STATE OF CALIFORNIA

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

ARNOLD SCHWARZENEGGER, *Governor*

July 2, 2008

Advice Letters 3233-E/E-A

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

Subject: PG&E Company's Conformed 2006 Long-Term Procurement Plan and Supplemental Filing

Dear Mr. Cherry:

Advice Letters 3233-E and 3233-E-A are effective June 26, 2008.

Sincerely,

Sean H. Gallagher, Director
Energy Division

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

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San Francisco, CA 94105

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Mail Code B10C
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March 19, 2008

Advice Letter 3233-E
(Pacific Gas and Electric Company ID U39 E)

Public Utilities Commission of the State of California

Subject: Pacific Gas and Electric Company's 2006 Long-Term Procurement Plan Proceeding Compliance Filing

Pursuant to Ordering Paragraph 1 in Decision ("D.") 07-12-052, PG&E respectfully submits its compliance filing and conformed 2006 Long-Term Procurement Plan ("Conformed 2006 LTPP") for Commission review and approval. This cover letter describes PG&E's Conformed 2006 LTPP. Included as Attachments A and B are red-line and clean public versions of PG&E's Conformed 2006 LTPP. Attachments C and D are red-line and clean confidential versions of PG&E's Conformed 2006 LTPP.

I. BACKGROUND FOR CONFORMED 2006 LTPP

In D.07-12-052, the Commission adopted PG&E's 2006 LTPP with modifications, and required PG&E to file a conformed copy of the 2006 LTPP within ninety days of the decision.[1] The Conformed 2006 LTPP "supersedes all previously approved plans" and includes the 2006 LTPP filing originally made by PG&E, with modifications indicated in D.07-12-052, and all advice letter amendments made since the 2006 LTPP was filed.[2] The Commission also indicated that the Conformed 2006 LTPP should be formatted similar to a tariff, including a tariff numbering system for the pages, so that future changes could be more easily tracked.[3] Finally, the Commission required that the Conformed 2006 LTPP be filed by Tier 3 Advice Letter.

II. DESCRIPTION OF CONFORMED 2006 LTPP SECTIONS

This section describes the Sections and Appendices in PG&E's Conformed 2006 LTPP. In general, PG&E used its March 5, 2007 amended LTPP filing in R.06-02-013 as

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[1] D.07-12-052 at 193-194, Conclusion of Law ("COL") 1, Ordering Paragraphs ("OP") 1-2.

[2] *Id*. at 193.

[3] *Id*. at 184.

the starting point for the Conformed 2006 LTPP.[4] PG&E did not include in the Conformed 2006 LTPP sections from its amended 2006 LTPP filing that were narrative, no longer applicable (*e.g.*, a description of scenario analysis, PG&E's Recommended Plan, discussions of the planning reserve margin, etc.), or made policy proposals (*e.g.*, Volume 2 of PG&E's amended 2006 LTPP filing). The remaining sections from the amended 2006 LTPP filing were included in the Conformed 2006 LTPP and were updated to reflect modifications adopted in D.07-12-052 or events that occurred after PG&E's amended 2006 LTPP filing in March 2007. In the red-line versions included as Attachments A and C to this filing, strike-through edits indicate portions of the amended 2006 LTPP filing that have been deleted and underlining indicates additions to the amended 2006 LTPP filing. Attachments B and D are clean versions of Attachments A and C, respectively.

A. Section I

Section I of the Conformed 2006 LTPP is entirely new and is an introduction to PG&E's filing. Section I provides a general description of PG&E's 2006 LTPP and the D.07-12-052 requirement to provide a conformed version.

B. Section II

Section II of the Conformed 2006 LTPP was originally Volume 1, Section III of PG&E's amended 2006 LTPP filing. Substantive modifications include:

- Updating the authority for Electric Product No. 6 ("Electricity Transmission Products") in Table II-2, consistent with D.07-12-052 and updating the authority for Electric Product No. 16 ("Resource Adequacy Product");

- Deleting PG&E's proposed Electric Product No. 28 ("Non-Discretionary Products Required by MRTU") in Table II-2, consistent with D.07-12-052;

- Adding a new Electric Product No. 28 ("Long-Term Congestion Revenue Rights ("LT-CRRs")") and Electric Product No. 29 ("Congestion Revenue Rights ("CRRs")") in Table II-2, a new Procurement Methods and Practices No. 12 in Table II-5 for CRRs and LT-CRRs, and a requirement for Procurement Review Group ("PRG") consultation regarding LT-CRRs and CRRs in Section II.A.8, consistent with Commission Resolutions E-4122 and E-4135, approving Advice Letters 3095-E and 3106-E, respectively.

[4] The public versions of PG&E's amended 2006 LTPP filing were marked as Exhibits 10-12 in Phase II, Track 2 of R.06-02-013. The confidential versions were marked as Exhibits 14-C – 16-C.

- Updating the authority for Gas Product No. 4 ("Biomethane") in Table II-3, consistent with D.07-12-052;
- Deleting from Sections II.A.5 and II.A.8 and Table II-5 references to PG&E's request to change the minimum time for PRG review from transactions three months and longer to six months and longer, consistent with the Commission's determination in D.07-12-052 rejecting PG&E's proposal;
- Updating Item No. 1 in Table II-5 and Sections II.A.5.a(1) to reference additional requirements established in D.07-12-052 for Requests for Offers ("RFOs");
- Updating Item No. 6 in Table II-5 to reference additional requirements established in D.07-12-052 for utility-owned generation proposals;
- Deleting outdated references to PG&E's 2006 Renewable Portfolio Standard ("RPS") solicitation in Section II.A.5.c, II.A.6.a.;
- Deleting references to the Emerging Renewable Resource Program ("ERRP") in Section II.A.6.a because this program is now at issue in a separate proceeding at the Commission;
- Deleting outdated references to Resource Adequacy ("RA") standards in Section II.A.6.b;
- Updating the description of PG&E's 2008 Long-Term Request for Offers ("LTRFO") in Section II.A.6.c, consistent with D.07-12-052;
- Deleting references to PG&E's Recommended Plan in Section II.A.6.c;
- Deleting the discussion of price forecasting in previous Section II.A.8;
- Deleting a narrative discussion of procurement barriers and challenges in previous Section II.A.11;
- Deleting references to PG&E's hedging strategy and targets in previous Section II.A.9 and current Section II.B and the discussion of PG&E's previous risk management plans in Section II.B.1 (which have now been superseded by the Conformed 2006 LTPP). PG&E's gas and electric hedging strategy, modified to be consistent with D.07-12-052, will be included in Appendix B of the Conformed 2006 LTPP, so references to the hedging strategy and targets could be deleted from the text;

- Updating Section II.B.2 to reflect changes to the portfolio risk assessment and customer risk tolerance consistent with the direction in D.07-12-052 to change TeVaR from 99% to 95% and to update the reporting procedure;

- Updating the gas operating targets in Table II-7 to be consistent with D.07-12-052 (the actual targets are confidential material under D.06-06-066);

- Updating PG&E's credit and collateral requirements in Section II.B.3;

- Deleting references in Section II.C.1 to the gas supply plan, which was not approved by the Commission[5];

- Deleting references in Section II.C.2 to PG&E's nuclear fuel supply plan. PG&E's nuclear fuel supply plan was approved in D.07-12-052[6] and is included in Appendix C of the Conformed 2006 LTPP. References to the nuclear fuel supply plan are duplicative and were therefore deleted from this section.

C. Section III

Section III of the Conformed 2006 LTPP is entirely new and explains the PG&E regional need determination established by the Commission in D.07-12-052, Table PGE-1. Section III describes each of the substantive lines in Table PGE-1 and the source of the data used for that line. Table PGE-1 is included in Appendix A of the Conformed 2006 LTPP.

D. Section IV

Section IV of the Conformed 2006 LTPP was originally Volume 1, Section V of PG&E's amended 2006 LTPP filing. Substantive modifications include:

- Updating Section IV.B to reflect changes in PG&E's energy efficiency programs that have occurred since the amended 2006 LTPP was filed on March 5, 2007;

- Updating Section IV.C to reflect changes in PG&E's demand response programs that have occurred since the amended 2006 LTPP was filed on March 5, 2007;

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[5] D.07-12-052 at 179-180.

[6] *Id*. at 179.

- Updating Section IV.D to reflect changes in PG&E's renewable energy programs that have occurred since the amended 2006 LTPP was filed on March 5, 2007;

- Updating Section IV.E to indicate that forecasts of customer generation are included in the California Energy Commission ("CEC") forecast used in Appendix A and providing a description of Assembly Bill ("AB") 1969;

- Updating information in Section IV.F.1 regarding California Department of Water Resources ("DWR") contracts;

- Updating Section IV.F.4 to reflect the issuance of D.07-09-040 and requirements in D.07-12-052 regarding QF contracting;

- Updating Section IV.F.5 to eliminate references to specific contracts from the 2004 Long-Term Request for Offers ("LTRFO"), to indicate that the EIF Fresno project contract has terminated, and to include language from D.07-12-052 that, to the extent any of the 2004 LTRFO contracts are terminated, the procurement authority for the megawatts associated with the terminated contract remains;

- Updating Section IV.F.6 to reflect the need determination made in D.07-12-052 and information regarding PG&E's 2008 LTRFO; and,

- Updating Section IV.H.1 and H.5 regarding the status of current transmission projects and deleting narrative discussions in Sections IV.H.2-H.4 regarding proposals for the transmission planning process and transmission upgrade strategies to achieve certain policies objectives.[7]

E. Section V

Section V of the Conformed 2006 LTPP is entirely new and describes an evaluation of the Commission-approved 2006 LTPP. In particular, Section V discusses how the approved plan meets current RA requirements, complies with the loading order, and provides environmental benefits.

F. Section VI

Section VI of the Conformed 2006 LTPP was originally Volume 1, Section VIII of PG&E's amended 2006 LTPP filing. Substantive modifications include:

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[7] A methodology for resource planning and analysis for higher renewables targets, including transmission issues, is to be developed by the Energy Division so that higher renewable targets can be addressed in subsequent LTPPs. *See* D.07-12-052 at 256.

- Updating Table VI-2, Item No. 1 to remove a reference to affiliate transactions and Item No. 4 to modify Standard of Conduct No. 4. Standard of Conduct No. 4 was modified in D.03-06-076, Ordering Paragraph 16, but this modification was inadvertently omitted from PG&E's amended 2006 LTPP filing;

- Deleting narrative language and requests for Commission approval in Sections VI.A and IV.B since the 2006 LTPP was approved in D.07-12-052;

- Updating in Section VI.C.1.a the description of PG&E's portfolio risk reporting;

- Updating in Section VI.C.1.b the description of PG&E's monthly ERRA report to reflect D.07-04-020; and,

- Updating in Section VI.C.2 the description of PG&E's quarterly ERRA filings to reflect D.07-12-052.

III. DESCRIPTION OF CONFORMED 2006 LTPP APPENDICES

A. Appendix A

Appendix A reflects the PG&E need determination established in D.07-12-052.[8] PG&E included a copy of Table PGE-1 in Appendix A and a table showing PG&E's bundled customer need, consistent with D.07-12-052, for the period 2007-2016.

B. Appendix B

Appendix B is PG&E's Electricity and Gas Hedging Plan. PG&E initially submitted a proposed Electricity and Gas Hedging Plan in Volume 1, Attachment IIIA of its amended 2006 LTPP. PG&E has revised its hedging plan consistent with the Commission's direction in D.07-12-052, and has reviewed the revised plan with the Energy Division and the PRG.[9] PG&E is currently finalizing approval of the hedging plan internally and intends to file an advice letter shortly seeking Commission review and approval. In the Conformed 2006 LTPP, PG&E left space in Appendix B for the Electricity and Gas Hedging Plan to be inserted once it is reviewed and approved by the Commission.

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[8] D.07-12-052 at 105-106 and Table PGE-1.

[9] *Id.* at 170.

C. Appendix C

Appendix C is PG&E's Nuclear Fuel Procurement Plan, which was submitted as Volume 1, Attachment IIIC in PG&E's amended 2006 LTPP, and approved by the Commission in D.07-12-052.[10]

D. Appendix D

Appendix D is PG&E's GHG Emissions Profile, which was submitted as Volume 1, Attachment 1 in PG&E's amended 2006 LTPP.

E. Appendix E

Appendix E is PG&E's TeVaR methodology which was submitted as Volume 1, Attachment 2 in PG&E's amended 2006 LTPP. This Appendix has been modified to reflect changes from D.07-12-052.

F. Appendix F

Appendix F is a copy of Advice Letter 3095-E concerning LT-CRRs that was approved by the Commission in Resolution E-4122. This advice letter was filed after PG&E's amended 2006 LTPP had been filed.

G. Appendix G

Appendix G is a copy of Advice Letter 3106-E concerning CRRs that was approved by the Commission in Resolution E-4135. This advice letter was filed after PG&E's amended 2006 LTPP had been filed.

H. Appendix H

Appendix F is an updated list of approved brokerages and exchanges from Advice Letter 3138-E by letter on December 11, 2007. This advice letter was filed after PG&E's amended 2006 LTPP had been filed.

I. Appendix I

Appendix I includes the requirements for the PRG, IE and RFOs from D.07-12-052, Appendix E. PG&E made several corrections to address typographical and reference errors. Otherwise, Appendix I reflects verbatim the language from D.07-12-052, Appendix E. PG&E notes that there are several petitions to modify that are pending that, if granted, may require changes to this Appendix.

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[10] *Id.* at 179.

J. Appendix J

Appendix J is a glossary which was submitted as Volume 1, Attachment 4 in PG&E's amended 2006 LTPP.

K. Appendix K

Appendix K is an updated list of acronyms which was submitted as Volume 1, Attachment 5 in PG&E's amended 2006 LTPP.

IV. CONFIDENTIAL INFORMATION

PG&E filed a *Motion to File Under Seal* on December 11, 2006 when it initially filed its 2006 LTPP. The motion also applied to PG&E's amended 2006 LTPP filing on March 5, 2007. PG&E's motion was granted on May 2, 2007.[11] The confidential information in the Conformed 2006 LTPP is the same information that was included in PG&E's amended 2006 LTPP filing, and thus remains confidential pursuant to ALJ Carol Brown's May 2nd order.

PROTESTS

Anyone wishing to protest this filing may do so by sending a letter by **April 8, 2008**, 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.

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[11] *Administrative Law Judge's Ruling Following April 24, 2007 PHC Establishing Schedules And Topics For Workshops, Evidentiary Hearings And Briefs And Ruling On Motions For: Party Status, Filing Under Seal, And To Strike Testimony*, filed May 2, 2007 in R.06-02-013.

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 its conformed 2006 LTPP become effective on **December 21, 2007**, which is the date D.07-12-052 approving the 2006 LTPP was issued.

NOTICE

In accordance with General Order 96-B, Section IV, a copy of this Advice Letter excluding the confidential appendices is being sent electronically and via U.S. mail to parties shown on the attached list and the service lists for R.06-02-013. 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

Brian K Cherry / DC

Brian K. Cherry
Vice President - Regulatory Relations

Attachments
Attachment A – Public Redline Version of PG&E's Conformed 2006 LTPP
Attachment B – Public Clean Version of PG&E's Conformed 2006 LTPP
Attachment C – Confidential Redline Version of PG&E's Conformed 2006 LTPP
Attachment D – Confidential Clean Version of PG&E's Conformed 2006 LTPP

cc: Service List for R.06-02-013
Pete Skala - Energy Division

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 (ID U39 M)**

Utility type:	Contact Person: Daren Chan
☑ ELC ☑ GAS	Phone #: (415) 973-5361
☐ PLC ☐ HEAT ☐ WATER	E-mail: d1ct@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **3233-E** **Tier:** 3

Subject of AL: Pacific Gas and Electric Company's 2006 Long-Term Procurement Plan Proceeding Compliance Filing

Keywords (choose from CPUC listing): Compliance

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.07-12-052

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: Yes, confidential information in the Conformed 2006 LTPP; Attachments C and D

Confidential information will be made available to those who have executed a nondisclosure agreement: ☑ Yes ☐ No

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: Charles Middlekauff, (415) 973-6971

Resolution Required? ☑ Yes ☐ No

Requested effective date: **December 21, 2007** No. of tariff sheets: N/A

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, dispositions, 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
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave.,
San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Pacific Gas and Electric Company
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

PACIFIC GAS AND ELECTRIC COMPANY

CONFORMED 2006 LONG-TERM PROCUREMENT PLAN

ATTACHMENT A

REDLINED PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY'S 2006 LONG-TERM PROCUREMENT PLAN

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") initially filed its 2006 Long-Term Procurement Plan ("LTPP") on December 11, 2006 in Rulemaking ("R.") 06-02-013. PG&E filed an amended 2006 LTPP on March 5, 2007. PG&E's amended 2006 LTPP consisted of three volumes. At the hearings in Phase II, Track 2 of R.06-02-013, conducted in June 2007, the volumes were marked as follows:

- The public version of Volume 1 of PG&E's amended 2006 LTPP was identified as Exhibit 10 and the confidential version was identified as Exhibit 14-C;
- The public version of Volume 1, Attachment IVA, was identified as Exhibit 11 and the confidential version was identified as Exhibit 15-C; and
- The public version of Volume 2 was identified as Exhibit 12 and the confidential version was identified as Exhibit 16-C.

PG&E's 2006 LTPP included descriptions of procurement activities and products, background material and a detailed discussion of PG&E's long-term resource planning approach. PG&E developed four scenarios to represent events or conditions that are outside of PG&E's control, and which could occur over the 10-year planning horizon. These scenarios were designed to take into account long-term uncertainties which may occur, such as changes in load, prices, market availability of resources, and regulatory changes.

PG&E then calculated 2007-2016 demand forecasts for the California Independent System Operator's ("CAISO") North of Path 26 ("NP26") region and for its service area using information from the California Energy Commission ("CEC"), with certain specified modifications. PG&E calculated demand forecasts under each of the four scenarios for both the NP26 region and the PG&E service area.

In addition to demand forecasts, PG&E also developed three candidate procurement plans. These plans included differing demand-side, supply-side and transmission actions that PG&E could take over the 10-year planning horizon. The plans were designed to highlight the trade-offs between reliability, environmental issues, and cost. PG&E then tested each of these three plans under the four scenarios, to see how future events captured in the scenarios would impact the reliability, environmentally-preferred resource, and cost elements of each of the three plans. PG&E used nine metrics to analyze the feasibility and performance of each of the candidate plans under the various scenarios. After completing its analysis, PG&E selected its Recommended Plan.

In Decision ("D.") 07-12-052, the Commission approved PG&E's 2006 LTPP with specific modifications. PG&E's 2006 LTPP covers a 10-year period from 2007 to 2016. The Commission required PG&E to make a compliance filing within ninety (90) days the issuance of D.07-12-052 to conform its 2006 LTPP to the decision and to include any updates filed through the Commission's Advice Letter process. This compliance filing constitutes PG&E's conformed 2006 LTPP, and supersedes and replaces all previous short- and long-term procurement plans submitted by PG&E. After the conformed 2006 LTPP is accepted by the Commission, all updates proposed before the next LTPP filing, currently scheduled for 2010,[1] will be made via advice letter. Advice letter updates will include redlined pages of the conformed 2006 LTPP, as well as clean replacement pages.[2]

[1] Rulemaking ("R.") 08-02-007, Scoping Memo at 5-6.

[2] D.07-12-052 at 184-185.

II. PROCUREMENT IMPLEMENTATION PLAN

A. Procurement Processes

1. PG&E's Energy Procurement Organization

~~Pacific Gas and Electric Company's ("~~PG&E's~~")~~ Energy Procurement ("EP") organization plans for and acquires resources to ensure an adequate and reliable energy supply. EP has a number of procurement objectives, including assembling a portfolio of reliable and operationally flexible resources, supporting the development of environmentally preferred resources, and managing customer costs. The organization is responsible for both front-office functions associated with planning, procuring, scheduling, and dispatching resources, and back-office functions associated with ensuring accurate payments to the ~~California Independent System Operator ("~~CAISO~~")~~ and other power suppliers. EP is comprised of the following departments:

- Energy Policy, Planning & Analysis ("EPPA");
- Energy Supply;
- Energy Contract Management and Settlements; and
- Market Redesign and Technology Upgrade ("MRTU") Implementation and Federal Energy Regulatory Commission ("FERC") Refund.

The following section discusses the primary goals and responsibilities of each of the departments listed above. In addition, PG&E describes how its EP organization complies with California Public Utilities Commission ("Commission") Standard of Conduct No. 2.[1]

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[1] The Commission originally adopted Standards of Conduct for procurement in Decision ("D.") 02-10-062. These standards have subsequently been modified. *See* D.02-12-074, Order Paragraph 24 (modifying standards); D.03-06-067, Ordering Paragraph 3 (modifying standards and eliminating Standard Nos. 6-7); and D.03-06-076, Ordering Paragraph 6 (clarifying that "Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges."). PG&E also received a waiver from Standard of Conduct 1 for certain gas transportation transactions in D.04-06-003.

a. Energy Policy, Planning & Analysis

EPPA strives to meet the EP organization objectives through electric and gas resource planning that truly integrates demand-side and supply-side resource alternatives, and transmission and generation alternatives. EPPA analyzes regional supply-demand balances, the composition of potential PG&E portfolios, and the value of incremental resources to PG&E customers and regional supply. EPPA performs these analyses using financial, economic, and engineering methodologies and tools. EPPA analyzes current and potential market structures and policy initiatives, such as the State Loading Order, capacity markets and resource adequacy, and considers how these developments impact PG&E's procurement.

b. Energy Supply

Energy Supply is responsible for all commercial transaction activities through competitive solicitations, bilateral negotiations and energy markets, including the development and execution of electric and fuels procurement strategies for short-term, medium-term, and long-term transactions, which will meet PG&E's customers' forecasted energy needs. The commercial transactions also include the procurement of renewable supplies to meet PG&E's Renewable Portfolio Standard requirements ("RPS"). Energy Supply's responsibilities also include: (1) the management, optimization, and scheduling of PG&E's resources and contracts; (2) PG&E's trading in the energy markets; and (3) the natural gas procurement and hedging activities for PG&E's resources, power purchase agreements and assigned California Department of Water Resources ("DWR") contracts.

Energy Supply also purchases natural gas supplies and transportation capacity to meet PG&E's bundled core gas customer demands. The gas procurement function relates generally to the process of acquiring gas supplies (*e.g.*, the gas commodity) and managing transmission and storage capacity for core gas customers.

c. Energy Contract Management & Settlements

The Energy Contract Management & Settlements department is responsible for the preparation of regulatory filings, and implementation of standard reporting and documentation related to energy procurement and settlements activities. The department monitors compliance with risk control and Sarbanes-Oxley ("SOX") requirements, and performs contract management, settlements and financial reporting related to energy procurement, including bilateral purchases and sales, Fuel, Qualifying Facility ("QF"), Irrigation District ("ID"), Reliability Must-Run ("RMR"), and DWR allocated contracts, as well as CAISO market settlements. This work includes contract monitoring, validating calculations and data, preparing invoices, processing payments, and duties related to PG&E's role as transmission owner and CAISO scheduling coordinator for both retail and existing transmission contract customers.

d. MRTU Implementation and FERC Refund

The CAISO's MRTU initiative significantly changes the electric markets administered by the CAISO and represents the largest change to the California wholesale energy market since electric restructuring began in 1998. It is scheduled to become effective in 2008~~November 2007~~. The MRTU Implementation and FERC Refund Department works with internal and external stakeholders to translate complex market designs into the needed systems and software and assure they perform as intended. In addition, on behalf of PG&E's customers, this department continues its efforts to obtain refunds for electricity overcharges during the 2000-2001 California Energy Crisis. The department provides support and expert analysis in the FERC Refund proceedings, negotiations with suppliers, and bankruptcy issues related to generator claims filed in PG&E's bankruptcy.

e. Compliance With Commission Standard of Conduct No. 2

The employees in PG&E's EP organization manage a substantial portfolio of resources to ensure PG&E acquires a reliable, environmentally preferred, and cost-effective portfolio of supply-side and demand-side resources for its customers. The EP employees, as well as the employees throughout PG&E, comply with the Commission's Standard of Conduct No. 2, to the extent it is applicable. Standard of Conduct No. 2 provides:

Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurements process that:

1) Identifies trade secrets and other confidential information;

2) Specifies procedures for ensuring that such information retains its trade secret and/or confidential status (*e.g.,* limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.);

3) Discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges;

4) Discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; and

5) Requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances (*e.g.,* where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer). All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility.

To ensure compliance, on the first day of employment with PG&E, employees are given an employee policy handbook on "Standards for Personal Conduct and Business Decisions, Code of Conduct for Employees" which can be found at the following link: http://www.pge-corp.com/aboutus/pdfs/EmployeePolicyHandbook2004.pdf. The handbook includes discussions regarding proprietary information and antitrust law. Upon completion of their review, employees are required to sign a summary form acknowledging receipt of the booklet and that they have reviewed and understood the material. In addition, PG&E employees are required to complete a Compliance and Ethics training course on an annual basis, a description of which can be found at the following link: http://www.pge-corp.com/aboutus/ethics_compliance. The annual Compliance and Ethics training includes a review of various parts of the Code of Conduct for Employees handbook.

2. Overview of PG&E's Procurement Process

PG&E's procurement process involves three phases: planning, competitive procurement and economic dispatch.

a. Planning

In the planning phase, PG&E identifies the resource needs of its customers and complies with the State Loading Order, Energy Action Plan II ("EAP II") and other Commission and legislative directives.[2] In analyzing its needs, PG&E identifies specific power products. These power products include energy products (baseload, shaping, and peaking), capacity products to meet Resource Adequacy ("RA") requirements, and various ancillary services products, including spinning, non-spinning, regulation, and black-start capability. The following table summarizes some of the power products available from various resource alternatives, which PG&E identifies in the planning phase.

TABLE II-1~~VOL. 1, IIIA-1~~
PACIFIC GAS AND ELECTRIC COMPANY
POWER PRODUCTS AVAILABLE FROM RESOURCE ALTERNATIVES

		Energy Products					Ancillary Service Products					
Line No.	Resource Types	Base-load	Inter-mittent Energy	Shaping	Peaking	Capacity (RA)	Black Start	Quick Start (10 min.)	Emer-gency (30 min-3 hr)	Regu-lation	Spinning	Non-Spinning
1	Preferred Resources											
2	Energy Efficiency	X				X						
3	Demand Response				X	X			X			X
4	Renewable-Intermittent		X			X						
5	Renewable-Baseload	X				X						

[2] PG&E also looks at the reliability need for its entire service area~~, as described in Volume 1, Section IV.E~~.

6	Distributed Generation-Non PV	X				X						
7	Conventional Resources											
8	Combustion Turbine				X	X	X	X	X	X	X	X
9	Reciprocating Engines				X	X	X	X	X	X	X	X
10	Combined Cycle			X		X			X	X	X	X
11	Base (*e.g.,* coal, nuclear)	X				X						

After identifying the amount and timing of its need, PG&E then prepares and files a procurement plan with the Commission, seeking authority to procure these products. Once the Commission approves a procurement plan, the procurement process shifts to the competitive procurement phase.

b. Competitive Procurement

PG&E implements its Commission-approved procurement plan through various processes, including solicitations, bilateral negotiations and participation in various markets. PG&E's procurement practices are described in detail in ~~Volume 1,~~ Section II.A.5~~III.A.5~~, below. PG&E enters into short-term, medium-term and long-term contracts that result from the competitive procurement process. PG&E defines short-term contracts as contracts with a term of one year or less in duration; medium-term contracts as contracts with a term greater than one year but less than five years in duration; and long-term contracts as contracts with a term five years or greater in duration. Renewable contracts are an exception to this rule, with anything under 10 years in duration being short-term for this contract category.

c. Dispatch

Consistent with Commission decisions,[3] PG&E economically dispatches its portfolio subject to the contractual and operating limitations of the resources in the portfolio. In

[3] The Commission's Standard of Conduct No. 4, adopted in D.02-10-062 and modified ~~on~~ in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054, requires PG&E to meet its electric load obligations in a least-cost manner. In addition, D.04-07-028 ordered that system reliability and deliverability of power be included as part of least-cost dispatch.

implementing least-cost dispatch, PG&E dispatches resources or purchases energy with the lowest incremental cost of providing energy, which includes the variable operating costs of its own resources or resources under its control and the market cost of generation.[4] PG&E uses incremental cost dispatch for all resources within its portfolio. This includes utility-owned generation, bilateral contracts, allocated DWR contracts, and resources available to PG&E from the marketplace.

Least cost dispatch includes market sales. When PG&E is "physically" or "economically" long, least-cost dispatch requires PG&E to undertake certain market sales. PG&E is "physically long" when must-take energy supply exceeds demand. During those periods, PG&E sells excess energy at market prices. Because PG&E is required to take or generate this energy in any event, the incremental cost of that energy is zero. PG&E is "economically long" when the incremental cost of dispatchable resources is less than the market price, even though PG&E has no need for the energy to serve its customers. Under these circumstances, the economically efficient dispatch decision is to use the dispatchable resource to generate power and market the surplus energy.

3. Description of Procurement Products

a. Electric Products

PG&E uses a variety of physical and financial electric products to meet its electric procurement needs. Table II-2~~Vol. 1, IIIA-2~~ below provides product names, descriptions and information about PG&E's existing regulatory authority to procure these products~~, and includes new products related to MRTU~~.

[4] Because the least-cost dispatch for hydro-electric resources takes into consideration the future value of water and the fact that because the amount of available water is limited, it may be more cost-effective to defer hydro-electric generation to higher value time periods.

TABLE II-2~~VOL. 1, IIIA-2~~
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS

	Product	Description~~(a)~~	Prior Authorization
1	Ancillary Services	Products that are utilized by the control area operator to ensure electric system reliability, for example, those that are listed in control area operator tariffs, such as the CAISO.	D.02-10-062
2	Capacity (demand side)	The amount of power consumed by a customer, measured in megawatts (“MW”), that can be reduced upon request.	D.02-10-062
3	Capacity (purchase or sale)	The amount of power capable of being generated, measured in MW, that can be converted to energy upon request.	D.02-10-062
4	Contingent Forward	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
5	Electric Product Exchange	The buyer has an obligation to receive electric products and an obligation to return electric products as part of the same transaction. The transaction may also include an exchange of payments, in fixed or variable terms. Electric products include energy, capacity, and ancillary services.	AL 2615-E
6	Electricity Transmission Products	Purchase, sale, or allocation of transmission rights, products (*e.g.*, Long-Term Firm Transmission Rights, Congestion Revenue Rights, ~~LT-FTRs, CRRs,~~ losses), or the use of locational spreads.	D.02-10-062 and D.07-12-052 ~~revision requested to generalize transmission products. See Volume 2, Section I.B.3 – Impact of MRTU on Procurement Practices~~
7	Financial Call (or Put) Option	The right, but not the obligation, to buy (call) a forward electric contract on a specific date (expiration) at a fixed or indexed price (strike). The right to sell is a put option.	D.02-10-062
8	Financial Swap	An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps, basis swaps and payment obligation swaps (*e.g.*, CAISO IFM Uplift Load Obligations). Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.	D.02-10-062 AL 2615-E D.07-12-052
9	Forward Energy (demand side)	Electric energy planned to be consumed by a customer, measured in megawatt-hour (“MWh”) that is agreed to be reduced for a specific period for a specified time in the future.	D.02-10-062
10	Forward Energy (purchase or sale)	Electric energy purchased or sold by a counterparty, measured in MWh that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.	D.02-10-062
11	Forward Spot (Day-Ahead & Hour-Ahead) purchase, sale, or exchange	Electric energy, capacity, ancillary services or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MW or MWh that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.	D.02-10-062

~~TABLE VOL. 1, IIIA-2~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~ELECTRIC PRODUCTS~~
~~(CONTINUED)~~

	Product	Description~~(a)~~	Prior Authorization
12	Insurance (counterparty credit insurance, cross commodity hedges)	A method for managing payment or performance risk for a fee.	D.02-10-062
13	New York Mercantile Exchange ("NYMEX") Electricity Futures (purchase or sale)	Standardized forward energy contract traded on NYMEX. Futures may be physically or financially settled.	AL 2615-E
14	On-Site Energy or Capacity (self-generation on customer side of the meter)	The amount of power measured in MW or MWh that can be generated downstream of the customer's electric meter that can be used to offset the customer's load served by the electric service provider.	D.02-10-062
15	Peak for Off-Peak Exchange	Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period. These transactions may also include an exchange of dollars.	D.02-10-062
16	Physical Call (or put) Option	The right, but not the obligation, to buy (call) physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to sell is a put option.	D.02-10-062
17	Real-Time (purchase or sale)	The amount of energy, measured in MWh supplied or received by the control area operator to balance an entity's load and supply.	D.02-10-062
18	Resource Adequacy Product	A capacity product intended to meet resource adequacy obligations.	AL 2615-E AL 2897-E
19	Seasonal Exchange	Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. These transactions may also include an exchange of dollars.	D.02-10-062
20	Tolling Agreement	An agreement to provide (receive) gas in exchange for receiving (providing) electricity.	D.02-10-062, D.04-12-048
21	Counterparty Sleeves	An agreement by a counterparty to buy (sell) electricity from one counterparty and sell it to (buy it from) another counterparty.	D.03-12-062
22	Emissions Credits Futures or Forwards	Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.	D.03-12-062
23	Forecast Insurance	A method for managing load forecast (volume and shape) risk.	D.03-12-062
24	Firm Transmission Rights ("FTR") Locational Swaps	Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062
25	Non-Firm Transmission Rights ("Non-FTR") Locational Swaps	Over-the-counter basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062

~~TABLE VOL. 1, IIIA-2~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~ELECTRIC PRODUCTS~~
~~(CONTINUED)~~

	Product	Description~~(a)~~	Prior Authorization
26	Weather Triggered Options	A method for managing temperature and other weather forecast risks.	D.03-12-062
27	RA Import Capacity Counting Right	Transfer the right to count import energy or import RA product at an intertie toward satisfying resource adequacy requirements.	AL 2897-E
~~28~~	~~Non-Discretionary Products Required by MRTU~~	~~MRTU products, which may be created by the CAISO during the finalization of MRTU and that would be *mandatory* in order to participate in MRTU.~~	~~New transaction requested in Volume 2, Section I.B.3 – Impact of MRTU on Procurement Practices~~
28	Long-Term Congestion Revenue Rights (“LT-CRRs”)	Financial instruments to hedge Locational Marginal Price (“LMP”) congestion in MRTU for ten years.	AL 3095-E
29	Congestion Revenue Rights	Financial instruments to hedge LMP congestion in MRTU, including, for example, monthly CRRs and seasonal CRRs.	D.02-10-062 D.07-12-052 AL 3106-E

~~(a) With the exceptions of the Non-Discretionary Products, all of the products described above are unchanged from the products approved in previous filings. Some of the descriptions differ in non-substantive ways from those included in previous filings. PG&E is updating these descriptions for purposes of the 2006 Long-Term Procurement Plan (“LTPP”).~~

b. Gas Products

PG&E uses a variety of physical and financial gas products to support electric procurement. Physical gas products are used to support least-cost dispatch and reliability. Table II-3 ~~Vol. 1, IIIA-3~~ below provides physical gas product names, descriptions and information about PG&E’s existing regulatory authority to procure these products~~ and includes a description for proposed new product – biomethane~~.

TABLE II-3~~VOL. 1, IIIA-3~~
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PHYSICAL PRODUCTS

	Product	Description~~(a)~~	Prior Authorization
1	Natural Gas Purchases (physical supply)	Purchases/sales/exchanges of physical natural gas for terms of one month or longer.	D.02-10-062
2	Spot Natural Gas (physical supply)	Purchases/sales/exchanges of physical natural gas for terms less than one month.	D.02-10-062
3	Physical Options on Natural Gas Supply	The right, but not the obligation, to buy (call) physical gas for delivery on a particular date at a fixed or index	D.02-10-062

	(purchase or sale)	price (strike). The right to sell is a put option.	
4	Biomethane (purchase or sale)	Pipeline quality natural gas produced from renewable (non-fossil based) resources. May include renewable or environmental attributes.	~~New~~ D.07-12-052
5	Contingent Forward (purchase or sale)	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
6	Gas Storage (purchase or sale)	Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.	D.02-10-062
7	Gas Transportation (purchase or sale)	Interstate, Intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.	D.02-10-062
8	Counterparty Sleeves	Facilitating a transaction with an un-contracted or non-creditworthy through a contracted, creditworthy counterparty.	D.02-10-062

~~(a) With the exception of Biomethane (purchase or sale), all of the products described above are unchanged from the products approved in previous filings. Some of the descriptions differ in non-substantive ways from those included in previous filings. PG&E is updating these descriptions for purposes of the 2006 LTPP.~~

Financial products are used to support gas hedging. Table II-4~~Vol. 1, IIIA-4~~ below provides financial gas product names, descriptions and information about PG&E's existing regulatory authority to procure these products.

TABLE II-4~~VOL. 1, IIIA-4~~
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS FINANCIAL PRODUCTS

	Product	Description~~(a)~~	Prior Authorization
1	Natural Gas Financial Swaps (purchase or sale)	Over-the-counter forward products including fixed-for-floating swaps, basis swaps and swing-swaps for gas. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	AL 2615-E D.02-10-062
2	Natural Gas Futures (purchase or sale)	Standardized forward contracts for gas that trade on an exchange. Futures may be physically or financially settled. Physically settled futures may be unwound by an offsetting trade, exchanged for a physical position, or held to physical delivery.	AL 2615-E
3	Financial Options (Call or Put) (purchase or sale)	The right, but not the obligation, to buy (call) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). The right to sell is a put option. OTC-traded options settle in cash, whereas exchange traded (NYMEX) options must be exercised, which causes delivery of a futures position to the option holder. Options may be combined with other options or swaps to hedge a wide variety of positions.	D.02-10-062

~~(a) All of the products described above are unchanged from the products approved in previous filings. Some of the~~

~~descriptions differ in non-substantive ways from those included in previous filings. PG&E is updating these descriptions for purposes of the 2006 LTPP.~~

The products presented in this section include those products PG&E is currently authorized to transact, as well as products that it knows may be required in the future. PG&E will request approval through advice letter filings of new products that arise from changed policies or market developments that are not covered by the above lists. Such products may be necessary to satisfy procurement needs arising from MRTU implementation, new legislation or other requirements such as the emergence of Renewable Energy Credit markets for compliance with the RPS Program.

4. Overview of Energy Product Markets

This section provides an overview of the markets available to PG&E to purchase the products described in ~~Volume 1,~~ Section II.A.3~~III.A.3~~, above. PG&E's specific procurement practices are described in detail in ~~Volume 1,~~ Section II.A.5~~III.A.5~~, which follows this section.

a. Exchanges

For electric and gas markets there are several types of transparent exchanges: Over-The-Counter electronic trading platforms such as the Intercontinental Exchange ("ICE"), New York Mercantile Exchange ("NYMEX") Clearport, NYMEX Globex, and the Natural Gas Exchange ("NGX"); and open outcry exchanges such as the NYMEX. The electronic platforms allow market participants to post bids and offers for specific gas and electric products. To complete a trade, a buyer must lift an offer or a seller must hit a bid. Once completed, the exchange confirms the transactions to both parties. NYMEX hosts open outcry trading for its natural gas futures contracts and natural gas options. Buyers and sellers transmit bids and offers to the trading pits through a Futures Commission Merchant ("FCM"). The trade is executed by the trader in the trading pit. The results of the trade are communicated back to the buyer or seller through the FCM.

For the electronic exchanges, buyers post bids to the system. If a seller hits the bid, the trade is completed. If a seller does not hit the bid, the buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer already posted on the exchange, the buyer can lift that offer to complete the trade.

For open outcry trading, the buyers work through their FCM to trade on the exchange. Buyers can submit two types of orders with their FCM, a limit order (a bid at a specific price) or a market order (which will buy the current offer in the trading pit). FCMs will work a limit order until it is executed in the pit or until the floor trader indicates that the order is unlikely to trade. At this point, the buyer can cancel the order or raise its bid. In this manner, the buyer can adjust its bid until the trade is executed.

Since the transparent exchanges trade standard products and trading is anonymous, selection is made on product availability, credit availability, and price.

b. Inter-dealer (Voice) Brokers

Inter-dealer or voice brokers facilitate trades in the wholesale market for electricity and gas. Brokers communicate bids and offers to market participants through squawk boxes[5] and telephone calls. Brokers work with buyers and sellers to facilitate trades. Once completed, brokers confirm the transactions with both parties and may initiate financial clearing with both NYMEX and the ICE. Brokers facilitate the trading of physical and financial gas and electric products. Brokers, as part of their price discovery role, provide price reporting services to subscribing clients.

Buyers communicate bids to the broker. If a seller hits the bid the trade is completed. If a seller does not hit the bid, the buyer can ask the broker to work its bid in the market. The broker will provide the buyer feedback if its offer is not hit by a seller. The buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer communicated by the broker, the buyer can lift that offer to complete the trade. Since brokers facilitate trades of

[5] A squawk box is an intercom speaker used for communication between brokers and traders. The box allows brokers to broadcast market information to traders and to have one-on-one conversations with traders. PG&E records all communication on its squawk boxes as part of its trading process controls.

standard products and trading is anonymous, selection is made by product availability, credit availability and price.

c. Spot Markets

The spot market for electricity and gas is the wholesale market for day-ahead, hour-ahead, and real-time for electric energy and day-ahead for natural gas. Day ahead for electricity normally includes two, two-day strips for weekends (Friday-Saturday and Sunday-Monday) and other combinations of days to accommodate holidays. Hour ahead for electricity is the market as traded intra-day. Real-time is the CAISO real-time market. Day ahead for gas normally includes a 3-day strip for weekends (Saturday-Monday) or a longer combination of days to accommodate holidays.

The bilateral spot market consists of buyers and sellers communicating bids and offers to counterparties through telephone calls and Instant Messaging (“IM”). Traders negotiate until a trade is completed. Spot trades are normally executed and then confirmed over the phone by schedulers and not with paper confirmation documents. Spot market trades are also executed though voice brokers, ICE and NGX.

Buyers communicate bids to potential sellers. If a seller hits the bid the trade is completed. If a seller does not hit the bid, the buyer adjusts the bid to entice the seller or they can call another potential seller. The process continues until the buyer finds a willing seller at the buyer’s price. Alternatively, sellers communicate offers to potential buyers, negotiate prices, and keep searching until they find a willing buyer. It is common for buyers and sellers to trade through brokers, exchanges and the bilateral spot market simultaneously. Selection is made by product availability, credit terms, credit availability, and price.

d. On-Line Auctions

On-line auctions facilitate the competitive purchase or sale of electricity and gas with approved counterparties. In an on-line energy auction, PG&E posts a commodity for purchase or sale on a secure internet site, while qualified bidders compete in a live format to provide PG&E with the most advantageous price. PG&E posts energy products for purchase or sale on the secure auction web site. Approved bidders are invited to participate and compete against one another in a live auction. Bidders are required to meet PG&E's credit qualifications in order to participate. Selection is made by product availability and price.

e. RPS Solicitations

RPS bidders include large corporations, small businesses, and individuals with ideas. Offers come from existing and proposed projects in California, the Pacific Northwest, and the Desert Southwest in response to PG&E's annual solicitation. Within California, the offers consist of those both on and off the CAISO grid. Following a Commission decision authorizing an RPS solicitation, PG&E issues a Request for Offer ("RFO") and then reviews the offers it receives. PG&E short-lists offers and then negotiates with the bidders to execute an RPS agreement. The RPS solicitation process is described in more detail below in ~~Volume 1,~~ Section II.A.5.c~~III.A.5~~, below.

f. Energy Product Solicitations and RFOs

PG&E can also obtain electric and gas products through all-source solicitations. PG&E defines the products it is seeking in its RFO and then reviews bids and offers received. PG&E can conduct RFOs for long-term resources, such as the 2004 Long Term Request for Offer ("LTRFO"), or for shorter-term products, such as capacity to satisfy Local or System RA requirements.

g. Bilaterally Negotiated Contracts

Bilateral negotiations are used for the purchase and sale of electric and gas products. The phrase "bilateral negotiations" is generally used in the context where negotiations take place in a one-on-one setting rather than as a part of a competitive solicitation. The process consists of direct one-on-one negotiations, but negotiated terms and conditions are constantly being weighed against best available market price benchmarks to justify the transactions, similar to selecting the best transactions in RFOs.

The decision to proceed is based on least-cost, best-fit principles. The evaluation criteria and methodologies are very similar, if not the same, as those used to evaluate transactions in recent and comparable product RFOs. PG&E uses the best available market price benchmarks in the evaluation process.

h. Inter-Utility Swaps

Inter-utility swaps can be used for the purchase and sale of electric and gas products. Negotiations take place in a one-on-one setting. Inter-utility swaps historically have been used for transactions that offer some form of operational benefits to both parties. However, as transactions have become more purely market oriented, such swaps are more simply combined buy and sell transactions, and evaluated as such. There is a diminishing need to make this product distinction. Inter-utility swaps have become less unique as parties can buy or sell each leg of the transaction from multiple parties. The process consists of direct one-on-one negotiations, but negotiated terms and conditions are constantly being weighed against best available market price benchmarks to justify the transactions. PG&E has not recently executed swaps with other utilities because of the combination of a current lack of need, and more readily available market opportunities for similar products from numerous other market participants.

The decision to proceed is based on least-cost, best-fit principles. Evaluation criteria and methodologies are very similar, if not the same used to evaluate transactions in recent and comparable product RFOs. PG&E uses the best available market price benchmarks in the evaluation process.

5. PG&E's Procurement Contracting Methods and Practices

In this section, PG&E describes its electric procurement methods and practices for short-term, medium-term and long-term contracts. Table II-5~~Vol. 1, IIIA-5~~ below reflects the procurement methods and practices that PG&E is authorized to use. ~~and PG&E's request that PRG review be required for transactions with delivery dates later than six calendar months from execution, or that have contract durations greater than six calendar months. Currently, the PRG trigger is three months. The six month request is discussed in Volume 2, Section II.A.1~~

TABLE II-5~~VOL. 1, IIIA – 5~~
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT METHODS AND PRACTICES

Item #	Transaction Process	Description	Prior Authorization
1	Competitive Solicitations (RFO)	Widely distributed request for offers or proposals. Required items include among other things: Description of product requirements, term, minimum and maximum bid quantities, scheduling and delivery attributes, credit requirements, and pricing attributes. Additional requirements for the RFO process are specified in D.07-12-052, pages 142-152.	D.02-10-062 D.04-12-048 AL 2615-E
2	Direct bilateral contracting with counterparties for short-term products (*e.g.,* ~~six~~ three months or less)	Bilateral process for products procured with a term ~~six~~ three months or less. Investor-owned utilities ("IOU") demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. The demonstration may include showing competing price offers, result of market surveys, broker and online quotes, and/or other source of price information such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction.	D.02-10-062 D.04-12-048 AL 2615-E ~~PG&E is proposing to revise the PRG process from a 3-month to a 6-month contract term or commencement date before PRG review is required. *See* Volume 2, Section II.A.1.~~
3	Inter-Utility Exchanges	Exchange with other regulated utilities and other load-serving entities negotiated through private negotiation crafted to best fit the resources and needs of both parties.	D.02-10-062 D.04-12-048 AL 2615-E
4	ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead	Spot market transactions are authorized to balance system and short-term needs. IOUs justify their planned spot market purchases if they exceed 5% of monthly needs.	D.02-10-062 D.04-12-048 AL 2615-E
5	Transparent exchanges, such as Bloomberg and Intercontinental Exchange, voice and on-line brokers	Electronic trading exchanges for transparent prices.	D.02-10-062 D.03-12-062 D.04-12-048 AL 2615-E
6	Utility ownership of generation ~~(interim rules set in D.04-01-050)~~	~~IOU proposes to buy or construct generation.~~ Utility-ownership of generation can be pursued through an RFO under certain conditions (*see* D.07-12-052 at 198-205) or outside of the RFO process under certain conditions (*see* D.07-12-052 at 209-213).	~~D.02-10-062~~ ~~D.03-12-062~~ ~~D.04-12-048~~ ~~AL 2615-E~~ D.07-12-052
7	Open Access Same-Time Information Systems ("OASIS")	Procure standard electric transmission products from transmission providers throughout the Western Electric Coordinating Council ("WECC") region at FERC tariffed rates and voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E

Item #	Transaction Process	Description	Prior Authorization
8	Negotiated bilateral contracts for non-standard products which terms exceed ~~six~~ three months provided that the IOUs include a product justification in quarterly compliance filings.	Process to purchase products provided they are included in quarterly compliance filings to justify the need and process in each case. Terms and conditions are benchmarked against the best available market information for similar products recently offered.	D.03-12-062 D.04-12-048 AL 2615-E

TABLE II-5~~VOL. 1, IIIA – 5~~
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT METHODS AND PRACTICES
(CONTINUED)

Item #	Transaction Process	Description	Prior Authorization
9	Transparent exchanges to include voice and on-line brokers	Transparent price products from voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E
10	Electronic Auction	IOUs are authorized to conduct procurement using an electronic auction format.	D.04-12-048 AL 2615-E
11	Generator Requests for Proposals	IOUs can bid in open season or RFPs held by generator owners.	D.04-01-050 AL 2615-E
12	CAISO Allocations and Auctions	CAISO allocation and auctions for LT-CRRs and CRRs.	AL-3095-E and AL 3106-E

In the remainder of this section, PG&E describes its procurement practices and methods for: (a) short- and medium-term procurement transactions; (b) long-term transactions; (c) RPS transactions; and (d) the length of time between the date contracts are executed and when actual deliveries commence.

a. Procurement Practices and Methods for Short-Term and Medium-Term Transactions

This section describes PG&E's methods and practices for short-term and medium-term procurement transactions. PG&E utilizes various Commission-approved transaction methods that are set forth in Table II-5~~Vol. 1, IIIA-5~~ for short- and medium-term transactions.[6]

PG&E's electric procurement process is not a one-time event. Rather, it is comprised of a series of ongoing analyses and activities that focus on different time frames and decisions. This process ensures that resources are available to meet energy and ancillary service

~~6 Short-term and medium-term contracts that are part of PG&E's electric portfolio are also discussed in Volume 1, Section IV.C.2 – Supply-Side Resources.~~

requirements and allows PG&E to minimize the cost of generation and risks by participating in a variety of transactions over time.

The short- and medium-term electric procurement time frames include: (1) multi-year;[7] (2) annual; quarterly, and monthly; (3) intra-month and weekly; (4) daily; and (5) hour-ahead. The CAISO also manages a "real-time" market. The procurement process is conceptually identical in all time frames insofar as all considered resources are reviewed on an equal basis in determining how to meet PG&E's demand and energy requirements in a least cost manner. The input assumptions and the granularity of those assumptions differ. PG&E begins by determining total load requirements, including customer retail demand, wholesale sales, transmission and distribution losses, ancillary services, and any and all operating constraints. PG&E then determines the quantity of generation from baseload "must-run" resources such as the Diablo Canyon Power Plant ("DCPP"), QFs, and DWR allocated contracts. Finally, PG&E assesses market conditions in order to optimize production from dispatchable resources and market transactions. PG&E's objectives are to meet any remaining load requirements as well as extract value from resources when it is economic to sell into the market.

The remainder of this discussion summarizes the short- and medium-term procurement process and describes some of the Commission-approved transaction methods that PG&E has undertaken in each time frame since it has resumed electric procurement.

(1) Multi-year

PG&E initially determines its need for short- and medium-term transactions. Multi-year transactions typically involve competitive solicitations that are reviewed in consultation with the Procurement Review Group ("PRG"). After negotiating a multi-year transaction, PG&E submits the agreement to the Commission for approval via an advice letter, if the term of the transaction is less than five years. An Independent Evaluator ("IE") is required for all competitive RFOs that seek products of more than three months in duration. Competitive RFOs

[7] For this discussion, the term "multi-year" is limited to less than five years.

include RFOs issued to satisfy service area need and supply-side resources, not including energy efficiency and demand response. ~~Use of an Independent Evaluator ("IE") is not required.~~

(2) Annual, Quarterly, and Monthly

PG&E performs and updates assessments of its net open position for a 12-month forward period on a regular basis to determine whether additional resources are required or it has excess resources for potential surplus sales. This process ensures that PG&E has resources to meet requirements, and determines by the close of the month prior to an operating month that it will control resources within 5% of expected requirements, as recommended by the Commission in D.02-10-062.

The analysis is the same as that employed for the multi-year time frame, with the primary difference being the assumptions used—forecasted loads, resource availability, gas prices, hydro availability and market prices are further refined as PG&E moves closer to the operating period, hence resource requirements and market opportunities become clearer.

Forward Energy Products (*e.g.*, term, balance-of-month and balance-of-week purchases and sales) are transacted to diversify the portfolio and reduce reliance on spot markets. ~~Currently, t~~Transactions with a delivery date later than three calendar months from execution, or for a term greater than three calendar months are reviewed by the PRG.[8] PG&E's monthly forward transactions represent the majority of PG&E's market transaction volume, and are primarily one-month purchases or sales of fixed price, standard block on-peak and off-peak energy, although some transactions span two or three months. Bilateral contracts are often used. Typically, bilateral contracts are benchmarked against pricing information obtained from recent competitive solicitations for a similar product or against forward price curves. In addition, brokers play a critical role in almost all of these transactions. Voice brokers and

[8] ~~PG&E is requesting that PRG review be required for transactions with a delivery date later than six calendar months from execution, or for a term greater than six calendar months. *See* Volume 2, Section II.A.1.~~

electronic exchanges are used for the purpose of price discovery and matching buyers with sellers in an anonymous fashion.

(3) Intra-month and Weekly

As part of an integrated process, results from the actions described in the previous section determine the amount of the residual open position (long or short) that is carried into the prompt month. Inside the month time horizon, PG&E reviews the availability of resources, hydro conditions, and makes an assessment of market prices and conditions to further assess how best to manage the open position. If market transactions are needed, the transaction methods listed in the foregoing section are generally used.

(4) Daily

In day-ahead procurement PG&E strives to balance projected energy requirements with resources, and provide hour-ahead traders and real-time operators with appropriate resources to respond to changes that may occur in system requirements subsequent to day-ahead trading. On a daily basis PG&E conducts a least-cost analysis to determine unit dispatch and market transactions to meet energy and ancillary services requirements.

Day-ahead trading generally occurs between 6 and 7 a.m. in the day prior to the operating day. The day-ahead market continues to evolve in terms of participants, products and character. Currently the market usually trades “standard” on-peak and off-peak “packages” of multiples of 25-MW blocks with specified delivery points. While some basis spread products are traded, there is only sporadic trading of hourly energy products or other non-standard products such as options. PG&E actively participates in the daily energy market using a combination of transparent exchanges with voice and on-line brokers, and direct bilateral transactions with counterparties.

PG&E has adapted its daily procurement process to incorporate the opportunities available in the day-ahead market as well as its must-run and must-take resource requirements. Similar to the market products discussed above, many of the must-take contracts are for standard blocks of on-peak hours. These contracts do not match PG&E’s load profile and often results in excess energy during some hours while leaving PG&E short during other hours. To manage this PG&E may: (1) either re-dispatch resources to the extent it is feasible or dispatch other flexible resources; (2) engage in non-standard product transactions; and (3) make a concerted determination to sell or purchase quantities of energy in the hour-ahead market in order to maximize the value of its energy and minimize real-time imbalances.

(5) Hour Ahead

"Hour-ahead" planning is something of a misnomer since it effectively begins at the conclusion of day-ahead trading. As day-ahead analysis and trading occurs early in the morning prior to the operating day, there can be substantial subsequent changes to operating requirements. PG&E prepares weather-adjusted load forecasts throughout the day to determine if changes in generation or system operation are required. Further, unit outages and transmission outages and constraints may also affect resource requirements prior to real-time. In order to balance its portfolio during this time frame, PG&E's hour-ahead staff has several resources at its disposal. Dispatchable resources are updated with incremental unit dispatch prices. Hour-ahead personnel will then optimize the portfolio, based on operating requirements and market opportunity costs, whether and which generating resources should be adjusted to minimize system costs, and whether market transactions are required or beneficial.

The hourly market, while active, is far less transparent than the day-ahead market or the real-time market. As there are few brokers operating in this market and nascent electronic exchange opportunities, the bulk of transactions are bilateral in nature, making it difficult to generally characterize the hour-ahead market. Despite this, PG&E participates in the hour-ahead market to optimize its resources and market transactions to reduce costs.

(6) CAISO "Real-Time"

While PG&E strives to achieve balanced loads and schedules in the Day- and Hour-Ahead time frames, mismatches are inevitable. Causes could be changes in electric demand, resource availability, or transmission availability. The CAISO "Real-Time" market is where load/resource balance is the goal. Imbalances after the close of the Hour-Ahead market are settled at the CAISO's "ex-post" price (*e.g.*, PG&E sells/purchases energy to/from the CAISO).

b. Procurement Methods and Practices for Long-Term Transactions

In this section, PG&E discusses procurement contracting methods and practices for various long-term (*e.g.*, 5 years or longer) procurement transactions.

(1) Negotiated Bilateral Contracts

PG&E generally does not negotiate bilateral contracts for long-term procurement. However, PG&E has conducted bilateral negotiations when appropriate and beneficial to its customers. For example, PG&E's acquisition through a bilateral transaction of the Gateway facility[9] stemmed from a settlement of PG&E's claims against Mirant. In its application to the Commission requesting approval of the acquisition and completion of Gateway, PG&E benchmarked the economics of the acquisition by comparing the cost to complete Gateway~~Contra Costa 8 ("CC8")~~ to the costs of other, similar power plant acquisitions recently approved by the Commission, namely the Mountainview and Palomar facilities. Both Mountainview and Palomar were viewed as "fleeting opportunities" for below-market acquisitions. PG&E was able to demonstrate that Gateway's forecast completion cost was lower than those other two fleeting opportunities on a $/kilowatt ("kW") basis. The Commission approved PG&E's acquisition of Gateway in D.06-06-035.

If PG&E considers long-term bilateral agreements in the future, the winning 2004 LTRFO bids may provide an appropriate starting point for market benchmarks to review those bilateral agreements. These winning bids are the result of a competitive solicitation and are good measures of market prices for dispatchable and operationally flexible products available at the time the winning bids were selected.

[9] The Gateway Facility was previously referred to as Contra Costa 8.

(2) Competitive Solicitations – PG&E's Experience With the 2004 LTRFO

PG&E recently concluded its 2004 LTRFO, which resulted in seven contracts that were recently approved by the Commission. The 2004 LTRFO process was complex and intensive. Below, PG&E provides a brief description of the various elements and aspects of the 2004 LTRFO process as an example of how long-term procurement solicitations can be administered.

PG&E's 2004 LTRFO involved both internal and external resources. PG&E formed an internal steering committee for the 2004 LTRFO to ensure the goals of the LTRFO and D.04-12-048 were met. The committee was responsible for establishing policies, making key decisions about offers and recommending the shortlist of projects and ultimately the final contracts for execution. PG&E also received feedback from market participants on its proposed LTRFO solicitation process before starting the process. After a pre-offer conference, in response to this feedback, PG&E modified the 2004 LTRFO protocol, including modifications to extend the schedule and increase the number of offer variations allowed for each offer. PG&E also made modifications to the Purchase and Sale Agreement ("PSA") and Power Purchase Agreement ("PPA") contracts based on feedback from the market participants prior to submission of final offers.

The actual 2004 LTRFO solicitation process included a number of key milestones. First, PG&E distributed a draft RFO and online registration for purposes of a pre-offer conference. PG&E established a location on its public website with information relevant to the 2004 LTRFO.

Second, PG&E held a Pre-Offer Conference to discuss the draft of PG&E's 2004 LTRFO for PPAs and Facility Ownership.

Third, PG&E issued its original 2004 LTRFO for PPAs and Facility Ownership and later revised the LTRFO in compliance with D.04-12-048.[10] Participants were then required to initiate Electric and Gas Interconnection Studies including a System Impact Study ("SIS") and Facility Study ("FS") with the CAISO and to submit to PG&E Gas Transmission and Distribution department or other applicable gas transmission company a request for a Preliminary Application for Gas Service.

Fourth, participants were requested to submit a Notice of Intent ("NOI") to offer and then submitted their initial offers. The IE was present to witness the opening of initial offers.

Fifth, PG&E notified participants of shortlisted projects and issued drafts of PPAs and PSAs and requested additional data from participants with projects on the shortlist.[11]

Sixth, PG&E issued revised drafts of PPAs and PSAs to participants. Participants with projects on the shortlist submitted final offers. The IE was present to witness the opening of final offers.

Finally, PG&E was involved in extensive negotiations with winning bidders and then executed agreements and presented them for approval by the Commission.

PG&E's 2004 LTRFO included certain eligibility requirements that were designed to ensure a diverse selection of resources, capacity, contract terms and technologies. These requirements were also designed to ensure that the resources would be timely constructed and online in time to meet resource needs in the 2008 through 2010 time frame.

- **PPAs:** For PPAs, new generating facilities were required to have a Commercial Operations Date ("COD") no earlier than January 1, 2007, and no later than May 31, 2010. Offers required a minimum term of five years and a minimum size of 25 MW or greater. Offers were required to provide for firm physical delivery of generation to a busbar in the North of Path-15 ("NP15") area. Only "unit specific"

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[10] This revision implemented a methodology to evaluate PPA offers and PSA offers directly on a head-to-head basis. In addition, an IE was selected, in consultation with the PRG, and retained. PG&E also included the solicitation for offers for the Humboldt Bay Power Plant ("HBPP") in the revised LTRFO.

[11] Participants providing offers for HBPP were requested to provide offers for a PSA, an Engineering, Procurement and Construction ("EPC") and the sale of development assets.

offers were accepted. Offers were required to confer upon PG&E exclusive rights to the unit's capacity, subject to CAISO requirements.

- **Facility Ownership:** For Facility Ownership, all generating facilities were required to have a Guaranteed Commercial Availability Date no earlier than January 1, 2007, and no later than May 31, 2010. Facilities were required to have a design life of 30 years, a size no less than 25 MW at any one site, and construction with new equipment. A proposed project's generation was required to physically interconnect to a busbar within the NP15 area.
- **Humboldt Generation:** For the Humboldt Bay area, PG&E required generation facilities to have a Guaranteed Commercial Availability Date no earlier than January 1, 2007, and no later than August 31, 2009. Facilities were also required to have a design life of 30 years, total peak capacity of at least 135 MW on a single site, functional specifications necessary for Humboldt area reliability, and be constructed with new equipment. A proposed project's generation was required to be physically interconnected to a busbar within Humboldt County.
- **Qualifying Facilities:** An existing QF in PG&E's service territory as of November 2, 2004, was required to meet the requirements of FERC's QF rules and not have waived these rights to PG&E. QFs also had the option to provide delivery within the ZP26 area. Offers were required to be for a minimum term of five years and a minimum of 1 MW or greater.
- **New Resources:** The 2004 LTRFO was only open to new resources (with the exception of existing QFs) because the purpose of the solicitation was to implement the directives of D.04-12-048 to bring new sources of reliable supply to northern California. For the purpose of the 2004 LTRFO, PG&E considered "new" resources to be resources that had not begun construction. PG&E assumed that resources that had begun, but not yet completed, construction would likely be completed without the need for contracts via PG&E's 2004 LTRFO.
- **Other Eligibility Requirements:** Additional 2004 LTRFO requirements included: (1) a Transmission System Impact Study and a Preliminary Application for Gas Service; (2) deposit requirements; and (3) site control.

PG&E also included a Greenhouse Gas ("GHG") adder in the evaluation of the 2004 LTRFO bids. In D.04-12-048, the Commission specified that a ~~Greenhouse Gas~~ GHG adder, in dollars per ton of carbon dioxide ("CO_2"), be used to calculate the cost of CO_2 emissions. In D.05-04-024, the Commission adopted a particular set of values for the GHG adder: for delivery year 2004, $8.00 per ton of CO_2, with escalation at 5% per year for delivery in subsequent years. For delivery year 2010, this amounts to $10.72 per ton of CO_2. PG&E used this GHG adder curve in project evaluations. For each offer, PG&E's modeling yielded estimates of the anticipated CO_2 emissions, based on the capacity factors associated with that offer's generating unit. The estimated quantities of CO_2 emitted were then multiplied by the costs per ton specified in the GHG adder. This calculation yielded the variable cost associated with CO_2 emissions. GHG adder cost was measured in present value (2006) dollars per kW-year of generating unit capacity.

In accordance with D.04-12-048, PG&E also contracted directly with an IE, in consultation with PG&E's PRG. The scope for the IE's responsibilities included the following activities: (1) review and comment on the appropriateness of PG&E's evaluation methodology, with a focus on how PPA and utility ownership offers are compared directly; (2) review and assess whether PG&E actually implemented the evaluation methodology as represented; (3) use the IE's Response Surface Model to check the numerical results for PG&E's market valuation of the contracts; and (4) deliver to the PRG, under existing confidentiality protections, the Response Surface Model and the results produced by the IE in performing the check of numerical results, as described above.

PG&E met with the PRG at least 15 times to discuss aspects of the 2004 LTRFO evaluation. The PRG was also consulted in the selection of the IE. PG&E held two workshops with the PRG to discuss PG&E's evaluation methodology in depth. PG&E's evaluation framework for credit was also discussed extensively with the PRG. In addition, PG&E met with the PRG to discuss evaluation of initial offers, final offers, and during final negotiations.

PG&E is satisfied with the results of the process developed for its 2004 LTRFO and intends to follow largely the same process in its next LTRFO. ~~PG&E intends to retain an IE in case it chooses to submit its own bid, and involve the PRG in various stages of the future LTRFO process.~~

c. Procurement Methods and Practices For RPS Transactions

The California RPS Program was established by California State Senate Bill ("SB") 1078, effective January 1, 2003.[12] The RPS Program requires that a retail seller of electricity such as PG&E purchase a certain percentage of electricity generated from eligible renewable energy resources. Each utility regulated by the Commission is required to increase its total procurement of capacity and energy generated by eligible renewables by at least 1% of annual retail sales per year so that 20% of its retail sales are supplied by eligible renewables by 2010.

PG&E procures RPS resources through competitive solicitations and bilateral negotiations. In bilateral negotiations, PG&E may execute contracts with renewable suppliers for one month up to 20 years, or more. These contracts are filed for Commission approval by advice letter. For competitive solicitations, PG&E conducts annual RPS solicitations. Prior to issuing its solicitations, the RPS procurement plan and solicitation protocols are submitted to the Commission for approval.

~~The following key milestones have already been achieved in PG&E's 2006 RPS solicitation: (1) PG&E issued the Solicitation Protocol; (2) participants submitted NOI to Bid containing basic project information and a reservation to attend the pre-bid conference[13]; (3) PG&E held a Pre-Bid Conference; (4) participant's offer(s) were submitted by the Offer Submittal Deadline; (5) PG&E selected a Shortlist of Offers for further negotiations; (6) participants selected for the Shortlist are required to post a Bid Deposit and execute a Confidentiality Agreement; and (7) the Commission released the Market Price Referent ("MPR") used to calculate how much of bidder's price will be paid directly by PG&E under the PPA and how much, if any, will be eligible to be paid as Supplemental Energy Payments~~

[12] *See* Cal. Pub. Util. Code §§ 399.11-399.25 and Cal. Pub. Res. Code §§ 25740-25751.

~~[13] The NOI to Bid is nonbinding and failure to submit it by the schedule date will not disqualify a participant.~~

~~("SEP") by the Public Good Charge account administered by the California Energy Commission ("CEC").~~

~~The remaining milestones in the 2006 RPS Solicitation are: (1) PG&E will conduct negotiations and reach final agreements with short-listed bidders; (2) the final agreements will then be shared with the PRG[14]; (3) PG&E and final bidders will execute agreements; and (4) PG&E will submit agreements for Commission approval via an advice letter filing. If a bid price exceeds the MPR and the bidder intends to seek SEPs from the CEC, bidders also submit an application to the CEC for SEP funding.~~

~~PG&E's 2006 RPS Solicitation includes the following eligibility requirements:~~

- ~~Projects must be certified as eligible renewable resources by the CEC.~~
- ~~Projects must use one or more of the following renewable resources or fuels:~~
  - ~~Biomass~~
  - ~~Biodiesel~~
  - ~~Fuel cells using renewable fuels~~
  - ~~Digester gas~~
  - ~~Geothermal~~
  - ~~Landfill gas~~
  - ~~Municipal solid waste~~
  - ~~Ocean wave, ocean thermal, and tidal current~~
  - ~~Photovoltaic~~
  - ~~Small hydroelectric (30 MW or less)~~
  - ~~Solar thermal~~
  - ~~Wind~~
- ~~Existing eligible renewable projects are eligible to bid.~~

[14] ~~PG&E consults with the PRG throughout the RPS solicitation process, including consultation with respect to solicitation design and shortlisting.~~

- ~~The project must either: (i) be located in California; or (ii) if located outside of California, demonstrate delivery of its energy to an in-state market hub or in-state substation. The bidder and PG&E may negotiate a delivery point location that is located out-of-state as long as the energy is ultimately delivered into the CAISO-controlled Grid or a location that otherwise satisfies applicable CPUC delivery rules to qualify as an RPS eligible resource.~~
- ~~Each bidder is solely responsible for securing all necessary interconnection, distribution, transmission, and scheduling services associated with the bidder's project.~~

As with the 2004 LTRFO, in consultation with the PRG, PG&E contracts directly with an IE for RPS Solicitations.

d. Procurement Methods and Practices: Length of Time Between Contract Date and Delivery Commencement

The time between contract execution and when delivery of a product begins depends on resource type (*e.g.,* existing or newly built resources), as well as the short- or long-term nature of the contract. For short-term contracts deliveries can begin as late as one year after execution, such as an RA contract signed in 2005 for Summer 2006. These contracts become effective when executed.

Medium-term contracts that are consistent with existing procurement authority may be filed for approval via advice letter filings, which could take up to a year. Long-term contracts (except for renewable contracts resulting from an RPS solicitation) are filed for approval via an application. The application, approval and permitting process for such contracts typically takes over a year. For contracts that require construction of facilities, construction will not begin until all regulatory approvals and permits are acquired and actual deliveries may not begin until five or more years after contract execution. Thus, for long-term contracts with newly-built resources, it could take several years or more between contract execution and the beginning of deliveries to allow for permitting and construction.

For renewable generation, it typically takes one year from a RFO issuance until Commission approval, and two to three years from Commission approval until deliveries are targeted to commence, for a total of three to four years from the RPS RFO issuance to actual contract deliveries.

6. Proposed Transaction Timing for Upcoming RFOs

~~Upon Commission approval of PG&E's 2006 LTPP, PG&E will implement its authorized plan through various processes, including solicitations, bilateral negotiations and participation in various markets.~~ The following section describes PG&E's proposed RFOs for the next one to five years.

a. Renewable RFOs

As described in ~~Volume 1,~~ Section IV.D~~V.D~~, PG&E will continue to issue annual Renewable RFOs to aggressively pursue RPS targets. These RFOs offer renewable developers a number of procurement alternatives—such as PPAs with and without buyout options, turnkey utility ownership, and greenfield development—in order to identify those mechanisms which are in the best interest of its customers. The developers include large corporations, small businesses, and individuals with ideas. Contracts with these developers typically range from 10 to 20 years; however, PG&E will also consider other contract lengths. The types of contracts include Power Purchase and Sale Agreements for As-Available Products and Power Purchase and Sale Agreements for Firm Products (which include peaking, baseload, and dispatchable products). Once PG&E issues these RFOs, the offers received are reviewed. PG&E shortlists offers and then negotiates with bidders to execute contracts. Executed contracts will be submitted to the Commission for approval.

~~PG&E's 2006 RPS RFO is currently in progress. PG&E issued the solicitation on June 30, 2006, and held a bidders conference on July 20, 2006. Following receipt of offers on September 8, 2006, PG&E performed a rigorous review of the offers, including follow-up requests to sellers for supplemental information. PG&E notified shortlisted bidders on November 2, 2006. Negotiations will follow for two to six months, depending on how close the parties are in the PPA terms and price. Executed contracts will be followed by an advice letter filing to the Commission, with an expected Commission approval within 180 days.~~

PG&E will continue to refine its renewable RFOs based on developer feedback, over the future planning horizon. ~~PG&E also anticipates developing new programs such as the emerging renewable resource program described in Volume 2, Section I.B.5, in order to assess and prepare for higher renewables goals in the post-2010 time frame.~~ As PG&E's procurement practices evolve, PG&E may identify the need for other types of renewables RFOs. These yet-to-be determined renewables RFOs will be issued only upon Commission approval.

b. Short-Term/Medium-Term RFOs

The residual net long/short energy and RA capacity requirements are the positions that PG&E may need to manage on a short-term (up to and including 1 year) and medium-term (greater than 1 year and less than 5 years) time horizon within the operating targets discussed in Appendix B~~Volume 1, Section III.B.1.a~~. Specifically, if the monthly subperiod positions fall outside the operating targets, strategies are developed and executed to bring the portfolio back to within the targets. PG&E's energy and capacity needs are managed using Commission-approved transaction contracting methods in Advice Letter 2615-E, including competitive solicitations. PG&E will continue to issue medium-term RFOs to manage the residual net long/short energy and RA capacity requirements. These RFOs can be issued for a variety of electric products. These electric products are described in ~~Volume 1,~~ Section II.A.3~~III.A.3.a~~. The contracts resulting from these RFOs can range from greater than one year to less than five years in length. Once PG&E issues these RFOs, the offers received are reviewed. PG&E shortlists offers and then negotiates with the bidders to execute agreements. Project costs are reviewed with the PRG during the process. Executed contracts are filed with the Commission through either the Quarterly Procurement filings or through stand-alone advice letter filings.

Resource adequacy requirements will be met by PG&E using competitive solicitations or other previously approved Commission mechanisms. As required by the Commission, PG&E will file its plan to meet 90% of its System RA requirements for the summer months ~~of 2008~~ (*i.e.*, May-September) by the specific date established by the Commission~~September 30, 2007~~.

Subsequently, all months require a 100% commitment to be in place one month ahead. PG&E will review its RA procurement activities with the PRG and file Advice Letter for necessary Commission approvals.

PG&E is required to acquire 100% of its share of the local area resource ("LAR") requirement in CAISO defined, transmission-constrained areas. ~~Since the rules for 2008 LAR procurement will not be known until mid-2007, PG&E must estimate its share of LAR utilizing information from 2007 in order to be prepared to complete procurement by late October 2007.~~ PG&E will seek to procure its LAR with Commission approved mechanisms at the lowest cost while considering the CAISO's area and sub-area RA needs.

c. LTRFOs

PG&E's ~~recommended plan~~ 2006 LTPP implements the State Loading Order and aggressively pursues renewable resources, as well as energy efficiency and demand response. However, even with these efforts, there will be a need for additional new generation in Northern California. As discussed in ~~Volume 1,~~ Section IV.F.6~~V.F.6~~, PG&E will issue a new all-source LTRFO in 2008~~7~~ to procure between 800 to 1,200 MW of dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources to be available in 2015.~~to 2,300 MW in new dispatchable and operationally flexible generation resources it has identified in this long-term plan~~. This solicitation will seek facilities to meet the identified need for the ~~2011-2014~~ 2015 time frame. ~~The eligibility requirements, rules, and process are anticipated to closely match those of the 2004 LTRFO described in Volume 1, Section III.A.5.b(2). Specifically, the eligibility requirements will be designed to ensure a diverse selection of resources, capacity, contract terms and technologies. The LTRFO will consider PPAs as well as utility ownership projects. The lengths of these contracts may be 10 years or more. PG&E anticipates filing for Commission approval upon execution of contracts with the winning bidders.~~

Ordering Paragraph 15 in D.07-01-039 directed PG&E to update its 2006 LTPP filing for compliance with the adopted Interim Emissions Performance Standard rules, as necessary, within sixty (60) days from the effective date of that decision. PG&E's 2006 LTPP is already in compliance with the decision and thus does not need to be further modified. For contracts of five years or more in duration, whether from new resources or existing resources, PG&E will comply with the Interim Emissions Performance Standard.

7. The Application of Least-Cost, Best-Fit and the Loading Order in PG&E's Procurement Planning and Transactions

Least-cost, best-fit provides for resource alternatives to be selected based on their relative cost-effectiveness and their ability to meet the specific needs of the portfolio. A resource's cost-effectiveness is determined relative to common market benchmarks or "market value," as explained below. A resource's portfolio fit can be a qualitative assessment or quantitative measure that represents how well its energy profile, location, and other operating characteristics meet the needs of the portfolio for a particular product in a given location.

In planning and procurement decisions, PG&E applies a consistent evaluation methodology to both supply-side and demand-side resources. By applying least-cost, best-fit principles to supply-side and demand-side alternatives, PG&E obtains the lowest cost for customers for a given set of portfolio needs. PG&E's procurement evaluation methodology considers both the market value and the portfolio fit of alternative resources that are available.

a. Market Valuation

Market value represents a resource's net market value from a market perspective, based on its costs and benefits, regardless of its fit with the rest of PG&E's portfolio. The costs that PG&E uses in calculating a resource's net market value include the value that the Commission has placed on CO_2 emissions.

In valuing demand-side alternatives, PG&E uses the Commission's Standard Practice Manual's[15] total resource cost ("TRC") test. Under that TRC test, the costs that PG&E and its

15 *Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, issued by the Commission in October 2001.

customers are expected to incur in implementing an alternative resource[16] are compared to the expected benefits that would be obtained from that alternative resource. Those benefits include the energy and/or capacity costs that would be avoided by utilizing that alternative resource. As long as PG&E's avoided energy and capacity costs are based on market prices, then PG&E's evaluations of supply-side resources and demand-side resources are consistent, and make it possible to compare supply-side resources to demand-side resources.

b. Portfolio Fit

Portfolio fit assesses how well a resource alternative matches PG&E's portfolio needs. For example, a resource that produces energy during time periods in which PG&E's portfolio is expected to be long (*i.e.*, periods in which PG&E expects to make spot market energy sales) has a poorer portfolio fit than a resource that produces energy during time periods in which PG&E's portfolio is expected to be short (*i.e.*, periods in which PG&E expects to make spot market energy purchases). As a result, the portfolio fit of a resource is different from, but complementary to, the net market value of that resource.

In the planning phase, when preparing a long-term procurement plan, PG&E considers portfolio fit based on how well a particular resource provides the power products that need to be added to the portfolio. Not all resources provide the same products. For example, photovoltaic distributed generation and energy efficiency do not provide dispatchable peaking energy.

In the planning phase, PG&E first identifies the types and amounts of power products that it needs to fill its open position over the planning horizon. Those power products include energy products (baseload, peaking and shaping), capacity or RA products, and ancillary services products (*e.g.*, spinning, non-spinning, regulation, and black-start capacity). Then, PG&E identifies the energy products that each alternative resource can provide (*e.g.*, baseload energy and dispatchable shaping or peaking energy.)

[16] When evaluating demand-side alternatives, PG&E considers the costs customers incur due to participation in demand-side program as well as the costs that non-participating customers incur due to that program.

Most resources can provide a capacity product, or have an RA value that PG&E can estimate by using the Commission-adopted RA counting rules. However, some resources are more likely to provide energy in the hours when the system's peak demand is most likely to occur, and which as a result have a higher RA value (per unit of installed capacity). With respect to ancillary services, a combustion turbine ("CT") can provide quick start capacity and can be used in emergencies to replace resources that are unavailable because of forced outages. Certain demand response ("DR") programs can also provide emergency capacity, because the demand reductions under that program can be activated on short notice (e.g., within 10 minutes to qualify as non-spinning reserves).[17] CTs and DR however, are not suited to provide system regulation services because they cannot respond instantaneously to automatic generation control ("AGC"). Regulation services are generally provided by units that are on-line, and operated under automatic control to continuously balance generation and load.

In the procurement phase, when evaluating transactions, portfolio fit can be a qualitative assessment or quantitative measure that represents how well a resource fits the portfolio's need. In addition to the market valuation, resources are compared based on their ability to meet the particular need being met, or their ability to provide additional features that are complementary to the portfolio. For example, if the proposed resource is not dispatchable by the utility, the offer with a generation profile that best matches the hourly profile of the open position will score more highly on PG&E's portfolio fit measure. Other portfolio fit considerations can include location and the volatility of the remaining portfolio open position.

c. Loading Order

According to EAP II, cost-effective Energy Efficiency ("EE") and DR are preferred to meet the State's growing energy needs, followed by cost-effective renewable and distributed generation, and finally clean and efficient fossil-fired generation. The EAP II also requires

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[17] *Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC),* revised April 6, 2005, p. 3.

improvements to T&D system to support demand growth and enable the interconnection of new generation.[18]

PG&E's 2006 LTPP follows the State Loading Order. ~~PG&E's recommended plan adds energy efficiency and demand response in order to meet the incremental needs of its electric portfolio.[19] Second, PG&E's plan adds renewable generation, to the extent available in the market. If not enough cost-effective renewable generation is available, then PG&E's plan adds, to the extent available, additional renewable generation even if this is not cost-effective in order to meet the existing 20% RPS goal by 2010. Third, the plans include distributed generation available from the recently adopted the CSI program, and historical amounts of non-CSI distributed generation. Finally, and to the extent needed to meet residual capacity and energy needs, the plans add clean, efficient fossil-fueled generation. PG&E's procurement plan also includes transmission additions based on PG&E's Transmission Expansion Plan. These transmission additions are designed to reduce the need for CAISO RMR contracts and to support PG&E meeting the 20% RPS goal.~~

8. ~~PG&E's Price Forecasting Methodology~~

a. ~~Gas Price Forecast~~

~~PG&E develops its gas price forecast using commodity prices based on the evaluation date closing price of forward contracts traded on the NYMEX exchange plus location basis obtained from broker quotes for gas delivered at AECO, Topock, Malin, San Juan, Rockies and PG&E Citygate for the period through December 2011, which currently marks the end of NYMEX contract availability. For January 2012 and beyond, PG&E extrapolates gas prices using monthly electricity prices through 2015 and maintaining the same monthly relationship between electricity and gas prices as exhibited in the 12 months prior to January 2012. Because broker quotes are not available for 2016 electricity prices, for this long-term plan, PG&E used~~

[18] EAP II, p. 2.

~~the gas forecast adopted in the 2005 MPR process starting 2016.[20] The annual price for 2016 is shaped based on the monthly profile observed in 2011.~~

~~PG&E estimates its 95th percentile gas price levels among other risk related metrics using a large number of natural gas and electricity price scenarios in a Monte Carlo simulation. The volatilities and correlations for these simulations are obtained from broker provided and historical data.~~

b. ~~Electricity Price Forecast~~

~~PG&E develops its electric price forecast by using electricity forward prices based on the evaluation date. Broker quotes currently extend out to 2015, and are collected and verified by PG&E's Risk Management Department. Beyond the first few near-term months, quotes are often quarterly or annual. PG&E uses these quotes to construct forward curves that are hourly in resolution. These electricity forward curves are then used by PG&E in its procurement activities (such as the solicitation for long-term resources), as well as for planning purposes. For this long-term plan, 2016 electricity prices are developed using the MPR gas price forecast for 2016, maintaining the same monthly relationship between electricity and gas prices as exhibited in 2011.~~

~~PG&E estimates its 95th percentile electricity price levels among other risk related metrics using a large number of natural gas and electricity price scenarios in a Monte Carlo simulation. The volatilities and correlations for these simulations are obtained from broker provided and historical data.~~

9. ~~PG&E's Hedging Strategy~~

~~PG&E's gas and electric hedging strategies for its electric portfolio, including execution strategy and timing, are described in detail in Volume 1, Section III.B and Volume 1, Attachment IIIA.~~

~~[19] As indicated in Volume 1, Section IV.D, PG&E has evaluated three candidate procurement plans under four scenarios which represent the uncertainty associated with load, market prices and the availability of resources, including the availability of the State's preferred resources.~~

10. PG&E's Use of the PRG Process

PG&E consults with the PRG on a wide range of transactions generally on a monthly basis, and sometimes more often as necessary ~~(approximately 10 meetings/year)~~. The Commission directed PG&E to consult with the PRG for specific types of transactions including: (1) overall interim procurement strategy; (2) proposed procurement contracts before the contracts are submitted to the Commission for expedited review; and (3) proposed procurement processes including but not limited to RFOs which result in contracts being entered into in compliance with the terms of the RFO.[21] Although the PRG acts in an advisory capacity only, PG&E actively solicits feedback from PRG members and incorporates that feedback into its procurement processes regularly. In particular, PG&E confers with the PRG on:

- **Procurement Plans and Customer Risk Tolerance:** PG&E provides the PRG regular updates of its portfolio position and risk. When the portfolio risk (measured at the 95~~99~~th percentile) exceeds 125% of the customer risk tolerance ("CRT"), PG&E meets and confers with the PRG to discuss the underlying risk drivers and factors affecting the change in portfolio risk and to decide whether specific hedging strategies and/or plan modifications are needed to reduce portfolio risk to within the CRT threshold.
- **Transactions That Begin More Than 3 Months Out, or Are More Than 3 Months in Length (D.04-01-050):** ~~Currently,~~ PG&E consults with the PRG at least once, and sometimes several times, on transactions greater than three months in length. PG&E discusses how transactions meet portfolio needs, solicitation processes, evaluation methods, negotiation processes and contract selection. ~~As described in Volume 2, Section II.A.1, in the 2006 LTPP, PG&E is requesting that PRG consultation only be required for transactions (including negotiated bilateral agreements) with delivery beginning greater than six calendar months or 2 quarters forward, or a term greater than six calendar months or 2 quarters forward (*i.e.*, increased from the current 3-month/3-month requirement). This will allow PG&E to act more quickly in response to market conditions, and will allow the PRG to focus on the transactions with the greatest impact on customers.~~

~~[20] Resolution E-3980, Appendix B, 2005 MPR California and Henry Hub Gas Forecast (2006-2031).~~

[21] D.02-08-071 at 24.

- **LTRFO Design and Administration (D.04-12-048 and D.07-12-052):** PG&E discusses both all-source and renewable RFOs with the PRG. Consultation with the PRG may encompass RFO design, the evaluation processes, short-list selection, negotiation strategy, and bid selection. ~~For the 2004 LTRFO, PG&E consulted with the PRG at least 15 times.~~

- **~~Gas~~ Hedging and Gas Supply Plans:** PG&E consults with the PRG before filing its DWR gas supply plans. PG&E also consulted with the PRG prior to presenting the ~~its Utility Gas H~~ hedging ~~Plans~~ plan in Appendix B to the Commission for approval.

- **Participation in a Generator Request for Bids (D.04-01-050):** PG&E consults with the PRG prior to making an offer in other Load-Serving Entity ("LSE") solicitations or generator requests for bids.

- **Long-Term Congestion Revenue Rights ("LT-CRRs") and Congestion Revenue Rights ("CRRs") (Resolutions E-4122 and E-4135):** PG&E discusses LT-CRR and CRR nominations and transactions with the PRG as required by Resolutions E-4122 and E-4135.

PG&E also takes advantage of the interactive nature of the PRG process to discuss a wide range of topics that it is not required to discuss with the PRG. For example, shortly after PG&E filed its 2006 ~~2004~~ LTPP, PG&E provided detailed briefing on the voluminous material in the long-term plan. PG&E has also provided educational sessions to the PRG on topics including credit, market valuation and portfolio fit, risk management and To-expiration-Value-at-Risk ("TeVaR"), and the principles and processes of gas hedging.

PG&E finds regular consultation with the PRG improves PG&E's and the PRG's understanding of the issues, enhances communication between the parties, and enhances the ultimate procurement decision-making process. Due to PG&E's ongoing dialogue with the PRG, PRG members have the opportunity to learn about challenges the utility faces contemporaneously, rather than hearing about them after the decisions have been made and submitted for Commission approval. PG&E also benefits from the PRG process because PRG members can advise the utility~~ies of potentially contentious issues or~~ on procurement activities prior to PG&E~~the utility~~ executing a transaction. ~~PG&E supports continuation of the PRG process, and thinks the Commission finding from D.03-12-062 is still relevant:~~

~~Though it only has consultative and informal advisory functions, the Commission finds the PRG to be an effective vehicle for IOU dialogue with Commission staff familiar with the nuances of their energy portfolios and the necessary policies/strategies needed to mitigate portfolio risks. The PRG has played a valuable role in identifying potential issues or concerns regarding IOU procurement. Perhaps the most significant achievement of the PRG process since its inception is the reduction of contested or litigated procurement transactions.~~[22]

11. ~~**Procurement Challenges and Barriers**~~

~~The Commission and Energy Division have made significant progress in eliminating procurement barriers since the utilities assumed procurement on January 1, 2003. As evidenced by the robust initial response in PG&E's 2004 LTRFO, PG&E does not believe that any significant barriers exist to long-term procurement. Specifically, PG&E received a large number of offers from well-qualified companies. PG&E's deposit and credit requirements struck a good balance between ensuring that there were a sufficient number of participants and that individual bidders were provided sufficient incentive to commit to their bid and project through the selection process.~~

~~Nevertheless, certain challenges remain. The following list contains examples of barriers, challenges or uncertainties PG&E (and other IOUs) may face when entering into contracts with new or existing resources.~~

- ~~**Cost Recovery:** PG&E looks for reasonable assurances it will be able to recover its costs of procurement contracts or the costs of ownership over the life of those contracts or facilities. If PG&E does not have a reasonable assurance at the time it considers entering into a PPA or utility ownership contract that it will recover all of its reasonably incurred costs, PG&E will be less inclined to make the resource commitments.~~

- ~~**Cost Allocation:** To the extent customers are able to avoid paying for their fair share of those contracts by choosing other suppliers or via self-generation, PG&E's risk profile increases and PG&E is less inclined to enter into agreements with new or existing resources.~~

- ~~**Cost Cap and 50/50 Sharing:** The cost cap and 50/50 sharing mechanism adopted by the Commission in D.04-12-048 creates an unlevel playing field for utility-owned~~

[22] ~~D.03-12-062 at 46.~~

~~generation and may create a barrier to utility-owned projects. The Commission has established a separate phase in this proceeding to address the cost cap and 50/50 sharing issues. PG&E intends to address the barriers created by the cost cap and 50/50 sharing mechanism in that separate phase.~~

- ~~**GHG Standards:** The evolution of GHG standards and regulation is an uncertainty which will present a set of additional considerations for PG&E as it contracts with fossil-fired resources, by monetizing the carbon emissions from the facilities or by requiring offsets to the carbon emissions. The use of an adder in evaluation is not a barrier, simply a consideration to assess the relative value of competing projects. Subject to implementing rules (*e.g.*, cap and trade), PG&E does not view the eventual institution of a GHG cap to be a barrier.~~

- ~~**Counterparty Risk:** When evaluating procurement transactions PG&E considers the financial strength and commercial capabilities of parties offering procurement contracts. Entering into contracts with risky counterparties can increase PG&E's financial risk profile or increase the risk that the resource will not be there when PG&E needs it.~~

- ~~**Transmission:** PG&E wants to be sure the power contracted for will be delivered where it needs the power. Lack of adequate transmission can be a barrier to contracting with a resource. In its 2004 LTRFO, PG&E required bidders to demonstrate firm physical delivery to NP15 and required bidders to obtain SIS and FS studies from the CAISO.~~

- ~~**Operating Characteristics:** PG&E and the CAISO need enough peaking and shaping resources across the ISO grid to reliably follow load and respond to resource outages. Resources that cannot provide operational flexibility will be less desirable to PG&E if it is specifically looking to fill those requirements.~~

- ~~**Permitting:** Problems with permitting a new resource, or retaining or renewing permits for an existing resource, can adversely affect project financing and operations.~~

- ~~**RA Rules:** RA rules can become a factor to contracting with a resource if that resource's capacity cannot be counted toward RA, or there is uncertainty as to their RA value.~~

- ~~**MRTU:** The locational marginal costs ultimately adopted in the CAISO's MRTU will encourage LSEs to contract with resources located in low marginal cost nodes and will discourage contracts with resources located in high marginal cost nodes.~~

- ~~**RPS Terms and Conditions:** The Commission has specified certain standard Terms and Conditions for RPS contracts and has specified that those Terms and Conditions are non-modifiable. This has led to difficulties in negotiating RPS contracts and concerns among developers. PG&E needs the flexibility in RPS negotiations to modify the Standard Terms and Conditions in appropriate circumstances. PG&E has raised this concern in R.06-05-027 and requested expedited consideration of the issue in that proceeding.~~

B. Risk Management Policy and Strategy

1. PG&E's Current Risk Management Practices

This section describes PG&E's current electric portfolio risk management practices. PG&E's electric portfolio risk management has evolved over time. PG&E's 2004 Short-Term Procurement Plan ("STPP") set out how the financial risks associated with the electric portfolio's open positions would be managed, including electricity and gas price risks.[23] In ~~mid~~ July 2005, PG&E formally expanded its price risk management process specifically for the gas component (*e.g.*, electric fuels) of the electric portfolio by implementing a gas hedging program [redacted].[24] PG&E's gas hedging plan was approved by the Commission in September 2005. Since September 2005, PG&E has updated its gas hedging plan twice, in Advice Letter 2723-E (effective November 1, 2005) and Advice Letter 2775-E (effective March 17, 2006).

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[23] D.03-12-062, PG&E 2004 Short-Term Procurement Plan, Chapter 3, Section E.

[24] *See* Advice Letter 2885-E, which was approved by the Commission on September 22, 2005, in Resolution E-3951.~~This gas program was filed and approved by the Commission in September 2005, and has been updated twice since that time. As provided for in Resolution E-3951, the updates to the hedging program have been approved by the Director of Energy Division~~.

PG&E submitted a proposed gas and electricity hedging plan with its 2006 LTPP. In D.07-12-052, the Commission did not approve the proposed gas and electricity hedging plan, but instead requested that the utilities work with the Energy Division and PRG to submit a revised risk management plan. Since D.07-12-052 was issued, PG&E has discussed its revised risk management plan for electricity and gas hedging with the PRG and Energy Division on several occasions and provided a draft of the revised electricity and gas hedging plan to both the PRG and the Energy Division. The revised electricity and gas hedging plan is included as Appendix B to the conformed 2006 LTPP. ~~This section provides an overview of PG&E's risk management practices. In its 2006 LTPP, PG&E is proposing additional price and physical risk strategies to augment its current practices.~~

a. ~~Short-term Electricity Price Risk~~

~~PG&E currently actively manages short-term electricity open positions covering the~~ [redacted] ~~using the process approved in the 2004 STPP. PG&E manages both short and long positions, measured in average megawatts for each monthly subperiod. The open position targets are shown below in Table Vol. 1, IIIB-1.~~

~~TABLE VOL. 1, IIIB-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~ELECTRICITY OPEN POSITION OPERATING TARGET RANGE~~
[redacted]

~~Line No.~~	~~Operating Target~~	[redacted]	[redacted]	[redacted]
~~1~~	[redacted]	[redacted]	[redacted]	[redacted]
~~2~~	[redacted]	[redacted]	[redacted]	[redacted]

~~When open positions fall outside the target range, PG&E will generally bring the position within the target range by executing transactions~~ [redacted]

[redacted]

[redacted]

~~Even by managing the portfolio within operating targets, there can be events that either cause the net open position to go beyond the operating target range immediately, or have the potential to cause large deviations from the operating target range within the short-term horizon. Examples of such events are extended force outages of major resources, major market disruptions, adverse hydro precipitation conditions and defaulting contracts. In such cases,~~ [redacted]

~~As part of the 2006 LTPP, PG&E is seeking to modify the term of its current electric open position operating targets so that they are consistent with the gas operating targets. This will make the management of the electricity open position consistent with management of the gas open position, as discussed in more detail in Volume 1, Section III.B.3.~~

b. ~~Gas Price Risk~~

~~PG&E actively manages the gas position of the electric portfolio~~ [redacted] ~~PG&E's initial gas price risk hedging authority was approved in the 2004 STPP. In early 2005, PG&E~~ [redacted] ~~developed and implemented an expanded gas hedging plan~~ [redacted] ~~The current gas operating targets are shown in Table Vol. 1, IIIB-2. The manner in which these targets are developed, re-evaluated and updated is discussed in Volume 1, Section III.B.3~~

~~below. The gas hedging strategy is currently under periodic Energy Division review that began in mid-2005 through an Advice Letter review process.~~[26]

~~TABLE VOL. 1, IIIB-2~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~GAS OPERATING TARGETS~~ [redacted]
~~(PERCENT HEDGED)~~

~~Line No.~~	~~Operating Target~~	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
~~1~~	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

~~As with the electric position, there can be events that either cause the gas open positions to go beyond operating targets immediately, or have the potential to cause large deviations from the operating targets within the short-term horizon. Examples of such events are addition of non-gas resources to the portfolio, major market disruptions, and above normal hydro conditions. In such cases~~ [redacted]

~~As part of the 2006 LTPP, these current practices are being augmented with the creation of longer-term electric open position operating targets that are consistent with the gas operating targets. This makes the management of the electricity open position consistent with~~

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[26] ~~This gas program was filed July 15, 2005 (AL 2685-E) and approved by the Commission on September 22, 2005 (Res. E-3951), and has been updated twice since that time (AL 2723-E and AL 2775-E). As provided for in Resolution E-3951, these updates to the hedging program have been approved by the Director of the Commission's Energy Division. When the 2006 LTPP is approved, a separate gas hedging plan will no longer be necessary as this will be encompassed within this Procurement Plan.~~

[27] [redacted]

~~management of gas open position. This is also discussed in more detail in Volume 1, Section III.B.3.~~

c. ~~Considerations for Physical Supply Risk~~

[redacted] ~~The purpose of the long-term gas strategy is to address longer-term physical gas objectives.~~

~~Similarly, there are a few physical supply requirements related to electricity. The first is the month-ahead requirement for at least 95% of the forecast load over the month to be physically covered by resources and contracts. Another physical requirement stems from RA requirements. While not requiring availability of resources to the utility, maintaining RA levels ensures sufficient contingency for the CAISO that it will have resources to dispatch to meet load under the vast majority of situations.~~

[redacted]

2. Portfolio Risk Assessment and Customer Risk Tolerance

PG&E's ability to manage its open position exposure in electricity and gas are affected by numerous risks, including: price, market liquidity, model, and credit.

First, with regard to price risk, to the extent that electricity and gas commodity prices rise or become more volatile, it makes managing financial exposure more difficult, requiring greater portions of the portfolio to be forward hedged in order to prevent potential large movements in future electric portfolio costs. Among the challenges are balancing how much to hedge, when to hedge and what products to use to hedge the exposures.

Second, PG&E faces market liquidity risk. Depending on the quantity of forward hedging and the hedge products desired, prices could move when the hedging is being implemented. When there is lack of market depth, this movement could be significant. One way to mitigate that risk is to establish hedge strategies whereby desired hedging quantities and execution timing are unlikely to cause this to happen.

Third, PG&E can be affected by model risk. Model risk relates to the risks involved in using models to value and hedge assets and commodities. Often, PG&E's portfolio positions are not directly traded in any marketplace. In this situation, models are used to estimate value, select hedging targets, and measure portfolio risk. Included in this is the risk of estimating, extrapolating, or forecasting inputs needed for portfolio evaluation: energy demand, hydro supply, forward prices, volatilities, and correlations. Model risk is addressed by performing sensitivity studies ~~and the development of robust hedging strategies~~.

Finally, PG&E can be affected by credit risk. Since returning to procurement, PG&E's credit department has employed a credit policy whereby all transactions with counterparties are subject to term and dollar~~volume~~ limits. Generally, these limits are based on collateral thresholds, credit ratings, and the policies that other companies have agreed to in posting to minimize credit risk, which is another form of financial risk of the electric portfolio. This is another means of controlling the financial risk of the electric portfolio. [redacted]

~~Currently,~~ PG&E ~~is required to~~ reports its electric portfolio TeVaR to the Commission's Energy Division on a monthly basis~~Commission~~. Consistent with D.07-12-052, PG&E measures TeVaR as the potential change in portfolio costs under a low probability (5~~1~~%) outcome or a 95% confidence level. ~~It reflects a potential (large) cost outcome over the next 12-month period relative to the mean cost.~~ ~~This cost~~ This measure assumes that no further forward hedging is performed, and that all existing positions are taken to delivery. In addition, D.03-12-062 requires PG&E to notify and meet and confer with the PRG if between quarterly PRG consultations, PG&E's estimated portfolio risk exceeds 125% of the Customer Risk Tolerance level which the Commission set at ~~The TeVaR reporting level is set at 1.25 times~~ a one cent per kWh impact to retail rates, which over the prompt 12-month period is approximately [redacted]

~~To further manage its portfolio risk, PG&E established as part of its procurement practice operating targets~~ [redacted] ~~While the TeVaR exposure of the electric portfolio has yet to reach this level, it has gotten quite close recently~~ [redacted] ~~given the high market volatilities.~~

~~This is the current Procurement Plan or regulatory measure that is tied to guidelines for managing portfolio risk. There are other Procurement Plan principles, such as the 95% of total load being covered in the prompt month, but that is more of a physical requirement because it has nothing to do with open position coverage, but rather having the physical capability to meet on a planning basis at least 95% of the expected load for the upcoming month.~~

3. ~~Electric and Gas Portfolio Hedging Targets~~

~~In Volume 1, Section III.B.1, PG&E described its current risk management practices, including an overview of its current electric and gas hedging targets. In the 2006 LTPP, PG&E expands on its current practices by proposing a more comprehensive risk strategy that integrates~~

~~both the electricity and gas components of the electric portfolio. As a part of this proceeding, PG&E requests that the Commission approve this expanded hedging program, including both its gas hedging program and the complementary electricity hedging program. The remainder of the portfolio hedging discussion is contained in Attachment IIIA.~~

4. PG&E's Credit and Collateral Requirements

The Commission has not established specific rules for customer risk that apply to credit. PG&E's credit and collateral requirements evolved from accepted energy industry practices, including concepts that can be found in EEI, NAESB, and ISDA master agreements. The primary elements of PG&E's credit and collateral requirements include: collateral thresholds (unsecured credit lines), collateral posting for sales of gas and power, and mark to market posting to cover the change in value of the contract relative to the market. The general goal is to protect the customer against the risk of default by parties ("counterparties") with whom PG&E enters into wholesale commodity transactions or hedging transactions. PG&E's credit risk management process includes: creditworthiness evaluations, collateral requirements for various types of transactions, and the level of collateral authority. Each of the aspects of the credit risk management is described below:

- **Creditworthiness** – PG&E manages the credit risk regarding its counterparties by assigning unsecured credit limits or unsecured credit thresholds to them based on PG&E's assessment of their financial condition, market and industry position, industry volatility and outlook, credit standing, and other credit criteria, as deemed appropriate. PG&E periodically reviews the assigned unsecured credit limits to assess their appropriateness in relation to the then-current credit quality of the counterparty.

- **Counterparty Collateral Requirements** – If a counterparty is a rated entity (*e.g.*, the debt of the entity is rated by S&P, Moody's or Fitch) assigned a credit rating below investment grade (for example investment grade is considered BBB- or above by S&P or Baa3 by Moody's) or is a "non-rated entity" not considered creditworthy by PG&E, then PG&E generally will require the counterparty to provide acceptable credit support. Such credit support can be in the form of a cash deposit, guaranty from an investment grade entity, or a letter of credit from an acceptable credit support provider, in form and substance satisfactory to PG&E. For creditworthy counterparties, PG&E establishes a specified unsecured credit limit beyond which posting of acceptable credit support is required. Some of the specific collateral requirements that apply to various categories of transactions are described below.

- **Renewable Contracts (New)** – Renewable counterparties are required to post a bid deposit of $3 per kW; a development and construction period deposit of up to $20 per kW for a dispatchable project or $20 per kW multiplied by the greater of: (i) the capacity factor; or (ii) 0.5; and 6, 9, or 12 months of the average ~~expected~~ revenue (for 10, 15, and 20 year terms) once commercial operations begin.

- **Resource Adequacy (RA)** – Resource adequacy counterparties (rated as non-investment grade) are generally required to post 25% to 33% of annual capacity payments particularly when RA is a clearly identified component.

- **Intermediate Term Tolling, Forward or Option Contracts** – Intermediate term tolling counterparties are subject to mark to market posting (this amount is generally capped). In addition if the counterparty is below investment grade or is unrated, it may be required to post an independent amount.[28]

- **Long-Term Tolling Contracts (New)** – Long-term tolling counterparties are required to post a bid deposit of $5 per kW; post an additional $10 per kW when an executed contract is submitted to the Commission (for a total of $15 per kW); a developmental and construction period deposit of $85~~60~~ per kW at the time the Commission approves the contract (for a total of $100 per kW); and once commercial operations begin the counterparty is subject to mark to market posting (this amount is capped and the cap depends on the technology).

- **Short-Term Transactions** – Short-term transactions include hour-ahead, day-ahead, balance of the month, multi-month, and swing deals. Exposures from purchases and sales of power and gas are tracked daily. Collateral requirements are governed by the master agreements under which these transactions are executed.

- **IOU Collateral Authority** – D.04-10-037 grants PG&E, among other things, authority to issue up to $2.5 billion[29] of short-term debt, subject to the restriction that $500 million of that authority may only be used for the following purposes:

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[28] An independent amount is a flat amount of collateral posted to cover market movements between collateral calls. If the counterparty defaults in between collateral calls (collateral calls typically are made daily or weekly) and fails to post the required margin, the utility can use the independent amount to cover some or the entire shortfall.

[29] On November 9, 2006, the Commission approved PG&E's petition to modify D.04-10-037, granting PG&E requested authority to issue up to $2.5 billion of short-term debt.

– Procuring natural gas for PG&E's customers during price spikes.[30]

– Procuring electricity for PG&E's customers during price spikes.

– Responding to major natural disasters, large scale terrorist attacks, or other cataclysms.

– Providing liquidity during a major disruption of PG&E's ability to bill, collect, and/or process utility customer bills.

Given these restrictions, PG&E effectively has $2.0 billion of general short-term debt authority, with the additional $500 million of authorization reserved for the foregoing specified contingencies.

C. ~~Fuel Supply Procurement Strategy~~

1. ~~Natural Gas Procurement Needs and Strategies~~

~~In order to meet the growing natural gas needs for PG&E's portfolio of gas generation and tolling agreements, PG&E is proposing the development of a portfolio of gas assets in 2007. PG&E's forecast need for natural gas is based on the generating units and tolling agreements that PG&E must procure gas for. These units and contracts are described fully in Volume 1, Appendix IIIB and summarized in the table below.~~

~~TABLE VOL. 1, IIIC-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~ELECTRIC PROCUREMENT GAS-FIRED UNITS AND TOLLING AGREEMENTS~~

~~Line No.~~	~~Unit Name~~	~~Portfolio~~
~~1~~	~~Bullard~~	~~PG&E Tolling Agreement~~
~~2~~	~~Humboldt Replacement~~	~~PG&E Owned~~
~~3~~	~~Calpeak Firebaugh~~	~~PG&E Tolling Agreement~~
~~4~~	~~Cinergy Firebaugh~~	~~PG&E Tolling Agreement~~
~~5~~	~~PG&E Colusa~~	~~PG&E Owned~~
~~6~~	~~Generic Combined Cycle~~	~~Generic Model~~
~~7~~	~~Generic Combustion Turbine~~	~~Generic Model~~

[30] D.04-10-037 defines the commencement of a "price spike" as an increase in the price of gas or electricity of at least 50% over the average of the preceding 12 months.

~~Line No.~~	~~Unit Name~~	~~Portfolio~~
~~8~~	~~Calpine Russell City~~	~~PG&E Tolling Agreement~~
~~9~~	~~PG&E Contra Costa 8~~	~~PG&E Owned~~
~~10~~	~~Generic Shaping~~	~~Generic Model~~
~~11~~	~~Hayward Black Hills~~	~~PG&E Tolling Agreement~~
~~12~~	~~Humboldt Bay (existing)~~	~~PG&E Owned~~
~~13~~	~~Calpine 3~~	~~CDWR Tolling Agreement~~
~~14~~	~~Calpeak Panoche~~	~~CDWR Tolling Agreement~~
~~15~~	~~Calpeak Vaca Dixon~~	~~CDWR Tolling Agreement~~
~~16~~	~~GWF I (Hanford) and II (Henrietta)~~	~~CDWR Tolling Agreement~~
~~17~~	~~GWF III (Tracy)~~	~~CDWR Tolling Agreement~~
~~18~~	~~PPM Klamath Falls~~	~~CDWR Tolling Agreement~~
~~19~~	~~Wellhead Gates~~	~~CDWR Tolling Agreement~~
~~20~~	~~Wellhead Panoche~~	~~CDWR Tolling Agreement~~
~~21~~	~~Mirant Contra Costa 6~~	~~PG&E Tolling Agreement~~
~~22~~	~~Mirant Contra Costa 7~~	~~PG&E Tolling Agreement~~
~~23~~	~~Mirant Pittsburgh 5~~	~~PG&E Tolling Agreement~~
~~24~~	~~Mirant Pittsburgh 6~~	~~PG&E Tolling Agreement~~
~~25~~	~~Morro Bay 3~~	~~PG&E Tolling Agreement~~
~~26~~	~~Morro Bay 4~~	~~PG&E Tolling Agreement~~
~~27~~	~~Mirant Pittsburgh 7~~	~~PG&E Tolling Agreement~~
~~28~~	~~Kings River Conservation District~~	~~CDWR Tolling Agreement~~
~~29~~	~~Wellhead Fresno~~	~~CDWR Tolling Agreement~~
~~30~~	~~Moss Landing 6~~	~~PG&E Tolling Agreement~~
~~31~~	~~Moss Landing 7~~	~~PG&E Tolling Agreement~~
~~32~~	~~Open from Existing~~	~~Generic Model~~

~~In order to satisfy these needs, PG&E has developed a gas supply plan. PG&E's Gas Supply Plan is described in confidential Attachment IIIB.~~

2. ~~Nuclear Fuel Procurement Needs and Strategies~~

~~In addition to strategies for natural gas procurement, PG&E is also proposing a nuclear fuel procurement plan in the 2006 LTPP. In order to support the ongoing operation of DCPP, PG&E purchases nuclear fuel materials. The requirements for each cycle of operation are determined by the length of the cycle. Nuclear fuel consists of four elements: uranium, conversion services, enrichment services and fabrication. PG&E contracts for all four of these elements to produce nuclear fuel specific to the requirements of DCPP.~~

~~PG&E's proposed nuclear fuel procurement plan includes a nuclear fuel materials and services procurement strategy for the period 2007 through 2016. The nuclear fuel plan~~

~~identifies the total quantity of fuel materials and services that are required to support ongoing operation of Diablo Canyon and the quantity distribution over the period 2007 through 2016. PG&E's plan also includes a proposal for establishing a strategic inventory ("SI") of final enriched uranium product to mitigate risk of supplier non-delivery or acts of Force Majeure, and includes measures to manage price and credit risk. The results of PG&E's proposed nuclear fuel procurement plan will be reviewed annually for compliance through the ongoing Energy Resource Recovery Account ("ERRA") proceedings. PG&E's Nuclear Fuel Procurement Plan is confidential and is contained in Attachment IIIC.~~

III. LONG-TERM PROCUREMENT RESOURCE PLAN

This section summarizes the load and resource assumptions for PG&E's service area need which were adopted by the Commission in D.07-12-052 in Table PGE-1. Table PGE-1 is reproduced in Appendix A.

A. Load Forecasts (Appendix A, Table PGE-1, Lines 1-2)

As directed by the Commission in D.07-12-052, the load forecast in Table PGE-1, lines 1-2, is based on the CEC's 2007 Integrated Energy Policy Report ("IEPR") 1-in-2 peak demand, which includes committed energy efficiency ("EE") and approximately 80% of uncommitted EE. The service area load forecast, line 2 includes PG&E bundled customers and current direct access ("DA") customers, but excludes current publicly-owned utility ("POU") customers located in NP26.

B. System Resources (Appendix A, Table PGE-1, Lines 3-12)

The CEC's Supply/Demand 5-year outlook[1] is the source for the 2007 base amount of existing generation resources in Table PGE-1, line 3. The CEC only considers known retirements in its 5-year outlook analysis. Additional retirements are itemized into two lines in PGE-1. Line 4 includes units that have announced retirement dates. This category includes the projected retirement of PG&E's existing HBPP facility. Line 5 provides a laddered reduction of aging units as described in the retirements section of D.07-12-052 (*see* D.07-12-052, Section 2.4.2) to reflect a measured retirement pace of approximately 600 MW per year beginning in 2009 until 4,200 MW are retired by 2015.

Resource additions to the CEC base amount of existing resources are shown in three categories: renewable resources that will increase from ongoing RPS requirements, non-RPS planned additions developed through PG&E's procurement process, and high probability additions expected to be on-line in the region.

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[1] CEC's *Revised Summer 2006 Demand and Supply Five Year Outlook,* June 30, 2006.

The NP26 RPS additions in Table PGE-1, line 6 reflect the capacity from future renewable generation additions. This includes generation procured by PG&E in its 2004 and 2005 RPS solicitations expected to become operational during the planning horizon and renewable additions based on the market availability of renewable resources to the NP26 region. The market availability of renewable resources is commensurate with the MWh amounts described in PG&E's RPS Plan for its bundled customers in Section IV.D. To account for the renewable resources available to POU customers within the NP26 region, the market availability of renewables is estimated to be 7.4% over the market availability for PG&E bundled load on an energy basis. By 2016, the total NP26 region RPS amount is 1,870 MW.

PG&E planned additions in Table PGE-1, line 7 include resources PG&E procured through from PG&E's 2004 LTRFO, which include plants in the Bay Area, Central Valley and Humboldt regions, along with the Gateway Generating Station. These PG&E planned additions result in an additional 2,851 MW in the region by 2010. Due to uncertainties regarding the development of these and other RPS and demand-side additions, in its March 5, 2007 filing, PG&E reduced this amount by 600 MW. (As directed by the Commission in D.07-12-052, line 19, Contract viability re-adjustment for PG&E's 2006 LTPP, gradually restores the full amount of those additions by 2012.)

High Probability California additions in Table PGE-1, line 8 represent approved new generating units in the region with an expected on-line date controlled by entities other than PG&E, including the 180 MW San Francisco peaker project, which is identified as a high probability addition. The generation from this project is shown beginning in 2009.

The Net Interchange into the NP26 region is based on several components. The first component, shown in PGE-1, line 9, includes 2,348 MWs of Northwest imports based on the CAISO estimate of import levels for RA.[2] The second component is additional imports from the Western Area Power Administration ("WAPA") to public entities within the CAISO NP26

[2] Supplemental Deliverability Study: Import Levels for Resource Adequacy (RA) Planning Purposes http://www.caiso.com/docs/2005/09/23/20050923165719616.pdf.

region which are estimated to be 700 MW. These additional imports are shown in Table PGE-1, line 10. The third component, Northwest ("NW") imports, are decreased to account for potential NW RPS imports already accounted for in Table PGE-1, line 6 as the NP26 RPS additions estimate includes potential Northwest renewable projects. These adjustments increase to 172 MW by 2016 and are shown in Table PGE-1, line 11. The final component is the exports to the CAISO SP26 region shown in Table PGE-1, line 12, which are based on the CEC 2006 Summer Outlook[3] assumption of 3,000 MW.

C. Service Area Specific Resources (Appendix A, Table PGE-1, Lines 16-19)

As directed by the Commission in D.07-12-052, the Uncommitted Energy Efficiency in Table PGE-1, line 16 represents the additional Uncommitted Energy Efficiency not captured in the CEC's demand forecast (approximately 20% of the total uncommitted EE goals plus a 10% line loss factor).

For purposes of this regional capacity analysis, DR programs are treated as supply resources. DR is split into two types: Price Sensitive Demand Response and Interruptible/Curtailable Programs. The Price Sensitive Demand Response in Table PGE-1, line 17 includes existing price responsive programs and the additional projected DR from the deployment of Smart Meter™ Program. DR increases from 342 MW in 2007 to 801 MW in 2016. Interruptible/Curtailable programs in Table PGE-1, Line 18 reflect existing DR programs. These existing programs are forecast to increase from 310 MW in 2007 to 353 MW in 2008 through 2016.

As directed by the Commission in D.07-12-052, the contract viability readjustment in Table PGE-1, line 19 replaces deductions for a 10% contract viability derate (600 MW) which, as previously discussed, were embedded in PG&E's original resource assumptions in line 7.

[3] CEC's *Revised Summer 2006 Demand and Supply Five Year Outlook*, June 30, 2006.

IV. PROCUREMENT STRATEGY BY RESOURCE

A. Introduction to Resource Acquisition Strategy

~~Pacific Gas and Electric Company's ("~~PG&E's~~"~~) 2006 ~~Long-Term Procurement Plan ("~~LTPP~~"~~) is designed to implement the state's Energy Action Plan ("EAP"), particularly the resource Loading Order, and the state's ~~Renewable Portfolio Standard ("~~RPS~~"~~) goals. It balances three primary objectives: (1) assembling a portfolio of reliable and operationally flexible resources; (2) supporting development of environmentally preferred resources; and (3) managing customer price and price volatility. In this section, PG&E describes its resource acquisition strategies for ~~energy efficiency ("~~EE~~"~~), ~~demand response ("~~DR~~"~~), renewables, distributed generation ("DG"), other generation including imports and the integration of transmission planning. This section also describes the authority PG&E currently has from the ~~California Public Utilities Commission ("~~Commission~~"~~) for each resource acquisition strategy~~, as well as authority that PG&E is requesting in order to implement the 2006 LTPP~~.

B. Energy Efficiency

1. PG&E's Pre-2006 Programs

PG&E has a long history of managing EE programs. Following Commission policy, PG&E pursued a strategy of acquiring EE as a resource in the early and mid-1990~~'~~s, of pursuing EE in order to transform the EE services markets during the period 1998-2001, and is now pursuing EE as a preferred resource in its procurement strategy consistent with the ~~Energy Action Plan ("~~EAP~~"~~). Over the years, PG&E has gained considerable expertise in designing and deploying EE programs. It has been able to develop strategies which address all customer groups. It has generally found that presenting EE in the context most familiar to the customer is most effective at achieving customers' positive response. PG&E has had significant success reducing consumption through EE programs. For example, during the 2004-2005 program authorization and funding cycle, PG&E achieved annual reductions of 1,166 gigawatt-hour ("GWh") and 357 ~~megawatt ("~~MW~~"~~).

2. PG&E's Approved Programs for 2006-2008

PG&E's 2006-2008 EE program portfolio was developed with input from PG&E's Program Advisory Group and ~~Peer Review Group ("~~PRG~~")~~ during 2005. PG&E filed its proposed portfolio in Application ("A.") 05-06-004 on June 1, 2005. The Commission approved PG&E's portfolio in ~~Decision ("~~D.~~")~~ 05-09-043, subject to a Compliance Advice Filing following completion of PG&E's competitive solicitation for third-party resources. PG&E ~~has~~ subsequently filed compliance advice letters detailing the comprehensive portfolio, including third-party programs, ~~modifying the plan,~~ on February 17, 2006 (Advice 24704-G/2786-E) and April 17, 2006 (Advice 24704-G-A/2786-E-A), respectively. These advice filings, and the annual MW and kilowatt-hour ("kWh") savings targets contained in the April 17 filing, were approved by the Commission on June 1, 2006. The annual savings targets for 2007-2008 are included in the 2006 LTPP ~~recommended plan~~. For the three years 2006-2008, PG&E's electric portfolio design is cost-effective and expected to achieve cumulative savings of 613 MW and 3,063 GWh by the end of 2008.

TABLE IV-1~~VOL. 1, VB-1~~
PACIFIC GAS AND ELECTRIC COMPANY
ENERGY EFFICIENCY SAVINGS, 2006-2008

Line No.		2006	2007	2008	Total
1	Total Annual Electricity (GWh/yr)	677	1,125	1,261	3,063
2	Total Peak Savings (MW)	132	223~~222~~	258	613

Note: Includes savings from low income energy efficiency programs.
Source: PG&E Advice 2704-G-A/2786-E-A, April 17, 2006, Attachment II, Table 1.1: Projected Program Impacts by year.

To achieve these high levels of savings, and lay the foundation for sustained high delivery as called for by the Commission's adopted targets, PG&E developed a market oriented program approach and proposed to the Commission the following, market-based portfolio:

- Resource market segments:
  - Mass Market (residential and small commercial customers)

Projected Net Program Impacts	
GWh	1,728
MW (Summer Peak)	334
MM Therms	15.9

The Mass Market is comprised of single family residential retrofit, multifamily residential retrofit, commercial and residential renters, and small commercial customers who have similar purchasing patterns and strategies, use the same vendors, and have similar approaches to energy efficiency. An integrated approach to these customers, historically viewed as separate segments, provides greater penetration into the commercial market while eliminating artificial boundaries and barriers thus providing for easier program delivery and expanded participation.

Vendors and contractors are ~~will be~~ a key delivery channel for the mass market sector, particularly for the direct install delivery channel. ~~, and integrates~~ This sector works with manufacturers, contractors, retailers and customers to maximize energy savings. PG&E ~~will~~ coordinates customer information, provides vendor/retailer/contractor support, and encourages manufacturer/distributor participation. Third parties and partnerships are ~~will be~~ integrated into the Mass Market program.

PG&E has identified the two largest areas of potential savings as lighting and heating, ventilation and air conditioning ("HVAC"). In addition, the Residential Low Income Energy Efficiency program serves over 55,000 homes a year with educational and direct installation services. Savings resulting from these activities are ~~will~~ also ~~be~~ included in the overall PG&E Portfolio.

- Targeted Markets:
  - Agricultural and Food Processing

Projected Net Program Impacts	
GWh	164
MW (Summer Peak)	23
MM Therms	3.1

This program targets the full range of agriculture and food processing customers. The program ~~will~~ addresses green field new construction and facility expansion and renovation as well as ongoing daily facility operation. Particular attention is ~~will be~~ given to key industry sub-segments identified as having high energy use and significant potential for efficiency improvement. The key sub-segments include wineries and dairies. Refrigerated warehouses, an activity that cuts across many of the agriculture and food processing market segments, have also been singled out for particular attention given their significant contribution to sector energy use and their potential for electricity and demand savings. ~~Two t~~Third-party implementers ~~will~~ focus on wineries, ~~two will focus on~~ customers with refrigerated warehouse facilities, and ~~one will focus on~~ dairies.

The majority of program marketing and outreach is ~~will be~~ conducted by PG&E ~~Account Services~~ staff and industry-specific consultants under contract to PG&E. The industry-specific implementers selected through PG&E's third-party solicitations ~~will~~ also provide marketing and outreach services to well-defined groups of customers within the agriculture and food processing market segments. All of these marketing and outreach efforts are ~~will be~~ coordinated through the PG&E Agriculture and Food Processing Segment manager.

– Schools and Colleges

Projected Net Program Impacts	
GWh	128
MW (Summer Peak)	29
MM Therms	2.6

The program design is based on the highly successful School Resources Program ("SRP") that has served K-12 public schools since 2003 and the 2004-2005 UC/CSU/IOU statewide partnership. SRP has evolved into a model that integrates seamless delivery of utility and state technical support and financial incentives programs to school districts. Most school districts and colleges are not subject to Title 24, and, therefore, may bypass energy efficient practices. The Division of the State Architect ("DSA") and the Office of Public School Construction are tightening their procedures, but in the past many school designs slipped past energy reviews. DSA is moving towards acceptance of Collaborative for High Performance Schools school performance standards for approval of all new school buildings. SRP will continue to support these efforts.

The UC/CSU/IOU Partnership ~~has also been determined to be~~ is the customer-preferred method for delivery of analytical and technical services to that sub-segment. Both programs have demonstrated the ability to overcome market barriers represented in this market sector. For 2006-2008, two- to four-year colleges are ~~will be~~ included in the program; independent private colleges in the PG&E service area are ~~will be~~ supported through a program design similar to that of the SRP, while selected public colleges are ~~will be~~ supported through a statewide program design similar to the present UC/CSU/IOU Partnership but coordinated with the Office of the Chancellor of California Community Colleges.

– Retail

Projected Net Program Impacts	
GWh	126
MW (Summer Peak)	21
MM Therms	0.02

The Retail program serves the diverse retail market segment including supermarkets, restaurants, big box retail and general retail. It ~~will~~ includes statewide elements (calculated incentives and deemed savings rebates) as well as elements specifically targeted to the energy needs of these customers (commissioning, retro-commissioning and demand response). This program ~~will~~ directly addresses the energy needs of big box retail, chain supermarkets and restaurants regardless of size in terms of kW demand. It ~~will~~ uses a team of retail and restaurant industry experts made up of internal staff and external contractors and consultants. This team

~~will~~ serve<u>s</u> as the point of contact and ~~will~~ coordinate<u>s</u> training and educational activities, marketing activities, audits if needed, design assistance, financial incentives, retro-commissioning and commissioning, information about distributed generation options and demand response efforts.

The majority of program marketing and outreach for the larger retail customers and large chain accounts <u>is</u> ~~will be~~ conducted by PG&E ~~Account Services~~ staff and industry-specific consultants under contract to PG&E. The industry-specific implementers selected through PG&E's third-party solicitations ~~will~~ also provide marketing and outreach services to well-defined groups of customers within the retail market segment, particularly mid-size and smaller customers not assigned individual PG&E account representatives. All of these marketing and outreach efforts <u>are</u> ~~will be~~ coordinated through the PG&E Retail Stores Segment manager.

<u>However,</u> PG&E's Mass Market program <u>is</u> ~~will~~ still ~~be~~ the primary delivery channel for the small retail stores and restaurants.

– Fabrication, Process and Heavy Industry

Projected Net Program Impacts	
GWh	475
MW (Summer Peak)	69
MM Therms	18.2

This program ~~will~~ address<u>es</u> green field new construction and facility expansion and renovation as well as ongoing daily facility operation. Particular attention <u>is</u> ~~will be~~ given to key industry sub-segments identified as having high energy use and significant potential for efficiency improvement. The key sub-segments include water and wastewater treatment, oil production, and oil refining. Boiler efficiency and compressed air efficiency, activities that cuts across many of the heavy industry market segments, have also been singled out for particular attention given their significant contribution to sector energy use and their potential for electricity and natural gas savings. ~~Eight t~~<u>Third</u>-party implementers ~~will~~ work within this market segment. ~~Three third-party implementers~~ They will focus on water and wastewater treatment, ~~and two third-party implementers will focus on~~ the oil industry, ~~. One third-party implementer will focus on~~ customers employing large boilers and ~~another will focus on~~ compressed air system efficiency improvements~~. The final third-party implementer will focus on~~, and the general industrial manufacturing sub-segment.

The majority of program marketing and outreach is ~~will be~~ conducted by PG&E ~~Account Services~~ staff and industry-specific consultants under contract to PG&E. The industry-specific implementers selected through PG&E's third-party solicitations ~~will~~ also provide marketing and outreach services to well-defined groups of customers within the Fabrication, Process, and Heavy Industries market segments. All of these marketing and outreach efforts are ~~will be~~ coordinated through the PG&E Fabrication, Process, and Heavy Industrial Manufacturing Segment manager.

– Medical Facilities

Projected Net Program Impacts	
GWh	69
MW (Summer Peak)	28
MM Therms	0.5

This program targets new and existing medical facilities using both PG&E and one currently selected third-party industry implementer to facilitate delivery of a portfolio of energy efficiency, demand response and distributed generation services. A new market integrated program effort ~~will~~ addresses the hospital segment, while PG&E's mass market effort ~~will~~ serves as the primary delivery vehicle for the medical office segment. The nursing home segment is ~~will~~ also ~~be~~ served by the mass market effort, although the market integrated approach ~~will~~ primarily addresses larger facilities that fall under the auspices of Office of Statewide Health Planning and Development review.

– High Technology Facilities

Projected Net Program Impacts	
GWh	45
MW (Summer Peak)	6
MM Therms	0.02

This program targets high technology facilities and their unique energy needs using both PG&E and third-party industry specialists to deliver a range of energy efficiency services. The program ~~will~~ addresses green field new construction and facility expansion and renovation as well as ongoing daily facility operation. The program ~~will~~ incorporates statewide financial incentive elements as well as elements specifically targeted to and customized for the high technology customers in PG&E's service area. Many high technology facilities, particularly electronics firms in the greater Bay Area, have significant lighting loads as well as office equipment and other plug loads. Energy efficiency opportunities within these more traditional end use categories are ~~will be~~ addressed by this program in conjunction with the Mass Market and Large Commercial programs.

Program marketing and outreach is ~~will be~~ conducted by PG&E ~~Account Services~~ staff, industry-specific consultants under contract to PG&E, implementers selected through PG&E's third-party solicitations, and local government partners. All of these marketing and outreach efforts are ~~will be~~ coordinated through the PG&E Hi-Tech Market Segment manager.

– Large Commercial

Projected Net Program Impacts	
GWh	220
MW (Summer Peak)	74
MM Therms	2.2

The Large Commercial program ~~will~~ primarily uses calculated energy savings incentive mechanisms. Upstream deemed or direct install measures may be used for office equipment. Much of the energy savings are ~~will be~~ oriented towards retrofit projects.

The overarching strategy is to work with the design community to make them aware of the value of integrated design strategies and the potential in high efficiency lighting, HVAC, and related technologies. This includes providing them with the tools to determine under what conditions the new strategies and technologies are appropriate, which approaches they can employ to move their clients, the building owners and managers, toward adoption of high efficiency technologies in the final designs.

The program team ~~will~~ continues to work directly with building owners through its direct relationships with large property management firms. This work ~~will~~ focuses on: (1) building support for the United States Green Building Council's Leadership in Energy and Environmental Design ("LEED") and green building concepts; and (2) in the case of government-owned office buildings, meeting State government desires to reduce in government building energy consumption. Third parties and partnerships are ~~will be~~ integrated into the Large Commercial program.

~~New for 2006 is a~~ During this program cycle there has been a new focus on workstation loads such as computers, video display terminals, printers, external disk drives, computer audio systems, telephones, under-cabinet task lighting, copiers, and faxes. These loads are growing to the point where they may equal the building load in power density (watts per square foot).

– Hospitality

Projected Net Program Impacts	
GWh	37
MW (Summer Peak)	8
MM Therms	0.03

This program targets new and existing lodging and hotel facilities using PG&E and ~~two~~ third-party industry specialists to facilitate delivery of a portfolio of energy efficiency services. It ~~will~~ includes statewide elements as well as elements specifically targeted to the customers in PG&E's service area. The market integrated program ~~will~~ addresses the energy needs of larger hotels, convention centers, and chains while PG&E's Mass Market program is ~~will be~~ the primary delivery channel for smaller hotels/motels and bed and breakfast inns.

The hospitality industry has substantial opportunity for energy efficiency. Remodeling in large hotels and corporate chains occurs fairly frequently, about every three to seven years, in order to remain competitive. Growth in this market sector is occurring in the Central Valley, coincident with economic and population growth, where air conditioning can be a significant load and advanced evaporative cooling could be a viable alternative to compressor based cooling.

– Residential New Construction

Projected Net Program Impacts	
GWh	13
MW (Summer Peak)	9
MM Therms	2.4

The California Energy Star New Home Program offers builders a choice of participating in a prescriptive or performance-based program. The performance-based program encourages and assists builders to incorporate energy efficient technologies and design in the homes they construct to exceed the California Title 24 Energy Efficiency Standards by 15 percent in both inland and coastal areas. In California, homes built to current Title 24 standards are 30 percent more efficient than homes built to the federal government's standards.

At this time, single family and low-rise multifamily building projects meeting the program requirements will also meet the requirements of the U. S. Environmental Protection Agency ("EPA") Energy Star® Homes Program. The EPA does not currently recognize high rise construction with the Energy Star label. The information gathered as a result of this program is shared with the EPA Energy Star®. The EPA is interested in the outcome of this program activity for possible future Energy Star® designation of multifamily buildings that are four or more stories.

- Non-resource programs ~~will~~ continue to be funded, including: education and training, emerging technologies, codes and standards, and marketing and outreach. PG&E's Education and Training program supports the Energy Training Center – Stockton, the Pacific Energy Center and the Food Service Technology Center. The emerging technologies program accelerates the introduction of innovative energy efficient technologies, applications and analytical tools. Codes and Standards Advocacy encourages the improvements to energy efficiency building codes and appliance standards through statewide codes and standards. Statewide Marketing and Outreach provides statewide energy efficiency marketing through three statewide agencies.

- Low Income Energy Efficiency ("LIEE") programs also contribute to the energy savings goals, but are funded separately from the energy efficiency programs. The LIEE programs have goals of 12 MW, 56 GWh, and 2.5 MM Therms.

In each area, program materials and efforts are ~~will be~~ tailored to address the specified interests and concerns in that market. In addition, over time, this approach will improve the integration of demand-side options available to the customer: energy efficiency, demand response, and preferred distributed generation, particularly solar. This gives the customer a wider array of options and improves both the resource value and the value of these programs to customers.

In D.05-09-043, the Commission authorized PG&E's new energy efficiency program portfolio structured around market segments and approved a 3-year implementation and funding cycle and a budget of $867 million. The Commission has also given PG&E increased flexibility to adjust programs and funding to meet customer demands and maximize the probability of reaching the savings targets.

To reach these customer segments, PG&E ~~will~~ employs three types of delivery channels: statewide and local government partnerships, competitively acquired third-party programs, and utility-delivered programs. ~~PG&E is currently completing contract development for the partnerships and first round of competitively acquired resources. All solicitations for third-party programs will be complete by the end of third quarter 2006.~~ PG&E has also integrated energy efficiency delivery with other demand-side resources such as Demand Response and the

Self-Generation Incentive Program ("SGIP") in order to achieve greater customer acceptance and better overall utilization of all these resources.

3. Programs for 2009 and Beyond

In ~~early~~ October 2007, the Commission issued D.07-10-032, which established the framework for the utilities to develop EE portfolio plans for the 2009-2011 time frame and ordered the California utilities to develop a joint Statewide EE Strategic Plan through 2020. D.07-10-032 also provided that the previously established energy savings goals for 2009-2011 would not be updated. ~~will begin a new cycle of assessing EE potential, reviewing savings targets and beginning portfolio and program planning for the 2009-2011 time frame. This latter process will include the first Commission-conducted studies of EE savings impacts. At this time, new energy savings targets have not been determined, and consequently PG&E's program strategies to achieve these updated goals are not finalized. The Customer Energy Efficiency ("CEE") cases described in Volume 1, Section IV.C.2, reflect the current status of these goals.~~ PG&E is currently in the process of ~~will review the Commission's new goals and studies when they are completed and will~~ developing programs to meet these goals. PG&E is fully committed to pursuing Customer Energy Efficiency ("CEE") opportunities as directed in D.04-12-048, Ordering Paragraph ("OP") 12. It considers CEE as an essential part of the 2006 LTPP. ~~and PG&E's recommended plan. The EE in PG&E's LTPP scenarios from 2009 to 2016 is shown in Table Vol. 1, IVC-2.~~[1]

C. Demand Response

In addition to EE, PG&E also fully supports demand response and believes it is appropriately placed along with energy efficiency and renewable resources as a priority resource in the EAP's Loading Order. As of January, 2008, PG&E has approximately 1,066 MW of load enrolled in DR programs. ~~Over the past three years, PG&E has enrolled nearly 1,800 new participants in its demand response programs, representing approximately a 20%~~

[1] ~~The peak savings figures shown below are based on the definition for peak reduction adopted in D.06-06-063.~~

~~penetration rate for eligible customers.~~ PG&E intends to continue to aggressively promote demand response, not only increasing participation rates but also increasing load reduction per participant site. PG&E is ~~also~~ developing demand response programs for its residential and small commercial customer classes ~~beginning in 2007~~. PG&E believes that increasing DR automation will increase customer participation in DR programs and actual demand reduction when system conditions most need these resources.

~~On August 30, 2006, PG&E filed for enhancements to its existing DR programs. These program modifications generally are focused on making it easier for customers to participate in demand response through automation. PG&E believes that automation is critical to the successful implementation of DR when system conditions must rely on these resources.~~

PG&E's existing programs ~~and those currently proposed at the Commission~~ are described in some detail below. ~~PG&E intends to achieve its demand response goals through the implementation of the existing programs and the proposed enhancements. In addition, the~~ The rollout of ~~Advanced Metering Infrastructure ("AMI")~~the SmartMeter™ Program and its complementary Critical Peak Pricing ("CPP") program will provide additional demand-side resources. The deployment of the SmartMeter™ Program will enable further DR via a CPP program.

1. Existing Programs

In June 2005, PG&E filed a comprehensive listing of commercial and industrial~~[2]~~ DR programs covering years 2006-2008 in A.05-06-006. This application was settled among various intervening parties and approved by the Commission in D.06-03-024. ~~This set of programs serves a critical function in achieving required demand reductions over the next three years.~~ The Commission expanded and revised certain parts of the programs in late 2006 to increase available DR for 2007 and 2008, in light of the summer 2006 heat storm. PG&E's DR

~~[2] Customers with demands greater than 200 kW.~~

portfolio serves a critical function in achieving required demand reductions. The following is a description of PG&E's ~~existing~~ programs:

Business Energy Coalition (Schedule E-BEC): The Business Energy Coalition ("BEC") ~~is a demonstration~~ was originally a project intended to strengthen ties with major San Francisco business and civic leaders and their facilities. The program targeted~~s~~ office, hospitality, and high-tech sectors for DR participation and is designed using the group aggregation concept. In 2007, the BEC program was expanded to include hard-to-reach (*e.g.*, beyond office, hospitality and high-tech) customers outside of San Francisco.

Capacity Bidding Program (Schedule E-CBP): The Capacity Bidding Program ("CBP") ~~will~~ replaced the California Consumer Power and Conservation Financing Authority ("CPA")-Demand Response Program ("DRP") when it ~~is scheduled to be~~ terminated in March 2007. The CBP is available to retail commercial, industrial and agricultural accounts of all sizes. Customers may choose to enroll in CBP through an aggregator or ~~rather than~~ directly with PG&E.

Critical Peak Pricing Program (Schedule E-CPP): The CPP program offers commercial/industrial customers greater than 200 kilowatt ("kW") an alternative to traditional Time-Of-Use ("TOU") rates. Customers on the ~~E-~~CPP program receive reduced energy rates for all non-CPP usage during on-peak and partial-peak time periods during PG&E's summer rate season, May 1-October 31. During CPP event days participants pay from three times their partial-peak rate to five times their normal on-peak rate. CPP event days are called based on the day-ahead forecasted temperatures or system reliability.

Demand Bidding Program (Schedule E-DBP): The Demand Bidding Program ("DBP") is a voluntary bidding program that ~~is~~ may be triggered on a day-ahead basis when by 3 p.m. the ~~California Independent System Operator ("~~CAISO~~")~~ has issued an Alert for the following day or when the CAISO's forecasted peak demand is expected to ~~meet or~~ exceed 43,000 MW. When notified of an event, participants can voluntarily bid-in the amount of load reduction that they wish to commit for the next day. Participants can earn an incentive for qualifying load reduction based on the forecasted hourly energy price plus an adder. In 2007, this program was modified to include a day-of event option. The day-ahead option may be triggered when the CAISO issues an energy warning or greater. Participants can earn an incentive for qualifying load reduction.

Technical Assistance (TA)/Technical Incentive (TI) Programs: The Technical Assistance Program ("TA") offers customers engineering assistance to help identify how, and by how much, customers may be able to reduce demand under a PG&E~~'s~~ DR or reliability program. PG&E provides a high-level facility evaluation identifying specific end uses where demand might be shifted or temporarily reduced. The audit is provided at no cost to the customer or, if the customer prefers, PG&E will offer to pay the customer up to $100~~50~~ per kW of identified DR capability for a third-party audit. The Technology Incentives Program ("TI") offers customers cash incentives for installing demand responsive equipment and/or control software. The combined programs ("TA/TI") are open to projects involving qualifying medium and large commercial, industrial and agricultural customers. Demand responsive hardware and software investments that enable customers to participate in programs qualify for incentive payments of up to $250~~100~~ per kW of verified load reduction capability. ~~Customers must participate in either the CPP or DBP program to qualify for the entire rebate amount.~~

Auto-DR Program: The Auto-DR Program helps customers to identify demand reduction strategies such as managing lighting and HVAC systems, where electrical usage can be reduced or even eliminated during times of high electricity prices or electricity system emergencies. These demand reduction strategies are then pre-programmed into each customer's building energy control systems. A signal is automatically sent by the utility via internet to these energy control systems during times of high electricity prices or system emergencies, which initiates a series of pre-programmed, pre-authorized demand reduction strategies. Automated hardware, software and technical assistances investments that enable customers to participate in DR programs qualify for incentive payments of up to $300 per kW of verified load reduction capability.

Non-Firm Service Program: The Non-Firm Service Program ~~is~~was a rate option under Schedules E-19 and E-20~~ and S~~. Pursuant to D.07-09-004, the program was closed effective January 1, 2008. ~~The program is currently closed to new participants. The Non-Firm Service Program gives participants the ability to provide load reduction during periods when the CAISO determines there is a need for demand/energy reduction. Participation in curtailment events is mandatory. A customer receives energy and demand rate discounts for being on the program as is prescribed in the schedule. If a customer is requested to curtail their usage and fails to reduce their load to or below their Firm Service Level, a substantial penalty is applied. This program also has an underfrequency relay ("UFR") option where customers will be automatically interrupted, through the operation of an underfrequency relay, if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. Participants receive an additional discount for being on the UFR option.~~

Base Interruptible Program (Schedule E-BIP): The Base Interruptible Program ("BIP~~BPI~~") is intended to provide load reductions on PG&E's system when the CAISO issues a curtailment notice. This program is very similar to the Non-Firm Service program ~~but with less risk to the customer~~. Option A ~~P~~participants receive a monthly incentive payment based on the difference between their average demand and their Firm Service Level. Customers receive 30-minute notice, and i~~I~~f a customer is requested to curtail ~~their~~ its usage and fails to reduce ~~their~~ load to or below ~~their~~ the customer's Firm Service Level, a substantial penalty is applied. Option A participants also have an underfrequency relay ("UFR") option where they will be automatically interrupted, though the operation of a UFR, if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. Participants receive an additional discount for being on the UFR option. Option B p~~P~~articipants receive 4-hour ~~can choose either a 30-minute or 3-hour~~ notice for events and receive an energy payment for any reductions. There is no penalty for failing to reduce load~~a $7/kW/Month or $3/kW/Month incentive respectively~~.

Air Conditioning Direct Load Control Program: Air Conditioning ("AC") direct load control will be an integral part of PG&E's future demand-side portfolio. AC load is one of the primary drivers of California's summer peak usage. An AC program reduces demand from this end-use by employing technology that will "hard wire" a reduction of air conditioning demand. AC programs can be called on short notice (such as in an emergency situation) and provide an important resource for PG&E and the CAISO to maintain system reliability in times of peak usage. In 2007, the Commission approved PG&E's request for a 5 MW AC program for summer 2007. The AC program has subsequently grown to 28 MW. On February 14, 2008, the Commission issued D.08-02-009, which approved the expansion of PG&E's AC direct load control program to approximately 305 MW by June 2011.

Request for Proposals and Contracts: PG&E issued a Request for Proposal ("RFP") for demand response proposals for up to five summer periods, beginning in summer 2007 to provide additional load reduction beyond that provided in PG&E's current DR programs. In D.07-05-029, the Commission approved five aggregated DR contracts that may provide up to 149 MW of load reduction by 2009.

2. Proposed Enhancements to PG&E's Demand Response ~~Existing~~ Programs

Cafeteria Style Menu: In July 2007, PG&E filed an advice letter requesting approval of a new demand response program called the Cafeteria Style Menu ("CSM") program for 2008. This program would increase enrollment in PG&E's existing DR programs and increase actual load reduction during a program event. PG&E forecasts that approximately 42 MW of DR may be achieved in 2008. The CSM program, unlike PG&E's other DR programs, would allow customers to choose several program characteristics to tailor a program to the customers' needs including the amount of load reduction, the event window, the event duration, the event notification time, and the number of consecutive events. On February 28, 2008, the Commission issued Resolution E-4127 approving the CSM program for 2008.

~~In August 2006, Commissioner Peevey issued two Assigned Commissioner Rulings that directed the IOUs to further enhance their DR efforts previously authorized in D.06-06-024 for years 2006-2008. The need for these DR program enhancements was tied to the July "heat~~

~~storms" and the unexpected high demands associated with that event. On August 30, in A.05-06-066, PG&E filed enhancements to its existing programs which are expected to provide an additional 235 MW of load relief for 2007 and ramping up to 720 MW in 2010. To achieve this additional DR reduction, PG&E proposed to expand several of its current programs through aggressive, targeted marketing efforts and, in some cases, additional monetary incentives. On November 30, 2006, the Commission issued a decision accepting some, but not all, of PG&E's proposed DR program enhancements.[3] As a result of this decision, PG&E will be able to achieve some of the additional demand response load relief it was anticipating, but not all 720 MW that it had projected.~~

~~The deployment of AMI will enable further demand response via a CPP program. PG&E forecasts its CPP program will provide between 210 and 450 MW by 2011.~~

~~The demand reductions resulting from PG&E's proposed programs and the program enhancements that were approved by the Commission are shown in Table Vol. 1, VC-1 for scenarios 1 through 4. Further information regarding the scenarios is presented in Volume 1, Section IV.D.2.~~

[3] ~~D.06-11-049.~~

~~TABLE VOL. 1, VC-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~DEMAND RESPONSE CAPABILITY, 2007-2016~~
~~(MW)~~

~~Line No.~~	~~Year~~	~~2007~~	~~2008~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~2016~~
~~1~~	~~Scenarios 1 and 2~~	~~779~~	~~1,021~~	~~1,194~~	~~1,362~~	~~1,387~~	~~1,394~~	~~1,397~~	~~1,401~~	~~1,405~~	~~1,409~~
~~2~~	~~Scenarios 3 and 4~~	~~779~~	~~1,072~~	~~1,332~~	~~1,573~~	~~1,628~~	~~1,643~~	~~1,652~~	~~1,661~~	~~1,670~~	~~1,679~~

~~A description of the proposed enhancements to PG&E's DR programs follows.~~

a. ~~Air Conditioning/Direct Load Control and Air Conditioning Cycling~~

~~Air Conditioning ("A/C") cycling will be an integral part of PG&E's future demand-side portfolio. Properly structured, A/C cycling programs can help facilitate both price responsive and reliability types of DR. Air conditioning load is one of the primary drivers of California's summer peak. An A/C cycling program can directly reduce demand from this end-use by employing technology that will "hard wire" a reduction of air conditioning demand. The benefit of A/C cycling programs is that they can be called on short notice (such as in an emergency situation) and provide an important resource for PG&E and the CAISO to maintain system reliability in times of peak usage.~~

~~PG&E believes that a switch based direct load control ("DLC") A/C cycling program and a thermostat set-back (*Smart Thermostat*) program are complementary to its AMI rollout and can help facilitate expanded enrollment in its price-responsive CPP program. Utility cycling of a customer's A/C unit via a switch or by increasing the thermostat temperature setting provides an automation feature that can reduce customer loads not only on a CPP day, but also on system emergency days that cannot be forecast a day in advance. This utility control feature should make the CPP program more attractive to those customers who would be less likely to participate in the program without a technology option to manage their reductions.~~

~~A/C cycling will also provide valuable DR alternatives for those who do not find the CPP program attractive. For instance, the Statewide Pricing Pilot ("SPP") research indicated that small commercial customers were not necessarily price responsive but could still provide DR with an enabling technology. PG&E's research also found that some mass market customers, including residential customers, may be unable to shift enough load on critical peak days to result in bill savings on PG&E's CPP program. An A/C cycling program may give these customers an opportunity to save money and reduce demand.~~

~~The AMI technology will also provide customers important information to enable them to measure their load reductions. Significantly, PG&E can utilize its AMI infrastructure to verify the demand reductions made by particular customers, as well as the magnitude of the overall reduction in demand due to the program. Given this functionality, PG&E can use a much less expensive "one-way" pager system to control the A/C switches. Therefore, PG&E believes that rolling out a full scale A/C program that will help met system needs well into the future during the implementation of AMI is an effective strategy.~~

~~The Commission approved PG&E's proposal in D.06-11-049.~~

b. ~~Request for Proposals and Contracts~~

~~PG&E issued a Request for Proposal ("RFP") for demand response proposals for up to five summer periods, beginning in summer 2007.~~[4] ~~The DR RFP would provide additional load reduction beyond that provided in PG&E's current DR programs. The RFP provides bidders a full opportunity to develop and propose innovative ways to increase DR in 2007 and 2008, such as energy bids, capacity bids or direct load control. PG&E will negotiate with the winning bidders for a final agreement. In addition, for large, unique wholesale customers, a directly negotiated bilateral contract may be negotiated outside the RFP process.~~

[4] ~~RFPs are used by other utilities to obtain DR. San Diego Gas and Electric Company ("SDG&E") recently included DR in an RFP. (SDG&E RFP All Source 2007-2009; DR, Renewables and Peak Capacity; Issued 05/24/2006) and in New York a DR RFP was recently issued (NYSERDA RFP for Large-Scale Demand Reduction Project; RFP 967; issued 07/13/2006). Nevada Power and Sierra Pacific Power are beginning a RFP process on August 29, 2006, for Integrated Demand-Side Management ("IDSM") including DR. PG&E's RFP would build on these efforts.~~

~~PG&E proposes that any resulting agreements that are submitted for review to the Commission through the advice-letter process be expedited, so that the DR resources can be put in place in time for summer 2007.~~

c. ~~Customer Back-Up Generators~~

~~PG&E proposed a new "Clean-Gen Program" for 2007 with an added feature to convert customer-owned generation units to run cleaner, and use the generators when necessary during CAISO stage 2 alerts. The program would only apply to customer generators used to back up their own internal site load, and not for generators that sell to the market or other entities. This proposed enhancement was rejected by the Commission in D.06-11-049.~~

d. ~~Modifications to the Demand Bidding Program~~

~~PG&E's DBP has the largest number of participants (850 customers), yet it yields only a fraction of the total demand response actually realized when called due to the voluntary nature of the program and lack of compliance penalties. To increase the participation in this program, PG&E proposes to increase customer incentives.~~

~~In addition, PG&E proposed adopting a "no bid" provision as part of its modifications to the DBP. This option would have allowed customers with loads exceeding 200 kW to engage in a DR program with little or minimal effort and prepare them for changes to be implemented in 2011.[5] This aspect of PG&E's proposal was not accepted by the Commission.~~

e. ~~Expansion of Business Energy Coalition Program~~

~~PG&E has requested authority to expand upon the successful and innovative BEC program in 2007, with the aim of achieving an additional 25 MW (50 MW total) of load reduction by June 1, 2007 through new enrollments of hard-to-reach customers. PG&E anticipates that the BEC, in close partnership with PG&E, will be able to build upon its current~~

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[5] ~~As directed by the Supplemental Scoping Memo (A.06-03-005) issued on July 25, 2006, PG&E will study the feasibility of CPP, TOU and Real-Time Pricing ("RTP") rates over the next few years, leading to a filing in Phase 2 of the 2010 General Rate Case ("GRC"). Since PG&E will not be integrating dynamic pricing tariffs into PG&E's rate design until 2011, PG&E believes now is the time to resurrect a program similar to E-SAVE.~~

~~participating customer base and enroll new hard-to-reach customers. In D.06-06-024, the Commission authorized an expansion of the BEC from 15 MW to 25 MW in 2008. In its August 30, 2006 filing, PG&E requested permission, in addition to expanding the program by 25 MW, to expedite the implementation of the BEC from 15 MW to 25 MW in 2007 rather than 2008 to achieve a total goal of 50 MW for summer 2007. In addition, PG&E has requested approval of a seven-year extension with the BEC to deliver an incremental increase in enrolled and participating DR targeted at 20 MW per year from hard-to-reach customers conditioned on Commission approval of funding. This proposal was accepted by the Commission.~~

f. ~~Expanding Technical Assistance and Technical Incentives and Automated Demand Response~~

~~PG&E's current TA/TI program has only had minimal impact on customers' participation in our DR programs. Customers have informed PG&E that the current incentive level of $50/kW for Technical Assistance and $100/kW for TI is not enough to merit serious consideration. PG&E has requested to increase the TA/TI incentive level significantly to "jump start" the market.~~

~~In addition, the more aggressive comprehensive TA assessment proposed by PG&E will include extensive review of customer facilities, not only including HVAC, lighting, and manufacturing equipment, but also possible re-wiring and controls scenarios. The assessment will also include a DR protocol list of the action items that need to be enacted when a DR event has been issued. In order to get the quality TA audits that are required for DR, PG&E proposes to increase the TA incentive level to $100/kW with a maximum incentive of $100,000. In addition, PG&E proposes to increase the TI incentive to $250/kW for the installation of the DR measures that will enable the customers to participate in our DR programs. The increase incentive level will further assist customers in the installation of equipment and controls that will allow the customers to curtail substantial load during event situations. As with the existing TI program, the incentive amount may not exceed the total cost of the project.~~

~~PG&E strongly supports enabling technology for DR programs and for the past two years has funded the Auto CPP Emerging Technology pilot program contracting with Lawrence Berkeley National Labs to conduct the research. Automation is essential to the long-term success of PG&E's DR portfolio and it is therefore appropriate to move from a pilot program to further develop automation and encourage the installation of enabling technologies for DR customers.~~

~~PG&E believes that the current TA/TI program is the proper channel to fund an "automation" program. Through the current TA/TI program, an integrated audit identifies potential DR measures, including those which may be automated, that may be applicable to a facility. The enabling equipment that is recommended by the audit would then be eligible for TA/TI program.~~

~~In order to encourage the installation of automatic DR technology, PG&E has recommended that an additional TI of $50/kW be applied to automated DR technology, bringing the total TI incentive for projects that included automated DR technology to $300/kW. The increased incentive would only be applicable to TI projects that would automatically take PG&E's DR event signals and implement a pre-established list of DR protocol using automated controls. Installation of the software, hardware and programming, would all be eligible for the enhanced automated DR incentive. This funding would be applicable for automated technology which facilitates any of PG&E's DR programs. This proposal was also accepted by the Commission.~~

g. ~~Modification of the Base Interruptible Program and Reopening of the Nonfirm Program~~

~~To encourage increased load reduction during a Stage 2 emergency when Base Interruptible Program ("BIP") events are issued, PG&E proposes to ratchet the incentive payment upwards as the customers' monthly Potential Load Reduction ("PLR") amount increases. The monthly dollar per kW incentive would be as follows:~~

~~100 kW to 500 kW PLR~~	~~$8.00 /kW incentive~~
~~501 kW to 1 MW PLR~~	~~$8.50 /kW incentive~~

~~1 MW PLR or greater~~	~~$9.00 /kW incentive~~

~~The ratcheted incentive schedule should encourage customers to commit as much as possible to achieve maximum incentive levels. In addition, this ratcheting would provide an added incentive and ease the transition of Schedule E-NF customers to the BIP, which is currently proposed in PG&E's 2007 GRC to occur on January 1, 2008.~~

~~PG&E also proposes to replace its current Option B of E-BIP with an option modeled on the existing NYISO and PJM emergency DR products that utilize a high minimum energy price for the DR performance. This type of product sends a strong price signal for DR.~~

~~Over the years, PG&E's non-firm program has been the backbone of its DR efforts. In its August 30 filing, PG&E proposed re-opening the non-firm program. However, this proposal was not accepted by the Commission in D.06-11-049.~~

h. ~~Advanced Metering Initiative~~ <u>SmartMeter™ Program</u> Rollout

Residential and commercial DR resulting from the deployment of ~~AMI~~<u>the SmartMeter™ Program</u> is a critical element in increasing DR. PG&E received approval of ~~its AMI~~<u>the SmartMeter™ Program</u> application in D.06-07-027 and began full roll out of the advanced meters in Bakersfield in November 2006. The entire rollout will take approximately five years to complete. ~~PG&E has used a base case and a low case scenario to account for uncertainty in DR from AMI implementation.~~

~~The base case (in Scenarios 3 and 4) is based on PG&E's CPP rate design. It assumes a marketing effort of $18 million to educate and increase customers' general awareness of the AMI meter installations and an aggressive marketing plan. The marketing plan includes additional marketing expenditures of $55 million targeted at customers most likely to have air conditioning load in hot, inland areas. With the combined general education and aggressive target marketing efforts, PG&E estimates a participation rate of 35% of the target residential market and 27% of the target small and medium commercial and industrial market. Together these levels of participation are expected to produce DR of approximately 450 MW by 2011, with a steady increase in subsequent years.~~

~~Participation of customers in the CPP rate and elasticity of customer response are two key uncertainties in the valuation of the DR benefits. PG&E created a low case (in Scenarios 1 and 2) to test the sensitivity of the results to these uncertainties. The low case produced a range of DR from approximately 210 MW by 2011, with small increases in subsequent years.~~

D. Renewable Energy Procurement Strategy

PG&E strongly supports renewable resources and renewable energy's preference in the State Loading Order. PG&E recognizes the distinct environmental attributes that eligible renewable resources provide to its customers. Since the beginning of the RPS program, PG&E has signed contracts totaling over 2,100 ~~1,000~~ MW of capacity that will be capable of producing 8,300~~5,600~~ GWh per year, or approximately 10~~8~~% of PG&E's forecast 2010 ~~2005~~ bundled retail sales.

PG&E intends to continue to aggressively pursue renewable energy procurement throughout the planning horizon of the 2006 LTPP to meet and exceed renewable targets set in SB 107 and Commission decisions. PG&E also anticipates developing new programs such as the Emerging Renewable Resource Program ("ERRP") ~~described below and in Volume 2, Section I.B.6,~~ in order to further facilitate the development of available renewable energy resources.

1. PG&E's Existing Renewable Resources

PG&E filed its August 2007~~6~~ RPS compliance report on August 1, 2007~~2006~~.[6] This report shows RPS-eligible renewable deliveries for 2006~~2005~~ of approximately 9,114~~8,800~~ GWh. These renewable deliveries came from resources that pre-date the RPS program and resources that PG&E has contracted with since the RPS program commenced in 2002. ~~PG&E provides a more detailed description of its existing renewable resources in~~

[6] ~~Compliance Filing of Pacific Gas and Electric Company (U 39-E) Reporting Progress Toward Achievement of Annual Procurement Target for Renewable Generation Pursuant to~~ Renewable Portfolio Standard Periodic Compliance Report of Pacific Gas and Electric Company (U 39-E), filed in R.06-05-027, August 1, 2007~~2006~~.

~~Volume 1, Section IV.C.2. PG&E will update volumes of 2006 renewable resource deliveries in its April 2007 RPS compliance report.~~

2. PG&E's Plan to Increase Renewable Resources

PG&E also intends to aggressively pursue RPS targets through annual RPS solicitations and bilateral agreements. PG&E will offer renewable developers a number of procurement options including power purchase agreements, turnkey and buyout options, and greenfield development, in order to offer flexibility to renewable resource developers and to identify the mechanisms which are in the best interest of PG&E customers. PG&E's specific plans to increase renewable energy are described below. ~~PG&E's 2006 LTPP scenarios contain the forecasted renewable capacities, as shown in Table Vol. 1, VD-1 below.~~

~~TABLE VOL. 1, VD-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~PG&E FORECAST RENEWABLE RESOURCE CAPACITY~~
~~(MW)(a)~~

~~Line No.~~	~~Year~~	~~2007~~	~~2008~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~2016~~
~~1~~	~~Basic Procurement Plan/Increased Reliability Scenario 1~~	~~0~~	~~260~~	~~520~~	~~980~~	~~1,400~~	~~1,800~~	~~2,100~~	~~2,400~~	~~2,700~~	~~2,800~~
~~2~~	~~Basic Procurement Plan/Increased Reliability Scenario 2~~	~~0~~	~~260~~	~~520~~	~~1,000~~	~~1,500~~	~~2,000~~	~~2,500~~	~~2,700~~	~~2,700~~	~~2,800~~
~~3~~	~~Basic Procurement Plan/Increased Reliability Scenario 3~~	~~0~~	~~260~~	~~520~~	~~1,000~~	~~1,500~~	~~2,000~~	~~2,500~~	~~3,000~~	~~3,300~~	~~3,600~~
4	~~Basic Procurement Plan/Increased Reliability Scenario 4~~	~~0~~	~~260~~	~~520~~	~~1,000~~	~~1,600~~	~~2,200~~	~~2,900~~	~~3,300~~	~~3,800~~	~~4,300~~
~~5~~	~~Increased Reliability and Preferred Resources Plan Scenario 1~~	~~0~~	~~260~~	~~520~~	~~980~~	~~1,400~~	~~1,800~~	~~2,100~~	~~2,400~~	~~2,700~~	~~2,900~~
~~6~~	~~Increased Reliability and Preferred~~	~~0~~	~~260~~	~~520~~	~~1,000~~	~~1,500~~	~~2,000~~	~~2,500~~	~~3,000~~	~~3,400~~	~~3,900~~

	~~Resources Plan Scenario 2~~										
~~7~~	~~Increased Reliability and Preferred Resources Plan Scenario 3~~	~~0~~	~~260~~	~~520~~	~~1,000~~	~~1,500~~	~~2,000~~	~~2,500~~	~~3,000~~	~~3,400~~	~~3,900~~
~~8~~	~~Increased Reliability and Preferred Resources Plan Scenario 4~~	~~0~~	~~260~~	~~520~~	~~1,000~~	~~1,600~~	~~2,200~~	~~2,900~~	~~3,700~~	~~4,500~~	~~5,000~~

~~(a) Generic future deliveries only. Does not include baseline or recently signed RPS contracts.~~

a. Renewables Request for Offer

PG&E's Renewables RFO program is one of the primary mechanisms through which PG&E procures renewable energy. PG&E has conducted four~~three~~ RPS solicitations to date, with the following results:

Solicitation Year	Signed Contracts (GWh/% of Retail Load)
2002 (under Interim Rules)	747 GWh / 1%
2004	1,966~~1,555~~ GWh / 2.5% (includes 2003)
2005	4,298~~1,803~~ GWh / 5.4~~2.5~~%
2006	1,328 GWh / 1.7%

PG&E filed its 2008 Renewable Energy Procurement Plan and Draft Solicitation on August 1, 2007~~2006 RPS Short Term Plan on December 22, 2005~~, and amended this Plan ~~its 2007 RPS Short Term Plan~~ on September 6, 2007 to include requests for short-term offers~~30, 2006~~,[7] with details on its strategy to improve its RPS RFOs and make renewable procurement even more successful. PG&E believes it has created significant awareness about its annual RFO over the past three~~two~~ years, but believes there are some groups it is still not reaching. PG&E has developed a distribution list for RFO outreach, doubled the amount of participants on the list, and will use this list to communicate with potential bidders. PG&E also has worked

[7] R.06-05-027.

directly with Renewable Energy Trade Associations to expand the distribution reach. Over the next several years, PG&E plans to identify additional markets and outreach. The goal of these activities is to ensure that every developer that is capable of participating in the California market is aware of the PG&E Renewables RFO and encouraged to participate.

PG&E is also streamlining and standardizing its solicitation process to further facilitate the RFO process. California is seen by developers as an expensive and complex state in which to develop projects, and as other markets become more active the relative attractiveness of the California market may diminish. As such, PG&E wants to be as responsive as possible to the needs of the development community. PG&E began to assess the needs of the development community in 2005 by conducting a developer survey. Based on feedback from that survey and from conversations with key stakeholders, PG&E is making a number of changes to increase participation, such as reducing credit requirements. In addition, as PG&E previously explained in its Supplement to its Long-Term Renewables Plan[8] and its 2008 Renewable Energy ~~2007 RPS~~ Procurement Plan, PG&E continues to enhance its outreach programs.

b. Bilateral Renewables

PG&E's annual Renewable RFO is an effective mechanism for renewable energy procurement. However, there are projects that require bilateral agreements either for timing reasons or due to special circumstances. In addition to the contracts filed through the solicitation process described above, PG&E has filed bilateral contracts in the past and is working with a number of additional counterparties currently. PG&E intends to continue to pursue bilateral opportunities when they arise.

c. PG&E-Owned Renewables

PG&E solicited ownership offers for the first time as part of its 2005 RPS Plan. PG&E announced that it would entertain turnkey proposals under which the developer could sell the project to PG&E at commercial operation date for a pre-determined price. PG&E also

[8] R.04-04-026, Supplement to PG&E's 2005 Renewable Energy Procurement Plan.

announced that it would entertain a buyout option, under which PG&E has the option to purchase the facility in either the fifth or the tenth year of a power purchase agreement at a pre-determined price. PG&E hoped that including these options would promote a more competitive and robust renewable development environment.

PG&E evaluated the ownership offers that were received, but there were no offers competitive with the power purchase offers received. PG&E expanded its 2006 RPS solicitation to include offers for sites on which the utility could develop eligible renewable energy resources in addition to the fully constructed projects solicited under the ownership options. PG&E will retain the protocol used to evaluate offers for utility ownership, such as consultation with an Independent Evaluator, ensuring the benefit of utility ownership options can be evaluated on equal terms with power purchase alternatives. PG&E is separately pursuing development opportunities both in and out of state. While renewable emerging technologies typically will not be available until the post-2010 time frame, PG&E is exploring these opportunities as well.

d. Emerging Renewable Resources Pilot Projects

PG&E believes that the development of new renewable technologies and resource areas is essential to a healthy renewables market in the post-2010 time frame. PG&E is working with a number of emerging renewables technologies and is beginning to assess new resources that could benefit customers by expanding long-term renewable supply. PG&E's current efforts are focused on a number of markets and technologies.

For example, PG&E is supporting the development of pipeline-quality biogas through long-term contracts at fixed prices. By injecting processed biogas into pipelines and transporting it to central plants, biomethane from Central Valley dairy farms is used productively, eliminating methane emissions that otherwise would add to global warming. PG&E has also signed an electricity purchase agreement with a dairy biodigester to take electricity generated on-site.

In addition to the dairy biogas projects, PG&E has also been working with biomass gasification developers. Biomass gasification could reduce electric transmission congestion and open up new biomass resources through utilization of the gas transmission network. While the commercial deployment of biomass gasification technologies has been limited so far, and additional technology risk exists, the possibility of opening up these new markets is promising.

PG&E has also actively pursued emerging marine energy resources, including wave and tidal power, to take advantage of PG&E's unique location, which contains the best tidal power location in the 48 contiguous states and which features the longest coastline of any utility in the U.S. PG&E has worked closely with Electric Power Research Institute ("EPRI"), the City and County of San Francisco ("CCSF"), and the CEC to evaluate potential wave and tidal projects. While these resources are somewhat unproven and the technologies have relatively limited deployment worldwide, PG&E sees value in early action and participation.

PG&E has also been aggressively pursuing new solar energy technologies and resources. PG&E is working with a number of companies with promising solar thermal and concentrating solar photovoltaic technologies. PG&E hosted Solar Power 2006 and anticipates supporting the demonstration of a number of emerging solar technologies over the planning horizon.

Finally, PG&E is investigating energy storage systems, which can help integrate, from a system operations perspective, the use of intermittent renewable resources. Utility-scale energy storage applications include the traditional pumped storage applications as well as smaller batteries and flow batteries. Distributed energy storage utilizing plug-in hybrid electric vehicles ("PHEV") also has many synergies with intermittent resources as well as the ability to create a major reduction in petroleum use. PHEVs that are charged at night using the excess off-peak power created by most renewable energy purchases would avoid the use of polluting petroleum during the day. PHEVs also have the potential to be connected to the grid during the daylight hours to provide peaking and ancillary services, such as regulation.

PG&E is seeking to build on its efforts with emerging technology by proposing ~~in the 2006 LTPP~~ the ERRP in A.07-07-015~~described in Volume 2, Section I.B.5~~. The ERRP would identify and support new technologies and resources that have the potential to expand the portfolio of renewable resources and commercially-viable technologies and reduce costs over the long term, by assisting promising technologies and resources in overcoming developmental barriers. ~~A detailed description of the proposed ERRP is included in Volume 2, Section I.B.5, and the ratemaking for recovery of this program costs is described in Volume 2, Section IV.G. PG&E proposes including the ERRP in its 2006 LTPP so that the ERRP would be subject to the provisions of Public Utilities Code section 454.5.~~

3. Renewable Resource Availability

D.05-10-014 recommends that the IOUs address in their long-term RPS planning the availability of renewable resources both in, and remote from, their service territories. ~~PG&E identifies renewable resource areas in its Volume 1, Section IV.C.2.~~ PG&E's strategy to support development of those resources involves transmission planning ~~described below in Volume 1, Section V.H.,~~ and active market development and resource validation. One example of market development and resource validation is PG&E's recent British Columbia ("BC") Renewable Resource Application, A.06-08-011 ~~described further in Volume 1, Section IV.C.2.b(7)~~. PG&E also anticipates that a portion of its proposed ERRP budget will be used to work with developers to identify new California and adjacent state resources. In general, PG&E plans to work proactively over the planning horizon to identify developer needs, identify additional resources, and identify transmission needed to serve them.

4. ~~PG&E's Compliance With Renewable Portfolio Standard Program Targets~~

~~PG&E provides a detailed assessment of its targets based on bundled load, its baseline RPS procurement, its incremental forecasted procurement, and the timing and likelihood of meeting its RPS targets in~~ ____________ ~~Volume 1, Section IV.C~~.

5. ~~Transmission Impacts on Renewable Portfolio Standard Development~~

~~PG&E is taking steps to support transmission for renewables in the short, medium, and long-term time frame. A detailed discussion of PG&E's activities and strategy is provided in Volume 1, Section V.H.4~~.

E. Distributed Generation (California Solar Initiative and Self-Generation Incentive Program)

PG&E's customers are playing an increasingly important role in adding generation to the electrical grid. Hundreds of photovoltaic solar systems are interconnected to PG&E's system every month by customers driven by environmental concerns or a desire for energy independence. Beginning in 2007, the California Solar Initiative ("CSI") will provide approximately $1 billion in rebates for customers in PG&E's service territory over a ten year period. In conjunction with the existing SGIP, there will be significant incentives for PG&E's customers to acquire their own generation for on-site use. This section describes PG&E's program implementation strategies for customer-owned generation ("CG"), such as solar and combined heat and power ("CHP"), and how CG will affect the overall resource plan.

1. PG&E's Customer Generation Policy

PG&E supports its customers making smart energy choices and CG is~~as~~ one of a variety of options customers should have available to address their energy needs. PG&E is implementing an integrated demand-side management ("IDSM") approach to delivering EE, DR, load management and CG programs to its customers. In 2004, PG&E developed and began implementing an audit tool which evaluates customers' facilities and offers information about IDSM measures, including information on the SGIP rebates. In 2007, PG&E ~~will~~ modified~~y~~ the audit tool and offered additional information regarding the CSI. PG&E believes an integrated approach is the most cost-effective and will best meet individual and overall customers' energy needs.

PG&E has supported CG before the legislature, the Commission, and through a variety of internal process improvements. PG&E is studying internal processes to simplify interconnections for our customers who choose CG, minimizing the points of contact for customers and structurally shortening learning curves. PG&E's goal is to make complex interconnections more routine and require less engineering review. ~~Currently,~~ PG&E's support of customer generation has resulted in a total of 177 MW from the following generation sources:

TABLE IV-2~~VOL. 1, VE-1~~
PACIFIC GAS AND ELECTRIC COMPANY
RECENT CUSTOMER GENERATION INSTALLATIONS
(MW)

Line No.	Resource Type	2003	2004	2005
1	Solar	14	23	30
2	CHP	25	34	26
3	Others	11	5	9
4	Total	50	62	65

Continued growth in customer generation is a key component of PG&E's 2006 LTPP. The forecast of customer generation is incorporated into the 2006 LTPP by reducing the demand forecast by the customer generation forecast. The Commission ordered PG&E to use the CEC forecast in this compliance filing, which has customer generation embedded in the estimates. ~~PG&E forecasts in this plan that its support of customer generation will result in the installed capacity and peak output levels presented in Table Vol. 1, VE-2.~~

~~**TABLE VOL. 1, VE-2**~~
~~**PACIFIC GAS AND ELECTRIC COMPANY**~~
~~**2007-2016 CUSTOMER GENERATION CAPABILITY**~~
~~**(MW)**~~

~~Line No.~~		~~2007~~	~~2008~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~2016~~
~~1~~	~~Solar~~										
~~2~~	~~Installed~~										
~~3~~	~~Scenario 1~~	~~28~~	~~56~~	~~84~~	~~112~~	~~140~~	~~168~~	~~196~~	~~224~~	~~252~~	~~280~~
~~4~~	~~Scenario 2~~	~~33~~	~~75~~	~~117~~	~~159~~	~~201~~	~~243~~	~~285~~	~~327~~	~~369~~	~~411~~
~~5~~	~~Scenario 3~~	~~33~~	~~75~~	~~130~~	~~191~~	~~252~~	~~315~~	~~380~~	~~446~~	~~513~~	~~581~~
~~6~~	~~Scenario 4~~	~~33~~	~~75~~	~~130~~	~~199~~	~~285~~	~~386~~	~~518~~	~~694~~	~~914~~	~~1,200~~

~~7~~	~~Available at Peak~~										
~~8~~	~~Scenario 1~~	~~11~~	~~22~~	~~33~~	~~44~~	~~55~~	~~66~~	~~77~~	~~87~~	~~98~~	~~109~~
~~9~~	~~Scenario 2~~	~~13~~	~~29~~	~~46~~	~~62~~	~~79~~	~~95~~	~~111~~	~~128~~	~~144~~	~~160~~
~~10~~	~~Scenario 3~~	~~13~~	~~29~~	~~51~~	~~74~~	~~98~~	~~123~~	~~148~~	~~174~~	~~200~~	~~227~~
~~11~~	~~Scenario 4~~	~~13~~	~~29~~	~~51~~	~~78~~	~~111~~	~~151~~	~~202~~	~~271~~	~~357~~	~~468~~
~~12~~	~~CHP~~										
~~13~~	~~Installed~~										
~~14~~	~~All Scenarios~~	~~28~~	~~57~~	~~85~~	~~113~~	~~142~~	~~170~~	~~198~~	~~226~~	~~255~~	~~283~~
~~15~~	~~Other DG~~										
~~16~~	~~Installed~~										
~~17~~	~~All Scenarios~~	~~8~~	~~17~~	~~25~~	~~34~~	~~42~~	~~50~~	~~59~~	~~67~~	~~75~~	~~84~~

Programs that support customer generation are described more fully below.

2. PG&E's Implementation of the California Solar Initiative Program

PG&E is committed to retaining its role as a leader in the solar market. For the past several years, PG&E has supported regulation and legislation that created or extended programs providing assistance to customers who choose to install solar generation. PG&E supported the California Solar Initiative established by the Commission in 2005 and the increased 2006 SGIP solar budget designed to address the significant backlog of customer applications. More recently, PG&E supported Senate Bill ("SB") 1, which codified the California Solar Initiative and increased the cap on the net metering program from 0.5% to 2.5% of PG&E's peak load.

Although the Commission has resolved many details of the CSI, the design phase is not yet complete. Some details are still in process, including low income and implementation of the eligibility criteria developed by the CEC pursuant to SB 1. PG&E has been an active participant in Commission and CEC workshops and proceedings and supports the direction the Commission has taken to implement the CSI. PG&E is committed to implementing a program that (as stated in the Commission Staff Proposal) achieves its "overall objectives with the lowest possible ratepayer contribution."[9] PG&E is committed to creating a robust market for customer solar generation so that over time the costs of solar generation decrease and customer participation increases without continued subsidies.

[9] *CPUC Energy Division Staff Proposal for California Solar Initiative Design and Administration 2007-2016*, R.06-03-004, April 24, 2006, page 10.

PG&E also supports the Commission's commitment to performance based incentives, extension of incentives to non-PV-based technologies (including solar hot water heating), making the benefits of the program available to low income customers, research and development, and measurement and evaluation. In a recent draft decision, the Commission adopted PG&E's suggestion that solar hot water heating displacing gas usage could be included in the SGIP program, since it was excluded from the California Solar Initiative by SB 1.

PG&E is the leading solar utility in terms of solar interconnections in the United States and is committed to continuing and expanding that leadership role. PG&E's continuing support for solar power has contributed to the installation of more solar units in its service area than any other utility in the country. Indeed, according to industry reports previously presented to this Commission, over half the solar projects installed in the entire United States in 2004 were installed in PG&E's service area.[10] PG&E has successfully interconnected over 21~~13~~,000 solar customers, who have installed over 160~~100~~ MW of solar generation.

PG&E began~~will be ready~~ on January 1, 2007 to administer the California Solar Initiative for its customers. PG&E worked diligently to prepare the CSI Handbook for adoption by the Commission and has led a cooperative effort with representatives of the low income housing development community to better understand how to bring solar benefits to low income customers. PG&E also instituted~~has nearly completed~~ simplification of the billing information provided to customers on the net metering program.

3. PG&E's Implementation of the Self-Generation Incentive Program and Other Customer Generation Options

In addition to solar CG, the SGIP also assists customers who are installing other types of customer generation, such as wind, renewable and nonrenewable fuel cells, renewable fuel internal combustion engines, renewable fuel micro turbines and small gas turbines, and

[10] *Vote Solar Opening Comments on Staff Solar Report*, R.04-03-017, July 7, 2005, page 3.

nonrenewable micro turbines and combustion engines that meet certain air quality standards.[11] Since 2001, the SGIP has provided over $190 million of incentives for 95 MW of customer generation (including solar). For clean and renewable customer generation, the SGIP can improve a customer's project economics by providing a rebate to offset the capital cost. In addition to the SGIP, some customers install CHP or other generation without participating in the SGIP. These customers benefit from any interconnection process improvements in addition to their savings on energy bills. Starting January 1, 2008, as a result of legislation, the SGIP program is closed to all technologies except wind and fuel cells.

4. PG&E's Commitment to Distributed Generation Research and Development

PG&E supports the commitment to research and development found in the Commission's decision that initially established the CSI, and subsequently included in SB 1. In addition to CSI research and development, PG&E is partnering with other utilities, industry stakeholders, the CEC, EPRI and the Federal government on research projects that examine the effects of customer generation in utility grids, including exploration of ways to make the grid smarter, and ways to incorporate customer generation into utility planning.

5. PG&E Supported the Expansion of AB 1969 to Renewable Generation by Any Customer

In 2006, the Legislature passed Assembly Bill ("AB") 1969, authorizing utilities to provide a tariff that allows public water and wastewater facilities to install renewable generation up to 1.5 MW and receive compensation for excess generation produced. In the Commission proceeding implementing AB 1969, PG&E proposed that customers be allowed to first offset concurrent energy needs and only sell excess generation. The Commission adopted PG&E's suggestion. PG&E also supported a Commission suggestion that the AB 1969 power purchase agreement be available to all customers installing renewable generation up to 1.5 MW.

[11] Systems must meet ~~Assembly Bill ("~~AB~~")~~ 1685 emissions standards to receive an incentive through the SGIP.

F. Other Generation Supply Resources

1. Department of Water Resources Contracts

The ~~California Department of Water Resources (“~~DWR~~”)~~ entered into contracts during the energy crisis that were subsequently allocated to the three California IOUs. In D.02-09-053, the Commission allocated to PG&E the power from all DWR contracts with a specified delivery point at ~~North of Path-15 (“~~NP15~~”)~~, plus the Coral contract. Contracts currently allocated to PG&E provide ~~2~~1,925 MW of must-take generation and 1,655~~475~~ MW of dispatchable generation for a total of 3,580~~4,400~~ MW.

For the 2008~~7~~-2016 period, PG&E has assumed that four turbines owned by the CCSF, with their output under contract to DWR, will be sited and put into operation in 2009, raising the total DWR capacity allocated to PG&E to 3,722~~4,580~~ MW. The current DWR contracts begin to expire in late 2009 and most will have expired by 2012. However, PG&E expects that the underlying resources will still be in operation and will be eligible to bid into PG&E’s competitive solicitations. PG&E’s currrent~~2006 LTPP~~ forecast of the DWR contract capacity is:

~~TABLE VOL. 1, VF-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~2007-2016 DWR CONTRACT CAPABILITY~~
~~(MW)~~

~~Line No.~~		~~2007~~	~~2008~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~2016~~
~~1~~	~~Must-Take~~	~~2,925~~	~~2,925~~	~~2,925~~	~~925~~	~~595~~	~~595~~	~~0~~	~~0~~	~~0~~	~~0~~
2	~~Dispatchable~~	~~1,475~~	~~1,475~~	~~1,655~~	~~1,655~~	~~1,655~~	447	276	276	276	180
~~3~~	~~Total DWR MW~~	~~4,400~~	~~4,400~~	~~4,580~~	~~2,580~~	~~2,250~~	~~1,041~~	~~276~~	~~276~~	~~276~~	~~180~~

TABLE IV-3~~VOL. 1, VF-1~~
PACIFIC GAS AND ELECTRIC COMPANY
2008-2016 DWR CONTRACT CAPABILITY
(MW)

Line No.		2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Must-Take	1,925	1,925	925	595	595	0	0	0	0
2	Dispatchable	1,655	1,847	1,667	1,667	459	288	288	288	0
3	Total DWR MW	3,580	3,772	2,592	2,262	1,053	288	288	288	0

2. Reliability Must-Run Contracts

~~Reliability Must-Run (“~~RMR~~”)~~ contracts are yearly contracts procured and administered by the CAISO to meet local reliability needs. PG&E participates in the CAISO’s determination of RMR need and in the CAISO’s pricing of RMR contracts, but does not directly contract for the RMR deliveries. California is in transition from RMR to Local Capacity Requirements (“LCR”). Unlike RMR, which is procured by the CAISO, LCR would be procured by the LSE, with any residual need being purchased by the CAISO. The amount of requirement for RMR (and in the future LCR) is determined by the CAISO through technical studies of the electric transmission system. ~~Information on RMR/LCR needs for the PG&E service area is presented below in Volume 1, Section V.H.3.~~

The LCR planning criteria uses a 1-in-10 standard rather than the 1-in-5 standard used for RMR, so LCR procurement amounts will be higher than the RMR amounts. However, unlike RMR, LCR capacity will count toward an LSE’s RA requirement, reducing the amount of capacity the LSE will need to procure for systemwide RA.

LSEs will contract for the LCR procurement, and will create an obligation from the unit to the CAISO. The general requirements for the CAISO will be that the unit will either need to be running, or will need to bid its capacity into the CAISO market. PG&E likely will procure LCR capacity as part of its other short-, medium- and long-term solicitations, bilateral negotiations and market purchases. If necessary, PG&E may conduct special solicitations and negotiations for LCR capacity to fully meet local needs. Any unmet needs will likely be filled by the CAISO through RMR contracting.

3. Market Purchases

PG&E enters into market purchases through several different mechanisms:

- Transparent exchanges, such as the ~~Intercontinental Exchange (~~"ICE"~~)~~ and ~~New York Mercantile Exchange (~~"NYMEX"~~)~~;
- Futures Commission Merchants;
- Inter-dealer or voice brokers;
- Spot markets; and
- On-line auctions.

Each of these markets has methods to communicate bids and offers and to complete trades. PG&E makes use of these market purchases to trade hour-ahead, day-ahead, month-ahead and term (one month to five years) electricity, and to enter into options and hedges. Market purchases are commonly used to procure power from existing resources. PG&E will make use of market purchases throughout the period 2007-2016. Further information on energy product market purchases is provided in ~~Volume 1,~~ Section II.A.4~~III.A.4~~.

4. Qualifying Facilities

~~PG&E procurement activities related to Qualifying Facilities ("QF") are limited currently to the administration of existing contracts.~~ PG&E currently has contracts with about 260 QF projects. Under D.07-12-052, PG&E is required to maintain 2,166 MW of QF capacity through recontracting with existing QFs and contracting with new QFs. The Commission determined ~~is considering~~ the conditions under which IOUs can enter into new QF contracts in D.07-09-040.~~the QF Avoided Cost Proceeding, which addresses various issues pending in Rulemakings ("R.") 99-11-022, 04-04-003 and 04-04-025~~.

~~PG&E has contracts with about 260 QF projects totaling about 4,100 MW of nameplate capacity. PG&E's 2006 LTPP scenarios assume QF capacity will decline at varying rates due~~

~~to contract expirations and limited renewals. Table Vol. 1, VF-2, shows the assumed year-to-year capacity for the four scenarios.~~

~~TABLE VOL. 1, VF-2~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~2007-2016 QF CONTRACT CAPABILITY~~
~~(MW)~~

~~Line No.~~		~~2007~~	~~2008~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~2016~~
~~1~~	~~Scenario 1~~	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
~~2~~	~~Scenario 2~~	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
~~3~~	~~Scenario 3~~	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	~~Scenario 4~~	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

~~For QF projects with expiring contracts, PG&E has taken the position that, post expiration, such projects can: (1) bid into a solicitation, such as PG&E's Long Term Request for Offers ("LTRFO"); (2) enter into a bilateral contract; or (3) enter into a year-to-year QF contract with PG&E with prices set at market rates.~~

5. New Generation From PG&E's 2004 Long-Term Request for Offers

PG&E's ~~recently completed~~ 2004 LTRFO will result in the construction of ~~2,250 MW of~~ new peaking and shaping generation in northern California. One of the winning 2004 LTRFO bidders, for the Energy Investors Funds ("EIF") Fresno project, recently announced that it was terminating its power purchase agreement with PG&E. ~~if all contracts are approved by the Commission and all projects are successfully completed.~~ Pursuant to D.07-12-052, pages 105-106, to the extent these approved resources are "determined unviable during the development process and the associated contract is terminated, the procurement authority for those megawatts remains." Thus, the authority associated with the EIF Fresno megawatts remains.[12] ~~The new facilities, size, commercial operation date and plant type are presented in Table Vol. 1, VF-3.~~

[12] On November 5, 2007, PG&E filed Advice Letter 3151-E submitting the EIF Fresno project to the energy auction cost allocation mechanism adopted in D.06-07-29. This advice letter is now moot given the termination of the EIF Fresno agreement.

~~TABLE VOL. 1, VF-3~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~2004 LTRFO CAPABILITY~~
~~(MW)~~

~~Line No.~~	~~Facility~~	~~Size (MW)~~	~~Purpose~~	~~Operational Date~~	~~Plant Type~~
~~1~~	~~Calpine Hayward~~	~~601~~	~~Long-Term Need~~	~~June 2010~~	~~Combined cycle~~
~~2~~	~~EIF Firebaugh~~	~~399~~	~~Long-Term Need~~	~~August 2009~~	~~Combustion turbine~~
~~3~~	~~EIF Fresno~~	~~196~~	~~Long-Term Need~~	~~September 2009~~	~~Combustion turbine~~
~~4~~	~~Starwood Firebaugh~~	~~118~~	~~Long-Term Need~~	~~May 2009~~	~~Combustion turbine~~
~~5~~	~~Tierra Energy Hayward~~	~~116~~	~~Long-Term Need~~	~~May 2009~~	~~Reciprocating engine~~
~~6~~	~~E&L Westcoast Colusa~~	~~657~~	~~Long-Term Need~~	~~May 2010~~	~~Combined cycle~~
~~7~~	~~Wartsila Humboldt~~	~~163~~	~~Humboldt~~	~~May 2009~~	~~Reciprocating engine~~
~~8~~	~~**Total**~~	~~2,250~~			

6. New All-Source Generation

PG&E will issue an all-source LTRFO to procure ~~up to 2,300~~ between 800 and 1,200 MW of new dispatchable ~~and operationally flexible generation~~ ramping resources that can be used to adjust for the morning and evening ramps created by intermittent types of renewable resources to come online ~~starting in~~ by 2015~~1~~. PG&E plans to issue its new LTRFO in 2008~~7~~. ~~The eligibility, rules and process used in this solicitation will closely match those in the 2004 LTRFO as described in Volume 1, Section III.A.5.b(2) above.~~ PG&E expects to file the results of the 2008~~7~~ LTRFO with the Commission ~~in 2008,~~ after executing contracts with winning bidders.

Ordering Paragraph 15 in D.07-01-039 directed PG&E to update its 2006 LTPP filing for compliance with the adopted Interim Emissions Performance Standard rules, as necessary, within sixty (60) days from the effective date of that decision. PG&E's 2006 LTPP is already in compliance with the decision and thus does not need to be further modified. For contracts of five years or more in duration, whether from new resources or existing resources, PG&E will comply with the Interim Emissions Performance Standard.

G. Imported Generation

The PG&E electric system is within the CAISO control area and it is electrically integrated with the western states included in the Western Electricity Coordinating Council

("WECC") electric grid. Electric power can be imported into the CAISO control area along transmission lines as far north as Canada and as far south as the Mexico/Desert Southwest regions. In PG&E's electric portfolio, imported generation consists of market purchases, existing contracts and future contracts as described below. Historically, PG&E has obtained ~~imported~~ most of its imported power from the Pacific Northwest.

Market purchases occur when the net open position is short and when it is economic (including transmission costs and constraints), compared to other alternatives, to purchase power outside the CAISO control area and import the power to meet demand. When the net open position is long, PG&E may sell and export the power when economic.

Currently, in PG&E's electric portfolio there are two contracts for generation located in the Northwest. The Puget Sound Power and Light ("PSPL") Exchange Contract is an exchange of 413 GWh on an annual energy basis between PSPL and PG&E. PG&E can take up to 300 MW hourly between June-September and in return PSPL can take up 300 MW on an hourly basis between January-February and November-December. This contract is an ever-green contract with a five-year termination notice. The second contract is the DWR-allocated contract with PacifiCorp in Klamath Falls, Oregon with a dispatchable contract capacity of 300 MW. This contract expires in June 2011.

In the past, power from these contracts was frequently reduced or curtailed due to transmission constraints. To decrease the risk of non-delivery due to transmission constraints, PG&E has purchased Firm Transmission Rights ("FTR") in the annual CAISO auction to import the majority of this energy on a firm basis into the CAISO NP26 region. ~~In 2007, PG&E will to need to access the amount of FTR capacity based on market conditions, portfolio need as contracts expire and new ones are added, and external conditions (*i.e.*, Market Redesign and Technology Upgrade ("MRTU")).~~

There will be changes in PG&E's imported generation in the future as the DWR PacifiCorp contract is due to expire within the 10-year timeframe of the 2006 LTPP and if contracts outside of the CAISO area are added to PG&E's electric portfolio. In its future contracting for imported power, PG&E will consider the "preferred loading order" and the effects of greenhouse gases.

H. Integration of Transmission and Procurement Planning

This section discusses: (1) electric transmission upgrades included as part of the most recent CAISO approved transmission plan and PG&E's 2007 Electric Transmission Grid Expansion Plan~~current year 2006 effort~~; ~~(2) integration of long-range transmission planning into the long-term procurement process for all resource categories, especially renewables; (3) how planned transmission upgrades identified in CAISO approved transmission plan will affect the achievement of the identified procurement resource strategies; (4) transmission options for facilitating a 33% renewables target by 2020;~~ and (2~~5~~) key transmission projects which are critical to PG&E's procurement resource plan expectations.

1. California Independent System Operator Approved Transmission Plan

PG&E continues to initiate and complete electric transmission projects to increase grid capacity and reliability for its customers. In accordance with the CAISO Tariff Section 3.2.1, PG&E is required to submit annual electric transmission facility expansion plans. The annual grid expansion plan identifies PG&E's electric transmission facilities that are projected to be insufficient with the CAISO Grid Planning Standards during the 10-year study planning horizon. The grid expansion plan also identifies transmission projects needed to meet planning standards, customer demand, or to improve grid operations.

In February 2008~~April 2006~~, the CAISO approved PG&E's 2007 ~~2005~~ Electric Grid Transmission Expansion Plan, submitted in December 2007~~2005~~. PG&E's 2007 ~~2005~~ grid expansion plan covers the years 2008 ~~2006~~ through 2017 ~~2015~~ and contains 103 ~~93~~ transmission expansion projects to increase electric transmission system capacity to serve the growing needs of electric customers, improve electric service reliability, reduce congestion and LCR ~~RMR contract costs~~, and connect resources (including renewable resources) to ~~and~~ deliver the associated capacity and energy to electric customers in California. The San Francisco Bay

Area ~~500 kilovolt (“kV”)~~ Bulk Transmission Project and the ~~Midway-Gregg 500 kV~~Central California Clean Energy Project are two of the major projects included in PG&E’s 2007 ~~2005~~ plan. The San Francisco Bay Area ~~500 kV~~ Bulk Transmission, if completed, would ~~drastically~~ reduce the local capacity requirement and increase electric transmission capacity and reliability in the Bay Area. The ~~Midway-Gregg 500 kV~~Central California Clean Energy Project, if completed, would increase transmission capacity and reliability, reduce LCR in the Fresno area, and increase utilization of Helms Pumped Storage Plant to enhance the value of off-peak generation. In addition, the California Clean Energy Project would also facilitate efficient management of renewables, as well as an increase in Path 15 transfer capability by approximately 1,250 MW.~~provide enough transmission capacity to import approximately an additional 1,000 MW of renewable generation resources from Tehachapi and other locations in the Southwest~~.

PG&E ~~is on schedule to~~ completed its 2007 ~~2006~~ grid expansion plan ~~that covers the years 2007 through 2016~~ in December 2007~~2006~~. A copy of PG&E’s ~~draft~~ grid expansion plan was released to the stakeholders on December 20, 2007~~November 14, 2006~~. In addition to transmission upgrades to provide safe and reliable electric service to its customers, PG&E’s ~~draft~~ plan included transmission plans to reduce local capacity requirement, support the retirement of old fossil power plants, and to facilitate the achievement of the renewable resource goals.

2. ~~Integration of Long-Range Transmission Plan Into the Long-Term Procurement Process~~

~~Many elements concerning the integration of electric transmission into the long-term procurement process in California are currently either directly or indirectly the subject of multiple Commission proceedings. These include PG&E’s Supplement to the 2005 Renewable Energy Procurement Plan,[13] Transmission for Renewables Order Instituting Investigation~~

~~[13] Renewable Portfolio Standard (R.04-04-026), December 6, 2005.~~

~~("OII"),[14] Local Resource Adequacy,[15] and the CEC/Commission/CAISO proposal on Integrated Planning.[16]~~

~~Integrated planning involves the development of generation resource, electric transmission and demand side plans such that the overall integrated plan results in the lowest total cost to the customer within the framework of the overall policy objectives. Currently, PG&E procures resources primarily through competitive solicitations and bilateral negotiations. It is through such commercial processes that resource options are contracted and realized. Therefore, while the structure for integrated planning can be framed in the planning environment, it is in the commercial procurement activity following the procurement plan that such integration is carried out. As such, the integration of generation, transmission, and demand resources requires a process which recognizes the critical role of such commercial activities.~~

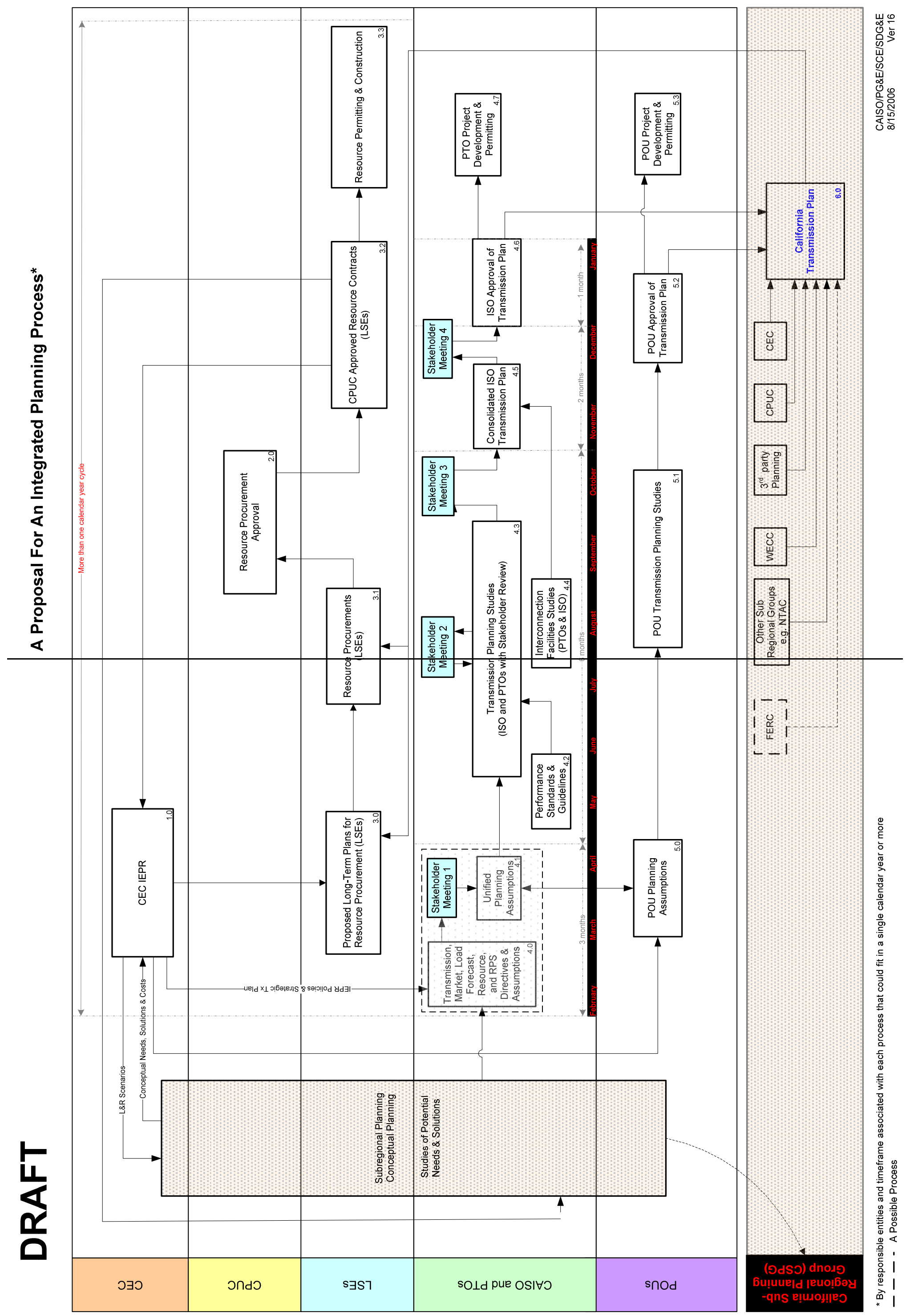
~~From an integrated planning framework standpoint, a proposal for coordinating the activities of the Commission, CEC and the CAISO to improve integrated planning was discussed at a December 2005 Commission Workshop. Parties have continued to develop and refine this coordinating process and the latest draft integrated planning flow diagram is attached below.~~

~~[14] Order Instituting Investigation to facilitate proactive development of transmission infrastructure to access renewable energy resources for California (I.05-09-005).~~

~~[15] Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program (R.05-12-013).~~

~~[16] Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning (R.04-04-003), December 2, 2005.~~

~~FIGURE VOL. 1, VH-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~CEC/COMMISSION/CAISO DRAFT INTEGRATED PLANNING PROCESS FLOW CHART~~



~~The integrated process starts with the CEC developing forecasts of loads, supply and demand side resources, and the resulting infrastructure implications. The CAISO then oversees the development of an integrated California Electric Transmission Plan. The Load-Serving Entities ("LSE"), using the CEC's forecast and the CAISO's electric transmission plan, will develop their resource procurement plans and submit these plans to the Commission for review and approval. The Commission's review of the procurement plans will consider, among other things, the resources' effect to planned transmission projects and need for additional transmission projects to interconnect and integrate the resources. Similarly, the CAISO and the Participating Transmission Owners ("PTO") will use resource planning information and procurement decisions from the Commission to finalize the planning and implementation of transmission projects.~~

~~One key output from the CAISO's transmission plan is an estimate of the future LCR which refers to load areas that require local generation to maintain local reliability as well as transmission alternatives to reduce the LCR. These data allow for the determination of the marginal transmission cost to serve increments of load or electric demand. Additionally the technical studies would produce the Transmission Ranking Cost Report ("TRCR") to provide information on cost to integrate new resources based on size and location.~~

~~The marginal transmission cost information would be available to all stakeholders. After the LSE resource needs have been confirmed by the Commission in the long-term planning process, developers and LSEs would use this information to prepare and evaluate resource bids. Use of these data in the procurement process provides a market mechanism whereby competitively-priced, local resource alternatives can displace transmission projects that are needed to reliably deliver power from remote resources. The Commission would then approve specific resource contracts which include transmission costs and benefits in their overall Least Cost/Best Fit evaluation.~~

~~The data on LCR and transmission marginal costs would also be available as inputs to the CEE and Demand-Side Management ("DSM") programs. These programs could then~~

~~prioritize and target their efforts considering those areas with the highest transmission marginal costs. The DSM programs and targeted CEE would then serve as inputs to future statewide and disaggregate load forecasts.~~

~~The CAISO Large and Small Generation Interconnection Process (LGIP and SGIP) would ultimately be followed for all new generation interconnections to the CAISO grid. These interconnection processes provide for more precise interconnection information through the System Impact Study and Facility Studies to ensure grid reliability and deliverability of the resource.[17] In the event resources are not procured in a local area, the PTOs would proceed with expansion of the transmission system to maintain appropriate reliability to the energy customers.~~

~~PG&E will continue to work with the Commission, CEC, CAISO, other PTOs, and stakeholders on this coordinated process for integrating generation, transmission and demand side planning.~~

3. ~~Affect of Planned Transmission Upgrades to the Achievement of Procurement Resource Strategies~~

~~Planned electric transmission upgrades could impact the achievement of procurement resource strategies in three aspects: deliverability, LCR or RA requirements, and renewable goals. This section describes deliverability and LCR while Volume 1, Section V.H.4 describes transmission options supporting the renewable goals.~~

~~Under RA counting rules, LSEs need to show that the resources they intend to procure to meet their load requirements can be delivered to load at the time of system peak. In 2005, the CAISO conducted a baseline study that assessed the "deliverability" of existing generators. The study assessed the ability of the electric transmission system to deliver the generation to the aggregate of load on the CAISO grid. The CAISO's analysis, using historical import levels,~~

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[17] ~~To the extent these studies are available in the procurement process, they can be used in the evaluation process in lieu of the less detailed TRCR information.~~

~~concluded that generally all existing generation resources are deliverable.[18] The Commission, in D.05-10-042, adopted this recommendation. Consequently, for the first compliance cycle, all internal generation is deemed deliverable.~~

~~The CAISO is proceeding with a second phase of the baseline study to account for new generation projects that are currently in the CAISO interconnection queue and have approved interconnection studies. The CAISO is proceeding with its study effort in two sub-phases: Phase II-A and Phase II-B.~~

~~The Phase II-A study is intended to provide deliverability results for generation projects in the CAISO interconnection queue prior to March 1, 2005, for deliveries on 2010. On June 30 and July 3, 2006, the CAISO released its draft Phase II-A deliverability study. PG&E expressed concern about the very different conclusions contained within the CAISO's draft study results. For example, the draft report concluded that a great number of new resources are non-deliverable, contrary to the new resources' interconnection studies. PG&E is concerned that this and other conclusions in the CAISO's draft report, if adopted, would well undermine the sustainability of the RA program. We understand the CAISO is in the process of finalizing its Phase II-A study considering PG&E's and other stakeholder comments.~~

~~The Phase II-B study is intended to provide deliverability results for generation projects in the CAISO interconnection queue after March 1, 2005, for deliveries by 2010. The CAISO recently started the Phase II-B study and a study plan can be found on the CAISO's website~~ http://www.caiso.com/188d/188da0bf1d440.pdf. ~~According to its study plan, the CAISO is scheduled to complete the Phase II-B study in January 2007.~~

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[18] ~~The CAISO study noted that a limited quantity of generation within certain generation pockets is not fully deliverable. However, the CAISO also concluded that relatively minor transmission remedies or operating solutions would resolve the deliverability limitations found in the study. The CAISO recommended that the existing units (and imports) be considered deliverable so long as the PTOs agree to complete the transmission upgrades by a date certain through their upcoming annual transmission expansion plans.~~

~~After the completion of the second phase of the baseline study, the deliverability of new resources will be assessed incrementally as part of the CAISO's interconnection technical studies to ensure the safe and reliable interconnection of new generators.~~

~~Similar to deliverability, electric transmission upgrades could impact LCR which refers to load areas that require local generation to maintain local reliability. Currently, the CAISO is meeting such local reliability needs through its Local Area Resource Requirements ("LAR") process. In this process, the CAISO enters into RMR contracts with generators to ensure that generators necessary for local reliability are available and to curb the market power of such generators.~~

~~California is in transition from RMR to LCR.~~[19] ~~Unlike RMR, which is procured by the CAISO, LCR would be procured by the LSE, with any residual need being purchased by the CAISO. The amount of RMR (and in the future LCR) is determined by the CAISO through technical studies of the electric transmission system. These CAISO technical studies are currently one-year studies that focus on the requirements of the following year, but the CAISO has indicated it will produce longer term studies in future iterations. For the operational year beginning January 1, 2007, the Commission has adopted the CAISO's LCR requirements for RA purposes. The CAISO's 2007 LCR Report dated July 18, 2006, identified seven local areas and 27 sub-areas totaling 11,310 MW of local capacity need for PG&E.~~

~~To provide a multi-year perspective on RMR and LCR, PG&E has been actively supporting the CAISO's RMR and LCR planning with PG&E's annual grid expansion planning process. Specifically, PG&E begins with a multi-year forecast of local reliability requirements and then evaluates transmission upgrades to reduce such requirements. PG&E and the CAISO then review the economic value of these transmission projects and implement those transmission projects that reduce the overall cost to customers. For example, at its April 20,~~

[19] ~~While technically serving the same function as RMR to support local reliability, the quantity of local resources required under LCR is typically higher due to a more stringent application of the reliability criteria.~~

~~2006 board meeting, the CAISO approved the Vaca Dixon 500/230 kV Transformer Project which, when completed, will lower the Bay Area LCR requirement by 400 to 500 MW.~~[20] ~~PG&E has started the construction of this transformer project and is targeting December 2007 for project completion.~~

~~As part of its 2006 Grid Expansion planning effort, PG&E published a draft report on November 14, 2006, that looked at the projected LCR in 2008 and 2011, and potential transmission upgrades. Table Vol. 1, VH-1, lists the CAISO's 2007 LCR and PG&E's forecasted LCR for the years 2008 and 2011.~~

~~TABLE VOL. 1, VH-1~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~LOCAL CAPACITY REQUIREMENTS~~
~~(MW)~~

			~~LCR With New Upgrades~~	
~~Line No.~~		~~Year 2007 (CAISO)~~	~~Year 2008 (PG&E Forecast)~~	~~Year 2011 (PG&E Forecast)~~
~~1~~	~~Humboldt~~	~~202~~	~~192~~	~~175~~
~~2~~	~~NC/NB~~	~~582~~	~~630~~	~~340~~
~~3~~	~~Sierra~~	~~2,161~~	~~1,597~~	~~1,380~~
~~4~~	~~Stockton~~	~~589~~	~~536~~	~~331~~
~~5~~	~~Bay Area~~	~~4,771~~	~~4,517~~	~~4,025~~
~~6~~	~~Fresno~~	~~2,219~~	~~1,685~~	~~1,335~~
~~7~~	~~Kern~~	~~786~~	~~639~~	~~669~~
~~8~~	~~Total~~	~~11,310~~	~~9,796~~	~~8,255~~

~~As demonstrated in the table above, PG&E's LCR needs can be reduced by completing certain electric transmission upgrades. PG&E will continue to work with the CAISO to evaluate the cost-effectiveness of these potential LCR reduction transmission projects.~~

~~Embedded in PG&E's LCR evaluation is an assumption on the timing of retirement of old fossil power plants. In its White Paper on *Resource, Reliability And Environmental Concerns Of Aging Power Plant Operations And Retirements*, the CEC Staff identified 66 aging generating units as representative of the type of plant most likely to retire. The northern~~

[20] ~~A second project, the Oakland C-X #2 115 kV Underground Cable would eliminate the Oakland sub-~~

~~California units are shown in Table Vol. 1, VH-2.[21] PG&E's forecast, included in its draft 2006 Grid Expansion Plan, identifies, in PG&E's view, which units (shown with shading in the table) are necessary to meet local reliability needs in the future.~~

~~TABLE VOL. 1, VH-2~~
~~PACIFIC GAS AND ELECTRIC COMPANY~~
~~NEED FOR AGING POWER PLANTS FOR LOCAL RELIABILITY~~

~~Line No.~~	~~Plant~~	~~Unit~~	~~Year In-Service~~	~~Capacity~~	~~2006~~	~~2007~~	~~2008~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~
~~1~~	~~Contra Costa~~	~~6~~	~~1964~~	~~337~~	-	-	-	-	-	-	-	-	-	-
~~2~~	~~Contra Costa~~	~~7~~	~~1964~~	~~337~~	-	-	-	-	-	-	-	-	-	-
~~3~~	~~Humboldt Bay~~	~~1~~	~~1956~~	~~52~~	-	-	-	-	-	-	-	-	-	-
~~4~~	~~Humboldt Bay~~	~~2~~	~~1958~~	~~53~~	-	-	-	-	-	-	-	-	-	-
~~5~~	~~MEPPS~~	~~2~~	~~1976~~	~~15~~	-	-	-	-	-	-	-	-	-	-
~~6~~	~~MEPPS~~	~~3~~	~~1976~~	~~15~~	-	-	-	-	-	-	-	-	-	-
~~7~~	~~Morro Bay~~	~~1~~	~~1956~~	~~163~~	-	-	-	-	-	-	-	-	-	-
~~8~~	~~Morro Bay~~	~~2~~	~~1955~~	~~163~~	-	-	-	-	-	-	-	-	-	-
~~9~~	~~Morro Bay~~	~~3~~	~~1962~~	~~337~~	-	-	-	-	-	-	-	-	-	-
~~10~~	~~Morro Bay~~	~~4~~	~~1963~~	~~336~~	-	-	-	-	-	-	-	-	-	-
~~11~~	~~Moss Landing~~	~~6~~	~~1967~~	~~754~~	-	-	-	-	-	-	-	-	-	-
~~12~~	~~Moss Landing~~	~~7~~	~~1968~~	~~756~~	-	-	-	-	-	-	-	-	-	-
~~13~~	~~Oakland~~	~~1~~	~~1978~~	~~55~~	-	-	-	-	-	-	-	-	-	-
~~14~~	~~Oakland~~	~~2~~	~~1978~~	~~55~~	-	-	-	-	-	-	-	-	-	-
~~15~~	~~Oakland~~	~~3~~	~~1978~~	~~55~~	-	-	-	-	-	-	-	-	-	-
~~16~~	~~Pittsburg~~	~~5~~	~~1960~~	~~325~~	-	-	-	-	-	-	-	-	-	-
~~17~~	~~Pittsburg~~	~~6~~	~~1961~~	~~325~~	-	-	-	-	-	-	-	-	-	-
~~18~~	~~Pittsburg~~	~~7~~	~~1972~~	~~720~~	-	-	-	-	-	-	-	-	-	-
~~19~~	~~Potrero~~	~~3~~	~~1965~~	~~206~~	-	-	-	-	-	-	-	-	-	-
~~20~~	~~Potrero~~	~~4~~	~~1976~~	~~52~~	-	-	-	-	-	-	-	-	-	-
~~21~~	~~Potrero~~	~~5~~	~~1976~~	~~52~~	-	-	-	-	-	-	-	-	-	-
~~22~~	~~Potrero~~	~~6~~	~~1976~~	~~52~~	-	-	-	-	-	-	-	-	-	-

~~Currently, Contra Costa Unit 7 is required to meet reliability requirements for the Greater Bay area. PG&E is proceeding with the construction of Contra Costa 8 ("CC8"), a new 530 MW combined cycle power plant. Completing the proposed Contra Costa 8 Power Plant,~~

~~area, but not impact the overall Bay Area requirement.~~

[21] ~~The list has been modified to include the combustion turbines at Oakland and Potrero and the MEPS units at Humboldt.~~

~~currently scheduled for 2010, would eliminate the need for the older Contra Costa units for local reliability requirements.~~

~~The Humboldt Bay Power Plant ("HBPP") serves a unique role in maintaining the reliability of the electric system along the north coast of the PG&E service area. This electrically-remote area is linked to the rest of the PG&E system through long distance (more than 110 miles) 115 and 60 kV transmission lines that are unable to reliably serve the peak demand in the area if one of the 115 kV lines is unavailable. Therefore, there will continue to be a need for local generation in this area for the foreseeable future. In September 2006, PG&E filed an Application for Certification with the CEC to construct the Humboldt Bay Repowering Project ("HBRP"). The HBRP will be a load following power plant consisting of 10 natural gas-fired 16.3 MW reciprocating engine-generator sets with a combined nominal generating capacity of 163 MW. Once the new project is on-line, currently anticipated by the fall of 2009, the existing units at HBPP can be retired.~~

~~According to the CAISO, two units at the Oakland Power Plant are necessary to reliably serve electric customers in the Oakland and Alameda area. In April 2006, the CAISO Board approved the Oakland C-X No. 2 115 kV Underground Cable Project. Completing this cable project, currently expected by 2010, should eliminate the need for the Oakland Power Plant for the reliability of this sub-area.~~

~~The Pittsburg Power Plant is located in the Pittsburg sub-area of the Greater Bay Area. In its 2006 LCR Report, the CAISO identified a LCR of 2,208 MW including the Pittsburg Units 5, 6 and 7, for the Pittsburg Sub-area. PG&E has identified a project to reconductor the Pittsburg-Tesla 230 kV transmission line by 2010 in its 2005 Grid Expansion Plan. Completing this reconductoring project would provide the necessary transmission capacity to reduce the Pittsburg sub-area capacity requirement by 600 MW and eliminate the need for the Pittsburg Units.~~

~~In September 2004, and revised in November 2004, the CAISO approved an Action Plan to release existing generation located within San Francisco from RMR Agreements with the~~

~~CAISO. In April 2006, PG&E completed the necessary electric transmission projects for the first half of the Action Plan and subsequently retired its Hunters Point Power Plant in May 2006. The remainder of the Action Plan addresses the need for Potrero Power Plant for local reliability needs. The Revised Action Plan calls for the release of Potrero 3 conditioned on the completion of four PG&E electric transmission projects and the four CCSF's peaking power plants. The CCSF peaking power plant project recently received its license from the CEC and is projected to be on-line in 2007 or 2008. PG&E's four transmission upgrade projects that would allow for the release of the Potrero Power Plant are currently scheduled for completion in 2007.[22] Completing these generation and transmission projects would eliminate the need for Potrero Power Plant for this sub-area.~~

4. ~~Transmission Options Facilitating a 33% Renewables Target by 2020~~

~~Electric transmission is increasingly becoming a critical element in meeting the state's RPS goals. It is important that additional transmission capacity is available when new resources become operational.[23] PG&E is finding that, with the exception of Altamont and Solano County wind sites, most proposed renewables development is remote from PG&E's load centers.~~

~~The CEC recently issued three reports on the technical potential of renewable resources development. The first report, entitled *Preliminary Renewable Resources Assessment* ("PRRA") was published on July 1, 2003. The second report, entitled *Renewable Resource Development Report* ("RRDR") was approved by the CEC in November 2003. The third report, entitled *Strategic Value Analysis for Integrating Renewable Technologies in Meeting*~~

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[22] ~~These upgrades include the following four transmission projects: (1) Upgrade the Newark-Dumbarton 115 kV line; (2) Upgrade the Bair-Belmont 115 kV Line; (3) Upgrade the Metcalf-Hicks & Metcalf-Vasona 230 kV lines; and (4) Add voltage support at Ravenswood substation.~~

[23] ~~The Commission's actions such as in D.06-06-034 that allows the utilities to record and recover the reasonable costs for environmental, engineering and permitting studies to determine the viability of proposed transmission facilities positively support the early development and siting of new transmission facilities.~~

~~*Target Renewable Penetration*[24] was released in July 2005. These reports show, among other things, the economic potential of various renewable resources by technology and location. These studies indicate that PG&E may not be able to meet its RPS goals exclusively from resources within the NP15 service area. In other words, PG&E will need to contract with renewable suppliers that are located in South of Path-26 ("SP26"), ZP-26 or out-of-state.~~

~~In August 2006, Energy and Environmental Economics, Inc. Consulting Group published a concept paper entitled British Columbia-California Partnership for Renewables Energy Development. This concept paper reported on the results of a working group that explored avenues for partnership between British Columbia and California on the development of renewable energy for electric power.~~

~~Similarly, a report entitled *Achieving A 33% Renewable Energy Target* prepared for the Commission in November 2005 reviewed the potential expansion of the RPS program to achieve a 33% renewables target by 2020. The report identified a range of resource options to achieve a 33% goal from as diverse locations as Washington, Oregon, Northeast Nevada and New Mexico.[25] Moving toward a 33% RPS share given the potential wide geographic dispersion of resources requires coordinated transmission planning and resources procurement.~~

~~The consistent conclusion from these studies is the need to expand transmission facilities in NP15, SP-26 and to out-of-state. In NP15 where PG&E has an extensive electric transmission system in northern California, the system's capacity is at times fully utilized in bringing distant low cost resources into California. Since 2003, PG&E has conducted a number of studies on transmission facilities needed to connect renewable resources within its service territory and deliver the renewable capacity and energy to load centers. These studies show a number of transmission upgrades that would need to be pursued to accommodate potential~~

[24] ~~Report CEC-500-2005-106, http://www.energy.ca.gov/2005publications/CEC-500-2005-106/CEC-500-2005-106.PDF.~~

[25] ~~"Achieving A 33% Renewable Energy Target." November 1, 2005, Tables II-3 and II-6.~~

~~resources and maintain the reliability of the transmission system. The following are some of the potential transmission upgrades:~~

- ~~Vaca Dixon-Contra Costa 230 kV Line Reconductoring;~~
- ~~Vaca Dixon-Moraga 230 kV Line Reconductoring;~~
- ~~A new 230 kV Substation to connect the Vaca Dixon-Moraga and Lakeville-Sobrante 230 kV Lines;~~
- ~~Contra Costa-Newark 230 kV Line Reconductoring;~~
- ~~Looping the Pit-Cottonwood 230 kV Lines into Round Mountain and reconductoring the Round Mountain-Cottonwood 230 kV Lines; and~~
- ~~A new Midway-Gregg 500 kV Line.~~

~~Additional transmission study work is needed as resource information such as wave power in Humboldt County and geothermal in Lassen County becomes defined.~~

~~Similarly for SP-26, the Southern California Edison Company's ("SCE") TRCR also suggests the need for significant transmission expansion to access new renewable resources located at Tehachapi, Imperial Valley and Mohave.~~

~~The Tehachapi area has been identified as having the potential for thousands of megawatts of generation. The Tehachapi Collaborative Study Group ("TCSG") was formed to identify an interconnection plan for up to 4,500 MW of wind in the area north of the Antelope Valley. The TCSG identified a potential development plan and SCE has been pro-active in moving forward with filing for the first phase of transmission expansion. This transmission development is important for PG&E to access wind generation from Tehachapi.~~

~~The Imperial Valley area has a substantial potential for geothermal generation. This generation would most likely connect to the Imperial Irrigation District's ("IID") electric system, which has only limited transmission capability to the CAISO grid. Similar to Tehachapi, an Imperial Valley Study Group ("IVSG") was formed to develop a transmission plan for accessing these resources. The IVSG recommended a new 500 kV line between IID~~

~~and SDG&E (Sunrise Project) and recognized that substantial upgrades would be required within the IID in order to integrate the proposed new power plant development. In addition to the Sunrise Project, there is also a proposal for a Green Path Project to establish an interconnection between Los Angeles Department of Water and Power ("LADWP") and IID. In August 2006, the CAISO approved the Sun Path (Sunrise and Green Path) Project and directed SDG&E and Citizen Energy to proceed with the permitting and construction of the project by the summer of 2010.~~

~~The Mohave Desert has a substantial potential for solar generation. The primary corridor for the connection of this generation is to southern Nevada along the transmission facilities between Victorville and Lugo. For projects which could connect directly into Lugo, there are existing transmission constraints until the Vincent-Mira Loma line is built to relieve the South of Lugo congestion. This project is still in the planning stage and has not been approved by the CAISO nor has an Application for Certification ("AFC") been filed with the Commission. Projects delivering to PG&E through Lugo would have a lower impact on South of Lugo congestion, but would still be at risk for curtailment. For projects located further northeast toward southern Nevada, new transmission lines would be needed to bring the power to the Lugo area.~~

~~Outside of California, a large potential for renewable resources exists in the Pacific Northwest including the northwestern United States, British Columbia and Alberta. The transmission challenges to access these potential projects include congestion in the Northwest transmission system and congestion south of California Oregon Intertie ("COI"). The Northwest to COI transmission system is generally congested and subject to a lengthy queue. Transmission must be procured from those entities that hold the existing rights or reliance must be made on short-term transmission until additional transmission can be built. Additionally, transmission into California at COI is managed by the CAISO through the allocation of Congestion Revenue Rights ("CRR"). However, the annual allocation of CRRs results in some uncertainties for long-term firm transmission access.~~

~~PG&E is actively involved in two electric transmission planning studies to access new renewable resources in the Pacific Northwest. They are the British Columbia-California ("BC-California") and the Frontier Line transmission studies.~~

~~On August 9, 2006, PG&E filed an application to the Commission requesting authority to evaluate the feasibility of obtaining wind and other renewable electric power from sites in British Columbia and transmitting that power to PG&E's service territory and to implement any resulting power procurement arrangements. A pre-hearing conference on PG&E's BC Wind Study request was conducted on October 31, 2006. Concurrently at the WECC, PG&E initiated a regional planning project review on August 16, 2006, of electric transmission alternatives to connect the northern California area to British Columbia. Potential project alternatives would include both 500 and 765 kV alternating current ("AC") and high voltage direct current ("HVDC") lines, via overhead or undersea routes. PG&E's BC Wind Study, if approved by the Commission, will focus on resource and transmission feasibility while the WECC regional planning review will focus on the technical transmission planning analysis.~~

~~The Frontier Line is a proposed interstate high-voltage transmission line envisioned by the Governors of California, Nevada, Utah, and Wyoming in April 2005 to deliver clean renewable and clean coal energy to consumers across the West. On a conceptual basis, the proposed line would originate in Wyoming and with terminal connection in Utah, Nevada, California, and possibly other Western states. PG&E, along with state agencies and other companies, is performing a feasibility study to determine the needs and the options for this new transmission project. The study work is divided into four subcommittees to evaluate: (1) load and resources; (2) transmission analysis; (3) economic analysis; and (4) stakeholder process. PG&E is actively participating in all four sub-committees and the project's Governors' Council.~~

5. Key Transmission Projects Critical to the Procurement Resource Plan Expectations

There are many electric transmission projects that are critical to support PG&E's procurement resource plan. These transmission projects can be generally separated into the near, medium and long term based on their schedules. Critical transmission projects in the near term (one to five years) are typically upgrades involving expansion of existing facilities or the reconductoring of transmission lines to reduce local capacity requirement and congestion and increase PG&E's ability to accept new renewable power from remote locations. These near-term projects and their anticipated schedules are:

- ~~Henrietta-Gregg 230 kV Line Reconductoring - 2007;~~
- ~~Vaca Dixon 500/230 kV Transformer - 2007;~~
- Metcalf-Moss Landing 230 kV Line Reconductoring - 2008;
- McCall 230/115 kV Transformer - 2008;
- Palermo-Rio Oso 115 kV Line Reconductoring - 2009;
- Vaca Dixon-Contra Costa 230 kV Line Reconductoring - 2009~~2008~~;
- Newark-Ravenswood 230 kV Line Reconductoring - 2010~~2009~~;
- Rio Oso 230/115 kV Transformers and Capacitors - 2011~~2009~~;
- Pittsburg-Tesla 230 kV Line Reconductoring - 2010;
- Tesla-Newark 230 kV Line Reconductoring - 2011;
- Vaca Dixon-Lakeville 230 kV Line Reconductoring - 2013~~2010~~; and
- Vaca Dixon-Sobrante-Moraga 230 kV Line Reconductoring - 2012, or later~~2010~~.

There are three proposed transmission projects in the medium term (next 5-10 years) that are in the environmental evaluation stage. They are: (1) ~~Midway-Gregg 500 kV Line~~Central California Clean Energy - 2013~~2012~~; (2) Bay Area Bulk Transmission Project - ~~500 kV Station~~ - 2015~~2013~~; and (3) Table Mountain-Vaca Dixon 230 kV Reinforcement – 2013 or later~~Vaca Dixon-Fulton Connection - 2015~~. The timing and scope of these mid-term projects can change based on the results of the environmental and transmission technical studies. For the long-term projects (next 10-15 years), PG&E will continue to participate in various regional planning efforts such as the ~~Frontier Line and~~ BC-California Transmission to better define future transmission needs to access and develop renewable resources in the western United States and Canada. In this regard, transmission plans must be flexible and robust to take advantage of evolving resource developments and to optimize benefits for the consumers.

V. EVALUATION OF COMMISSION-APPROVED PROCUREMENT PLAN

PG&E evaluated the long-term procurement plan that the Commission adopted for PG&E in D.07-12-052 ("Approved Plan"). The following summarizes this evaluation.

A. The Approved Plan Meets the Current Resource Adequacy Requirements

Based on the load and resource assumptions included in D.07-12-052, Table PGE-1, the Approved Plan meets the Commission's current RA requirements.[1] The major assumptions in Table PGE-1 include: (1) peak-demand based on the CEC's *California Energy Demand 2008-2018 Staff Revised Forecast* developed as part of the 2007 IEPR, dated November 2007; (2) existing resource retirements at a pace of approximately 600 MW per year beginning in 2009 until all 4,400 MW of aging power plants are retired by 2015[2]; (3) demand-side and supply-side resource additions that are developed and available to meet the annual peak-demand; and (4) the current 15% to 17% planning reserve margin ("PRM") on a 1-in-2 peak-demand load forecast that is adequate to protect against short-term load and resource contingencies.[3]

B. The Approved Plan Complies With the State Loading Order

The State Loading Order adopted in the EAP includes cost-effective EE, DR, renewable resources, distributed generation and clean and efficient fossil-fired generation. PG&E's Approved Plan complies with the loading order. First, the plan includes EE savings at levels targeted by D.04-09-060. Embedded in the CEC's load forecast are the committed EE savings attributed to the PG&E's 2006-2008 and earlier EE programs, as well as 80% of the uncommitted EE savings attributable to future EE program cycles.[4] The remaining 20% of the uncommitted EE goals is shown separately in Table PGE-1. Second, the Approved Plan includes price sensitive and curtailable DR programs. Third, the Approved Plan procures at

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[1] D.07-12-052 at 116.
[2] D.07-12-052 at 87.
[3] A new rulemaking announced on November 19, 2007 in R.05-12-013 and R.06-02-013 is expected to review the adequacy of the current PRM, and adopt a system reliability reserve margin methodology for all jurisdictional load serving entities.
[4] D.07-12-052 at 272.

least 20% of RPS, consistent with State law. Those amounts are shown in Table PGE-1. Fourth, the Approved Plan includes distributed generation by implementing the CSI approved in D.06-01-024 and a forecast of additional distributed generation. Finally, the Approved Plan procures 800 – 1,200 MW of new dispatchable ramping resources (including clean and efficient fossil-fuel resources) for commercial operation by 2015, consistent with OP 4 in D.07-12-052. In addition, to the extent a new resource from PG&E's 2004 LTRFO is determined to be unviable during the development process and the associated contract is terminated, the procurement authority for those MWs remains.

C. The Approved Plan Provides Environmental Benefits Through Reduced CO_2 Emissions

PG&E's Approved Plan uses EE and preferred resources to reduce customer demand for electricity and the use of conventional supply resources. Preferred resources that reduce demand are EE savings and self-generation, both of which have for the most part been reflected in the CEC's demand forecast. Decreasing demand can reduce conventional resource use. In addition, DR and RPS generation can reduce conventional resource use. Preferred resources may cost more than conventional resources, but provide environmental benefits in the form of reduced GHG emissions.

By 2016, PG&E estimates that the Approved Plan reduces at a minimum 6 to 9 million metric tons of CO_2 emissions per year, as compared to meeting a higher load without energy efficiency and self-generation through use of conventional resources. Included in the estimate are the incremental amounts of EE, CSI, and RPS additions calculated using the CEC's load forecast adopted in D.07-12-052, and a minimum 20% RPS target. The range of CO_2 emission reductions corresponds to a range of the avoided resources' heat rate. For this evaluation, PG&E assumes a heat rate range of 6,916 British Thermal Unit ("Btu")/kWh to 9,400 Btu/kWh. The first heat rate is the average heat rate of the 2007 Market Price Referent ("MPR"). The second heat rate corresponds to the Emission

Performance Standard ("EPS") of 1,100 lb of CO_2 per MWh adopted by D.07-01-039.[5] The following table shows the derivation of the CO_2 emissions savings provided by the Approved Plan. In addition, PG&E's GHG emissions profile submitted to the California Climate Registry, which was included in PG&E's March 5, 2007 amended 2006 LTPP filing, is included as Appendix D. This profile provides additional information regarding PG&E's current GHG emissions.

[5] D.07-01-039, Conclusion of Law No. 16.

Derivation of CO2 emissions saved by D. 07-12-052's Approved Plan

Line	Item	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Preferred resources included in CEC load forecast, GWh										
2	PV (Source: CEC Form 1.2 - PGE)	52	105	157	209	262	314	367	419	471	524
3	Non-PV Self-gen increase from 2006 (Source: CEC Form 1.2 - PGE)	32	66	101	136	170	205	240	274	309	343
4	80% of CPUC adopted EE goals in D. 04-09-060, Table 1A			854	1,666	2,534	3,473	4,494	5,516	6,538	7,559
5											
6	Additional preferred resources not included in CEC's load forecast, GWh										
7	20% of CPUC adopted EE goals in D. 04-09-060 not included in CEC load forecast			213	416	634	868	1,124	1,379	1,634	1,890
8	RPS (incremental amounts above 2007, increasing to 20% in 2010)	0	1,990	3,979	5,969	6,220	6,466	6,700	6,925	7,152	7,376
9											
10	Total preferred resources in PG&E's recommended plan	84	2,161	5,304	8,396	9,820	11,326	12,924	14,513	16,104	17,692
11											
12	CO2 savings, million metric tons per year										
13	Based on a 9,400 Btu/kWh heat rate (EPS of 1,100 lb of CO2/MWh)	0.04	1.08	2.65	4.20	4.91	5.66	6.46	7.26	8.05	8.84
14	Based on a 6,916 Btu/kWh heat rate (2007 MPR average heat rate)	0.03	0.79	1.95	3.09	3.61	4.17	4.75	5.34	5.92	6.51

Notes

Item	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Sales in PG&E's service area from CEC's Dec 2007 final load forecast, GWh			Source CEC Form 1.9a - PG&E Planning Area							
Bundled	78,860	79,981	81,149	82,303	83,558	84,788	85,959	87,086	88,220	89,339
Direct Access	6,883	6,814	6,814	6,814	6,814	6,814	6,814	6,814	6,814	6,814
Total	85,743	86,795	87,963	89,117	90,372	91,602	92,773	93,900	95,034	96,153
CPUC adopted EE goals in D. 04-09-060, Table 1A, extended beyond 2013 at 2013 level			1,067	1,015	1,086	1,173	1,277	1,277	1,277	1,277
Cumulative "uncommitted" EE savings			1,067	2,082	3,168	4,341	5,618	6,895	8,172	9,449
Line 8 RPS volumes used	10,492	12,482	14,471	16,461	16,712	16,958	17,192	17,417	17,644	17,868
	13.3%	15.6%	17.8%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%

Lines 13 and 14 million metric tons/year of CO2 savings = GWh of avoided gas-fired generation/year x 117 lb/MMBtu x heat rate Btu/kWh x 1,000 kWh/MWh / 2,200 lb/Ton / 1,000,000

VI. COMMISSION REVIEW OF IMPLEMENTATION OF PROCUREMENT PLAN

A. Compliance With AB 57

~~Assembly Bill (“~~AB~~”)~~ 57 (Public Utilities Code section 454.5) includes detailed requirements for a ~~Load-serving Entity’s (“~~LSE’s~~”)~~ procurement plan. ~~In this proceeding, Pacific Gas and Electric Company’s (“~~PG&E’s~~”)~~ 2006 ~~Long-Term Procurement Plan (“~~LTPP~~”)~~ fully complies with these requirements, as the table below demonstrates:

TABLE VI-1~~VOL. 1, VIIIA-1~~
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH AB 57

PUC Section 454.5(b) Requirements	Summary of Compliance And Citation To 2006 LTPP
1. An assessment of price risk associated with PG&E’s portfolio.	~~Volume 1,~~ Section II.B and Appendix B~~s~~ ~~III.B, IV.F, VI~~
2. Definition of electricity products, electricity-related products and procurement-related financial products, including justification and the amount to be procured.	~~Volume 1,~~ Section~~s~~ II.A.3~~III.A and IV~~
3. The plan duration.	~~Volume 1,~~ Section I ~~II.B.3~~
4. The duration, timing and range of quantities of each product to be procured.	~~Volume 1,~~ Sections IV and Appendix A~~III.A, IV and V~~
5. A description of PG&E’s competitive procurement process.	~~Volume 1,~~ Section IV ~~III.A.2 and III.A.5~~
6. Any proposed incentive mechanism.	Not applicable ~~PG&E is not proposing an incentive mechanism in this proceeding~~.
7. The upfront standards and criteria for the acceptability and eligibility for rate recovery, and any expedited approval process.	~~Volume 1,~~ Section II.A.5 ~~III, IV, V and VI~~
8. Procedures for updating the plan.	~~Volume 1,~~ Section I ~~VIII~~
9. A showing that the plan achieves: (a) the 20% RPS standard and 1% incremental RPS procurement standard; (b) a diversified portfolio; and (c) meeting resource needs through energy efficiency and demand reduction when it is cost effective, reliable and feasible.	~~Volume 1,~~ Section IV ~~IV and V~~

10. PG&E's risk management policies.	~~Volume 1,~~ Section II.B and Appendix B~~III.B~~
11. A diversity of ownership and fuel supply.	~~Volume 1,~~ Section IV ~~III.C~~

TABLE VI-1~~VOL. 1, VIIIA-1~~
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH AB 57
(CONTINUED)

PUC Section 454.5(b) Requirements	Summary of Compliance And Citation To 2006 LTPP
12. A mechanism for recovery of reasonable administrative costs related to procurement in the generation component of rates.	~~Volume 1,~~ Section VI.C ~~VIII~~

~~The California Public Utilities Commission ("Commission") should approve PG&E's 2006 LTPP as being fully compliant with the requirements of Section 454.5(b). Approving PG&E's 2006 LTPP will ensure timely procurement of new resources, that PG&E is not subject to after-the-fact reasonableness reviews and that PG&E fully recovers its procurement costs – three of the primary goals of AB 57.~~

B. Compliance With the Commission's Procurement Standards of Conduct

In ~~Decision ("~~D.~~")~~ 02-10-062, the Commission adopted seven Standards of Conduct for utility procurement.[1] These standards have subsequently been modified, and two of them have been eliminated.[2] PG&E's 2006 LTPP is in full compliance with Commission's Standards of Conduct. The following table includes each standards of conduct, a summary of PG&E's compliance with the standard and the portion of the 2006 LTPP that addresses PG&E's compliance:

[1] D.02-10-062 at 51-52.

[2] See D.02-12-074, Order Paragraph 24 (modifying standards); D.03-06-067, Ordering Paragraph 3 (modifying standards and eliminating Standard Nos. 6-7); and D.03-06-076, Ordering Paragraph 6 (clarifying that "Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges."). PG&E also received a waiver from Standard of Conduct 1 for certain gas transportation transactions in D.04-06-003.

TABLE VI-2~~VOL. 1, VIIIA-2~~
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT

Standard of Conduct	Summary of Compliance And Citation To 2006 LTPP
1. Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited.	PG&E's procurement practices and competitive, arms-length solicitations are described in ~~Volume 1,~~ Section II.A.5. ~~III.A.5~~. ~~PG&E has not conducted any affiliate transactions since it resumed procurement in 2003.~~ To the extent PG&E conducts any affiliate transactions ~~in the future~~, these transactions will be conducted in full compliance with the Commission's affiliate and procurement rules.
2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process that: (1) identifies trade secrets and other confidential information; (2) specifies procedures for ensuring that such information retains its trade secret and/or confidential status [*e.g.*, limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.]; (3) discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges; (4) discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; and (5) requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances [*e.g.*, where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer]. All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility.	PG&E's compliance practices are described in ~~Volume 1,~~ Section II.A.1.e.~~III.A.1.e~~.
3. In filing transactions for approval, the utilities shall make no misrepresentation or omission of material facts of which they are, or should be	PG&E has filed procurement information in a number of different reports, which are described in more detail in ~~Volume 1,~~ Section VI.C~~VIII.C~~, below.

aware.	PG&E has not misrepresented any information, or made any omission of material fact in any of these reports.

TABLE VI-2~~VOL. 1, VIIIA-2~~
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT (CONTINUED)

Standard of Conduct	Summary of Compliance And Citation To 2006 LTPP
4. The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our definitions of prudent contract administration and least cost dispatch is the same as our existing standard. Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. ~~PG&E's description of least-cost economic dispatch methodology described in its 1992 "Resource: An encyclopedia of energy utility terms," 2d edition, at pages 152-3 is appropriate with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations.~~ The utility bears the burden of proving compliance with the standard set forth in its plan.	PG&E's dispatch and administration of procurement contracts is described in ~~Volume 1,~~ Section II.A.7.~~III.A.1.c and III.A.5.a (4)-(5)~~.
5. The utilities shall not engage in fraud, abuse, negligence, or gross incompetence in negotiating procurement transactions or administering contracts and generation resources.	PG&E procurement practices have been fair, open and transparent. PG&E has used an independent evaluator for long-term transactions and discussed short- and long-term transactions with the PRG. PG&E's procurement practices are described in detail in ~~Volume 1,~~ Sections II.A.6 and II.A.8.~~III.A.5~~. PG&E's has also appropriately administered its procurement contracts. PG&E's ongoing administration is reviewed through the Energy Resource Recovery Account ("ERRA") process and

	quarterly audits.

~~The 2006 LTPP filing demonstrates that PG&E has been, and will continue to be, in full compliance with the Commission's Standards of Conduct. As a part of its ongoing regulatory oversight, the Commission ensures PG&E's compliance with these standards by reviewing the numerous filings made by PG&E, conducting proceedings regarding the approval of long-term contracts, and allowing other parties to file complaints regarding PG&E's practices, if any such complaint arises. PG&E's contract administration is also reviewed by the Commission through the ERRA process and quarterly audits.~~

C. Description of PG&E Filings Made to Demonstrate Compliance

PG&E submits monthly, quarterly, and annual filings to demonstrate compliance with its approved procurement plan and Commission policy. These filings are described below. ~~PG&E has fully complied with all of the Commission-mandated filing requirements. In addition, in Volume 2, Section IV.F., PG&E puts forth a proposal for streamlining the existing procurement reporting requirements.~~

1. Monthly Reports

a. Portfolio Risk Reduction Report

~~D.03-12-062, which adopted the investor-owned utility's ("IOU") 2004 Short-Term Procurement Plan ("STPP"), mandated that the IOUs report the To-expiration-Value-at-Risk ("TeVaR") as measured on a 12-month rolling basis at the 99% confidence level.[3] The decision also provided that the report be filed monthly in 2004 and quarterly in 2005.[4] TeVaR consists of the following components: the electric and gas net open position, market prices and price uncertainty, hydro generation uncertainty, and load uncertainty. In addition to this decision, the Division of Ratepayer Advocates ("DRA") issued a standing data request (dated October 22, 2006) for similar information. Accordingly,~~ PG&E reports TeVaR on a monthly basis to both

~~[3] D.03-12-062, Ordering Paragraph 2.~~

~~[4] D.03-12-062, Ordering Paragraph 4. D.04-12-048 subsequently directed the IOUs to continue filing the monthly portfolio risk report. *See* D.04-12-048 at 152.~~

the Energy Division ("ED") and Division Ratepayer of Advocates ("DRA"). Due to differences in the requested data, PG&E had previously met with ED in order to agree on a reporting format. While minor modifications have been made over time, the basic format continues with TeVaR currently reported on both a 95% and 99% Confidence Interval for the following periods:

- Monthly for the rolling 12-month period (*e.g.*, October 2006 to October 2007);
- Quarterly for the balance of the current calendar year (*e.g.*, 2006);
- Quarterly for the next three calendar years (*e.g.*, 2007, 2008 and 2009); and
- Yearly for the last calendar year of reporting (*e.g.*, 2010).

~~PG&E has submitted each of the Portfolio Risk Reduction Report filings in a timely manner and intends to continue to provide these reports as long as it is required to do so by the Commission.~~

b. **Monthly ERRA Report**

In D.02-12-074, the Commission directed the three IOUs to file with the "Energy Division each month a report showing the activity in the ERRA balancing account with copies of original source document supporting each entry over $100.00 recorded in the account" no later than the 20th following the end of the month and be served on interested parties in the proceeding.[5] The stated intention of this report was to give the Commission an opportunity to anticipate when an IOU might file an expedited trigger application and to reduce the time to review such an application. D.07-04-020~~04-12-048~~ directed the IOUs to continue to file a monthly ERRA report, but reduced the amount of supporting documentation.[6] ~~PG&E has submitted each of the monthly ERRA reports in a timely manner and intends to continue to provide these reports as long as it is required to do so by the Commission.~~

[5] D.02-12-074 at 43.

~~[6] D.04-12-048 at 152.~~

c. Standing Data Requests From Energy Division

PG&E responds on a monthly basis to the ED data request for electric generation procurement information. The requested procurement information relates to weekly and monthly weighted average cost of electric procurement, monthly energy and maximum capacity load forecasts for a rolling 12-month period, monthly residual net short forecast for a rolling 12-month period, and monthly electricity and gas price forecasts used to derive the residual net short forecast.

2. Quarterly Filings

D.02-10-062 ordered each IOU to file the Quarterly Procurement Compliance Reports. The purpose of this report is to describe all electric generation procurement transactions executed in a given quarter that are not more than five years in duration, not filed through a separate advice filing or application, and within the procurement authority authorized by the Commission in D.02-10-062, D.03-12-062, D.04-07-028, D.04-01-050, ~~and~~ D.04-12-048 and D.07-12-052. These Quarterly Procurement Compliance Reports are filed within 30 days of the end of the quarter, as specified in D.03-12-062. As stated in D.07-12-052~~02-10-062~~, Quarterly Procurement Compliance advice filings are to be reviewed by the Commission within ~~30~~ 60 days. If the Commission receives no protests and the ED staff concludes that the transactions included in this report are in compliance with the IOU's approved procurement plan, the ED Director can approve the reports. If a protest is filed, a resolution will be drafted for Commission's final approval.

~~D.04-12-048 directed the IOUs to file a joint proposal to reformat the Quarterly Procurement Compliance Report to provide the Commission concise and coherent information. A description of efforts by the IOUs to reformat and streamline this report is presented in Volume 2, Section IV.E.~~

3. Semi/Annual Filings

a. ERRA Forecast and Compliance Review Filings

PG&E files two annual filings related to ERRA: an ERRA forecast revenue requirement application and an ERRA compliance review application. In D.02-10-062, the Commission established the ERRA balancing account for all three IOUs and established a semiannual update process whereby the IOUs would once a year (1) "file applications proposing to establish annual fuel and purchased power forecasts and true up 2002 fuel and purchased costs" (*i.e.*, ERRA Forecast Revenue Requirement proceeding); and (2) undergo a "review of balancing accounts, contract administration, URG expenses and least-cost dispatch" (*i.e.*, ERRA Compliance Review proceeding).[7] In D.02-12-074, the Commission directed PG&E to file its forecast application on February 1 and the balancing account review application on August 1, 2003.[8] In D.04-01-050, the Commission adopted revised schedules for the 2004 and 2005 semi-annual ERRA filings with PG&E's ERRA compliance review application to be filed in February and the ERRA forecast application to be filed on June 1.

b. ERRA Trigger

In AB 57, the California state legislature established a trigger mechanism that would ensure that any overcollection or undercollection in the appropriate electric procurement balancing account does not exceed 5% of a utility's recorded generation revenues, excluding ~~California Department of Water Resources ("~~DWR~~")~~ revenues, for the prior year.[9] This trigger mechanism provides the necessary assurance to PG&E that its electric procurement costs will be recovered in a timely fashion.

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7 D.02-10-062 at 62.

8 D.02-12-074 at 42.

9 Pub. Util. Code § 454.5(d)(3).

In D.02-10-062, the Commission adopted the AB 57 balancing account trigger mechanism for the California utilities. In that decision, the Commission directed the utilities to file an expedited "trigger" application for approval within 60 days of filing when the ERRA balance reaches or exceeds 4% of the prior year recorded generation revenues excluding DWR revenues. This application is to include a projected account balance in 60 days or more to illustrate when the balance will reach the 5% threshold. The application is also to propose an amortization period of not less than 90 days to ensure timely recovery of the projected ERRA balance.[10] In D.04-01-050, the Commission adopted April 1 as the date when all three California utilities are to file their annual ERRA trigger advice letter, which sets the trigger amount for the following 12 months.

4. **Biennial Filings**

D.05-01-040 adopted the long-term procurement regulatory framework and established that the IOUs shall file long-term plans on a biennial cycle that follows the ~~California Energy Commission's ("~~CEC'~~s"~~ s ~~)~~ adoption of a final ~~Integrated Energy Policy Report ("~~IEPR~~") report~~. D.04-12-048, which approved PG&E's 2004 LTPP, established that starting with the 2006 LTPP proceeding the Short-Term Plans will be eliminated and the IOUs will act in accordance with a single Commission-approved plan. The decision also determined that any updates or modifications to the plans in between the biennial review will be filed with an advice letter. ~~PG&E supports this framework.~~

5. **Additional Monthly, Quarterly, Annual Filings and Data Requests**

The Commission requires ~~Resource Adequacy ("~~RA~~")~~ reporting on a monthly and yearly basis. RA compliance submissions are made directly to the Commission through the advice filing process. In addition, forecasting related data is submitted to the CEC on a monthly as well as a yearly basis. These submissions are not made through advice filings. Both the CEC and Commission submissions are described below.

[10] D.02-10-062 at 63-65, Conclusions of Law 15, and Ordering Paragraph 14.

D.05-10-042 required that PG&E submit advice letter filings that identify load growth changes within its service territory due to load migration, demonstrates that PG&E has acquired sufficient resources to satisfy its 100% commitment obligation for loads plus reserve requirements, and demonstrates that PG&E has met 90% of its summer months obligations one year in advance. D.06-06-064 required that PG&E submit an advice letter filing which demonstrated whether it had entered into any contract with a unit that is among the list of units proposed for 2007 ~~Reliability Must-Run (“~~RMR~~”)~~ Contracts, as well as demonstrating the LSEs’ full Local ~~Resource Adequacy~~ RA Requirement ~~(“RAR”)~~ compliance and an advice letter filing demonstrating that it had met its local RA obligation for each month of the 2007 calendar year period. In addition, PG&E provides the CEC with an annual year-ahead load forecast as well as annual historical data.

APPENDIX A

PG&E NEED DETERMINATION

REDACTED VERSION

TABLE PGE-1
NP-26 Regional Need (MW)

Based on PG&E's LTPP Scenario - 4

	LOAD FORECASTS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	1-in-2 System Summer Temperature Demand [1]	21,406	21,671	21,954	22,236	22,547	22,855	23,158	23,453	23,752	24,050
2	1-in-2 PG&E Service Area Summer Temperature Demand [2]	19,845	20,096	20,364	20,633	20,928	21,222	21,511	21,793	22,078	22,363
	RESOURCES										
	System Resources										
3	Existing Generation	24417	24417	24417	24417	24417	24417	24417	24417	24417	24417
4	Retirements (Announced)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
5	Retirements (Laddered Reduction of Aging Units) [3]	0	0	(600)	(1200)	(1800)	(2400)	(3000)	(3600)	(4200)	(4200)
6	NP26 RPS Additions (Including Imports)	28	142	293	635	895	1181	1496	1609	1733	1870
7	PG&E Planned Additions	0	0	998	2251	2251	2251	2251	2251	2251	2251
8	Other Known/High Probability NP-26 Additions	0	0	180	180	180	180	180	180	180	180
9	Imports -- NW	2348	2348	2348	2348	2348	2348	2348	2348	2348	2348
10	Imports -- WAPA (Firm)	700	700	700	700	700	700	700	700	700	700
11	Adjustment RPS NW Imports	0	(12)	(23)	(42)	(62)	(85)	(110)	(128)	(149)	(172)
12	Exports -- to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
13	Net Interchange	48	36	25	6	(14)	(37)	(62)	(80)	(101)	(124)
14	Total System Resources	24,493	24,596	25,178	26,154	25,793	25,457	25,147	24,642	24,145	24,259
15	Service Area Portion of System Resources [4]	22,707	22,808	23,354	24,268	23,941	23,638	23,359	22,897	22,443	22,557
	Service Area Specific Resources										
16	Uncommitted Energy Efficiency [5]			56	109	166	228	295	362	430	497
17	Price Sensitive Demand Response (DR)	342	394	554	695	750	765	774	783	792	801
18	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
19	Contract viability re-adjustment (for PGE 2006 LTPP) [6]	100	200	300	400	500	600	600	600	600	600
20	Total Service Area Specific Resources	752	947	1263	1557	1769	1946	2022	2098	2174	2251
21	Total Service Area Resources	23,459	23,755	24,617	25,825	25,711	25,584	25,381	24,996	24,618	24,808
	PLANNING RESERVES										
22	Planning Reserve	3,614	3,659	4,253	5,192	4,783	4,362	3,870	3,203	2,540	2,445
23	Planning Reserve (%) [7]	18.2%	18.2%	20.9%	25.2%	22.9%	20.6%	18.0%	14.7%	11.5%	10.9%
24	Lower Bound of Planning Reserve Requirement (15%)	2,977	3,014	3,055	3,095	3,139	3,183	3,227	3,269	3,312	3,354
25	Upper Bound of Planning Reserve Requirement (17%)	3,374	3,416	3,462	3,508	3,558	3,608	3,657	3,705	3,753	3,802
26	**1 in 2 PG&E Service Area Surplus (Deficit) [8]**	**240**	**243**	**791**	**1,685**	**1,225**	**754**	**213**	**(66)**	**(772)**	**(909)**

[1] Based on CEC's 2007 IEPR 1-in-2 peak demand, which embeds self-served load, committed EE and approximately 80% of uncommitted EE. Note the average growth rate of the forecast peak including uncommitted EE (Line 2 - Line 16) is 1.06% per year.
[2] Service area calculation includes bundled and DA customers and excludes POUs.
[3] This line provides a laddered reduction of aging units as described in the Retirements section of the decision.
[4] This line provides the portion of system resources that are available to PG&E's service area (system resources * Line 2/Line 1).
[5] Uncommitted EE not captured in the CEC's demand forecast (approximately 20% total uncommited EE goals plus a 10% line loss factor).
[6] This line replaces deductions for a 10% contract viability derate embedded in PG&E's resource assumptions.
[7] Planning Reserve % = [(Service Area Resources/Service Area Demand)-1].
[8] Surplus represents amount above upper bound of PRM, deficit represent amount below lower bound. No deficit or surplus for values within PRM bounds.

Electricity Resource Planning Form S-1
PG&E Annual Capacity Resource Accounting Table (CRATs)
Bundled Customer Need, Consistent with D. 07-12-052

Line	Applies To:	Capacity Resource Accounting Table Form S-1	Sum of lines:	August 2007	August 2008	August 2009	August 2010	August 2011	August 2012	August 2013	August 2014	August 2015	August 2016
		PEAK LSE LOAD CALCULATIONS (MW)[1]:											
1	All	Forecast Total Peak-Hour Load (1 in 2 Summer)		19,845	20,096	20,364	20,632	20,928	21,222	21,511	21,793	22,078	22,363
1a	IOU/POU	Direct Access Loads in the UDC territory		1,017	967	967	967	967	967	967	967	967	967
2	ESP	Peak Load: Existing Contracts											
3	ESP	Peak Load: New & Renewed Contracts	1 minus 2	19,845	20,096	20,364	20,632	20,928	21,222	21,511	21,793	22,078	22,363
4	IOU/POU	CCA & Departing/Arriving-New Municipal Loads (-/+)											
5	IOU/POU	Uncommitted Price-Sensitive DR Programs (-)											
6	IOU/POU	Uncommitted Energy Efficiency (2009-2016) (-)[2]				52	101	154	211	273	336	399	462
7	IOU/POU	Distributed Generation for Customer Use (-)											
7a	IOU/POU	Peak Coincidence		209	220	222	225	228	231	233	236	238	241
8	All	Net Peak Demand for End-Use Customers	1 - 1a- (sum 4 thru 7a)	18,619	18,909	19,123	19,340	19,580	19,814	20,038	20,254	20,475	20,694
9	IOU/ESP	Net Peak Demand + 15% Planning Reserve Margin[3]	(8 x 1.15)-((53 + 54)*.15)	21,318	21,638	21,860	22,088	22,356	22,622	22,878	23,126	23,378	23,629
10	IOU/POU	Firm Sales Obligations		0	0	0	0	0	0	0	0	0	0
11	All	Firm LSE Peak Resource Requirement	Sum 9 + 10	21,318	21,638	21,860	22,088	22,356	22,622	22,878	23,126	23,378	23,629
		EXISTING & PLANNED RESOURCES											
		Utility-Controlled Fossil and Nuclear Resources:											
15	IOU/POU	Total Dependable Fossil and Nuclear Capacity											
		Utility-Controlled Hydroelectric Resources:											
16	IOU/POU	Total for all Hydro Plants over 30 MW											
17	IOU/POU	Total for all Hydro Plants 30 MW or less		246	246	246	237	237	237	225	224	224	224
		Utility-Controlled Renewable Resources:											
24	IOU/POU	Total Renewable Capacity		0	0	0	0	0	0	0	0	0	0
25	IOU/POU	Total Utility-Controlled Physical Resources	Sum 15 thru 17 + 24										
		DWR Contractual Resources:											
29	IOU	Total DWR Contracts[4]		4,247	3,427	3,607	2,127	1,332	442	276	276	276	180
		Qualifying Facility (QF) Contractual Resources:											
37	IOU	Total QF Capacity[5]		2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166
		Renewable Energy Contractual Resources:											
42	All	Total Capacity from Renewable Energy Contracts		304	347	428	533	533	533	433	406	406	404
		Other Bilateral Contracts:											
47	All	Total Other Bilateral Contracts		6,340	5,575	5,933	6,048	3,909	2,082	1,720	1,720	1,720	1,720
		Short Term and Spot Market Purchases & Sales:											
51	All	Net of Short Term Spot Market Purchases & Sales											
52	All	**TOTAL: EXISTING & PLANNED CAPACITY**	Sum 25+29+37+42+47+51				19,112	16,178	13,462	12,772	12,732	12,732	12,562
		DEMAND SIDE DISPATCHABLE RESOURCES											
53	All	Price Sensitive Demand Response (DR)[6]		287	327	327	328	328	328	329	329	329	329
54	All	Interruptible/DR Curtailable Programs[6]		337	391	551	692	747	762	772	781	790	799
55	All	Total Capacity with I/E and DDR	Sum 52 + 53 + 54				20,132	17,254	14,552	13,872	13,841	13,850	13,690
		FUTURE GENERIC RESOURCE NEEDS											
56	All	Generic Renewable Resources[7]		0	65	131	351	593	860	1,153	1,258	1,374	1,501
		Non-Renewable Generic Resources:											
57	All	Capacity for Baseload Energy											
58	All	Capacity for Load-Following and Peaking Energy											
59	All	Load-Following (year-round) Capacity											
60	All	Peaking (seasonal) Capacity											
61	All	Total Capacity of Non-Renewable Generic Resources	Sum 57 thru 60				0	0	0	0	0	0	0
62	All	Total Capacity of Future Generic Resources	Sum 56 + 61				351	593	860	1,153	1,258	1,374	1,501
		CAPACITY BALANCE CHECK											
63	All	Total Capacity of all Resources	Sum 55 + 62				19,463	16,771	14,321	13,925	13,989	14,105	14,063
64	All	Net Open or Net Surplus Capacity Position[8]	63 minus 11				-2,625	-5,584	-8,301	-8,954	-9,137	-9,273	-9,566
		UDC & SYSTEM NEEDS ACCOUNTING											
65	IOU/POU	Firm LSE Peak Resource Requirement	Repeat line 11										
66	IOU/POU	Direct Access Loads in the UDC territory	Repeat line 1a										
67	IOU/POU	Other non-IOU & non-DA loads in the UDC											
68	IOU/POU	System Needs (quick start, black start, VARs)											
69	IOU/POU	Total UDC Capacity Needs	Sum 65 thru 68										

[1]Per D.12-07-052, reflects the CEC's 2007 IEPR 1 in 2 peak demand for PG&E's bundled customers.
[2]Per D.12-07-052 (Table PGE-1), additional Uncommitted EE not captured in the CEC's demand forecast. Adjusted to reflect only bundled customers' portion.
[2]Per D.12-07-052, planning reserve margin to be 15%-17% of the 1 in 2 monthly peak
[4]For 2008 and 2009, represents an adjustment to account for the Calpine 2 amended contract.
[5]To comply with D. 07-12-052, PG&E is including 2,166 MW for QF capacity. However, PG&E estimates this number is higher by a few hundred MW.
[6]Per D.12-07-052 (Table PGE-1). Adjusted to reflect only bundled customers' portion.
[7]Per D.12-07-052 (Table PGE-1). Adjusted to reflect only generation to meet bundled customers' need.
[8]The open position here will be filled through a variety of existing resources as well as the 800-1,200 MW of new generation by 2015 as authorized in D. 07-12-052.
Note: For consistency with the CEC's IEPR process, line numbering/naming convention is consistent with PG&E's March 5, 2007 amended 2006 LTPP filing.

APPENDIX B

ELECTRICITY AND GAS HEDGING PLAN

WILL BE PROVIDED SUBSEQUENTLY

APPENDIX C

NUCLEAR FUEL PROCUREMENT PLAN

CONFIDENTIAL

REDACTED IN ITS ENTIRETY

UNDER PROTECTIONS OF D.06-06-066

AND

CPUC CODE SECTION 583

APPENDIX D

A COPY OF PG&E'S GHG EMISSIONS PROFILE SUBMITTED TO THE CALIFORNIA CLIMATE REGISTRY

Annual Emissions Report

Report 11/3/06 4:15 PM

Pacific Gas & Electric Company

77 Beale Street, B24A
San Francisco, CA 94105 United States
http://www.pge.com
415-973-6905
gjs8@pge.com

Legend

Blue	=
Orang	=

Contact:	Greg San Martin
Industry	Utility
NAIC Code:	221-Utilities
SIC Code:	4931-Electric and Other Services Combined
Description	Pacific Gas and Electric Company is the principal provider of electricity and natural gas distribution and transmission services in northern and central California. Our service territory covers 70,000 square miles (46 of California's 58 counties). We hav

CERTIFIED EMISSIONS INFORMATION

Reporting Year:	2004
Reporting	CA
Reporting Protocol:	General Reporting Protocol, Version 1 (October 2002); Power/Utility Reporting Protocol, Version 1 (April 2005)
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Mobile Combustion	**86,171.65**	86,171.65	0.00	0.00	0.00	0.00	0.00	metric ton
Stationary Combustion	**926,064.75**	926,064.75	0.00	0.00	0.00	0.00	0.00	metric ton
Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Fugitive Emissions	**125,235.69**	0.00	0.00	0.00	0.00	0.00	5.24	metric ton
TOTAL DIRECT	**1,137,472.10**	1,012,236.41	0.00	0.00	0.00	0.00	5.24	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of w hich has a unique Global Warming Potential (GWP). Emissions of each gas are first multip

Energy Imports	**1,222,681.37**	1,222,681.37	0.00	0.00	metric ton
Energy Exports	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**1,222,681.37**	1,222,681.37	0.00	0.00	metric ton

CERTIFICATION INFORMATION

Certifier Name:	SGS North America Inc
Basis of Certification	PG&E's inventory has been verified against the General and Power and Utilities Protocols. The data for 2004 is found to be free from material error or omission.
Certifier Comments:	

Comments We use Registry default factors.
We rely largely on FERC and the data management structures in place to roll up source-, facility-, and department-specific emissions into an entity-wide or sub-entity-wide emissions.

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not certified under Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Other Indirect Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric:

Emissions Management Programs:
US EPA's SF6 Emission Reduction Program (voluntary effort)
US EPA's Natural Gas Star Program (voluntary effort)
US EPA's Energy Star Program (voluntary effort)
Customer Energy Efficiency (a PUC mandated program)
Customer Energy Efficiency and Conservation

Emissions Reduction Projects:

Emissions Reduction Goals: PG&E has a number of emission reduction goals. In the SF6 partnership with US EPA, we committed to a 60 % reduction in SF6 emissions. Since 1998, we have achieved in excess of a 75 % reduciton in leak rates. We established an internal target for electr

REFERENCE DOCUMENTS

Title	Author	Publish Date
2004 PUP Spreadsheet	Greg San Martin	10/12/2006 12:00:00 AM

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of w hich has a unique Global Warming Potential (GWP). Emissions of each gas are first multip

Annual Entity Emissions: Electric Power Generation/Electric Utility Sector

Pacific Gas & Electric Corporation

77 Beale Street
San Francisco, California 94115
www.pge.com

Reporting Year: **2004**

Reporting Scope: **CA and U.S.**
Reporting Protocols: **General Reporting Protocol Version 2.0 (April 2006)**
Power/Utility Reporting Protocol Version 1.0 (April 2005)

Contact: Greg San Martin
Title: Climate Change Coordinator
Telephone: (415) 973-6905
Email: gjs8@pge.com
Industry Type: Electric utility
NAIC Code: 2211 - Electric Power Generation, Transmission and Distribution
SIC Code: 4931 - Electric and Other Services Combined

Entity Descrip. Pacific Gas and Electric Company is the principal provider of electricity and natural gas distribution and transmission services in northern and central California. Our service territory covers 70,000 square miles (46 of California's 58 counties). We have 4.9 million electric accounts and 3.9 million gas accounts. We serve a total of 14 million customers (1 in 21 Americans). We maintain 139,000 miles of electric transmission and distribution lines and 46,000 miles of natural gas transmission and distribution pipelines. Each year, PG&E delivers approximately 75 billion KWhs of electricity and 279,000 MMCF of natural gas. Approximately two-thirds of the electricity we deliver to customers is purchased rather than generated. The purchased and PG&E generated power includes a diverse mix of fuel sources including fossil fuel (oil and natural gas), nuclear, hydroelectric, and renewable sources such as biomass, geothermal, small hydro, solar, and wind.

POWER/UTILITY ENTITY EMISSIONS

Direct Emissions from Owned Facilities	CO_2e	CO_2	CH_4	N_2O	HFCs	PFCs	SF_6	Unit
Mobile Combustion	**86,172**	86,172	0.00	0.00		0.00	n.a.	metric tons
Total Stationary Combustion	**926,065**	926,065	0.00	0.00	n.a.	n.a.	n.a.	metric tons
from Electric Power Generation, Transmission & Distribution Activities	590,671	590,671	0.00	0.00	n.a.	n.a.	n.a.	metric tons
from Natural Gas-Related Activities	323,162	323,162	0.00	0.00	n.a.	n.a.	n.a.	metric tons
from Other On-Site Combustion	12,232	12,232	0.00	0.00	n.a.	n.a.	n.a.	metric tons
Process Emissions	**0.00**	0	0.00	0.00	0.00	0.00	n.a.	metric tons
Fugitive Emissions	**125,236**	0	0.00	0.00	0.00	0.00	5.24	metric tons
TOTAL DIRECT EMISSIONS	**1,137,448**	1,012,236	0.00	0.00	0.00	0.00	5.24	metric tons
% of Net Generation Delivered to CA	100							
% of Net Generation Delivered Outside of CA	0							
Total Direct Emissions from Deliveries to CA	**1,137,448**	1,012,236	0.00	0.00	0.00	0.00	523.90	metric tons
Total Direct Emissions from Deliveries outside of CA	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons

Comments:

Indirect Emissions from Owned Facilities	CO_2e	CO_2	CH_4	N_2O	Unit
Electricity Purchased and Consumed	**49,704**	49,704	0.00	0.00	metric tons
Steam Purchased and Consumed	**0.00**	0	0.00	0.00	metric tons
Heat Purchased and Consumed	**0.00**	0	0.00	0.00	metric tons
Cooling Purchased and Consumed	**0.00**	0	0.00	0.00	metric tons
Total Transmission and Distribution Losses	**1,172,977**	1,172,977	0.00	0.00	metric tons
from Purchased Power	526,640	526,640	0.00	0.00	metric tons
from Wheeled Power (excluding Direct Access)	193,860	193,860	0.00	0.00	metric tons
from Direct Access	452,477.00	452,477	0.00	0.00	metric tons
TOTAL INDIRECT EMISSIONS	**1,222,681**	1,222,681	0.00	0.00	metric tons

	A	C	E	F	G	H	I	J	K
56	**POWER/UTILITY GENERATION/PURCHASES INFORMATION**	**Amount**	**Unit**	**CO_2**	**Unit**				
57	Owned Generation Total (Net)	**26,096,035**	**MWh**	**590,671**	**metric tons**				
58	Fossil Generation (Net)	911,590	MWh	590,671	metric tons				
59	Biogenic Generation (Net)	0.00	MWh	0.00	metric tons				
60	Geothermal Generation (Net)	0.00	MWh	0.00	metric tons				
61	Other Renewable Generation (Net)	9,974,144	MWh	0.00	metric tons				
62	Zero Emission Generation (Net)	15,210,301	MWh	0.00	metric tons				
63	Steam Generation (Net)	0.00	MWh	0.00	metric tons				
64	Purchased Generation Total (Net)	**46,884,970**	**MWh**	**18,152,809**	**metric tons**				
65	Purchased Fossil Generation (Net)	36,146,007	MWh	18,152,809	metric tons				
66	Purchased Biogenic Generation (Net)	3,268,621	MWh	0.00	metric tons				
67	Purchased Geothermal Generation (Net)	1,732,857	MWh	0.00	metric tons				
68	Purchased Other Renewable Generation (Net)	5,737,485	MWh	0.00	metric tons				
69	Purchased Zero Emission Generation (Net)	0.00	MWh	0.00	metric tons				
70	Purchased Cogeneration (Net)	0.00	MWh	0.00	metric tons				
71	Purchased Wholesale Power (Net)	0.00	MWh	0.00	metric tons				
72	**TOTAL FOSSIL GENERATION/PURCHASES**	**37,057,597**	**MWh**	**18,743,479**	**metric tons**				
73	**TOTAL FROM BIOGENIC/GEOTHERMAL SOURCES**	**5,001,478**	**MWh**	**0.00**	**metric tons**				
74	**TOTAL OTHER GENERATION/PURCHASES**	**30,921,930**	**MWh**	**0.00**	**metric tons**				
75	**TOTAL FROM ALL GENERATION SOURCES**	**72,981,005**	**MWh**	**18,743,479**	**metric tons**				
76									
77									
78									
79	**OTHER BIOGENIC EMISSIONS**	**Amount**	**Unit**	**CO_2e**	CO_2	CH_4	N_2O	**Unit**	
80	Stationary Combustion	0.00	MWh	0.00	0.00	0.00	0.00	metric tons	
81	Mobile Combustion	0.00	gallons	0.00	0.00	0.00	0.00	metric tons	
82	Process Emissions			0.00	0.00	0.00	0.00	metric tons	
83	TOTAL OTHER BIOGENIC EMISSIONS			0.00	0.00	0.00	0.00	metric tons	
84	*Comments:*								
85									
86	**EMISSIONS EFFICIENCY METRICS**		**Ratio**						
87	Electricity Deliveries:	566.20	lbs CO_2/MWh delivered *(includes CO_2 from owned and purchased generation)*						
88	Net Generation:	49.90	lbs CO_2/MWh net owned generation *(fossil, hydroelectric, nuclear, solar, DG)*						
89	Net Fossil Generation:	1,428.48	lbs CO_2/MWh net owned fossil generation only						
90	*Comments:*								
91									
92	**De Minimis Emissions**	**CO_2e**	CO_2	CH_4	N_2O	HFCs	PFCs	SF_6	**Unit**
93	*Emissions reported in this section are estimated; these estimates are reviewed by the certifier and found to be less than 5% of the total entity emissions.*								
94	Mobile Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
95	Stationary Emissions	**11,052.70**	11,052.70	0.00	0.00	0.00	0.00	0.00	metric tons
96	Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
97	Fugitive Emissions	**23,879.40**	23,879.40	0.00	0.00	0.00	0.00	0.00	metric tons
98	Indirect Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
99	TOTAL DE MINIMIS EMISSIONS	**34,932.10**	34,932.10	0.00	0.00	0.00	0.00	0.00	metric tons

	A	C	E	F	G	H	I	J	K
102	**OPTIONAL INFORMATION**								
103	*Information in this section is voluntarily provided by the participant for public information, but is not required, and thus, not certified under Registry protocols.*								
104									
105	**Optional Emissions**	**CO_2e**	CO_2	CH_4	N_2O	HFCs	PFCs	SF_6	**Unit**
106	Upstream emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
107	Other Indirect Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
108	TOTAL OPTIONAL EMISSIONS	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
109	*Comments:*								
110									
111	**Information on Environmental Goals and Programs:**								
112									
113	**Information on GHG Risk and Liability:**								
114									
115	**Company Activities Related to Renewable Energy**								
116	Purchases of Tradable Renewable Certificates:	0.00	metric tons CO2e						
117	Sales of Tradable Renewable Certificates:	0.00	metric tons CO2e						
118	Purpose of Transaction:								
119	Geographic Origin of Certificates:								
120	Parties Notified of Transaction(s):								
121	*Comments:*								
122									
123	**Company Activities to Offset GHG Emissions**								
124	Purchases of GHG Emission Offsets:	0.00	metric tons CO2e						
125	Sales of GHG Emission Offsets	0.00	metric tons CO2e						
126	Type of Project(s):								
127	Terms of Purchase/Sale:								
128	Parties Notified of Transaction(s):								
129	*Comments:*								
130									
131	**Company Activities to Improve Energy Efficiency**								
132	Description:								
133									
134									
135									
136									
137	Estimated Annual Energy Efficiency Savings:	0.00	MWh						
138		0.00	therms						
139	Reasons for Undertaking Energy Efficiency Programs:	Demand-side management, reduce peak load, improve energy efficiency of buildings							
140	*Comments:*								
141									
142	**Other Company Actions to Reduce GHG Emissions:**								
143	**Benefits of Actions:**								
144									
145	**Other Emissions Efficiency Metric(s):**								
146									
147									

APPENDIX E
PG&E'S TEVAR METHODOLOGY

Fluctuations in natural gas and electric power prices, hydroelectric generation, and electric load variations result in fluctuations in the overall cost of the PG&E electric portfolio. The To-expiration-Value-at-Risk ("TeVaR") metric is a measure of unexpected changes in PG&E's electric portfolio ~~generation~~ costs, net of electric portfolio ~~generation~~ revenues from sales of cumulative long positions, that accumulate~~d~~ over some specified time period, typically twelve months. TeVaR measures how high the net generation cost to PG&E customers for the period may become if certain market changes occur.

Revenues and costs which accrue to PG&E's electric portfolio, and thus to PG&E customers, depend on prices for natural gas and power at several delivery points. Currently, PG&E's TeVaR model includes power prices (on- and off-peak) at North of Path-15 ("NP15"), South of Path-15 ("SP15"), and the California-Oregon Border ("COB") energy trading hubs, and natural gas prices at PG&E Citygate, ~~Topock,~~ Henry Hub, and Malin delivery points.

The TeVaR metric is computed using a Monte Carlo simulation. In this simulation, for each Monte Carlo "trial," daily spot prices are randomly generated for each of the delivery points and for each day of the projection period, and hydro conditions and electric load are simulated for each month of the projection period. The prices used in the simulation are consistent with current market forward prices, volatility term-structures implied by market data, and with historical correlations of market data. For each day of the projection period, the net cost is computed for every position in the portfolio. The daily and monthly net costs are accumulated over the portfolio and over the projection period to produce a single (aggregated) net cost for each such trial. The variation of net costs over trials produces a probability distribution of net costs. Costs are represented as negative numbers, so the 1st percentile in the distribution of net cost represents more cost to customers than the 10th percentile in the same distribution of net cost. The difference between the mean net cost and the ~~1st~~ 5th percentile of net cost ~~and the mean net cost~~ is identified as TeVaR at the 95th ~~99th~~ percentile, or "TeVaR95~~99~~."

TeVaR95~~99~~ represents the largest additional unexpected cost for PG&E's electric portfolio, with probability 0.95~~9~~. There is a small 0.05~~1~~ probability that unexpected costs can be even greater than TeVaR95~~99~~. Using TeVaR95~~99~~ as a metric for PG&E's hedging program ensures that the unexpected costs to PG&E's customers are closely monitored.

APPENDIX F

ADVICE LETTER 3095-E CONCERNING LONG-TERM CONGESTION REVENUE RIGHTS APPROVED BY RESOLUTION E-4122

July 31, 2007

Advice 3095-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Update to PG&E's Assembly Bill 57 Procurement Plan to Authorize PG&E's Participation In The Long-Term Congestion Revenue Rights Allocation Process That Will Result In Transmission Products With A Term Of Ten Years**

Purpose

By this advice letter, Pacific Gas and Electric Company ("PG&E") requests expedited approval of an update to its California Public Utilities Commission ("Commission") approved Assembly Bill ("AB") 57 Procurement Plan ("PP")[1] and its pending 2006 Long-Term Procurement Plan ("LTPP") to clarify that PG&E is authorized to participate in the California Independent System Operator Corporation's ("CAISO") Long-Term Congestion Revenue Rights ("LT-CRRs") allocation process that will result in LT-CRRs being allocated to PG&E for a 10-year term.

Background

As part of the CAISO's Market Redesign and Technology Upgrade ("MRTU"), the current transmission rights mechanism, known as Firm Transmission Rights ("FTRs"), will be replaced by CRRs. The CAISO's CRR process distinguishes LT-CRRs, which have a delivery term of ten years, from other CRRs, which have delivery terms up to one year. The CAISO intends to allocate LT-CRRs to Load Serving Entities ("LSEs") based upon their historical load and a demonstration of resources owned or under contract. The CAISO's

[1] PG&E filed its 2004 Short-Term Procurement Plan ("2004 STPP") on May 15, 2003, and it was approved by the Commission in D.03-12-062. PG&E's 2004 STPP has been updated via the Commission-approved Advice Letter 2464-E (submitted January 20, 2004, to update certain tables in PG&E's 2004 STPP and provide a list identifying the brokerages and exchanges). In D.04-12-048, the Commission approved PG&E's 2004 Long-Term Procurement Plan. Subsequently, pursuant to D.04-12-048, PG&E filed an updated STPP via Advice Letter 2615-E, which was approved by the Commission and made effective January 28, 2005. The collective set of PG&E's 2004 STPP, including subsequent modifications and updates, and PG&E's 2004 LTPP constitute PG&E's current AB 57 Procurement Plan. PG&E's 2006 LTPP is currently pending in Rulemaking ("R.") 06-02-013.

LT-CRR proposal and allocation process was recently approved by the Federal Energy Regulatory Commission ("FERC") in a July 6, 2007 order.[2]

PG&E's current PP authority includes a category for transmission products, which would includes CRRs,[3] and provides authority for PG&E to enter into transactions having a delivery term up to five years without Commission pre-approval. Thus, procurement of most CRRs is already permitted under the PP.[4] However, the acquisition of LT-CRRs requires additional Commission authority because LT-CRRs have a ten-year term.

Under the CAISO's process, PG&E can nominate LT-CRRs from its Tier 1 and 2 award of CRRs in the CAISO allocation process. Unfortunately, there is not enough time for PG&E to submit its nominations to the Commission for pre-approval, following PG&E's receipt of Tier 1 and 2 awards and for the Commission to act on PG&E's request. Under the CAISO's current schedule Tier 1 and 2 are to be completed by September 12, 2007, and LSEs nominate LT-CRRs between September 21-25, 2007. The CAISO will then allocate the LT-CRRs among LSEs pursuant to its FERC-approved allocation methodology and will announce the results by October 2, 2007. Thus, PG&E needs pre-approved authority from the Commission to participate in the CAISO's LT-CRR nomination and allocation process, which will result in LT-CRRs be allocated to PG&E for a term of ten years.

Update Request

Since LT-CRRs are a recent development and are allocated after a nomination process, rather than through a market, PG&E is filing this update request to modify its PP and its 2006 LTPP to specifically include participation in the CAISO's LT-CRR allocation process as an authorized process for PG&E to participate in, which will result in LT-CRRs with a 10-year term, without the need for Commission pre-approval of specific LT-CRRs.[5]

PG&E is requesting an effective date for this advice filing of September 6, 2007, and thus is

---

[2] *California Independent System Operator*, 120 FERC ¶ 61,023 (2007).

[3] D.04-12-048 at 115 (listing approved products for all three utilities).

[4] PG&E reviewed its policy and analytical approach regarding the annual CRR allocation nominations with its Procurement Review Group ("PRG") on May 30, 2007 and July 11, 2007. In addition, PG&E plans on reviewing its LT-CRR allocation nomination policy with the PRG on August 24, 2007.

[5] PG&E identified CRRs and LT-CRRs as products related to MRTU and transmission products in its 2006 LTPP. *See* Volume 2, Section I at I-8 – I-14, filed March 5, 2007 in R.06-02-013.

requesting that the Commission act expeditiously on this advice letter filing. PG&E's request for expedited review and approval is reasonable and appropriate since participation in the CAISO's process should be beneficial to customers.

Tier Designation

Pursuant to D.07-01-024, Rule 5.3, this advice letter is submitted with a Tier 3 designation.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than **August 20, 2007,** with replies to protests due **August 27, 2007**. Protests should be mailed to:

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Avenue
San Francisco, California 94102

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

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, 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:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
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 and Expedited Consideration

PG&E requests that this advice filing become effective on **September 6, 2007**. In accordance with Public Utilities Code § 311(g)(2), PG&E asks for the Commission to reduce the 30-day review period of the draft resolution in order to have this expeditiously approved by September 6, 2007 so that PG&E can have authorization to participate in the CAISO's LT-CRR nomination and allocation process.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for R.06-02-013. Address changes to the General Order 96-B service list should be directed to Rose de la Torre at (415) 973-4716. Send all electronic approval letters to: PGETariffs@pge.com. Advice letter filings can also be accessed electronically at:

http://www.pge.com/tariffs

Vice President, Regulatory Relations

Attachments

cc: Service List R.06-02-013

APPENDIX G

ADVICE LETTER 3106-E CONCERNING CONGESTION REVENUE RIGHTS APPROVED BY RESOLUTION E-4135

August 20, 2007

Advice 3106-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Update to PG&E's Assembly Bill 57 Procurement Plan to Clarify the Upfront Achievable Standards and Criteria for the Procurement of Congestion Revenue Rights**

Purpose

By this advice letter, Pacific Gas and Electric Company ("PG&E") requests expedited approval of an update to its Commission-approved Assembly Bill ("AB") 57 Procurement Plan ("PP")[1] and its pending 2006 Long-Term Procurement Plan ("LTPP") in order to establish upfront and achievable standards and criteria applicable in procuring Congestion Revenue Rights ("CRRs"), including Long-Term CRRs ("LT-CRRs"), through the California Independent System Operator Corporation's ("CAISO") CRR allocation and auction processes. PG&E recently filed Advice Letter 3095-E, which requested Commission authorization for PG&E to participate in the CAISO's LT-CRR allocation process. This advice letter seeks Commission approval of the upfront standards and criteria for procuring all CRRs, including LT-CRRs.

Background

As part of the CAISO's Market Redesign and Technology Upgrade ("MRTU"), the current transmission rights mechanism, known as Firm Transmission Rights ("FTRs"), will be replaced by CRRs. The attributes of CRRs and the process for making such rights available to market participants differ from the FTR process. Some of these differences warrant an update to PG&E's PP and 2006 LTPP in order to provide upfront and achievable standards and criteria that are more applicable to CRR and LT-CRR transactions.

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[1] PG&E filed its 2004 Short-Term Procurement Plan ("2004 STPP") on May 15, 2003, and it was approved by the Commission in D.03-12-062. PG&E's 2004 STPP has been updated via the Commission-approved Advice Letter 2464-E (submitted January 20, 2004, to update certain tables in PG&E's 2004 STPP and provide a list identifying the brokerages and exchanges). In D.04-12-048, the Commission approved PG&E's 2004 Long-Term Procurement Plan. Subsequently, pursuant to D.04-12-048, PG&E filed an updated STPP via Advice Letter 2615-E, which was approved by the Commission and made effective January 28, 2005. The collective set of PG&E's 2004 STPP, including subsequent modifications and updates, and PG&E's 2004 LTPP constitute PG&E's current AB 57 Procurement Plan. PG&E's 2006 LTPP is currently pending in Rulemaking ("R.") 06-02-013.

In order to understand why this update is needed, it is first important to understand how CRRs will differ from FTRs and how the process for obtaining the rights is different. An FTR is a right with both physical and financial attributes. An FTR has a physical attribute in that it conveys a scheduling priority in the CAISO day-ahead scheduling process for a certain direction on a transmission path if adjustment bids are unavailable to alleviate the congestion (*e.g.*, South to North on Path 15). Additionally, the FTR provides a financial hedge against congestion costs. This hedge is an "option" hedge, meaning that it pays the holder based on the congestion costs along the FTR path, but does not charge the holder if the congestion reverses direction. FTRs are specified on a path and direction basis. That is, the holder has rights to congestion revenues on a transmission branch group for congestion in a particular direction. FTRs are procured through an auction conducted by the CAISO on an annual basis. The FTRs that are acquired are valid in all hours of the term as defined by the CAISO. Additionally, parties may trade FTRs bilaterally and register the change in ownership through the CAISO's Secondary Registration System ("SRS").

CRRs, on the other hand, are financial instruments only and do not convey any scheduling priority. Instead, the CAISO will dispatch resources based upon a Security Constrained Economic Dispatch algorithm. That is, the CAISO will dispatch resources in a least-cost manner subject to transmission system constraints. Since MRTU utilizes a network model, CRRs are designated on a source-to-sink basis. Unlike FTRs, they are not branch group specific. Rather, any network source-sink pair (a point of injection and point of withdrawal of electricity on the grid) can become a CRR. For this reason, there are many more potential CRRs as compared to FTRs to consider when selecting CRRs for PG&E's customers. Another important difference is that CRRs are a financial "obligation." This means that the CAISO will pay the holder if congestion is in the same direction (*i.e.*, from the source to the sink) as the CRR that is held. However, if congestion occurs in the opposite direction (*i.e.*, from the sink to the source), the CRR holder is obligated to pay the congestion value to the CAISO.

The CAISO will be using CRRs as part of its implementation of MRTU. CRRs will initially be allocated to Load Serving Entities ("LSEs") based upon their historical load and a demonstration of resources owned or under contract for which the CRR will serve as a hedge.[2] The allocation of CRRs is followed by an auction process similar to the auction process utilized

[2] Pursuant to the CAISO tariff, the demonstration of a need based upon having a generation resource is applicable to two out of three tiers in the annual allocation process and one out of two tiers in the monthly allocation process in the first year. Subsequent years currently have no source verification process.

for FTRs. The CRR auction is open to any entity meeting the CAISO tariff requirements.[3] The auction and allocation process will occur annually and monthly. The annual CRR allocation process includes a step that allows LSEs to convert a portion of their awarded annual rights into LT-CRRs which have a term of ten years. Finally, CRRs may be transacted bilaterally, and the ownership change must be registered in the CAISO's SRS similar to FTRs.

II. UPDATE REQUEST

In light of the fact that CRRs have different attributes and procurement processes than FTRs, PG&E requests that the Commission adopt the following upfront and achievable standards and criteria related to the procurement of CRRs which will enhance PG&E's PP and 2006 LTPP on a going-forward basis.

1. CRR Source-Sink Pairs Or "Paths"

a. PG&E's current PP imposes no restrictions on the source-sink pairs or paths on which PG&E might obtain transmission service or FTRs. In practice, PG&E has sought transmission service or FTRs on interstate or interzonal transmission paths, or on paths that PG&E reasonably anticipates that it might need to flow energy in the future due to the addition of new contracts, resources or load obligations. If PG&E is able to obtain transmission service or an FTR at an attractive price, for example, PG&E can later sign an energy contract at the market price that uses that transmission service or FTR to bring energy to PG&E's customers at an attractive, all-in delivered price. FTRs have helped PG&E manage its overall energy portfolio. Their availability and future expected availability influences ongoing energy purchases. If PG&E were prohibited from obtaining the transmission service or FTR first, due to the absence of an existing energy contract or source, then opportunities to obtain attractively priced energy going forward might be lost. Stated another way, PG&E currently has the flexibility to obtain either energy or transmission service or a transmission hedge (such as an FTR) first, depending on the opportunities that are available in the market.

b. PG&E believes it should have similar flexibility to obtain CRRs. Specifically, PG&E proposes that it be allowed to obtain CRRs for any path (represented by a source-sink pair) connecting existing generation sources to existing loads (either

[3] These tariff requirements include, among other things, credit requirements, training requirements, and an application to become a CRR holder.

retail loads or wholesale load obligations)[4] or for any path that PG&E reasonably anticipates that it might need to flow energy in the future due to the addition of new contracts, resources or load obligations.[5] Additionally, there may be CRRs which are positively correlated in value with CRRs for paths that have limited availability. PG&E proposes that it be allowed to obtain CRRs for such positively correlated paths as well. It might be desirable for PG&E to obtain CRRs on positively correlated paths if limited CRRs are available for the target path or if the CRRs for the positively correlated path can be obtained at lower prices.

2. Maximum Volume Limits

a. Currently, PG&E has no maximum (or minimum) volume limits for procurement of transmission service or FTRs.

b. Overall or total CRR volume limits are unnecessary for the CAISO's allocation process. This is because the CAISO tariff establishes volume limits for PG&E as an LSE based on PG&E's adjusted load metric.[6] Specifically, PG&E cannot obtain CRRs exceeding 75% of its adjusted load metric in the annual CRR allocation process, and more than 100% cumulatively of its adjusted load metric through the monthly CRR allocation process. Similarly, PG&E cannot obtain LT-CRRs exceeding 50% of its adjusted load metric in the long-term allocation process.

c. Therefore, PG&E proposes that the Commission does not establish total or overall limits for PG&E's procurement of CRRs, including LT-CRRs. Instead, PG&E

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[4] For the initial year of MRTU, all CRRs allocated to an LSE in all but the last "tier" of the annual or monthly CAISO allocation process must be "source-verified," based on a review of actual LSE sources used in 2006. Additionally, the sink for all CRRs allocated to an LSE must be the LSE's Load Aggregation Point ("LAP"), except in the final tier, in which case the sink can be one of the LSE's sub-LAPs.

[5] Technically, under MRTU, market participants do not necessarily schedule energy to flow between two points on the transmission grid. When PG&E refers to the flow of energy on a path under MRTU in this Advice Letter, it is referring to the existence of a generation source at one termination of the path and a load (or load obligation) at the other termination. Typically, there is not a direct, physical connection between the energy source and sink. Rather, the energy source and sink are points on the transmission network and the actual flow of electricity is determined by the configuration of the network and the operation of other interconnected resources and loads.

[6] Adjusted Load Metric is defined by the CAISO as the level of demand that is exceeded in only 0.5% of the hours for the prior year less any Existing Transmissions Contract, Converted Rights, and Transmission Ownership Rights.

proposes source-specific volume limits. That is, PG&E proposes limiting the "net" volume[7] that it could procure at each source node to the maximum non-coincident capacity of the sources (existing, potential, planned, or "positively correlated"[8]) at that node. PG&E proposes separate monthly limits for the on-peak and off-peak hours of the month.

3. PRG Consultation

a. Prior to executing transactions longer than one calendar quarter in delivery duration, PG&E is required by its PP to consult with its Procurement Review Group ("PRG"). As a result of this requirement, PG&E has reviewed with its PRG its proposed bidding strategy for each annual FTR auction in advance of the auction, including discussing the maximum total volume of FTRs that PG&E might acquire.

b. PG&E will continue to consult with its PRG prior to transacting for any CRR having a term greater than one calendar quarter.

c. CRRs awarded in the annual CAISO allocation/auction process only have a term of one calendar quarter. However, notwithstanding the quarterly term, PG&E will consult with the PRG prior to making CRR nominations for any of the tiers in the annual allocation process, or prior to converting awarded CRRs to LT-CRRs. PG&E will also consult with its PRG prior to participating in the annual CRR auction.

d. PG&E does not intend to consult with the PRG prior to each monthly CRR allocation/auction process. However, PG&E will review its CRR position with the PRG in its periodic position update discussions.

4. Valuation and Risk Analysis

a. Prior to participating in the annual and monthly CRR allocation/auction process, PG&E will identify candidate CRRs for consideration based on the location and magnitude of its resources and loads (existing and potential), and may also

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[7] By "net" volume, PG&E is referring to the result of netting CRRs in one direction with CRRs in the counter-flow direction.

[8] See Paragraph 1.b above for the meaning of the term "correlated."

identify additional candidate CRRs that are potentially positively correlated in value with other CRRs of interest.

b. For the overall portfolio and for each of the candidate CRRs, PG&E will estimate the expected value for the relevant time period by using various methods, such as:

   i. Running a model of the transmission network simulating the dispatch of generation to serve load and forecasting Marginal Congestion Costs ("MCCs") or Locational Marginal Prices ("LMPs") at CAISO nodes and hubs;

   ii. Obtaining a forecast of MCCs or LMPs from one or more expert consulting firms;

   iii. Obtaining market price quotations (where available) at trading hubs;

   iv. Analyzing historical MCC and LMP data for trends, relationships, and correlations and using this data and observed trends and relationships to forecast future MCCs or LMPs; or,

   v. Averaging (or weight-averaging) forecasts of MCCs and LMPs that were developed using two or more of the methodologies described above.

   These methods for calculating expected value should not be considered exhaustive, nor will all of these methods necessarily be used, and PG&E expects to make further enhancements over time to its ability to estimate value. The methodologies used for valuation will be reviewed with the PRG during the consultations proposed above.

c. Similarly, prior to participating in the annual and monthly CRR allocation/auction process, or prior to converting awarded CRRs to LT-CRRs, PG&E proposes to evaluate the risks of obtaining CRRs or not obtaining CRRs for the candidate CRR paths. Risk can be created by a number of factors, including: a large congestion cost differential between a PG&E source and sink;[9] variability in the dollar amounts paid or received by holding a CRR; potential generation or transmission outages; higher or lower loads than normal; and future changes to

[9] Such congestion can vary in magnitude considerably over time, can occur in both directions at different times, and is unbounded in MRTU. Congestion is created when the energy delivered to a node exceeds the capacity of the transmission network to flow energy from that point.

the transmission grid, including the interconnection of new generation. One of the risks of not having a CRR is that PG&E may pay a high congestion cost to flow energy from its source to its sink. Having a CRR provides an offsetting payment to compensate PG&E for having to pay that congestion cost. In contrast, one of the risks of having a CRR is that PG&E may have to pay a high congestion cost if congestion counter-flows to the direction of that CRR.[10] For a particular path, PG&E's risk is also impacted by the character of its resource(s) using that path. That is, risk is potentially much higher if the resource is must-take and non-dispatchable, meaning that PG&E must take delivery of energy regardless of the congestion cost from the source to the sink. Another risk PG&E may face is the impact of having to post high amounts of collateral to CAISO to secure its CRR holdings in a stress case scenario. PG&E may employ several different metrics to quantify its risk assessment, including, but not limited, to:

i. Simulating random variables, such as load, hydro, gas prices, and outages, creating a distribution of congestion costs or CRR values for a period of time, and calculating metrics based on that distribution;

ii. Creating a marginal cost of congestion duration curve indicating the number of hours (or percent of the time) that congestion exceeds a particular value and calculating metrics based on that duration curve;

iii. Creating a distribution of the hourly dollar amounts received or paid for holding a CRR and calculating metrics based on that distribution (such as TeVaR at the 99th percentile);[11]

iv. Running various scenarios (or stress cases), such as for high or low loads, high or low gas prices, high or low generation/transmission outages, determining the expected congestion cost or CRR value for these scenarios over a period of time, and calculating the change in cost/value compared to the base case scenario;

v. Forecasting how congestion costs paid might vary depending on whether the resource at the CRR source location is must-take or dispatchable;

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[10] This payment may be offset by PG&E receiving a payment for flowing energy from its source to its sink counter-flow to the direction of congestion. However, if PG&E's source is not available (for example, due to an outage), PG&E would not receive a payment for counter-flowing energy.

[11] To-expiration-Value-at-Risk ("TeVaR") at the 99th percentile is the difference between the value that is not exceeded 99% of the time and the average or expected value.

vi. Estimating the risk mitigation achieved by the addition of candidate CRRs to the overall portfolio; or,

vii. Forecasting the potential amounts paid for holding a CRR during periods of counter-flow.

d. PG&E will review its CRR valuation and risk analysis with its PRG (prospectively for the annual CRR auction/allocation process). Because MRTU is new to California and there is no history on CRRs, MCCs, or LMPs, and because (in PG&E's experience) models, assumptions, methodologies, and technologies continue to improve over time, PG&E does not recommend that the Commission mandate that PG&E use any particular method or model to value or assess the risk of congestion or CRRs.

5. Nomination Criteria in CRR Allocation Process

a. In nominating CRRs in the CAISO's allocation process, and when converting awarded CRRs to LT-CRRs, PG&E may consider a number of factors, including, but not limited to:

i. The expected cost of congestion (and value of the CRR);

ii. Various risk metrics (discussed above) for obtaining or not obtaining a candidate CRR;

iii. The probability that a portion of requested CRR volumes might or might not be awarded due to competing requests for the same CRR; and,[12]

iv. The likelihood and potential cost (or opportunity cost) for PG&E to obtain the candidate CRR in a subsequent tier, the auction, the monthly CRR allocation/auction process, or the secondary market.

[12] If PG&E is not able to obtain certain MWs of CRRs in the allocation process due to oversubscription (non-feasibility of simultaneous award), PG&E has lost the ability to obtain those MWs in that tier. PG&E may seek to replace these MWs with other CRRs in lower priority tiers.

6. PG&E's Participation In The CRR Auction And Conversion Of CRRs To LT-CRRs

a. Because the CRR auction is competitive and likely will involve a number of market participants, PG&E anticipates that the resulting auction prices will fairly reflect the value of CRRs obtained. Accordingly, PG&E requests that the Commission approve PG&E's participation in the CRR auction process and establish that all PG&E auction awards are in compliance with upfront standards and therefore are *per se* reasonable. The CPUC has previously approved PG&E's participation in existing CAISO markets, including the FTR market, and has established that PG&E's transactions in these markets done in compliance with upfront standards are per se reasonable.

b. The annual CRR allocation process includes a step that allows LSEs to convert a portion of their awarded annual rights into LT-CRRs which have a term of ten years. In Advice Letter 3095-E, filed July 31, 2007, PG&E has separately requested Commission authority to participate in the LT-CRR conversion and allocation process. This request was necessary because LT-CRRs have a term of 10-years. Under PG&E's current PP, it is required to seek pre-approval for transactions with a term longer than five years. PG&E requests that in approving this advice letter, the Commission authorize PG&E to convert CRRs to LT-CRRs as a part of the CRR allocation and auction process. PG&E should be able to use its judgment as to which CRRs to convert to LT-CRRs and will review these decisions with its PRG.

7. Transactions In Secondary CRR Market

a. The CRR product is similar to a locational spread, which PG&E is currently authorized to transact under its PP. In a locational spread, PG&E sells energy at one point of the grid and buys energy at another point of the grid. The financial result is the same as if PG&E were to pay to flow energy from the point of the energy sale to the point of the energy purchase.

b. Because of the similarity between CRRs and energy transactions, such as locational spreads, PG&E will use the same transaction processes that its PP authorizes PG&E to use for energy transactions – *e.g.*, transact using brokers or exchanges[13], bilaterally subject to providing a "strong showing" in the

[13] PG&E does not anticipate that there will be any exchanges offering CRRs in the secondary market initially or for some time after MRTU start-up.

Quarterly PP Compliance filing, through an RFO (if feasible), etc. Among valid, competing offers for the same CRR, PG&E will select based on the better price (all else being equal). Particular locational spreads may also be purchased if related CRRs are not available.

c. PG&E will pursue both sales and purchases in the CRR secondary market.

d. PG&E anticipates that there will not be much liquidity (market volume), outside of the CAISO auction, in CRRs at least initially and probably for some considerable time.

Tier Designation

Pursuant to D.07-01-024, Rule 5.3, this advice letter is submitted with a Tier 3 designation.

Protests

PG&E requests an expedited protest period and review period pursuant to General Order 96-B, Section 1.3. Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than **August 29, 2007** with replies to protests due **August 31, 2007**.

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Avenue
San Francisco, California 94102

Facsimile: (415) 703-2200
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Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, 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:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
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 and Expedited Consideration

PG&E requests that this advice filing become effective on **September 6, 2007**. In accordance with Public Utilities Code § 311(g)(2), PG&E asks for the Commission to reduce/waive the 30 day review period of the draft resolution in order to have this expeditiously approved by September 6, 2007 so that PG&E can have authorization to participate in the CAISO's CRR nomination and allocation process with the upfront achievable standards and criteria presented in this Advice Letter.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes to the General Order 96-B service list should be directed to Rose de la Torre at (415) 973-4716. Advice letter filings can also be accessed electronically at:
http://www.pge.com/tariffs

Vice President, Regulatory Relations

APPENDIX H

UPDATED LIST OF BROKERAGES AND EXCHANGES

Brokerages

- Tullett Liberty (acquired Natsource)
- ICAP Energy LLC (acquired APB)
- Prebon
- TFS
- Amerex (recently acquired by GFI Group, Inc.)
- Landmark
- Saddleback
- Anahau Energy LLC
- Evolution Markets Inc

Exchanges and Futures Commission Merchants

- Intercontinental Exchange (ICE) – Exchange and Cleared (London Clearinghouse) trades
- New York Mercantile Exchange (NYMEX) – Exchange and Cleared trades
- R.J. O'Brien (allows accessibility to NYMEX and NYMEX Clearing)
- Barclays (allows accessibility to NYMEX, NYMEX Clearing, and ICE Clearing (London Clearinghouse))

APPENDIX I
PRG, IE, AND RFO REQUIREMENTS
FROM APPENDIX E TO D.07-12-052

Procurement Review Group

- IOUs are to provide PRG members with meeting agendas and materials a minimum of 48 hours in advance of the PRG meeting, unless there are unusual, extenuating circumstances that the IOU communicates to PRG members in an email announcing a meeting or distributing meeting materials on a tighter timeframe.
- The IOUs are to provide confidential meeting summaries to PRG members that include a list of attending PRG members (including the organizations represented), a summary of topics presented and discussed, and a list of information requested or offered to be supplied after the meeting, (and identify the requesting party).
- The IOUs are to individually set up and maintain a web-based PRG calendar that can be accessed and updated by the IOU.
- The IOUs are to provide the following information to the public through a web-based forum: date, meeting time and duration of the meeting; the individuals participating in the meeting and organization represented by the individual; and a list of non-confidential items discussed.
- When procuring or potentially procuring CAM resources, the IOUs are to utilize an advisory CAM Group consistent with the proposal as presented in D.07-12-052, Attachment D.
- The IOUs are required to consult with their PRGs for any transaction with a delivery term greater than three months' duration.

Independent Evaluator

- Each IOU, in conjunction with each respective PRG, shall develop a pool of at least three, but preferably more, IEs to be used beginning January 1, 2009. Each IOU should develop and periodically add to its IE pool as follows:

    1. The IOU shall develop a list of prospective IEs via industry contacts, literature searches, PRG recommendations, and similar methods, solicit information from the prospective IEs and circulate the list of candidates and their "resumes" to the PRG and ED staff for feedback.

    2. The IOU should rely on the guidance regarding IE expertise and qualifications provided in D.04-12-048. However, these qualifications should represent the minimum necessary for an IE to be effective, and the IOU and the PRG should include any additional relevant information that it has gained through its experiences implementing the IE requirements;

3. The IOU and PRG shall interview a subset of prospective candidates that the IOU, PRG, and ED staff deem most suitable for the role (IOUs should arrange for the PRG to conduct interviews with candidate IEs in isolation from the contracting IOU);

4. The PRG shall coordinate the development and submittal to the IOU of its recommendations on each prospective candidate (including the general consensus and any opposition to the consensus). The IOU shall submit a written list of qualified IEs to ED to add to the contracting IOU's pool. The list must contain the recommendations of the PRG that were submitted to the IOU. ED will evaluate the proposed IE's competencies based on the guidelines in D.04-12-048 as well as evaluating the IE's independence including any conflicts of interest. ED shall give final approval for inclusion of an IE in the IE pool by letter to the submitting IOU. ED will also have the right to final approval of the use of a particular IE for each RFO.

5. Beyond the development of the initial IE pool, additional IEs may be added to the pool by following the same procedures listed above.

6. An IE may remain in the IE pool for two years, after which he/she must go through a reevaluation process based upon the inclusion criteria to assure continued compliance. The reevaluation process will involve additional reviews of the IE candidate by the PRG, IOU and ED staff including additional interviews, if necessary.

7. The IOU shall develop a pro forma contract to be used each time it contracts with an IE. If deviations from the pro forma contract are necessary, the modifications must be fully supported when the IOU seeks final approval of the contract. This pro forma contract shall be submitted as part of the next LTPP filing and will be subject to Commission approval.

- Each IOU is to provide the name and information of the IE for each IOU, the type of procurement solicitation the IE was used for and the amount of money involved in the procurement solicitation be reported to the IOUs PRG before and after the solicitation takes place.

- An IE shall be contracted with and retained for all competitive solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids and for all competitive RFOs seeking products greater than three months in length regardless of the bidders. Competitive RFOs include RFOs issued to satisfy service area need and supply side resources not including EE and DR. For solicitations of less than five years, the IE report shall be filed with the QCR. An IE shall be utilized for all competitive RFOs regardless of length, the bidders or the type of the product being sought. For solicitations greater than five years, the IE report shall be filed with the application.
- The IOUs, in consultation with the PRG and ED, shall develop comprehensive conflict of interest disclosure requirements for the IE. An IE may be disqualified from participating in an RFO process if there are particular egregious conflicts of interest that arise during the contract. The conflict of interest disclosure requirements shall be approved along with the standard contracts in the next LTPP~~s~~ proceeding.
- In order to clarify the information required in IE reports, we direct ED to develop a template for IEs to use when developing their reports.

RFO & RFO Process

- The IOUs shall use a project application template developed by ED when developing an application for an approval of winning bid projects.

- The IOUs are to hold a meeting with the IE, PRG and ED to outline their plans and solicit feedback prior to drafting RFO bid documents. Draft RFO bid documents are to be developed under the oversight of an IE, vetted through the PRGs and any differences resolved by ED staff in advance of the public issuance of the bid documents.

- If an IOU needs new fossil resources not formally authorized in a LTPP decision, the IOU must make a showing through an Advice Letter that unusual or extreme circumstances warrant such an action.

- Debt Equivalence is no longer applicable to the evaluation of PPA bids in an RFO.

- IOUs are to consider the use of Brownfield sites first before building new generation on Greenfield sites, subject to the parameters set forth in the decision.

- An IOU must publicly reveal the names of winning bidders after key commercial terms have been finalized, within thirty days of filing an application, or withdraw the application until the bidder's identity and other required information can be released. The actual contract does not have to be revealed.

APPENDIX J

GLOSSARY

A

ABOVE-MARKET COST - The cost of a service in excess of the price of comparable services in the market.

ABNORMAL PEAK DAY (APD) - An abnormal peak day is the coldest day which could reasonably be expected to occur within the Pacific Gas and Electric Company system for planning purposes and is based on the coldest day of record for the Pacific Gas and Electric Company territory.

ACCESS CHARGE - A charge paid by all market participants withdrawing energy from the ISO controlled grid. The access charge will recover the portion of a utility's transmission revenue requirement not recovered through the variable usage charge.

AFFILIATE – A company that is controlled by another or that has the same owner as another company.

AFFILIATED POWER PRODUCER - A generating company that is affiliated with a utility.

AGGREGATION - The process of organizing small groups, businesses or residential customer into a larger, more effective bargaining unit that strengthens their purchasing power with utilities.

AGGREGATOR - An entity that puts together customers into a buying group for the purchase of a commodity service. The vertically integrated investor owned utility, municipal utilities and rural electric cooperatives perform this function in today's power market. Other entities such as buyer cooperatives or brokers could perform this function in a restructured power market.

ALTERNATIVE ENERGY SOURCES – (See RENEWABLE ENERGY)

ANCILLARY SERVICES – Capacity, measured in MW, that is utilized by the control area operator to ensure electric system reliability.

ANIMAL WASTE CONVERSION - Process of obtaining energy from animal wastes. This is a type of biomass energy.

ANNUAL MAXIMUM DEMAND - The greatest of all demands of the electrical load which occurred during a prescribed interval in a calendar year.

AREA LOAD - The electrical load in given geographic area irrespective of what LSEs are providing generation services to end-users within the area.

> **Service Area Load** is generally used to mean the load in an IOU distribution service area including loads served by IOUs through bundled service tariffs, loads served by ESPs under direct access, and loads served by CCAs through the provisions of AB 117. In addition, for the SCE service area the generation and loads of MWD Metropolitan Water district included.

Planning Area Load is generally used to mean Service Area Load plus the loads of publicly-owned utilities embedded within an IOU distribution service area or adjacent to the IOU distribution service area which collectively received transmission service from the PTO unit of an IOU.

PG&E and SCE provide transmission services to, and plan such services for, an extensive list of publicly-owned utilities in common with their own distribution service area customers. In contrast, SDG&E provides no such transmission services to publicly-owned utilities.

ASSOCIATED GAS - Natural gas that can be developed for commercial use, and which is found in contact with oil in naturally occurring underground formations.

ATTRIBUTES - The outcomes by which the relative "goodness" of a particular expansion plan is measured e.g. fuel usage.

AUXILIARY ENERGY SUBSYSTEM - Equipment using conventional fuel to supplement the energy output of a solar system. This might be, for example, an oil-fueled generator that adds to the electrical output of substitutes for the solar system during long overcast periods when there is not enough sunlight.

AUXILIARY EQUIPMENT - Extra machinery needed to support the operation of a power plant or other large facility.

AVAILABLE BUT NOT NEEDED CAPABILITY - Capability of generating units that are operable but not necessary to carry load.

AVERAGE COST - The revenue requirement of a utility divided by the utility's sales. Average cost typically includes the costs of existing power plants, transmission, and distribution lines, and other facilities used by a utility to serve its customers. It also included operating and maintenance, tax, and fuel expenses.

AVERAGE DEMAND - The energy demand in a given geographical area over a period of time. For example, the number of kilowatt-hours used in a 24-hour period, divided by 24, tells the average demand for that period.

AVERAGE HYDRO - Rain, snow and runoff conditions that provide water for hydroelectric generation equal to the most commonly occurring levels. Average hydro usually is a mean indicating the levels experienced most often in a 104-year period.

AVOIDED COST (Regulatory) - The amount of money that an electric utility would need to spend for the next increment of electric generation to produce or purchase elsewhere the power that it instead buys from a cogenerator or small-power producer.

B

BALANCED SCHEDULE - A Scheduling Coordinator's schedule is balanced when generation, adjusted for transmission losses, equals demand.

BALANCING - Making receipts and deliveries of gas into or withdrawals from a pipeline equal. Balancing may be accomplished daily, monthly or seasonally, with non-compliance charges generally assessed for excessive imbalance.

BASE LOAD - The lowest level of power production needs during a season or year.

BASE LOAD (For Gas) - As applied to gas, a given consumption of gas remaining fairly constant over a period of time, usually not temperature-sensitive.

BASE LOAD UNIT - A power generating facility that is economic to run in all hours at full or near full capacity levels.

BASELINE FORECAST - A prediction of future energy needs which does not take into account the likely effects of new conservation programs that have not yet been started.

BASELOAD CAPACITY - Generating equipment operated to serve loads 24-hours per day.

BASE RATE - That portion of the total electric or gas rate covering the general costs of doing business unrelated to fuel expenses.

BILATERAL CONTRACT - A two-party agreement for the purchase and the sale of energy and/or capacity products and services or financially settled products.

BIO-GAS - Methane produced by the decomposition or processing of organic matter.

BIOMASS - Energy resources derived from organic matter. These include wood, agricultural waste and other living-cell material that can be burned to produce heat energy. They also include algae, sewage and other organic substances that may be used to make energy through chemical processes.

BIOMETHANE (Purchase or Sale) - Pipeline quality natural gas produced from renewable (non-fossil based) resources. May include renewable or environmental attributes.

BLACK START – Critical generating units to ensure “black start” capability for purposes of system restoration.

BLACKOUT - A power loss affecting many electricity consumers over a large geographical area for a significant period of time.

BRITISH THERMAL UNIT (Btu) - The quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293 watt hours.

BULK POWER MARKET - Wholesale purchases and sales of electricity.

BULK POWER SUPPLY - Often this term is used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines, and related-equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

BUNDLED CUSTOMERS - Bundled customers are those customers of the IOU for whom the IOU provides a suite of "bundled" services, including procuring and supplying electricity, as well as providing transmission, distribution and customer services.

BUNDLED SERVICE - Electric power, transmission, distribution, billing, metering and related service provided by the IOU.

BURNER TIP - A generic term that refers to the ultimate point of consumption for natural gas.

BUSBAR - In electric utility operations, a busbar is a conductor that serves as a common connection for two or more circuits. It may be in the form of metal bars or high-tension cables.

BUY THROUGH - An agreement between utility and customer to import power when the customer's service would otherwise be interrupted.

BUYER - An entity that purchases electrical energy or services from the Power Exchange (PX) or through a bilateral contract on behalf of end-use customers.

C

CALIFORNIA ENERGY COMMISSION - The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act in 1974 (Public Resources Code, Sections 25000 et seq.) responsible for energy policy. The Energy Commission's five major areas of responsibilities are:

1. Forecasting future statewide energy needs
2. Licensing power plants sufficient to meet those needs
3. Promoting energy conservation and efficiency measures
4. Developing renewable and alternative energy resources, including providing assistance to develop clean transportation fuels
5. Planning for and directing state response to energy emergencies

Funding for the Commission's activities comes from the Energy Resources Program Account, Federal Petroleum Violation Escrow Account and other sources.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA - pronounced See' quah) - Enacted in 1970 and amended through 1983, established state policy to maintain a high-quality environment in California and set up regulations to inhibit degradation of the environment.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) - A state agency created by constitutional amendment in 1911 to regulate the rates and services of more than 1,500 privately owned utilities and 20,000 transportation companies. The CPUC is an administrative agency that exercises both legislative and judicial powers; its decisions and orders may be appealed only to the California Supreme Court.

The major duties of the CPUC are to regulate privately owned utilities, securing adequate service to the public at rates that are just and reasonable both to customers and shareholders of the utilities; including rates, electricity transmission lines and natural gas pipelines. The CPUC also provides electricity and natural gas forecasting, and analysis and planning of energy supply and resources. Its main headquarters are in San Francisco.

CALL-BACK - A provision included in some power sale contracts that lets the supplier stop delivery when the power is needed to meet certain other obligations.

CAPABILITY - Maximum load that a generating unit can carry without exceeding approved limits.

CAPACITY (Demand side) – The amount of power consumed by a customer, measured in MWs, that can be produced upon request.

CAPACITY (Purchase or Sale) - The amount of power capable of being generated, measured in MWs, that can be reduced upon request.

There are various types of electricity capacity:

Dependable Capacity: The system's ability to carry the electric power for the time interval and period specific, when related to the characteristics of the load to be supplied. Dependable capacity is determined by such factors as capability, operating power factor, weather, and portion of the load the station is to supply.

Installed (or Nameplate) Capacity: The total manufacturer-rated capacities of equipment such as turbines, generators, condensers, transformers, and other system components.

Peaking Capacity: The capacity of generating equipment intended for operation during the hours of highest daily, weekly or seasonal loads.

Purchased Capacity: The amount of energy and capacity available for purchase from outside the system

Reserve Capacity: Extra generating capacity available to meet peak or abnormally high demands for power and to generate power during scheduled or unscheduled outages. Units available for service, but not maintained at operating temperature, are termed "cold." Those units ready and available for service, though not in actual operation, are termed "hot."

CAPACITY CHARGE - An assessment on the amount of capacity being purchased.

CAPACITY FACTOR - A percentage that tells how much of a power plant's capacity is used over time. For example, typical plant capacity factors range as high as 80 percent for geothermal and 70 percent for cogeneration.

CAPACITY RELEASE - A secondary market for capacity that is contracted by a customer which is not using all of its capacity.

CARBON DIOXIDE - A colorless, odorless, non-poisonous gas that is a normal part of the air. Carbon dioxide, also called CO2, is exhaled by humans and animals and is absorbed by green growing things and by the sea.

CARBON MONOXIDE (CO) - A colorless, odorless, highly poisonous gas made up of carbon and oxygen molecules formed by the incomplete combustion of carbon or carbonaceous material, including gasoline. It is a major air pollutant on the basis of weight.

CIRCUIT - One complete run of a set of electric conductors from a power source to various electrical devices (appliances, lights, etc.) and back to the same power source.

CITYGATE, PG&E - On the PG&E gas system, the Citygate is any point at which the backbone transmission system connects to the local transmission and distribution system.

CLEAN FUEL VEHICLE - Is frequently incorrectly used interchangeably with "alternative fuel vehicle." Generally, refers to vehicles that use low-emission, clean-burning fuels. Public Resources Code Section 25326 defines clean fuels, for purposes of the section only, as fuels designated by ARB for use in LEVs, ULEVs or ZEVs and include, but are not limited to, electricity, ethanol, hydrogen, liquefied petroleum gas, methanol, natural gas, and reformulated gasoline.

COGENERATION - Cogeneration means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards:

(a) At least 5 percent of the cogeneration project's total annual energy output shall be in the form of useful thermal energy.

(b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

COGENERATOR - Cogenerators use the waste heat created by one process, for example during manufacturing, to produce steam which is used, in turn, to spin a turbine and generate electricity. Cogenerators may also be QFs.

COINCIDENCE FACTOR - The ratio of the coincident maximum demand of two or more loads to the sum of their noncoincident maximum demands for a given period. The coincidence factor is the reciprocal of the diversity factor and is always less than or equal to one.

COMBINED CYCLE PLANT - An electric generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

COMBUSTION - Rapid oxidation, with the release of energy in the form of heat and light.

COMBUSTION TURBINE - A fossil-fuel-fired power plant that uses the conversion process known as the Brayton cycle. The fuel, oil, or gas is combusted and drives a turbine-generator.

COMMERCIAL OPERATION - Occurs when control of the generator is turned over to the system dispatcher.

COMMODITY CHARGE - A charge per unit volume or heat content (i.e., therm) of gas delivered to the buyer. Compare DEMAND CHARGE.

COMPETITIVE TRANSMISSION CHARGE (CTC) - A non-bypassable charge that customers pay to a utility for the recovery of its stranded costs.

COMMUNITY CHOICE AGGREGATION SERVICE (CCA SERVICE) - Allows customers to purchase electric power and, at the customer's election, participate in additional energy efficiency or conservation programs from non-utility entities known as Community Choice Aggregators (CCAs). It is a form of direct access.

COMMUNITY CHOICE AGGREGATOR - Any city, county, or city and county, or group of cities, counties, or cities and counties, whose governing board or boards elect to combine the loads of their residents, businesses, and municipal facilities in a community wide electricity buyers' program. (see PU Code § 331.5.) A CCA may also provide certain energy efficiency and conservation programs to its CCA customers.

COMPETITIVE BIDDING - This is a procedure that utilities use to select suppliers of new electric capacity and energy. Under competitive bidding, an electric utility solicits bids from prospective power generators to meet current or future power demands.

CONDENSER - A heat exchanger in which the refrigerant, compressed to a hot gas, is condensed to liquid by rejecting heat.

CONGESTION - A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously.

CONGESTION MANAGEMENT - Alleviation of congestion by the ISO.

CONSERVATION - Steps taken to cause less energy to be used than would otherwise be the case. These steps may involve improved efficiency, avoidance of waste, reduced consumption, etc. They may involve installing equipment (such as a computer to ensure efficient energy use), modifying equipment (such as making a boiler more efficient), adding insulation, changing behavior patterns, etc.

CONTINGENT FORWARD (Purchase or Sale) - A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.

CONTRACT PATH - The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to take place across the "contract path", notwithstanding the electric fact that power flow in the network will distribute in accordance with network flow conditions. This term can also mean to arrange for power transfer between systems.

CONTRACTS FOR DIFFERENCES - A type of bilateral contract where the electric generation seller is paid a fixed amount over time which is a combination of the short-term market price and an adjustment with the purchaser for the difference.

CONTROL AREA - An electric power system, or a combination of electric power systems, to which a common automatic generation control (AGC) is applied to match the power output of generating units within the area to demand. The control area of the ISO is the state of California.

CORE CUSTOMERS - Residential and small commercial customers who must rely on the traditional distributor bundled service of sales and transportation. Compare NON-CORE CUSTOMERS.

COUNTERPARTY SLEEVES (For Electric Products) - An agreement by a counterparty to buy (sell) electricity from one counterparty and sell it to (buy it from) another counterparty.

COUNTERPARTY SLEEVES (For Natural Gas Physical Products) - Facilitating a transaction with an un-contracted or non-creditworthy through a contracted, creditworthy counterparty.

CRUDE OIL - Petroleum as found in the earth, before it is refined into oil products.

CUSTOMER CLASS - Refers to, in general, a group of customers with similar service requirements. Typical customer classes include residential, industrial, commercial and agricultural.

D

DAILY PEAK - The maximum amount of energy or service demanded in one day from a company or utility service.

DAY-AHEAD MARKET - The forward market for energy and ancillary services to be supplied during the settlement period of a particular trading day that is conducted by the ISO, the PX, and other Scheduling Coordinators. This market closes with the ISO's acceptance of the final day-ahead schedule.

DAY-AHEAD SCHEDULE - Day-ahead Schedule A schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a trading day. This schedule indicates the levels of generation and demand scheduled for each settlement period of that trading day.

DAYLIGHTING - The use of sunlight to supplement or replace electric lighting.

DEKATHERM - A unit of heating value equivalent to 10 therms or 1,000,000 Btus.

DELIVERY POINT - Point at which gas leaves a transporter's system completing a sale or transportation service transaction between the pipeline company and a sale or transportation service customer.

DEMAND (Utility) - The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts.

DEMAND CHARGE - The sum to be paid by a large electricity consumer for its peak usage level.

DEMAND CHARGE - The portion of a rate for gas service which is billed to the customer whether they use the service or not. Depending on the rate design this charge is based on actual or estimated peak usage (1 or 3 days), annual needs or a combination of the two. Compare COMMODITY CHARGE.

DEMAND RESPONSE PROGRAMS - “Demand response” refers to actions taken by end-users to reduce power demand during critical peak times or to shift demand to off-peak times. A demand response program provides customers with incentives for reducing load in response to an event signal. These incentives can take the form of a financial credit or their bill, a dynamic rate or exemption from rolling blackouts. Events can be called for economic or reliability reasons. Because demand response programs are designed to operate only a few hours per event, they typically reduce capacity (kW) but not energy (kWh).

DEMAND SIDE MANAGEMENT (DSM) - The methods used to manage energy demand including energy efficiency, load management, fuel substitution and load building. (See LOAD MANAGEMENT)

DEMONSTRATION - The application and integration of a new product or service into an existing or new system. Most commonly, demonstration involves the construction and operation of a new electric technology interconnected with the electric utility system to demonstrate how it interacts with the system. This includes the impacts the technology may have on the system and the impacts that the larger utility system might have on the functioning of the technology.

DEPENDABLE CAPACITY - The system's ability to carry the electric power for the time interval and period specified. Dependable capacity is determined by such factors as capability, operating power factor and portion of the load the station is to supply.

DEREGULATION - The elimination of regulation from a previously regulated industry or sector of an industry.

DERIVATIVES - A specialized security or contract that has no intrinsic overall value, but whose value is based on an underlying security or factor as an index. A generic term that, in the energy field, may include options, futures, forwards, etc.

DIRECT ACCESS - The ability of end-use customers located in the service territory of an IOU to purchase electricity from retail sellers other than their local utility. (See also RETAIL COMPETITION)

DIRECT ACCESS CUSTOMERS - Customers located within the service territory of an IOU who purchase electricity from sellers other than their local utility. DA customers continue to receive and pay for delivery services from their local utility.

DIRECT ACCESS-ELIGIBLE CUSTOMER – A customer located within the service territory of an IOU who is eligible for Direct Access.

DISPATCH - The operating control of an integrated electric system to: Assign generation to specific generating plants and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls. Control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures. Operate the interconnection. Schedule energy transactions with other interconnected electric utilities.

DISPATCHABILITY - This is the ability of a generating unit to increase or decrease generation, or to be brought on line or shut down at the request or a utility's system operator.

DISTRIBUTION - The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

DISTRIBUTED GENERATION - A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

DISTRIBUTION LINES - Overhead and underground facilities which are operated at distribution voltages, and which are designed to supply two or more customers.

DISTRIBUTION SYSTEM (Electric utility) - The substations, transformers and lines that convey electricity from high-power transmission lines to ultimate consumers, or for Electric Microutilities, the distribution lines that convey electricity from the generating units to the ultimate customer. (See GRID)

DISTRIBUTION UTILITY - The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The distribution utility can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers. The "wires" and "customer service" functions provided by a distribution utility could be split so that two totally separate entities are used to supply these two types of distribution services.

DISTRIBUTIVE POWER - A packaged power unit located at the point of demand. While the technology is still evolving, examples include fuel cells and photovoltaic applications.

DIVESTITURE or DISAGGREGATION - The stripping off of one utility function from the others by selling (spinning-off) or in some other way changing the ownership of the assets related to that function. Most commonly associated with spinning-off generation assets so they are no longer owned by the shareholders that own the transmission and distribution assets.

DUCT - A passageway made of sheet metal or other suitable material used for conveying air or other gas at relatively low pressures.

DWR CONTRACTS - Contracts for generating resource capacity and energy deliveries executed by the California Department of Water Resources during 2001 and allocated to the investor owned utilities for contract administration purposes only.

E

ECONOMIC DISPATCH - The distribution of total generation requirements among alternative sources for optimum system economy with consideration to both incremental generating costs and incremental transmission losses.

ECONOMY ENERGY (Electricity utility) - Electricity purchased by one utility from another to take the place of electricity that would have cost more to produce on the utility's own system.

EEI CONTRACT – Edison Electric Institute contract is a standard master agreement that provides the base terms and conditions for transactions executed between two parties of a particular master agreement.

EFFICIENCY - The ratio of the useful energy delivered by a dynamic system (such as a machine, engine, or motor) to the energy supplied to it over the same period or cycle of operation. The ratio is usually determined under specific test conditions.

ELECTRIC CAPACITY - This refers to the ability of a power plant to produce a given output of electric energy at an instant in time, measured in kilowatts or megawatts (1,000 kilowatts).

ELECTRIC PLANT (PHYSICAL) - A facility that contains all necessary equipment for converting energy into electricity.

ELECTRIC SERVICE PROVIDER (ESP) - An entity that is licensed by the CPUC to provide electric power service to Direct Access Customers (see PU Code §§ 218.3 and 394). An end-use customer can act as its own ESP as long as it complies with all requirements of being an ESP. Also referred to as Energy Service Providers.

ELECTRIC SYSTEM - This term refers to all of the elements needed to distribute electrical power. It includes overhead and underground lines, poles, transformers, and other equipment.

ELECTRIC UTILITY - Any person or state agency with a monopoly franchise (including any municipality), which sells electric energy to end-use customers; this term includes the Tennessee valley Authority, but does not include other Federal power marketing agency (from EPAct).

ELECTRICITY - A property of the basic particles of matter. A form of energy having magnetic, radiant and chemical effects. Electric current is created by a flow of charged particles (electrons).

ELECTRONIC QUARTERLY REPORTS (EQRs) - All FERC jurisdictional public utilities, including power marketers, must file EQRs, in which they:

- Summarize contractual terms and conditions in their agreements for all jurisdictional services, including:
    1. Market-based power sales;
    2. Cost-based power sales; and
    3. Transmission service
- Detail transaction information for short-term and long-term market-based power sales and cost-based power sales during the most recent calendar quarter.
- Tariff holders without effective contracts and transactions must file the ID Data portion of the EQR.

ELECTRICITY TRANSMISSION PRODUCTS – The amount of electricity transportation capability of a transmission line measured in MWs.

EMISSIONS CREDITS FUTURES OR FORWARDS - Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.

END-USE - The specific purpose for which electric is consumed (i.e. heating, cooling, cooking, etc.).

ENERGY - The amount of electricity produced, flowing or supplied by generation, transmission or distribution facilities or consumed over time. Usually it is measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.

ENERGY CHARGE - The amount of money owed by an electric customer for kilowatt-hours consumed.

ENERGY CONSUMPTION - The amount of energy consumed in the form in which it is acquired by the user. The term excludes electrical generation and distribution losses.

ENERGY DELIVERIES - Energy generated by one system delivered to another system.

ENERGY EFFICIENCY - Programs and measures designed to reduce consumer energy consumption. Example of programs and measures include lighting retrofit, process redesign and appliance rebates which encourage consumers to purchase high-efficiency appliances.

ENERGY POLICY ACT OF 1992 - This act which was the first comprehensive federal energy law promulgated in more than a decade will help create a more competitive U.S. electric power marketplace by removing barriers to competition. By doing so, this act allows a broad spectrum of independent energy producers to compete in wholesale electric power markets. The act also made significant changes in the way power transmission grids are regulated. Specifically, the law gives the Federal Energy Regulatory Commission the authority to order electric utilities to provide access to their transmission facilities to other power suppliers.

ENERGY RECEIPTS - Energy generated by one utility system that is received by another through transmission lines.

ENERGY RESERVES - The portion of total energy resources that is known and can be recovered with presently available technology at an affordable cost.

ENERGY RESOURCES - Everything that could be used by society as a source of energy.

ENERGY USE - Energy consumed during a specified time period for a specific purpose (usually expressed in kWh).

ENTHALPY - The quantity of heat necessary to raise the temperature of a substance from one point to a higher temperature. The quantity of heat includes both latent and sensible.

ENTITLEMENT - Electric energy or generating capacity that a utility has a right to access under power exchange or sales agreements.

ENVIRONMENTAL ATTRIBUTES - Environmental attributes quantity the impact of various options on the environment. These attributes include particulate emissions, SO2 or Nox, and thermal discharge (air and water).

ENVIRONMENTAL PROTECTION AGENCY (EPA) - A federal agency created in 1970 to permit coordinated governmental action for protection of the environment by systematic abatement and control of pollution through integration or research, monitoring, standards setting and enforcement activities.

EXCHANGE (Electric utility) - Agreements between utilities providing for purchase, sale and trading of power. Usually relates to capacity (kilowatts) but sometimes energy (kilowatt-hours).

EXCHANGE TRADED CONTRACTS - Contract for electric capacity and energy executed through electronic and voice exchange markets under standard product terms and conditions. Products are generally for “standard products” (peak, on-peak or flat) and standard periods of duration (hourly, daily, balance of month, monthly, quarterly).

EXHAUST - Air removed deliberately from a space, by a fan or other means, usually to remove contaminants from a location near their source.

EXPORTS (Electric utility) - Power capacity or energy that a utility is required by contract to supply outside of its own service area and not covered by general rate schedules.

F

FACILITY - A location where electric energy is generated from energy sources.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) - An independent regulatory commission within the U.S. Department of Energy that has jurisdiction over energy producers that sell or transport fuels for resale in interstate commerce; the authority to set oil and gas pipeline transportation rates and to set the value of oil and gas pipelines for ratemaking purposes; and regulates wholesale electric rates and hydroelectric plant licenses.

FEDERAL POWER ACT - An act that includes the regulation of interstate transmission of electrical energy and rates. This act is administered by the Federal Energy Regulatory Commission.

FEEDER - This is an electrical supply line, either overhead or underground, which runs from the substation, through various paths, ending with the transformers. It is a distribution circuit, usually less than 69,000 volts, which carries power from the substation.

FINANCIAL CALL (OR PUT) OPTION (For Electric Products) – The right, but not the obligation, to buy (call) a forward electric contract on a specific date (expiration) at a specific price (strike). The right to sell is a put option.

FINANCIAL CALL (OR PUT) OPTION (For Natural Gas Financial Products) - The right, but not the obligation, to buy (call) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). The right to sell is a put option. OTC-traded options settle in cash, whereas exchange traded (NYMEX) options must be exercised, which causes delivery of a futures position to the option holder. Options may be combined to hedge a wide variety of positions.

FINANCIAL SWAP – An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps and basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.

FIRM ENERGY - Power supplies that are guaranteed to be delivered under terms defined by contract.

FIRM SERVICE - Service offered to customers (regardless of Class of Service) under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in Off-Peak Service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency. Compare INTERRUPTIBLE SERVICE and OFF-PEAK SERVICE.

FIXED COSTS - The annual costs associated with the ownership of property such as depreciation, taxes, insurance, and the cost of capital.

FORCED OUTAGE - An outage that results from emergency conditions and requires a component to be taken out of service automatically or as soon as switching operations can be performed. The forced outage can be caused by improper operation of equipment or by human error. If it is possible to defer the outage, the outage becomes a scheduled outage.

FORECAST INSURANCE - A method for managing load forecast (volume and shape) risk.

FORWARD ENERGY (Demand side) – Electric energy planned to be consumed by a customer, measured in MWhs that is agreed to be reduced for a specific period for a specified time in the future.

FORWARD ENERGY (Purchase or Sale) – Electric energy purchased or sold by a counterparty, measured in MWhs that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.

FORWARD SPOT (DAY-AHEAD & HOUR-AHEAD) PURCHASE, SALE, OR EXCHANGE – Electric energy, capacity, ancillary services or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.

FOSSIL FUEL - Oil, coal, natural gas or their by-products. Fuel that was formed in the earth in prehistoric times from remains of living-cell organisms.

FREQUENCY - The number of cycles which an alternating current moves through in each second. Standard electric utility frequency in the United States is 60 cycles per second, or 60 Hertz.

FTR LOCATIONAL SWAPS - Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

FUEL - A substance that can be used to produce heat.

FUEL CELL - A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

FUEL DIVERSITY - Policy that encourages the development of energy technologies to diversify energy supply sources, thus reducing reliance on conventional (petroleum) fuels; applies to all energy sectors.

FUEL OIL - Petroleum products that are burned to produce heat or power.

FUTURES MARKET - A trade center for quoting prices on contracts for the delivery of a specified quantity of a commodity at a specified time and place in the future.

G

GAS - Gaseous fuel (usually natural gas) that is burned to produce heat energy.

GAS IMBALANCE - a. Producer/Producer - When one or more producers sell or utilize a volume of natural gas in excess of their gross working interest. b. Pipeline/Pipeline - When a pipeline receives a volume of natural gas and redelivers a larger or smaller volume of natural gas under the terms of a transportation agreement. c. Producer/Pipeline - When a producer delivers a volume of natural gas that is larger or smaller than the volume of natural gas that the pipeline redelivers for the producer's account to another party.

GAS, NATURAL - A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane. 1. Dry. Gas whose water content has been reduced by a dehydration

process. Gas containing little or no hydrocarbons commercially recoverable as liquid product. Specified small quantities of liquids are permitted by varying statutory definitions in certain states. 2. Liquefied (LNG). See LIQUEFIED NATURAL GAS. 3. Sour. Gas found in its natural state, containing such amounts of compounds of sulfur as to make it impractical to use, without purifying, because of its corrosive effect on piping and equipment. 4. Sweet. Gas found in its natural state, containing such small amounts of compounds of sulfur that it can be used without purifying, with no deleterious effect on piping and equipment. 5. Wet. Wet natural gas is unprocessed natural gas or partially processed natural gas produced from strata containing condensable hydrocarbons. The term is subject to varying legal definitions as specified by certain state statutes. (The usual maximum allowable is 7 lbs./MMcf water content and .02 gallons/Mcf of Natural Gasoline.)

GAS STORAGE (Purchase or Sale) - Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.

GAS TRANSPORTATION (Purchase or Sale) - Interstate, Intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.

GAS UTILITY - Any person engaged in, or authorized to engage in, distributing or transporting natural gas, including, but not limited to, any such person who is subject to the regulation of the Public Utilities Commission.

GENERATING STATION - A station that consists of electric generators and auxiliary equipment for converting mechanical, chemical, or nuclear energy into electric energy.

GENERATING UNIT - Any combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power.

GENERATION (Electricity) - Process of producing electric energy by transforming other forms of energy.

GENERATION COMPANY or GENERATOR - A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. The generation company may own the generation plants or interact with the short term market on behalf of plant owners.

GENERATION DISPATCH AND CONTROL - Aggregation and dispatching (sending off to some location) generation from various generating facilities, providing backup and reliability services.

GEOTHERMAL - An electric generating station in which steam tapped from the earth drives a turbine-generator, generating electricity.

GIGAWATT (GW) - One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity. One gigawatt is enough to supply the electric demand of about one million average California homes.

GIGAWATT-HOUR (GWH) - One million kilowatt-hours of electric power. California's electric utilities generated a total of about 270,000 gigawatt-hours in 1988.

GLOBAL CLIMATE CHANGE - Gradual changing of global climates due to buildup of carbon dioxide and other greenhouse gases in the earth's atmosphere. Carbon dioxide produced by burning fossil fuels has reached levels greater than what can be absorbed by green plants and the seas.

GREENFIELD PLANT - Refers to a new electric power generating facility built from the ground up.

GRID - A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points.

GROSS GENERATION - Amount of electric energy produced by generating units as measured at the generator terminals.

H

HEAT RATE - A number that tells how efficient a fuel-burning power plant is. Measured by Btu/kWh. The heat rate equals the Btu content of the fuel input divided by the kWh or power output. The lower the heat rate of a generating unit is, the more efficient the unit is.

HEAT STORM - Heat storms occur when temperatures exceed 100 degrees Fahrenheit over a large area for three days in a row. Normal hot temperatures cause electricity demand to increase during the peak summertime hours of 4 to 7 p.m. when air conditioners are straining to overcome the heat. If a hot spell extends to three days or more, however, nighttime temperatures do not cool down, and the thermal mass in homes and buildings retains the heat from previous days. This heat build-up causes air conditioners to turn on earlier and to stay on later in the day. As a result, available electricity supplies are challenged during a higher, wider peak electricity consumption period.

HEATING VALUE - The amount of heat produced by the complete combustion of a given amount of fuel.

HEDGING - Any method of minimizing the risk of price change. Since the movement of cash prices is usually in the same direction and about in the same degree as the movement of the present prices of futures contracts, any loss (or gain) resulting from carrying the actual merchandise is approximately offset by a corresponding gain (or loss) when the contract is liquidated.

HEDGING CONTRACTS - Contracts which establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose. (See the following: 1.) CONTRACTS FOR DIFFERENCES, 2.) FUTURES MARKET, and 3.) OPTIONS.)

HENRY HUB - A pipeline interchange, located in Vermilion Parish, Louisiana, which serves as the delivery point of natural gas futures contracts.

HIGH HEAT VALUE (HHV) - The high or gross heat content of the fuel with the heat of vaporization included; the water vapor is assumed to be in a liquid state.

HYDROELECTRIC POWER - Electricity produced by falling water that turns a turbine generator. (Also referred to as HYDRO).

I

ICE – Intercontinental Exchange (ICE) is the world’s leading electronic marketplace for energy trading and price discovery.

IMBALANCE ENERGY - The real-time change in generation output or demand requested by the ISO to maintain reliability of the ISO-controlled grid. Sources of imbalance energy include regulation, spinning and non-spinning reserves, replacement reserve, and energy from other generating units that are able to respond to the ISO's request for more or less energy.

IMPORTS (Electric utility) - Power capacity or energy obtained by one utility from others under purchase or exchange agreement.

INDEPENDENT POWER PRODUCER (IPP) - A private entity that operates a generation facility and sells power to electric utilities for resale to retail customers. Although IPPs generate power, they are not franchised utilities, government agencies or QFs. IPPs usually do not own transmission lines to transmit the power that they generate.

INDEPENDENT SYSTEM OPERATOR (ISO) - The entity charged with reliable operation of the grid and provision of open transmission access to all market participants on a non-discriminatory basis. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

INDEX PRICE - Tying the commodity price in a contract to other published prices, such as spot prices for gas or alternate fuels, or general indexes like the Consumer Price Index or Producer Price Index.

INFILTRATION - The uncontrolled inward leakage of air through cracks and gaps in the building envelope, especially around windows, doors and duct systems.

INFRASTRUCTURE - Generally refers to the recharging and refueling network necessary to successful development, production, commercialization and operation of alternative fuel vehicles, including fuel supply, public and private recharging and refueling facilities, standard specifications for refueling outlets, customer service, education and training, and building code regulations.

INSTALLED CAPACITY - The total generating units' capacities in a power plant or on a total utility system. The capacity can be based on the nameplate rating or the net dependable capacity.

INSURANCE (COUNTERPARTY CREDIT INSURANCE, CROSS COMMODITY HEDGES) – A method for managing payment or performance risk for a fee.

INTEGRATED RESOURCE PLAN - A comprehensive and systematic blueprint developed by a supplier, distributor, or end-user of energy who has evaluated demand-side and supply-side resource options and economic parameters and determined which options will best help them meet their energy goals at the lowest reasonable energy, environmental, and societal cost.

INTEGRATED RESOURCE PLANNING (IRP) - A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, IRP includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives. IRP has become a formal process prescribed by law in some states and under some provisions of the Clean Air Act amendments of 1992.

INTEGRATED RESOURCE PLANNING PRINCIPLES - The underlying principles of IRP can be distinguished from the formal process of developing an approved utility resource plan for utility investments in supply- and demand-side resources. A primary principle is to provide a framework for comparing a variety of supply- and demand-side and transmission resource costs and attributes outside of the basic provision (or reduction) of electric capacity and energy. These resources may be owned or constructed by any entity and may be acquired through contracts as well as through direct investments. Another principle is the incorporation of risk and uncertainty into the planning analysis. The public participation aspects of IRP allow public and regulatory involvement in the planning rather than the siting stage of project development.

INTERCHANGE (Electric utility) - The agreement among interconnected utilities under which they buy, sell and exchange power among themselves. This can, for example, provide for economy energy and emergency power supplies.

INTERCONNECTION (Electric utility) - The linkage of transmission lines between two utilities, enabling power to be moved in either direction. Interconnections allow the utilities to help contain costs while enhancing system reliability.

INTERESTED PARTY - Any person whom the commission finds and acknowledges as having a real and direct interest in any proceeding or action carried on, under, or as a result of the operation of, this division.

INTERMEDIATE LOAD – Range from base load to a point between that and peak load.

INTERMEDIATE UNIT - A generator unit that is used for energy production as required with a capacity factor normally in the range of 15-60%.

INTERMITTENT RESOURCES - Resources whose output depends on some other factory that cannot be controlled by the utility e.g. wind or sun. Thus, the capacity varies by day and by hour.

INTERRUPTIBLE LOADS - Loads that can be interrupted in the event of capacity or energy deficiencies on the supplying system.

INTERRUPTIBLE POWER - This refers to power whose delivery can be curtailed by the supplier, usually under some sort of agreement by the parties involved.

INTERRUPTIBLE SERVICE OR TARIFF (Electric utility) - Electricity supplied under agreements that allow the supplier to curtail or stop services at times. A service under which, upon notification from the Independent System Operator, the IOU requires the customer to reduce the demand imposed on the electrical system to firm service level (i.e., a level below which the customer's load will not be interruptible), and the customer must comply within 30 minutes.

INTERTIE - A transmission line that links two or more regional electric power systems.

INTERVAL METERING - The process by which power consumption is measured at regular intervals in order that specific load usage for a set period of time can be determined.

INVESTOR-OWNED UTILITY (IOU) - A private company owned by stockholders that provides electric utility services to a specific service area. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives. A California investor-owned utility is regulated by the California Public Utilities Commission.

INVOLUNTARY DIVERSION - Involuntary Diversions are called when there is a severe supply shortage and deliveries to core customers are threatened. Emergency Flow Order provisions apply and Pacific Gas and Electric Company may divert as from non-core to core customers. Pacific Gas and Electric Company may also divert as-available off-system deliveries, but firm off-system deliveries will not be diverted.

J

No entries for the letter J.

K

KILOVOLT (kv) - One-thousand volts (1,000). Distribution lines in residential areas usually are 12 kv (12,000 volts).

KILOWATT (kW) - One thousand (1,000) watts. A unit of measure of the amount of electricity needed to operate given equipment. On a hot summer afternoon a typical home, with central air conditioning and other equipment in use, might have a demand of four kW each hour.

KILOWATT-HOUR (kWh) - The most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt of electricity supplied for one hour. In 1989, a typical California household consumes 534 kWh in an average month.

L

LEVELIZED - A lump sum that has been divided into equal amounts over period of time.

LINE - A system of poles, conduits, wires, cables, transformers, fixtures, and accessory equipment used for the distribution of electricity to the public.

LIQUEFIED NATURAL GAS (LNG) - Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. It remains a liquid at -116 degrees Fahrenheit and 673 psig. In volume, it occupies 1/600 of that of the vapor at standard conditions.

LOAD - The amount of electric power supplied to meet end users' needs. Load is also an end-use device of an end-use customer that consumes power. Load should not be confused with demand, which is the measure of power that a load receives or requires.

LOAD CENTERS - A geographical area where large amounts of power are drawn by end-users.

LOAD DIVERSITY - The condition that exists when the peak demands of a variety of electric customers occur at different times. This is the objective of "load molding" strategies, ultimately curbing the total capacity requirements of a utility.

LOAD DURATION CURVE - A curve that displays load values on the horizontal axis in descending order of magnitude against percent of time (on the vertical axis) the load values are exceeded.

LOAD FACTOR - The ratio of the average load supplied to the peak or maximum load during a designated period. Load factor, in percent, also may be derived by multiplying the kWh in a given period by 100, and dividing by the product of the maximum demand in kW and the number of hours in the same period. The term also is used to mean the percentage of capacity of an energy facility - such as power plant or gas pipeline -- that is utilized in a given period of time.

LOAD MANAGEMENT - Steps taken to reduce power demand at peak load times or to shift some of it to off-peak times. This may be with reference to peak hours, peak days or peak seasons. The main thing affecting electric peaks is air-conditioning usage, which is therefore a prime target for load management efforts. Load management may be pursued by persuading consumers to modify behavior or by using equipment that regulates some electric consumption.

LOAD-SERVING ENTITY (LSE) - An entity that provides electric power service to end-use customers. LSEs include but are not limited to IOUs, ESPs, CCAs and public-owned utilities.

LOAD SHAPE - A curve on a chart showing power (kW) supplied (on the horizontal axis) plotted against time of occurrence (on the vertical axis), and illustrating the varying magnitude of the load during the period covered.

LOAD SHIFTING - A load shape objective that involves moving loads from peak periods to off-peak periods. If a utility does not expect to meet its demand during peak periods but has excess capacity in the off-peak periods, this strategy might be considered.

LOSS OF LOAD PROBABILITY (LOLP) - A measure of the probability that system demand will exceed capacity during a given period; this period is often expressed as the expected number of days per year over a long period, frequently taken as ten consecutive years. An example of LOLP is one day in ten years.

LOSSES (Electric utility) - Electric energy or capacity that is wasted in the normal operation of a power system. Some kilowatt-hours are lost in the form of waste heat in electrical apparatus such as substation conductors. LINE LOSSES are kilowatts or kilowatt-hours lost in transmission and distribution lines under certain conditions.

M

MARGINAL COST - The sum that has to be paid the next increment of product of service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity. In the utility context, the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.

MARKET-BASED PRICE - A price set by the mutual decisions of many buyers and sellers in a competitive market.

MARKET CLEARING PRICE - The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.

MARKET PARTICIPANT - An entity, including a Scheduling Coordinator, who participates in the energy marketplace through the buying, selling, transmission, or distribution of energy or ancillary services into, out of, or through the ISO-controlled grid.

Market Redesign and Technology Upgrade (MRTU) - represents the largest change to the California wholesale energy market since electric restructuring began in 1998. CAISO has proposed that MRTU become effective in November 2007. Significant efforts will be required by PG&E to implement the systems and software to interface with the CAISO.

MARKETER (For Gas) - Marketers generally purchase gas supplies from producers and then resell them to end-users. Marketers add value and make a profit by saving producers and end-users the trouble of finding each other, arranging transportation and storage, and sometimes by arranging financing or assumption of price risk. Marketers also sometimes market a specific producer's gas without taking title in return for a marketing fee. Numerous marketers currently serve the California market.

MASTER FILE - A file maintained by the PX for use in bidding and bid evaluation protocol that contains information on generating units, loads, and other resources eligible to bid into the PX.

MAXIMUM DEMAND - Highest demand of the load within a specified period of time.

MCF - The quantity of natural gas occupying a volume of one thousand cubic feet at a temperature of sixty degrees Fahrenheit and at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute.

MDQ - The term MDQ refers to maximum daily quantity of gas which a buyer, seller, or transporter is obligated to receive or deliver at each receipt or delivery point or in the aggregate as specified in an agreement.

MEGAWATT (MW) - One thousand kilowatts (1,000 kW) or one million (1,000,000) watts. One megawatt is enough energy to power 1,000 average California homes.

MEGAWATT HOUR (MWh) - One thousand kilowatt-hours, or an amount of electricity that would supply the monthly power needs of 1,000 typical homes in the Western U.S. (This is a rounding up to 8,760 kWh/year per home based on an average of 8,549 kWh used per household per year [U.S. DOE EIA, 1997 annual per capita electricity consumption figures]).

METER - A device for measuring levels and volumes of a customer’s gas and electricity use.

METHANE (CH_4) - The first of the paraffin series of hydrocarbons. The chief constituent of natural gas. Pure methane has a heating value of 1012 Btu per cubic foot.

MINIMUM GENERATION - Generally, the required minimum generation level of a utility system’s thermal units. Specifically, the lowest level of operation of oil-fired and gas-fired units at which they can be currently available to meet peak load needs.

MMBTU - A thermal unit of energy equal to 1,000,000 Btus, that is, the equivalent of 1,000 cubic feet of gas having a heating content of 1,000 Btus per cubic foot, as provided by contract measurement terms. See DEKATHERM.

MMCF - A million cubic feet.

MUNICIPAL UTILITY - A provider of utility services owned and operated by a municipal government.

MUNICIPALIZATION - The process by which a municipal entity assumes responsibility for supplying utility service to its constituents. In supplying electricity, the municipality may generate and distribute the power or purchase wholesale power from other generators and distribute it.

MUST-TAKE GENERATION - Utilities are mandated to take electricity from specific resources identified by the CPUC. Except for Electric Microutilities, the receiver of must-take generation will pay for the electrical energy output of must-take resource even if they refuse to schedule and receive that energy. For this reason, these resources are always economic to receive and scheduled in order to minimize financial loss. Regulatory must-take generation include QF generating units under federal law, nuclear units and pre-existing power-purchase contracts that have minimum-take provisions.

N

NATURAL GAS - Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NATURAL GAS FINANCIAL SWAPS (Purchase or Sale) - Over-the-counter forward products including fixed-for-floating swaps, basis swaps and swing-swaps for gas. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

NATURAL GAS FUTURES (Purchase or Sale) - Standardized forward contracts for gas that trade on an exchange. Futures may be physically or financially settled. Physically settled futures may be unwound by an offsetting trade, exchanged for a physical position, or held to physical delivery.

NATURAL GAS PURCHASES (Physical Supply) - Purchases/sales/exchanges of physical natural gas for terms of one month or longer.

NETWORK - A system of transmission and distribution lines cross-connected and operated to permit multiple power supply to any principal point on it. A network is usually installed in urban areas. It makes it possible to restore power quickly to customers by switching them to another circuit.

NEW-WORLD CONTRACTS - IOU Contracts for electric capacity and energy executed after January 1, 2003 when utilities returned to procurement.

NON-BYPASSABLE CHARGE - charge generally placed on distribution services to recover utility costs incurred as a result of restructuring (stranded costs - usually associated with generation facilities and services) and not recoverable in other ways.

NON-CORE CUSTOMERS - End-users with enough gas volume to justify consideration of transportation-only service from the distributor. Compare CORE CUSTOMERS.

NON-FIRM ENERGY - Electricity that is not required to be delivered or to be taken under the terms of an electric purchase contract.

NON-FTR LOCATIONAL SWAPS - Over-the-counter basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL (NERC) - Council formed by electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply in utility systems of North America. NERC consists of ten regional reliability councils: Alaskan System Coordination Council (ASCC); East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid-America Interconnected Network (MAIN); Mid-Atlantic Area Council (MAAC); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western systems Coordinating Council (WSCC).

NOx - Oxides of nitrogen that are a chief component of air pollution that can be produced by the burning of fossil fuels. Also called nitrogen oxides.

NUCLEAR ENERGY - Power obtained by splitting heavy atoms (fission) or joining light atoms (fusion). A nuclear energy plant uses a controlled atomic chain reaction to produce heat. The heat is used to make steam run conventional turbine generators.

NUCLEAR REGULATORY COMMISSION (NRC) - An independent federal agency that ensures that strict standards of public health and safety, environmental quality and national security are adhered to by individuals and organizations possessing and using radioactive materials. The NRC is the agency that is mandated with licensing and regulating nuclear power plants in the United States. It was formally established in 1975 after its predecessor, the Atomic Energy Commission, was abolished.

NYMEX - New York Mercantile Exchange. The New York Mercantile Exchange, Inc., is the world's largest physical commodity futures exchange and the preeminent trading forum for energy and precious metals.

O

OFF-PEAK - Periods of low demands. All the time outside the on-peak period.

ON-PEAK - Periods of the highest demand.

ON-SITE ENERGY OR CAPACITY (SELF-GENERATION ON CUSTOMER SIDE OF THE METER) – The amount of power measured in MWs or MWhs that can be generated downstream of the customer’s electric meter that can be used to offset the customer’s load served by the electric service provider.

OPTIONS - An option is a contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (for example, a commodity or commodity futures contract), at a fixed price, within a specified period of time. May either be standardized, exchange-traded, and government regulated, or over-the-counter customized and non-regulated.

OUTAGE (Electric utility) - An interruption of electric service that is temporary (minutes or hours) and affects a relatively small area (buildings or city blocks). (See BLACKOUT)

OVER GENERATION - A condition that occurs when total PX participant demand is less that or equal to the sum of regulatory must-take generation, regulatory must-run generation, and reliability must-run generation.

OVERLOAD - The flow of electricity into conductors or devices when normal load exceeds capacity.

P

PARKING SERVICE - Short-term storage of a shipper's excess gas so that shipper doesn't have to sell it in the market.

PARTIAL LOAD - An electrical demand that uses only part of the electrical power available. [See California Code of Regulations, Title 24, Section 2-5342(e) 2]

PEAK DAY CURTAILMENT - Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for gas exceed the maximum daily delivery capability of a pipeline or distribution system. Peak day curtailment is applied independent of seasonal curtailment and does not affect overall authorized volumes to customers under seasonal curtailment.

PEAK DEMAND OR PEAK LOAD - The electric load that corresponds to a maximum level of electric demand in a specified time period.

PEAK FOR OFF-PEAK EXCHANGE – Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period.

PEAKER - A nickname for a power generating station that is normally used to produce extra electricity during peak load times. Typically peaking resources are fully dispatchable and deliver in approximately 10% of hours.

PEAKING CAPACITY - Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads; this equipment is usually designed to meet the portion of load that is above base load.

PG&E (PACIFIC GAS AND ELECTRIC COMPANY) - An electric and natural gas utility serving the central and northern California region.

PHOTOVOLTAICS - A technology that directly converts light into electricity. The process uses modules, which are usually made up of many cells (thin layers of semiconductors).

PHYSICAL CALL (OR PUT) OPTION - The right, but not the obligation, to buy (call) physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to sell is a put option.

PHYSICAL OPTIONS ON NATURAL GAS SUPPLY (Purchase or Sale) - The right, but not the obligation, to buy (call) physical gas for delivery on a particular date at a fixed or index price (strike). The right to sell is a put option.

PIPELINE - A line of pipe with pumping machinery and apparatus (including valves, compressor units, metering stations, regulator stations, etc.) for conveying a liquid or gas.

PIPELINE CAPACITY - The maximum quantity of gas that can be moved through a pipeline system at any given time based on existing service conditions such as available horsepower, pipeline diameter(s), maintenance schedules, regional demand for natural gas, etc.

PIPELINE FUEL - Natural gas consumed in the operation of a natural gas pipeline, primarily in compressors.

POINT(S) OF DELIVERY - Point(s) for interconnection on the Transmission Provider's System where capacity and/or energy are made available to the end user.

PORTFOLIO MANAGEMENT - The functions of resource planning and procurement under a traditional utility structure.

POWER - Electricity for use as energy.

POWER EXCHANGE - This is a commercial entity responsible for facilitating the development of transparent spot prices for energy capacity, and/or ancillary services.

POWER GRID - A network of power lines and associated equipment used to transmit and distribute electricity over a geographic area.

POWER MARKETER - An agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, the difference is that a marketer represents the generator while a broker acts as a middleman.

POWER PLANT - A central station generating facility that produces energy.

POWER PURCHASE AGREEMENT - Specifies the terms and conditions under which electric power will be generated and purchased. Power purchase agreements require the Seller to supply power under specific terms and conditions for the life of the agreement. While power purchase agreements vary, their common elements include: specification of the size, pricing structure, operating flexibility, delivery point, various service and performance obligations; dispatchability options; credit/collateral terms, and conditions of termination or default.

PREFERRED SCHEDULE - The initial schedule produced by a Scheduling Coordinator that represents its preferred mix of generation to meet demand. The schedule includes the quantity of output (generators) and consumption (loads), details of any adjustment bids, and the location of each generator and load. The schedule also specifies the quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators, and is balanced with respect to generation, transmission losses, load, and trades.

PRICE CAP - Situation where a price has been determined and fixed.

PRICE CURVES -

- **Forward Curve (or Futures Price)** - A term structure of forward prices observed in the market. Forward contracts, like futures, are agreements to buy or sell a commodity at a future time. Forward price is the price to be paid at delivery.
- **Price Forecast** - A projection of future price levels (these could be day-ahead prices, futures prices, monthly prices etc.) expressed either in nominal or a given year's dollars, not necessarily reflective of market prices.

PRODUCTION - The act or process of generating electric energy.

PROVIDER OF LAST RESORT - A legal obligation (traditionally given to utilities) to provide service to a customer where competitors have decided they do not want that customer's business.

PUBLIC ADVISOR - An appointee of the governor who attends all meetings of the California Energy Commission and provides assistance to members of the public and intervenors in cases before the Commission.

PUBLICLY OWNED UTILITIES (POUs) - Municipal utilities (utilities owned by branches of local government) and/or co-ops (utilities owned cooperatively by customers).

PUMPED STORAGE - Facility designed to generate electric power during peak load periods with a hydroelectric plant using water pumped into a storage reservoir during off-peak periods.

PURCHASE AND SALE AGREEMENT - The written contract between buyer and seller indicating all terms and conditions of the sale.

PURPA (THE PUBLIC UTILITY REGULATORY ACT OF 1978) - Among other things, this federal legislation requires utilities to buy electric power from private "qualifying facilities," at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced back-up supply of electricity.

PURPA is implemented by the Federal Energy Regulatory Commission and the California Public Utilities Commission (CPUC). Under PURPA each electric utility is required to offer to purchase available electric energy from cogeneration and small power production facilities.

PX - The California Power Exchange Corporation, a state chartered, non-profit corporation charged with providing Day-Ahead and Hour-Ahead markets for energy and ancillary services, if it chooses to self-provide, in accordance with the PX tariff. The PX is a Scheduling Coordinator, and is independent of both the ISO and all other market participants. This exchange is no longer a market participant.

Q

QUALIFYING FACILITY (QF) - “Qualifying facilities” (QFs) are non-utility cogeneration or other power producers that often generate electricity using renewable and alternative resources, such as hydro, wind, solar, geothermal, or biomass (solid waste). QFs must meet certain operating, efficiency, and fuel-use standards set forth by the Federal Energy Regulatory Commission (FERC) pursuant to PURPA (The Public Utility Regulatory Policies Act of 1978).

QUICK-START CAPABILITY - Refers to generating units that can be available for load within a 30-minute period.

R

R-VALUE - A unit of thermal resistance used for comparing insulating values of different material. It is basically a measure of the effectiveness of insulation in stopping heat flow. The higher the R-value number, a material, the greater its insulating properties and the slower the heat flow through it. The specific value needed to insulate a home depends on climate, type of heating system and other factors.

RAMP RATE - The rate at which you can increase load on a power plant. The ramp rate for a hydroelectric facility may be dependent on how rapidly water surface elevation on the river changes.

RAMP UP (SUPPLY SIDE) - Increasing load on a generating unit at a rate called the ramp rate.

REACTIVE POWER AND VOLTAGE CONTROL – Required to maintain adequate transmission system voltage for reliable interconnected system operation.

REAL-TIME (Purchase or Sale) - The amount of energy, measured in MWhs supplied or received by the control area operator to balance an entity’s load and supply.

REAL-TIME MARKET - The competitive generation market controlled and coordinated by the ISO for arranging real-time imbalance energy.

REAL-TIME PRICING - The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

REACTOR - A device in which a controlled nuclear chain reaction can be maintained, producing heat energy.

REGULATION - The service provided by generating units equipped and operating with automatic generation controls that enables the units to respond to the ISO's direct digital control signals to match real-time demand and resources, consistent with established operating criteria.

REGULATION AND RAMPING CAPABILITY – The portion of a generating unit's unloaded capability which can be loaded, or loaded capability which can be unloaded, in response to Automatic Generation Control signals from the ISO's energy management system control computer.

RELIABILITY - Electric system reliability has two components -- adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

RELIABILITY MUST-RUN (RMR) AGREEMENTS - A Must-Run Service Agreement between the owner of an RMR Unit and the ISO within geographical areas identified via the Local Area Reliability Service (LARS) process.

RELIABILITY MUST-RUN (RMR) GENERATION - Generation that the ISO determines is required to be on line to meet applicable reliability criteria requirements. This includes:

i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation;
ii) Generation needed to meet load demand in constrained areas; and
iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.

RELIABILITY MUST-RUN (RMR) UNIT - In return for payment, the ISO may call upon the owner of a generating unit under a Reliability Must-Run Agreement to run the unit when required for grid reliability.

RENEWABLE ENERGY - Resources that constantly renew themselves or that are regarded as practically inexhaustible. These include solar, wind, geothermal, hydro and wood. Although particular geothermal formations can be depleted, the natural heat in the earth is a virtually inexhaustible reserve of potential energy. Renewable resources also include some experimental or less-developed sources such as tidal power, sea currents and ocean thermal gradients.

RENEWABLE RESOURCES - Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

REPLACEMENT RESERVE – A quantity of capacity that will ramp up within 60 minutes.

RESERVE - The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its users ¼ needs.

RESERVE CAPACITY - Capacity in excess of that required to carry peak load.

RESERVE MARGIN - The differences between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

RESIDUAL NET LONG FOR CAPACITY (SURPLUS) – When the capacity resources under an LSE's control exceed the peak hourly demand (MW), including the required planning reserve margin, of the LSE's customers, the LSE is in a residual net long situation for capacity.

RESIDUAL NET LONG FOR ENERGY - When the energy requirement (kWh or MWh) of the LSE's customers load, for a given period of time (i.e. hour, month, year, etc), is less than the total energy supply available to serve the LSE's customers, the LSE is in a residual net long situation for energy.

RESIDUAL NET SHORT FOR CAPACITY (DEFICIT) - When the peak hourly demand (MW), including the required planning reserve margin, of the LSE's customers exceeds the capacity resources under the LSE's control, the LSE is in a residual net short situation for capacity.

RESIDUAL NET SHORT FOR ENERGY - When the energy requirement (kWh or MWh) of an LSE's customer load, for a given time interval (i.e. hour, month, year, etc), is greater than the total energy supply available to serve the LSE's customers, the LSE is in a residual net short situation for energy.

RESOURCE ADEQUACY - A common term used to describe sufficiency of capacity resources to meet contingencies that may be caused by unexpected energy usage (e.g., heat storm or cold spell), generation outages or transmission constraints.

RESOURCE ADEQUACY PROCEEDING - The CPUC undertook a process of addressing Resource Adequacy (RA) through the implementation of system and local RA standards. The system RA implemented in 2006 requires LSEs to meet a 15% to 17% planning reserve margin within their service territory. More recently, the CPUC implemented local RA standards for 2007, which requires LSEs to meet specific capacity targets (or Local Capacity Requirements known as LCR) within one of the nine transmission constrained areas (or load pockets) located within the ISO's control area. Both system and local RA standards are in the process of being clarified, modified and potentially expanded through the current RA proceeding (R.05-12-013).

RESOURCE EFFICIENCY - The use of smaller amounts of physical resources to produce the same product or service. Resource efficiency involves a concern for the use of all physical resource sand materials used in the production and use cycle, not just the energy input.

RETAIL COMPETITION - A system under which more than one electric provider can sell to retail customers, and retail customers are allowed to buy from more than one provider. (See also DIRECT ACCESS)

RETAIL MARKET - A market in which electricity and other energy services are sold directly to the end-use customer.

S

SCE (SOUTHERN CALIFORNIA EDISON COMPANY) - An electric utility serving the southern California region.

SDG&E (SAN DIEGO GAS & ELECTRIC) - An electric and natural gas utility serving the San Diego, California, region.

SCHEDULING COORDINATOR - Scheduling coordinators (SCs) submit balanced schedules and provide settlement-ready meter data to the ISO. Scheduling coordinators also:

- Settle with generators and retailers, the PX and the ISO
- Maintain a year-round, 24-hour scheduling center
- Provide non-emergency operating instructions to generators and retailers
- Transfer schedules in and out of the PX. (The PX is a marketplace. As bids are accepted, power is being bought and sold. Once a bid is accepted, the power sold is "transferred out" of the PX, since is it no longer available. Power that is available for sale is "transferred in" to the PX. These transfers may also take place directly between the buyer and seller, without involvement of the PX.)

The PX is considered a scheduling coordinator.

SEASONAL EXCHANGE - Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. Dollars may or may not be exchanged in such a transaction.

SELF-GENERATION - A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

SERVICE, LENDING (BORROWING) - Short-term borrowing of a pipeline or storage provider's working gas by a shipper.

SERVICE AREA - The geographical territory served by a utility.

SERVICE LIFE - The length of time a piece of equipment can be expected to perform at its full capacity.

SERVICE TERRITORY - This is the state, area or region served exclusively by a single electric utility.

SETTLEMENT - The process of financial settlement for products and services purchased and sold. Each settlement involves a price and quantity. Both the ISO and PX may perform settlement functions.

SITE - Any location on which a facility is constructed or is proposed to be constructed.

SMALL POWER PRODUCER - Refers to a producer that generates at least 75% of its energy from renewable sources.

SOLAR ENERGY - Heat and light radiated from the sun.

SPARK SPREAD - The difference between the market price of electricity and its cost of production for a specific natural gas fired generating plant.

SPINNING RESERVE – The portion of unloaded synchronized generating capacity, controlled by the ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

SPOT MARKET - A market in which transactions take place at most one day ahead of scheduled delivery.

SPOT MARKET (For Gas) - A market characterized by short-term, interruptible (or best efforts) contracts for specified volumes of gas. Participants may be any of the elements of the gas industry - producer, transporter, distributor, or end user. Brokers may also be utilized.

SPOT NATURAL GAS (Physical Supply) - Purchases/sales/exchanges of physical natural gas for terms less than one month.

SPOT PRICE - The price for spot transactions. (Also see MARKET CLEARING PRICE)

STORAGE, UNDERGROUND - The utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of load balancing. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be man-made or natural caverns.

STRANDED COSTS - Costs incurred by a utility which may not be recoverable under market-based retail competition. Costs incurred by a utility which may not be recoverable under market-based retail competition.

STRUCTURED TRANSACTIONS - Transactions that involve non-standard provisions for supplying electricity or electricity related products.

SUBSTATION - A facility that steps up or steps down the voltage in utility power lines. Voltage is stepped up where power is sent through long-distance transmission lines. It is stepped down where the power is to enter local distribution lines.

SUMMER - As applied to gas, the period April 1 of one year through October 31 of that same year.

SUMMER PEAK - The greatest load on an electric system during any prescribed demand interval in the summer.

SUPPLIER - A person or corporation, generator, broker, marketer, aggregator or any other entity, that sells electricity to customers, using the transmission or distribution facilities of an electric distribution company.

SUPPLY BID - A bid into the PX indicating a price at which a seller is prepared to sell energy or ancillary services.

SUPPLY-SIDE - Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load though energy efficiency measures or on-site generation on the customer side of the meter.

SURPLUS (Electric utility) - Excess firm energy available from a utility or region for which there is no market at the established rates.

SYSTEM - A combination of equipment and/or controls, accessories, interconnecting means and terminal elements by which energy is transformed to perform a specific function, such as climate control, service water heating, or lighting. [See California Code of Regulations, Title 24, Section 2-5302]

SYSTEM NET ENERGY FORECAST - Energy used by IOU and direct access customers, as measured at generation (includes T&D losses).

SYSTEM PEAK DEMAND - The highest demand value that has occurred during a specified period for the utility system.

T

TEMPERATURE - Degree of hotness or coldness measured on one of several arbitrary scales based on some observable phenomenon (such as the expansion).

TOLLING AGREEMENT – An agreement to provide (receive) gas in exchange for receiving (providing) electricity.

TRANSFER - To move electric energy from one utility system to another over transmission lines.

TRANSFORMER - A device, which through electromagnetic induction but without the use of moving parts, transforms alternating or intermittent electric energy in one circuit into energy of similar type in another circuit, commonly with altered values of voltage and current.

TRANSITION COSTS – Stranded costs which are charged to utility customers through some type of fee or surcharge after the assets are sold or separated from the vertically-integrated utility

TRANSMISSION - Transporting bulk power over long distances.

TRANSMISSION AND DISTRIBUTION (T&D) LOSSES - Electric energy or capacity that is wasted in the normal operation of a power system. Some kilowatt-hours are lost in the form of waste heat in electrical apparatus such as substation transformers. Line losses are kilowatts or kilowatt-hours lost in transmission and distribution of electricity.

TRANSMISSION AND DISTRIBUTION (T&D) SYSTEM - An interconnected group of electric transmission lines and associated equipment for the movement or transfer or electric energy in bulk between points of supply and points at which it is transformed for delivery to the ultimate customers.

TRANSMISSION LINES - Heavy wires that carry large amounts of electricity over long distances from a generating station to places where electricity is needed. Transmission lines are held high above the ground on tall towers called transmission towers.

TRANSMISSION OWNER - An entity that owns transmission facilities or has firm contractual right to use transmission facilities.

TURBINE GENERATOR - A device that uses steam, heated gases, water flow or wind to cause spinning motion that activates electromagnetic forces and generates electricity.

U

UPGRADE (Electric utility) - Replacement or addition of electrical equipment resulting in increased generation or transmission capability.

U.S. DEPARTMENT OF ENERGY (DOE) - The DOE manages programs of research, development and commercialization for various energy technologies, and associated environmental, regulatory and defense programs. DOE announces energy policies and acts as a principal advisor to the President on energy matters.

UNCERTAINTIES - Uncertainties are factors over which the utility has little or no foreknowledge, and include load growth, fuel prices, or regulatory changes. Uncertainties are modeled in a probabilistic manner. However, in the Detailed Workbook, you may find it is more convenient to treat uncertainties as "unknown but bounded" variables without assuming a probabilistic structure. A specified uncertainty is a specific value taken on by an uncertainty factor (e.g. 3 percent per year for load growth). A future uncertainty is a combination of specified uncertainties (e.g. 3 percent per year load growth, 1 percent per year real coal and oil price escalation, and 2.5 percent increase in housing starts).

UNSERVED ENERGY - The average energy that will be demanded but not served during a specified period due to inadequate available generating capacity.

UPGRADE - An increase in the rating or stated measure of generation or transfer capability.

UTILITY - A regulated entity which exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.

UTILITY-OWNED GENERATION - Resources owned by an investor-owned utility. Does not include resources that may be under contract or otherwise available to utilities, such as DWR contracts.

V

VARIABLE COSTS - Costs, such as fuel costs, that depend upon the amount of electric energy supplied.

W

WASTE-TO-ENERGY - This is a technology that uses refuse to generate electricity. In mass burn plants, untreated waste is burned to produce steam, which is used to drive a steam turbine generator. In refuse-derived fuel plants, refuse is pre-treated, partially to enhance its energy content prior to burning.

WEATHER SCENARIOS – 1:5, 1:10, & 1:20 - Forecasts of expected highest demand (MW) under different weather scenarios. 1:2 means average weather conditions. 1:5, 1:10, 1:20 mean probability of hot temperature (one in every five, ten or twenty years).

WEATHER TRIGGERED OPTIONS - A method for managing temperature and other weather forecast risks.

WHEELING - The transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially as meaning transmission.

WHOLESALE COMPETITION - A system whereby a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

WHOLESALE POWER MARKET - The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

WINTER - As applied to gas, the period November 1 of one year through March 31 of the following year.

WINTER PEAK - The greatest load on an electric system during any prescribed demand interval in the winter season or months.

WIRES CHARGE - A broad term which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

X

X-RAY - A type of electromagnetic radiation having low energy levels.

Y

No entries for the letter Y.

Z

No entries for the letter Z.

List of Sources:

1. http://www.energy.ca.gov/glossary/
2. http://www.energycentral.com/sections/directories/glossary/
3. http://www.eia.doe.gov/glossary/index.html
4. CPUC Decisions (D.) 02-10-062, 03-12-062, 04-12-048, and 06-06-066
5. Advice Letter E-2615
6. http://www.aga.org
7. http://www.pge.com

APPENDIX K

UPDATED ACRONYM LIST

Acronym	Full Name
2003 STPP	2003 Short Term Procurement Plan
2004 LTPP	2004 Long Term Procurement Plan
2004 LTRFO	2004 Long-Term Request for Offers
2004 STPP	2004 Short-Term Procurement Plans
2006 LTPP	2006 Long-Term Procurement Plan
A.	Application
A/C	Air Conditioning
AB	Assembly Bill
AB 117	Assembly Bill 117
AB 32	Assembly Bill 32
AB 380	Assembly Bill 380
AB 57	Assembly Bill 57
AC	Alternating Current
AFC	Application for Certification
AGC	Automatic Generation Control
AL	Advice Letter
ALJ	Administrative Law Judge
APD	Abnormal Peak Day
APT	Annual Procurement Targets
ARR	Auction Revenue Rights

Acronym	Full Name
AS	Ancillary Services
BC	British Columbia
BC-California	British Columbia-California
BCF/D	Billion Cubic Feet per Day
BEC	Business Energy Coalition
BIP	Base Interruptible Program
BOM	Balance of Month
BPM	Business Practice Manual
Btu	British Thermal Unit
BUG	Back-up Generation
CAISO	California Independent System Operator Corporation
CBP	Capacity Bidding Program
CC8	Contra Costa 8
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CCSF	City and County of San Francisco
CEC	California Energy Commission
CEE	Customer Energy Efficiency
CEQA	California Environmental Quality Act
CEUS	Commercial End Use Surveys
CG	Customer Generation

Acronym	Full Name
CGT	California Gas Transmission
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COB	California-Oregon Border
COD	Commercial Operations Date
COI	California-Oregon Intertie
Commission	California Public Utilities Commission
CPA	California Consumer Power and Conservation Financing Authority
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CRR	Congestion Revenue Rights
CRT	Consumer Risk Tolerance
CSI	California Solar Initiative
CSM	Cafeteria Style Menu
CT	Combustion Turbine
CTC	Competitive Transmission Charge
CWD	Cold Winter Day
D.	Decision
DA	Direct Access

Acronym	Full Name
DBP	Demand Bidding Program
DCPP	Diablo Canyon Power Plant
DG	Distributed Generation
DLC	Direct Load Control
DOC	Department of Commerce
DOE	U.S. Department of Energy
DR	Demand Response
DRA	Division of Ratepayer Advocates
DRP	Demand Response Program
DSA	Division of the State Architect
DSM	Demand Side Management
DWR	California Department of Water Resources
EAP	Energy Action Plan
EAP II	Energy Action Plan II
ECAR	East Central Area Reliability Coordination Agreement
ED	Energy Division
EE	Energy Efficiency
EEI	Edison Electric Institute
EIA	Energy Information Agency
EIF	Energy Investors Funds
ENS	Energy Not Served

Acronym	Full Name
EP	PG&E's Energy Procurement organization
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPPA	Energy Policy, Planning & Analysis
EPRI	Electric Power Research Institute
EPS	Emissions Performance Standard
EQR	Electronic Quarterly Report
ERCOT	Electric Reliability Council of Texas
ERRA	Energy Resource Recovery Account
ERRP	Emerging Renewable Resource Program
ESP	Energy Service Provider
EUP	Enriched Uranium Product
FCM	Futures Commission Merchant
FERC	Federal Energy Regulatory Commission
FRR	Frequency Reserve Requirements
FS	Facility Study
FTR	Firm Transmission Rights
GDP-IPD	Gross Domestic Product Implicit Price Deflator
GHG	Greenhouse Gas
GHP	Gas Hedging Plan
GRC TY	General Rate Case Test Year

Acronym	Full Name
GTN	Gas Transmission Northwest
GW	Gigawatt
GWH	Gigawatt-hour
GWP	Global Warming Potential
HASP	Hour Ahead Scheduling Process
HBPP	Humboldt Bay Power Plant
HHV	High Heat Value
HVAC	Heating Ventilation and Air-Conditioning
HVDC	High Voltage Direct Current
ICE	Intercontinental Exchange
ID	Irrigation Districts
IDSM	Integrated Demand Side Management
IE	Independent Evaluator
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IM	Instant Messaging
IOU	Investor-owned Utility
IPP	Independent Power Producer
IPT	Incremental Procurement Target
IRP	Integrated Resource Plan
ITC	Investment Tax Credit

Acronym	Full Name
IVSG	Imperial Valley Study Group
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LAR	Local Area Resource Requirement
LARS	Local Area Reliability Service
LBNL	Lawrence Berkeley National Labs
LCR	Local Capacity Requirement
LEED	Leadership Energy Environmental Design
LGIP	Large Generation Interconnection Process
LIEE	Low Income Energy Efficiency
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LSE	Load-serving Entity
LT	Long Term
LT-CRR	Long-Term Congestion Reverse Rights
LT-FTR	Long Term Firm Transmission Rights
LTPP	Long-Term Procurement Plan

Acronym	Full Name
LTRFO	Long Term Request for Offers
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MMBtu	Millions of British Thermal Units
MORC	Minimum Operating Reliability Criteria
MPR	Market Price Referant
MRTU	Market Redesign and Technology Upgrade
MW	Megawatt
MWD	Metropolitan Water District
MWh	Megawatt-hour
NBC	Non-bypassable Charge
NCBA	Net Cost Balancing Account
NERC	North American Electric Reliability Council
NGX	Natural Gas Exchange
NOI	Notice of Intent
Non-FTR	Non-Firm Transmission Rights
NP15	North of Path-15
NP26	North of Path-26
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission

Acronym	Full Name
NRDC	Natural Resources Defense Council
NW	Pacific Northwest
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
OASIS	Open Access Same-time Information Systems
OFO	Operational Flow Order
OII	Order Instituting Investigation
OP	Ordering Paragraph
PAC	Project Advisory Committee
PG&E	Pacific Gas and Electric Company
PHEV	Plug-In Hybrid Electric Vehicles
PLR	Potential Load Reduction
POU	Publicly Owned Utility
PP	Procurement Plan
PPA	Power Purchase Agreement
PRG	Procurement Review Group
PRM	Planning Reserve Margin
PRRA	Preliminary Renewable Resources Assessment
PSA	Purchase and Sale Agreement
PSPL	Puget Sound Power and Light
PTC	Production Tax Credit

Acronym	Full Name
PTO	Participating Transmission Owner
PURPA	Public Utility Regulatory Policy Act of 1978
PX	Power Exchange
QF	Qualifying Facility
QF-SRAC	Qualifying Facility-Short Run Avoided Costs
R.	Rulemaking
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RCST	Reliability Capacity Services Tariff
REC	Renewable Energy Credit
RFB	Request for Bids
RFO	Request for Offer
RFP	Request for Proposal
RMR	Reliability Must-Run
RNS	Residual Net Short
RPS	Renewable Portfolio Standard
RRDR	Renewable Resource Development Report
RUC	Residual Unit Commitment
SB	Senate Bill
SB 1	Senate Bill 1
SB 107	Senate Bill 107

Acronym	Full Name
SB 1368	Senate Bill 1368
SC	Scheduling Coordinator
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SEP	Supplemental Energy Payments
SERC	Southeastern Electric Reliability Council
SGIP	Small Generation Interconnection Program
SI	Strategic Inventory
SIS	System Impact Study
SO1	Standard Offer 1
SOX	Sarbanes-Oxley
SP26	South of Path 26
SPP	Statewide Pricing Pilot
SRAC	Short-Run Avoided Costs
SRP	School Resources Program
SRS	Secondary Registrations System
STPP	Short Term Procurement Plan
SVA	Strategic Value Analysis
SWU	Separative Work Unit
T&D	Transmission and Distribution
TA	Technical Assistance

Acronym	Full Name
TA/TI	Technical Assistance and Technical Incentives
TCSG	Tehachapi Collaborative Study Group
TeVaR	To-expiration-Value-at-Risk
TI	Technical Incentive
TOU	Time-of-Use
TRC	Total Resource Cost
TRCR	Transmission Ranking Cost Report
TXU	TXU Generation Company LP
U.S.	United States
UAFCB	Utility Audit and Finance Compliance Branch
UFE	Unaccounted For Energy
UFR	Underfrequency Relay
URG	Utility Retained Generation
VOM	Variable operations and maintenance
WACC	Weighted Average Cost of Capital
WAPA	Western Area Power Administration
WCSB	Western Canadian Sedimentary Basin
WECC	Western Electric Coordinating Council
WNA	World Nuclear Association
WSCC	Western Systems Coordinating Council
WSPP	Western Systems Power Pool

PACIFIC GAS AND ELECTRIC COMPANY

CONFORMED 2006 LONG-TERM PROCUREMENT PLAN

ATTACHMENT B

CLEAN PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
CONFORMED 2006 LONG-TERM PROCUREMENT PLAN

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PACIFIC GAS AND ELECTRIC COMPANY'S 2006 LONG-TERM PROCUREMENT PLAN

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") initially filed its 2006 Long-Term Procurement Plan ("LTPP") on December 11, 2006 in Rulemaking ("R.") 06-02-013. PG&E filed an amended 2006 LTPP on March 5, 2007. PG&E's amended 2006 LTPP consisted of three volumes. At the hearings in Phase II, Track 2 of R.06-02-013, conducted in June 2007, the volumes were marked as follows:

- The public version of Volume 1 of PG&E's amended 2006 LTPP was identified as Exhibit 10 and the confidential version was identified as Exhibit 14-C;
- The public version of Volume 1, Attachment IVA, was identified as Exhibit 11 and the confidential version was identified as Exhibit 15-C; and
- The public version of Volume 2 was identified as Exhibit 12 and the confidential version was identified as Exhibit 16-C.

PG&E's 2006 LTPP included descriptions of procurement activities and products, background material and a detailed discussion of PG&E's long-term resource planning approach. PG&E developed four scenarios to represent events or conditions that are outside of PG&E's control, and which could occur over the 10-year planning horizon. These scenarios were designed to take into account long-term uncertainties which may occur, such as changes in load, prices, market availability of resources, and regulatory changes.

PG&E then calculated 2007-2016 demand forecasts for the California Independent System Operator's ("CAISO") North of Path 26 ("NP26") region and for its service area using information from the California Energy Commission ("CEC"), with certain specified modifications. PG&E calculated demand forecasts under each of the four scenarios for both the NP26 region and the PG&E service area.

In addition to demand forecasts, PG&E also developed three candidate procurement plans. These plans included differing demand-side, supply-side and transmission actions that PG&E could take over the 10-year planning horizon. The plans were designed to highlight the trade-offs between reliability, environmental issues, and cost. PG&E then tested each of these three plans under the four scenarios, to see how future events captured in the scenarios would impact the reliability, environmentally-preferred resource, and cost elements of each of the three plans. PG&E used nine metrics to analyze the feasibility and performance of each of the candidate plans under the various scenarios. After completing its analysis, PG&E selected its Recommended Plan.

In Decision ("D.") 07-12-052, the Commission approved PG&E's 2006 LTPP with specific modifications. PG&E's 2006 LTPP covers a 10-year period from 2007 to 2016. The Commission required PG&E to make a compliance filing within ninety (90) days the issuance of D.07-12-052 to conform its 2006 LTPP to the decision and to include any updates filed through the Commission's Advice Letter process. This compliance filing constitutes PG&E's conformed 2006 LTPP, and supersedes and replaces all previous short- and long-term procurement plans submitted by PG&E. After the conformed 2006 LTPP is accepted by the Commission, all updates proposed before the next LTPP filing, currently scheduled for 2010,[1] will be made via advice letter. Advice letter updates will include redlined pages of the conformed 2006 LTPP, as well as clean replacement pages.[2]

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1 Rulemaking ("R.") 08-02-007, Scoping Memo at 5-6.

2 D.07-12-052 at 184-185.

II. PROCUREMENT IMPLEMENTATION PLAN

A. Procurement Processes

1. PG&E's Energy Procurement Organization

PG&E's Energy Procurement ("EP") organization plans for and acquires resources to ensure an adequate and reliable energy supply. EP has a number of procurement objectives, including assembling a portfolio of reliable and operationally flexible resources, supporting the development of environmentally preferred resources, and managing customer costs. The organization is responsible for both front-office functions associated with planning, procuring, scheduling, and dispatching resources, and back-office functions associated with ensuring accurate payments to the CAISO and other power suppliers. EP is comprised of the following departments:

- Energy Policy, Planning & Analysis ("EPPA");
- Energy Supply;
- Energy Contract Management and Settlements; and
- Market Redesign and Technology Upgrade ("MRTU") Implementation and Federal Energy Regulatory Commission ("FERC") Refund.

The following section discusses the primary goals and responsibilities of each of the departments listed above. In addition, PG&E describes how its EP organization complies with California Public Utilities Commission ("Commission") Standard of Conduct No. 2.[1]

[1] The Commission originally adopted Standards of Conduct for procurement in Decision ("D.") 02-10-062. These standards have subsequently been modified. *See* D.02-12-074, Order Paragraph 24 (modifying standards); D.03-06-067, Ordering Paragraph 3 (modifying standards and eliminating Standard Nos. 6-7); and D.03-06-076, Ordering Paragraph 6 (clarifying that "Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges."). PG&E also received a waiver from Standard of Conduct 1 for certain gas transportation transactions in D.04-06-003.

a. Energy Policy, Planning & Analysis

EPPA strives to meet the EP organization objectives through electric and gas resource planning that truly integrates demand-side and supply-side resource alternatives, and transmission and generation alternatives. EPPA analyzes regional supply-demand balances, the composition of potential PG&E portfolios, and the value of incremental resources to PG&E customers and regional supply. EPPA performs these analyses using financial, economic, and engineering methodologies and tools. EPPA analyzes current and potential market structures and policy initiatives, such as the State Loading Order, capacity markets and resource adequacy, and considers how these developments impact PG&E's procurement.

b. Energy Supply

Energy Supply is responsible for all commercial transaction activities through competitive solicitations, bilateral negotiations and energy markets, including the development and execution of electric and fuels procurement strategies for short-term, medium-term, and long-term transactions, which will meet PG&E's customers' forecasted energy needs. The commercial transactions also include the procurement of renewable supplies to meet PG&E's Renewable Portfolio Standard requirements ("RPS"). Energy Supply's responsibilities also include: (1) the management, optimization, and scheduling of PG&E's resources and contracts; (2) PG&E's trading in the energy markets; and (3) the natural gas procurement and hedging activities for PG&E's resources, power purchase agreements and assigned California Department of Water Resources ("DWR") contracts.

Energy Supply also purchases natural gas supplies and transportation capacity to meet PG&E's bundled core gas customer demands. The gas procurement function relates generally to the process of acquiring gas supplies (*e.g.*, the gas commodity) and managing transmission and storage capacity for core gas customers.

c. Energy Contract Management & Settlements

The Energy Contract Management & Settlements department is responsible for the preparation of regulatory filings, and implementation of standard reporting and documentation related to energy procurement and settlements activities. The department monitors compliance with risk control and Sarbanes-Oxley ("SOX") requirements, and performs contract management, settlements and financial reporting related to energy procurement, including bilateral purchases and sales, Fuel, Qualifying Facility ("QF"), Irrigation District ("ID"), Reliability Must-Run ("RMR"), and DWR allocated contracts, as well as CAISO market settlements. This work includes contract monitoring, validating calculations and data, preparing invoices, processing payments, and duties related to PG&E's role as transmission owner and CAISO scheduling coordinator for both retail and existing transmission contract customers.

d. MRTU Implementation and FERC Refund

The CAISO's MRTU initiative significantly changes the electric markets administered by the CAISO and represents the largest change to the California wholesale energy market since electric restructuring began in 1998. It is scheduled to become effective in 2008. The MRTU Implementation and FERC Refund Department works with internal and external stakeholders to translate complex market designs into the needed systems and software and assure they perform as intended. In addition, on behalf of PG&E's customers, this department continues its efforts to obtain refunds for electricity overcharges during the 2000-2001 California Energy Crisis. The department provides support and expert analysis in the FERC Refund proceedings, negotiations with suppliers, and bankruptcy issues related to generator claims filed in PG&E's bankruptcy.

e. Compliance With Commission Standard of Conduct No. 2

The employees in PG&E's EP organization manage a substantial portfolio of resources to ensure PG&E acquires a reliable, environmentally preferred, and cost-effective portfolio of supply-side and demand-side resources for its customers. The EP employees, as well as the employees throughout PG&E, comply with the Commission's Standard of Conduct No. 2, to the extent it is applicable. Standard of Conduct No. 2 provides:

Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurements process that:

1) Identifies trade secrets and other confidential information;

2) Specifies procedures for ensuring that such information retains its trade secret and/or confidential status (*e.g.,* limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.);

3) Discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges;

4) Discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; and

5) Requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances (*e.g.,* where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer). All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility.

To ensure compliance, on the first day of employment with PG&E, employees are given an employee policy handbook on "Standards for Personal Conduct and Business Decisions, Code of Conduct for Employees" which can be found at the following link: http://www.pge-corp.com/aboutus/pdfs/EmployeePolicyHandbook2004.pdf. The handbook includes discussions regarding proprietary information and antitrust law. Upon completion of their review, employees are required to sign a summary form acknowledging receipt of the booklet and that they have reviewed and understood the material. In addition, PG&E employees are required to complete a Compliance and Ethics training course on an annual basis, a description of which can be found at the following link: http://www.pge-corp.com/aboutus/ethics_compliance. The annual Compliance and Ethics training includes a review of various parts of the Code of Conduct for Employees handbook.

2. Overview of PG&E's Procurement Process

PG&E's procurement process involves three phases: planning, competitive procurement and economic dispatch.

a. Planning

In the planning phase, PG&E identifies the resource needs of its customers and complies with the State Loading Order, Energy Action Plan II ("EAP II") and other Commission and legislative directives.[2] In analyzing its needs, PG&E identifies specific power products. These power products include energy products (baseload, shaping, and peaking), capacity products to meet Resource Adequacy ("RA") requirements, and various ancillary services products, including spinning, non-spinning, regulation, and black-start capability. The following table summarizes some of the power products available from various resource alternatives, which PG&E identifies in the planning phase.

[2] PG&E also looks at the reliability need for its entire service area.

TABLE II-1
PACIFIC GAS AND ELECTRIC COMPANY
POWER PRODUCTS AVAILABLE FROM RESOURCE ALTERNATIVES

		Energy Products					Ancillary Service Products					
Line No.	Resource Types	Base-load	Inter-mittent Energy	Shaping	Peaking	Capacity (RA)	Black Start	Quick Start (10 min.)	Emer-gency (30 min- 3 hr)	Regu-lation	Spinning	Non-Spinning
1	Preferred Resources											
2	Energy Efficiency	X				X						
3	Demand Response				X	X			X			X
4	Renewable-Intermittent		X			X						
5	Renewable-Baseload	X				X						
6	Distributed Generation-Non PV	X				X						
7	Conventional Resources											
8	Combustion Turbine				X	X	X	X	X	X	X	X
9	Reciprocating Engines				X	X	X	X	X	X	X	X
10	Combined Cycle			X		X			X	X	X	X
11	Base (*e.g.,* coal, nuclear)	X				X						

After identifying the amount and timing of its need, PG&E then prepares and files a procurement plan with the Commission, seeking authority to procure these products. Once the Commission approves a procurement plan, the procurement process shifts to the competitive procurement phase.

b. Competitive Procurement

PG&E implements its Commission-approved procurement plan through various processes, including solicitations, bilateral negotiations and participation in various markets. PG&E's procurement practices are described in detail in Section II.A.5, below. PG&E enters into short-term, medium-term and long-term contracts that result from the competitive procurement process. PG&E defines short-term contracts as contracts with a term of one year or less in duration; medium-term contracts as contracts with a term greater than one year but less than five years in duration; and long-term contracts as contracts with a term five years or greater in duration. Renewable contracts are an exception to this rule, with anything under 10 years in duration being short-term for this contract category.

c. Dispatch

Consistent with Commission decisions,[3] PG&E economically dispatches its portfolio subject to the contractual and operating limitations of the resources in the portfolio. In implementing least-cost dispatch, PG&E dispatches resources or purchases energy with the lowest incremental cost of providing energy, which includes the variable operating costs of its own resources or resources under its control and the market cost of generation.[4] PG&E uses incremental cost dispatch for all resources within its portfolio. This includes utility-owned generation, bilateral contracts, allocated DWR contracts, and resources available to PG&E from the marketplace.

Least cost dispatch includes market sales. When PG&E is "physically" or "economically" long, least-cost dispatch requires PG&E to undertake certain market sales. PG&E is "physically long" when must-take energy supply exceeds demand. During those periods, PG&E sells excess energy at market prices. Because PG&E is required to take or generate this energy in any event, the incremental cost of that energy is zero. PG&E is "economically long" when the incremental cost of dispatchable resources is less than the market price, even though PG&E has no need for the energy to serve its customers. Under these circumstances, the economically efficient dispatch decision is to use the dispatchable resource to generate power and market the surplus energy.

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[3] The Commission's Standard of Conduct No. 4, adopted in D.02-10-062 and modified ~~on~~ in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054, requires PG&E to meet its electric load obligations in a least-cost manner. In addition, D.04-07-028 ordered that system reliability and deliverability of power be included as part of least-cost dispatch.

[4] Because the least-cost dispatch for hydro-electric resources takes into consideration the future value of water and the fact that because the amount of available water is limited, it may be more cost-effective to defer hydro-electric generation to higher value time periods.

3. Description of Procurement Products

a. Electric Products

PG&E uses a variety of physical and financial electric products to meet its electric procurement needs. Table II-2 below provides product names, descriptions and information about PG&E's existing regulatory authority to procure these products.

TABLE II-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS

Line No.	Product	Description	Prior Authorization
1	Ancillary Services	Products that are utilized by the control area operator to ensure electric system reliability, for example, those that are listed in control area operator tariffs, such as the CAISO.	D.02-10-062
2	Capacity (demand side)	The amount of power consumed by a customer, measured in megawatts ("MW"), that can be reduced upon request.	D.02-10-062
3	Capacity (purchase or sale)	The amount of power capable of being generated, measured in MW, that can be converted to energy upon request.	D.02-10-062
4	Contingent Forward	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
5	Electric Product Exchange	The buyer has an obligation to receive electric products and an obligation to return electric products as part of the same transaction. The transaction may also include an exchange of payments, in fixed or variable terms. Electric products include energy, capacity, and ancillary services.	AL 2615-E
6	Electricity Transmission Products	Purchase, sale, or allocation of transmission rights, products (*e.g.*, Long-Term Firm Transmission Rights, Congestion Revenue Rights, losses), or the use of locational spreads.	D.02-10-062 and D.07-12-052
7	Financial Call (or Put) Option	The right, but not the obligation, to buy (call) a forward electric contract on a specific date (expiration) at a fixed or indexed price (strike). The right to sell is a put option.	D.02-10-062
8	Financial Swap	An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps, basis swaps and payment obligation swaps (*e.g.*, CAISO IFM Uplift Load Obligations). Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.	D.02-10-062 AL 2615-E D.07-12-052
9	Forward Energy (demand side)	Electric energy planned to be consumed by a customer, measured in megawatt-hour ("MWh") that is agreed to be reduced for a specific period for a specified time in the future.	D.02-10-062

TABLE II-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS
(CONTINUED)

Line No.	Product	Description	Prior Authorization
10	Forward Energy (purchase or sale)	Electric energy purchased or sold by a counterparty, measured in MWh that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.	D.02-10-062
11	Forward Spot (Day-Ahead & Hour-Ahead) purchase, sale, or exchange	Electric energy, capacity, ancillary services or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MW or MWh that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.	D.02-10-062
12	Insurance (counterparty credit insurance, cross commodity hedges)	A method for managing payment or performance risk for a fee.	D.02-10-062
13	New York Mercantile Exchange (“NYMEX”) Electricity Futures (purchase or sale)	Standardized forward energy contract traded on NYMEX. Futures may be physically or financially settled.	AL 2615-E
14	On-Site Energy or Capacity (self-generation on customer side of the meter)	The amount of power measured in MW or MWh that can be generated downstream of the customer’s electric meter that can be used to offset the customer’s load served by the electric service provider.	D.02-10-062
15	Peak for Off-Peak Exchange	Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period. These transactions may also include an exchange of dollars.	D.02-10-062
16	Physical Call (or put) Option	The right, but not the obligation, to buy (call) physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to sell is a put option.	D.02-10-062
17	Real-Time (purchase or sale)	The amount of energy, measured in MWh supplied or received by the control area operator to balance an entity’s load and supply.	D.02-10-062
18	Resource Adequacy Product	A capacity product intended to meet resource adequacy obligations.	AL 2615-E AL 2897-E
19	Seasonal Exchange	Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. These transactions may also include an exchange of dollars.	D.02-10-062
20	Tolling Agreement	An agreement to provide (receive) gas in exchange for receiving (providing) electricity.	D.02-10-062, D.04-12-048
21	Counterparty Sleeves	An agreement by a counterparty to buy (sell) electricity from one counterparty and sell it to (buy it from) another counterparty.	D.03-12-062
22	Emissions Credits Futures or Forwards	Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.	D.03-12-062
23	Forecast Insurance	A method for managing load forecast (volume and shape) risk.	D.03-12-062

TABLE II-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS
(CONTINUED)

Line No.	Product	Description	Prior Authorization
24	Firm Transmission Rights ("FTR") Locational Swaps	Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062
25	Non-Firm Transmission Rights ("Non-FTR") Locational Swaps	Over-the-counter basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062
26	Weather Triggered Options	A method for managing temperature and other weather forecast risks.	D.03-12-062
27	RA Import Capacity Counting Right	Transfer the right to count import energy or import RA product at an intertie toward satisfying resource adequacy requirements.	AL 2897-E
28	Long-Term Congestion Revenue Rights ("LT-CRRs")	Financial instruments to hedge Locational Marginal Price ("LMP") congestion in MRTU for ten years.	AL 3095-E
29	Congestion Revenue Rights	Financial instruments to hedge LMP congestion in MRTU, including, for example, monthly CRRs and seasonal CRRs.	D.02-10-062 D.07-12-052 AL 3106-E

b. Gas Products

PG&E uses a variety of physical and financial gas products to support electric procurement. Physical gas products are used to support least-cost dispatch and reliability. Table II-3 below provides physical gas product names, descriptions and information about PG&E's existing regulatory authority to procure these products.

TABLE II-3
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PHYSICAL PRODUCTS

	Product	Description	Prior Authorization
1	Natural Gas Purchases (physical supply)	Purchases/sales/exchanges of physical natural gas for terms of one month or longer.	D.02-10-062
2	Spot Natural Gas (physical supply)	Purchases/sales/exchanges of physical natural gas for terms less than one month.	D.02-10-062
3	Physical Options on Natural Gas Supply (purchase or sale)	The right, but not the obligation, to buy (call) physical gas for delivery on a particular date at a fixed or index price (strike). The right to sell is a put option.	D.02-10-062
4	Biomethane (purchase or sale)	Pipeline quality natural gas produced from renewable (non-fossil based) resources. May include renewable or environmental attributes.	D.07-12-052
5	Contingent Forward (purchase or sale)	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
6	Gas Storage (purchase or sale)	Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.	D.02-10-062
7	Gas Transportation (purchase or sale)	Interstate, Intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.	D.02-10-062
8	Counterparty Sleeves	Facilitating a transaction with an un-contracted or non-creditworthy through a contracted, creditworthy counterparty.	D.02-10-062

Financial products are used to support gas hedging. Table II-4 below provides financial gas product names, descriptions and information about PG&E's existing regulatory authority to procure these products.

TABLE II-4
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS FINANCIAL PRODUCTS

	Product	Description	Prior Authorization
1	Natural Gas Financial Swaps (purchase or sale)	Over-the-counter forward products including fixed-for-floating swaps, basis swaps and swing-swaps for gas. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	AL 2615-E D.02-10-062
2	Natural Gas Futures (purchase or sale)	Standardized forward contracts for gas that trade on an exchange. Futures may be physically or financially settled. Physically settled futures may be unwound by an offsetting trade, exchanged for a physical position, or held to physical delivery.	AL 2615-E
3	Financial Options (Call or Put) (purchase or sale)	The right, but not the obligation, to buy (call) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). The right to sell is a put option. OTC-traded options settle in cash, whereas exchange traded (NYMEX) options must be exercised, which causes delivery of a futures position to the option holder. Options may be combined with other options or swaps to hedge a wide variety of positions.	D.02-10-062

The products presented in this section include those products PG&E is currently authorized to transact, as well as products that it knows may be required in the future. PG&E will request approval through advice letter filings of new products that arise from changed policies or market developments that are not covered by the above lists. Such products may be necessary to satisfy procurement needs arising from MRTU implementation, new legislation or other requirements such as the emergence of Renewable Energy Credit markets for compliance with the RPS Program.

4. Overview of Energy Product Markets

This section provides an overview of the markets available to PG&E to purchase the products described in Section II.A.3, above. PG&E's specific procurement practices are described in detail in Section II.A.5, which follows this section.

a. Exchanges

For electric and gas markets there are several types of transparent exchanges: Over-The-Counter electronic trading platforms such as the Intercontinental Exchange ("ICE"), New York Mercantile Exchange ("NYMEX") Clearport, NYMEX Globex, and the Natural Gas

Exchange ("NGX"); and open outcry exchanges such as the NYMEX. The electronic platforms allow market participants to post bids and offers for specific gas and electric products. To complete a trade, a buyer must lift an offer or a seller must hit a bid. Once completed, the exchange confirms the transactions to both parties. NYMEX hosts open outcry trading for its natural gas futures contracts and natural gas options. Buyers and sellers transmit bids and offers to the trading pits through a Futures Commission Merchant ("FCM"). The trade is executed by the trader in the trading pit. The results of the trade are communicated back to the buyer or seller through the FCM.

For the electronic exchanges, buyers post bids to the system. If a seller hits the bid, the trade is completed. If a seller does not hit the bid, the buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer already posted on the exchange, the buyer can lift that offer to complete the trade.

For open outcry trading, the buyers work through their FCM to trade on the exchange. Buyers can submit two types of orders with their FCM, a limit order (a bid at a specific price) or a market order (which will buy the current offer in the trading pit). FCMs will work a limit order until it is executed in the pit or until the floor trader indicates that the order is unlikely to trade. At this point, the buyer can cancel the order or raise its bid. In this manner, the buyer can adjust its bid until the trade is executed.

Since the transparent exchanges trade standard products and trading is anonymous, selection is made on product availability, credit availability, and price.

b. Inter-dealer (Voice) Brokers

Inter-dealer or voice brokers facilitate trades in the wholesale market for electricity and gas. Brokers communicate bids and offers to market participants through squawk boxes[5] and telephone calls. Brokers work with buyers and sellers to facilitate trades. Once completed,

[5] A squawk box is an intercom speaker used for communication between brokers and traders. The box allows brokers to broadcast market information to traders and to have one-on-one conversations with traders. PG&E records all communication on its squawk boxes as part of its trading process controls.

brokers confirm the transactions with both parties and may initiate financial clearing with both NYMEX and the ICE. Brokers facilitate the trading of physical and financial gas and electric products. Brokers, as part of their price discovery role, provide price reporting services to subscribing clients.

Buyers communicate bids to the broker. If a seller hits the bid the trade is completed. If a seller does not hit the bid, the buyer can ask the broker to work its bid in the market. The broker will provide the buyer feedback if its offer is not hit by a seller. The buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer communicated by the broker, the buyer can lift that offer to complete the trade. Since brokers facilitate trades of standard products and trading is anonymous, selection is made by product availability, credit availability and price.

c. Spot Markets

The spot market for electricity and gas is the wholesale market for day-ahead, hour-ahead, and real-time for electric energy and day-ahead for natural gas. Day ahead for electricity normally includes two, two-day strips for weekends (Friday-Saturday and Sunday-Monday) and other combinations of days to accommodate holidays. Hour ahead for electricity is the market as traded intra-day. Real-time is the CAISO real-time market. Day ahead for gas normally includes a 3-day strip for weekends (Saturday-Monday) or a longer combination of days to accommodate holidays.

The bilateral spot market consists of buyers and sellers communicating bids and offers to counterparties through telephone calls and Instant Messaging ("IM"). Traders negotiate until a trade is completed. Spot trades are normally executed and then confirmed over the phone by schedulers and not with paper confirmation documents. Spot market trades are also executed though voice brokers, ICE and NGX.

Buyers communicate bids to potential sellers. If a seller hits the bid the trade is completed. If a seller does not hit the bid, the buyer adjusts the bid to entice the seller or they can call another potential seller. The process continues until the buyer finds a willing seller at the buyer's price. Alternatively, sellers communicate offers to potential buyers, negotiate prices, and keep searching until they find a willing buyer. It is common for buyers and sellers to trade through brokers, exchanges and the bilateral spot market simultaneously. Selection is made by product availability, credit terms, credit availability, and price.

d. On-Line Auctions

On-line auctions facilitate the competitive purchase or sale of electricity and gas with approved counterparties. In an on-line energy auction, PG&E posts a commodity for purchase or sale on a secure internet site, while qualified bidders compete in a live format to provide PG&E with the most advantageous price. PG&E posts energy products for purchase or sale on the secure auction web site. Approved bidders are invited to participate and compete against one another in a live auction. Bidders are required to meet PG&E's credit qualifications in order to participate. Selection is made by product availability and price.

e. RPS Solicitations

RPS bidders include large corporations, small businesses, and individuals with ideas. Offers come from existing and proposed projects in California, the Pacific Northwest, and the Desert Southwest in response to PG&E's annual solicitation. Within California, the offers consist of those both on and off the CAISO grid. Following a Commission decision authorizing an RPS solicitation, PG&E issues a Request for Offer ("RFO") and then reviews the offers it receives. PG&E short-lists offers and then negotiates with the bidders to execute an RPS agreement. The RPS solicitation process is described in more detail below in Section II.A.5.c, below.

f. Energy Product Solicitations and RFOs

PG&E can also obtain electric and gas products through all-source solicitations. PG&E defines the products it is seeking in its RFO and then reviews bids and offers received. PG&E can conduct RFOs for long-term resources, such as the 2004 Long Term Request for Offer ("LTRFO"), or for shorter-term products, such as capacity to satisfy Local or System RA requirements.

g. Bilaterally Negotiated Contracts

Bilateral negotiations are used for the purchase and sale of electric and gas products. The phrase "bilateral negotiations" is generally used in the context where negotiations take place in a one-on-one setting rather than as a part of a competitive solicitation. The process consists of direct one-on-one negotiations, but negotiated terms and conditions are constantly being weighed against best available market price benchmarks to justify the transactions, similar to selecting the best transactions in RFOs.

The decision to proceed is based on least-cost, best-fit principles. The evaluation criteria and methodologies are very similar, if not the same, as those used to evaluate transactions in recent and comparable product RFOs. PG&E uses the best available market price benchmarks in the evaluation process.

h. Inter-Utility Swaps

Inter-utility swaps can be used for the purchase and sale of electric and gas products. Negotiations take place in a one-on-one setting. Inter-utility swaps historically have been used for transactions that offer some form of operational benefits to both parties. However, as transactions have become more purely market oriented, such swaps are more simply combined buy and sell transactions, and evaluated as such. There is a diminishing need to make this product distinction. Inter-utility swaps have become less unique as parties can buy or sell each leg of the transaction from multiple parties. The process consists of direct one-on-one negotiations, but negotiated terms and conditions are constantly being weighed against best available market price benchmarks to justify the transactions. PG&E has not recently executed swaps with other utilities because of the combination of a current lack of need, and more readily available market opportunities for similar products from numerous other market participants.

The decision to proceed is based on least-cost, best-fit principles. Evaluation criteria and methodologies are very similar, if not the same used to evaluate transactions in recent and comparable product RFOs. PG&E uses the best available market price benchmarks in the evaluation process.

5. PG&E's Procurement Contracting Methods and Practices

In this section, PG&E describes its electric procurement methods and practices for short-term, medium-term and long-term contracts. Table II-5 below reflects the procurement methods and practices that PG&E is authorized to use.

TABLE II-5
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT METHODS AND PRACTICES

Item #	Transaction Process	Description	Prior Authorization
1	Competitive Solicitations (RFO)	Widely distributed request for offers or proposals. Required items include among other things: Description of product requirements, term, minimum and maximum bid quantities, scheduling and delivery attributes, credit requirements, and pricing attributes. Additional requirements for the RFO process are specified in D.07-12-052, pages 142-152.	D.02-10-062 D.04-12-048 AL 2615-E
2	Direct bilateral contracting with counterparties for short-term products (*e.g.,* three months or less)	Bilateral process for products procured with a term three months or less. Investor-owned utilities ("IOU") demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. The demonstration may include showing competing price offers, result of market surveys, broker and online quotes, and/or other source of price information such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction.	D.02-10-062 D.04-12-048 AL 2615-E
3	Inter-Utility Exchanges	Exchange with other regulated utilities and other load-serving entities negotiated through private negotiation crafted to best fit the resources and needs of both parties.	D.02-10-062 D.04-12-048 AL 2615-E
4	ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead	Spot market transactions are authorized to balance system and short-term needs. IOUs justify their planned spot market purchases if they exceed 5% of monthly needs.	D.02-10-062 D.04-12-048 AL 2615-E
5	Transparent exchanges, such as Bloomberg and Intercontinental Exchange, voice and on-line brokers	Electronic trading exchanges for transparent prices.	D.02-10-062 D.03-12-062 D.04-12-048 AL 2615-E

TABLE II-5
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT METHODS AND PRACTICES
(CONTINUED)

Item #	Transaction Process	Description	Prior Authorization
6	Utility ownership of generation	Utility-ownership of generation can be pursued through an RFO under certain conditions (*see* D.07-12-052 at 198-205) or outside of the RFO process under certain conditions (*see* D.07-12-052 at 209-213).	D.07-12-052
7	Open Access Same-Time Information Systems ("OASIS")	Procure standard electric transmission products from transmission providers throughout the Western Electric Coordinating Council ("WECC") region at FERC tariffed rates and voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E
8	Negotiated bilateral contracts for non-standard products which terms exceed three months provided that the IOUs include a product justification in quarterly compliance filings.	Process to purchase products provided they are included in quarterly compliance filings to justify the need and process in each case. Terms and conditions are benchmarked against the best available market information for similar products recently offered.	D.03-12-062 D.04-12-048 AL 2615-E
9	Transparent exchanges to include voice and on-line brokers	Transparent price products from voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E
10	Electronic Auction	IOUs are authorized to conduct procurement using an electronic auction format.	D.04-12-048 AL 2615-E
11	Generator Requests for Proposals	IOUs can bid in open season or RFPs held by generator owners.	D.04-01-050 AL 2615-E
12	CAISO Allocations and Auctions	CAISO allocation and auctions for LT-CRRs and CRRs.	AL-3095-E and AL 3106-E

In the remainder of this section, PG&E describes its procurement practices and methods for: (a) short- and medium-term procurement transactions; (b) long-term transactions; (c) RPS transactions; and (d) the length of time between the date contracts are executed and when actual deliveries commence.

a. Procurement Practices and Methods for Short-Term and Medium-Term Transactions

This section describes PG&E's methods and practices for short-term and medium-term procurement transactions. PG&E utilizes various Commission-approved transaction methods that are set forth in Table II-5 for short- and medium-term transactions.

PG&E's electric procurement process is not a one-time event. Rather, it is comprised of a series of ongoing analyses and activities that focus on different time frames and decisions. This process ensures that resources are available to meet energy and ancillary service requirements and allows PG&E to minimize the cost of generation and risks by participating in a variety of transactions over time.

The short- and medium-term electric procurement time frames include: (1) multi-year;[6] (2) annual; quarterly, and monthly; (3) intra-month and weekly; (4) daily; and (5) hour-ahead. The CAISO also manages a "real-time" market. The procurement process is conceptually identical in all time frames insofar as all considered resources are reviewed on an equal basis in determining how to meet PG&E's demand and energy requirements in a least cost manner. The input assumptions and the granularity of those assumptions differ. PG&E begins by determining total load requirements, including customer retail demand, wholesale sales, transmission and distribution losses, ancillary services, and any and all operating constraints. PG&E then determines the quantity of generation from baseload "must-run" resources such as the Diablo Canyon Power Plant ("DCPP"), QFs, and DWR allocated contracts. Finally, PG&E assesses market conditions in order to optimize production from dispatchable resources and market transactions. PG&E's objectives are to meet any remaining load requirements as well as extract value from resources when it is economic to sell into the market.

[6] For this discussion, the term "multi-year" is limited to less than five years.

The remainder of this discussion summarizes the short- and medium-term procurement process and describes some of the Commission-approved transaction methods that PG&E has undertaken in each time frame since it has resumed electric procurement.

(1) Multi-year

PG&E initially determines its need for short- and medium-term transactions. Multi-year transactions typically involve competitive solicitations that are reviewed in consultation with the Procurement Review Group ("PRG"). After negotiating a multi-year transaction, PG&E submits the agreement to the Commission for approval via an advice letter, if the term of the transaction is less than five years. An Independent Evaluator ("IE") is required for all competitive RFOs that seek products of more than three months in duration. Competitive RFOs include RFOs issued to satisfy service area need and supply-side resources, not including energy efficiency and demand response.

(2) Annual, Quarterly, and Monthly

PG&E performs and updates assessments of its net open position for a 12-month forward period on a regular basis to determine whether additional resources are required or it has excess resources for potential surplus sales. This process ensures that PG&E has resources to meet requirements, and determines by the close of the month prior to an operating month that it will control resources within 5% of expected requirements, as recommended by the Commission in D.02-10-062.

The analysis is the same as that employed for the multi-year time frame, with the primary difference being the assumptions used—forecasted loads, resource availability, gas prices, hydro availability and market prices are further refined as PG&E moves closer to the operating period, hence resource requirements and market opportunities become clearer.

Forward Energy Products (*e.g.*, term, balance-of-month and balance-of-week purchases and sales) are transacted to diversify the portfolio and reduce reliance on spot markets. Transactions with a delivery date later than three calendar months from execution, or for a term greater than three calendar months are reviewed by the PRG. PG&E's monthly forward transactions represent the majority of PG&E's market transaction volume, and are primarily one-month purchases or sales of fixed price, standard block on-peak and off-peak energy, although some transactions span two or three months. Bilateral contracts are often used. Typically, bilateral contracts are benchmarked against pricing information obtained from recent competitive solicitations for a similar product or against forward price curves. In addition, brokers play a critical role in almost all of these transactions. Voice brokers and electronic exchanges are used for the purpose of price discovery and matching buyers with sellers in an anonymous fashion.

(3) Intra-month and Weekly

As part of an integrated process, results from the actions described in the previous section determine the amount of the residual open position (long or short) that is carried into the prompt month. Inside the month time horizon, PG&E reviews the availability of resources, hydro conditions, and makes an assessment of market prices and conditions to further assess how best to manage the open position. If market transactions are needed, the transaction methods listed in the foregoing section are generally used.

(4) Daily

In day-ahead procurement PG&E strives to balance projected energy requirements with resources, and provide hour-ahead traders and real-time operators with appropriate resources to respond to changes that may occur in system requirements subsequent to day-ahead trading. On a daily basis PG&E conducts a least-cost analysis to determine unit dispatch and market transactions to meet energy and ancillary services requirements.

Day-ahead trading generally occurs between 6 and 7 a.m. in the day prior to the operating day. The day-ahead market continues to evolve in terms of participants, products and character. Currently the market usually trades "standard" on-peak and off-peak "packages" of multiples of 25-MW blocks with specified delivery points. While some basis spread products are traded, there is only sporadic trading of hourly energy products or other non-standard products such as options. PG&E actively participates in the daily energy market using a combination of transparent exchanges with voice and on-line brokers, and direct bilateral transactions with counterparties.

PG&E has adapted its daily procurement process to incorporate the opportunities available in the day-ahead market as well as its must-run and must-take resource requirements. Similar to the market products discussed above, many of the must-take contracts are for standard blocks of on-peak hours. These contracts do not match PG&E's load profile and often results in excess energy during some hours while leaving PG&E short during other hours. To manage this PG&E may: (1) either re-dispatch resources to the extent it is feasible or dispatch other flexible resources; (2) engage in non-standard product transactions; and (3) make a concerted determination to sell or purchase quantities of energy in the hour-ahead market in order to maximize the value of its energy and minimize real-time imbalances.

(5) Hour Ahead

"Hour-ahead" planning is something of a misnomer since it effectively begins at the conclusion of day-ahead trading. As day-ahead analysis and trading occurs early in the morning prior to the operating day, there can be substantial subsequent changes to operating requirements. PG&E prepares weather-adjusted load forecasts throughout the day to determine if changes in generation or system operation are required. Further, unit outages and transmission outages and constraints may also affect resource requirements prior to real-time. In order to balance its portfolio during this time frame, PG&E's hour-ahead staff has several resources at its disposal. Dispatchable resources are updated with incremental unit dispatch prices. Hour-ahead personnel will then optimize the portfolio, based on operating requirements and market opportunity costs, whether and which generating resources should be adjusted to minimize system costs, and whether market transactions are required or beneficial.

The hourly market, while active, is far less transparent than the day-ahead market or the real-time market. As there are few brokers operating in this market and nascent electronic exchange opportunities, the bulk of transactions are bilateral in nature, making it difficult to generally characterize the hour-ahead market. Despite this, PG&E participates in the hour-ahead market to optimize its resources and market transactions to reduce costs.

(6) CAISO "Real-Time"

While PG&E strives to achieve balanced loads and schedules in the Day- and Hour-Ahead time frames, mismatches are inevitable. Causes could be changes in electric demand, resource availability, or transmission availability. The CAISO "Real-Time" market is where load/resource balance is the goal. Imbalances after the close of the Hour-Ahead market are settled at the CAISO's "ex-post" price (*e.g.*, PG&E sells/purchases energy to/from the CAISO).

b. Procurement Methods and Practices for Long-Term Transactions

In this section, PG&E discusses procurement contracting methods and practices for various long-term (*e.g.*, 5 years or longer) procurement transactions.

(1) Negotiated Bilateral Contracts

PG&E generally does not negotiate bilateral contracts for long-term procurement. However, PG&E has conducted bilateral negotiations when appropriate and beneficial to its customers. For example, PG&E's acquisition through a bilateral transaction of the Gateway facility[7] stemmed from a settlement of PG&E's claims against Mirant. In its application to the Commission requesting approval of the acquisition and completion of Gateway, PG&E benchmarked the economics of the acquisition by comparing the cost to complete Gateway to the costs of other, similar power plant acquisitions recently approved by the Commission, namely the Mountainview and Palomar facilities. Both Mountainview and Palomar were viewed as "fleeting opportunities" for below-market acquisitions. PG&E was able to demonstrate that Gateway's forecast completion cost was lower than those other two fleeting opportunities on a $/kilowatt ("kW") basis. The Commission approved PG&E's acquisition of Gateway in D.06-06-035.

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[7] The Gateway Facility was previously referred to as Contra Costa 8.

If PG&E considers long-term bilateral agreements in the future, the winning 2004 LTRFO bids may provide an appropriate starting point for market benchmarks to review those bilateral agreements. These winning bids are the result of a competitive solicitation and are good measures of market prices for dispatchable and operationally flexible products available at the time the winning bids were selected.

(2) Competitive Solicitations – PG&E's Experience With the 2004 LTRFO

PG&E recently concluded its 2004 LTRFO, which resulted in seven contracts that were recently approved by the Commission. The 2004 LTRFO process was complex and intensive. Below, PG&E provides a brief description of the various elements and aspects of the 2004 LTRFO process as an example of how long-term procurement solicitations can be administered.

PG&E's 2004 LTRFO involved both internal and external resources. PG&E formed an internal steering committee for the 2004 LTRFO to ensure the goals of the LTRFO and D.04-12-048 were met. The committee was responsible for establishing policies, making key decisions about offers and recommending the shortlist of projects and ultimately the final contracts for execution. PG&E also received feedback from market participants on its proposed LTRFO solicitation process before starting the process. After a pre-offer conference, in response to this feedback, PG&E modified the 2004 LTRFO protocol, including modifications to extend the schedule and increase the number of offer variations allowed for each offer. PG&E also made modifications to the Purchase and Sale Agreement ("PSA") and Power Purchase Agreement ("PPA") contracts based on feedback from the market participants prior to submission of final offers.

The actual 2004 LTRFO solicitation process included a number of key milestones. First, PG&E distributed a draft RFO and online registration for purposes of a pre-offer conference. PG&E established a location on its public website with information relevant to the 2004 LTRFO.

Second, PG&E held a Pre-Offer Conference to discuss the draft of PG&E's 2004 LTRFO for PPAs and Facility Ownership.

Third, PG&E issued its original 2004 LTRFO for PPAs and Facility Ownership and later revised the LTRFO in compliance with D.04-12-048.[8] Participants were then required to initiate Electric and Gas Interconnection Studies including a System Impact Study ("SIS") and Facility Study ("FS") with the CAISO and to submit to PG&E Gas Transmission and Distribution department or other applicable gas transmission company a request for a Preliminary Application for Gas Service.

Fourth, participants were requested to submit a Notice of Intent ("NOI") to offer and then submitted their initial offers. The IE was present to witness the opening of initial offers.

Fifth, PG&E notified participants of shortlisted projects and issued drafts of PPAs and PSAs and requested additional data from participants with projects on the shortlist.[9]

Sixth, PG&E issued revised drafts of PPAs and PSAs to participants. Participants with projects on the shortlist submitted final offers. The IE was present to witness the opening of final offers.

Finally, PG&E was involved in extensive negotiations with winning bidders and then executed agreements and presented them for approval by the Commission.

PG&E's 2004 LTRFO included certain eligibility requirements that were designed to ensure a diverse selection of resources, capacity, contract terms and technologies. These requirements were also designed to ensure that the resources would be timely constructed and online in time to meet resource needs in the 2008 through 2010 time frame.

- **PPAs:** For PPAs, new generating facilities were required to have a Commercial Operations Date ("COD") no earlier than January 1, 2007, and no later than May 31, 2010. Offers required a minimum term of five years and a minimum size of

8 This revision implemented a methodology to evaluate PPA offers and PSA offers directly on a head-to-head basis. In addition, an IE was selected, in consultation with the PRG, and retained. PG&E also included the solicitation for offers for the Humboldt Bay Power Plant ("HBPP") in the revised LTRFO.

9 Participants providing offers for HBPP were requested to provide offers for a PSA, an Engineering, Procurement and Construction ("EPC") and the sale of development assets.

25 MW or greater. Offers were required to provide for firm physical delivery of generation to a busbar in the North of Path-15 ("NP15") area. Only "unit specific" offers were accepted. Offers were required to confer upon PG&E exclusive rights to the unit's capacity, subject to CAISO requirements.

- **Facility Ownership:** For Facility Ownership, all generating facilities were required to have a Guaranteed Commercial Availability Date no earlier than January 1, 2007, and no later than May 31, 2010. Facilities were required to have a design life of 30 years, a size no less than 25 MW at any one site, and construction with new equipment. A proposed project's generation was required to physically interconnect to a busbar within the NP15 area.
- **Humboldt Generation:** For the Humboldt Bay area, PG&E required generation facilities to have a Guaranteed Commercial Availability Date no earlier than January 1, 2007, and no later than August 31, 2009. Facilities were also required to have a design life of 30 years, total peak capacity of at least 135 MW on a single site, functional specifications necessary for Humboldt area reliability, and be constructed with new equipment. A proposed project's generation was required to be physically interconnected to a busbar within Humboldt County.
- **Qualifying Facilities:** An existing QF in PG&E's service territory as of November 2, 2004, was required to meet the requirements of FERC's QF rules and not have waived these rights to PG&E. QFs also had the option to provide delivery within the ZP26 area. Offers were required to be for a minimum term of five years and a minimum of 1 MW or greater.
- **New Resources:** The 2004 LTRFO was only open to new resources (with the exception of existing QFs) because the purpose of the solicitation was to implement the directives of D.04-12-048 to bring new sources of reliable supply to northern California. For the purpose of the 2004 LTRFO, PG&E considered "new" resources to be resources that had not begun construction. PG&E assumed that resources that had begun, but not yet completed, construction would likely be completed without the need for contracts via PG&E's 2004 LTRFO.
- **Other Eligibility Requirements:** Additional 2004 LTRFO requirements included: (1) a Transmission System Impact Study and a Preliminary Application for Gas Service; (2) deposit requirements; and (3) site control.

PG&E also included a Greenhouse Gas ("GHG") adder in the evaluation of the 2004 LTRFO bids. In D.04-12-048, the Commission specified that a GHG adder, in dollars per ton of carbon dioxide ("CO_2"), be used to calculate the cost of CO_2 emissions. In D.05-04-024, the Commission adopted a particular set of values for the GHG adder: for delivery year 2004, \$8.00 per ton of CO_2, with escalation at 5% per year for delivery in subsequent years. For delivery year 2010, this amounts to \$10.72 per ton of CO_2. PG&E used this GHG adder curve in project evaluations. For each offer, PG&E's modeling yielded estimates of the anticipated CO_2 emissions, based on the capacity factors associated with that offer's generating unit. The estimated quantities of CO_2 emitted were then multiplied by the costs per ton specified in the GHG adder. This calculation yielded the variable cost associated with CO_2 emissions. GHG adder cost was measured in present value (2006) dollars per kW-year of generating unit capacity.

In accordance with D.04-12-048, PG&E also contracted directly with an IE, in consultation with PG&E's PRG. The scope for the IE's responsibilities included the following activities: (1) review and comment on the appropriateness of PG&E's evaluation methodology, with a focus on how PPA and utility ownership offers are compared directly; (2) review and assess whether PG&E actually implemented the evaluation methodology as represented; (3) use the IE's Response Surface Model to check the numerical results for PG&E's market valuation of the contracts; and (4) deliver to the PRG, under existing confidentiality protections, the Response Surface Model and the results produced by the IE in performing the check of numerical results, as described above.

PG&E met with the PRG at least 15 times to discuss aspects of the 2004 LTRFO evaluation. The PRG was also consulted in the selection of the IE. PG&E held two workshops with the PRG to discuss PG&E's evaluation methodology in depth. PG&E's evaluation framework for credit was also discussed extensively with the PRG. In addition, PG&E met with the PRG to discuss evaluation of initial offers, final offers, and during final negotiations.

PG&E is satisfied with the results of the process developed for its 2004 LTRFO and intends to follow largely the same process in its next LTRFO.

c. Procurement Methods and Practices For RPS Transactions

The California RPS Program was established by California State Senate Bill ("SB") 1078, effective January 1, 2003. [10] The RPS Program requires that a retail seller of electricity such as PG&E purchase a certain percentage of electricity generated from eligible renewable energy resources. Each utility regulated by the Commission is required to increase its total procurement of capacity and energy generated by eligible renewables by at least 1% of annual retail sales per year so that 20% of its retail sales are supplied by eligible renewables by 2010.

PG&E procures RPS resources through competitive solicitations and bilateral negotiations. In bilateral negotiations, PG&E may execute contracts with renewable suppliers for one month up to 20 years, or more. These contracts are filed for Commission approval by advice letter. For competitive solicitations, PG&E conducts annual RPS solicitations. Prior to issuing its solicitations, the RPS procurement plan and solicitation protocols are submitted to the Commission for approval.

As with the 2004 LTRFO, in consultation with the PRG, PG&E contracts directly with an IE for RPS Solicitations.

d. Procurement Methods and Practices: Length of Time Between Contract Date and Delivery Commencement

The time between contract execution and when delivery of a product begins depends on resource type (*e.g.,* existing or newly built resources), as well as the short- or long-term nature of the contract. For short-term contracts deliveries can begin as late as one year after execution, such as an RA contract signed in 2005 for Summer 2006. These contracts become effective when executed.

Medium-term contracts that are consistent with existing procurement authority may be filed for approval via advice letter filings, which could take up to a year. Long-term contracts (except for renewable contracts resulting from an RPS solicitation) are filed for approval via an

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[10] *See* Cal. Pub. Util. Code §§ 399.11-399.25 and Cal. Pub. Res. Code §§ 25740-25751.

application. The application, approval and permitting process for such contracts typically takes over a year. For contracts that require construction of facilities, construction will not begin until all regulatory approvals and permits are acquired and actual deliveries may not begin until five or more years after contract execution. Thus, for long-term contracts with newly-built resources, it could take several years or more between contract execution and the beginning of deliveries to allow for permitting and construction.

For renewable generation, it typically takes one year from a RFO issuance until Commission approval, and two to three years from Commission approval until deliveries are targeted to commence, for a total of three to four years from the RPS RFO issuance to actual contract deliveries.

6. Proposed Transaction Timing for Upcoming RFOs

The following section describes PG&E's proposed RFOs for the next one to five years.

a. Renewable RFOs

As described in Section IV.D, PG&E will continue to issue annual Renewable RFOs to aggressively pursue RPS targets. These RFOs offer renewable developers a number of procurement alternatives—such as PPAs with and without buyout options, turnkey utility ownership, and greenfield development—in order to identify those mechanisms which are in the best interest of its customers. The developers include large corporations, small businesses, and individuals with ideas. Contracts with these developers typically range from 10 to 20 years; however, PG&E will also consider other contract lengths. The types of contracts include Power Purchase and Sale Agreements for As-Available Products and Power Purchase and Sale Agreements for Firm Products (which include peaking, baseload, and dispatchable products). Once PG&E issues these RFOs, the offers received are reviewed. PG&E shortlists offers and then negotiates with bidders to execute contracts. Executed contracts will be submitted to the Commission for approval.

PG&E will continue to refine its renewable RFOs based on developer feedback, over the future planning horizon. As PG&E's procurement practices evolve, PG&E may identify the need for other types of renewables RFOs. These yet-to-be determined renewables RFOs will be issued only upon Commission approval.

b. Short-Term/Medium-Term RFOs

The residual net long/short energy and RA capacity requirements are the positions that PG&E may need to manage on a short-term (up to and including 1 year) and medium-term (greater than 1 year and less than 5 years) time horizon within the operating targets discussed in Appendix B. Specifically, if the monthly subperiod positions fall outside the operating targets, strategies are developed and executed to bring the portfolio back to within the targets. PG&E's energy and capacity needs are managed using Commission-approved transaction contracting methods in Advice Letter 2615-E, including competitive solicitations. PG&E will continue to issue medium-term RFOs to manage the residual net long/short energy and RA capacity requirements. These RFOs can be issued for a variety of electric products. These electric products are described in Section II.A.3. The contracts resulting from these RFOs can range from greater than one year to less than five years in length. Once PG&E issues these RFOs, the offers received are reviewed. PG&E shortlists offers and then negotiates with the bidders to execute agreements. Project costs are reviewed with the PRG during the process. Executed contracts are filed with the Commission through either the Quarterly Procurement filings or through stand-alone advice letter filings.

Resource adequacy requirements will be met by PG&E using competitive solicitations or other previously approved Commission mechanisms. As required by the Commission, PG&E will file its plan to meet 90% of its System RA requirements for the summer months (*i.e.*, May-September) by the specific date established by the Commission. Subsequently, all months require a 100% commitment to be in place one month ahead. PG&E will review its RA procurement activities with the PRG and file Advice Letter for necessary Commission approvals.

PG&E is required to acquire 100% of its share of the local area resource ("LAR") requirement in CAISO defined, transmission-constrained areas. PG&E will seek to procure its

LAR with Commission approved mechanisms at the lowest cost while considering the CAISO's area and sub-area RA needs.

c. LTRFOs

PG&E's 2006 LTPP implements the State Loading Order and aggressively pursues renewable resources, as well as energy efficiency and demand response. However, even with these efforts, there will be a need for additional new generation in Northern California. As discussed in Section IV.F.6, PG&E will issue a new all-source LTRFO in 2008 to procure between 800 to 1,200 MW of dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources to be available in 2015. This solicitation will seek facilities to meet the identified need for the 2015 time frame.

Ordering Paragraph 15 in D.07-01-039 directed PG&E to update its 2006 LTPP filing for compliance with the adopted Interim Emissions Performance Standard rules, as necessary, within sixty (60) days from the effective date of that decision. PG&E's 2006 LTPP is already in compliance with the decision and thus does not need to be further modified. For contracts of five years or more in duration, whether from new resources or existing resources, PG&E will comply with the Interim Emissions Performance Standard.

7. The Application of Least-Cost, Best-Fit and the Loading Order in PG&E's Procurement Planning and Transactions

Least-cost, best-fit provides for resource alternatives to be selected based on their relative cost-effectiveness and their ability to meet the specific needs of the portfolio. A resource's cost-effectiveness is determined relative to common market benchmarks or "market value," as explained below. A resource's portfolio fit can be a qualitative assessment or quantitative measure that represents how well its energy profile, location, and other operating characteristics meet the needs of the portfolio for a particular product in a given location.

In planning and procurement decisions, PG&E applies a consistent evaluation methodology to both supply-side and demand-side resources. By applying least-cost, best-fit principles to supply-side and demand-side alternatives, PG&E obtains the lowest cost for customers for a given set of portfolio needs. PG&E's procurement evaluation methodology considers both the market value and the portfolio fit of alternative resources that are available.

a. Market Valuation

Market value represents a resource's net market value from a market perspective, based on its costs and benefits, regardless of its fit with the rest of PG&E's portfolio. The costs that PG&E uses in calculating a resource's net market value include the value that the Commission has placed on CO_2 emissions.

In valuing demand-side alternatives, PG&E uses the Commission's Standard Practice Manual's[11] total resource cost ("TRC") test. Under that TRC test, the costs that PG&E and its customers are expected to incur in implementing an alternative resource[12] are compared to the expected benefits that would be obtained from that alternative resource. Those benefits include the energy and/or capacity costs that would be avoided by utilizing that alternative resource. As long as PG&E's avoided energy and capacity costs are based on market prices, then PG&E's evaluations of supply-side resources and demand-side resources are consistent, and make it possible to compare supply-side resources to demand-side resources.

b. Portfolio Fit

Portfolio fit assesses how well a resource alternative matches PG&E's portfolio needs. For example, a resource that produces energy during time periods in which PG&E's portfolio is expected to be long (*i.e.*, periods in which PG&E expects to make spot market energy sales) has a poorer portfolio fit than a resource that produces energy during time periods in which PG&E's portfolio is expected to be short (*i.e.*, periods in which PG&E expects to make spot market

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[11] *Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, issued by the Commission in October 2001.

[12] When evaluating demand-side alternatives, PG&E considers the costs customers incur due to participation in demand-side program as well as the costs that non-participating customers incur due to that program.

energy purchases). As a result, the portfolio fit of a resource is different from, but complementary to, the net market value of that resource.

In the planning phase, when preparing a long-term procurement plan, PG&E considers portfolio fit based on how well a particular resource provides the power products that need to be added to the portfolio. Not all resources provide the same products. For example, photovoltaic distributed generation and energy efficiency do not provide dispatchable peaking energy.

In the planning phase, PG&E first identifies the types and amounts of power products that it needs to fill its open position over the planning horizon. Those power products include energy products (baseload, peaking and shaping), capacity or RA products, and ancillary services products (*e.g.*, spinning, non-spinning, regulation, and black-start capacity). Then, PG&E identifies the energy products that each alternative resource can provide (*e.g.*, baseload energy and dispatchable shaping or peaking energy.)

Most resources can provide a capacity product, or have an RA value that PG&E can estimate by using the Commission-adopted RA counting rules. However, some resources are more likely to provide energy in the hours when the system's peak demand is most likely to occur, and which as a result have a higher RA value (per unit of installed capacity). With respect to ancillary services, a combustion turbine ("CT") can provide quick start capacity and can be used in emergencies to replace resources that are unavailable because of forced outages. Certain demand response ("DR") programs can also provide emergency capacity, because the demand reductions under that program can be activated on short notice (e.g., within 10 minutes to qualify as non-spinning reserves).[13] CTs and DR however, are not suited to provide system regulation services because they cannot respond instantaneously to automatic generation control ("AGC"). Regulation services are generally provided by units that are on-line, and operated under automatic control to continuously balance generation and load.

[13] *Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC),* revised April 6, 2005, p. 3.

In the procurement phase, when evaluating transactions, portfolio fit can be a qualitative assessment or quantitative measure that represents how well a resource fits the portfolio's need. In addition to the market valuation, resources are compared based on their ability to meet the particular need being met, or their ability to provide additional features that are complementary to the portfolio. For example, if the proposed resource is not dispatchable by the utility, the offer with a generation profile that best matches the hourly profile of the open position will score more highly on PG&E's portfolio fit measure. Other portfolio fit considerations can include location and the volatility of the remaining portfolio open position.

c. Loading Order

According to EAP II, cost-effective Energy Efficiency ("EE") and DR are preferred to meet the State's growing energy needs, followed by cost-effective renewable and distributed generation, and finally clean and efficient fossil-fired generation. The EAP II also requires improvements to T&D system to support demand growth and enable the interconnection of new generation.[14]

PG&E's 2006 LTPP follows the State Loading Order.

8. PG&E's Use of the PRG Process

PG&E consults with the PRG on a wide range of transactions generally on a monthly basis, and sometimes more often as necessary. The Commission directed PG&E to consult with the PRG for specific types of transactions including: (1) overall interim procurement strategy; (2) proposed procurement contracts before the contracts are submitted to the Commission for expedited review; and (3) proposed procurement processes including but not limited to RFOs which result in contracts being entered into in compliance with the terms of the RFO.[15] Although the PRG acts in an advisory capacity only, PG&E actively solicits feedback from PRG

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[14] EAP II, p. 2.

[15] D.02-08-071 at 24.

members and incorporates that feedback into its procurement processes regularly. In particular, PG&E confers with the PRG on:

- **Procurement Plans and Customer Risk Tolerance:** PG&E provides the PRG regular updates of its portfolio position and risk. When the portfolio risk (measured at the 95th percentile) exceeds 125% of the customer risk tolerance ("CRT"), PG&E meets and confers with the PRG to discuss the underlying risk drivers and factors affecting the change in portfolio risk and to decide whether specific hedging strategies and/or plan modifications are needed to reduce portfolio risk to within the CRT threshold.
- **Transactions That Begin More Than 3 Months Out, or Are More Than 3 Months in Length (D.04-01-050):** PG&E consults with the PRG at least once, and sometimes several times, on transactions greater than three months in length. PG&E discusses how transactions meet portfolio needs, solicitation processes, evaluation methods, negotiation processes and contract selection.
- **LTRFO Design and Administration (D.04-12-048 and D.07-12-052):** PG&E discusses both all-source and renewable RFOs with the PRG. Consultation with the PRG may encompass RFO design, the evaluation processes, short-list selection, negotiation strategy, and bid selection.
- **Hedging and Gas Supply Plans:** PG&E consults with the PRG before filing its DWR gas supply plans. PG&E also consulted with the PRG prior to presenting the hedging plan in Appendix B to the Commission for approval.
- **Participation in a Generator Request for Bids (D.04-01-050):** PG&E consults with the PRG prior to making an offer in other Load-Serving Entity ("LSE") solicitations or generator requests for bids.
- **Long-Term Congestion Revenue Rights ("LT-CRRs") and Congestion Revenue Rights ("CRRs") (Resolutions E-4122 and E-4135):** PG&E discusses LT-CRR and CRR nominations and transactions with the PRG as required by Resolutions E-4122 and E-4135.

PG&E also takes advantage of the interactive nature of the PRG process to discuss a wide range of topics that it is not required to discuss with the PRG. For example, shortly after PG&E filed its 2006 LTPP, PG&E provided detailed briefing on the voluminous material in the long-term plan. PG&E has also provided educational sessions to the PRG on topics including credit, market valuation and portfolio fit, risk management and To-expiration-Value-at-Risk ("TeVaR"), and the principles and processes of gas hedging.

PG&E finds regular consultation with the PRG improves PG&E's and the PRG's understanding of the issues, enhances communication between the parties, and enhances the ultimate procurement decision-making process. Due to PG&E's ongoing dialogue with the PRG, PRG members have the opportunity to learn about challenges the utility faces contemporaneously, rather than hearing about them after the decisions have been made and submitted for Commission approval. PG&E also benefits from the PRG process because PRG members can advise the utility on procurement activities prior to PG&E executing a transaction.

B. Risk Management Policy and Strategy

1. PG&E's Current Risk Management Practices

This section describes PG&E's current electric portfolio risk management practices. PG&E's electric portfolio risk management has evolved over time. PG&E's 2004 Short-Term Procurement Plan ("STPP") set out how the financial risks associated with the electric portfolio's open positions would be managed, including electricity and gas price risks.[16] In July 2005, PG&E formally expanded its price risk management process specifically for the gas component (*e.g.*, electric fuels) of the electric portfolio by implementing a gas hedging program.[17] PG&E's gas hedging plan was approved by the Commission in September 2005. Since September 2005, PG&E has updated its gas hedging plan twice, in Advice Letter 2723-E (effective November 1, 2005) and Advice Letter 2775-E (effective March 17, 2006).

PG&E submitted a proposed gas and electricity hedging plan with its 2006 LTPP. In D.07-12-052, the Commission did not approve the proposed gas and electricity hedging plan, but instead requested that the utilities work with the Energy Division and PRG to submit a revised risk management plan. Since D.07-12-052 was issued, PG&E has discussed its revised

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[16] D.03-12-062, PG&E 2004 Short-Term Procurement Plan, Chapter 3, Section E.

[17] *See* Advice Letter 2885-E, which was approved by the Commission on September 22, 2005, in Resolution E-3951.

risk management plan for electricity and gas hedging with the PRG and Energy Division on several occasions and provided a draft of the revised electricity and gas hedging plan to both the PRG and the Energy Division. The revised electricity and gas hedging plan is included as Appendix B to the conformed 2006 LTPP.

2. Portfolio Risk Assessment and Customer Risk Tolerance

PG&E's ability to manage its open position exposure in electricity and gas are affected by numerous risks, including: price, market liquidity, model, and credit.

First, with regard to price risk, to the extent that electricity and gas commodity prices rise or become more volatile, it makes managing financial exposure more difficult, requiring greater portions of the portfolio to be forward hedged in order to prevent potential large movements in future electric portfolio costs. Among the challenges are balancing how much to hedge, when to hedge and what products to use to hedge the exposures.

Second, PG&E faces market liquidity risk. Depending on the quantity of forward hedging and the hedge products desired, prices could move when the hedging is being implemented. When there is lack of market depth, this movement could be significant. One way to mitigate that risk is to establish hedge strategies whereby desired hedging quantities and execution timing are unlikely to cause this to happen.

Third, PG&E can be affected by model risk. Model risk relates to the risks involved in using models to value and hedge assets and commodities. Often, PG&E's portfolio positions are not directly traded in any marketplace. In this situation, models are used to estimate value, select hedging targets, and measure portfolio risk. Included in this is the risk of estimating, extrapolating, or forecasting inputs needed for portfolio evaluation: energy demand, hydro supply, forward prices, volatilities, and correlations. Model risk is addressed by performing sensitivity studies.

Finally, PG&E can be affected by credit risk. Since returning to procurement, PG&E's credit department has employed a credit policy whereby all transactions with counterparties are subject to term and dollar limits. Generally, these limits are based on collateral thresholds, credit ratings, and the policies that other companies have agreed to in posting to minimize credit risk, which is another form of financial risk of the electric portfolio. This is another means of controlling the financial risk of the electric portfolio. [redacted]

PG&E reports its electric portfolio TeVaR to the Commission's Energy Division on a monthly basis. Consistent with D.07-12-052, PG&E measures TeVaR as the potential change in portfolio costs under a low probability (5%) outcome or a 95% confidence level. This measure assumes that no further forward hedging is performed, and that all existing positions are taken to delivery. In addition, D.03-12-062 requires PG&E to notify and meet and confer with the PRG if between quarterly PRG consultations, PG&E's estimated portfolio risk exceeds 125% of the Customer Risk Tolerance level which the Commission set at a one cent per kWh impact to retail rates, which over the prompt 12-month period is approximately [redacted]

3. PG&E's Credit and Collateral Requirements

The Commission has not established specific rules for customer risk that apply to credit. PG&E's credit and collateral requirements evolved from accepted energy industry practices, including concepts that can be found in EEI, NAESB, and ISDA master agreements. The primary elements of PG&E's credit and collateral requirements include: collateral thresholds (unsecured credit lines), collateral posting for sales of gas and power, and mark to market posting to cover the change in value of the contract relative to the market. The general goal is to protect the customer against the risk of default by parties ("counterparties") with whom PG&E enters into wholesale commodity transactions or hedging transactions. PG&E's credit risk management process includes: creditworthiness evaluations, collateral requirements for various types of transactions, and the level of collateral authority. Each of the aspects of the credit risk management is described below:

- **Creditworthiness** – PG&E manages the credit risk regarding its counterparties by assigning unsecured credit limits or unsecured credit thresholds to them based on PG&E's assessment of their financial condition, market and industry position, industry volatility and outlook, credit standing, and other credit criteria, as deemed appropriate.

PG&E periodically reviews the assigned unsecured credit limits to assess their appropriateness in relation to the then-current credit quality of the counterparty.

- **Counterparty Collateral Requirements** – If a counterparty is a rated entity (*e.g.*, the debt of the entity is rated by S&P, Moody's or Fitch) assigned a credit rating below investment grade (for example investment grade is considered BBB- or above by S&P or Baa3 by Moody's) or is a "non-rated entity" not considered creditworthy by PG&E, then PG&E generally will require the counterparty to provide acceptable credit support. Such credit support can be in the form of a cash deposit, guaranty from an investment grade entity, or a letter of credit from an acceptable credit support provider, in form and substance satisfactory to PG&E. For creditworthy counterparties, PG&E establishes a specified unsecured credit limit beyond which posting of acceptable credit support is required. Some of the specific collateral requirements that apply to various categories of transactions are described below.

- **Renewable Contracts (New)** – Renewable counterparties are required to post a bid deposit of $3 per kW; a development and construction period deposit of up to $20 per kW for a dispatchable project or $20 per kW multiplied by the greater of: (i) the capacity factor; or (ii) 0.5; and 6, 9, or 12 months of the average revenue (for 10, 15, and 20 year terms) once commercial operations begin.

- **Resource Adequacy (RA)** – Resource adequacy counterparties (rated as non-investment grade) are generally required to post 25% to 33% of annual capacity payments particularly when RA is a clearly identified component.

- **Intermediate Term Tolling, Forward or Option Contracts** – Intermediate term tolling counterparties are subject to mark to market posting (this amount is generally capped). In addition if the counterparty is below investment grade or is unrated, it may be required to post an independent amount.[18]

- **Long-Term Tolling Contracts (New)** – Long-term tolling counterparties are required to post a bid deposit of $5 per kW; post an additional $10 per kW when an executed contract is submitted to the Commission (for a total of $15 per kW); a developmental and construction period deposit of $85 per kW at the time the Commission approves the contract (for a total of $100 per kW); and once commercial operations begin the counterparty is subject to mark to market posting (this amount is capped and the cap depends on the technology).

[18] An independent amount is a flat amount of collateral posted to cover market movements between collateral calls. If the counterparty defaults in between collateral calls (collateral calls typically are made daily or weekly) and fails to post the required margin, the utility can use the independent amount to cover some or the entire shortfall.

- **Short-Term Transactions** – Short-term transactions include hour-ahead, day-ahead, balance of the month, multi-month, and swing deals. Exposures from purchases and sales of power and gas are tracked daily. Collateral requirements are governed by the master agreements under which these transactions are executed.

- **IOU Collateral Authority** – D.04-10-037 grants PG&E, among other things, authority to issue up to $2.5 billion[19] of short-term debt, subject to the restriction that $500 million of that authority may only be used for the following purposes:

  – Procuring natural gas for PG&E's customers during price spikes.[20]

  – Procuring electricity for PG&E's customers during price spikes.

  – Responding to major natural disasters, large scale terrorist attacks, or other cataclysms.

  – Providing liquidity during a major disruption of PG&E's ability to bill, collect, and/or process utility customer bills.

Given these restrictions, PG&E effectively has $2.0 billion of general short-term debt authority, with the additional $500 million of authorization reserved for the foregoing specified contingencies.

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[19] On November 9, 2006, the Commission approved PG&E's petition to modify D.04-10-037, granting PG&E requested authority to issue up to $2.5 billion of short-term debt.

[20] D.04-10-037 defines the commencement of a "price spike" as an increase in the price of gas or electricity of at least 50% over the average of the preceding 12 months.

III. LONG-TERM PROCUREMENT RESOURCE PLAN

This section summarizes the load and resource assumptions for PG&E's service area need which were adopted by the Commission in D.07-12-052 in Table PGE-1. Table PGE-1 is reproduced in Appendix A.

A. Load Forecasts (Appendix A, Table PGE-1, Lines 1-2)

As directed by the Commission in D.07-12-052, the load forecast in Table PGE-1, lines 1-2, is based on the CEC's 2007 Integrated Energy Policy Report ("IEPR") 1-in-2 peak demand, which includes committed energy efficiency ("EE"), approximately 80% of uncommitted EE, and forecasted distributed generation including the California Solar Initiative ("CSI") program additions. The service area load forecast, line 2 includes PG&E bundled customers and current direct access ("DA") customers, but excludes current publicly-owned utility ("POU") customers located in NP26.

B. System Resources (Appendix A, Table PGE-1, Lines 3-12)

The CEC's Supply/Demand 5-year outlook[1] is the source for the 2007 base amount of existing generation resources in Table PGE-1, line 3. The CEC only considers known retirements in its 5-year outlook analysis. Additional retirements are itemized into two lines in PGE-1. Line 4 includes units that have announced retirement dates. This category includes the projected retirement of PG&E's existing HBPP facility. Line 5 provides a laddered reduction of aging units as described in the retirements section of D.07-12-052 (*see* D.07-12-052, Section 2.4.2) to reflect a measured retirement pace of approximately 600 MW per year beginning in 2009 until 4,200 MW are retired by 2015.

Resource additions to the CEC base amount of existing resources are shown in three categories: renewable resources that will increase from ongoing RPS requirements,

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[1] CEC's *Revised Summer 2006 Demand and Supply Five Year Outlook,* June 30, 2006.

non-RPS planned additions developed through PG&E's procurement process, and high probability additions expected to be on-line in the region.

The NP26 RPS additions in Table PGE-1, line 6 reflect the capacity from future renewable generation additions. This includes generation procured by PG&E in its 2004 and 2005 RPS solicitations expected to become operational during the planning horizon and renewable additions based on the market availability of renewable resources to the NP26 region. The market availability of renewable resources is commensurate with the MWh amounts described in PG&E's RPS Plan for its bundled customers in Section IV.D. To account for the renewable resources available to POU customers within the NP26 region, the market availability of renewables is estimated to be 7.4% over the market availability for PG&E bundled load on an energy basis. By 2016, the total NP26 region RPS amount is 1,870 MW.

PG&E planned additions in Table PGE-1, line 7 include resources PG&E procured through from PG&E's 2004 LTRFO, which include plants in the Bay Area, Central Valley and Humboldt regions, along with the Gateway Generating Station. These PG&E planned additions result in an additional 2,851 MW in the region by 2010. Due to uncertainties regarding the development of these and other RPS and demand-side additions, in its March 5, 2007 filing, PG&E reduced this amount by 600 MW. (As directed by the Commission in D.07-12-052, line 19, Contract viability re-adjustment for PG&E's 2006 LTPP, gradually restores the full amount of those additions by 2012.)

High Probability California additions in Table PGE-1, line 8 represent approved new generating units in the region with an expected on-line date controlled by entities other than PG&E, including the 180 MW San Francisco peaker project, which is identified as a high probability addition. The generation from this project is shown beginning in 2009.

The Net Interchange into the NP26 region is based on several components. The first component, shown in PGE-1, line 9, includes 2,348 MWs of Northwest imports based on the

CAISO estimate of import levels for RA.[2] The second component is additional imports from the Western Area Power Administration ("WAPA") to public entities within the CAISO NP26 region which are estimated to be 700 MW. These additional imports are shown in Table PGE-1, line 10. The third component, Northwest ("NW") imports, are decreased to account for potential NW RPS imports already accounted for in Table PGE-1, line 6 as the NP26 RPS additions estimate includes potential Northwest renewable projects. These adjustments increase to 172 MW by 2016 and are shown in Table PGE-1, line 11. The final component is the exports to the CAISO SP26 region shown in Table PGE-1, line 12, which are based on the CEC 2006 Summer Outlook[3] assumption of 3,000 MW.

C. Service Area Specific Resources (Appendix A, Table PGE-1, Lines 16-19)

As directed by the Commission in D.07-12-052, the Uncommitted Energy Efficiency in Table PGE-1, line 16 represents the additional Uncommitted Energy Efficiency not captured in the CEC's demand forecast (approximately 20% of the total uncommitted EE goals plus a 10% line loss factor).

For purposes of this regional capacity analysis, DR programs are treated as supply resources. DR is split into two types: Price Sensitive Demand Response and Interruptible/Curtailable Programs. The Price Sensitive Demand Response in Table PGE-1, line 17 includes existing price responsive programs and the additional projected DR from the deployment of Smart Meter™ Program. DR increases from 342 MW in 2007 to 801 MW in 2016. Interruptible/Curtailable programs in Table PGE-1, Line 18 reflect existing DR programs. These existing programs are forecast to increase from 310 MW in 2007 to 353 MW in 2008 through 2016.

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[2] Supplemental Deliverability Study: Import Levels for Resource Adequacy (RA) Planning Purposes http://www.caiso.com/docs/2005/09/23/20050923165719616.pdf.

[3] CEC's *Revised Summer 2006 Demand and Supply Five Year Outlook*, June 30, 2006.

As directed by the Commission in D.07-12-052, the contract viability readjustment in Table PGE-1, line 19 replaces deductions for a 10% contract viability derate (600 MW) which, as previously discussed, were embedded in PG&E's original resource assumptions in line 7.

D. PG&E's Service Area Need (Appendix A, Table PGE-1, Lines 22-26)

Based on the load and resource assumptions reflected in Table PGE-1, and factoring in the 15% to 17% PRM, Lines 22 through 26 of the table calculate PG&E's net long (or short) position in each planning year.

Lines 22 and 23 provide the forecasted reserves based on forecast load and existing and planned/anticipated resources, in MWs and percentage terms, respectively. Lines 24 and 25 provide the lower and upper bounds of the needed PRM (15% and 17%, respectively) for the forecast load. Finally, Line 26 calculates the amount of existing service area resources in excess of the 17% upper PRM bound (or the amount of additional resources needed to meet the 15% lower PRM bound) for each planning year. Based on this analysis, D.07-12-052 identified a need in PG&E's service area of 800 to 1,200 MW of new generation by 2015.

E. Bundled Capacity Resource Accounting Table (Appendix A, Table PGE-2)

Table PGE-2 provides the annual load and resource capacities for PG&E's bundled customers with categories based on the CEC's Electricity Resource Planning Form S-1. Loads are consistent with D.07-12-052 and reflect the CEC's 2007 IEPR 1-in-2 peak demand for PG&E's bundled customers. Resources reflect a combination of utility-owned as well as existing and planned contractual capacity.

IV. PROCUREMENT STRATEGY BY RESOURCE

A. Introduction to Resource Acquisition Strategy

PG&E's 2006 LTPP is designed to implement the state's Energy Action Plan ("EAP"), particularly the resource Loading Order, and the state's RPS goals. It balances three primary objectives: (1) assembling a portfolio of reliable and operationally flexible resources; (2) supporting development of environmentally preferred resources; and (3) managing customer price and price volatility. In this section, PG&E describes its resource acquisition strategies for EE, DR, renewables, distributed generation ("DG"), other generation including imports and the integration of transmission planning. This section also describes the authority PG&E currently has from the Commission for each resource acquisition strategy.

B. Energy Efficiency

1. PG&E's Pre-2006 Programs

PG&E has a long history of managing EE programs. Following Commission policy, PG&E pursued a strategy of acquiring EE as a resource in the early and mid-1990's, of pursuing EE in order to transform the EE services markets during the period 1998-2001, and is now pursuing EE as a preferred resource in its procurement strategy consistent with the EAP. Over the years, PG&E has gained considerable expertise in designing and deploying EE programs. It has been able to develop strategies which address all customer groups. It has generally found that presenting EE in the context most familiar to the customer is most effective at achieving customers' positive response. PG&E has had significant success reducing consumption through EE programs. For example, during the 2004-2005 program authorization and funding cycle, PG&E achieved annual reductions of 1,166 gigawatt-hour ("GWh") and 357 MW.

2. PG&E's Approved Programs for 2006-2008

PG&E's 2006-2008 EE program portfolio was developed with input from PG&E's Program Advisory Group and PRG during 2005. PG&E filed its proposed portfolio in

Application ("A.") 05-06-004 on June 1, 2005. The Commission approved PG&E's portfolio in D.05-09-043, subject to a Compliance Advice Filing following completion of PG&E's competitive solicitation for third-party resources. PG&E subsequently filed compliance advice letters detailing the comprehensive portfolio, including third-party programs, on February 17, 2006 (Advice 2704-G/2786-E) and April 17, 2006 (Advice 2704-G-A/2786-E-A), respectively. These advice filings, and the annual MW and kilowatt-hour ("kWh") savings targets contained in the April 17 filing, were approved by the Commission on June 1, 2006. The annual savings targets for 2007-2008 are included in the 2006 LTPP. For the three years 2006-2008, PG&E's electric portfolio design is cost-effective and expected to achieve cumulative savings of 613 MW and 3,063 GWh by the end of 2008.

TABLE IV-1
PACIFIC GAS AND ELECTRIC COMPANY
ENERGY EFFICIENCY SAVINGS, 2006-2008

Line No.		2006	2007	2008	Total
1	Total Annual Electricity (GWh/yr)	677	1,125	1,261	3,063
2	Total Peak Savings (MW)	132	223	258	613

Note: Includes savings from low income energy efficiency programs.
Source: PG&E Advice 2704-G-A/2786-E-A, April 17, 2006, Attachment II, Table 1.1: Projected Program Impacts by year.

To achieve these high levels of savings, and lay the foundation for sustained high delivery as called for by the Commission's adopted targets, PG&E developed a market oriented program approach and proposed to the Commission the following, market-based portfolio:

- Resource market segments:
  - Mass Market (residential and small commercial customers)

Projected Net Program Impacts	
GWh	1,728
MW (Summer Peak)	334
MM Therms	15.9

The Mass Market is comprised of single family residential retrofit, multifamily residential retrofit, commercial and residential renters, and small commercial customers who have similar purchasing patterns and strategies, use the same vendors, and have similar approaches to energy efficiency. An integrated approach to these customers, historically viewed as separate segments, provides greater penetration into the commercial market while eliminating artificial boundaries and barriers thus providing for easier program delivery and expanded participation.

Vendors and contractors are a key delivery channel for the mass market sector, particularly for the direct install delivery channel. This sector works with manufacturers, contractors, retailers and customers to maximize energy savings. PG&E coordinates customer information, provides vendor/retailer/contractor support, and encourages manufacturer/ distributor participation. Third parties and partnerships are integrated into the Mass Market program.

PG&E has identified the two largest areas of potential savings as lighting and heating, ventilation and air conditioning (“HVAC”). In addition, the Residential Low Income Energy Efficiency program serves over 55,000 homes a year with educational and direct installation services. Savings resulting from these activities are also included in the overall PG&E Portfolio.

- Targeted Markets:
  - Agricultural and Food Processing

Projected Net Program Impacts	
GWh	164
MW (Summer Peak)	23
MM Therms	3.1

This program targets the full range of agriculture and food processing customers. The program addresses green field new construction and facility expansion and renovation as well as ongoing daily facility operation. Particular attention is given to key industry sub-segments identified as having high energy use and significant potential for efficiency improvement. The key sub segments include wineries and dairies. Refrigerated warehouses, an activity that cuts across many of the agriculture and food processing market segments, have also been singled out for particular attention given their significant contribution to sector energy use and their potential for electricity and demand savings. Third-party implementers focus on wineries, customers with refrigerated warehouse facilities, and dairies.

The majority of program marketing and outreach is conducted by PG&E staff and industry-specific consultants under contract to PG&E. The industry-specific implementers selected through PG&E's third-party solicitations also provide marketing and outreach services to well-defined groups of customers within the agriculture and food processing market segments. All of these marketing and outreach efforts are coordinated through the PG&E Agriculture and Food Processing Segment manager.

- Schools and Colleges

Projected Net Program Impacts	
GWh	128
MW (Summer Peak)	29
MM Therms	2.6

The program design is based on the highly successful School Resources Program ("SRP") that has served K-12 public schools since 2003 and the 2004-2005 UC/CSU/IOU statewide partnership. SRP has evolved into a model that integrates seamless delivery of utility and state technical support and financial incentives programs to school districts. Most school districts and colleges are not subject to Title 24, and, therefore, may bypass energy efficient practices. The Division of the State Architect ("DSA") and the Office of Public School Construction are tightening their procedures, but in the past many school designs slipped past energy reviews. DSA is moving towards acceptance of Collaborative for High Performance Schools school performance standards for approval of all new school buildings. SRP will continue to support these efforts.

The UC/CSU/IOU Partnership is the customer-preferred method for delivery of analytical and technical services to that sub-segment. Both programs have demonstrated the ability to overcome market barriers represented in this market sector. For 2006-2008, two- to four-year colleges are included in the program; independent private colleges in the PG&E service area are supported through a program design similar to that of the SRP, while selected public colleges are supported through a statewide program design similar to the present UC/CSU/IOU Partnership but coordinated with the Office of the Chancellor of California Community Colleges.

- Retail

Projected Net Program Impacts	
GWh	126
MW (Summer Peak)	21
MM Therms	0.02

The Retail program serves the diverse retail market segment including supermarkets, restaurants, big box retail and general retail. It includes statewide elements (calculated incentives and deemed savings rebates) as well as elements specifically targeted to the energy needs of these customers (commissioning, retro-commissioning and demand response). This program directly addresses the energy needs of big box retail, chain supermarkets and restaurants regardless of size in terms of kW demand. It uses a team of retail and restaurant industry experts made up of internal staff and external contractors and consultants. This team serves as the point of contact and coordinates training and educational activities, marketing activities, audits if needed, design assistance, financial incentives, retro-commissioning and commissioning, information about distributed generation options and demand response efforts.

The majority of program marketing and outreach for the larger retail customers and large chain accounts is conducted by PG&E staff and industry-specific consultants under contract to PG&E. The industry-specific implementers selected through PG&E's third-party solicitations also provide marketing and outreach services to well-defined groups of customers within the retail market segment, particularly mid-size and smaller customers not assigned individual PG&E account representatives. All of these marketing and outreach efforts are coordinated through the PG&E Retail Stores Segment manager.

However, PG&E's Mass Market program is still the primary delivery channel for the small retail stores and restaurants.

- Fabrication, Process and Heavy Industry

Projected Net Program Impacts	
GWh	475
MW (Summer Peak)	69
MM Therms	18.2

This program addresses green field new construction and facility expansion and renovation as well as ongoing daily facility operation. Particular attention is given to key industry sub-segments identified as having high energy use and significant potential for efficiency improvement. The key sub-segments include water and wastewater treatment, oil production, and oil refining. Boiler efficiency and compressed air efficiency, activities that cuts across many of the heavy industry market segments, have also been singled out for particular attention given their significant contribution to sector energy use and their potential for electricity and natural gas savings. Third-party implementers work within this market segment. They will focus on water and wastewater treatment, the oil industry, customers employing large boilers and compressed air system efficiency improvements, and the general industrial manufacturing sub-segment.

The majority of program marketing and outreach is conducted by PG&E staff and industry-specific consultants under contract to PG&E. The industry-specific implementers selected through PG&E's third-party solicitations also provide marketing and outreach services to well-defined groups of customers within the Fabrication, Process, and Heavy Industries market segments. All of these marketing and outreach efforts are coordinated through the PG&E Fabrication, Process, and Heavy Industrial Manufacturing Segment manager.

– Medical Facilities

Projected Net Program Impacts	
GWh	69
MW (Summer Peak)	28
MM Therms	0.5

This program targets new and existing medical facilities using both PG&E and one currently selected third-party industry implementer to facilitate delivery of a portfolio of energy efficiency, demand response and distributed generation services. A new market integrated program effort addresses the hospital segment, while PG&E's mass market effort serves as the primary delivery vehicle for the medical office segment. The nursing home segment is also served by the mass market effort, although the market integrated approach primarily addresses larger facilities that fall under the auspices of Office of Statewide Health Planning and Development review.

– High Technology Facilities

Projected Net Program Impacts	
GWh	45
MW (Summer Peak)	6
MM Therms	0.02

This program targets high technology facilities and their unique energy needs using both PG&E and third-party industry specialists to deliver a range of energy efficiency services. The program addresses green field new construction and facility expansion and renovation as well as ongoing daily facility operation. The program incorporates statewide financial incentive elements as well as elements specifically targeted to and customized for the high technology customers in PG&E's service area. Many high technology facilities, particularly electronics firms in the greater Bay Area, have significant lighting loads as well as office equipment and other plug loads. Energy efficiency opportunities within these more traditional end use categories are addressed by this program in conjunction with the Mass Market and Large Commercial programs.

Program marketing and outreach is conducted by PG&E staff, industry-specific consultants under contract to PG&E, implementers selected through PG&E's third-party solicitations, and local government partners. All of these marketing and outreach efforts are coordinated through the PG&E Hi-Tech Market Segment manager.

- Large Commercial

Projected Net Program Impacts	
GWh	220
MW (Summer Peak)	74
MM Therms	2.2

The Large Commercial program primarily uses calculated energy savings incentive mechanisms. Upstream deemed or direct install measures may be used for office equipment. Much of the energy savings are oriented towards retrofit projects.

The overarching strategy is to work with the design community to make them aware of the value of integrated design strategies and the potential in high efficiency lighting, HVAC, and related technologies. This includes providing them with the tools to determine under what conditions the new strategies and technologies are appropriate, which approaches they can employ to move their clients, the building owners and managers, toward adoption of high efficiency technologies in the final designs.

The program team continues to work directly with building owners through its direct relationships with large property management firms. This work focuses on: (1) building support for the United States Green Building Council's Leadership in Energy and

Environmental Design ("LEED") and green building concepts; and (2) in the case of government-owned office buildings, meeting State government desires to reduce in government building energy consumption. Third parties and partnerships are integrated into the Large Commercial program.

During this program cycle there has been a new focus on workstation loads such as computers, video display terminals, printers, external disk drives, computer audio systems, telephones, under-cabinet task lighting, copiers, and faxes. These loads are growing to the point where they may equal the building load in power density (watts per square foot).

- Hospitality

Projected Net Program Impacts	
GWh	37
MW (Summer Peak)	8
MM Therms	0.03

This program targets new and existing lodging and hotel facilities using PG&E and third-party industry specialists to facilitate delivery of a portfolio of energy efficiency services. It includes statewide elements as well as elements specifically targeted to the customers in PG&E's service area. The market integrated program addresses the energy needs of larger hotels, convention centers, and chains while PG&E's Mass Market program is the primary delivery channel for smaller hotels/motels and bed and breakfast inns.

The hospitality industry has substantial opportunity for energy efficiency. Remodeling in large hotels and corporate chains occurs fairly frequently, about every three to seven years, in order to remain competitive. Growth in this market sector is occurring in the Central Valley, coincident with economic and population growth, where air conditioning can be a significant load and advanced evaporative cooling could be a viable alternative to compressor based cooling.

– Residential New Construction

Projected Net Program Impacts	
GWh	13
MW (Summer Peak)	9
MM Therms	2.4

The California Energy Star New Home Program offers builders a choice of participating in a prescriptive or performance-based program. The performance-based program encourages and assists builders to incorporate energy efficient technologies and design in the homes they construct to exceed the California Title 24 Energy Efficiency Standards by 15 percent in both inland and coastal areas. In California, homes built to current Title 24 standards are 30 percent more efficient than homes built to the federal government's standards.

At this time, single family and low-rise multifamily building projects meeting the program requirements will also meet the requirements of the U. S. Environmental Protection Agency ("EPA") Energy Star® Homes Program. The EPA does not currently recognize high rise construction with the Energy Star label. The information gathered as a result of this program is shared with the EPA Energy Star®. The EPA is interested in the outcome of this program activity for possible future Energy Star® designation of multifamily buildings that are four or more stories.

- Non-resource programs continue to be funded, including: education and training, emerging technologies, codes and standards, and marketing and outreach. PG&E's Education and Training program supports the Energy Training Center – Stockton, the Pacific Energy Center and the Food Service Technology Center. The emerging technologies program accelerates the introduction of innovative energy efficient technologies, applications and analytical tools. Codes and Standards Advocacy encourages the improvements to energy efficiency building codes and appliance standards through statewide codes and standards. Statewide Marketing and Outreach provides statewide energy efficiency marketing through three statewide agencies.

- Low Income Energy Efficiency ("LIEE") programs also contribute to the energy savings goals, but are funded separately from the energy efficiency programs. The LIEE programs have goals of 12 MW, 56 GWh, and 2.5 MM Therms.

In each area, program materials and efforts are tailored to address the specified interests and concerns in that market. In addition, over time, this approach will improve the integration of demand-side options available to the customer: energy efficiency, demand response, and preferred distributed generation, particularly solar. This gives the customer a wider array of options and improves both the resource value and the value of these programs to customers.

In D.05-09-043, the Commission authorized PG&E's new energy efficiency program portfolio structured around market segments and approved a 3-year implementation and funding cycle and a budget of $867 million. The Commission has also given PG&E increased flexibility to adjust programs and funding to meet customer demands and maximize the probability of reaching the savings targets.

To reach these customer segments, PG&E employs three types of delivery channels: statewide and local government partnerships, competitively acquired third-party programs, and utility-delivered programs. PG&E has also integrated energy efficiency delivery with other demand-side resources such as Demand Response and the Self-Generation Incentive Program ("SGIP") in order to achieve greater customer acceptance and better overall utilization of all these resources.

3. Programs for 2009 and Beyond

In October 2007, the Commission issued D.07-10-032, which established the framework for the utilities to develop EE portfolio plans for the 2009-2011 time frame and ordered the California utilities to develop a joint Statewide EE Strategic Plan through 2020. D.07-10-032 also provided that the previously established energy savings goals for 2009-2011 would not be updated. PG&E is currently in the process of developing programs to meet these goals. PG&E is fully committed to pursuing Customer Energy Efficiency ("CEE") opportunities as directed in D.04-12-048, Ordering Paragraph ("OP") 12. It considers CEE as an essential part of the 2006 LTPP.

C. Demand Response

In addition to EE, PG&E also fully supports demand response and believes it is appropriately placed along with energy efficiency and renewable resources as a priority resource in the EAP's Loading Order. As of January, 2008, PG&E has approximately 1,066 MW of load enrolled in DR programs. PG&E intends to continue to aggressively promote demand response, not only increasing participation rates but also increasing load reduction per participant site. PG&E is developing demand response programs for its residential and small commercial customer classes. PG&E believes that increasing DR automation will increase customer participation in DR programs and actual demand reduction when system conditions most need these resources.

PG&E's existing programs are described in some detail below. The rollout of the SmartMeter™ Program and its complementary Critical Peak Pricing ("CPP") program will provide additional demand-side resources. The deployment of the SmartMeter™ Program will enable further DR via a CPP program.

1. Existing Programs

In June 2005, PG&E filed a comprehensive listing of commercial and industrial DR programs covering years 2006-2008 in A.05-06-006. This application was settled among various intervening parties and approved by the Commission in D.06-03-024. The Commission expanded and revised certain parts of the programs in late 2006 to increase available DR for 2007 and 2008, in light of the summer 2006 heat storm. PG&E's DR portfolio serves a critical function in achieving required demand reductions. The following is a description of PG&E's programs:

Business Energy Coalition (Schedule E-BEC): The Business Energy Coalition ("BEC") was originally a project intended to strengthen ties with major San Francisco business and civic leaders and their facilities. The program targeted office, hospitality, and high-tech sectors for DR participation and is designed using the group aggregation concept. In 2007, the

BEC program was expanded to include hard-to-reach (*e.g.*, beyond office, hospitality and high-tech) customers outside of San Francisco.

Capacity Bidding Program (Schedule E-CBP): The Capacity Bidding Program ("CBP") replaced the California Consumer Power and Conservation Financing Authority ("CPA")-Demand Response Program ("DRP") when it terminated in March 2007. The CBP is available to retail commercial, industrial and agricultural accounts of all sizes. Customers may choose to enroll in CBP through an aggregator or directly with PG&E.

Critical Peak Pricing Program (Schedule E-CPP): The CPP program offers commercial/industrial customers greater than 200 kilowatt ("kW") an alternative to traditional Time-Of-Use ("TOU") rates. Customers on the CPP program receive reduced energy rates for all non-CPP usage during on-peak and partial-peak time periods during PG&E's summer rate season, May 1-October 31. During CPP event days participants pay from three times their partial-peak rate to five times their normal on-peak rate. CPP event days are called based on the day-ahead forecasted temperatures or system reliability.

Demand Bidding Program (Schedule E-DBP): The Demand Bidding Program ("DBP") is a voluntary bidding program that may be triggered on a day-ahead basis when by 3 p.m. the CAISO has issued an Alert for the following day or when the CAISO's forecasted peak demand is expected to exceed 43,000 MW. When notified of an event, participants can voluntarily bid-in the amount of load reduction that they wish to commit for the next day. In 2007, this program was modified to include a day-of event option. The day-ahead option may be triggered when the CAISO issues an energy warning or greater. Participants can earn an incentive for qualifying load reduction.

Technical Assistance (TA)/Technical Incentive (TI) Programs: The Technical Assistance Program ("TA") offers customers engineering assistance to help identify how, and by how much, customers may be able to reduce demand under a PG&E DR or reliability program. PG&E provides a high-level facility evaluation identifying specific end uses where demand might be shifted or temporarily reduced. The audit is provided at no cost to the customer or, if the customer prefers, PG&E will offer to pay the customer up to $100 per kW of identified DR capability for a third-party audit. The Technology Incentives Program ("TI") offers customers cash incentives for installing demand responsive equipment and/or control software. The combined programs ("TA/TI") are open to projects involving qualifying medium and large commercial, industrial and agricultural customers. Demand responsive hardware and software investments that enable customers to participate in programs qualify for incentive payments of up to $250 per kW of verified load reduction capability.

Auto-DR Program: The Auto-DR Program helps customers to identify demand reduction strategies such as managing lighting and HVAC systems, where electrical usage can be reduced or even eliminated during times of high electricity prices or electricity system emergencies. These demand reduction strategies are then pre-programmed into each customer's building energy control systems. A signal is automatically sent by the utility via internet to these energy control systems during times of high electricity prices or system emergencies, which initiates a series of pre-programmed, pre-authorized demand reduction strategies. Automated hardware, software and technical assistances investments that enable customers to participate in DR programs qualify for incentive payments of up to $300 per kW of verified load reduction capability.

Non-Firm Service Program: The Non-Firm Service Program was a rate option under Schedules E-19 and E-20. Pursuant to D.07-09-004, the program was closed effective January 1, 2008.

Base Interruptible Program (Schedule E-BIP): The Base Interruptible Program ("BIP") is intended to provide load reductions on PG&E's system when the CAISO issues a curtailment notice. This program is very similar to the Non-Firm Service program. Option A participants receive a monthly incentive payment based on the difference between their average demand and their Firm Service Level. Customers receive 30-minute notice, and if a customer is requested to curtail its usage and fails to reduce load to or below the customer's Firm Service

Level, a substantial penalty is applied. Option A participants also have an underfrequency relay ("UFR") option where they will be automatically interrupted, through the operation of a UFR, if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. Participants receive an additional discount for being on the UFR option. Option B participants receive 4-hour notice for events and receive an energy payment for any reductions. There is no penalty for failing to reduce load.

Air Conditioning Direct Load Control Program: Air Conditioning ("AC") direct load control will be an integral part of PG&E's future demand-side portfolio. AC load is one of the primary drivers of California's summer peak usage. An AC program reduces demand from this end-use by employing technology that will "hard wire" a reduction of air conditioning demand. AC programs can be called on short notice (such as in an emergency situation) and provide an important resource for PG&E and the CAISO to maintain system reliability in times of peak usage. In 2007, the Commission approved PG&E's request for a 5 MW AC program for summer 2007. The AC program has subsequently grown to 28 MW. On February 14, 2008, the Commission issued D.08-02-009, which approved the expansion of PG&E's AC direct load control program to approximately 305 MW by June 2011.

Request for Proposals and Contracts: PG&E issued a Request for Proposal ("RFP") for demand response proposals for up to five summer periods, beginning in summer 2007 to provide additional load reduction beyond that provided in PG&E's current DR programs. In D.07-05-029, the Commission approved five aggregated DR contracts that may provide up to 149 MW of load reduction by 2009.

2. Proposed Enhancements to PG&E's Demand Response Programs

Cafeteria Style Menu: In July 2007, PG&E filed an advice letter requesting approval of a new demand response program called the Cafeteria Style Menu ("CSM") program for 2008. This program would increase enrollment in PG&E's existing DR programs and increase actual load reduction during a program event. PG&E forecasts that approximately 42 MW of DR may be achieved in 2008. The CSM program, unlike PG&E's other DR programs, would allow customers to choose several program characteristics to tailor a program to the customers' needs including the amount of load reduction, the event window, the event duration, the event notification time, and the number of consecutive events. On February 28, 2008, the Commission issued Resolution E-4127 approving the CSM program for 2008.

a. SmartMeter™ Program Rollout

Residential and small commercial DR resulting from the deployment of the SmartMeter™ Program is a critical element in increasing DR. PG&E received approval of the SmartMeter™ Program application in D.06-07-027 and began full roll out of the advanced meters in Bakersfield in November 2006. The DR SmartRate tariff is a critical peak pricing option available for those customers with the new interval meters starting summer 2008. The entire rollout will take approximately five years to complete. An additional DR rate option for residential customers is proposed in the SmartMeter™ Program Upgrade, A.07-12-009, Peak Time Rebate ("PTR"), to encourage expanded participation for residential customers on critical peak days beginning 2010.

D. Renewable Energy Procurement Strategy

PG&E strongly supports renewable resources and renewable energy's preference in the State Loading Order. PG&E recognizes the distinct environmental attributes that eligible renewable resources provide to its customers. Since the beginning of the RPS program, PG&E has signed contracts totaling over 2,100 MW of capacity that will be capable of producing 8,300 GWh per year, or approximately 10% of PG&E's forecast 2010 bundled retail sales.

PG&E intends to continue to aggressively pursue renewable energy procurement throughout the planning horizon of the 2006 LTPP to meet and exceed renewable targets set in SB 107 and Commission decisions. PG&E also anticipates developing new programs such as the Emerging Renewable Resource Program ("ERRP") in order to further facilitate the development of available renewable energy resources.

1. PG&E's Existing Renewable Resources

PG&E filed its August 2007 RPS compliance report on August 1, 2007.[1] This report shows RPS-eligible renewable deliveries for 2006 of approximately 9,114 GWh. These

[1] Renewable Portfolio Standard Periodic Compliance Report of Pacific Gas and Electric Company (U 39-E), filed in R.06-05-027, August 1, 2007.

renewable deliveries came from resources that pre-date the RPS program and resources that PG&E has contracted with since the RPS program commenced in 2002.

2. PG&E's Plan to Increase Renewable Resources

PG&E also intends to aggressively pursue RPS targets through annual RPS solicitations and bilateral agreements. PG&E will offer renewable developers a number of procurement options including power purchase agreements, turnkey and buyout options, and greenfield development, in order to offer flexibility to renewable resource developers and to identify the mechanisms which are in the best interest of PG&E customers. PG&E's specific plans to increase renewable energy are described below.

a. Renewables Request for Offer

PG&E's Renewables RFO program is one of the primary mechanisms through which PG&E procures renewable energy. Another mechanism to procure renewable energy is through bilateral agreements as described further in Section D.2.b. PG&E has conducted four RPS solicitations and executed bilateral agreements to date, with the following results:

Solicitation Year	Signed Contracts (GWh/% of Retail Load)
2002 (under Interim Rules)	747 GWh / 1%
2004	1,966 GWh / 2.5% (includes 2003)
2005	4,298 GWh / 5.4%
2006	1,328 GWh / 1.7%

Note: The volumes in GWh represent the maximum expected output per the signed contracts.

PG&E filed its 2008 Renewable Energy Procurement Plan and Draft Solicitation on August 1, 2007, and amended this Plan on September 6, 2007 to include requests for short-term offers,[2] with details on its strategy to improve its RPS RFOs and make renewable procurement

[2] R.06-05-027.

even more successful. PG&E believes it has created significant awareness about its annual RFO over the past three years, but believes there are some groups it is still not reaching. PG&E has developed a distribution list for RFO outreach, doubled the amount of participants on the list, and will use this list to communicate with potential bidders. PG&E also has worked directly with Renewable Energy Trade Associations to expand the distribution reach. Over the next several years, PG&E plans to identify additional markets and outreach. The goal of these activities is to ensure that every developer that is capable of participating in the California market is aware of the PG&E Renewables RFO and encouraged to participate.

PG&E is also streamlining and standardizing its solicitation process to further facilitate the RFO process. California is seen by developers as an expensive and complex state in which to develop projects, and as other markets become more active the relative attractiveness of the California market may diminish. As such, PG&E wants to be as responsive as possible to the needs of the development community. PG&E began to assess the needs of the development community in 2005 by conducting a developer survey. Based on feedback from that survey and from conversations with key stakeholders, PG&E is making a number of changes to increase participation, such as reducing credit requirements. In addition, as PG&E previously explained in its Supplement to its Long-Term Renewables Plan[3] and its 2008 Renewable Energy Procurement Plan, PG&E continues to enhance its outreach programs.

b. Bilateral Renewables

PG&E's annual Renewable RFO is an effective mechanism for renewable energy procurement. However, there are projects that require bilateral agreements either for timing reasons or due to special circumstances. In addition to the contracts filed through the solicitation process described above, PG&E has filed bilateral contracts in the past and is working with a number of additional counterparties currently. PG&E intends to continue to pursue bilateral opportunities when they arise.

[3] R.04-04-026, Supplement to PG&E's 2005 Renewable Energy Procurement Plan.

c. PG&E-Owned Renewables

PG&E solicited ownership offers for the first time as part of its 2005 RPS Plan. PG&E announced that it would entertain turnkey proposals under which the developer could sell the project to PG&E at commercial operation date for a pre-determined price. PG&E also announced that it would entertain a buyout option, under which PG&E has the option to purchase the facility in either the fifth or the tenth year of a power purchase agreement at a pre-determined price. PG&E hoped that including these options would promote a more competitive and robust renewable development environment.

PG&E evaluated the ownership offers that were received, but there were no offers competitive with the power purchase offers received. PG&E expanded its 2006 RPS solicitation to include offers for sites on which the utility could develop eligible renewable energy resources in addition to the fully constructed projects solicited under the ownership options. PG&E will retain the protocol used to evaluate offers for utility ownership, such as consultation with an Independent Evaluator, ensuring the benefit of utility ownership options can be evaluated on equal terms with power purchase alternatives. PG&E is separately pursuing development opportunities both in and out of state. While renewable emerging technologies typically will not be available until the post-2010 time frame, PG&E is exploring these opportunities as well.

d. Emerging Renewable Resources Pilot Projects

PG&E believes that the development of new renewable technologies and resource areas is essential to a healthy renewables market in the post-2010 time frame. PG&E is working with a number of emerging renewables technologies and is beginning to assess new resources that could benefit customers by expanding long-term renewable supply. PG&E's current efforts are focused on a number of markets and technologies.

For example, PG&E is supporting the development of pipeline-quality biogas through long-term contracts at fixed prices. By injecting processed biogas into pipelines and transporting it to central plants, biomethane from Central Valley dairy farms is used productively, eliminating methane emissions that otherwise would add to global warming. PG&E has also signed an electricity purchase agreement with a dairy biodigester to take electricity generated on-site.

In addition to the dairy biogas projects, PG&E has also been working with biomass gasification developers. Biomass gasification could reduce electric transmission congestion and open up new biomass resources through utilization of the gas transmission network. While the commercial deployment of biomass gasification technologies has been limited so far, and additional technology risk exists, the possibility of opening up these new markets is promising.

PG&E has also actively pursued emerging marine energy resources, including wave and tidal power, to take advantage of PG&E's unique location, which contains the best tidal power location in the 48 contiguous states and which features the longest coastline of any utility in the U.S. PG&E has worked closely with Electric Power Research Institute ("EPRI"), the City and County of San Francisco ("CCSF"), and the CEC to evaluate potential wave and tidal projects. While these resources are somewhat unproven and the technologies have relatively limited deployment worldwide, PG&E sees value in early action and participation.

PG&E has also been aggressively pursuing new solar energy technologies and resources. PG&E is working with a number of companies with promising solar thermal and concentrating solar photovoltaic technologies. PG&E hosted Solar Power 2006 and anticipates supporting the demonstration of a number of emerging solar technologies over the planning horizon.

Finally, PG&E is investigating energy storage systems, which can help integrate, from a system operations perspective, the use of intermittent renewable resources. Utility-scale energy storage applications include the traditional pumped storage applications as well as smaller batteries and flow batteries. Distributed energy storage utilizing plug-in hybrid electric vehicles ("PHEV") also has many synergies with intermittent resources as well as the ability to create a major reduction in petroleum use. PHEVs that are charged at night using the excess off-peak power created by most renewable energy purchases would avoid the use of polluting petroleum during the day. PHEVs also have the potential to be connected to the grid during the daylight hours to provide peaking and ancillary services, such as regulation.

PG&E is seeking to build on its efforts with emerging technology by proposing the ERRP in A.07-07-015. The ERRP would identify and support new technologies and resources that have the potential to expand the portfolio of renewable resources and commercially-viable technologies and reduce costs over the long term, by assisting promising technologies and resources in overcoming developmental barriers.

3. Renewable Resource Availability

D.05-10-014 recommends that the IOUs address in their long-term RPS planning the availability of renewable resources both in, and remote from, their service territories. PG&E's strategy to support development of those resources involves transmission planning and active market development and resource validation. One example of market development and resource validation is PG&E's recent British Columbia ("BC") Renewable Resource Application, A.06-08-011. PG&E also anticipates that a portion of its proposed ERRP budget will be used to work with developers to identify new California and adjacent state resources. In general, PG&E plans to work proactively over the planning horizon to identify developer needs, identify additional resources, and identify transmission needed to serve them.

E. Distributed Generation (California Solar Initiative and Self-Generation Incentive Program)

PG&E's customers are playing an increasingly important role in adding generation to the electrical grid. Hundreds of photovoltaic solar systems are interconnected to PG&E's system every month by customers driven by environmental concerns or a desire for energy independence. Beginning in 2007, the California Solar Initiative ("CSI") will provide approximately $1 billion in rebates for customers in PG&E's service territory over a ten year period. In conjunction with the existing SGIP, there will be significant incentives for PG&E's customers to acquire their own generation for on-site use. This section describes PG&E's

program implementation strategies for customer-owned generation ("CG"), such as solar and combined heat and power ("CHP"), and how CG will affect the overall resource plan.

1. PG&E's Customer Generation Policy

PG&E supports its customers making smart energy choices and CG is one of a variety of options customers should have available to address their energy needs. PG&E is implementing an integrated demand-side management ("IDSM") approach to delivering EE, DR, load management and CG programs to its customers. In 2004, PG&E developed and began implementing an audit tool which evaluates customers' facilities and offers information about IDSM measures, including information on the SGIP rebates. In 2007, PG&E modified the audit tool and offered additional information regarding the CSI. PG&E believes an integrated approach is the most cost-effective and will best meet individual and overall customers' energy needs.

PG&E has supported CG before the legislature, the Commission, and through a variety of internal process improvements. PG&E is studying internal processes to simplify interconnections for our customers who choose CG, minimizing the points of contact for customers and structurally shortening learning curves. PG&E's goal is to make complex interconnections more routine and require less engineering review. PG&E's support of customer generation has resulted in a total of 177 MW from the following generation sources:

**TABLE IV-2
PACIFIC GAS AND ELECTRIC COMPANY
RECENT CUSTOMER GENERATION INSTALLATIONS
(MW)**

Line No.	Resource Type	2003	2004	2005
1	Solar	14	23	30
2	CHP	25	34	26
3	Others	11	5	9
4	Total	50	62	65

Continued growth in customer generation is a key component of PG&E's 2006 LTPP. The forecast of customer generation is incorporated into the 2006 LTPP by reducing the demand forecast by the customer generation forecast. The Commission ordered PG&E to use the CEC forecast in this compliance filing, which has customer generation embedded in the estimates.

Programs that support customer generation are described more fully below.

2. PG&E's Implementation of the California Solar Initiative Program

PG&E is committed to retaining its role as a leader in the solar market. For the past several years, PG&E has supported regulation and legislation that created or extended programs providing assistance to customers who choose to install solar generation. PG&E supported the California Solar Initiative established by the Commission in 2005 and the increased 2006 SGIP solar budget designed to address the significant backlog of customer applications. More recently, PG&E supported Senate Bill ("SB") 1, which codified the California Solar Initiative and increased the cap on the net metering program from 0.5% to 2.5% of PG&E's peak load.

Although the Commission has resolved many details of the CSI, the design phase is not yet complete. Some details are still in process, including low income and implementation of the eligibility criteria developed by the CEC pursuant to SB 1. PG&E has been an active participant in Commission and CEC workshops and proceedings and supports the direction the Commission has taken to implement the CSI. PG&E is committed to implementing a program that (as stated in the Commission Staff Proposal) achieves its "overall objectives with the lowest possible ratepayer contribution."[4] PG&E is committed to creating a robust market for customer solar generation so that over time the costs of solar generation decrease and customer participation increases without continued subsidies.

PG&E also supports the Commission's commitment to performance based incentives, extension of incentives to non-PV-based technologies (including solar hot water heating),

[4] *CPUC Energy Division Staff Proposal for California Solar Initiative Design and Administration 2007-2016*, R.06-03-004, April 24, 2006, page 10.

making the benefits of the program available to low income customers, research and development, and measurement and evaluation. In a recent draft decision, the Commission adopted PG&E's suggestion that solar hot water heating displacing gas usage could be included in the SGIP program, since it was excluded from the California Solar Initiative by SB 1.

PG&E is the leading solar utility in terms of solar interconnections in the United States and is committed to continuing and expanding that leadership role. PG&E's continuing support for solar power has contributed to the installation of more solar units in its service area than any other utility in the country. Indeed, according to industry reports previously presented to this Commission, over half the solar projects installed in the entire United States in 2004 were installed in PG&E's service area.[5] PG&E has successfully interconnected over 21,000 solar customers, who have installed over 160 MW of solar generation.

PG&E began on January 1, 2007 to administer the California Solar Initiative for its customers. PG&E worked diligently to prepare the CSI Handbook for adoption by the Commission and has led a cooperative effort with representatives of the low income housing development community to better understand how to bring solar benefits to low income customers. PG&E also instituted simplification of the billing information provided to customers on the net metering program.

3. PG&E's Implementation of the Self-Generation Incentive Program and Other Customer Generation Options

In addition to solar CG, the SGIP also assists customers who are installing other types of customer generation, such as wind, renewable and nonrenewable fuel cells, renewable fuel internal combustion engines, renewable fuel micro turbines and small gas turbines, and nonrenewable micro turbines and combustion engines that meet certain air quality standards.[6]

[5] *Vote Solar Opening Comments on Staff Solar Report*, R.04-03-017, July 7, 2005, page 3.

[6] Systems must meet AB 1685 emissions standards to receive an incentive through the SGIP.

Since 2001, the SGIP has provided over $190 million of incentives for 95 MW of customer generation (including solar). For clean and renewable customer generation, the SGIP can improve a customer's project economics by providing a rebate to offset the capital cost. In addition to the SGIP, some customers install CHP or other generation without participating in the SGIP. These customers benefit from any interconnection process improvements in addition to their savings on energy bills. Starting January 1, 2008, as a result of legislation, the SGIP program is closed to all technologies except wind and fuel cells.

4. PG&E's Commitment to Distributed Generation Research and Development

PG&E supports the commitment to research and development found in the Commission's decision that initially established the CSI, and subsequently included in SB 1. In addition to CSI research and development, PG&E is partnering with other utilities, industry stakeholders, the CEC, EPRI and the Federal government on research projects that examine the effects of customer generation in utility grids, including exploration of ways to make the grid smarter, and ways to incorporate customer generation into utility planning.

5. PG&E Supported the Expansion of AB 1969 to Renewable Generation by Any Customer

In 2006, the Legislature passed Assembly Bill ("AB") 1969, authorizing utilities to provide a tariff that allows public water and wastewater facilities to install renewable generation up to 1.5 MW and receive compensation for excess generation produced. In the Commission proceeding implementing AB 1969, PG&E proposed that customers be allowed to first offset concurrent energy needs and only sell excess generation. The Commission adopted PG&E's suggestion. PG&E also supported a Commission suggestion that the AB 1969 power purchase agreement be available to all customers installing renewable generation up to 1.5 MW.

F. Other Generation Supply Resources

1. Department of Water Resources Contracts

The DWR entered into contracts during the energy crisis that were subsequently allocated to the three California IOUs. In D.02-09-053, the Commission allocated to PG&E the power from all DWR contracts with a specified delivery point at NP15, plus the Coral contract. Contracts currently allocated to PG&E provide 1,925 MW of must-take generation and 1,655 MW of dispatchable generation for a total of 3,580 MW.

For the 2008-2016 period, PG&E has assumed that four turbines owned by the CCSF, with their output under contract to DWR, will be sited and put into operation in 2009, raising the total DWR capacity allocated to PG&E to 3,722 MW. The current DWR contracts begin to expire in late 2009 and most will have expired by 2012. However, PG&E expects that the underlying resources will still be in operation and will be eligible to bid into PG&E's competitive solicitations. PG&E's current forecast of the DWR contract capacity is:

TABLE IV-3
PACIFIC GAS AND ELECTRIC COMPANY
2008-2016 DWR CONTRACT CAPABILITY
(MW)

Line No.		2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Must-Take	1,925	1,925	925	595	595	0	0	0	0
2	Dispatchable	1,655	1,847	1,667	1,667	459	288	288	288	0
3	Total DWR MW	3,580	3,772	2,592	2,262	1,053	288	288	288	0

2. Reliability Must-Run Contracts

RMR contracts are yearly contracts procured and administered by the CAISO to meet local reliability needs. PG&E participates in the CAISO's determination of RMR need and in the CAISO's pricing of RMR contracts, but does not directly contract for the RMR deliveries. California is in transition from RMR to Local Capacity Requirements ("LCR"). Unlike RMR, which is procured by the CAISO, LCR would be procured by the LSE, with any residual need being purchased by the CAISO. The amount of requirement for RMR (and in the future LCR) is determined by the CAISO through technical studies of the electric transmission system.

The LCR planning criteria uses a 1-in-10 standard rather than the 1-in-5 standard used for RMR, so LCR procurement amounts will be higher than the RMR amounts. However, unlike RMR, LCR capacity will count toward an LSE's RA requirement, reducing the amount of capacity the LSE will need to procure for systemwide RA.

LSEs will contract for the LCR procurement, and will create an obligation from the unit to the CAISO. The general requirements for the CAISO will be that the unit will either need to be running, or will need to bid its capacity into the CAISO market. PG&E likely will procure LCR capacity as part of its other short-, medium- and long-term solicitations, bilateral negotiations and market purchases. If necessary, PG&E may conduct special solicitations and negotiations for LCR capacity to fully meet local needs. Any unmet needs will likely be filled by the CAISO through RMR contracting.

3. Market Purchases

PG&E enters into market purchases through several different mechanisms:

- Transparent exchanges, such as the ICE and NYMEX;
- Futures Commission Merchants;
- Inter-dealer or voice brokers;
- Spot markets; and
- On-line auctions.

Each of these markets has methods to communicate bids and offers and to complete trades. PG&E makes use of these market purchases to trade hour-ahead, day-ahead, month-ahead and term (one month to five years) electricity, and to enter into options and hedges. Market purchases are commonly used to procure power from existing resources. PG&E will make use of market purchases throughout the period 2007-2016. Further information on energy product market purchases is provided in Section II.A.4.

4. Qualifying Facilities

PG&E currently has contracts with about 260 QF projects. Under D.07-12-052, PG&E is required to maintain 2,166 MW of QF capacity through recontracting with existing QFs and contracting with new QFs. The Commission determined the conditions under which IOUs can enter into new QF contracts in D.07-09-040.

5. New Generation From PG&E's 2004 Long-Term Request for Offers

PG&E's 2004 LTRFO will result in the construction of new peaking and shaping generation in northern California. One of the winning 2004 LTRFO bidders, for the Energy Investors Funds ("EIF") Fresno project, recently announced that it was terminating its power purchase agreement with PG&E. Pursuant to D.07-12-052, pages 105-106, to the extent these approved resources are "determined unviable during the development process and the associated contract is terminated, the procurement authority for those megawatts remains." Thus, the authority associated with the EIF Fresno megawatts remains.[7]

6. New All-Source Generation

PG&E will issue an all-source LTRFO to procure between 800 and 1,200 MW of new dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by intermittent types of renewable resources to come online by 2015. PG&E plans to issue its new LTRFO in 2008. PG&E expects to file the results of the 2008 LTRFO with the Commission after executing contracts with winning bidders.

Ordering Paragraph 15 in D.07-01-039 directed PG&E to update its 2006 LTPP filing for compliance with the adopted Interim Emissions Performance Standard rules, as necessary, within sixty (60) days from the effective date of that decision. PG&E's 2006 LTPP is already in compliance with the decision and thus does not need to be further modified. For contracts of

[7] On November 5, 2007, PG&E filed Advice Letter 3151-E submitting the EIF Fresno project to the energy auction cost allocation mechanism adopted in D.06-07-29. This advice letter is now moot given the termination of the EIF Fresno agreement.

five years or more in duration, whether from new resources or existing resources, PG&E will comply with the Interim Emissions Performance Standard.

G. Imported Generation

The PG&E electric system is within the CAISO control area and it is electrically integrated with the western states included in the Western Electricity Coordinating Council ("WECC") electric grid. Electric power can be imported into the CAISO control area along transmission lines as far north as Canada and as far south as the Mexico/Desert Southwest regions. In PG&E's electric portfolio, imported generation consists of market purchases, existing contracts and future contracts as described below. Historically, PG&E has obtained most of its imported power from the Pacific Northwest.

Market purchases occur when the net open position is short and when it is economic (including transmission costs and constraints), compared to other alternatives, to purchase power outside the CAISO control area and import the power to meet demand. When the net open position is long, PG&E may sell and export the power when economic.

Currently, in PG&E's electric portfolio there are two contracts for generation located in the Northwest. The Puget Sound Power and Light ("PSPL") Exchange Contract is an exchange of 413 GWh on an annual energy basis between PSPL and PG&E. PG&E can take up to 300 MW hourly between June-September and in return PSPL can take up 300 MW on an hourly basis between January-February and November-December. This contract is an ever-green contract with a five-year termination notice. The second contract is the DWR-allocated contract with PacifiCorp in Klamath Falls, Oregon with a dispatchable contract capacity of 300 MW. This contract expires in June 2011.

In the past, power from these contracts was frequently reduced or curtailed due to transmission constraints. To decrease the risk of non-delivery due to transmission constraints, PG&E has purchased Firm Transmission Rights ("FTR") in the annual CAISO auction to import the majority of this energy on a firm basis into the CAISO NP26 region.

There will be changes in PG&E's imported generation in the future as the DWR PacifiCorp contract is due to expire within the 10-year timeframe of the 2006 LTPP and if contracts outside of the CAISO area are added to PG&E's electric portfolio. In its future contracting for imported power, PG&E will consider the "preferred loading order" and the effects of greenhouse gases.

H. Integration of Transmission and Procurement Planning

This section discusses: (1) electric transmission upgrades included as part of the most recent CAISO approved transmission plan and PG&E's 2007 Electric Transmission Grid Expansion Plan; and (2) key transmission projects which are critical to PG&E's procurement resource plan expectations.

1. California Independent System Operator Approved Transmission Plan

PG&E continues to initiate and complete electric transmission projects to increase grid capacity and reliability for its customers. In accordance with the CAISO Tariff Section 3.2.1, PG&E is required to submit annual electric transmission facility expansion plans. The annual grid expansion plan identifies PG&E's electric transmission facilities that are projected to be insufficient with the CAISO Grid Planning Standards during the 10-year study planning horizon. The grid expansion plan also identifies transmission projects needed to meet planning standards, customer demand, or to improve grid operations.

In February 2008, the CAISO approved PG&E's 2007 Electric Grid Transmission Expansion Plan, submitted in December 2007. PG&E's 2007 grid expansion plan covers the years 2008 through 2017 and contains 103 transmission expansion projects to increase electric transmission system capacity to serve the growing needs of electric customers, improve electric service reliability, reduce congestion and LCR, and connect resources (including renewable resources) to deliver the associated capacity and energy to electric customers in California. The San Francisco Bay Area Bulk Transmission Project and the Central California Clean Energy Project are two of the major projects included in PG&E's 2007 plan. The San Francisco

Bay Area Bulk Transmission, if completed, would reduce the local capacity requirement and increase electric transmission capacity and reliability in the Bay Area. The Central California Clean Energy Project, if completed, would increase transmission capacity and reliability, reduce LCR in the Fresno area, and increase utilization of Helms Pumped Storage Plant to enhance the value of off-peak generation. In addition, the California Clean Energy Project would also facilitate efficient management of renewables, as well as an increase in Path 15 transfer capability by approximately 1,250 MW.

PG&E completed its 2007 grid expansion plan in December 2007. A copy of PG&E's grid expansion plan was released to the stakeholders on December 20, 2007. In addition to transmission upgrades to provide safe and reliable electric service to its customers, PG&E's plan included transmission plans to reduce local capacity requirement, support the retirement of old fossil power plants, and to facilitate the achievement of the renewable resource goals.

2. Key Transmission Projects Critical to the Procurement Resource Plan Expectations

There are many electric transmission projects that are critical to support PG&E's procurement resource plan. These transmission projects can be generally separated into the near, medium and long term based on their schedules. Critical transmission projects in the near term (one to five years) are typically upgrades involving expansion of existing facilities or the reconductoring of transmission lines to reduce local capacity requirement and congestion and increase PG&E's ability to accept new renewable power from remote locations. These near-term projects and their anticipated schedules are:

- Metcalf-Moss Landing 230 kV Line Reconductoring - 2008;
- McCall 230/115 kV Transformer - 2008;
- Palermo-Rio Oso 115 kV Line Reconductoring - 2009;
- Vaca Dixon-Contra Costa 230 kV Line Reconductoring - 2009;
- Newark-Ravenswood 230 kV Line Reconductoring - 2010;

- Rio Oso 230/115 kV Transformers and Capacitors - 2011;
- Pittsburg-Tesla 230 kV Line Reconductoring - 2010;
- Tesla-Newark 230 kV Line Reconductoring - 2011;
- Vaca Dixon-Lakeville 230 kV Line Reconductoring - 2013; and
- Vaca Dixon-Sobrante-Moraga 230 kV Line Reconductoring - 2012, or later.

There are three proposed transmission projects in the medium term (next 5-10 years) that are in the environmental evaluation stage. They are: (1) Central California Clean Energy - 2013; (2) Bay Area Bulk Transmission Project - 2015; and (3) Table Mountain-Vaca Dixon 230 kV Reinforcement – 2013 or later. The timing and scope of these mid-term projects can change based on the results of the environmental and transmission technical studies. For the long-term projects (next 10-15 years), PG&E will continue to participate in various regional planning efforts such as the BC-California Transmission to better define future transmission needs to access and develop renewable resources in the western United States and Canada. In this regard, transmission plans must be flexible and robust to take advantage of evolving resource developments and to optimize benefits for the consumers.

V. EVALUATION OF COMMISSION-APPROVED PROCUREMENT PLAN

PG&E evaluated the long-term procurement plan that the Commission adopted for PG&E in D.07-12-052 ("Approved Plan"). The following summarizes this evaluation.

A. The Approved Plan Meets the Current Resource Adequacy Requirements

Based on the load and resource assumptions included in D.07-12-052, Table PGE-1, the Approved Plan meets the Commission's current RA requirements.[1] The major assumptions in Table PGE-1 include: (1) peak-demand based on the CEC's *California Energy Demand 2008-2018 Staff Revised Forecast* developed as part of the 2007 IEPR, dated November 2007; (2) existing resource retirements at a pace of approximately 600 MW per year beginning in 2009 until all 4,400 MW of aging power plants are retired by 2015[2]; (3) demand-side and supply-side resource additions that are developed and available to meet the annual peak-demand; and (4) the current 15% to 17% planning reserve margin ("PRM") on a 1-in-2 peak-demand load forecast that is adequate to protect against short-term load and resource contingencies.[3]

B. The Approved Plan Complies With the State Loading Order

The State Loading Order adopted in the EAP includes cost-effective EE, DR, renewable resources, distributed generation and clean and efficient fossil-fired generation. PG&E's Approved Plan complies with the loading order. First, the plan includes EE savings at levels targeted by D.04-09-060. Embedded in the CEC's load forecast are the committed EE savings attributed to the PG&E's 2006-2008 and earlier EE programs, as well as 80% of the uncommitted EE savings attributable to future EE program cycles.[4] The remaining 20% of the uncommitted EE goals is shown separately in Table PGE-1. Second, the Approved Plan

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[1] D.07-12-052 at 116.

[2] D.07-12-052 at 87.

[3] A new rulemaking announced on November 19, 2007 in R.05-12-013 and R.06-02-013 is expected to review the adequacy of the current PRM, and adopt a system reliability reserve margin methodology for all jurisdictional load serving entities.

[4] D.07-12-052 at 272.

includes price sensitive and curtailable DR programs. Third, the Approved Plan procures at least 20% of RPS, consistent with State law. Those amounts are shown in Table PGE-1. Fourth, the Approved Plan includes distributed generation by implementing the CSI approved in D.06-01-024 and a forecast of additional distributed generation. Finally, the Approved Plan procures 800 – 1,200 MW of new dispatchable ramping resources (including clean and efficient fossil-fuel resources) for commercial operation by 2015, consistent with OP 4 in D.07-12-052. In addition, to the extent a new resource from PG&E's 2004 LTRFO is determined to be unviable during the development process and the associated contract is terminated, the procurement authority for those MWs remains.

C. The Approved Plan Provides Environmental Benefits Through Reduced CO_2 Emissions

PG&E's Approved Plan uses EE and preferred resources to reduce customer demand for electricity and the use of conventional supply resources. Preferred resources that reduce demand are EE savings and self-generation, both of which have for the most part been reflected in the CEC's demand forecast. Decreasing demand can reduce conventional resource use. In addition, DR and RPS generation can reduce conventional resource use. Preferred resources may cost more than conventional resources, but provide environmental benefits in the form of reduced GHG emissions.

By 2016, PG&E estimates that the Approved Plan reduces at a minimum 6 to 9 million metric tons of CO_2 emissions per year, as compared to meeting a higher load without energy efficiency and self-generation through use of conventional resources. Included in the estimate are the incremental amounts of EE, CSI, and RPS additions calculated using the CEC's load forecast adopted in D.07-12-052, and a minimum 20% RPS target. The range of CO_2 emission reductions corresponds to a range of the avoided resources' heat rate. For this evaluation, PG&E assumes a heat rate range of 6,916 British Thermal Unit ("Btu")/kWh to 9,400 Btu/kWh. The first heat rate is the average heat rate of the 2007 Market Price Referent ("MPR"). The second heat rate corresponds to the Emission

Performance Standard ("EPS") of 1,100 lb of CO_2 per MWh adopted by D.07-01-039.[5] The following table shows the derivation of the CO_2 emissions savings provided by the Approved Plan. In addition, PG&E's GHG emissions profile submitted to the California Climate Registry, which was included in PG&E's March 5, 2007 amended 2006 LTPP filing, is included as Appendix D. This profile provides additional information regarding PG&E's current GHG emissions.

[5] D.07-01-039, Conclusion of Law No. 16.

Derivation of CO2 emissions saved by D. 07-12-052's Approved Plan

Line	Item	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Preferred resources included in CEC load forecast, GWh										
2	PV (Source: CEC Form 1.2 - PGE)	52	105	157	209	262	314	367	419	471	524
3	Non-PV Self-gen increase from 2006 (Source: CEC Form 1.2 - PGE)	32	66	101	136	170	205	240	274	309	343
4	80% of CPUC adopted EE goals in D. 04-09-060, Table 1A			854	1,666	2,534	3,473	4,494	5,516	6,538	7,559
5											
6	Additional preferred resources not included in CEC's load forecast, GWh										
7	20% of CPUC adopted EE goals in D. 04-09-060 not included in CEC load forecast			213	416	634	868	1,124	1,379	1,634	1,890
8	RPS (incremental amounts above 2007, increasing to 20% in 2010)	0	1,990	3,979	5,969	6,220	6,466	6,700	6,925	7,152	7,376
9											
10	Total preferred resources in PG&E's recommended plan	84	2,161	5,304	8,396	9,820	11,326	12,924	14,513	16,104	17,692
11											
12	CO2 savings, million metric tons per year										
13	Based on a 9,400 Btu/kWh heat rate (EPS of 1,100 lb of CO2/MWh)	0.04	1.08	2.65	4.20	4.91	5.66	6.46	7.26	8.05	8.84
14	Based on a 6,916 Btu/kWh heat rate (2007 MPR average heat rate)	0.03	0.79	1.95	3.09	3.61	4.17	4.75	5.34	5.92	6.51

Notes

Source CEC Form 1.9a - PG&E Planning Area

Item	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Sales in PG&E's service area from CEC's Dec 2007 final load forecast, GWh										
Bundled	78,860	79,981	81,149	82,303	83,558	84,788	85,959	87,086	88,220	89,339
Direct Access	6,883	6,814	6,814	6,814	6,814	6,814	6,814	6,814	6,814	6,814
Total	85,743	86,795	87,963	89,117	90,372	91,602	92,773	93,900	95,034	96,153
CPUC adopted EE goals in D. 04-09-060, Table 1A, extended beyond 2013 at 2013 level			1,067	1,015	1,086	1,173	1,277	1,277	1,277	1,277
Cumulative "uncommitted" EE savings			1,067	2,082	3,168	4,341	5,618	6,895	8,172	9,449
Line 8 RPS volumes used	10,492	12,482	14,471	16,461	16,712	16,958	17,192	17,417	17,644	17,868
	13.3%	15.6%	17.8%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%

Lines 13 and 14 million metric tons/year of CO2 savings = GWh of avoided gas-fired generation/year x 117 lb/MMBtu x heat rate Btu/kWh x 1,000 kWh/MWh / 2,200 lb/Ton / 1,000,000

VI. COMMISSION REVIEW OF IMPLEMENTATION OF PROCUREMENT PLAN

A. Compliance With AB 57

AB 57 (Public Utilities Code section 454.5) includes detailed requirements for LSE's procurement plan. PG&E's 2006 LTPP fully complies with these requirements, as the table below demonstrates:

TABLE VI-1
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH AB 57

PUC Section 454.5(b) Requirements	Summary of Compliance And Citation To 2006 LTPP
1. An assessment of price risk associated with PG&E's portfolio.	Section II.B and Appendix B
2. Definition of electricity products, electricity-related products and procurement-related financial products, including justification and the amount to be procured.	Section II.A.3
3. The plan duration.	Section I
4. The duration, timing and range of quantities of each product to be procured.	Sections IV and Appendix A
5. A description of PG&E's competitive procurement process.	Section IV
6. Any proposed incentive mechanism.	Not applicable
7. The upfront standards and criteria for the acceptability and eligibility for rate recovery, and any expedited approval process.	Section II.A.5
8. Procedures for updating the plan.	Section I
9. A showing that the plan achieves: (a) the 20% RPS standard and 1% incremental RPS procurement standard; (b) a diversified portfolio; and (c) meeting resource needs through energy efficiency and demand reduction when it is cost effective, reliable and feasible.	Section IV
10. PG&E's risk management policies.	Section II.B and Appendix B

TABLE VI-1
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH AB 57
(CONTINUED)

PUC Section 454.5(b) Requirements	Summary of Compliance And Citation To 2006 LTPP
11. A diversity of ownership and fuel supply.	Section IV
12. A mechanism for recovery of reasonable administrative costs related to procurement in the generation component of rates.	Section VI.C

B. Compliance With the Commission's Procurement Standards of Conduct

In D.02-10-062, the Commission adopted seven Standards of Conduct for utility procurement.[1] These standards have subsequently been modified, and two of them have been eliminated.[2] PG&E's 2006 LTPP is in full compliance with Commission's Standards of Conduct. The following table includes each standards of conduct, a summary of PG&E's compliance with the standard and the portion of the 2006 LTPP that addresses PG&E's compliance:

[1] D.02-10-062 at 51-52.

[2] See D.02-12-074, Order Paragraph 24 (modifying standards); D.03-06-067, Ordering Paragraph 3 (modifying standards and eliminating Standard Nos. 6-7); and D.03-06-076, Ordering Paragraph 6 (clarifying that "Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges."). PG&E also received a waiver from Standard of Conduct 1 for certain gas transportation transactions in D.04-06-003.

TABLE VI-2
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT

Standard of Conduct	Summary of Compliance And Citation To 2006 LTPP
1. Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited.	PG&E's procurement practices and competitive, arms-length solicitations are described in Section II.A.5. To the extent PG&E conducts any affiliate transactions, these transactions will be conducted in full compliance with the Commission's affiliate and procurement rules.
2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process that: (1) identifies trade secrets and other confidential information; (2) specifies procedures for ensuring that such information retains its trade secret and/or confidential status [*e.g.*, limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.]; (3) discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges; (4) discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; and (5) requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances [*e.g.*, where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer]. All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility.	PG&E's compliance practices are described in Section II.A.1.e.

TABLE VI-2
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT
(CONTINUED)

Standard of Conduct	Summary of Compliance And Citation To 2006 LTPP
3. In filing transactions for approval, the utilities shall make no misrepresentation or omission of material facts of which they are, or should be aware.	PG&E has filed procurement information in a number of different reports, which are described in more detail in Section VI.C, below. PG&E has not misrepresented any information, or made any omission of material fact in any of these reports.
4. The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our definitions of prudent contract administration and least cost dispatch is the same as our existing standard. Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. The utility bears the burden of proving compliance with the standard set forth in its plan.	PG&E's dispatch and administration of procurement contracts is described in Section II.A.7.
5. The utilities shall not engage in fraud, abuse, negligence, or gross incompetence in negotiating procurement transactions or administering contracts and generation resources.	PG&E procurement practices have been fair, open and transparent. PG&E has used an independent evaluator for long-term transactions and discussed short- and long-term transactions with the PRG. PG&E's procurement practices are described in detail in Sections II.A.6 and II.A.8. PG&E's has also appropriately administered its procurement contracts. PG&E's ongoing administration is reviewed through the Energy Resource Recovery Account ("ERRA") process and quarterly audits.

C. Description of PG&E Filings Made to Demonstrate Compliance

PG&E submits monthly, quarterly, and annual filings to demonstrate compliance with its approved procurement plan and Commission policy. These filings are described below.

1. Monthly Reports

a. Portfolio Risk Reduction Report

PG&E reports TeVaR on a monthly basis to both the Energy Division ("ED") and Division Ratepayer of Advocates ("DRA"). Due to differences in the requested data, PG&E had previously met with ED in order to agree on a reporting format. While minor modifications have been made over time, the basic format continues with TeVaR currently reported on both a 95% and 99% Confidence Interval for the following periods:

- Monthly for the rolling 12-month period (*e.g.*, October 2006 to October 2007);
- Quarterly for the balance of the current calendar year (*e.g.*, 2006);
- Quarterly for the next three calendar years (*e.g.*, 2007, 2008 and 2009); and
- Yearly for the last calendar year of reporting (*e.g.*, 2010).

b. Monthly ERRA Report

In D.02-12-074, the Commission directed the three IOUs to file with the "Energy Division each month a report showing the activity in the ERRA balancing account with copies of original source document supporting each entry over $100.00 recorded in the account" no later than the 20th following the end of the month and be served on interested parties in the proceeding.[3] The stated intention of this report was to give the Commission an opportunity to anticipate when an IOU might file an expedited trigger application and to reduce the time to review such an application. D.07-04-020 directed the IOUs to continue to file a monthly ERRA report, but reduced the amount of supporting documentation.

c. Standing Data Requests From Energy Division

PG&E responds on a monthly basis to the ED data request for electric generation procurement information. The requested procurement information relates to weekly and monthly weighted average cost of electric procurement, monthly energy and maximum capacity

[3] D.02-12-074 at 43.

load forecasts for a rolling 12-month period, monthly residual net short forecast for a rolling 12-month period, and monthly electricity and gas price forecasts used to derive the residual net short forecast.

2. Quarterly Filings

D.02-10-062 ordered each IOU to file the Quarterly Procurement Compliance Reports. The purpose of this report is to describe all electric generation procurement transactions executed in a given quarter that are not more than five years in duration, not filed through a separate advice filing or application, and within the procurement authority authorized by the Commission in D.02-10-062, D.03-12-062, D.04-07-028, D.04-01-050, D.04-12-048 and D.07-12-052. These Quarterly Procurement Compliance Reports are filed within 30 days of the end of the quarter, as specified in D.03-12-062. As stated in D.07-12-052, Quarterly Procurement Compliance advice filings are to be reviewed by the Commission within 60 days. If the Commission receives no protests and the ED staff concludes that the transactions included in this report are in compliance with the IOU's approved procurement plan, the ED Director can approve the reports. If a protest is filed, a resolution will be drafted for Commission's final approval.

3. Semi/Annual Filings

a. ERRA Forecast and Compliance Review Filings

PG&E files two annual filings related to ERRA: an ERRA forecast revenue requirement application and an ERRA compliance review application. In D.02-10-062, the Commission established the ERRA balancing account for all three IOUs and established a semiannual update process whereby the IOUs would once a year (1) "file applications proposing to establish annual fuel and purchased power forecasts and true up 2002 fuel and purchased costs" (*i.e.*, ERRA Forecast Revenue Requirement proceeding); and (2) undergo a "review of balancing accounts, contract administration, URG expenses and least-cost dispatch" (*i.e.*, ERRA

Compliance Review proceeding).[4] In D.02-12-074, the Commission directed PG&E to file its forecast application on February 1 and the balancing account review application on August 1, 2003.[5] In D.04-01-050, the Commission adopted revised schedules for the 2004 and 2005 semi-annual ERRA filings with PG&E's ERRA compliance review application to be filed in February and the ERRA forecast application to be filed on June 1.

b. ERRA Trigger

In AB 57, the California state legislature established a trigger mechanism that would ensure that any overcollection or undercollection in the appropriate electric procurement balancing account does not exceed 5% of a utility's recorded generation revenues, excluding DWR revenues, for the prior year.[6] This trigger mechanism provides the necessary assurance to PG&E that its electric procurement costs will be recovered in a timely fashion.

In D.02-10-062, the Commission adopted the AB 57 balancing account trigger mechanism for the California utilities. In that decision, the Commission directed the utilities to file an expedited "trigger" application for approval within 60 days of filing when the ERRA balance reaches or exceeds 4% of the prior year recorded generation revenues excluding DWR revenues. This application is to include a projected account balance in 60 days or more to illustrate when the balance will reach the 5% threshold. The application is also to propose an amortization period of not less than 90 days to ensure timely recovery of the projected ERRA balance.[7] In D.04-01-050, the Commission adopted April 1 as the date when all three California utilities are to file their annual ERRA trigger advice letter, which sets the trigger amount for the following 12 months.

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[4] D.02-10-062 at 62.

[5] D.02-12-074 at 42.

[6] Pub. Util. Code § 454.5(d)(3).

[7] D.02-10-062 at 63-65, Conclusions of Law 15, and Ordering Paragraph 14.

4. Biennial Filings

D.05-01-040 adopted the long-term procurement regulatory framework and established that the IOUs shall file long-term plans on a biennial cycle that follows the CEC's adoption of a final IEPR. D.04-12-048, which approved PG&E's 2004 LTPP, established that starting with the 2006 LTPP proceeding the Short-Term Plans will be eliminated and the IOUs will act in accordance with a single Commission-approved plan. The decision also determined that any updates or modifications to the plans in between the biennial review will be filed with an advice letter.

5. Additional Monthly, Quarterly, Annual Filings and Data Requests

The Commission requires RA reporting on a monthly and yearly basis. RA compliance submissions are made directly to the Commission through the advice filing process. In addition, forecasting related data is submitted to the CEC on a monthly as well as a yearly basis. These submissions are not made through advice filings. Both the CEC and Commission submissions are described below.

D.05-10-042 required that PG&E submit advice letter filings that identify load growth changes within its service territory due to load migration, demonstrates that PG&E has acquired sufficient resources to satisfy its 100% commitment obligation for loads plus reserve requirements, and demonstrates that PG&E has met 90% of its summer months obligations one year in advance. D.06-06-064 required that PG&E submit an advice letter filing which demonstrated whether it had entered into any contract with a unit that is among the list of units proposed for 2007 RMR Contracts, as well as demonstrating the LSEs' full Local RA Requirement compliance and an advice letter filing demonstrating that it had met its local RA obligation for each month of the 2007 calendar year period. In addition, PG&E provides the CEC with an annual year-ahead load forecast as well as annual historical data.

APPENDIX A

PG&E NEED DETERMINATION

REDACTED VERSION

TABLE PGE-1
NP-26 Regional Need (MW)

Based on PG&E's LTPP Scenario - 4

	LOAD FORECASTS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	1-in-2 System Summer Temperature Demand [1]	21,406	21,671	21,954	22,236	22,547	22,855	23,158	23,453	23,752	24,050
2	1-in-2 PG&E Service Area Summer Temperature Demand [2]	19,845	20,096	20,364	20,633	20,928	21,222	21,511	21,793	22,078	22,363
	RESOURCES										
	System Resources										
3	Existing Generation	24417	24417	24417	24417	24417	24417	24417	24417	24417	24417
4	Retirements (Announced)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
5	Retirements (Laddered Reduction of Aging Units) [3]	0	0	(600)	(1200)	(1800)	(2400)	(3000)	(3600)	(4200)	(4200)
6	NP26 RPS Additions (Including Imports)	28	142	293	635	895	1181	1496	1609	1733	1870
7	PG&E Planned Additions	0	0	998	2251	2251	2251	2251	2251	2251	2251
8	Other Known/High Probability NP-26 Additions	0	0	180	180	180	180	180	180	180	180
9	Imports -- NW	2348	2348	2348	2348	2348	2348	2348	2348	2348	2348
10	Imports -- WAPA (Firm)	700	700	700	700	700	700	700	700	700	700
11	Adjustment RPS NW Imports	0	(12)	(23)	(42)	(62)	(85)	(110)	(128)	(149)	(172)
12	Exports -- to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
13	Net Interchange	48	36	25	6	(14)	(37)	(62)	(80)	(101)	(124)
14	Total System Resources	24,493	24,596	25,178	26,154	25,793	25,457	25,147	24,642	24,145	24,259
15	Service Area Portion of System Resources [4]	22,707	22,808	23,354	24,268	23,941	23,638	23,359	22,897	22,443	22,557
	Service Area Specific Resources										
16	Uncommitted Energy Efficiency [5]			56	109	166	228	295	362	430	497
17	Price Sensitive Demand Response (DR)	342	394	554	695	750	765	774	783	792	801
18	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
19	Contract viability re-adjustment (for PGE 2006 LTPP) [6]	100	200	300	400	500	600	600	600	600	600
20	Total Service Area Specific Resources	752	947	1263	1557	1769	1946	2022	2098	2174	2251
21	Total Service Area Resources	23,459	23,755	24,617	25,825	25,711	25,584	25,381	24,996	24,618	24,808
	PLANNING RESERVES										
22	Planning Reserve	3,614	3,659	4,253	5,192	4,783	4,362	3,870	3,203	2,540	2,445
23	Planning Reserve (%) [7]	18.2%	18.2%	20.9%	25.2%	22.9%	20.6%	18.0%	14.7%	11.5%	10.9%
24	Lower Bound of Planning Reserve Requirement (15%)	2,977	3,014	3,055	3,095	3,139	3,183	3,227	3,269	3,312	3,354
25	Upper Bound of Planning Reserve Requirement (17%)	3,374	3,416	3,462	3,508	3,558	3,608	3,657	3,705	3,753	3,802
26	**1 in 2 PG&E Service Area Surplus (Deficit) [8]**	**240**	**243**	**791**	**1,685**	**1,225**	**754**	**213**	**(66)**	**(772)**	**(909)**

[1] Based on CEC's 2007 IEPR 1-in-2 peak demand, which embeds self-served load, committed EE, approximately 80% of uncommitted EE, and forecasted distributed generation including the CSI program additions. Note the average growth rate of the forecast peak including uncommitted EE (Line 2 - Line 16) is 1.06% per year.

[2] Service area calculation includes bundled and DA customers and excludes POUs.

[3] This line provides a laddered reduction of aging units as described in the Retirements section of the decision.

[4] This line provides the portion of system resources that are available to PG&E's service area (system resources * Line 2/Line 1).

[5] Uncommitted EE not captured in the CEC's demand forecast (approximately 20% total uncommited EE goals plus a 10% line loss factor).

[6] This line replaces deductions for a 10% contract viability derate embedded in PG&E's resource assumptions.

[7] Planning Reserve % = [(Service Area Resources/Service Area Demand)-1].

[8] Surplus represents amount above upper bound of PRM, deficit represent amount below lower bound. No deficit or surplus for values within PRM bounds.

TABLE PGE-2

Electricity Resource Planning Form S-1
PG&E Annual Capacity Resource Accounting Table (CRATs)
Bundled Customer Need, Consistent with D. 07-12-052

Line	Applies To:	Capacity Resource Accounting Table Form S-1	Sum of lines:	August 2007	August 2008	August 2009	August 2010	August 2011	August 2012	August 2013	August 2014	August 2015	August 2016
		PEAK LSE LOAD CALCULATIONS (MW)[1]:											
1	All	Forecast Total Peak-Hour Load (1 in 2 Summer)		19,845	20,096	20,364	20,632	20,928	21,222	21,511	21,793	22,078	22,363
1a	IOU/POU	Direct Access Loads in the UDC territory		1,017	967	967	967	967	967	967	967	967	967
2	ESP	Peak Load: Existing Contracts											
3	ESP	Peak Load: New & Renewed Contracts	1 minus 2	19,845	20,096	20,364	20,632	20,928	21,222	21,511	21,793	22,078	22,363
4	IOU/POU	CCA & Departing/Arriving-New Municipal Loads (-/+)											
5	IOU/POU	Uncommitted Price-Sensitive DR Programs (-)											
6	IOU/POU	Uncommitted Energy Efficiency (2009-2016) (-)[2]				52	101	154	211	273	336	399	462
7	IOU/POU	Distributed Generation for Customer Use (-)											
7a	IOU/POU	Peak Coincidence		209	220	222	225	228	231	233	236	238	241
8	All	Net Peak Demand for End-Use Customers	1 - 1a- (sum 4 thru 7a)	18,619	18,909	19,123	19,340	19,580	19,814	20,038	20,254	20,475	20,694
9	IOU/ESP	Net Peak Demand + 15% Planning Reserve Margin[3]	(8 x 1.15)-((53 + 54)*.15)	21,318	21,638	21,860	22,088	22,356	22,622	22,878	23,126	23,378	23,629
10	IOU/POU	Firm Sales Obligations		0	0	0	0	0	0	0	0	0	0
11	All	Firm LSE Peak Resource Requirement	Sum 9 + 10	21,318	21,638	21,860	22,088	22,356	22,622	22,878	23,126	23,378	23,629
		EXISTING & PLANNED RESOURCES											
		Utility-Controlled Fossil and Nuclear Resources:											
12	IOU/POU	Diablo Canyon		2,244	2,244	2,244	2,244	2,244	2,244	2,244	2,244	2,244	2,244
13	IOU/POU	Humboldt Bay		120	120	0	0	0	0	0	0	0	0
14	IOU/POU	Wartsila Humboldt		0	0	163	163	163	163	163	163	163	163
14.a	IOU/POU	Colusa		0	0	0	657	657	657	657	657	657	657
14.b	IOU/POU	Gateway		0	0	601	601	601	601	601	601	601	601
15	IOU/POU	Total Dependable Fossil and Nuclear Capacity	Sum 12 thru 14b	2,364	2,364	3,008	3,665	3,665	3,665	3,665	3,665	3,665	3,665
		Utility-Controlled Hydroelectric Resources:											
16	IOU/POU	Total for all Hydro Plants over 30 MW		[redacted]									
17	IOU/POU	Total for all Hydro Plants 30 MW or less		246	246	246	237	237	237	225	224	224	224
		Utility-Controlled Renewable Resources:											
24	IOU/POU	Total Renewable Capacity		0	0	0	0	0	0	0	0	0	0
25	IOU/POU	Total Utility-Controlled Physical Resources	Sum 15 thru 17 + 24	[redacted]									
		DWR Contractual Resources:											
26	IOU	Calpine #1 Product 1		1,000	1,000	1,000	0	0	0	0	0	0	0
27	IOU	Calpine #2 Product 1		1,000	0	0	0	0	0	0	0	0	0
27a	IOU	Los Esteros		0	180	180	0	0	0	0	0	0	0
28	IOU	Coral		850	850	850	550	550	0	0	0	0	0
28a	IOU	Calpine #3		495	495	495	495	0	0	0	0	0	0
28b	IOU	CalPeak Panoche		43	43	43	43	43	0	0	0	0	0
28c	IOU	CalPeak Vaca Dixon		42	42	42	42	42	0	0	0	0	0
28d	IOU	Wellhead Fresno		16	16	16	16	16	0	0	0	0	0
28e	IOU	GWF		341	341	341	341	341	166	0	0	0	0
28f	IOU	PacifiCorp		300	300	300	300	0	0	0	0	0	0
28g	IOU	Wellhead Gates		31	31	31	31	31	0	0	0	0	0
28h	IOU	Wellhead Panoche		33	33	33	33	33	0	0	0	0	0
28i	IOU	Kings River		96	96	96	96	96	96	96	96	96	0
28j	IOU	CCSF		0	0	180	180	180	180	180	180	180	180
29	IOU	Total DWR Contracts[4]	Sum 26 thru 28	4,247	3,427	3,607	2,127	1,332	442	276	276	276	180
		Qualifying Facility (QF) Contractual Resources:											
37	IOU	Total QF Capacity[5]		2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166
		Renewable Energy Contractual Resources:											
38	All	Calpine Geysers		200	200	200	200	200	200	100	100	100	100
39	All	Wheelabrator		3	1	1	1	1	1	1	1	1	1
40	All	Madera		20	20	20	20	20	20	20	10	10	10
40a	All	CRES		10	10	10	10	10	10	10	5	5	5
40b	All	Sierra		6	6	6	6	6	6	6	3	3	3
40c	All	Diablo Winds		3	3	3	3	3	3	3	3	3	2
40d	All	Etiwanda		19	19	19	19	19	19	19	9	9	9
40e	All	PPM Shiloh		16	16	16	16	16	16	16	16	16	16
40f	All	BuenaVista Altamont		8	8	8	8	8	8	8	8	8	8
40g	All	Pacific Renewable Lompoc		0	0	16	16	16	16	16	16	16	16
40h	All	FPL Montezuma		0	6	6	6	6	6	6	6	6	6
40i	All	Global Common		0	18	18	18	18	18	18	18	18	18
40j	All	Vulcan		0	0	60	60	60	60	60	60	60	60
40k	All	HFI-Silvan		0	20	20	20	20	20	20	20	20	20
40l	All	Liberty		0	0	5	5	5	5	5	5	5	5
40m	All	Newberry		0	0	0	60	60	60	60	60	60	60
40n	All	Truckhaven		0	0	0	45	45	45	45	45	45	45
40o	All	BottleRock		20	20	20	20	20	20	20	20	20	20
41	IOU/POU	Renewable DG Supply											
42	All	Total Capacity from Renewable Energy Contracts	Sum 38 thru 41	304	347	428	533	533	533	433	406	406	404

TABLE PGE-2
(continued)

Electricity Resource Planning Form S-1
PG&E Annual Capacity Resource Accounting Table (CRATs)
Bundled Customer Need, Consistent with D. 07-12-052

Line	Applies To:	Capacity Resource Accounting Table Form S-1	Sum of lines:	August 2007	August 2008	August 2009	August 2010	August 2011	August 2012	August 2013	August 2014	August 2015	August 2016
		Other Bilateral Contracts:											
43	All	Puget Sound Power & Light Contract (Take)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
44	All	Pittsburg 5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	All	Pittsburg 6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45a	All	Pittsburg 7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45b	All	Potrero 3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45c	All	Potrero 4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45d	All	Potrero 5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45e	All	Potrero 6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45f	All	Contra Costa 6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45g	All	Contra Costa 7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45h	All	Duke Morro Bay 3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45i	All	Duke Morro Bay 4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45j	All	Duke Moss Landing 6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45k	All	Duke Moss Landing 7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45l	All	J. Aron		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45m	All	PEC		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45n	All	NRG (Chowchilla)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45o	All	NRG (Red Bluff)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45p	All	WAPA RA Sale		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45q	All	Los Medanos		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45r	All	Metcalf		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45s	All	EIF Fresno		0	0	0	196	196	196	196	196	196	196
45t	All	Starwood Firebaugh		0	0	118	118	118	118	118	118	118	118
45u	All	EIF Firebaugh		0	0	399	399	399	399	399	399	399	399
45v	All	Tierra Energy Hayward		0	0	116	116	116	116	116	116	116	116
45w	All	Calpine Hayward		0	0	0	601	601	601	601	601	601	601
46	IOU/POU	Non-Renewable DG Supply		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
47	All	Total Other Bilateral Contracts	Sum 43 thru 46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Short Term and Spot Market Purchases & Sales:											
51	All	Net of Short Term Spot Market Purchases & Sales											
52	All	**TOTAL: EXISTING & PLANNED CAPACITY**	Sum 25+29+37+42+47+51	[redacted]	[redacted]	[redacted]	19,112	16,178	13,462	12,772	12,732	12,732	12,562
		DEMAND SIDE DISPATCHABLE RESOURCES											
53	All	Price Sensitive Demand Response (DR)[6]		287	327	327	328	328	328	329	329	329	329
54	All	Interruptible/DR Curtailable Programs[6]		337	391	551	692	747	762	772	781	790	799
55	All	Total Capacity with I/E and DDR	Sum 52 + 53 + 54	[redacted]	[redacted]	[redacted]	20,132	17,254	14,552	13,872	13,841	13,850	13,690
		FUTURE GENERIC RESOURCE NEEDS											
56	All	Generic Renewable Resources[7]		0	65	131	351	593	860	1,153	1,258	1,374	1,501
		Non-Renewable Generic Resources:											
57	All	Capacity for Baseload Energy		[redacted]	[redacted]	[redacted]							
58	All	Capacity for Load-Following and Peaking Energy		[redacted]	[redacted]	[redacted]							
59	All	Load-Following (year-round) Capacity											
60	All	Peaking (seasonal) Capacity											
61	All	Total Capacity of Non-Renewable Generic Resources	Sum 57 thru 60	[redacted]	[redacted]	[redacted]	0	0	0	0	0	0	0
62	All	Total Capacity of Future Generic Resources	Sum 56 + 61	[redacted]	[redacted]	[redacted]	351	593	860	1,153	1,258	1,374	1,501
		CAPACITY BALANCE CHECK											
63	All	Total Capacity of all Resources	Sum 55 + 62	[redacted]	[redacted]	[redacted]	19,463	16,771	14,321	13,925	13,989	14,105	14,063
64	All	Net Open or Net Surplus Capacity Position[8]	63 minus 11	[redacted]	[redacted]	[redacted]	-2,625	-5,584	-8,301	-8,954	-9,137	-9,273	-9,566
		UDC & SYSTEM NEEDS ACCOUNTING											
65	IOU/POU	Firm LSE Peak Resource Requirement	Repeat line 11										
66	IOU/POU	Direct Access Loads in the UDC territory	Repeat line 1a										
67	IOU/POU	Other non-IOU & non-DA loads in the UDC											
68	IOU/POU	System Needs (quick start, black start, VARs)											
69	IOU/POU	Total UDC Capacity Needs	Sum 65 thru 68										

[1] Per D.12-07-052, reflects the CEC's 2007 IEPR 1 in 2 peak demand for PG&E's bundled customers.
[2] Per D.12-07-052 (Table PGE-1), additional Uncommitted EE not captured in the CEC's demand forecast. Adjusted to reflect only bundled customers' portion.
[2] Per D.12-07-052, planning reserve margin to be 15%-17% of the 1 in 2 monthly peak
[4] For 2008 and 2009, represents an adjustment to account for the Calpine 2 amended contract.
[5] To comply with D. 07-12-052, PG&E is including 2,166 MW for QF capacity. However, PG&E estimates this number is higher by a few hundred MW.
[6] Per D.12-07-052 (Table PGE-1). Adjusted to reflect only bundled customers' portion.
[7] Per D.12-07-052 (Table PGE-1). Adjusted to reflect only generation to meet bundled customers' need.
[8] The open position here will be filled through a variety of existing resources as well as the 800-1,200 MW of new generation by 2015 as authorized in D. 07-12-052.
Note: For consistency with the CEC's IEPR process, line numbering/naming convention is consistent with PG&E's March 5, 2007 amended 2006 LTPP filing.

APPENDIX B

ELECTRICITY AND GAS HEDGING PLAN

WILL BE PROVIDED SUBSEQUENTLY

APPENDIX C

NUCLEAR FUEL PROCUREMENT PLAN

CONFIDENTIAL

REDACTED IN ITS ENTIRETY

UNDER PROTECTIONS OF D.06-06-066

AND

CPUC CODE SECTION 583

APPENDIX D

A COPY OF PG&E'S GHG EMISSIONS PROFILE SUBMITTED TO THE CALIFORNIA CLIMATE REGISTRY

Annual Emissions Report

Report 11/3/06 4:15 PM

Pacific Gas & Electric Company

77 Beale Street, B24A
San Francisco, CA 94105 United States
http://www.pge.com
415-973-6905
gjs8@pge.com

Legend
Blue = required
Orang = optional

Contact: Greg San Martin
Industry Type: Utility
NAIC Code: 221-Utilities
SIC Code: 4931-Electric and Other Services Combined
Description: Pacific Gas and Electric Company is the principal provider of electricity and natural gas distribution and transmission services in northern and central California. Our service territory covers 70,000 square miles (46 of California's 58 counties). We hav

CERTIFIED EMISSIONS INFORMATION

Reporting Year: 2004
Reporting Scope: CA
Reporting Protocol: General Reporting Protocol, Version 1 (October 2002); Power/Utility Reporting Protocol, Version 1 (April 2005)
Baseline Year (Direct Emissions):
Baseline Year (Indirect Emissions):

Mobile Combustion	**86,171.65**	86,171.65	0.00	0.00	0.00	0.00	0.00	metric ton
Stationary Combustion	**926,064.75**	926,064.75	0.00	0.00	0.00	0.00	0.00	metric ton
Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Fugitive Emissions	**125,235.69**	0.00	0.00	0.00	0.00	0.00	5.24	metric ton
TOTAL DIRECT	**1,137,472.10**	1,012,236.41	0.00	0.00	0.00	0.00	5.24	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multip

Energy Imports	**1,222,681.37**	1,222,681.37	0.00	0.00	metric ton
Energy Exports	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**1,222,681.37**	1,222,681.37	0.00	0.00	metric ton

CERTIFICATION INFORMATION

Certifier Name: SGS North America Inc
Basis of Certification Opinion: PG&E's inventory has been verified against the General and Power and Utilities Protocols. The data for 2004 is found to be free from material error or omission.

Certifier Comments:

Comments: We use Registry default factors.
We rely largely on FERC and the data management structures in place to roll up source-, facility-, and department-specific emissions into an entity-wide or sub-entity-wide emissions.

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not certified under Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Other Indirect Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric:

Emissions Management Programs:
US EPA's SF6 Emission Reduction Program (voluntary effort)
US EPA's Natural Gas Star Program (voluntary effort)
US EPA's Energy Star Program (voluntary effort)
Customer Energy Efficiency (a PUC mandated program)
Customer Energy Efficiency and Conservation

Emissions Reduction Projects:

Emissions Reduction Goals: PG&E has a number of emission reduction goals. In the SF6 partnership with US EPA, we committed to a 60 % reduction in SF6 emissions. Since 1998, we have achieved in excess of a 75 % reduciton in leak rates. We established an internal target for electr

REFERENCE DOCUMENTS

Title	Author	Publish Date
2004 PUP Spreadsheet	Greg San Martin	10/12/2006 12:00:00 AM

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of w hich has a unique Global Warming Potential (GWP). Emissions of each gas are first multip

Annual Entity Emissions: Electric Power Generation/Electric Utility Sector

Pacific Gas & Electric Corporation

77 Beale Street
San Francisco, California 94115
www.pge.com

Reporting Year: **2004**

Reporting Scope: **CA and U.S.**
Reporting Protocols: **General Reporting Protocol Version 2.0 (April 2006)**
Power/Utility Reporting Protocol Version 1.0 (April 2005)

Contact: Greg San Martin
Title: Climate Change Coordinator
Telephone: (415) 973-6905
Email: gjs8@pge.com
Industry Type: Electric utility
NAIC Code: 2211 - Electric Power Generation, Transmission and Distribution
SIC Code: 4931 - Electric and Other Services Combined

Entity Descrip. Pacific Gas and Electric Company is the principal provider of electricity and natural gas distribution and transmission services in northern and central California. Our service territory covers 70,000 square miles (46 of California's 58 counties). We have 4.9 million electric accounts and 3.9 million gas accounts. We serve a total of 14 million customers (1 in 21 Americans). We maintain 139,000 miles of electric transmission and distribution lines and 46,000 miles of natural gas transmission and distribution pipelines. Each year, PG&E delivers approximately 75 billion KWhs of electricity and 279,000 MMCF of natural gas. Approximately two-thirds of the electricity we deliver to customers is purchased rather than generated. The purchased and PG&E generated power includes a diverse mix of fuel sources including fossil fuel (oil and natural gas), nuclear, hydroelectric, and renewable sources such as biomass, geothermal, small hydro, solar, and wind.

POWER/UTILITY ENTITY EMISSIONS

Direct Emissions from Owned Facilities	CO_2e	CO_2	CH_4	N_2O	HFCs	PFCs	SF_6	Unit
Mobile Combustion	**86,172**	86,172	0.00	0.00		0.00	n.a.	metric tons
Total Stationary Combustion	**926,065**	926,065	0.00	0.00	n.a.	n.a.	n.a.	metric tons
from Electric Power Generation, Transmission & Distribution Activities	590,671	590,671	0.00	0.00	n.a.	n.a.	n.a.	metric tons
from Natural Gas-Related Activities	323,162	323,162	0.00	0.00	n.a.	n.a.	n.a.	metric tons
from Other On-Site Combustion	12,232	12,232	0.00	0.00	n.a.	n.a.	n.a.	metric tons
Process Emissions	**0.00**	0	0.00	0.00	0.00	0.00	n.a.	metric tons
Fugitive Emissions	**125,236**	0	0.00	0.00	0.00	0.00	5.24	metric tons
TOTAL DIRECT EMISSIONS	**1,137,448**	1,012,236	0.00	0.00	0.00	0.00	5.24	metric tons
% of Net Generation Delivered to CA	100							
% of Net Generation Delivered Outside of CA	0							
Total Direct Emissions from Deliveries to CA	**1,137,448**	1,012,236	0.00	0.00	0.00	0.00	523.90	metric tons
Total Direct Emissions from Deliveries outside of CA	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons

Comments:

Indirect Emissions from Owned Facilities	CO_2e	CO_2	CH_4	N_2O	Unit
Electricity Purchased and Consumed	**49,704**	49,704	0.00	0.00	metric tons
Steam Purchased and Consumed	**0.00**	0	0.00	0.00	metric tons
Heat Purchased and Consumed	**0.00**	0	0.00	0.00	metric tons
Cooling Purchased and Consumed	**0.00**	0	0.00	0.00	metric tons
Total Transmission and Distribution Losses	**1,172,977**	1,172,977	0.00	0.00	metric tons
from Purchased Power	526,640	526,640	0.00	0.00	metric tons
from Wheeled Power (excluding Direct Access)	193,860	193,860	0.00	0.00	metric tons
from Direct Access	452,477.00	452,477	0.00	0.00	metric tons
TOTAL INDIRECT EMISSIONS	**1,222,681**	1,222,681	0.00	0.00	metric tons

	A	C	E	F	G	H	I	J	K
56	**POWER/UTILITY GENERATION/PURCHASES INFORMATION**	**Amount**	**Unit**	**CO_2**	**Unit**				
57	Owned Generation Total (Net)	**26,096,035**	**MWh**	**590,671**	**metric tons**				
58	Fossil Generation (Net)	911,590	MWh	590,671	metric tons				
59	Biogenic Generation (Net)	0.00	MWh	0.00	metric tons				
60	Geothermal Generation (Net)	0.00	MWh	0.00	metric tons				
61	Other Renewable Generation (Net)	9,974,144	MWh	0.00	metric tons				
62	Zero Emission Generation (Net)	15,210,301	MWh	0.00	metric tons				
63	Steam Generation (Net)	0.00	MWh	0.00	metric tons				
64	Purchased Generation Total (Net)	**46,884,970**	**MWh**	**18,152,809**	**metric tons**				
65	Purchased Fossil Generation (Net)	36,146,007	MWh	18,152,809	metric tons				
66	Purchased Biogenic Generation (Net)	3,268,621	MWh	0.00	metric tons				
67	Purchased Geothermal Generation (Net)	1,732,857	MWh	0.00	metric tons				
68	Purchased Other Renewable Generation (Net)	5,737,485	MWh	0.00	metric tons				
69	Purchased Zero Emission Generation (Net)	0.00	MWh	0.00	metric tons				
70	Purchased Cogeneration (Net)	0.00	MWh	0.00	metric tons				
71	Purchased Wholesale Power (Net)	0.00	MWh	0.00	metric tons				
72	**TOTAL FOSSIL GENERATION/PURCHASES**	**37,057,597**	**MWh**	**18,743,479**	**metric tons**				
73	**TOTAL FROM BIOGENIC/GEOTHERMAL SOURCES**	**5,001,478**	**MWh**	**0.00**	**metric tons**				
74	**TOTAL OTHER GENERATION/PURCHASES**	**30,921,930**	**MWh**	**0.00**	**metric tons**				
75	**TOTAL FROM ALL GENERATION SOURCES**	**72,981,005**	**MWh**	**18,743,479**	**metric tons**				
76									
77									
78									
79	**OTHER BIOGENIC EMISSIONS**	**Amount**	**Unit**	**CO_2e**	CO_2	CH_4	N_2O	**Unit**	
80	Stationary Combustion	0.00	MWh	0.00	0.00	0.00	0.00	metric tons	
81	Mobile Combustion	0.00	gallons	0.00	0.00	0.00	0.00	metric tons	
82	Process Emissions			0.00	0.00	0.00	0.00	metric tons	
83	TOTAL OTHER BIOGENIC EMISSIONS			0.00	0.00	0.00	0.00	metric tons	
84	*Comments:*								
85									
86	**EMISSIONS EFFICIENCY METRICS**		**Ratio**						
87	Electricity Deliveries:	566.20	lbs CO_2/MWh delivered *(includes CO_2 from owned and purchased generation)*						
88	Net Generation:	49.90	lbs CO_2/MWh net owned generation *(fossil, hydroelectric, nuclear, solar, DG)*						
89	Net Fossil Generation:	1,428.48	lbs CO_2/MWh net owned fossil generation only						
90	*Comments:*								
91									
92	**De Minimis Emissions**	**CO_2e**	CO_2	CH_4	N_2O	HFCs	PFCs	SF_6	**Unit**
93	*Emissions reported in this section are estimated; these estimates are reviewed by the certifier and found to be less than 5% of the total entity emissions.*								
94	Mobile Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
95	Stationary Emissions	**11,052.70**	11,052.70	0.00	0.00	0.00	0.00	0.00	metric tons
96	Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
97	Fugitive Emissions	**23,879.40**	23,879.40	0.00	0.00	0.00	0.00	0.00	metric tons
98	Indirect Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
99	TOTAL DE MINIMIS EMISSIONS	**34,932.10**	34,932.10	0.00	0.00	0.00	0.00	0.00	metric tons

	A	C	E	F	G	H	I	J	K
102	**OPTIONAL INFORMATION**								
103	*Information in this section is voluntarily provided by the participant for public information, but is not required, and thus, not certified under Registry protocols.*								
104									
105	**Optional Emissions**	**CO_2e**	CO_2	CH_4	N_2O	HFCs	PFCs	SF_6	**Unit**
106	Upstream emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
107	Other Indirect Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
108	TOTAL OPTIONAL EMISSIONS	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	metric tons
109	*Comments:*								
110									
111	**Information on Environmental Goals and Programs:**								
112									
113	**Information on GHG Risk and Liability:**								
114									
115	**Company Activities Related to Renewable Energy**								
116	Purchases of Tradable Renewable Certificates:	0.00	metric tons CO2e						
117	Sales of Tradable Renewable Certificates:	0.00	metric tons CO2e						
118	Purpose of Transaction:								
119	Geographic Origin of Certificates:								
120	Parties Notified of Transaction(s):								
121	*Comments:*								
122									
123	**Company Activities to Offset GHG Emissions**								
124	Purchases of GHG Emission Offsets:	0.00	metric tons CO2e						
125	Sales of GHG Emission Offsets	0.00	metric tons CO2e						
126	Type of Project(s):								
127	Terms of Purchase/Sale:								
128	Parties Notified of Transaction(s):								
129	*Comments:*								
130									
131	**Company Activities to Improve Energy Efficiency**								
132	Description:								
133									
134									
135									
136									
137	Estimated Annual Energy Efficiency Savings:	0.00	MWh						
138		0.00	therms						
139	Reasons for Undertaking Energy Efficiency Programs:	Demand-side management, reduce peak load, improve energy efficiency of buildings							
140	*Comments:*								
141									
142	**Other Company Actions to Reduce GHG Emissions:**								
143	**Benefits of Actions:**								
144									
145	**Other Emissions Efficiency Metric(s):**								
146									
147									

APPENDIX E

PG&E'S TEVAR METHODOLOGY

Fluctuations in natural gas and electric power prices, hydroelectric generation, and electric load variations result in fluctuations in the overall cost of the PG&E electric portfolio. The To-expiration-Value-at-Risk ("TeVaR") metric is a measure of unexpected changes in PG&E's electric portfolio costs, net of electric portfolio revenues from sales of cumulative long positions, that accumulate over some specified time period, typically twelve months. TeVaR measures how high the net generation cost to PG&E customers for the period may become if certain market changes occur.

Revenues and costs which accrue to PG&E's electric portfolio, and thus to PG&E customers, depend on prices for natural gas and power at several delivery points. Currently, PG&E's TeVaR model includes power prices (on- and off-peak) at North of Path-15 ("NP15"), South of Path-15 ("SP15"), and the California-Oregon Border ("COB") energy trading hubs, and natural gas prices at PG&E Citygate, Henry Hub, and Malin delivery points.

The TeVaR metric is computed using a Monte Carlo simulation. In this simulation, for each Monte Carlo "trial," daily spot prices are randomly generated for each of the delivery points and for each day of the projection period, and hydro conditions and electric load are simulated for each month of the projection period. The prices used in the simulation are consistent with current market forward prices, volatility term-structures implied by market data, and with historical correlations of market data. For each day of the projection period, the net cost is computed for every position in the portfolio. The daily and monthly net costs are accumulated over the portfolio and over the projection period to produce a single (aggregated) net cost for each such trial. The variation of net costs over trials produces a probability distribution of net costs. Costs are represented as negative numbers, so the 1st percentile in the distribution of net cost represents more cost to customers than the 10th percentile in the same distribution of net cost. The difference between the mean net cost and the 5th percentile of net cost is identified as TeVaR at the 95th percentile, or "TeVaR95."

TeVaR95 represents the largest additional unexpected cost for PG&E's electric portfolio, with probability 0.95. There is a small 0.05 probability that unexpected costs can be even greater than TeVaR95. Using TeVaR95 as a metric for PG&E's hedging program ensures that the unexpected costs to PG&E's customers are closely monitored.

APPENDIX F

ADVICE LETTER 3095-E CONCERNING LONG-TERM CONGESTION REVENUE RIGHTS APPROVED BY RESOLUTION E-4122

July 31, 2007

Advice 3095-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Update to PG&E's Assembly Bill 57 Procurement Plan to Authorize PG&E's Participation In The Long-Term Congestion Revenue Rights Allocation Process That Will Result In Transmission Products With A Term Of Ten Years**

Purpose

By this advice letter, Pacific Gas and Electric Company ("PG&E") requests expedited approval of an update to its California Public Utilities Commission ("Commission") approved Assembly Bill ("AB") 57 Procurement Plan ("PP")[1] and its pending 2006 Long-Term Procurement Plan ("LTPP") to clarify that PG&E is authorized to participate in the California Independent System Operator Corporation's ("CAISO") Long-Term Congestion Revenue Rights ("LT-CRRs") allocation process that will result in LT-CRRs being allocated to PG&E for a 10-year term.

Background

As part of the CAISO's Market Redesign and Technology Upgrade ("MRTU"), the current transmission rights mechanism, known as Firm Transmission Rights ("FTRs"), will be replaced by CRRs. The CAISO's CRR process distinguishes LT-CRRs, which have a delivery term of ten years, from other CRRs, which have delivery terms up to one year. The CAISO intends to allocate LT-CRRs to Load Serving Entities ("LSEs") based upon their historical load and a demonstration of resources owned or under contract. The CAISO's

[1] PG&E filed its 2004 Short-Term Procurement Plan ("2004 STPP") on May 15, 2003, and it was approved by the Commission in D.03-12-062. PG&E's 2004 STPP has been updated via the Commission-approved Advice Letter 2464-E (submitted January 20, 2004, to update certain tables in PG&E's 2004 STPP and provide a list identifying the brokerages and exchanges). In D.04-12-048, the Commission approved PG&E's 2004 Long-Term Procurement Plan. Subsequently, pursuant to D.04-12-048, PG&E filed an updated STPP via Advice Letter 2615-E, which was approved by the Commission and made effective January 28, 2005. The collective set of PG&E's 2004 STPP, including subsequent modifications and updates, and PG&E's 2004 LTPP constitute PG&E's current AB 57 Procurement Plan. PG&E's 2006 LTPP is currently pending in Rulemaking ("R.") 06-02-013.

LT-CRR proposal and allocation process was recently approved by the Federal Energy Regulatory Commission ("FERC") in a July 6, 2007 order.[2]

PG&E's current PP authority includes a category for transmission products, which would includes CRRs,[3] and provides authority for PG&E to enter into transactions having a delivery term up to five years without Commission pre-approval. Thus, procurement of most CRRs is already permitted under the PP.[4] However, the acquisition of LT-CRRs requires additional Commission authority because LT-CRRs have a ten-year term.

Under the CAISO's process, PG&E can nominate LT-CRRs from its Tier 1 and 2 award of CRRs in the CAISO allocation process. Unfortunately, there is not enough time for PG&E to submit its nominations to the Commission for pre-approval, following PG&E's receipt of Tier 1 and 2 awards and for the Commission to act on PG&E's request. Under the CAISO's current schedule Tier 1 and 2 are to be completed by September 12, 2007, and LSEs nominate LT-CRRs between September 21-25, 2007. The CAISO will then allocate the LT-CRRs among LSEs pursuant to its FERC-approved allocation methodology and will announce the results by October 2, 2007. Thus, PG&E needs pre-approved authority from the Commission to participate in the CAISO's LT-CRR nomination and allocation process, which will result in LT-CRRs be allocated to PG&E for a term of ten years.

Update Request

Since LT-CRRs are a recent development and are allocated after a nomination process, rather than through a market, PG&E is filing this update request to modify its PP and its 2006 LTPP to specifically include participation in the CAISO's LT-CRR allocation process as an authorized process for PG&E to participate in, which will result in LT-CRRs with a 10-year term, without the need for Commission pre-approval of specific LT-CRRs.[5]

PG&E is requesting an effective date for this advice filing of September 6, 2007, and thus is

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[2] *California Independent System Operator*, 120 FERC ¶ 61,023 (2007).

[3] D.04-12-048 at 115 (listing approved products for all three utilities).

[4] PG&E reviewed its policy and analytical approach regarding the annual CRR allocation nominations with its Procurement Review Group ("PRG") on May 30, 2007 and July 11, 2007. In addition, PG&E plans on reviewing its LT-CRR allocation nomination policy with the PRG on August 24, 2007.

[5] PG&E identified CRRs and LT-CRRs as products related to MRTU and transmission products in its 2006 LTPP. *See* Volume 2, Section I at I-8 – I-14, filed March 5, 2007 in R.06-02-013.

requesting that the Commission act expeditiously on this advice letter filing. PG&E's request for expedited review and approval is reasonable and appropriate since participation in the CAISO's process should be beneficial to customers.

Tier Designation

Pursuant to D.07-01-024, Rule 5.3, this advice letter is submitted with a Tier 3 designation.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than **August 20, 2007,** with replies to protests due **August 27, 2007**. Protests should be mailed to:

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Avenue
San Francisco, California 94102

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

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, 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:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
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 and Expedited Consideration

PG&E requests that this advice filing become effective on **September 6, 2007**. In accordance with Public Utilities Code § 311(g)(2), PG&E asks for the Commission to reduce the 30-day review period of the draft resolution in order to have this expeditiously approved by September 6, 2007 so that PG&E can have authorization to participate in the CAISO's LT-CRR nomination and allocation process.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for R.06-02-013. Address changes to the General Order 96-B service list should be directed to Rose de la Torre at (415) 973-4716. Send all electronic approval letters to: PGETariffs@pge.com. Advice letter filings can also be accessed electronically at:

http://www.pge.com/tariffs

Vice President, Regulatory Relations

Attachments

cc: Service List R.06-02-013

APPENDIX G

ADVICE LETTER 3106-E CONCERNING CONGESTION REVENUE RIGHTS APPROVED BY RESOLUTION E-4135

August 20, 2007

Advice 3106-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Update to PG&E's Assembly Bill 57 Procurement Plan to Clarify the Upfront Achievable Standards and Criteria for the Procurement of Congestion Revenue Rights**

Purpose

By this advice letter, Pacific Gas and Electric Company ("PG&E") requests expedited approval of an update to its Commission-approved Assembly Bill ("AB") 57 Procurement Plan ("PP")[1] and its pending 2006 Long-Term Procurement Plan ("LTPP") in order to establish upfront and achievable standards and criteria applicable in procuring Congestion Revenue Rights ("CRRs"), including Long-Term CRRs ("LT-CRRs"), through the California Independent System Operator Corporation's ("CAISO") CRR allocation and auction processes. PG&E recently filed Advice Letter 3095-E, which requested Commission authorization for PG&E to participate in the CAISO's LT-CRR allocation process. This advice letter seeks Commission approval of the upfront standards and criteria for procuring all CRRs, including LT-CRRs.

Background

As part of the CAISO's Market Redesign and Technology Upgrade ("MRTU"), the current transmission rights mechanism, known as Firm Transmission Rights ("FTRs"), will be replaced by CRRs. The attributes of CRRs and the process for making such rights available to market participants differ from the FTR process. Some of these differences warrant an update to PG&E's PP and 2006 LTPP in order to provide upfront and achievable standards and criteria that are more applicable to CRR and LT-CRR transactions.

[1] PG&E filed its 2004 Short-Term Procurement Plan ("2004 STPP") on May 15, 2003, and it was approved by the Commission in D.03-12-062. PG&E's 2004 STPP has been updated via the Commission-approved Advice Letter 2464-E (submitted January 20, 2004, to update certain tables in PG&E's 2004 STPP and provide a list identifying the brokerages and exchanges). In D.04-12-048, the Commission approved PG&E's 2004 Long-Term Procurement Plan. Subsequently, pursuant to D.04-12-048, PG&E filed an updated STPP via Advice Letter 2615-E, which was approved by the Commission and made effective January 28, 2005. The collective set of PG&E's 2004 STPP, including subsequent modifications and updates, and PG&E's 2004 LTPP constitute PG&E's current AB 57 Procurement Plan. PG&E's 2006 LTPP is currently pending in Rulemaking ("R.") 06-02-013.

In order to understand why this update is needed, it is first important to understand how CRRs will differ from FTRs and how the process for obtaining the rights is different. An FTR is a right with both physical and financial attributes. An FTR has a physical attribute in that it conveys a scheduling priority in the CAISO day-ahead scheduling process for a certain direction on a transmission path if adjustment bids are unavailable to alleviate the congestion (*e.g.*, South to North on Path 15). Additionally, the FTR provides a financial hedge against congestion costs. This hedge is an "option" hedge, meaning that it pays the holder based on the congestion costs along the FTR path, but does not charge the holder if the congestion reverses direction. FTRs are specified on a path and direction basis. That is, the holder has rights to congestion revenues on a transmission branch group for congestion in a particular direction. FTRs are procured through an auction conducted by the CAISO on an annual basis. The FTRs that are acquired are valid in all hours of the term as defined by the CAISO. Additionally, parties may trade FTRs bilaterally and register the change in ownership through the CAISO's Secondary Registration System ("SRS").

CRRs, on the other hand, are financial instruments only and do not convey any scheduling priority. Instead, the CAISO will dispatch resources based upon a Security Constrained Economic Dispatch algorithm. That is, the CAISO will dispatch resources in a least-cost manner subject to transmission system constraints. Since MRTU utilizes a network model, CRRs are designated on a source-to-sink basis. Unlike FTRs, they are not branch group specific. Rather, any network source-sink pair (a point of injection and point of withdrawal of electricity on the grid) can become a CRR. For this reason, there are many more potential CRRs as compared to FTRs to consider when selecting CRRs for PG&E's customers. Another important difference is that CRRs are a financial "obligation." This means that the CAISO will pay the holder if congestion is in the same direction (*i.e.*, from the source to the sink) as the CRR that is held. However, if congestion occurs in the opposite direction (*i.e.*, from the sink to the source), the CRR holder is obligated to pay the congestion value to the CAISO.

The CAISO will be using CRRs as part of its implementation of MRTU. CRRs will initially be allocated to Load Serving Entities ("LSEs") based upon their historical load and a demonstration of resources owned or under contract for which the CRR will serve as a hedge.[2] The allocation of CRRs is followed by an auction process similar to the auction process utilized

[2] Pursuant to the CAISO tariff, the demonstration of a need based upon having a generation resource is applicable to two out of three tiers in the annual allocation process and one out of two tiers in the monthly allocation process in the first year. Subsequent years currently have no source verification process.

for FTRs. The CRR auction is open to any entity meeting the CAISO tariff requirements.[3] The auction and allocation process will occur annually and monthly. The annual CRR allocation process includes a step that allows LSEs to convert a portion of their awarded annual rights into LT-CRRs which have a term of ten years. Finally, CRRs may be transacted bilaterally, and the ownership change must be registered in the CAISO's SRS similar to FTRs.

II. UPDATE REQUEST

In light of the fact that CRRs have different attributes and procurement processes than FTRs, PG&E requests that the Commission adopt the following upfront and achievable standards and criteria related to the procurement of CRRs which will enhance PG&E's PP and 2006 LTPP on a going-forward basis.

1. CRR Source-Sink Pairs Or "Paths"

a. PG&E's current PP imposes no restrictions on the source-sink pairs or paths on which PG&E might obtain transmission service or FTRs. In practice, PG&E has sought transmission service or FTRs on interstate or interzonal transmission paths, or on paths that PG&E reasonably anticipates that it might need to flow energy in the future due to the addition of new contracts, resources or load obligations. If PG&E is able to obtain transmission service or an FTR at an attractive price, for example, PG&E can later sign an energy contract at the market price that uses that transmission service or FTR to bring energy to PG&E's customers at an attractive, all-in delivered price. FTRs have helped PG&E manage its overall energy portfolio. Their availability and future expected availability influences ongoing energy purchases. If PG&E were prohibited from obtaining the transmission service or FTR first, due to the absence of an existing energy contract or source, then opportunities to obtain attractively priced energy going forward might be lost. Stated another way, PG&E currently has the flexibility to obtain either energy or transmission service or a transmission hedge (such as an FTR) first, depending on the opportunities that are available in the market.

b. PG&E believes it should have similar flexibility to obtain CRRs. Specifically, PG&E proposes that it be allowed to obtain CRRs for any path (represented by a source-sink pair) connecting existing generation sources to existing loads (either

[3] These tariff requirements include, among other things, credit requirements, training requirements, and an application to become a CRR holder.

retail loads or wholesale load obligations)[4] or for any path that PG&E reasonably anticipates that it might need to flow energy in the future due to the addition of new contracts, resources or load obligations.[5] Additionally, there may be CRRs which are positively correlated in value with CRRs for paths that have limited availability. PG&E proposes that it be allowed to obtain CRRs for such positively correlated paths as well. It might be desirable for PG&E to obtain CRRs on positively correlated paths if limited CRRs are available for the target path or if the CRRs for the positively correlated path can be obtained at lower prices.

2. Maximum Volume Limits

a. Currently, PG&E has no maximum (or minimum) volume limits for procurement of transmission service or FTRs.

b. Overall or total CRR volume limits are unnecessary for the CAISO's allocation process. This is because the CAISO tariff establishes volume limits for PG&E as an LSE based on PG&E's adjusted load metric.[6] Specifically, PG&E cannot obtain CRRs exceeding 75% of its adjusted load metric in the annual CRR allocation process, and more than 100% cumulatively of its adjusted load metric through the monthly CRR allocation process. Similarly, PG&E cannot obtain LT-CRRs exceeding 50% of its adjusted load metric in the long-term allocation process.

c. Therefore, PG&E proposes that the Commission does not establish total or overall limits for PG&E's procurement of CRRs, including LT-CRRs. Instead, PG&E

[4] For the initial year of MRTU, all CRRs allocated to an LSE in all but the last "tier" of the annual or monthly CAISO allocation process must be "source-verified," based on a review of actual LSE sources used in 2006. Additionally, the sink for all CRRs allocated to an LSE must be the LSE's Load Aggregation Point ("LAP"), except in the final tier, in which case the sink can be one of the LSE's sub-LAPs.

[5] Technically, under MRTU, market participants do not necessarily schedule energy to flow between two points on the transmission grid. When PG&E refers to the flow of energy on a path under MRTU in this Advice Letter, it is referring to the existence of a generation source at one termination of the path and a load (or load obligation) at the other termination. Typically, there is not a direct, physical connection between the energy source and sink. Rather, the energy source and sink are points on the transmission network and the actual flow of electricity is determined by the configuration of the network and the operation of other interconnected resources and loads.

[6] Adjusted Load Metric is defined by the CAISO as the level of demand that is exceeded in only 0.5% of the hours for the prior year less any Existing Transmissions Contract, Converted Rights, and Transmission Ownership Rights.

proposes source-specific volume limits. That is, PG&E proposes limiting the "net" volume[7] that it could procure at each source node to the maximum non-coincident capacity of the sources (existing, potential, planned, or "positively correlated"[8]) at that node. PG&E proposes separate monthly limits for the on-peak and off-peak hours of the month.

3. PRG Consultation

a. Prior to executing transactions longer than one calendar quarter in delivery duration, PG&E is required by its PP to consult with its Procurement Review Group ("PRG"). As a result of this requirement, PG&E has reviewed with its PRG its proposed bidding strategy for each annual FTR auction in advance of the auction, including discussing the maximum total volume of FTRs that PG&E might acquire.

b. PG&E will continue to consult with its PRG prior to transacting for any CRR having a term greater than one calendar quarter.

c. CRRs awarded in the annual CAISO allocation/auction process only have a term of one calendar quarter. However, notwithstanding the quarterly term, PG&E will consult with the PRG prior to making CRR nominations for any of the tiers in the annual allocation process, or prior to converting awarded CRRs to LT-CRRs. PG&E will also consult with its PRG prior to participating in the annual CRR auction.

d. PG&E does not intend to consult with the PRG prior to each monthly CRR allocation/auction process. However, PG&E will review its CRR position with the PRG in its periodic position update discussions.

4. Valuation and Risk Analysis

a. Prior to participating in the annual and monthly CRR allocation/auction process, PG&E will identify candidate CRRs for consideration based on the location and magnitude of its resources and loads (existing and potential), and may also

[7] By "net" volume, PG&E is referring to the result of netting CRRs in one direction with CRRs in the counter-flow direction.

[8] See Paragraph 1.b above for the meaning of the term "correlated."

identify additional candidate CRRs that are potentially positively correlated in value with other CRRs of interest.

b. For the overall portfolio and for each of the candidate CRRs, PG&E will estimate the expected value for the relevant time period by using various methods, such as:

   i. Running a model of the transmission network simulating the dispatch of generation to serve load and forecasting Marginal Congestion Costs ("MCCs") or Locational Marginal Prices ("LMPs") at CAISO nodes and hubs;

   ii. Obtaining a forecast of MCCs or LMPs from one or more expert consulting firms;

   iii. Obtaining market price quotations (where available) at trading hubs;

   iv. Analyzing historical MCC and LMP data for trends, relationships, and correlations and using this data and observed trends and relationships to forecast future MCCs or LMPs; or,

   v. Averaging (or weight-averaging) forecasts of MCCs and LMPs that were developed using two or more of the methodologies described above.

   These methods for calculating expected value should not be considered exhaustive, nor will all of these methods necessarily be used, and PG&E expects to make further enhancements over time to its ability to estimate value. The methodologies used for valuation will be reviewed with the PRG during the consultations proposed above.

c. Similarly, prior to participating in the annual and monthly CRR allocation/auction process, or prior to converting awarded CRRs to LT-CRRs, PG&E proposes to evaluate the risks of obtaining CRRs or not obtaining CRRs for the candidate CRR paths. Risk can be created by a number of factors, including: a large congestion cost differential between a PG&E source and sink;[9] variability in the dollar amounts paid or received by holding a CRR; potential generation or transmission outages; higher or lower loads than normal; and future changes to

[9] Such congestion can vary in magnitude considerably over time, can occur in both directions at different times, and is unbounded in MRTU. Congestion is created when the energy delivered to a node exceeds the capacity of the transmission network to flow energy from that point.

the transmission grid, including the interconnection of new generation. One of the risks of not having a CRR is that PG&E may pay a high congestion cost to flow energy from its source to its sink. Having a CRR provides an offsetting payment to compensate PG&E for having to pay that congestion cost. In contrast, one of the risks of having a CRR is that PG&E may have to pay a high congestion cost if congestion counter-flows to the direction of that CRR.[10] For a particular path, PG&E's risk is also impacted by the character of its resource(s) using that path. That is, risk is potentially much higher if the resource is must-take and non-dispatchable, meaning that PG&E must take delivery of energy regardless of the congestion cost from the source to the sink. Another risk PG&E may face is the impact of having to post high amounts of collateral to CAISO to secure its CRR holdings in a stress case scenario. PG&E may employ several different metrics to quantify its risk assessment, including, but not limited, to:

i. Simulating random variables, such as load, hydro, gas prices, and outages, creating a distribution of congestion costs or CRR values for a period of time, and calculating metrics based on that distribution;

ii. Creating a marginal cost of congestion duration curve indicating the number of hours (or percent of the time) that congestion exceeds a particular value and calculating metrics based on that duration curve;

iii. Creating a distribution of the hourly dollar amounts received or paid for holding a CRR and calculating metrics based on that distribution (such as TeVaR at the 99th percentile);[11]

iv. Running various scenarios (or stress cases), such as for high or low loads, high or low gas prices, high or low generation/transmission outages, determining the expected congestion cost or CRR value for these scenarios over a period of time, and calculating the change in cost/value compared to the base case scenario;

v. Forecasting how congestion costs paid might vary depending on whether the resource at the CRR source location is must-take or dispatchable;

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[10] This payment may be offset by PG&E receiving a payment for flowing energy from its source to its sink counter-flow to the direction of congestion. However, if PG&E's source is not available (for example, due to an outage), PG&E would not receive a payment for counter-flowing energy.

[11] To-expiration-Value-at-Risk ("TeVaR") at the 99th percentile is the difference between the value that is not exceeded 99% of the time and the average or expected value.

vi. Estimating the risk mitigation achieved by the addition of candidate CRRs to the overall portfolio; or,

vii. Forecasting the potential amounts paid for holding a CRR during periods of counter-flow.

d. PG&E will review its CRR valuation and risk analysis with its PRG (prospectively for the annual CRR auction/allocation process). Because MRTU is new to California and there is no history on CRRs, MCCs, or LMPs, and because (in PG&E's experience) models, assumptions, methodologies, and technologies continue to improve over time, PG&E does not recommend that the Commission mandate that PG&E use any particular method or model to value or assess the risk of congestion or CRRs.

5. Nomination Criteria in CRR Allocation Process

a. In nominating CRRs in the CAISO's allocation process, and when converting awarded CRRs to LT-CRRs, PG&E may consider a number of factors, including, but not limited to:

i. The expected cost of congestion (and value of the CRR);

ii. Various risk metrics (discussed above) for obtaining or not obtaining a candidate CRR;

iii. The probability that a portion of requested CRR volumes might or might not be awarded due to competing requests for the same CRR; and,[12]

iv. The likelihood and potential cost (or opportunity cost) for PG&E to obtain the candidate CRR in a subsequent tier, the auction, the monthly CRR allocation/auction process, or the secondary market.

[12] If PG&E is not able to obtain certain MWs of CRRs in the allocation process due to oversubscription (non-feasibility of simultaneous award), PG&E has lost the ability to obtain those MWs in that tier. PG&E may seek to replace these MWs with other CRRs in lower priority tiers.

6. PG&E's Participation In The CRR Auction And Conversion Of CRRs To LT-CRRs

a. Because the CRR auction is competitive and likely will involve a number of market participants, PG&E anticipates that the resulting auction prices will fairly reflect the value of CRRs obtained. Accordingly, PG&E requests that the Commission approve PG&E's participation in the CRR auction process and establish that all PG&E auction awards are in compliance with upfront standards and therefore are *per se* reasonable. The CPUC has previously approved PG&E's participation in existing CAISO markets, including the FTR market, and has established that PG&E's transactions in these markets done in compliance with upfront standards are per se reasonable.

b. The annual CRR allocation process includes a step that allows LSEs to convert a portion of their awarded annual rights into LT-CRRs which have a term of ten years. In Advice Letter 3095-E, filed July 31, 2007, PG&E has separately requested Commission authority to participate in the LT-CRR conversion and allocation process. This request was necessary because LT-CRRs have a term of 10-years. Under PG&E's current PP, it is required to seek pre-approval for transactions with a term longer than five years. PG&E requests that in approving this advice letter, the Commission authorize PG&E to convert CRRs to LT-CRRs as a part of the CRR allocation and auction process. PG&E should be able to use its judgment as to which CRRs to convert to LT-CRRs and will review these decisions with its PRG.

7. Transactions In Secondary CRR Market

a. The CRR product is similar to a locational spread, which PG&E is currently authorized to transact under its PP. In a locational spread, PG&E sells energy at one point of the grid and buys energy at another point of the grid. The financial result is the same as if PG&E were to pay to flow energy from the point of the energy sale to the point of the energy purchase.

b. Because of the similarity between CRRs and energy transactions, such as locational spreads, PG&E will use the same transaction processes that its PP authorizes PG&E to use for energy transactions – *e.g.*, transact using brokers or exchanges[13], bilaterally subject to providing a "strong showing" in the

[13] PG&E does not anticipate that there will be any exchanges offering CRRs in the secondary market initially or for some time after MRTU start-up.

Quarterly PP Compliance filing, through an RFO (if feasible), etc. Among valid, competing offers for the same CRR, PG&E will select based on the better price (all else being equal). Particular locational spreads may also be purchased if related CRRs are not available.

c. PG&E will pursue both sales and purchases in the CRR secondary market.

d. PG&E anticipates that there will not be much liquidity (market volume), outside of the CAISO auction, in CRRs at least initially and probably for some considerable time.

Tier Designation

Pursuant to D.07-01-024, Rule 5.3, this advice letter is submitted with a Tier 3 designation.

Protests

PG&E requests an expedited protest period and review period pursuant to General Order 96-B, Section 1.3. Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than **August 29, 2007** with replies to protests due **August 31, 2007**.

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Avenue
San Francisco, California 94102

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

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, 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:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
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 and Expedited Consideration

PG&E requests that this advice filing become effective on **September 6, 2007**. In accordance with Public Utilities Code § 311(g)(2), PG&E asks for the Commission to reduce/waive the 30 day review period of the draft resolution in order to have this expeditiously approved by September 6, 2007 so that PG&E can have authorization to participate in the CAISO's CRR nomination and allocation process with the upfront achievable standards and criteria presented in this Advice Letter.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes to the General Order 96-B service list should be directed to Rose de la Torre at (415) 973-4716. Advice letter filings can also be accessed electronically at:

http://www.pge.com/tariffs

Vice President, Regulatory Relations

APPENDIX H

UPDATED LIST OF BROKERAGES AND EXCHANGES

Brokerages

- Tullett Liberty (acquired Natsource)
- ICAP Energy LLC (acquired APB)
- Prebon
- TFS
- Amerex (recently acquired by GFI Group, Inc.)
- Landmark
- Saddleback
- Anahau Energy LLC
- Evolution Markets Inc

Exchanges and Futures Commission Merchants

- Intercontinental Exchange (ICE) – Exchange and Cleared (London Clearinghouse) trades
- New York Mercantile Exchange (NYMEX) – Exchange and Cleared trades
- R.J. O'Brien (allows accessibility to NYMEX and NYMEX Clearing)
- Barclays (allows accessibility to NYMEX, NYMEX Clearing, and ICE Clearing (London Clearinghouse))

APPENDIX I

PRG, IE, AND RFO REQUIREMENTS

FROM APPENDIX E TO D.07-12-052

Procurement Review Group

- IOUs are to provide PRG members with meeting agendas and materials a minimum of 48 hours in advance of the PRG meeting, unless there are unusual, extenuating circumstances that the IOU communicates to PRG members in an email announcing a meeting or distributing meeting materials on a tighter timeframe.
- The IOUs are to provide confidential meeting summaries to PRG members that include a list of attending PRG members (including the organizations represented), a summary of topics presented and discussed, and a list of information requested or offered to be supplied after the meeting, (and identify the requesting party).
- The IOUs are to individually set up and maintain a web-based PRG calendar that can be accessed and updated by the IOU.
- The IOUs are to provide the following information to the public through a web-based forum: date, meeting time and duration of the meeting; the individuals participating in the meeting and organization represented by the individual; and a list of non-confidential items discussed.
- When procuring or potentially procuring CAM resources, the IOUs are to utilize an advisory CAM Group consistent with the proposal as presented in D.07-12-052, Attachment D.
- The IOUs are required to consult with their PRGs for any transaction with a delivery term greater than three months' duration.

Independent Evaluator

- Each IOU, in conjunction with each respective PRG, shall develop a pool of at least three, but preferably more, IEs to be used beginning January 1, 2009. Each IOU should develop and periodically add to its IE pool as follows:

  1. The IOU shall develop a list of prospective IEs via industry contacts, literature searches, PRG recommendations, and similar methods, solicit information from the prospective IEs and circulate the list of candidates and their "resumes" to the PRG and ED staff for feedback.

  2. The IOU should rely on the guidance regarding IE expertise and qualifications provided in D.04-12-048. However, these qualifications should represent the minimum necessary for an IE to be effective, and the IOU and the PRG should include any additional relevant information that it has gained through its experiences implementing the IE requirements;

3. The IOU and PRG shall interview a subset of prospective candidates that the IOU, PRG, and ED staff deem most suitable for the role (IOUs should arrange for the PRG to conduct interviews with candidate IEs in isolation from the contracting IOU);

4. The PRG shall coordinate the development and submittal to the IOU of its recommendations on each prospective candidate (including the general consensus and any opposition to the consensus). The IOU shall submit a written list of qualified IEs to ED to add to the contracting IOU's pool. The list must contain the recommendations of the PRG that were submitted to the IOU. ED will evaluate the proposed IE's competencies based on the guidelines in D.04-12-048 as well as evaluating the IE's independence including any conflicts of interest. ED shall give final approval for inclusion of an IE in the IE pool by letter to the submitting IOU. ED will also have the right to final approval of the use of a particular IE for each RFO.

5. Beyond the development of the initial IE pool, additional IEs may be added to the pool by following the same procedures listed above.

6. An IE may remain in the IE pool for two years, after which he/she must go through a reevaluation process based upon the inclusion criteria to assure continued compliance. The reevaluation process will involve additional reviews of the IE candidate by the PRG, IOU and ED staff including additional interviews, if necessary.

7. The IOU shall develop a pro forma contract to be used each time it contracts with an IE. If deviations from the pro forma contract are necessary, the modifications must be fully supported when the IOU seeks final approval of the contract. This pro forma contract shall be submitted as part of the next LTPP filing and will be subject to Commission approval.

- Each IOU is to provide the name and information of the IE for each IOU, the type of procurement solicitation the IE was used for and the amount of money involved in the procurement solicitation be reported to the IOUs PRG before and after the solicitation takes place.

- An IE shall be contracted with and retained for all competitive solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids and for all competitive RFOs seeking products greater than three months in length regardless of the bidders. Competitive RFOs include RFOs issued to satisfy service area need and supply side resources not including EE and DR. For solicitations of less than five years, the IE report shall be filed with the QCR. An IE shall be utilized for all competitive RFOs regardless of length, the bidders or the type of the product being sought. For solicitations greater than five years, the IE report shall be filed with the application.
- The IOUs, in consultation with the PRG and ED, shall develop comprehensive conflict of interest disclosure requirements for the IE. An IE may be disqualified from participating in an RFO process if there are particular egregious conflicts of interest that arise during the contract. The conflict of interest disclosure requirements shall be approved along with the standard contracts in the next LTPP~~s~~ proceeding.
- In order to clarify the information required in IE reports, we direct ED to develop a template for IEs to use when developing their reports.

RFO & RFO Process

- The IOUs shall use a project application template developed by ED when developing an application for an approval of winning bid projects.

- The IOUs are to hold a meeting with the IE, PRG and ED to outline their plans and solicit feedback prior to drafting RFO bid documents. Draft RFO bid documents are to be developed under the oversight of an IE, vetted through the PRGs and any differences resolved by ED staff in advance of the public issuance of the bid documents.

- If an IOU needs new fossil resources not formally authorized in a LTPP decision, the IOU must make a showing through an Advice Letter that unusual or extreme circumstances warrant such an action.

- Debt Equivalence is no longer applicable to the evaluation of PPA bids in an RFO.

- IOUs are to consider the use of Brownfield sites first before building new generation on Greenfield sites, subject to the parameters set forth in the decision.

- An IOU must publicly reveal the names of winning bidders after key commercial terms have been finalized, within thirty days of filing an application, or withdraw the application until the bidder's identity and other required information can be released. The actual contract does not have to be revealed.

APPENDIX J

GLOSSARY

A

ABOVE-MARKET COST - The cost of a service in excess of the price of comparable services in the market.

ABNORMAL PEAK DAY (APD) - An abnormal peak day is the coldest day which could reasonably be expected to occur within the Pacific Gas and Electric Company system for planning purposes and is based on the coldest day of record for the Pacific Gas and Electric Company territory.

ACCESS CHARGE - A charge paid by all market participants withdrawing energy from the ISO controlled grid. The access charge will recover the portion of a utility's transmission revenue requirement not recovered through the variable usage charge.

AFFILIATE – A company that is controlled by another or that has the same owner as another company.

AFFILIATED POWER PRODUCER - A generating company that is affiliated with a utility.

AGGREGATION - The process of organizing small groups, businesses or residential customer into a larger, more effective bargaining unit that strengthens their purchasing power with utilities.

AGGREGATOR - An entity that puts together customers into a buying group for the purchase of a commodity service. The vertically integrated investor owned utility, municipal utilities and rural electric cooperatives perform this function in today's power market. Other entities such as buyer cooperatives or brokers could perform this function in a restructured power market.

ALTERNATIVE ENERGY SOURCES – (See RENEWABLE ENERGY)

ANCILLARY SERVICES – Capacity, measured in MW, that is utilized by the control area operator to ensure electric system reliability.

ANIMAL WASTE CONVERSION - Process of obtaining energy from animal wastes. This is a type of biomass energy.

ANNUAL MAXIMUM DEMAND - The greatest of all demands of the electrical load which occurred during a prescribed interval in a calendar year.

AREA LOAD - The electrical load in given geographic area irrespective of what LSEs are providing generation services to end-users within the area.

> **Service Area Load** is generally used to mean the load in an IOU distribution service area including loads served by IOUs through bundled service tariffs, loads served by ESPs under direct access, and loads served by CCAs through the provisions of AB 117. In addition, for the SCE service area the generation and loads of MWD Metropolitan Water district included.

Planning Area Load is generally used to mean Service Area Load plus the loads of publicly-owned utilities embedded within an IOU distribution service area or adjacent to the IOU distribution service area which collectively received transmission service from the PTO unit of an IOU.

PG&E and SCE provide transmission services to, and plan such services for, an extensive list of publicly-owned utilities in common with their own distribution service area customers. In contrast, SDG&E provides no such transmission services to publicly-owned utilities.

ASSOCIATED GAS - Natural gas that can be developed for commercial use, and which is found in contact with oil in naturally occurring underground formations.

ATTRIBUTES - The outcomes by which the relative "goodness" of a particular expansion plan is measured e.g. fuel usage.

AUXILIARY ENERGY SUBSYSTEM - Equipment using conventional fuel to supplement the energy output of a solar system. This might be, for example, an oil-fueled generator that adds to the electrical output of substitutes for the solar system during long overcast periods when there is not enough sunlight.

AUXILIARY EQUIPMENT - Extra machinery needed to support the operation of a power plant or other large facility.

AVAILABLE BUT NOT NEEDED CAPABILITY - Capability of generating units that are operable but not necessary to carry load.

AVERAGE COST - The revenue requirement of a utility divided by the utility's sales. Average cost typically includes the costs of existing power plants, transmission, and distribution lines, and other facilities used by a utility to serve its customers. It also included operating and maintenance, tax, and fuel expenses.

AVERAGE DEMAND - The energy demand in a given geographical area over a period of time. For example, the number of kilowatt-hours used in a 24-hour period, divided by 24, tells the average demand for that period.

AVERAGE HYDRO - Rain, snow and runoff conditions that provide water for hydroelectric generation equal to the most commonly occurring levels. Average hydro usually is a mean indicating the levels experienced most often in a 104-year period.

AVOIDED COST (Regulatory) - The amount of money that an electric utility would need to spend for the next increment of electric generation to produce or purchase elsewhere the power that it instead buys from a cogenerator or small-power producer.

B

BALANCED SCHEDULE - A Scheduling Coordinator's schedule is balanced when generation, adjusted for transmission losses, equals demand.

BALANCING - Making receipts and deliveries of gas into or withdrawals from a pipeline equal. Balancing may be accomplished daily, monthly or seasonally, with non-compliance charges generally assessed for excessive imbalance.

BASE LOAD - The lowest level of power production needs during a season or year.

BASE LOAD (For Gas) - As applied to gas, a given consumption of gas remaining fairly constant over a period of time, usually not temperature-sensitive.

BASE LOAD UNIT - A power generating facility that is economic to run in all hours at full or near full capacity levels.

BASELINE FORECAST - A prediction of future energy needs which does not take into account the likely effects of new conservation programs that have not yet been started.

BASELOAD CAPACITY - Generating equipment operated to serve loads 24-hours per day.

BASE RATE - That portion of the total electric or gas rate covering the general costs of doing business unrelated to fuel expenses.

BILATERAL CONTRACT - A two-party agreement for the purchase and the sale of energy and/or capacity products and services or financially settled products.

BIO-GAS - Methane produced by the decomposition or processing of organic matter.

BIOMASS - Energy resources derived from organic matter. These include wood, agricultural waste and other living-cell material that can be burned to produce heat energy. They also include algae, sewage and other organic substances that may be used to make energy through chemical processes.

BIOMETHANE (Purchase or Sale) - Pipeline quality natural gas produced from renewable (non-fossil based) resources. May include renewable or environmental attributes.

BLACK START – Critical generating units to ensure “black start” capability for purposes of system restoration.

BLACKOUT - A power loss affecting many electricity consumers over a large geographical area for a significant period of time.

BRITISH THERMAL UNIT (Btu) - The quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293 watt hours.

BULK POWER MARKET - Wholesale purchases and sales of electricity.

BULK POWER SUPPLY - Often this term is used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines, and related-equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

BUNDLED CUSTOMERS - Bundled customers are those customers of the IOU for whom the IOU provides a suite of "bundled" services, including procuring and supplying electricity, as well as providing transmission, distribution and customer services.

BUNDLED SERVICE - Electric power, transmission, distribution, billing, metering and related service provided by the IOU.

BURNER TIP - A generic term that refers to the ultimate point of consumption for natural gas.

BUSBAR - In electric utility operations, a busbar is a conductor that serves as a common connection for two or more circuits. It may be in the form of metal bars or high-tension cables.

BUY THROUGH - An agreement between utility and customer to import power when the customer's service would otherwise be interrupted.

BUYER - An entity that purchases electrical energy or services from the Power Exchange (PX) or through a bilateral contract on behalf of end-use customers.

C

CALIFORNIA ENERGY COMMISSION - The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act in 1974 (Public Resources Code, Sections 25000 et seq.) responsible for energy policy. The Energy Commission's five major areas of responsibilities are:

1. Forecasting future statewide energy needs
2. Licensing power plants sufficient to meet those needs
3. Promoting energy conservation and efficiency measures
4. Developing renewable and alternative energy resources, including providing assistance to develop clean transportation fuels
5. Planning for and directing state response to energy emergencies

Funding for the Commission's activities comes from the Energy Resources Program Account, Federal Petroleum Violation Escrow Account and other sources.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA - pronounced See' quah) - Enacted in 1970 and amended through 1983, established state policy to maintain a high-quality environment in California and set up regulations to inhibit degradation of the environment.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) - A state agency created by constitutional amendment in 1911 to regulate the rates and services of more than 1,500 privately owned utilities and 20,000 transportation companies. The CPUC is an administrative agency that exercises both legislative and judicial powers; its decisions and orders may be appealed only to the California Supreme Court.

The major duties of the CPUC are to regulate privately owned utilities, securing adequate service to the public at rates that are just and reasonable both to customers and shareholders of the utilities; including rates, electricity transmission lines and natural gas pipelines. The CPUC also provides electricity and natural gas forecasting, and analysis and planning of energy supply and resources. Its main headquarters are in San Francisco.

CALL-BACK - A provision included in some power sale contracts that lets the supplier stop delivery when the power is needed to meet certain other obligations.

CAPABILITY - Maximum load that a generating unit can carry without exceeding approved limits.

CAPACITY (Demand side) – The amount of power consumed by a customer, measured in MWs, that can be produced upon request.

CAPACITY (Purchase or Sale) - The amount of power capable of being generated, measured in MWs, that can be reduced upon request.

There are various types of electricity capacity:

Dependable Capacity: The system's ability to carry the electric power for the time interval and period specific, when related to the characteristics of the load to be supplied. Dependable capacity is determined by such factors as capability, operating power factor, weather, and portion of the load the station is to supply.

Installed (or Nameplate) Capacity: The total manufacturer-rated capacities of equipment such as turbines, generators, condensers, transformers, and other system components.

Peaking Capacity: The capacity of generating equipment intended for operation during the hours of highest daily, weekly or seasonal loads.

Purchased Capacity: The amount of energy and capacity available for purchase from outside the system

Reserve Capacity: Extra generating capacity available to meet peak or abnormally high demands for power and to generate power during scheduled or unscheduled outages. Units available for service, but not maintained at operating temperature, are termed "cold." Those units ready and available for service, though not in actual operation, are termed "hot."

CAPACITY CHARGE - An assessment on the amount of capacity being purchased.

CAPACITY FACTOR - A percentage that tells how much of a power plant's capacity is used over time. For example, typical plant capacity factors range as high as 80 percent for geothermal and 70 percent for cogeneration.

CAPACITY RELEASE - A secondary market for capacity that is contracted by a customer which is not using all of its capacity.

CARBON DIOXIDE - A colorless, odorless, non-poisonous gas that is a normal part of the air. Carbon dioxide, also called CO2, is exhaled by humans and animals and is absorbed by green growing things and by the sea.

CARBON MONOXIDE (CO) - A colorless, odorless, highly poisonous gas made up of carbon and oxygen molecules formed by the incomplete combustion of carbon or carbonaceous material, including gasoline. It is a major air pollutant on the basis of weight.

CIRCUIT - One complete run of a set of electric conductors from a power source to various electrical devices (appliances, lights, etc.) and back to the same power source.

CITYGATE, PG&E - On the PG&E gas system, the Citygate is any point at which the backbone transmission system connects to the local transmission and distribution system.

CLEAN FUEL VEHICLE - Is frequently incorrectly used interchangeably with "alternative fuel vehicle." Generally, refers to vehicles that use low-emission, clean-burning fuels. Public Resources Code Section 25326 defines clean fuels, for purposes of the section only, as fuels designated by ARB for use in LEVs, ULEVs or ZEVs and include, but are not limited to, electricity, ethanol, hydrogen, liquefied petroleum gas, methanol, natural gas, and reformulated gasoline.

COGENERATION - Cogeneration means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards:

> (a) At least 5 percent of the cogeneration project's total annual energy output shall be in the form of useful thermal energy.
>
> (b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

COGENERATOR - Cogenerators use the waste heat created by one process, for example during manufacturing, to produce steam which is used, in turn, to spin a turbine and generate electricity. Cogenerators may also be QFs.

COINCIDENCE FACTOR - The ratio of the coincident maximum demand of two or more loads to the sum of their noncoincident maximum demands for a given period. The coincidence factor is the reciprocal of the diversity factor and is always less than or equal to one.

COMBINED CYCLE PLANT - An electric generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

COMBUSTION - Rapid oxidation, with the release of energy in the form of heat and light.

COMBUSTION TURBINE - A fossil-fuel-fired power plant that uses the conversion process known as the Brayton cycle. The fuel, oil, or gas is combusted and drives a turbine-generator.

COMMERCIAL OPERATION - Occurs when control of the generator is turned over to the system dispatcher.

COMMODITY CHARGE - A charge per unit volume or heat content (i.e., therm) of gas delivered to the buyer. Compare DEMAND CHARGE.

COMPETITIVE TRANSMISSION CHARGE (CTC) - A non-bypassable charge that customers pay to a utility for the recovery of its stranded costs.

COMMUNITY CHOICE AGGREGATION SERVICE (CCA SERVICE) - Allows customers to purchase electric power and, at the customer's election, participate in additional energy efficiency or conservation programs from non-utility entities known as Community Choice Aggregators (CCAs). It is a form of direct access.

COMMUNITY CHOICE AGGREGATOR - Any city, county, or city and county, or group of cities, counties, or cities and counties, whose governing board or boards elect to combine the loads of their residents, businesses, and municipal facilities in a community wide electricity buyers' program. (see PU Code § 331.5.) A CCA may also provide certain energy efficiency and conservation programs to its CCA customers.

COMPETITIVE BIDDING - This is a procedure that utilities use to select suppliers of new electric capacity and energy. Under competitive bidding, an electric utility solicits bids from prospective power generators to meet current or future power demands.

CONDENSER - A heat exchanger in which the refrigerant, compressed to a hot gas, is condensed to liquid by rejecting heat.

CONGESTION - A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously.

CONGESTION MANAGEMENT - Alleviation of congestion by the ISO.

CONSERVATION - Steps taken to cause less energy to be used than would otherwise be the case. These steps may involve improved efficiency, avoidance of waste, reduced consumption, etc. They may involve installing equipment (such as a computer to ensure efficient energy use), modifying equipment (such as making a boiler more efficient), adding insulation, changing behavior patterns, etc.

CONTINGENT FORWARD (Purchase or Sale) - A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.

CONTRACT PATH - The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to take place across the "contract path", notwithstanding the electric fact that power flow in the network will distribute in accordance with network flow conditions. This term can also mean to arrange for power transfer between systems.

CONTRACTS FOR DIFFERENCES - A type of bilateral contract where the electric generation seller is paid a fixed amount over time which is a combination of the short-term market price and an adjustment with the purchaser for the difference.

CONTROL AREA - An electric power system, or a combination of electric power systems, to which a common automatic generation control (AGC) is applied to match the power output of generating units within the area to demand. The control area of the ISO is the state of California.

CORE CUSTOMERS - Residential and small commercial customers who must rely on the traditional distributor bundled service of sales and transportation. Compare NON-CORE CUSTOMERS.

COUNTERPARTY SLEEVES (For Electric Products) - An agreement by a counterparty to buy (sell) electricity from one counterparty and sell it to (buy it from) another counterparty.

COUNTERPARTY SLEEVES (For Natural Gas Physical Products) - Facilitating a transaction with an un-contracted or non-creditworthy through a contracted, creditworthy counterparty.

CRUDE OIL - Petroleum as found in the earth, before it is refined into oil products.

CUSTOMER CLASS - Refers to, in general, a group of customers with similar service requirements. Typical customer classes include residential, industrial, commercial and agricultural.

D

DAILY PEAK - The maximum amount of energy or service demanded in one day from a company or utility service.

DAY-AHEAD MARKET - The forward market for energy and ancillary services to be supplied during the settlement period of a particular trading day that is conducted by the ISO, the PX, and other Scheduling Coordinators. This market closes with the ISO's acceptance of the final day-ahead schedule.

DAY-AHEAD SCHEDULE - Day-ahead Schedule A schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a trading day. This schedule indicates the levels of generation and demand scheduled for each settlement period of that trading day.

DAYLIGHTING - The use of sunlight to supplement or replace electric lighting.

DEKATHERM - A unit of heating value equivalent to 10 therms or 1,000,000 Btus.

DELIVERY POINT - Point at which gas leaves a transporter's system completing a sale or transportation service transaction between the pipeline company and a sale or transportation service customer.

DEMAND (Utility) - The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts.

DEMAND CHARGE - The sum to be paid by a large electricity consumer for its peak usage level.

DEMAND CHARGE - The portion of a rate for gas service which is billed to the customer whether they use the service or not. Depending on the rate design this charge is based on actual or estimated peak usage (1 or 3 days), annual needs or a combination of the two. Compare COMMODITY CHARGE.

DEMAND RESPONSE PROGRAMS - “Demand response” refers to actions taken by end-users to reduce power demand during critical peak times or to shift demand to off-peak times. A demand response program provides customers with incentives for reducing load in response to an event signal. These incentives can take the form of a financial credit or their bill, a dynamic rate or exemption from rolling blackouts. Events can be called for economic or reliability reasons. Because demand response programs are designed to operate only a few hours per event, they typically reduce capacity (kW) but not energy (kWh).

DEMAND SIDE MANAGEMENT (DSM) - The methods used to manage energy demand including energy efficiency, load management, fuel substitution and load building. (See LOAD MANAGEMENT)

DEMONSTRATION - The application and integration of a new product or service into an existing or new system. Most commonly, demonstration involves the construction and operation of a new electric technology interconnected with the electric utility system to demonstrate how it interacts with the system. This includes the impacts the technology may have on the system and the impacts that the larger utility system might have on the functioning of the technology.

DEPENDABLE CAPACITY - The system's ability to carry the electric power for the time interval and period specified. Dependable capacity is determined by such factors as capability, operating power factor and portion of the load the station is to supply.

DEREGULATION - The elimination of regulation from a previously regulated industry or sector of an industry.

DERIVATIVES - A specialized security or contract that has no intrinsic overall value, but whose value is based on an underlying security or factor as an index. A generic term that, in the energy field, may include options, futures, forwards, etc.

DIRECT ACCESS - The ability of end-use customers located in the service territory of an IOU to purchase electricity from retail sellers other than their local utility. (See also RETAIL COMPETITION)

DIRECT ACCESS CUSTOMERS - Customers located within the service territory of an IOU who purchase electricity from sellers other than their local utility. DA customers continue to receive and pay for delivery services from their local utility.

DIRECT ACCESS-ELIGIBLE CUSTOMER – A customer located within the service territory of an IOU who is eligible for Direct Access.

DISPATCH - The operating control of an integrated electric system to: Assign generation to specific generating plants and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls. Control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures. Operate the interconnection. Schedule energy transactions with other interconnected electric utilities.

DISPATCHABILITY - This is the ability of a generating unit to increase or decrease generation, or to be brought on line or shut down at the request or a utility's system operator.

DISTRIBUTION - The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

DISTRIBUTED GENERATION - A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

DISTRIBUTION LINES - Overhead and underground facilities which are operated at distribution voltages, and which are designed to supply two or more customers.

DISTRIBUTION SYSTEM (Electric utility) - The substations, transformers and lines that convey electricity from high-power transmission lines to ultimate consumers, or for Electric Microutilities, the distribution lines that convey electricity from the generating units to the ultimate customer. (See GRID)

DISTRIBUTION UTILITY - The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The distribution utility can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers. The "wires" and "customer service" functions provided by a distribution utility could be split so that two totally separate entities are used to supply these two types of distribution services.

DISTRIBUTIVE POWER - A packaged power unit located at the point of demand. While the technology is still evolving, examples include fuel cells and photovoltaic applications.

DIVESTITURE or DISAGGREGATION - The stripping off of one utility function from the others by selling (spinning-off) or in some other way changing the ownership of the assets related to that function. Most commonly associated with spinning-off generation assets so they are no longer owned by the shareholders that own the transmission and distribution assets.

DUCT - A passageway made of sheet metal or other suitable material used for conveying air or other gas at relatively low pressures.

DWR CONTRACTS - Contracts for generating resource capacity and energy deliveries executed by the California Department of Water Resources during 2001 and allocated to the investor owned utilities for contract administration purposes only.

E

ECONOMIC DISPATCH - The distribution of total generation requirements among alternative sources for optimum system economy with consideration to both incremental generating costs and incremental transmission losses.

ECONOMY ENERGY (Electricity utility) - Electricity purchased by one utility from another to take the place of electricity that would have cost more to produce on the utility's own system.

EEI CONTRACT – Edison Electric Institute contract is a standard master agreement that provides the base terms and conditions for transactions executed between two parties of a particular master agreement.

EFFICIENCY - The ratio of the useful energy delivered by a dynamic system (such as a machine, engine, or motor) to the energy supplied to it over the same period or cycle of operation. The ratio is usually determined under specific test conditions.

ELECTRIC CAPACITY - This refers to the ability of a power plant to produce a given output of electric energy at an instant in time, measured in kilowatts or megawatts (1,000 kilowatts).

ELECTRIC PLANT (PHYSICAL) - A facility that contains all necessary equipment for converting energy into electricity.

ELECTRIC SERVICE PROVIDER (ESP) - An entity that is licensed by the CPUC to provide electric power service to Direct Access Customers (see PU Code §§ 218.3 and 394). An end-use customer can act as its own ESP as long as it complies with all requirements of being an ESP. Also referred to as Energy Service Providers.

ELECTRIC SYSTEM - This term refers to all of the elements needed to distribute electrical power. It includes overhead and underground lines, poles, transformers, and other equipment.

ELECTRIC UTILITY - Any person or state agency with a monopoly franchise (including any municipality), which sells electric energy to end-use customers; this term includes the Tennessee valley Authority, but does not include other Federal power marketing agency (from EPAct).

ELECTRICITY - A property of the basic particles of matter. A form of energy having magnetic, radiant and chemical effects. Electric current is created by a flow of charged particles (electrons).

ELECTRONIC QUARTERLY REPORTS (EQRs) - All FERC jurisdictional public utilities, including power marketers, must file EQRs, in which they:

- Summarize contractual terms and conditions in their agreements for all jurisdictional services, including:
    1. Market-based power sales;
    2. Cost-based power sales; and
    3. Transmission service
- Detail transaction information for short-term and long-term market-based power sales and cost-based power sales during the most recent calendar quarter.
- Tariff holders without effective contracts and transactions must file the ID Data portion of the EQR.

ELECTRICITY TRANSMISSION PRODUCTS – The amount of electricity transportation capability of a transmission line measured in MWs.

EMISSIONS CREDITS FUTURES OR FORWARDS - Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.

END-USE - The specific purpose for which electric is consumed (i.e. heating, cooling, cooking, etc.).

ENERGY - The amount of electricity produced, flowing or supplied by generation, transmission or distribution facilities or consumed over time. Usually it is measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.

ENERGY CHARGE - The amount of money owed by an electric customer for kilowatt-hours consumed.

ENERGY CONSUMPTION - The amount of energy consumed in the form in which it is acquired by the user. The term excludes electrical generation and distribution losses.

ENERGY DELIVERIES - Energy generated by one system delivered to another system.

ENERGY EFFICIENCY - Programs and measures designed to reduce consumer energy consumption. Example of programs and measures include lighting retrofit, process redesign and appliance rebates which encourage consumers to purchase high-efficiency appliances.

ENERGY POLICY ACT OF 1992 - This act which was the first comprehensive federal energy law promulgated in more than a decade will help create a more competitive U.S. electric power marketplace by removing barriers to competition. By doing so, this act allows a broad spectrum of independent energy producers to compete in wholesale electric power markets. The act also made significant changes in the way power transmission grids are regulated. Specifically, the law gives the Federal Energy Regulatory Commission the authority to order electric utilities to provide access to their transmission facilities to other power suppliers.

ENERGY RECEIPTS - Energy generated by one utility system that is received by another through transmission lines.

ENERGY RESERVES - The portion of total energy resources that is known and can be recovered with presently available technology at an affordable cost.

ENERGY RESOURCES - Everything that could be used by society as a source of energy.

ENERGY USE - Energy consumed during a specified time period for a specific purpose (usually expressed in kWh).

ENTHALPY - The quantity of heat necessary to raise the temperature of a substance from one point to a higher temperature. The quantity of heat includes both latent and sensible.

ENTITLEMENT - Electric energy or generating capacity that a utility has a right to access under power exchange or sales agreements.

ENVIRONMENTAL ATTRIBUTES - Environmental attributes quantity the impact of various options on the environment. These attributes include particulate emissions, SO2 or Nox, and thermal discharge (air and water).

ENVIRONMENTAL PROTECTION AGENCY (EPA) - A federal agency created in 1970 to permit coordinated governmental action for protection of the environment by systematic abatement and control of pollution through integration or research, monitoring, standards setting and enforcement activities.

EXCHANGE (Electric utility) - Agreements between utilities providing for purchase, sale and trading of power. Usually relates to capacity (kilowatts) but sometimes energy (kilowatt-hours).

EXCHANGE TRADED CONTRACTS - Contract for electric capacity and energy executed through electronic and voice exchange markets under standard product terms and conditions. Products are generally for “standard products” (peak, on-peak or flat) and standard periods of duration (hourly, daily, balance of month, monthly, quarterly).

EXHAUST - Air removed deliberately from a space, by a fan or other means, usually to remove contaminants from a location near their source.

EXPORTS (Electric utility) - Power capacity or energy that a utility is required by contract to supply outside of its own service area and not covered by general rate schedules.

F

FACILITY - A location where electric energy is generated from energy sources.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) - An independent regulatory commission within the U.S. Department of Energy that has jurisdiction over energy producers that sell or transport fuels for resale in interstate commerce; the authority to set oil and gas pipeline transportation rates and to set the value of oil and gas pipelines for ratemaking purposes; and regulates wholesale electric rates and hydroelectric plant licenses.

FEDERAL POWER ACT - An act that includes the regulation of interstate transmission of electrical energy and rates. This act is administered by the Federal Energy Regulatory Commission.

FEEDER - This is an electrical supply line, either overhead or underground, which runs from the substation, through various paths, ending with the transformers. It is a distribution circuit, usually less than 69,000 volts, which carries power from the substation.

FINANCIAL CALL (OR PUT) OPTION (For Electric Products) – The right, but not the obligation, to buy (call) a forward electric contract on a specific date (expiration) at a specific price (strike). The right to sell is a put option.

FINANCIAL CALL (OR PUT) OPTION (For Natural Gas Financial Products) - The right, but not the obligation, to buy (call) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). The right to sell is a put option. OTC-traded options settle in cash, whereas exchange traded (NYMEX) options must be exercised, which causes delivery of a futures position to the option holder. Options may be combined to hedge a wide variety of positions.

FINANCIAL SWAP – An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps and basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.

FIRM ENERGY - Power supplies that are guaranteed to be delivered under terms defined by contract.

FIRM SERVICE - Service offered to customers (regardless of Class of Service) under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in Off-Peak Service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency. Compare INTERRUPTIBLE SERVICE and OFF-PEAK SERVICE.

FIXED COSTS - The annual costs associated with the ownership of property such as depreciation, taxes, insurance, and the cost of capital.

FORCED OUTAGE - An outage that results from emergency conditions and requires a component to be taken out of service automatically or as soon as switching operations can be performed. The forced outage can be caused by improper operation of equipment or by human error. If it is possible to defer the outage, the outage becomes a scheduled outage.

FORECAST INSURANCE - A method for managing load forecast (volume and shape) risk.

FORWARD ENERGY (Demand side) – Electric energy planned to be consumed by a customer, measured in MWhs that is agreed to be reduced for a specific period for a specified time in the future.

FORWARD ENERGY (Purchase or Sale) – Electric energy purchased or sold by a counterparty, measured in MWhs that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.

FORWARD SPOT (DAY-AHEAD & HOUR-AHEAD) PURCHASE, SALE, OR EXCHANGE – Electric energy, capacity, ancillary services or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.

FOSSIL FUEL - Oil, coal, natural gas or their by-products. Fuel that was formed in the earth in prehistoric times from remains of living-cell organisms.

FREQUENCY - The number of cycles which an alternating current moves through in each second. Standard electric utility frequency in the United States is 60 cycles per second, or 60 Hertz.

FTR LOCATIONAL SWAPS - Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

FUEL - A substance that can be used to produce heat.

FUEL CELL - A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

FUEL DIVERSITY - Policy that encourages the development of energy technologies to diversify energy supply sources, thus reducing reliance on conventional (petroleum) fuels; applies to all energy sectors.

FUEL OIL - Petroleum products that are burned to produce heat or power.

FUTURES MARKET - A trade center for quoting prices on contracts for the delivery of a specified quantity of a commodity at a specified time and place in the future.

G

GAS - Gaseous fuel (usually natural gas) that is burned to produce heat energy.

GAS IMBALANCE - a. Producer/Producer - When one or more producers sell or utilize a volume of natural gas in excess of their gross working interest. b. Pipeline/Pipeline - When a pipeline receives a volume of natural gas and redelivers a larger or smaller volume of natural gas under the terms of a transportation agreement. c. Producer/Pipeline - When a producer delivers a volume of natural gas that is larger or smaller than the volume of natural gas that the pipeline redelivers for the producer's account to another party.

GAS, NATURAL - A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane. 1. Dry. Gas whose water content has been reduced by a dehydration

process. Gas containing little or no hydrocarbons commercially recoverable as liquid product. Specified small quantities of liquids are permitted by varying statutory definitions in certain states. 2. Liquefied (LNG). See LIQUEFIED NATURAL GAS. 3. Sour. Gas found in its natural state, containing such amounts of compounds of sulfur as to make it impractical to use, without purifying, because of its corrosive effect on piping and equipment. 4. Sweet. Gas found in its natural state, containing such small amounts of compounds of sulfur that it can be used without purifying, with no deleterious effect on piping and equipment. 5. Wet. Wet natural gas is unprocessed natural gas or partially processed natural gas produced from strata containing condensable hydrocarbons. The term is subject to varying legal definitions as specified by certain state statutes. (The usual maximum allowable is 7 lbs./MMcf water content and .02 gallons/Mcf of Natural Gasoline.)

GAS STORAGE (Purchase or Sale) - Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.

GAS TRANSPORTATION (Purchase or Sale) - Interstate, Intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.

GAS UTILITY - Any person engaged in, or authorized to engage in, distributing or transporting natural gas, including, but not limited to, any such person who is subject to the regulation of the Public Utilities Commission.

GENERATING STATION - A station that consists of electric generators and auxiliary equipment for converting mechanical, chemical, or nuclear energy into electric energy.

GENERATING UNIT - Any combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power.

GENERATION (Electricity) - Process of producing electric energy by transforming other forms of energy.

GENERATION COMPANY or GENERATOR - A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. The generation company may own the generation plants or interact with the short term market on behalf of plant owners.

GENERATION DISPATCH AND CONTROL - Aggregation and dispatching (sending off to some location) generation from various generating facilities, providing backup and reliability services.

GEOTHERMAL - An electric generating station in which steam tapped from the earth drives a turbine-generator, generating electricity.

GIGAWATT (GW) - One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity. One gigawatt is enough to supply the electric demand of about one million average California homes.

GIGAWATT-HOUR (GWH) - One million kilowatt-hours of electric power. California's electric utilities generated a total of about 270,000 gigawatt-hours in 1988.

GLOBAL CLIMATE CHANGE - Gradual changing of global climates due to buildup of carbon dioxide and other greenhouse gases in the earth's atmosphere. Carbon dioxide produced by burning fossil fuels has reached levels greater than what can be absorbed by green plants and the seas.

GREENFIELD PLANT - Refers to a new electric power generating facility built from the ground up.

GRID - A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points.

GROSS GENERATION - Amount of electric energy produced by generating units as measured at the generator terminals.

H

HEAT RATE - A number that tells how efficient a fuel-burning power plant is. Measured by Btu/kWh. The heat rate equals the Btu content of the fuel input divided by the kWh or power output. The lower the heat rate of a generating unit is, the more efficient the unit is.

HEAT STORM - Heat storms occur when temperatures exceed 100 degrees Fahrenheit over a large area for three days in a row. Normal hot temperatures cause electricity demand to increase during the peak summertime hours of 4 to 7 p.m. when air conditioners are straining to overcome the heat. If a hot spell extends to three days or more, however, nighttime temperatures do not cool down, and the thermal mass in homes and buildings retains the heat from previous days. This heat build-up causes air conditioners to turn on earlier and to stay on later in the day. As a result, available electricity supplies are challenged during a higher, wider peak electricity consumption period.

HEATING VALUE - The amount of heat produced by the complete combustion of a given amount of fuel.

HEDGING - Any method of minimizing the risk of price change. Since the movement of cash prices is usually in the same direction and about in the same degree as the movement of the present prices of futures contracts, any loss (or gain) resulting from carrying the actual merchandise is approximately offset by a corresponding gain (or loss) when the contract is liquidated.

HEDGING CONTRACTS - Contracts which establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose. (See the following: 1.) CONTRACTS FOR DIFFERENCES, 2.) FUTURES MARKET, and 3.) OPTIONS.)

HENRY HUB - A pipeline interchange, located in Vermilion Parish, Louisiana, which serves as the delivery point of natural gas futures contracts.

HIGH HEAT VALUE (HHV) - The high or gross heat content of the fuel with the heat of vaporization included; the water vapor is assumed to be in a liquid state.

HYDROELECTRIC POWER - Electricity produced by falling water that turns a turbine generator. (Also referred to as HYDRO).

I

ICE – Intercontinental Exchange (ICE) is the world's leading electronic marketplace for energy trading and price discovery.

IMBALANCE ENERGY - The real-time change in generation output or demand requested by the ISO to maintain reliability of the ISO-controlled grid. Sources of imbalance energy include regulation, spinning and non-spinning reserves, replacement reserve, and energy from other generating units that are able to respond to the ISO's request for more or less energy.

IMPORTS (Electric utility) - Power capacity or energy obtained by one utility from others under purchase or exchange agreement.

INDEPENDENT POWER PRODUCER (IPP) - A private entity that operates a generation facility and sells power to electric utilities for resale to retail customers. Although IPPs generate power, they are not franchised utilities, government agencies or QFs. IPPs usually do not own transmission lines to transmit the power that they generate.

INDEPENDENT SYSTEM OPERATOR (ISO) - The entity charged with reliable operation of the grid and provision of open transmission access to all market participants on a non-discriminatory basis. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

INDEX PRICE - Tying the commodity price in a contract to other published prices, such as spot prices for gas or alternate fuels, or general indexes like the Consumer Price Index or Producer Price Index.

INFILTRATION - The uncontrolled inward leakage of air through cracks and gaps in the building envelope, especially around windows, doors and duct systems.

INFRASTRUCTURE - Generally refers to the recharging and refueling network necessary to successful development, production, commercialization and operation of alternative fuel vehicles, including fuel supply, public and private recharging and refueling facilities, standard specifications for refueling outlets, customer service, education and training, and building code regulations.

INSTALLED CAPACITY - The total generating units' capacities in a power plant or on a total utility system. The capacity can be based on the nameplate rating or the net dependable capacity.

INSURANCE (COUNTERPARTY CREDIT INSURANCE, CROSS COMMODITY HEDGES) – A method for managing payment or performance risk for a fee.

INTEGRATED RESOURCE PLAN - A comprehensive and systematic blueprint developed by a supplier, distributor, or end-user of energy who has evaluated demand-side and supply-side resource options and economic parameters and determined which options will best help them meet their energy goals at the lowest reasonable energy, environmental, and societal cost.

INTEGRATED RESOURCE PLANNING (IRP) - A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, IRP includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives. IRP has become a formal process prescribed by law in some states and under some provisions of the Clean Air Act amendments of 1992.

INTEGRATED RESOURCE PLANNING PRINCIPLES - The underlying principles of IRP can be distinguished from the formal process of developing an approved utility resource plan for utility investments in supply- and demand-side resources. A primary principle is to provide a framework for comparing a variety of supply- and demand-side and transmission resource costs and attributes outside of the basic provision (or reduction) of electric capacity and energy. These resources may be owned or constructed by any entity and may be acquired through contracts as well as through direct investments. Another principle is the incorporation of risk and uncertainty into the planning analysis. The public participation aspects of IRP allow public and regulatory involvement in the planning rather than the siting stage of project development.

INTERCHANGE (Electric utility) - The agreement among interconnected utilities under which they buy, sell and exchange power among themselves. This can, for example, provide for economy energy and emergency power supplies.

INTERCONNECTION (Electric utility) - The linkage of transmission lines between two utilities, enabling power to be moved in either direction. Interconnections allow the utilities to help contain costs while enhancing system reliability.

INTERESTED PARTY - Any person whom the commission finds and acknowledges as having a real and direct interest in any proceeding or action carried on, under, or as a result of the operation of, this division.

INTERMEDIATE LOAD – Range from base load to a point between that and peak load.

INTERMEDIATE UNIT - A generator unit that is used for energy production as required with a capacity factor normally in the range of 15-60%.

INTERMITTENT RESOURCES - Resources whose output depends on some other factory that cannot be controlled by the utility e.g. wind or sun. Thus, the capacity varies by day and by hour.

INTERRUPTIBLE LOADS - Loads that can be interrupted in the event of capacity or energy deficiencies on the supplying system.

INTERRUPTIBLE POWER - This refers to power whose delivery can be curtailed by the supplier, usually under some sort of agreement by the parties involved.

INTERRUPTIBLE SERVICE OR TARIFF (Electric utility) - Electricity supplied under agreements that allow the supplier to curtail or stop services at times. A service under which, upon notification from the Independent System Operator, the IOU requires the customer to reduce the demand imposed on the electrical system to firm service level (i.e., a level below which the customer's load will not be interruptible), and the customer must comply within 30 minutes.

INTERTIE - A transmission line that links two or more regional electric power systems.

INTERVAL METERING - The process by which power consumption is measured at regular intervals in order that specific load usage for a set period of time can be determined.

INVESTOR-OWNED UTILITY (IOU) - A private company owned by stockholders that provides electric utility services to a specific service area. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives. A California investor-owned utility is regulated by the California Public Utilities Commission.

INVOLUNTARY DIVERSION - Involuntary Diversions are called when there is a severe supply shortage and deliveries to core customers are threatened. Emergency Flow Order provisions apply and Pacific Gas and Electric Company may divert as from non-core to core customers. Pacific Gas and Electric Company may also divert as-available off-system deliveries, but firm off-system deliveries will not be diverted.

J

No entries for the letter J.

K

KILOVOLT (kv) - One-thousand volts (1,000). Distribution lines in residential areas usually are 12 kv (12,000 volts).

KILOWATT (kW) - One thousand (1,000) watts. A unit of measure of the amount of electricity needed to operate given equipment. On a hot summer afternoon a typical home, with central air conditioning and other equipment in use, might have a demand of four kW each hour.

KILOWATT-HOUR (kWh) - The most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt of electricity supplied for one hour. In 1989, a typical California household consumes 534 kWh in an average month.

L

LEVELIZED - A lump sum that has been divided into equal amounts over period of time.

LINE - A system of poles, conduits, wires, cables, transformers, fixtures, and accessory equipment used for the distribution of electricity to the public.

LIQUEFIED NATURAL GAS (LNG) - Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. It remains a liquid at -116 degrees Fahrenheit and 673 psig. In volume, it occupies 1/600 of that of the vapor at standard conditions.

LOAD - The amount of electric power supplied to meet end users' needs. Load is also an end-use device of an end-use customer that consumes power. Load should not be confused with demand, which is the measure of power that a load receives or requires.

LOAD CENTERS - A geographical area where large amounts of power are drawn by end-users.

LOAD DIVERSITY - The condition that exists when the peak demands of a variety of electric customers occur at different times. This is the objective of "load molding" strategies, ultimately curbing the total capacity requirements of a utility.

LOAD DURATION CURVE - A curve that displays load values on the horizontal axis in descending order of magnitude against percent of time (on the vertical axis) the load values are exceeded.

LOAD FACTOR - The ratio of the average load supplied to the peak or maximum load during a designated period. Load factor, in percent, also may be derived by multiplying the kWh in a given period by 100, and dividing by the product of the maximum demand in kW and the number of hours in the same period. The term also is used to mean the percentage of capacity of an energy facility - such as power plant or gas pipeline -- that is utilized in a given period of time.

LOAD MANAGEMENT - Steps taken to reduce power demand at peak load times or to shift some of it to off-peak times. This may be with reference to peak hours, peak days or peak seasons. The main thing affecting electric peaks is air-conditioning usage, which is therefore a prime target for load management efforts. Load management may be pursued by persuading consumers to modify behavior or by using equipment that regulates some electric consumption.

LOAD-SERVING ENTITY (LSE) - An entity that provides electric power service to end-use customers. LSEs include but are not limited to IOUs, ESPs, CCAs and public-owned utilities.

LOAD SHAPE - A curve on a chart showing power (kW) supplied (on the horizontal axis) plotted against time of occurrence (on the vertical axis), and illustrating the varying magnitude of the load during the period covered.

LOAD SHIFTING - A load shape objective that involves moving loads from peak periods to off-peak periods. If a utility does not expect to meet its demand during peak periods but has excess capacity in the off-peak periods, this strategy might be considered.

LOSS OF LOAD PROBABILITY (LOLP) - A measure of the probability that system demand will exceed capacity during a given period; this period is often expressed as the expected number of days per year over a long period, frequently taken as ten consecutive years. An example of LOLP is one day in ten years.

LOSSES (Electric utility) - Electric energy or capacity that is wasted in the normal operation of a power system. Some kilowatt-hours are lost in the form of waste heat in electrical apparatus such as substation conductors. LINE LOSSES are kilowatts or kilowatt-hours lost in transmission and distribution lines under certain conditions.

M

MARGINAL COST - The sum that has to be paid the next increment of product of service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity. In the utility context, the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.

MARKET-BASED PRICE - A price set by the mutual decisions of many buyers and sellers in a competitive market.

MARKET CLEARING PRICE - The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.

MARKET PARTICIPANT - An entity, including a Scheduling Coordinator, who participates in the energy marketplace through the buying, selling, transmission, or distribution of energy or ancillary services into, out of, or through the ISO-controlled grid.

Market Redesign and Technology Upgrade (MRTU) - represents the largest change to the California wholesale energy market since electric restructuring began in 1998. CAISO has proposed that MRTU become effective in November 2007. Significant efforts will be required by PG&E to implement the systems and software to interface with the CAISO.

MARKETER (For Gas) - Marketers generally purchase gas supplies from producers and then resell them to end-users. Marketers add value and make a profit by saving producers and end-users the trouble of finding each other, arranging transportation and storage, and sometimes by arranging financing or assumption of price risk. Marketers also sometimes market a specific producer's gas without taking title in return for a marketing fee. Numerous marketers currently serve the California market.

MASTER FILE - A file maintained by the PX for use in bidding and bid evaluation protocol that contains information on generating units, loads, and other resources eligible to bid into the PX.

MAXIMUM DEMAND - Highest demand of the load within a specified period of time.

MCF - The quantity of natural gas occupying a volume of one thousand cubic feet at a temperature of sixty degrees Fahrenheit and at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute.

MDQ - The term MDQ refers to maximum daily quantity of gas which a buyer, seller, or transporter is obligated to receive or deliver at each receipt or delivery point or in the aggregate as specified in an agreement.

MEGAWATT (MW) - One thousand kilowatts (1,000 kW) or one million (1,000,000) watts. One megawatt is enough energy to power 1,000 average California homes.

MEGAWATT HOUR (MWh) - One thousand kilowatt-hours, or an amount of electricity that would supply the monthly power needs of 1,000 typical homes in the Western U.S. (This is a rounding up to 8,760 kWh/year per home based on an average of 8,549 kWh used per household per year [U.S. DOE EIA, 1997 annual per capita electricity consumption figures]).

METER - A device for measuring levels and volumes of a customer’s gas and electricity use.

METHANE (CH_4) - The first of the paraffin series of hydrocarbons. The chief constituent of natural gas. Pure methane has a heating value of 1012 Btu per cubic foot.

MINIMUM GENERATION - Generally, the required minimum generation level of a utility system’s thermal units. Specifically, the lowest level of operation of oil-fired and gas-fired units at which they can be currently available to meet peak load needs.

MMBTU - A thermal unit of energy equal to 1,000,000 Btus, that is, the equivalent of 1,000 cubic feet of gas having a heating content of 1,000 Btus per cubic foot, as provided by contract measurement terms. See DEKATHERM.

MMCF - A million cubic feet.

MUNICIPAL UTILITY - A provider of utility services owned and operated by a municipal government.

MUNICIPALIZATION - The process by which a municipal entity assumes responsibility for supplying utility service to its constituents. In supplying electricity, the municipality may generate and distribute the power or purchase wholesale power from other generators and distribute it.

MUST-TAKE GENERATION - Utilities are mandated to take electricity from specific resources identified by the CPUC. Except for Electric Microutilities, the receiver of must-take generation will pay for the electrical energy output of must-take resource even if they refuse to schedule and receive that energy. For this reason, these resources are always economic to receive and scheduled in order to minimize financial loss. Regulatory must-take generation include QF generating units under federal law, nuclear units and pre-existing power-purchase contracts that have minimum-take provisions.

N

NATURAL GAS - Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NATURAL GAS FINANCIAL SWAPS (Purchase or Sale) - Over-the-counter forward products including fixed-for-floating swaps, basis swaps and swing-swaps for gas. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

NATURAL GAS FUTURES (Purchase or Sale) - Standardized forward contracts for gas that trade on an exchange. Futures may be physically or financially settled. Physically settled futures may be unwound by an offsetting trade, exchanged for a physical position, or held to physical delivery.

NATURAL GAS PURCHASES (Physical Supply) - Purchases/sales/exchanges of physical natural gas for terms of one month or longer.

NETWORK - A system of transmission and distribution lines cross-connected and operated to permit multiple power supply to any principal point on it. A network is usually installed in urban areas. It makes it possible to restore power quickly to customers by switching them to another circuit.

NEW-WORLD CONTRACTS - IOU Contracts for electric capacity and energy executed after January 1, 2003 when utilities returned to procurement.

NON-BYPASSABLE CHARGE - charge generally placed on distribution services to recover utility costs incurred as a result of restructuring (stranded costs - usually associated with generation facilities and services) and not recoverable in other ways.

NON-CORE CUSTOMERS - End-users with enough gas volume to justify consideration of transportation-only service from the distributor. Compare CORE CUSTOMERS.

NON-FIRM ENERGY - Electricity that is not required to be delivered or to be taken under the terms of an electric purchase contract.

NON-FTR LOCATIONAL SWAPS - Over-the-counter basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL (NERC) - Council formed by electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply in utility systems of North America. NERC consists of ten regional reliability councils: Alaskan System Coordination Council (ASCC); East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid-America Interconnected Network (MAIN); Mid-Atlantic Area Council (MAAC); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western systems Coordinating Council (WSCC).

NOx - Oxides of nitrogen that are a chief component of air pollution that can be produced by the burning of fossil fuels. Also called nitrogen oxides.

NUCLEAR ENERGY - Power obtained by splitting heavy atoms (fission) or joining light atoms (fusion). A nuclear energy plant uses a controlled atomic chain reaction to produce heat. The heat is used to make steam run conventional turbine generators.

NUCLEAR REGULATORY COMMISSION (NRC) - An independent federal agency that ensures that strict standards of public health and safety, environmental quality and national security are adhered to by individuals and organizations possessing and using radioactive materials. The NRC is the agency that is mandated with licensing and regulating nuclear power plants in the United States. It was formally established in 1975 after its predecessor, the Atomic Energy Commission, was abolished.

NYMEX - New York Mercantile Exchange. The New York Mercantile Exchange, Inc., is the world's largest physical commodity futures exchange and the preeminent trading forum for energy and precious metals.

O

OFF-PEAK - Periods of low demands. All the time outside the on-peak period.

ON-PEAK - Periods of the highest demand.

ON-SITE ENERGY OR CAPACITY (SELF-GENERATION ON CUSTOMER SIDE OF THE METER) – The amount of power measured in MWs or MWhs that can be generated downstream of the customer’s electric meter that can be used to offset the customer’s load served by the electric service provider.

OPTIONS - An option is a contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (for example, a commodity or commodity futures contract), at a fixed price, within a specified period of time. May either be standardized, exchange-traded, and government regulated, or over-the-counter customized and non-regulated.

OUTAGE (Electric utility) - An interruption of electric service that is temporary (minutes or hours) and affects a relatively small area (buildings or city blocks). (See BLACKOUT)

OVER GENERATION - A condition that occurs when total PX participant demand is less that or equal to the sum of regulatory must-take generation, regulatory must-run generation, and reliability must-run generation.

OVERLOAD - The flow of electricity into conductors or devices when normal load exceeds capacity.

P

PARKING SERVICE - Short-term storage of a shipper's excess gas so that shipper doesn't have to sell it in the market.

PARTIAL LOAD - An electrical demand that uses only part of the electrical power available. [See California Code of Regulations, Title 24, Section 2-5342(e) 2]

PEAK DAY CURTAILMENT - Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for gas exceed the maximum daily delivery capability of a pipeline or distribution system. Peak day curtailment is applied independent of seasonal curtailment and does not affect overall authorized volumes to customers under seasonal curtailment.

PEAK DEMAND OR PEAK LOAD - The electric load that corresponds to a maximum level of electric demand in a specified time period.

PEAK FOR OFF-PEAK EXCHANGE – Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period.

PEAKER - A nickname for a power generating station that is normally used to produce extra electricity during peak load times. Typically peaking resources are fully dispatchable and deliver in approximately 10% of hours.

PEAKING CAPACITY - Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads; this equipment is usually designed to meet the portion of load that is above base load.

PG&E (PACIFIC GAS AND ELECTRIC COMPANY) - An electric and natural gas utility serving the central and northern California region.

PHOTOVOLTAICS - A technology that directly converts light into electricity. The process uses modules, which are usually made up of many cells (thin layers of semiconductors).

PHYSICAL CALL (OR PUT) OPTION - The right, but not the obligation, to buy (call) physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to sell is a put option.

PHYSICAL OPTIONS ON NATURAL GAS SUPPLY (Purchase or Sale) - The right, but not the obligation, to buy (call) physical gas for delivery on a particular date at a fixed or index price (strike). The right to sell is a put option.

PIPELINE - A line of pipe with pumping machinery and apparatus (including valves, compressor units, metering stations, regulator stations, etc.) for conveying a liquid or gas.

PIPELINE CAPACITY - The maximum quantity of gas that can be moved through a pipeline system at any given time based on existing service conditions such as available horsepower, pipeline diameter(s), maintenance schedules, regional demand for natural gas, etc.

PIPELINE FUEL - Natural gas consumed in the operation of a natural gas pipeline, primarily in compressors.

POINT(S) OF DELIVERY - Point(s) for interconnection on the Transmission Provider's System where capacity and/or energy are made available to the end user.

PORTFOLIO MANAGEMENT - The functions of resource planning and procurement under a traditional utility structure.

POWER - Electricity for use as energy.

POWER EXCHANGE - This is a commercial entity responsible for facilitating the development of transparent spot prices for energy capacity, and/or ancillary services.

POWER GRID - A network of power lines and associated equipment used to transmit and distribute electricity over a geographic area.

POWER MARKETER - An agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, the difference is that a marketer represents the generator while a broker acts as a middleman.

POWER PLANT - A central station generating facility that produces energy.

POWER PURCHASE AGREEMENT - Specifies the terms and conditions under which electric power will be generated and purchased. Power purchase agreements require the Seller to supply power under specific terms and conditions for the life of the agreement. While power purchase agreements vary, their common elements include: specification of the size, pricing structure, operating flexibility, delivery point, various service and performance obligations; dispatchability options; credit/collateral terms, and conditions of termination or default.

PREFERRED SCHEDULE - The initial schedule produced by a Scheduling Coordinator that represents its preferred mix of generation to meet demand. The schedule includes the quantity of output (generators) and consumption (loads), details of any adjustment bids, and the location of each generator and load. The schedule also specifies the quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators, and is balanced with respect to generation, transmission losses, load, and trades.

PRICE CAP - Situation where a price has been determined and fixed.

PRICE CURVES -

- **Forward Curve (or Futures Price)** - A term structure of forward prices observed in the market. Forward contracts, like futures, are agreements to buy or sell a commodity at a future time. Forward price is the price to be paid at delivery.
- **Price Forecast** - A projection of future price levels (these could be day-ahead prices, futures prices, monthly prices etc.) expressed either in nominal or a given year's dollars, not necessarily reflective of market prices.

PRODUCTION - The act or process of generating electric energy.

PROVIDER OF LAST RESORT - A legal obligation (traditionally given to utilities) to provide service to a customer where competitors have decided they do not want that customer's business.

PUBLIC ADVISOR - An appointee of the governor who attends all meetings of the California Energy Commission and provides assistance to members of the public and intervenors in cases before the Commission.

PUBLICLY OWNED UTILITIES (POUs) - Municipal utilities (utilities owned by branches of local government) and/or co-ops (utilities owned cooperatively by customers).

PUMPED STORAGE - Facility designed to generate electric power during peak load periods with a hydroelectric plant using water pumped into a storage reservoir during off-peak periods.

PURCHASE AND SALE AGREEMENT - The written contract between buyer and seller indicating all terms and conditions of the sale.

PURPA (THE PUBLIC UTILITY REGULATORY ACT OF 1978) - Among other things, this federal legislation requires utilities to buy electric power from private "qualifying facilities," at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced back-up supply of electricity.

PURPA is implemented by the Federal Energy Regulatory Commission and the California Public Utilities Commission (CPUC). Under PURPA each electric utility is required to offer to purchase available electric energy from cogeneration and small power production facilities.

PX - The California Power Exchange Corporation, a state chartered, non-profit corporation charged with providing Day-Ahead and Hour-Ahead markets for energy and ancillary services, if it chooses to self-provide, in accordance with the PX tariff. The PX is a Scheduling Coordinator, and is independent of both the ISO and all other market participants. This exchange is no longer a market participant.

Q

QUALIFYING FACILITY (QF) - "Qualifying facilities" (QFs) are non-utility cogeneration or other power producers that often generate electricity using renewable and alternative resources, such as hydro, wind, solar, geothermal, or biomass (solid waste). QFs must meet certain operating, efficiency, and fuel-use standards set forth by the Federal Energy Regulatory Commission (FERC) pursuant to PURPA (The Public Utility Regulatory Policies Act of 1978).

QUICK-START CAPABILITY - Refers to generating units that can be available for load within a 30-minute period.

R

R-VALUE - A unit of thermal resistance used for comparing insulating values of different material. It is basically a measure of the effectiveness of insulation in stopping heat flow. The higher the R-value number, a material, the greater its insulating properties and the slower the heat flow through it. The specific value needed to insulate a home depends on climate, type of heating system and other factors.

RAMP RATE - The rate at which you can increase load on a power plant. The ramp rate for a hydroelectric facility may be dependent on how rapidly water surface elevation on the river changes.

RAMP UP (SUPPLY SIDE) - Increasing load on a generating unit at a rate called the ramp rate.

REACTIVE POWER AND VOLTAGE CONTROL – Required to maintain adequate transmission system voltage for reliable interconnected system operation.

REAL-TIME (Purchase or Sale) - The amount of energy, measured in MWhs supplied or received by the control area operator to balance an entity's load and supply.

REAL-TIME MARKET - The competitive generation market controlled and coordinated by the ISO for arranging real-time imbalance energy.

REAL-TIME PRICING - The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

REACTOR - A device in which a controlled nuclear chain reaction can be maintained, producing heat energy.

REGULATION - The service provided by generating units equipped and operating with automatic generation controls that enables the units to respond to the ISO's direct digital control signals to match real-time demand and resources, consistent with established operating criteria.

REGULATION AND RAMPING CAPABILITY – The portion of a generating unit's unloaded capability which can be loaded, or loaded capability which can be unloaded, in response to Automatic Generation Control signals from the ISO's energy management system control computer.

RELIABILITY - Electric system reliability has two components -- adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

RELIABILITY MUST-RUN (RMR) AGREEMENTS - A Must-Run Service Agreement between the owner of an RMR Unit and the ISO within geographical areas identified via the Local Area Reliability Service (LARS) process.

RELIABILITY MUST-RUN (RMR) GENERATION - Generation that the ISO determines is required to be on line to meet applicable reliability criteria requirements. This includes:

i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation;
ii) Generation needed to meet load demand in constrained areas; and
iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.

RELIABILITY MUST-RUN (RMR) UNIT - In return for payment, the ISO may call upon the owner of a generating unit under a Reliability Must-Run Agreement to run the unit when required for grid reliability.

RENEWABLE ENERGY - Resources that constantly renew themselves or that are regarded as practically inexhaustible. These include solar, wind, geothermal, hydro and wood. Although particular geothermal formations can be depleted, the natural heat in the earth is a virtually inexhaustible reserve of potential energy. Renewable resources also include some experimental or less-developed sources such as tidal power, sea currents and ocean thermal gradients.

RENEWABLE RESOURCES - Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

REPLACEMENT RESERVE – A quantity of capacity that will ramp up within 60 minutes.

RESERVE - The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its users ¼ needs.

RESERVE CAPACITY - Capacity in excess of that required to carry peak load.

RESERVE MARGIN - The differences between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

RESIDUAL NET LONG FOR CAPACITY (SURPLUS) – When the capacity resources under an LSE’s control exceed the peak hourly demand (MW), including the required planning reserve margin, of the LSE’s customers, the LSE is in a residual net long situation for capacity.

RESIDUAL NET LONG FOR ENERGY - When the energy requirement (kWh or MWh) of the LSE’s customers load, for a given period of time (i.e. hour, month, year, etc), is less than the total energy supply available to serve the LSE’s customers, the LSE is in a residual net long situation for energy.

RESIDUAL NET SHORT FOR CAPACITY (DEFICIT) - When the peak hourly demand (MW), including the required planning reserve margin, of the LSE’s customers exceeds the capacity resources under the LSE’s control, the LSE is in a residual net short situation for capacity.

RESIDUAL NET SHORT FOR ENERGY - When the energy requirement (kWh or MWh) of an LSE’s customer load, for a given time interval (i.e. hour, month, year, etc), is greater than the total energy supply available to serve the LSE’s customers, the LSE is in a residual net short situation for energy.

RESOURCE ADEQUACY - A common term used to describe sufficiency of capacity resources to meet contingencies that may be caused by unexpected energy usage (e.g., heat storm or cold spell), generation outages or transmission constraints.

RESOURCE ADEQUACY PROCEEDING - The CPUC undertook a process of addressing Resource Adequacy (RA) through the implementation of system and local RA standards. The system RA implemented in 2006 requires LSEs to meet a 15% to 17% planning reserve margin within their service territory. More recently, the CPUC implemented local RA standards for 2007, which requires LSEs to meet specific capacity targets (or Local Capacity Requirements known as LCR) within one of the nine transmission constrained areas (or load pockets) located within the ISO’s control area. Both system and local RA standards are in the process of being clarified, modified and potentially expanded through the current RA proceeding (R.05-12-013).

RESOURCE EFFICIENCY - The use of smaller amounts of physical resources to produce the same product or service. Resource efficiency involves a concern for the use of all physical resource sand materials used in the production and use cycle, not just the energy input.

RETAIL COMPETITION - A system under which more than one electric provider can sell to retail customers, and retail customers are allowed to buy from more than one provider. (See also DIRECT ACCESS)

RETAIL MARKET - A market in which electricity and other energy services are sold directly to the end-use customer.

S

SCE (SOUTHERN CALIFORNIA EDISON COMPANY) - An electric utility serving the southern California region.

SDG&E (SAN DIEGO GAS & ELECTRIC) - An electric and natural gas utility serving the San Diego, California, region.

SCHEDULING COORDINATOR - Scheduling coordinators (SCs) submit balanced schedules and provide settlement-ready meter data to the ISO. Scheduling coordinators also:

- Settle with generators and retailers, the PX and the ISO
- Maintain a year-round, 24-hour scheduling center
- Provide non-emergency operating instructions to generators and retailers
- Transfer schedules in and out of the PX. (The PX is a marketplace. As bids are accepted, power is being bought and sold. Once a bid is accepted, the power sold is "transferred out" of the PX, since is it no longer available. Power that is available for sale is "transferred in" to the PX. These transfers may also take place directly between the buyer and seller, without involvement of the PX.)

The PX is considered a scheduling coordinator.

SEASONAL EXCHANGE - Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. Dollars may or may not be exchanged in such a transaction.

SELF-GENERATION - A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

SERVICE, LENDING (BORROWING) - Short-term borrowing of a pipeline or storage provider's working gas by a shipper.

SERVICE AREA - The geographical territory served by a utility.

SERVICE LIFE - The length of time a piece of equipment can be expected to perform at its full capacity.

SERVICE TERRITORY - This is the state, area or region served exclusively by a single electric utility.

SETTLEMENT - The process of financial settlement for products and services purchased and sold. Each settlement involves a price and quantity. Both the ISO and PX may perform settlement functions.

SITE - Any location on which a facility is constructed or is proposed to be constructed.

SMALL POWER PRODUCER - Refers to a producer that generates at least 75% of its energy from renewable sources.

SOLAR ENERGY - Heat and light radiated from the sun.

SPARK SPREAD - The difference between the market price of electricity and its cost of production for a specific natural gas fired generating plant.

SPINNING RESERVE – The portion of unloaded synchronized generating capacity, controlled by the ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

SPOT MARKET - A market in which transactions take place at most one day ahead of scheduled delivery.

SPOT MARKET (For Gas) - A market characterized by short-term, interruptible (or best efforts) contracts for specified volumes of gas. Participants may be any of the elements of the gas industry - producer, transporter, distributor, or end user. Brokers may also be utilized.

SPOT NATURAL GAS (Physical Supply) - Purchases/sales/exchanges of physical natural gas for terms less than one month.

SPOT PRICE - The price for spot transactions. (Also see MARKET CLEARING PRICE)

STORAGE, UNDERGROUND - The utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of load balancing. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be man-made or natural caverns.

STRANDED COSTS - Costs incurred by a utility which may not be recoverable under market-based retail competition. Costs incurred by a utility which may not be recoverable under market-based retail competition.

STRUCTURED TRANSACTIONS - Transactions that involve non-standard provisions for supplying electricity or electricity related products.

SUBSTATION - A facility that steps up or steps down the voltage in utility power lines. Voltage is stepped up where power is sent through long-distance transmission lines. It is stepped down where the power is to enter local distribution lines.

SUMMER - As applied to gas, the period April 1 of one year through October 31 of that same year.

SUMMER PEAK - The greatest load on an electric system during any prescribed demand interval in the summer.

SUPPLIER - A person or corporation, generator, broker, marketer, aggregator or any other entity, that sells electricity to customers, using the transmission or distribution facilities of an electric distribution company.

SUPPLY BID - A bid into the PX indicating a price at which a seller is prepared to sell energy or ancillary services.

SUPPLY-SIDE - Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load though energy efficiency measures or on-site generation on the customer side of the meter.

SURPLUS (Electric utility) - Excess firm energy available from a utility or region for which there is no market at the established rates.

SYSTEM - A combination of equipment and/or controls, accessories, interconnecting means and terminal elements by which energy is transformed to perform a specific function, such as climate control, service water heating, or lighting. [See California Code of Regulations, Title 24, Section 2-5302]

SYSTEM NET ENERGY FORECAST - Energy used by IOU and direct access customers, as measured at generation (includes T&D losses).

SYSTEM PEAK DEMAND - The highest demand value that has occurred during a specified period for the utility system.

T

TEMPERATURE - Degree of hotness or coldness measured on one of several arbitrary scales based on some observable phenomenon (such as the expansion).

TOLLING AGREEMENT – An agreement to provide (receive) gas in exchange for receiving (providing) electricity.

TRANSFER - To move electric energy from one utility system to another over transmission lines.

TRANSFORMER - A device, which through electromagnetic induction but without the use of moving parts, transforms alternating or intermittent electric energy in one circuit into energy of similar type in another circuit, commonly with altered values of voltage and current.

TRANSITION COSTS – Stranded costs which are charged to utility customers through some type of fee or surcharge after the assets are sold or separated from the vertically-integrated utility

TRANSMISSION - Transporting bulk power over long distances.

TRANSMISSION AND DISTRIBUTION (T&D) LOSSES - Electric energy or capacity that is wasted in the normal operation of a power system. Some kilowatt-hours are lost in the form of waste heat in electrical apparatus such as substation transformers. Line losses are kilowatts or kilowatt-hours lost in transmission and distribution of electricity.

TRANSMISSION AND DISTRIBUTION (T&D) SYSTEM - An interconnected group of electric transmission lines and associated equipment for the movement or transfer or electric energy in bulk between points of supply and points at which it is transformed for delivery to the ultimate customers.

TRANSMISSION LINES - Heavy wires that carry large amounts of electricity over long distances from a generating station to places where electricity is needed. Transmission lines are held high above the ground on tall towers called transmission towers.

TRANSMISSION OWNER - An entity that owns transmission facilities or has firm contractual right to use transmission facilities.

TURBINE GENERATOR - A device that uses steam, heated gases, water flow or wind to cause spinning motion that activates electromagnetic forces and generates electricity.

U

UPGRADE (Electric utility) - Replacement or addition of electrical equipment resulting in increased generation or transmission capability.

U.S. DEPARTMENT OF ENERGY (DOE) - The DOE manages programs of research, development and commercialization for various energy technologies, and associated environmental, regulatory and defense programs. DOE announces energy policies and acts as a principal advisor to the President on energy matters.

UNCERTAINTIES - Uncertainties are factors over which the utility has little or no foreknowledge, and include load growth, fuel prices, or regulatory changes. Uncertainties are modeled in a probabilistic manner. However, in the Detailed Workbook, you may find it is more convenient to treat uncertainties as "unknown but bounded" variables without assuming a probabilistic structure. A specified uncertainty is a specific value taken on by an uncertainty factor (e.g. 3 percent per year for load growth). A future uncertainty is a combination of specified uncertainties (e.g. 3 percent per year load growth, 1 percent per year real coal and oil price escalation, and 2.5 percent increase in housing starts).

UNSERVED ENERGY - The average energy that will be demanded but not served during a specified period due to inadequate available generating capacity.

UPGRADE - An increase in the rating or stated measure of generation or transfer capability.

UTILITY - A regulated entity which exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.

UTILITY-OWNED GENERATION - Resources owned by an investor-owned utility. Does not include resources that may be under contract or otherwise available to utilities, such as DWR contracts.

V

VARIABLE COSTS - Costs, such as fuel costs, that depend upon the amount of electric energy supplied.

W

WASTE-TO-ENERGY - This is a technology that uses refuse to generate electricity. In mass burn plants, untreated waste is burned to produce steam, which is used to drive a steam turbine generator. In refuse-derived fuel plants, refuse is pre-treated, partially to enhance its energy content prior to burning.

WEATHER SCENARIOS – 1:5, 1:10, & 1:20 - Forecasts of expected highest demand (MW) under different weather scenarios. 1:2 means average weather conditions. 1:5, 1:10, 1:20 mean probability of hot temperature (one in every five, ten or twenty years).

WEATHER TRIGGERED OPTIONS - A method for managing temperature and other weather forecast risks.

WHEELING - The transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially as meaning transmission.

WHOLESALE COMPETITION - A system whereby a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

WHOLESALE POWER MARKET - The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

WINTER - As applied to gas, the period November 1 of one year through March 31 of the following year.

WINTER PEAK - The greatest load on an electric system during any prescribed demand interval in the winter season or months.

WIRES CHARGE - A broad term which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

X

X-RAY - A type of electromagnetic radiation having low energy levels.

Y

No entries for the letter Y.

Z

No entries for the letter Z.

List of Sources:

1. http://www.energy.ca.gov/glossary/
2. http://www.energycentral.com/sections/directories/glossary/
3. http://www.eia.doe.gov/glossary/index.html
4. CPUC Decisions (D.) 02-10-062, 03-12-062, 04-12-048, and 06-06-066
5. Advice Letter E-2615
6. http://www.aga.org
7. http://www.pge.com

APPENDIX K

UPDATED ACRONYM LIST

Acronym	Full Name
2003 STPP	2003 Short Term Procurement Plan
2004 LTPP	2004 Long Term Procurement Plan
2004 LTRFO	2004 Long-Term Request for Offers
2004 STPP	2004 Short-Term Procurement Plans
2006 LTPP	2006 Long-Term Procurement Plan
A.	Application
A/C	Air Conditioning
AB	Assembly Bill
AB 117	Assembly Bill 117
AB 32	Assembly Bill 32
AB 380	Assembly Bill 380
AB 57	Assembly Bill 57
AC	Alternating Current
AFC	Application for Certification
AGC	Automatic Generation Control
AL	Advice Letter
ALJ	Administrative Law Judge
APD	Abnormal Peak Day
APT	Annual Procurement Targets
ARR	Auction Revenue Rights

Acronym	Full Name
AS	Ancillary Services
BC	British Columbia
BC-California	British Columbia-California
BCF/D	Billion Cubic Feet per Day
BEC	Business Energy Coalition
BIP	Base Interruptible Program
BOM	Balance of Month
BPM	Business Practice Manual
Btu	British Thermal Unit
BUG	Back-up Generation
CAISO	California Independent System Operator Corporation
CBP	Capacity Bidding Program
CC8	Contra Costa 8
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CCSF	City and County of San Francisco
CEC	California Energy Commission
CEE	Customer Energy Efficiency
CEQA	California Environmental Quality Act
CEUS	Commercial End Use Surveys
CG	Customer Generation

Acronym	Full Name
CGT	California Gas Transmission
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COB	California-Oregon Border
COD	Commercial Operations Date
COI	California-Oregon Intertie
Commission	California Public Utilities Commission
CPA	California Consumer Power and Conservation Financing Authority
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CRR	Congestion Revenue Rights
CRT	Consumer Risk Tolerance
CSI	California Solar Initiative
CSM	Cafeteria Style Menu
CT	Combustion Turbine
CTC	Competitive Transmission Charge
CWD	Cold Winter Day
D.	Decision
DA	Direct Access

Acronym	Full Name
DBP	Demand Bidding Program
DCPP	Diablo Canyon Power Plant
DG	Distributed Generation
DLC	Direct Load Control
DOC	Department of Commerce
DOE	U.S. Department of Energy
DR	Demand Response
DRA	Division of Ratepayer Advocates
DRP	Demand Response Program
DSA	Division of the State Architect
DSM	Demand Side Management
DWR	California Department of Water Resources
EAP	Energy Action Plan
EAP II	Energy Action Plan II
ECAR	East Central Area Reliability Coordination Agreement
ED	Energy Division
EE	Energy Efficiency
EEI	Edison Electric Institute
EIA	Energy Information Agency
EIF	Energy Investors Funds
ENS	Energy Not Served

Acronym	Full Name
EP	PG&E's Energy Procurement organization
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPPA	Energy Policy, Planning & Analysis
EPRI	Electric Power Research Institute
EPS	Emissions Performance Standard
EQR	Electronic Quarterly Report
ERCOT	Electric Reliability Council of Texas
ERRA	Energy Resource Recovery Account
ERRP	Emerging Renewable Resource Program
ESP	Energy Service Provider
EUP	Enriched Uranium Product
FCM	Futures Commission Merchant
FERC	Federal Energy Regulatory Commission
FRR	Frequency Reserve Requirements
FS	Facility Study
FTR	Firm Transmission Rights
GDP-IPD	Gross Domestic Product Implicit Price Deflator
GHG	Greenhouse Gas
GHP	Gas Hedging Plan
GRC TY	General Rate Case Test Year

Acronym	Full Name
GTN	Gas Transmission Northwest
GW	Gigawatt
GWH	Gigawatt-hour
GWP	Global Warming Potential
HASP	Hour Ahead Scheduling Process
HBPP	Humboldt Bay Power Plant
HHV	High Heat Value
HVAC	Heating Ventilation and Air-Conditioning
HVDC	High Voltage Direct Current
ICE	Intercontinental Exchange
ID	Irrigation Districts
IDSM	Integrated Demand Side Management
IE	Independent Evaluator
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IM	Instant Messaging
IOU	Investor-owned Utility
IPP	Independent Power Producer
IPT	Incremental Procurement Target
IRP	Integrated Resource Plan
ITC	Investment Tax Credit

Acronym	Full Name
IVSG	Imperial Valley Study Group
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LAR	Local Area Resource Requirement
LARS	Local Area Reliability Service
LBNL	Lawrence Berkeley National Labs
LCR	Local Capacity Requirement
LEED	Leadership Energy Environmental Design
LGIP	Large Generation Interconnection Process
LIEE	Low Income Energy Efficiency
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LSE	Load-serving Entity
LT	Long Term
LT-CRR	Long-Term Congestion Reverse Rights
LT-FTR	Long Term Firm Transmission Rights
LTPP	Long-Term Procurement Plan

Acronym	Full Name
LTRFO	Long Term Request for Offers
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MMBtu	Millions of British Thermal Units
MORC	Minimum Operating Reliability Criteria
MPR	Market Price Referant
MRTU	Market Redesign and Technology Upgrade
MW	Megawatt
MWD	Metropolitan Water District
MWh	Megawatt-hour
NBC	Non-bypassable Charge
NCBA	Net Cost Balancing Account
NERC	North American Electric Reliability Council
NGX	Natural Gas Exchange
NOI	Notice of Intent
Non-FTR	Non-Firm Transmission Rights
NP15	North of Path-15
NP26	North of Path-26
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission

Acronym	Full Name
NRDC	Natural Resources Defense Council
NW	Pacific Northwest
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
OASIS	Open Access Same-time Information Systems
OFO	Operational Flow Order
OII	Order Instituting Investigation
OP	Ordering Paragraph
PAC	Project Advisory Committee
PG&E	Pacific Gas and Electric Company
PHEV	Plug-In Hybrid Electric Vehicles
PLR	Potential Load Reduction
POU	Publicly Owned Utility
PP	Procurement Plan
PPA	Power Purchase Agreement
PRG	Procurement Review Group
PRM	Planning Reserve Margin
PRRA	Preliminary Renewable Resources Assessment
PSA	Purchase and Sale Agreement
PSPL	Puget Sound Power and Light
PTC	Production Tax Credit

Acronym	Full Name
PTO	Participating Transmission Owner
PURPA	Public Utility Regulatory Policy Act of 1978
PX	Power Exchange
QF	Qualifying Facility
QF-SRAC	Qualifying Facility-Short Run Avoided Costs
R.	Rulemaking
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RCST	Reliability Capacity Services Tariff
REC	Renewable Energy Credit
RFB	Request for Bids
RFO	Request for Offer
RFP	Request for Proposal
RMR	Reliability Must-Run
RNS	Residual Net Short
RPS	Renewable Portfolio Standard
RRDR	Renewable Resource Development Report
RUC	Residual Unit Commitment
SB	Senate Bill
SB 1	Senate Bill 1
SB 107	Senate Bill 107

Acronym	Full Name
SB 1368	Senate Bill 1368
SC	Scheduling Coordinator
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SEP	Supplemental Energy Payments
SERC	Southeastern Electric Reliability Council
SGIP	Small Generation Interconnection Program
SI	Strategic Inventory
SIS	System Impact Study
SO1	Standard Offer 1
SOX	Sarbanes-Oxley
SP26	South of Path 26
SPP	Statewide Pricing Pilot
SRAC	Short-Run Avoided Costs
SRP	School Resources Program
SRS	Secondary Registrations System
STPP	Short Term Procurement Plan
SVA	Strategic Value Analysis
SWU	Separative Work Unit
T&D	Transmission and Distribution
TA	Technical Assistance

Acronym	Full Name
TA/TI	Technical Assistance and Technical Incentives
TCSG	Tehachapi Collaborative Study Group
TeVaR	To-expiration-Value-at-Risk
TI	Technical Incentive
TOU	Time-of-Use
TRC	Total Resource Cost
TRCR	Transmission Ranking Cost Report
TXU	TXU Generation Company LP
U.S.	United States
UAFCB	Utility Audit and Finance Compliance Branch
UFE	Unaccounted For Energy
UFR	Underfrequency Relay
URG	Utility Retained Generation
VOM	Variable operations and maintenance
WACC	Weighted Average Cost of Capital
WAPA	Western Area Power Administration
WCSB	Western Canadian Sedimentary Basin
WECC	Western Electric Coordinating Council
WNA	World Nuclear Association
WSCC	Western Systems Coordinating Council
WSPP	Western Systems Power Pool

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Advice Filing List
General Order 96-B, Section IV

ABAG Power Pool
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Aglet Consumer Alliance
Agnews Developmental Center
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Applied Power Technologies
APS Energy Services Co Inc
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Bartle Wells Associates
Blue Ridge Gas
Bohannon Development Co
BP Energy Company
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CA League of Food Processors
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DGS Natural Gas Services
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Duke Energy North America
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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
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International Power Technology
Interstate Gas Services, Inc.
IUCG/Sunshine Design LLC
J. R. Wood, Inc
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Matthew V. Brady & Associates
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Mirant California, LLC
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New United Motor Mfg, Inc
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PPL EnergyPlus, LLC
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Recon Research
Regional Cogeneration Service
RMC Lonestar
Sacramento Municipal Utility District
SCD Energy Solutions
Seattle City Light
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