriation or diversion of water from a water course.' Given the difference in statutory language, the terms 'appropriation' and 'diversion' for RPS eligibility may be defined consistent with Water Code Section 1200 et seq., or may be defined differently.

a. Should the terms 'appropriation' and 'diversion' of water be defined the same or differently for new facilities seeking RPS eligibility versus new facilities seeking RPS and SEP eligibility?

No. Staff notes that Water Code section 1200 et seq. of the Water Code, which defines when an appropriation has occurred, is employed by Public Resources Code Section 25743 (b)(3)(C) as the standard for determining whether a "new or increased appropriation of water" has occurred. In such event, Sec. 25743(b)(3)(C) disqualifies a small hydro facility from receiving SEPs.

Public Resource Code section 399.12(b)(1) also uses the term "appropriation" to define small hydro eligibility for RPS, although it does not refer to the Water Code. PG&E is not aware of any reason to find that the term "appropriation" should be defined any differently if SEPs are not being sought for a new hydroelectric facility. As the term "diversion" is not referred to exclusively by the section on SEP eligibility, there does not seem to be any reason to differentiate the diversion of water by an applicant for SEPs from diversion by any other potentially eligible small hydro facility.

b. If these terms should be defined differently for RPS eligibility, how should they be defined?

The terms should be defined according to statute. As explained above, PG&E believes that there is no option to define these terms differently depending on whether the issue is eligibility for RPS or for SEPs.

2. Regarding RPS-eligible gas injection into the gas transmission pipeline:

a. *The draft guidebook proposes that biogas injected into the gas transmission pipeline and converted into electricity be RPS-eligible. Is the proposed methodology for this appropriate?*

Yes, as qualified below.

Generally speaking the methodology, which recognizes that the energy content of the RPS-eligible biogas can be monitored and converted into RPS-eligible electricity by the nomination of the gas to an RPS-eligible generating facility is appropriate. However, because the draft arbitrarily requires an in-state biogas injection point and does not propose the most straightforward, easily verifiable conversion methodology, it should be revised.

(i) The requirement "the gas must be injected at a point within the California border" is arbitrary. Gas-fired electric generators in California are not limited to purchasing only California gas, i.e., gas injected into the pipeline system at a location within the state. This term would disqualify biogas manufactured outside of California from generating RPS-eligible electricity, foreclose the environmental benefits resulting from the manufacture of bio-gas, including the containment and destruction of potent greenhouse gases, deny PG&E's customers access a significant supply of renewable energy even though there are a number of current opportunities to purchase biogas from out of state sources which can be transported just like any other purchased gas through interstate gas pipelines to in-state generation facilities. So long as the terms of the retail seller's biogas purchase agreement require the product to meet the CEC's definition of digester gas and the gas is injected into facilities that interconnect with the natural gas transmission pipeline system from which the RPS-eligible generating facility takes its gas, then the conversion of biogas to RPS-eligible electricity will occur.

(ii) Because the CEC strives to make its regulatory process as open to public review as possible, it should adopt a methodology that uses publicly-available, inherently reliable inputs for converting the heating value of the biogas resource into eligible RPS deliveries. Reliable data will also assure the reliability of the resultant delivered electricity figures. The preferred means of converting MMBtu to MWh is as follows:

> Assume that for a specific electric generating facility that generates "Q" MWh per period, using "B" quantity of digester gas and "N" quantity of natural gas, the quantity of RPS-eligible electricity "R" is calculated as
>
> Q MWh x (B/N) MMBtu = R MWh

The identification of a specific generation facility enables the use of verifiable fuel and output data based upon the historic performance of a particular generating facility. In the case of an investor-owned utility such as PG&E, records of the fuel used to generate electricity are reported in PG&E's Quarterly Procurement Transaction Report, which is filed quarterly at the CPUC as the basis of PG&E's request for gas cost recovery. A plant-specific heat rate would have to be a forecast heat rate, and is not considered to be public information.

The amount of electricity generated by an IOU-owned generating facility is reported to both the CPUC and the CEC.

The report to the CPUC is done on a quarterly basis in the IOU's quarterly ERRA (Electric Revenue Recovery Account) filing, which is tendered to substantiate IOU requests to recover costs in rates.

The CEC reporting consists of two annual reports – the "Power Source Disclosure" (Disclosure) and the "Procurement of Renewable Energy by Retail Sellers" (Procurement Report). The Disclosure Report documents the total amount of generation from all of an IOU's generation resources while the Procurement Report indicates the amount of RPS-eligible generation from the IOU's RPS-eligible generation resources. The amount of RPS-eligible renewable energy generated by a co-fired facility would be computed in accordance with the above formula, and be tracked and reported in the Procurement Report until that report is superseded by the WREGIS system.

The nomination of specified quantities of gas that are injected into the gas transportation system at Point A for delivery to Point B is a well-established transaction that is performed under existing public utility tariffs. For example, PG&E uses its G-AA (As Available Transmission) Redwood Path and G-EG (Transportation to Electric Generation) tariffs to transport gas from the interconnection of the TransCanada Gas Transmission Northwest pipeline at Malin to the Humboldt Plant in Eureka.

Although the MWh output of an electric generating facility is often expressed as the product of MMBtu and the facility's heat rate, the result could be subject to debate due to the potential variance of the assumed heat rate from actual heat rate. Instead of relying on an assumed plant heat rate, PG&E's recommended model employs an actual heat rate averaged over the period of time "t" for which N is stated. The plant's output during t is multiplied by the ratio of green gas molecules to total fuel consumed by the plant, and the result would constitute the green MWh.

The public disclosure of the annual average heat rate of a facility within PG&E's generation portfolio the facility could harm PG&E's customers. (par. 4, p.26). The plant-specific annual average heat rate is proprietary business information because knowledge of this information, plus the published cost of natural gas, could reveal PG&E's cost of electricity at the margin (depending on the plant's position in PG&E's loading order and actual operating conditions). This information could be used by potential sellers to extract a windfall above their cost of production, and thus has been consistently protected from public disclosure by PG&E.

b. *What published data are available to determine an annual average heat rate for a facility?*

There is no publicly available reporting of an annual average heat rate for an electric generating facility. The average annual heat rate can be calculated on a historical basis using data submitted by investor-owned utilities such as PG&E as part of its justification for rates authorized under the Energy Revenue Rates Account (ERRA). However, this data is submitted on a confidential basis, and the resultant heat rate would also be confidential.

c. *What, if any, additional information should the facility operator be required to report on a monthly or annual basis to ensure the facility is only credited for that portion of the generation associated with RPS-eligible fuel?*

In addition to the information identified in "d.", below, the facility operator should identify the electric generation facility and the facility's monthly electric generation, in terms of output metered for ISO purposes.

d. *Should the facility operator be required to report the monthly volume of RPS eligible fuel supplied to the gas transmission pipeline and the monthly volume of natural gas used at the facility?*

Yes; although deliveries of RPS-eligible fuel to the gas purchaser and the deliveries of pipeline gas to the facility will be recorded on a monthly basis, reporting to the CEC should occur on an annual basis, as needed to facilitate the CEC's annual tracking of RPS deliveries by all eligible renewable resource facilities, to avoid an undue burden on this type of resource.

e. *What information should the fuel supplier be required to report to the Energy Commission to verify the eligibility of the fuel?*

Initially the fuel supplier should provide a description of the process to produce the fuel to demonstrate compliance with RPS eligibility criteria. The fuel supplier can demonstrate the continued eligibility of the fuel by reference to the terms and conditions of its biogas purchase agreement with the gas transmission pipeline. Under PG&E's form of agreement, the fuel supplier will be paid only for volumes that meet the CEC's criteria for RPS-eligible fuel.

3. The draft Guidebook establishes a process for the Energy Commission to certify tradable RECs as a prerequisite for retail sellers interested in procuring RECs from publicly owned utilities, in the event that tradable RECs are allowed for RPS compliance. The *Guidebook* does not address the possible sale of RECs and electricity bundled together for sale to retail sellers from POUs. However, if POUs sell bundled RECs that they otherwise need to satisfy their RPS, then the state would make no net gain in its RPS-eligible retail sales.

a. Should the process for the Energy Commission's certification of RECs sold by a POU to a retail seller to satisfy a retail seller's RPS targets be expanded to include certification of bundled RECs?

Yes, it should. PG&E believes that achievement of the state's RPS goals will be most credible if all RECs available to retail sellers for the purpose of meeting California's RPS program are subject to consistent verification by one monitoring agency.

B. Existing Renewable Facilities Program Guidebook

1. A facility must not sell its generation under a power purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter, with certain exceptions (the pertinent legal code is in the Eligibility Requirements of the *Existing Renewable Facilities Guidebook*).

a. How many prospective ERFP applicants, if any, satisfy the provisions of Section 25740.5, subdivision (e), paragraph (1)(C)?[1]

[1] The cited section of the Public Resources Code provides that, "... production incentives may be allowed in any month for incremental new electricity generated by an in-state renewable electricity generation facility that is repowered or refurbished, where the electricity is delivered under an electricity purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether

PG&E is not aware of any such facilities.

b. *What information and records should the Energy Commission require of prospective ERFP applicants to ensure compliance?*

The Energy Commission should require copies of the original and amended power purchase contract to demonstrate compliance. This information should not be public.

2. Interested parties are encouraged to comment on whether any of the information below, requested for purposes of determining target prices, should or should not be confidential and the rationale for the recommendation.

a. *The cumulative amount of funds the facility has previously received from the Energy Commission and other state sources.*

The amount and source of financial resources, including total amount of public support already received by or committed to a facility, tend to demonstrate the viability of a facility. Public knowledge of the financial position of a facility may impair the ability of the facility's developers to achieve the most advantageous contractual arrangements and ultimately increase the cost of procurement to utility customers. This information should not be public.

b. *The value of any past and current federal or state tax credits.*

The value of any past and current federal or state tax credits may be based upon the contract price for electricity produced, or the facility's cost of production. Both types of information are a trade secret, and should be protected in all cases from public disclosure.

c. *The facility's contract price for energy and capacity.*

This should be protected in all cases from public disclosure because knowledge of one facility's contract price under the shortage conditions that will exist in the foreseeable future will establish a defacto "most favored nation" or floor price, forcing utility customers to pay more for renewable energy than if no benchmark floor price is revealed.

d. *The market value of the facility.*

PG&E believes that a knowledgeable industry observer could estimate the market value of the facility using publicly available information that is disclosed when a public utility

---

amended or restated thereafter, if all of the following occur: (i) The purchase contract price does not exceed the CPUC – approved short run avoided cost of energy, (ii) The kWh used to determine the capacity payment shall be equal to certain criteria, which are generally the actual kWh production, but no greater than the actual kWh delivered during certain TOD periods and months, during historical periods, and (iii) The production incentive is payable only with respect to the kWh delivered in a particular month that exceeds the corresponding 5-yr. average calculated pursuant to clause (ii).

seeks CPUC approval of its power purchase contract with the facility, so the CEC's release of an estimate of the facility's market value would probably have little effect upon the interests of the facility owner or utility customers. The market value may be made public.

e. An estimate of the incentive payment needed (in cents/kWh) above the energy and capacity payments the facility will receive during the calendar year for which the applicant is applying.

Since information about a facility's technology and vintage would be publicly available, the estimate of a single facility's incentive payment would tend to reveal the price for energy and capacity to be paid by the utility, and should not be public. If the purpose of the disclosure is to notify other developers of the potential for public support for their facilities, the incentive payments for a calendar year may be expressed in cents/kWh as an *average* of all grants made during that year.

f. An explanation of how the incentive payments from the ERFP will allow the facility to become cost-competitive by the end of 2011.

This explanation may require the facility to divulge information that it considers to be proprietary business information. So long as the price paid for capacity and energy under the utility power purchase agreement is not revealed, PG&E suggests that the CEC consider the interests of the facility in the confidentiality of this information.

3. The average capacity price component will be based on an annual average of the capacity payments received by each facility on a cents/kWh basis. This annual average capacity price component will be determined at the beginning of each year with the determination of the facility's specific target prices. *Public input is invited on how to craft a* ***methodology to determine the annual average capacity price component for each facility****.*

The annual average capacity price can be determined by dividing the prior year's total annual capacity payments by the total kWh generated by the facility during that same year. If applicable the annual average capacity price should be adjusted to reflect any expected escalation in the capacity price.

4. All applicants are required to submit information on the 'market value' of the facility as part of the application process.

a. How should the 'market value' of a facility be defined?

In theory, the market value of a facility is the amount that a buyer would pay the owner for the ownership of the facility and the associated assets, as of the valuation date, in a hypothetical, mutually voluntary, 100% equity-financed transaction, in which neither the seller nor the current owner were under an obligation to engage in the transaction, and in which both the owner and the seller had the same information relevant to the value of the facility and the associated assets.

The assets associated with the facility could include any existing contract under which the power produced by the facility is sold to a buyer, as well as any contracts under which the facility owner obtains the inputs utilized by the facility (e.g., fuel, labor, etc.).

This definition assumes that the buyer would not be assuming any of the liabilities of the facility's current owner (e.g., outstanding debt and/or accounts payable), nor obtaining other assets (e.g., cash, accounts receivable, etc.).

There are various ways to estimate that market value amount. In theory, the most appropriate method is to determine the net present value of the after tax cash flows that the facility (and the associated assets) is expected to generate for its owner(s) to generate over the remainder of its economic useful life, assuming that the investment was 100% equity financed, based on a discount rate that reflects the relative risk of owning and operating the facility.

Another way to estimate the market value is to review the range of amounts paid in roughly similar contemporaneous voluntary transactions for comparable facilities under comparable circumstances, adjusted to reflect any differences between this facility (and its associated assets) and those other facilities and their associated assets (e.g., $/MW for facilities that have different capacities, differences between the expected remaining economic lives of the facilities, their power purchase contracts, technologies, the tax status of the legal entities (e.g., partnerships vs. LLCs vs. Sub-Chapter C corporations) that engaged in those transactions, etc.).

b. What information and/or records should be submitted to the Energy Commission to verify a facility's market value?

Please see preceding answer.

III. COMMENTS ON RENEWABLES PORTFOLIO STANDARD ELIGIBILITY GUIDEBOOK

PG&E offers the following comments on the requirements for demonstrating the eligibility of electricity generated through the use of specific electric energy resources addressed in the Draft RPS Eligibility Guidebook.

A. Digester Gas

Since Digester Gas is listed as a renewable resource or fuel, the Staff may consider identifying this resource by a separate heading, just as "biodiesel" and "biomass" have their own descriptions.

B. Small Hydroelectric and Conduit Hydroelectric (pp.16-20)

The RPS eligibility requirements for small hydroelectric generating facilities have always been complex and became even more confusing after the concept of conduit hydro facilities and SB 107's criteria for out-of-state resources were overlaid on the pre-existing Guidelines.

1. Reference to December 31, 2005 must be removed from eligibility criteria of conduit hydroelectric resources (p.17).

The Staff Draft asserts that, "The RPS eligibility of a conduit hydroelectric facility depends in part on whether the facility was operational by December 31, 2005." This statement is not true. New Section 299.12(b)(1)(B) provides the entire definition of a conduit hydro facility. It states:

> "Notwithstanding subparagraph (A), an existing conduit hydroelectric facility as defined by Section 823a of title 16 of the United States code, of 30 megawatts or less, shall be an eligible renewable energy resource. A new conduit hydroelectric facility, as defined by Section 382a of Title 16 of the United States Code, of 30 megawatts or less, shall be an eligible renewable energy resource so long as it does not require a new or increase appropriation or diversion of water from a watercourse."

The word "notwithstanding" particularly emphasizes that the operational deadline of December 31, 2005 does NOT apply to the definition of conduit facilities. An existing conduit form of small hydro qualifies regardless of when it began operations. PG&E suggests the following changes:

4. Conduit Hydroelectric

~~The RPS eligibility of a conduit hydroelectric facility depends in part on whether the facility was operational by December 31, 2005.~~

RPS Eligibility

- ~~Pre-December 31, 2005:~~ **Existing Conduit Hydro** ~~Generation from a conduit hydroelectric facility that commenced commercial operations on or before December 31, 2005,~~ is eligible for the RPS if the facility meets all of the following criteria:

  Etc.

- ~~Post- December 31, 2005:~~ **New Conduit Hydro** ~~Generation from a conduit hydroelectric facility that commences commercial operations or is repowered after December 31, 2005,~~ is eligible for the RPS if the facility meets all of the following criteria:

  Etc.

In addition, the description of "Hydroelectric Facilities and Conduit Hydroelectric located within California" which appears on p. 20 of the Guidebook should be modified. Items 1, 2, and 3 under that subheading are redundant, as they all refer to a new permit or license from a single agency, the State Water Resources Control Board (SWRCB). They should be replaced by a single bullet point as follows: A new or revised water right permit or license. This requirement makes most new hydroelectric project ineligible.

The "Supplemental Instructions for Small Hydroelectric and Conduit Hydroelectric Facilities" that appear on pp. 38-39 makes a generalization about water rights that is misleading. It requires small hydro and conduit facility applicant to submit proof of water rights in the form of water right permit or license. Pre-1914 and riparian rights do not have permits or licenses associated with them. However, those who use such rights are supposed to have Statements of Water Diversion and Use on file with the SWRCB. The Guidebook should be amended to accept "Statements of Water Diversion and Use" as an acceptable form of proof of water rights.

C. Hybrid Systems – "Conversion of RPS – eligible Fuel from Natural Gas Pipeline" (pp. 26-26)

The Guidebook considers the injection of the RPS-eligible fuel into the natural gas distribution system for combustion in a specified natural gas-fired power plant to be a "hybrid system" and proposes a methodology for calculating the amount of RPS-eligible electricity. The staff's careful attention to detail and familiarity with the natural gas nomination process is evident in the description of the conversion methodology on pp. 26-28. However, the description of the conversion methodology raises a few issues that should be clarified.

1. Requirement to Certify "Hybrid System" Plant as RPS-Eligible should be Explicit.

Page 24 states that new and repowered facilities that operate on co-fired fuels or a mix of fuels that includes fossil fuel will be allowed "two alternatives for eligibility", (1) the facility is a certified QF, or (2) if the facility is NOT a QF, only the renewable portion of the electricity production can qualify for the RPS, once a tracking system has been developed. Actually, the Guidebook departs from this two-track methodology by directing, "The operator of the power plant for which the biogas is nominated "must certify its facility as RPS eligible, recognizing that the facility will use a blend of RPS-eligible and ineligible fuel, " (p.25) and the biogas "must be used at a facility that has been certified as RPS-eligible." (p. 26.) If the plant operator must certify its facility as "RPS eligible" before the biogas-derived electric generation can be counted, this requirement should be added to the list on p. 24.

2. Conversion Methodology Should be Revised to Apply Ratio of RPS-Eligible Fuel to the Output of the RPS-Eligible Plant.

The process for calculating the amount of electricity generated with biogas appears in the third full paragraph of p. 25. PG&E suggests that the amount of RPS-eligible electricity generated by a fossil-fueled facility can be calculated simply by applying the ratio of biogas versus conventional pipeline gas nominated to the facility against the facility's metered electric generation during the relevant time period. The facility operator would report these three data points, instead of the average annual heat rate for the facility, to maintain certification of the facility as RPS-eligible. PG&E suggests the following change to the third full paragraph on p. 25:

> Although blending the biogas into the gas transmission system mixes the biogas with other pipeline gas, an injection of gas is nominated for use to one specific power plant. When RPS-eligible gas is injected into the pipeline mix, ~~the heat rate~~ **the ratio of biogas to conventional gas nominated to the facility shall be** used to calculate the RPS-eligible energy ~~shall be the annual average heat rate of~~ **generated by** the nominated power plant.

3. Requirement that Biogas must be injected at a point within California should be stricken.

The Eligibility Guidebook states that pipeline-quality biogas "must be injected at a point within the California border". (Draft guidebook at 25.) This term should appear as follows in the final version of the Eligibility Guidebook:

> 2. The gas must be injected ~~at a point within the California border~~ **into a natural gas transmission pipeline system from which the RPS-eligible generating facility nominates its gas.**

4. PG&E offers the following comments on the five biogas implementation issues on p. 26:

• *Should biogas injected into the gas transmission pipeline and converted into electricity be RPS-eligible? If so, is this methodology appropriate?*

Yes. The CEC has already adopted the policy position that digester gas is an eligible renewable resource. While digester gas could be burned on-site to generate electricity in small-scale turbines, the transportation of the digester gas to a larger, more efficient facility located in an air-quality attainment basin, instead of the air-quality impacted Central Valley, would multiply the environmental benefits of generation with the biogas.

As noted above, the amount of RPS-eligible electricity should be equal to the electric generation of the facility times the ratio of RPS-eligible biogas nominated to the facility to non-RPS natural gas consumed by the facility.

• *What published data are available for an annual average heat rate for a facility?*

There is no publicly available published data showing the annual average heat rate for a facility.

• *What additional information should the facility operator be required to report on a monthly or annual basis to ensure the* *facility is only credited for that portion of the facility's generation associated with RPS-eligible fuel?*

As noted above, the amount of RPS-eligible electricity should be equal to the electric generation of the facility times the ratio of RPS-eligible biogas to the facility to non-RPS natural gas nominated by the facility.

• *Should the facility operator be required to report the monthly volume of RPS eligible fuel supplied to the gas transmission pipeline and the monthly volume of natural gas used at the facility?*

Yes.

• *What information should the fuel supplier be required to report to the Energy Commission to verify the eligibility of the fuel?*

PG&E suggests the CEC consult with developers of biogas to develop the technical criteria for verifying that the pipeline-quality biogas is the product of the anaerobic digestion of organic wastes. It may be important to verify the composition of the waste in the digester mechanism, the digester process, and the feed mechanism from the digester to the point of injection into the natural gas pipeline.

D. Delivery Requirements (p.29)

This section implements the statutory requirement that a renewable energy resource must be an "in-state renewable electricity generation facility," that is, be located in-state or have its first point of interconnection to the transmission network within the state to be eligible, unless it meets the specific requirements of Public Resources Code section 25741(b). The electricity produced by an out-of-state resource must be "delivered to an in-state location" for it to be RPS-eligible. (Pub. Res. Code section 25741(b)(2)(A).

1. Requirements Should be Edited for Consistency

The Draft Guidebook sets forth the conditions of delivery by out-of-state resources in at least the following two places:

> "D. Eligibility of Out-of-State Resources", which requires that the facility "... (c) Demonstrates delivery of its generation to an in-state market hub or in-state location", (p. 28) and
>
> "E. Delivery Requirements", paragraph 2, which states that "To count generation from out-of-state facilities for purposes of RPS compliance, the electricity must be delivered to an in-state market hub (also referred to as "zone") or in-state substation (also referred to as "node") located within California ~~the CA ISO control area of the WECC transmission system(or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO). ...~~" (pp. 29 and 30.)

These two requirements can and should be drafted to be mutually consistent. In the section on "eligibility of out-of-state resources", the delivery must be either to an in-state market hub or in-state location. However, the section on "delivery requirements" requires delivery to be made to an "in-state substation" located within California. The delivery requirement to an "in-state substation" should be stricken because not all deliveries from out of area are directed to a substation, whereas it would be consistent with ISO usage to state that all deliveries are made to an "in state Point of Delivery." The reference to "(also referred to as "node") should also be stricken because under the CAISO's upcoming Market Redesign Technology Upgrade (MRTU) which includes locational marginal pricing (LMP), there will be nodes which are not Points of Delivery. The term "in-state substation" should be changed to "in-state Point of Delivery" throughout the NRFP Guidebook and accompanying materials. Thus, the final version of "E. Delivery Requirements" should state:

> To count generation from out-of-state facilities for purposes of RPS compliance, the electricity must be delivered to an in-state market hub (also referred to as "zone") or in-state Point of Delivery located within California.

2. The commercial structure of the banking function should be clarified and should not be limited to the control area of the generating facility.

The Staff Draft contains an initial description of one simple structure for a banking arrangement. However, the description of banking and shaping should be modified to recognize that renewable energy will be banked at other control areas or a trading hub. Accordingly, the banking provisions should be described in terms of these commercial structures, so long as the renewable facility is clearly documented in the NERC tag for the delivered energy. PG&E suggests the following modifications to p.30 of the Staff Draft be shown by the bolded text:

The retail seller or procurement entity may document delivery from the control area operator (also referred to as the "balancing authority") in which the RPS-eligible facility is located, **or the control area or market hub to which the renewable generation is delivered.** The Energy Commission will compare the amount of ~~RPS-eligible~~ **energy metered from an RPS-eligible facility** ~~procured~~ per calendar year with the amount of energy delivered into California for the same calendar year and the lesser of the two amounts ~~may~~ **will** be counted as RPS-eligible procurement (for more discussion see "verification of delivery").

3. NERC Tag Information Should be Revised to Reflect Banking and Shaping.

In the section on delivery requirements, the parties are instructed to use a NERC tag to either (a) document an interchange transaction with the CA ISO to deliver the facility's generation to the market hub or substation in the CA ISO control area, or (b) to engage in an interchange transaction with another balancing authority to deliver the facility's generation to an "in-state location" that satisfies the CPUC rules for delivery location. [2]

---

[2] The CEC should be aware of how a NERC tag should be used to document the delivery of electricity into California. A NERC tag is used to provide scheduling instructions between control areas, e.g., it notifies the CAISO that a certain amount of electricity will be provided to the CAISO at a certain time. The notice will document the delivery of electricity from another control area to the point of receipt under the CAISO's control, which for

The description of the use of NERC tags on pp. 30-31 of the Staff Draft should be modified to reflect their use in documenting banked and shaped deliveries as shown by the bolded text:

> 1. … In accordance with the policies of the NERC, the interchange transaction must be ~~tagged as~~ **scheduled with** what is commonly referred to as a "NERC tag", which requires, among other things, that information be provided identifying the Generation Providing Entity, the "Source" or the "Point of Receipt", the physical transmission path for delivery showing intermediary "Points of Delivery", the contract or market path, the final Point of Delivery or load center known as the "sink", and the Load Serving Entity responsible for the consumption of electricity delivered.
>
> 2. The Source identified on the NERC tag may be a specific RPS-eligible facility registered as a unique source, ~~**or may be**~~ the balancing authority for the facility, **or** ~~**may be**~~ **the control area or market hub to which the renewable generation was delivered.**
>
> 3. The RPS-certification number **for the facility** from which the retail seller or procurement entity procures the energy must be shown on the comment field of the NERC tag.
>
> 4. The facility must provide the Energy Commission with its NERC identification (Source point name) if it registers as a unique source, or the Source point name of its balancing authority, when it applies for RPS certification.
>
> 5. The **retail seller** ~~facility~~ must request ~~submit for~~ and receive acceptance of a NERC tag between a balancing authority in California and **either** the balancing authority in which the facility is located **or the control area or market hub to which the renewable generation was delivered**.
>
> 6., 7, and 8. No changes

4. Annual True-Ups Between Eligible Generation and Deliveries from Control Area Are Based Upon the Correct Interval.

The CEC staff has described a process whereby the retail seller or procurement entity may document delivery from the control area operator in which the RPS-eligible facility is located, instead of generation from the eligible facility itself, subject to a comparison between the two

---

deliveries from the north could be "COB" (California-Oregon Border). Based on this requirement, the NERC tag would show "CISO" as the recipient.

As a scheduling tool, the NERC tag indicates the contract path over which the delivery will be made. Since the origin and destination of the routes correspond to physical facilities or trading hubs, once a delivery is scheduled the NERC tag will document delivery of the electricity to the CAISO controlled-end of the route.

amounts accrued during the calendar year (and the lesser of the two amounts may be counted as RPS-eligible procurement).

PG&E strongly endorses this annual-based true up process, as it astutely accommodates both the seasonality of available transmission capacity and of many renewable energy resources, particularly intermittent resources. The annual true up recognizes the actual amount of electricity generated by the renewable resource facility, but allows the electricity to be delivered to the retail seller at a different time, including when the cost of transmission is lower, or for "shaped" deliveries that optimize the procurement and use of scarce intertie transmission capacity.

The description of the true-up process does, however, contain a drafting error: that the Energy Commission compare the amount of RPS-eligible energy "procured" with the amount of energy "delivered" each year. The RPS statute defines RPS procurement as the amount of RPS-eligible energy delivered, so the two terms are one in the same. PG&E recommends that the following language be substituted on draft guidebook pages 30 ("Delivery Requirements") and 54 ("Verification of Delivery"):

> The Energy Commission will compare the ~~amount of~~ ~~RPS-eligible~~ metered energy ~~procured~~generated by the RPS-eligible facility per calendar year with the amount of energy delivered into California for the same calendar year and the lesser of the two amounts may be counted as RPS-eligible procurement (for more discussion see "verification of delivery").

The "Verification of Delivery" on p. 54 of the Staff Draft should be modified as shown by the bolded text, below:

> ... To verify deliveries from out-of-state facilities, the Energy Commission intends to compare the ~~monthly~~ metered generation from an RPS-eligible facility with the monthly NERC tag data for that facility**'s deliveries** on an annual basis. **Metered data** ~~**Procurement**~~ and deliveries must be reported annually but the data must show metered data and delivery per month for the entire calendar year. The Energy Commission will compare the total **metered** amount ~~**procured**~~ in the previous calendar year with the total amount delivered in the previous calendar year and the lesser of the two ~~**may**~~ **will** be **deemed** RPS-eligible procurement ~~with the lesser of the two considered to be eligible RPS procurement~~. For example, if the annual ~~monthly~~ energy delivery shown on the NERC tags for a facility exceeds the annual ~~monthly~~ amount of energy ~~procured~~ **metered from an RPS-eligible facility**, then the Energy Commission will count the **metered** amount ~~procured~~ as RPS-eligible procurement. Conversely, if the amount **metered from an RPS-eligible facility** ~~procured~~ exceeds the annual ~~monthly~~ amount that was delivered **into California** as demonstrated by the NERC tags, the Energy Commission will assume some of the generation was delivered elsewhere and will ~~only~~ count as RPS-eligible **only** the amount of procurement supported by the NERC tag data.

5. The use of Calendar Year for Annual Banking Without True-Ups May Result in Stranded Deliveries.

Under the immediately preceding provision, an annual banking process without provisions for truing-up will fail to count renewable electricity produced during a calendar year if there are insufficient deliveries made into California during that same year. To better ensure that ALL RPS-eligible generation is counted toward RPS compliance, the CEC should allow any metered renewable generation that exceeds deliveries (surplus renewable generation) to roll over into the first quarter of the next calendar year for delivery into California. Likewise, the CEC should allow for truing up if energy deliveries into California exceed renewable generation during a calendar year by including the following provision: first quarter renewable generation should be allowed to be "carried back" to the fourth quarter of the prior year to cover any deficit of that year's renewable generation vs. energy deliveries. Obviously, any renewable generation that was allocated and counted in one year could only be used once and not in both years. These provisions are fair, easily verified through the facility's meter data and NERC tags, and will allow both developers and retail sellers to capture the full benefit of its renewable generation.

6. Minor Technical Amendment Needed to Recognize Retail Seller's Role

The deliverability requirements for out of state power are described on page 30, which states that "The facility" must either engage in a transaction with the CA ISO to deliver the facility's generation to the market hub or substation in the CA ISO control area…" In PG&E's experience, the entity consuming the electricity is the one that arranges for the interchange transaction with the CA ISO. PG&E suggests a minor amendment to the first sentence of paragraph 1. which appears on p. 30, to better describe the actual transaction:

> 1. The <u>retail seller or</u> facility<u>'s representative</u> must (a) <u>arrange for</u> an interchange transaction with the CA ISO to deliver the facility's generation to the market hub or Point of Delivery in the CA ISO control area or (b) <u>arrange for</u> an interchange transaction with another balancing authority to deliver the facility's generation to an in-state Point of Delivery.

E. Certification (p.33)

The ability of deliveries to count toward an RPS obligation if the generating facility was mot certified as RPS-eligible is the subject of paragraphs 2 and 3 on p. 33. Paragraph 2 states, "Electricity generation from a facility cannot be counted towards meeting a retail seller's RPS procurement requirement until the Energy Commission certifies the facility as a Renewable Supplier Eligible for the RPS or as a Renewable Supplier Eligible for the RPS and SEPs." Paragraph 3 states, "Procurement may count toward a retail seller's RPS obligation even though facilities were not RPS certified at the time of procurement. The electricity will not be considered eligible, however, and will not be counted toward meeting an RPS obligation until the facility is certified by the Energy Commission as being eligible for the RPS."

PG&E seeks clarification regarding its ability to count deliveries from an eligible renewable energy resource received prior to the facility's certification by the CEC. In some cases, developers seek to deliver "test power" before commercial operation date, and certification by the CEC (as opposed to pre-certification) appears to require the facility to have commenced commercial operation. For example, please see CEC-RPS-1A "Application for Certification" CA RPS Program, p. A-3, last item in Section III: Facility Information. Out of state facilities are required to "demonstrate delivery of its generation to the in-state market hub/zone or in-state substation/node", which also implies actual deliveries must occur to establish eligibility for CEC certification (see, CEC-RPS-1A p. A-9, Section VIII: Out of State Facility Information item 31.)

1. The CEC should clearly state that all generation by a pre-certified renewable energy facility that is delivered to a retail seller prior to final CEC certification of RPS eligibility will count toward the retail seller's RPS obligation when the generator receives CEC its RPS certification.

The third paragraph on p. 33, under "III. Certification Process" might be susceptible to this interpretation, but this is unclear, given the original reference of this section to procurement during 2001 and 2002, prior to the inception of the SB 1078 RPS program. PG&E would appreciate clarification on this issue.

F. Renewing Certification and Pre-Certification (p.36)

1. The CEC Should Avoid Unnecessarily Changing Eligibility Criteria for Certified Projects.

The Draft Guideline states,

> "... (F)acilities may be required to renew their certification based on changes in the law after being notified in writing by the CEC." (p. 37)

PG&E interprets this to mean that the CEC may require a facility to seek recertification under new standards before the expiration of the current 2-year effective period of RPS certification. In practical terms, this means that the cost of doing business as a renewable energy resource in California cannot be assumed to be stable and reliable, even for a two year period.

This business-oriented reaction against the notion that a certificated facility might lose its RPS-eligible status during its certificate period finds support in well-established principles of statutory construction. A statute that attaches new legal consequences to a transaction or conduct that was completed before the law's effective date is retroactive. Generally, statutes have prospective effect, and there is a presumption against the retroactive application of statutes. The presumption against retroactive application of statutes is subordinate to the intent of the Legislature, but courts will generally presume that prospective, rather than retrospective operation was intended, unless express language negates the presumption. (58 Cal.Jur.3d , Statutes, sec. 32.) Including this provision in the Guidebook creates unnecessary uncertainty for certified eligible renewable energy resources and a corresponding risk of ineligible deliveries for retail sellers. The threat of premature regulatory change should be avoided to protect the legitimate interests of resource developers and to maintain the availability of renewable energy resources to achieve the state's RPS goals.

As the administrative agency with primary responsibility for implementing the RPS eligibility statutes, the CEC should replace the above-quoted sentence with the following:

> "...In the event of amendment of RPS eligibility criteria, the eligibility of an existing certified RPS-eligible resource shall remain in effect during the remainder of its certification period.

2. Recertification Should be Retroactive to the Date of Expiration of Certification, in Case of Delay

It appears that applications to renew certifications in 2008 are due on October 15, 2007. This re-certification will mark the first time that the investor-owned-utilities will not tender the majority of certification applications, and PG&E is seriously concerned that some recertification may be delayed. In the event that RPS certification lapses, but is eventually renewed, the CEC should apply its recertification retroactively to the first date on which the facility was eligible for re-certification. Also, it would be helpful if the CEC notified the retail seller of the determination of eligibility at the same time each renewable resource is re-certified to ensure consistent reporting..

G. Supplemental Instructions for Out-of State Facilities (p.43)

A renewable resource facility that is not an "in-state renewable electricity generation facility" as defined by Public Resources Code section 25741(b) may not cause or contribute to any violation of a California environmental quality standard or requirement (laws, ordinances, regulations, and standards, or "LORS"). A facility located outside of the United States must be developed and operated in a manner that is as protective of the environment as a similar facility located in the state.

The statute makes an out of state facility located within the United States ineligible for California's RPS if it affects California's environment in a way that violates California's environmental standards. The eligibility guidebook should clarify that the reason for the survey of laws, ordinances, rules, and standards (LORS) and the assessment as to potential violation of the LORS is to enable the CEC staff to determine whether the facility's development or operation will impact California's environment in terms of any of features (e.g., air and water quality, biological resources, etc.) listed in the Energy Commission's regulations, and not to enable the CEC to apply its environmental laws to the territories of other states. This clarification would greatly assist developers of out-of-state facilities to understand and circumscribe their burden to demonstrate the RPS eligibility of their proposed facilities.

The proposed guidelines addressing the eligibility of out-of-country facilities require, a statement of the LORS , an assessment of the facility's compliance with the LORS, and an explanation as to how the facility's developer and/or operator will meet the LORS in developing or operating the facility. PG&E is concerned that the developer could be required to conform to California standards as a condition of RPS-eligibility even if the California LORS are different from those of the host country. Noncompliance with LORS of the country in which the facility is located could prevent the development of the resource. PG&E suggests a modification of the standard to require mitigation to comply with California LORS to the extent they are not different from those of the host country.

H. Supplemental Information – Repowered Facilities (pp.46-48)

To apply for certification or pre-certification as a repowered facility, an applicant must document both that (1) it is replacing the facility's prime generating equipment and (2) the value of capital investment in the repowered facility must equal at least 80 percent of the total value of the repowered facility. Each of these requirements individually represents a very significant investment of capital, and the effect of the high investment threshold may be to prevent developers from qualifying for SEPs. PG&E would like to encourage repowered facilities to compete for SEPs, which are available only if the bidder participates in an RPS-solicitation, so that consumers will have the benefit of being able to evaluate repowered entities against other renewable energy resources participating in the IOU's competitive solicitation. For this to occur, the investment requirement for repowered facilities would have to be changed from BOTH prime generating equipment and 80% investment to EITHER category of investment.

IV. COMMENTS ON NEW RENEWABLE FACILITIES PROGRAM GUIDEBOOK

These comments are numbered according to the pages on which the subject text appears in the Staff Draft of the New Renewable Facilities Program (NRFP) Guidebook.

A. **Introduction** -- Apprise Sellers of Maximum Potential Grant (p.1)

Under the section that begins with, "The applicable law contains the following specific directions for awarding SEPs. The Energy Commission:...", insert the following statement:

- Shall award SEPs equal to the cumulative above-market costs relative to the applicable market price referent at the time of initial contracting, over the duration of the contract with the retail seller or procurement entity, subject to any applicable CEC payment caps."

This proposed language would bring the provisions of Public Resources Code section 25743 (b)(1)(C) to the reader's attention. This newly enacted term from SB 107 is critically important to developers because it indicates that the entire amount above the market price referent (MPR) may be obtained in the form of a SEP, subject to the CEC's cap on SEPs. Prior to enactment of this section, there was ambiguity over how much of the above-MPR price could be awarded through SEPs, because the payout period was limited to the lesser of the contract term or ten years. Public resources code section 25743 states that SEPs shall be equal to cumulative above-market costs, subject to payment caps imposed by the CEC, *over the duration of a contract*. The new availability of SEPs for ALL above market costs calculated over the full duration of the power purchase agreement, subject to any CEC-imposed cap, solves the developer's problem of receiving a subsidy for only up to ten years, then facing a decreased cash flow from generation. The clear availability of SEPs over the entire term of the contract, subject to a cap, may encourage bidders to participate in the solicitation and so, should be noted.

B. Program overview

1. Approval by CPUC is limited to IOU contracts. (p.4)

The draft guidebook's statement that, "Any contracts proposed by a retail seller are subject to CPUC approval" is overly inclusive. The term "retail seller" is defined by Public Utilities Code section 399.12(g) to include energy service providers and community choice aggregators, along with electrical corporations (i.e. investor-owned utilities). Only the electrical corporations must submit their power purchase agreements to the CPUC for approval. It would be clearer if the sentence were deleted.

2. SEPs Are Now Available For Cumulative Above-Market Costs Over Duration of Contract (p.5).

This suggestion reflects the first issue, above, but the point should be repeated in the context of the basis of supplemental energy payments (SEPs). The second full paragraph on p. 5, which states: "SEPs are calculated based on the difference between the ~~contract~~ final bid or negotiated price and the project-specific MPR up to any energy Commission-established caps," omits an important change to the way that SEPs are computed. PG&E suggests adding the underlined language and deleting the stricken language from the text in the middle of the second full paragraph on p. 5, since the statute states that payments *shall* be equal to the *cumulative above market costs* over the duration of the contract:

> "SEPs are calculated based on the **cumulative** difference between the ~~contract~~ final bid or negotiated price and the project-specific MPR **over the duration of the contract,** up to any energy commission-established caps." (emphasis added).

3. Confidentiality of Price and Other Contract Terms Should be Subject to Blanket Protection. (p.5)

The NRFP Guidelines require each major investor-owned utility (IOU) to provide the price and expected deliveries for each bid received in each of its RPS solicitations, as listed in CEC-SEP-1 data request and CEC-SEP-2 data request.3 within 30 days of the CPUC's adoption of its market price referent, and require each developer and the IOU to submit the initial and final bid price, along with an explanation of how the price was negotiated, in support of each application for SEPs. While the draft guidelines state that the Energy Commission will consider applications to hold the above-mentioned data confidential pursuant to its regulations for confidential designation, PG&E suggests that the better practice is to hold all of the above-described commercial information confidential per se. The affected parties should not be forced to devote the considerable energy it takes to argue about the trade secret nature of each piece of information when the character of the information provided in response to the identical data

[3] In addition to seeking the bid price and deliveries of each bid, the data requests seek the levelized bid price, TOD-adjusted price, and above market costs for the entire term. This information could provide significant insight into the business plans of RPS bidders, and the public availability of this information would subject RPS bidders to competitive disadvantages not faced by other generators.

request will not vary with each RPS solicitation or sep application, CEC precedent supports a finding that the bid information will be treated as confidential, and the CEC's sister state agency deems the confidentiality of the information to be protected for a period of three years.

For example, on September 29, 2006, the CEC's executive director granted SDG&E's request for confidential protection of its SEP data responses for a term of three years, based upon SDG&E's showing that the information constituted a trade secret that was entitled to protection under the Public Records Act. All applicants for SEPs and their associated purchasers will respond to the CEC's SEP data requests with substantially the same information, only the specifications of the particular project will vary. Given the identical nature of the information, it must be assumed that the Executive Director would protect the confidentiality of all SEP-related data responses.

Even if the CEC believed it necessary to review each application for confidentiality on a case-by-case basis, it should find that every application is entitled to confidential protection. According to the CEC's regulations, "An application shall be granted if the applicant makes a reasonable claim that the Public Records Act or other provision of law authorizes the Commission to keep the record confidential." (Sec 2505(a)(3)(A).) The developers who submit bids into the utility RPS solicitation have a proprietary business interest in maintaining the confidentiality of the terms of their competitive bids, and the compiled results of the solicitation will constitute a trade secret which, if revealed while the utility is attempting to negotiate purchases from participants in the solicitation, or within three years, could place the utilities and their ratepayers at a competitive disadvantage when seeking to procure electricity at the lowest cost.

The CEC's regulations provide another basis for the automatic protection of the SEP data responses. "When another state or local agency possesses information pertinent to the responsibilities of the Commission that has been designated by that agency as confidential under the Public Records Act, or the Freedom of Information Act, the Commission, the Executive Director, or the Chief Counsel may request and the agency submit the information to the Commission without an application for confidential designation. The Commission *shall* designate this information confidential." (Sec 2505(b), emphasis added.) The bids received in response to IOU bid solicitations, particularly their prices and delivery terms, constitute electric generation information that the CPUC has determined is entitled to non-disclosure for three years under the terms of its opinion implementing Senate Bill No. 1488, relating to confidentiality of electric procurement data submitted to the CPUC.4 The CEC's policy in favor of comity supports the protection of SEP data responses in the same way.

The CEC can improve access to SEPs by adopting the following statement at the bottom of page 5 of the Staff Draft of the CEC Eligibility Guidebook:

[4] See, CPUC Decision 06-06-066, specifically appendix a, "IOU matrix", items viii competitive solicitation (bidding) information – electric: (a) bid information and (b) specific quantitative analysis involved in scoring and evaluation of participating bids, and item vii - renewable resource contracts under rps program: (f) contracts with seps and (g) contracts without seps.

> The Energy Commission will ~~consider applications~~ **grant requests** to hold the above mentioned data confidential pursuant to its regulations for confidential designation, California Code of Regulations, Title 20, Section 2501, et seq.

The following sentence erroneously describes a power purchase agreement between one retail seller with another retail seller and should be corrected as shown:

> The Energy Commission will only consider a SEP application after a ~~retail~~ seller ~~executes~~ **has executed** an eligible contract with a retail seller. (p.6.)

Unless the intent is to broaden the scope of the NRFP Guidebook to promulgate new RPS policy, the following directive should be rephrased as shown:

> If the contract price exceeds the MPR, ~~final bid or negotiated price~~ ~~requires SEPs~~, then the seller ~~should~~ may apply to the Energy Commission for SEP funding, and the retail seller must provide supplemental information to the Energy Commission regarding the Seller's application. (p.6.)

C. Multiple Awards

- The Payments Under Multiple Awards Are Ambiguous (p.12)

It is not clear whether the limitation on "SEP applicants" applies to the entrepreneurs, such as a corporation, or to individual generating facilities. This section states "SEP applicants, however, are only eligible for SEPs for the first ten years of generation from their initial RPS contract(s)." It would be helpful to know if the developer of a phased project could receive SEPs if the bid price of any one of the phases was in excess of the MPR.

D. Award Determination - p. 14

The final bid price and related amounts such as the above-MPR and time-of-delivery differentiated prices, are proprietary information that must be protected from public disclosure to avoid consumer harm. PG&E concurs that this information is needed to calculate the SEP award. However, the request for levelized initial and final bid prices (with an explanation if these are not equivalent) exceeds the bounds of information necessary for the CEC to make "informed and timely decisions in evaluating SEP requests." The difference between the initial and final bid price, and certainly, the reasons for the difference, is confidential business information that would subject both the buyer and seller to a competitive disadvantage if third parties were to learn how the final price was negotiated. Like other proprietary information, CEC protection of its confidentiality is discretionary.

Given the indisputable sensitivity of price information for commercial parties, this information most certainly constitutes a trade secret that qualifies for confidential treatment. The CEC should refrain from subjecting commercial parties to the unreasonable risk of disclosure and simply designate all price information as confidential without need for any such request as follows:

To make informed and timely decisions in evaluating SEP requests, the Energy Commission needs to review the full range of bids that the retail seller received in response to its PRS solicitation (the term "bids" includes all offers considered in a LCBF process approved by the CPUC). **Because the public disclosure of price information would reveal proprietary business information about the buyer and seller and subject them to commercial disadvantage, the CEC shall preserve the confidentiality of all price information for three years from the date it is provided pursuant to this Guidebook.**

- PG&E appreciates the deletion of the underlying power purchase contract from the SEP application package, as this eliminates the risk that proprietary business information could be obtained by a third party with interests adverse to the contracting parties. (NRFP Guidebook p. 15).

V. COMMENTS ON EXISTING RENEWABLE FACILITIES PROGRAM GUIDEBOOK

A. The Commission Should Exercise its Discretion to Preserve Existing Deliveries.

The Existing Renewable Facilities Program (ERFP) Guidebook describes the criteria for the award of funding for existing biomass resource generating facilities, among other technologies. Biomass generation constituted approximately one-third of PG&E's RPS procurement in 2005 (Source: PG&E's August 2006 RPS Compliance Report, Table 2.). Thus, existing biomass facilities are an important cornerstone of California's RPS portfolio, and it would be counterproductive to the achievement of the 2010 goal of having 20% of the state's retail sales served by renewable energy resources to reduce the operating ability of existing biomass facilities.

By law, the Energy Commission must evaluate certain factors to determine a facility's need for funding, and then establish facility-specific target prices and incentives. PG&E encourages the Commission to exercise its discretion so that existing deliveries of renewable resources are maintained, and that changes be made to increase the effectiveness of incremental distribution of incentives.

B. Continued Incidental Use of Fossil Fuel Should Not Jeopardize Eligibility Because Fuel Use Restrictions Were Intended to Address the Renewable Category of Fuel.

The Staff Draft states that SB 1250 no longer allows the use of fossil fuel for biomass facilities. PG&E disagrees. SB 1250 provides that a biomass facility qualifies as renewable "only if they report to the commission types and quantities of biomass fuels used and certify to the satisfaction of the commission that fuel utilization is limited to the fuels specified in subdivision (f) of Section 25743." The Commission is then to report the types and quantities of biomass fuels used by each facility to the Legislature (Pub. Res. Code sec. 25742(d)).

Throughout this section, it is obvious that the legislature is concerned about the consumption of biomass fuels, specifically the types of fuels listed in Section 25743(f): agricultural crops, wastes, and residues, solid waste materials, and wood and wood waste gathered pursuant to an approved timber harvest plan for the purpose of forest fire fuel reduction or forest stand improvement, and do not transport insects or disease. The legislature is clearly concerned that biomass generators should use only the kinds of *biomass* fuel sanctioned by statute. Since it did not address the use of other forms of fuel by biomass generators, the Staff Draft should not have made the use of fossil fuels a disqualifying event. PG&E recommends the following change to the ERFP Guidebook on p. 4:

> Prior to January 1, 2007, eligible biomass facilities were permitted to use up to 25 percent fossil fuel annually on a total energy input basis consistent with the Federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617) and Section 292.204, subdivision (b) of Title 18 of the Code of Federal Regulations. **The 25 percent allowance continues to be available for biomass facilities and other PURPA-eligible technologies.** ~~However, the law as amended by SB 1250 no longer permits this use of fossil fuel for biomass facilities.~~

C. Conclusion

PG&E hopes that the Renewables Committee has found the foregoing comments to be informative and helpful, if not downright persuasive. We would be more than happy to assist in any way necessary to develop and maintain the broadest pool of potential renewable resources for California's energy needs.

PG&E Gas and Electric Advice Filing List
General Order 96-A, Section III(G)

ABAG Power Pool
Accent Energy
Aglet Consumer Alliance
Agnews Developmental Center
Ahmed, Ali
Alcantar & Kahl
Ancillary Services Coalition
Anderson Donovan & Poole P.C.
Applied Power Technologies
APS Energy Services Co Inc
Arter & Hadden LLP
Avista Corp
Barkovich & Yap, Inc.
BART
Bartle Wells Associates
Blue Ridge Gas
Bohannon Development Co
BP Energy Company
Braun & Associates
C & H Sugar Co.
CA Bldg Industry Association
CA Cotton Ginners & Growers Assoc.
CA League of Food Processors
CA Water Service Group
California Energy Commission
California Farm Bureau Federation
California Gas Acquisition Svcs
California ISO
Calpine
Calpine Corp
Calpine Gilroy Cogen
Cambridge Energy Research Assoc
Cameron McKenna
Cardinal Cogen
Cellnet Data Systems
Chevron Texaco
Chevron USA Production Co.
City of Glendale
City of Healdsburg
City of Palo Alto
City of Redding
CLECA Law Office
Commerce Energy
Constellation New Energy
CPUC
Cross Border Inc
Crossborder Inc
CSC Energy Services
Davis, Wright, Tremaine LLP
Defense Fuel Support Center
Department of the Army
Department of Water & Power City
DGS Natural Gas Services
Douglass & Liddell
Downey, Brand, Seymour & Rohwer
Duke Energy
Duke Energy North America
Duncan, Virgil E.
Dutcher, John
Dynegy Inc.
Ellison Schneider
Energy Law Group LLP
Energy Management Services, LLC
Exelon Energy Ohio, Inc
Exeter Associates
Foster Farms
Foster, Wheeler, Martinez
Franciscan Mobilehome
Future Resources Associates, Inc
G. A. Krause & Assoc
Gas Transmission Northwest Corporation
GLJ Energy Publications
Goodin, MacBride, Squeri, Schlotz &
Hanna & Morton
Heeg, Peggy A.
Hitachi Global Storage Technologies
Hogan Manufacturing, Inc
House, Lon
Imperial Irrigation District
Integrated Utility Consulting Group
International Power Technology
Interstate Gas Services, Inc.
IUCG/Sunshine Design LLC
J. R. Wood, Inc
JTM, Inc
Luce, Forward, Hamilton & Scripps
Manatt, Phelps & Phillips
Marcus, David
Matthew V. Brady & Associates
Maynor, Donald H.
MBMC, Inc.
McKenzie & Assoc
McKenzie & Associates
Meek, Daniel W.
Mirant California, LLC
Modesto Irrigation Dist
Morrison & Foerster
Morse Richard Weisenmiller & Assoc.
Navigant Consulting
New United Motor Mfg, Inc
Norris & Wong Associates
North Coast Solar Resources
Northern California Power Agency
Office of Energy Assessments
OnGrid Solar
Palo Alto Muni Utilities
PG&E National Energy Group
Pinnacle CNG Company
PITCO
Plurimi, Inc.
PPL EnergyPlus, LLC
Praxair, Inc.
Price, Roy
Product Development Dept
R. M. Hairston & Company
R. W. Beck & Associates
Recon Research
Regional Cogeneration Service
RMC Lonestar
Sacramento Municipal Utility District
SCD Energy Solutions
Seattle City Light
Sempra
Sempra Energy
Sequoia Union HS Dist
SESCO
Sierra Pacific Power Company
Silicon Valley Power
Smurfit Stone Container Corp
Southern California Edison
SPURR
St. Paul Assoc
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc
TFS Energy
Transcanada
Turlock Irrigation District
U S Borax, Inc
United Cogen Inc.
URM Groups
Utility Cost Management LLC
Utility Resource Network
Wellhead Electric Company
Western Hub Properties, LLC
White & Case
WMA