STATE OF CALIFORNIA

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

Edmund G. Brown Jr., *Governor*

August 15, 2011

Advice Letter 3200-G

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

Subject: Implementation of the Gas Accord V Settlement Agreement and May 1, 2011 NonCore Gas Transportation and Gas Accord V Rate Changes

Dear Mr. Cherry:

Advice Letter 3200-G is approved. The tariff sheets contained in PG&E AL 3200-G shall go into effect on the effective date shown on each tariff sheet as filed in the AL; either January 1, 2011 or May 1, 2011.

Sincerely,

Julie A. Fitch, Director
Energy Division

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulation and Rates

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

Fax: 415.973.6520

April 22, 2011

Advice 3200-G
(Pacific Gas and Electric Company ID U 39 G)

Public Utilities Commission of the State of California

Subject: **Implementation of the Gas Accord V Settlement Agreement and May 1, 2011 Noncore Gas Transportation and Gas Accord V Rate Changes**

Pacific Gas and Electric Company ("PG&E") hereby submits for filing revisions to its gas tariffs. The affected tariff sheets are listed on the enclosed Attachment 1.

Purpose

The purpose of this advice letter is to implement the Gas Accord V (GAV) Settlement Agreement and the associated noncore transportation rate tariffs, as well as the non-rate tariffs, pursuant to the California Public Utilities Commission (CPUC) Decision (D.) 11-04-031. A separate advice letter for core transportation rate changes will be submitted on April 25, 2011, along with PG&E's monthly gas pricing rate changes. PG&E seeks a January 1, 2011 effective date for the tariff changes associated with revenue requirements and balancing accounts, consistent with D.10-12-037[1]. PG&E seeks a May 1, 2011 effective date for tariff changes associated with rates.

Background

On August 20, 2010, PG&E and 24 other settling parties submitted a Joint Motion of Settlement Parties for Approval of the "Gas Accord V" Settlement Agreement. On April 14, 2011, CPUC D. 11-04-031 granted the motion and approved the GAV Settlement Agreement without modification. Ordering Paragraph (OP) 2 of D. 11-04-031 states that the pro forma tariff sheets contained in the Joint Motion may be used as a basis for an advice letter filing to implement the GAV Settlement

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[1] D.10-12-037, issued on December 16, 2010, recognized that a decision setting 2011 GT&S rates would not be adopted by the end of 2010. Ordering Paragraph 1 of D.10-12-037 therefore allowed the revenue requirements (and other elements of the GAV Settlement Agreement that are inextricably linked to the revenue requirements) to be deemed effective as of January 1, 2011.

Agreement. In addition, OP 3 states that PG&E must file necessary advice letters with the Energy Division under Tier 1 of General Order 96-B to implement and carry out the terms of the GAV Settlement Agreement, and to present the necessary tariff revisions. This advice letter 3200-G is filed pursuant to OPs 2 and 3 of D. 11-04-031.

The GAV Settlement Agreement sets the revenue requirements and the rates for each of the four Gas Transmission and Storage (GT&S) functions — backbone transmission, local transmission, gas storage, and the Customer Access Charge — for 2011, 2012, 2013 and 2014. Under the GAV Settlement Agreement, the total 2011 GT&S revenue requirement is $514.2 million.[2] OP 4 of D.11-04-031 authorizes PG&E to collect the 2011 GT&S revenue requirement over the remaining months of 2011 pursuant to D.10-12-037. Accordingly, PG&E has adjusted its 2011 GAV rates upward or downward, as appropriate, to account for late (May 1, 2011) implementation of the GAV Settlement Agreement. PG&E will implement the revenue requirements and rates adopted for 2012, 2013 and 2014, including potential backbone and local transmission rate "adders," balancing account and revenue sharing balances, and other rate adjustments as allowed by the GAV Settlement Agreement in conjunction with PG&E's Annual Gas True-Up advice filing for each year.

As stated in Section 7.5 of the GAV Settlement Agreement, certain costs determined in other proceedings can affect the GAV revenue requirements and rates. These proceedings include PG&E's General Rate Case (GRC), Pension Recovery Proceeding, and Cost of Capital Proceeding (or Annual Cost of Capital Adjustment Mechanism). The Settlement Agreement provided for the possibility that a CPUC Decision in those proceedings might be rendered after implementation of GAV. The Settlement Agreement therefore established a balancing account (called Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP)) to record the difference in revenue requirements associated with the costs determined in other PG&E proceedings and the placeholder amounts for these costs included in the GAV Settlement Agreement. PG&E intends to use this balancing account to refund to or collect from customers the appropriate changes to costs determined in other proceedings.[3]

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[2] The 2011 revenue requirement and rate increase include the Line 406 local transmission "adder" project, which PG&E put into service in late 2010, and therefore qualifies for recovery in 2011 pursuant to Section 7.4 of the GAV Settlement Agreement.

[3] PG&E's Annual Cost of Capital Adjustment Mechanism produced no changes to the Utility's cost of capital parameters for 2011. PG&E's 2011 GRC is still pending a decision at the Commission. GAV revenue requirements reflect the final decision received in PG&E's last Pension Recovery Proceeding and certain allocation factors submitted as part of PG&E's 2011 GRC Notice of Intent (NOI). Final allocation factors are pending a decision in PG&E's 2011 GRC.

Tariff Revisions

Pro forma tariff sheets for the non-rate changes were submitted with the GAV Settlement Agreement. Three of the tariffs (Gas Rule 14, Gas Rule 21, and Gas Schedule G-WSL) contain revisions to currently established tariffs. Six tariffs are new (TID Almond Power Plant Balancing Account, Integrity Management Expense Balancing Account, Electricity Cost Balancing Account, Topock Adder Projects Balancing Account, Adjustment Mechanism for Costs Determined in Other Proceedings, and Gas Transmission & Storage Revenue Sharing Mechanism).

The following tariff sheets have been updated from the *pro forma* versions submitted with the GAV Settlement Agreement to accommodate the terms of the settlement and/or provide clarification to the entries related to the new accounts. PG&E submits these tariffs in compliance with OP 2 of D. 11-04-031.

- ***Gas Rule No. 21 – Transportation of Natural Gas (Sheet 3)***
  The GAV Settlement Agreement replaces the annual Core Distribution in-kind shrinkage allowance with seasonal allowances. On April 19, 2011, the CPUC approved PG&E's advice letter 3194-G for revisions to natural gas in-kind shrinkage allowances for backbone transmission and distribution service, effective May 1, 2011. Footnote 4 of advice letter 3194-G described the seasonal Core Distribution shrinkage allowances applicable upon implementation of the GAV Settlement Agreement. Accordingly, PG&E is updating Sheet 3 of Gas Rule 21 to reflect the seasonal Core Distribution shrinkage allowances approved in advice letter 3194-G. These allowances, including the proposed in-kind shrinkage credit adjustment, are 0.9% for summer (April-October) and 1.6% for winter (November-March).

- ***Gas Schedule G-WSL – Gas Transportation Service to Wholesale/ Resale Customers (Sheet 2)***
  The GAV Settlement Agreement, Section 3.3, provides that existing wholesale customers will have a one-time option prior to April 1, 2011, to subscribe to their allocation of core vintage Redwood and/or core Baja firm capacity for the Settlement Period at the same rate paid by CGS (Core Gas Supply). Due to the timing of D.11-04-031, PG&E sent letters to all existing wholesale customers on April 15, 2011 notifying them that this one-time option has been extended and must be exercised by June 1, 2011.

- ***TID Almond Power Plant Balancing Account (TIDBA)***
  The TIDBA preliminary statement has been updated to reflect the assignment of Part CK and to reflect the final decision number D.11-04-031.

- ***Integrity Management Expense Balancing Account (IMEBA)***
  The IMEBA preliminary statement has been updated to reflect the assignment of Part CL, to reflect the final decision number D.11-04-031, and to clarify that entry 5.b. should reflect "actual" integrity management expenses incurred for the current month.

- ***Electricity Cost Balancing Account (ECBA)***
  The ECBA preliminary statement has been updated to reflect the assignment of Part CM, to reflect the final decision number D.11-04-031, and to clarify that entry 5.b. should reflect "actual" expenses incurred for the current month.

- ***Topock Adder Projects Balancing Account (TAPBA)***
  The TAPBA preliminary statement has been updated to reflect the assignment of Part CN, to reflect the final decision number D.11-04-031, and to clarify that entry 5.b. should reflect the "revenue requirement" amount included in rates.

- ***Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP)***
  The AMCDOP preliminary statement has been updated to reflect the assignment of Part CO, to reflect the final decision number D.11-04-031, and to add a description of the fifth subaccount (Other GRC Costs Subaccount).

- ***Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM)***
  The GTSRSM preliminary statement has been updated to reflect the assignment of Part CP, to reflect the final decision number D.11-04-031, and to clarify additional language in the tariff. The clarifying language conforms to the understanding of the mechanics of the account as agreed upon by the Settlement Parties. Language has been added to make clear that the Backbone Subaccount revenue requirement to be recorded is inclusive of the portion of the Local Transmission bill credits recovered through the surcharge on backbone rates. Similarly, language has been added to make clear that the Local Transmission Subaccount revenue requirement to be recorded excludes the Local Transmission bill credits. In addition, language has been added to make clear that Rate Schedule G-XF is subject to incremental ratemaking and therefore not included in the calculation of the GTSRSM. Finally, clarification has been added to entries 5.a.1., 5.b.1., 5.c.1., and 5.d.1. to reflect the recording of "one-twelfth" of the authorized annual revenue requirements or seed value embedded in rates, as appropriate.

All other rate schedules reflecting noncore transportation rate changes and preliminary statement changes typically included in PG&E's Annual Gas True-up of Transportation Balancing Accounts, some of which are described below, are also filed herein.

PG&E updates Preliminary Statement Part B for noncore customer class schedules to reflect the changes to noncore transportation rates submitted herein.

PG&E updates Preliminary Statement Part C to reflect the changes in authorized gas transportation, illustrative gas procurement, and Gas Accord revenue requirements; to reflect a change in terminology from "non-cycled storage gas" to "PG&E working gas in storage," which is a more accurate designation; to reflect the changes in certain authorized cost allocation factors; to reflect the addition of the new balancing accounts, as appropriate; and to reflect the new core distribution seasonal shrinkage dates. The resulting core transportation rates included in this advice letter will be incorporated into PG&E's separate advice letter filing on April 25, 2011, which is PG&E's core procurement monthly pricing filing and includes all tariff changes to core rates effective May 1, 2011.

PG&E updates entry 6.b.6. of Preliminary Statement Part F, the Core Fixed Cost Account, to reflect that the GAV 2011 allocation to Core of the Local Transmission revenue requirement is 65.907 percent.

PG&E updates entry 6.b. of Preliminary Statement Part AG, the Core Firm Storage Account, to reflect a change in terminology from "non-cycled storage gas" to "PG&E working gas in storage," which is a more accurate designation.

PG&E updates entry 6.a.5. of Preliminary Statement Part J, the Noncore Customer Class Charge Account, to reflect that the GAV 2011 allocation to Noncore of the Local Transmission revenue requirement is 34.093 percent.

Attachment 2 provides a summary of average rates and revenue requirement allocations across customer classes.

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 **May 12, 2011,** which is 20 days from the date of this filing. 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 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, Regulation and Rates
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-6520
E-mail: PGETariffs@pge.com

Effective Date

In accordance with OP 4 of D.11-04-031 and OP 1 of D.10-12-037, PG&E requests that this advice filing, upon Energy Division approval, become effective **January 1, 2011**, except for rate changes for which PG&E requests an effective date of **May 1, 2011**.

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 service list for A.09-09-013. Address changes to the General Order 96-B service list and all electronic approvals should be directed to e-mail PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Advice letter filings can also be accessed electronically at http://www.pge.com/tariffs/.

Brian Cherry /BCD

Vice President – Regulation and Rates

cc: Service List – 2011 Gas Transmission and Storage Proceeding (A.09-09-013)

Attachments

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: Conor Doyle
☑ ELC ☑ GAS	Phone #: 415-973-7817
☐ PLC ☐ HEAT ☐ WATER	E-mail: jcdt@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) #: **3200-G** **Tier: 1**

Subject of AL: **Implementation of the Gas Accord V Settlement Agreement and May 1, 2011 Noncore Gas Transportation and Gas Accord V Rate Changes**

Keywords (choose from CPUC listing): **Non-Core, Balancing Account, Transportation Rates**

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: **D.11-04-031, D.10-12-037**

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:

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: ____

Resolution Required? ☐ Yes ☑No

Requested effective date: **January 1, 2011 and May 1, 2011** No. of tariff sheets: **64**

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: Gas Rate Schedules **G-EG, G-NGV4, G-NT, G-WSL, G-AA, G-AAOFF, G-AFT, G-AFTOFF, G-BAL, GCFS, G-LEND, G-LNG, G-NAS, G-NFS, G-PARK, G-SFS, G-SFT, and G-XF. Gas Preliminary Statements B, C, J, F, AG, CK, CL, CM, CN, CO, CP. Gas Rules 14, and 21.**

Service affected and changes proposed:

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 Cherry, Vice President, Regulation and Rates
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
28867-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 12	28676-G
28868-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 13	28677-G
28869-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 14	28678-G
28870-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 15	28679-G
28871-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 16	28680-G
28872-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 17	28681-G
28873-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 18	28682-G
28874-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 19	28683-G
28875-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 20	28844-G
28876-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 1	23345-G
28877-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 2	28685-G
28878-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 3	28686-G

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
28879-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 4	28687-G
28880-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 6	23347-G
28881-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 7	23760-G
28882-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 8	27453-G
28883-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 9	24431-G
28884-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 11	23561-G
28885-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 12	23795-G
28886-G	GAS PRELIMINARY STATEMENT PART F CORE FIXED COST ACCOUNT Sheet 3	27764-G
28887-G	GAS PRELIMINARY STATEMENT PART J NONCORE CUSTOMER CLASS CHARGE ACCOUNT Sheet 2	25108-G
28888-G	GAS PRELIMINARY STATEMENT PART AG CORE FIRM STORAGE ACCOUNT Sheet 1	23280-G
28889-G	GAS PRELIMINARY STATEMENT PART CK TID ALMOND POWER PLANT BALANCING ACCOUNT Sheet 1	

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
28890-G	GAS PRELIMINARY STATEMENT PART CK TID ALMOND POWER PLANT BALANCING ACCOUNT Sheet 2	
28891-G	GAS PRELIMINARY STATEMENT PART CL INTEGRITY MANAGEMENT EXPENSE BALANCING ACCOUNT Sheet 1	
28892-G	GAS PRELIMINARY STATEMENT PART CM ELECTRICITY COST BALANCING ACCOUNT Sheet 1	
28893-G	GAS PRELIMINARY STATEMENT PART CN TOPOC ADDER PROJECTS BALANCING ACCOUNT Sheet 1	
28894-G	PRELIMINARY STATEMENT PART CO ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS Sheet 1	
28895-G	PRELIMINARY STATEMENT PART CO ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS Sheet 2	
28896-G	PRELIMINARY STATEMENT PART CO ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS Sheet 3	
28897-G	PRELIMINARY STATEMENT PART CO ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS Sheet 4	
28898-G	GAS PRELIMINARY STATEMENT PART CP GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM Sheet 1	

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
28899-G	GAS PRELIMINARY STATEMENT PART CP GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM Sheet 2	
28900-G	GAS PRELIMINARY STATEMENT PART CP GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM Sheet 3	
28901-G	GAS PRELIMINARY STATEMENT PART CP GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM Sheet 4	
28902-G	GAS SCHEDULE G-AA AS AVAILABLE TRANSPORTATION ON-SYSTEM Sheet 2	27962-G
28903-G	GAS SCHEDULE G-AAOFF AS-AVAILABLE TRANSPORTATION OFF-SYSTEM Sheet 2	27963-G
28904-G	GAS SCHEDULE G-AFT ANNUAL FIRM TRANSPORTATION ON-SYSTEM Sheet 2	27959-G
28905-G	GAS SCHEDULE G-AFTOFF ANNUAL FIRM TRANSPORTATION OFF-SYSTEM Sheet 2	27960-G
28906-G	GAS SCHEDULE G-BAL GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS Sheet 4	22047-G
28907-G	GAS SCHEDULE G-CFS CORE FIRM STORAGE Sheet 1	24590-G
28908-G	GAS SCHEDULE G-EG GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION Sheet 1	28688-G

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
28909-G	GAS SCHEDULE G-LEND MARKET CENTER LENDING SERVICES Sheet 1	24598-G
28910-G	GAS SCHEDULE G-NAS NEGOTIATED AS-AVAILABLE STORAGE SERVICE Sheet 1	24589-G
28911-G	GAS SCHEDULE G-NFS NEGOTIATED FIRM STORAGE SERVICE Sheet 1	24588-G
28912-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 1	27656-G
28913-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 2	28690-G
28914-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 1	24583-G
28915-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 2	28691-G
28916-G	GAS SCHEDULE G-PARK MARKET CENTER PARKING SERVICES Sheet 1	24597-G
28917-G	GAS SCHEDULE G-SFS STANDARD FIRM STORAGE SERVICE Sheet 1	24587-G
28918-G	GAS SCHEDULE G-SFT SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY Sheet 2	27961-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
28919-G	GAS SCHEDULE G-WSL GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS Sheet 1	28692-G
28920-G	GAS SCHEDULE G-WSL GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS Sheet 2	26781-G
28921-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 1	27964-G
28922-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 2	27965-G
28923-G	GAS RULE NO. 14 CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE Sheet 16	28284-G
28924-G	GAS RULE NO. 21 TRANSPORTATION OF NATURAL GAS Sheet 3	28813-G
28925-G	GAS TABLE OF CONTENTS Sheet 1	28865-G
28926-G	GAS TABLE OF CONTENTS Sheet 2	28866-G
28927-G	GAS TABLE OF CONTENTS Sheet 3	28862-G
28928-G	GAS TABLE OF CONTENTS Sheet 4	28863-G
28929-G	GAS TABLE OF CONTENTS Sheet 5	28672-G
28930-G	GAS TABLE OF CONTENTS Sheet 6	28815-G

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 12

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 1

	G-NT TRANSMISSION	G-NT—DISTRIBUTION SUMMER			
THERMS:		0-20,833	20,834-49,999	50,000-166,666	166,667-249,999*
NCA – NONCORE	0.00466	0.00466	0.00466	0.00466	0.00466
NCA – INTERIM RELIEF AND DISTRIBUTION	(0.00013)	(0.00214)	(0.00214)	(0.00214)	(0.00214)
CPUC FEE**	0.00069	0.00069	0.00069	0.00069	0.00069
EOR	0.00000	0.00000	0.00000	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00013	0.00013	0.00013	0.00013
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00585	0.12601 (I)	0.08033 (I)	0.07100 (I)	0.06370 (I)
TOTAL RATE	**0.03246 (I)**	**0.15074 (I)**	**0.10506 (I)**	**0.09573 (I)**	**0.08843 (I)**

* Rate components for G-NT Distribution over 249,999 therms are the same as G-NT Transmission.

** The CPUC Fee includes a $0.00068 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U).

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 13

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 2

	G-NT BACKBONE	G-NT—DISTRIBUTION WINTER			
THERMS:		0-20,833	20,834-49,999	50,000-166,666	166,667-249,999*
NCA – NONCORE	0.00465	0.00466	0.00466	0.00466	0.00466
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000	(0.00214)	(0.00214)	(0.00214)	(0.00214)
CPUC FEE**	0.00069	0.00069	0.00069	0.00069	0.00069
EOR	0.00000	0.00000	0.00000	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00013	0.00013	0.00013	0.00013
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	0.00065 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000	0.17012 (I)	0.10845 (I)	0.09585 (I)	0.08600 (I)
TOTAL RATE	**0.00599 (I)**	**0.19485 (I)**	**0.13318 (I)**	**0.12058 (I)**	**0.11073 (I)**

* Rate components for G-NT Distribution over 249,999 therms are the same as G-NT Transmission.

** The CPUC Fee includes a $0.00068 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U).

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 14

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

NONCORE p. 3

	G-EG (3)*	G-EG BACKBONE
NCA – NONCORE	0.00466	0.00466
NCA – INTERIM RELIEF AND DISTRIBUTION	(0.00004)	(0.00004)
CPUC FEE*	0.00003	0.00003
EOR	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00000
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	0.02139 (I)	0.00065 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00183	0.00183
TOTAL RATE	**0.02787 (I)**	**0.00713 (I)**

* Refer to footnotes at end of Noncore Default Tariff Rate Components.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

NONCORE p. 4

	G-WSL			
	Palo Alto-T	Coalinga-T	Island Energy-T	Alpine-T
NCA – NONCORE	0.00375	0.00375	0.00375	0.00375
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000	0.00000	0.00000	0.00000
CPUC FEE*	0.00000	0.00000	0.00000	0.00000
EOR	0.00000	0.00000	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00000	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000	0.00000	0.00000	0.00000
TOTAL RATE	**0.02514 (I)**	**0.02514 (I)**	**0.02514(I)**	**0.02514 (I)**

* The CPUC Fee does not apply to customers on Schedule G-WSL.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

	G-WSL		
	West Coast Mather-T	West Coast Mather-D	West Coast Castle-D
NCA – NONCORE	0.00375	0.00375	0.00375
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000	(0.00130)	(0.00155)
CPUC FEE*	0.00000	0.00000	0.00000
EOR	0.00000	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.02139 (I)	0.02139 (I)	0.02139 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000	0.09318	0.07094
TOTAL RATE	**0.02514 (I)**	**0.11702 (I)**	**0.09453 (I)**

* The CPUC Fee does not apply to customers on Schedule G-WSL.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

NONCORE p. 6

	G-NGV4 TRANSMISSION	G-NGV4—DISTRIBUTION SUMMER			
THERMS:		0- 20,833	20,834- 49,999	50,000- 166,666	166,667- 249,999
NCA – NONCORE	0.00465	0.00466	0.00466	0.00466	0.00466
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000	(0.00214)	(0.00214)	(0.00214)	(0.00214)
CPUC FEE**	0.00069	0.00069	0.00069	0.00069	0.00069
EOR	0.00000	0.00000	0.00000	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00013	0.00013	0.00013	0.00013
NGV BALANCING ACCOUNT	0.00000	0.00000	0.00000	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000	0.12601 (I)	0.08033 (I)	0.07100 (I)	0.06370 (I)
TOTAL RATE	**0.02673 (I)**	**0.15074 (I)**	**0.10506 (I)**	**0.09573 (I)**	**0.08843 (I)**

* Refer to footnotes at end of Noncore Default Tariff Rate Components.

** The CPUC Fee includes a $0.00068 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U).

(Continued)

GAS PRELIMINARY STATEMENT PART B Sheet 18
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 7

	G-NGV4 BACKBONE	G—NGV4-DISTRIBUTION WINTER			
THERMS:		0-20,833	20,834-49,999	50,000-166,666	166,667-249,999
NCA – NONCORE	0.00465	0.00466	0.00466	0.00466	0.00466
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000	(0.00214)	(0.00214)	(0.00214)	(0.00214)
CPUC FEE**	0.00069	0.00069	0.00069	0.00069	0.00069
EOR	0.00000	0.00000	0.00000	0.00000	0.00000
CEE INCENTIVE	0.00000	0.00013	0.00013	0.00013	0.00013
NGV BALANCING ACCOUNT	0.00000	0.00000	0.00000	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.00065 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)	0.02139 (I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000	0.17012 (I)	0.10845 (I)	0.09585 (I)	0.08600 (I)
TOTAL RATE	**0.00599 (I)**	**0.19485 (I)**	**0.13318 (I)**	**0.12058 (I)**	**0.11073 (I)**

* Refer to footnotes at end of Noncore Default Tariff Rate Components.

** The CPUC Fee includes a $0.00068 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U).

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

	G-LNG (1)*
NCA – NONCORE	0.00000
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000
CPUC Fee**	0.00069
EOR	0.00000
CEE	0.00000
NGV BALANCING ACCOUNT	0.16502 (I)
LOCAL TRANSMISSION (AT RISK)	0.00000
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000
TOTAL RATE	**0.16571 (I)**

* Refer to footnotes at end of Noncore Default Tariff Rate Components.

** The CPUC Fee includes a $0.00068 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U).

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

MAINLINE EXTENSION RATES (1)

Core Schedules (2)	Mainline Extension Rate (Per Therm) (T)	Core Customer Charges (3) ADU (therms) (4)	Per Day
Schedule G-NR1	$0.23049	0 – 5.0	$0.27048
		5.1 to 16.0	$0.52106
		16.1 to 41.0	$0.95482
		41.1 to 123.0	$1.66489
		123.1 & Up	$2.14936
Schedule G-NR2	$0.09134	All Usage Levels	$4.95518
Schedule G-NGV1	$0.06189	All Usage Levels	$0.44121
Schedule G-NGV2	N/A	All Usage Levels	N/A

Noncore Schedules	Mainline Extension Rate (Per Therm) (T)		
Schedule G-NT			
Distribution	$0.09042	(I)	
Local Transmission	$0.00586		
Backbone	$0.00000		
Schedule G-EG			
Distribution	$0.00183		
Local Transmission	$0.00183		
Backbone	$0.00183		
Schedule G-NGV4			
Distribution	$0.09042	(I)	
Local Transmission	$0.00000		
Backbone	$0.00000		

Noncore Customer Access Charges (5) Average Monthly Use (Therms)	Per Day	
0 to 5,000	$1.78652	(R)
5,001 to 10,000	$ 5.32175	I
10,001 to 50,000	$ 9.90477	I
50,001 to 200,000	$ 12.99912	I
200,001 to 1,000,000	$ 18.86038	I
1,000,001 and above	$ 159.98499	(R)

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(1) Mainline Extension Rates are required to support calculation of distribution-based revenues described in Rule 15.
(2) For all residential schedules, see Rule 15 for extension allowances.
(3) The Core Customer Charge is in addition to the core Mainline Extension Rates specified above.
(4) The applicable Schedule G-NR1 Customer Charge is based on the customer's highest Average Daily Usage (ADU) determined from among the billing periods occurring within the last twelve (12) months, including the current billing period. PG&E calculates the ADU for each billing period by dividing the total usage by the number of days in the billing period.
(5) The Noncore Customer Access Charge is in addition to the noncore Mainline Extension Rates specified above.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 1

C. GAS ACCOUNTING TERMS AND DEFINITIONS

These accounting terms and definitions are used in the authorized gas revenue requirements and surcharge funding as well as the accounting procedure descriptions that follow in this Preliminary Statement. They are consistent with and apply to PG&E's Gas Rate Schedules and Rules. Additional definitions can be found in Rule 1.

1. BALANCING ACCOUNT: In the context of this tariff, a balancing account is an account in which:

   a. expenses are compared with revenues from rates designed to recover those expenses, or

   b. forecast expenses are compared with recorded expenses, or

   c. forecast revenues are compared with recorded revenues, or

   d. authorized funding is compared to surcharge amounts.

   The resulting under- or overcollection, plus interest, is recorded on PG&E's financial statements as an asset or liability, which is owed from or due to the ratepayers. Balances in balancing accounts, plus interest, are to be amortized in rates.

BASE REVENUE AND AUTHORIZED FUNDING AMOUNTS: The GRC Distribution Base Revenue Amount is the annual operating revenue, less other operating revenue adopted in the General Rate Case (GRC) or other proceedings.

Adjustments and credits to GRC Base Revenues were approved in various CPUC decisions. In Decision 05-06-029, the CPUC adopted specific levels of Enhanced Oil Recovery (EOR) revenue. In Decision 04-12-050, the CPUC revised the core brokerage fee authorized in Decision 97-08-055. Adjustments for G-10 employee discounts are revised when the CPUC authorizes revisions to illustrative residential core procurement rates in the BCAP or other proceedings. The currently effective GRC Distribution Base Revenue Amount (with adjustments and credits) is shown in Table C.2.

The Gas Accord Base Revenues are comprised of Local Transmission, Backbone Transmission, Storage and transmission-level customer access adopted in Gas Accord Decision 11-04-031. The (N)
currently effective Gas Accord Revenue Requirement is shown in Table C.2.

The Public Purpose Program (PPP) authorized funding includes amounts for Energy Efficiency (EE) and Low Income Energy Efficiency (LIEE) Programs, public interest Research, Development and Demonstration (RD&D), State Board of Equalization (BOE) and CPUC Surcharge Administration Fees, California Alternate Rates for Energy (CARE) Administrative Expenses and CARE shortfall. PPP-authorized funding and the subsidy for CARE customers are recovered through the gas PPP surcharge, as authorized by Public Utilities Code Sections 890-900, Resolution G-3303 and Decision 04-08-010.* The currently authorized PPP funding amounts are shown in Table C.2.

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* Decision 04-08-010 determined that franchise fees and uncollectible accounts expense (FF&U) should not be included in the calculation of gas PPP surcharges.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

Description	Core	Noncore	Unbundled	Core Procurement	Total	
	Amount ($000)					
BASE REVENUES (incl. F&U) :						
Authorized GRC Distribution Base Revenue (1)					1,110,089	
Pension (2)					35,009	
Less: Other Operating Revenue					(26,023)	
Authorized Distribution Revenues in Rates	1,080,225	38,850			1,119,075	
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:						
G-10 Procurement-Related Employee Discount	(1,128) (I)				(1,128)(I)	
G-10 Procurement Discount Allocation	445 (R)	683(R)			1,128 (R)	
Less: Front Counter Closures	(355)				(355)	
Core Brokerage Fee Credit	(6,583)				(6,583)	
Distribution Base Revenue with Adj. and Credits	1,072,604 (I)	39,533 (R)			1,112,137	
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):						
Transportation Balancing Accounts	91,716	15,049			106,765	
Self-Generation Incentive Program Revenue Requirement	2,569	3,911			6,480	
CPUC Fee	1,970	1,240			3,210	
ClimateSmart	0	0			0	
SmartMeter™ Project	45,997				45,997	
Winter Gas Savings Plan (WGSP) – Transportation	2,179				2,179	
Franchise Fees and Uncollectible Expense (F&U) (on items above)	1,747	253			2,000	
CARE Discount included in PPP Funding Requirement	(110,499)				(110,499)	
CARE Discount not included in PPP Surcharge Rates	0				0	
Transportation Forecast Period Costs & Balancing Account Balances	35,679	20,453			56,132	
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):						
Local Transmission	130,386 (I)	67,447 (I)			197,833 (I)	
Customer Access Charge – Transmission		4,691 (R)			4,691 (R)	
Storage	48,133 (I)		35,493 (I)		83,627 (I)	
Carrying Cost on PG&E Working Gas in Storage	1,122 (R)		302 (I)		1,424 (R)	(N)
Backbone Transmission/L-401	94,929 (I)		131,698 (R)		226,627 (R)	
Gas Accord Revenue Requirement	274,571 (I)	72,138 (I)	167,493 (R)		514,202 (I)	

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2007, in General Rate Case D.07-03-044, and $22M for Attrition as approved in AL 2877-G, 2954-G, and AL 3050-G. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. Prior to 2011, Pension was included in GRC Distribution Base Revenue. Going forward, Pension is shown as its own line item.

(2) D.09-09-020 authorized a $140.5 million total revenue requirement, of which $35 million is allocated to gas distribution.

(3) - The total 2011 SGIP revenue requirement (RRQ) was approved in D.09-12-047.
- On April 27, 2009, PG&E filed an Application requesting a 2-year extension of the ClimateSmart program. PG&E seeks no additional customer funding.
- D.06-07-027 authorized Advanced Metering Infrastructure ("AMI")/SmartMeter™ Project deployment. The gas portion of the adopted 2010 SmartMeter™ RRQ is $46 million. The Phase 1 of the GRC settlement agreement resolves most issues including several related to SmartMeter™. This RRQ amount remains the same as 2010 and will be revised once the Phase 1 GRC decision is issued.
- The Energy Division approved PG&E's AL 3130-G-A to continue PG&E's Winter Gas Savings Program (WGSP). The approved marketing, outreach and administration costs are shown here allocated between transportation and procurement on an estimated basis pending the results of the WGSP. The estimated program credits are collected in rates, resulting in a net zero revenue requirement.

(4) The Gas Accord V revenue requirement effective January 1, 2011, was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates. (N)/(D)

*Some numbers may not add precisely due to rounding. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

	Amount ($000)				
Description	Core	Noncore	Unbundled	Core Procurement	Total
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):					
Illustrative Gas Supply Portfolio				1,151,818 (R)	1,151,818 (R)
Interstate and Canadian Capacity				178,209	178,209
WGSP – Procurement – Residential				2,122	2,122
F&U (on items above and Procurement Account Balances Below)				16,093 (R)	16,093 (R)
Backbone Capacity (incl. F&U)	(66,749)(R)			66,749 (I)	0
Backbone Volumetric (incl. F&U)	(28,180)(R)			28,180 (I)	0
Storage (incl. F&U)	(48,133)(R)			48,133 (I)	0
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(1,122)(I)			1,122 (R)	0
Core Brokerage Fee (incl. F&U)				6,583	6,583
Procurement Account Balances				(3,984)	(3,984)
Illus. Core Procurement Revenue Requirement	(144,184)(R)			1,495,026 (R)	1,350,841 (R)
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**1,238,669 (I)**	**132,124 (I)**	**167,493 (R)**	**1,495,026 (R)**	**3,033,312 (I)**
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):					
Energy Efficiency (EE)	70,052	7,798			77,850
Low Income Energy Efficiency (LIEE)	57,845	6,439			64,284
Research, Demonstration and Development (RD&D)	6,586	3,762			10,348
CARE Administrative Expense	1,128	776			1,904
BOE and CPUC Administrative Cost	181	103			284
PPP Balancing Accounts	2,268	(4,568)			(2,300)
CARE Discount Recovered from non-CARE customers	65,447	45,052			110,499
Total PPP Funding Requirement in Rates	**203,507**	**59,362**			**262,869**
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**1,442,176 (I)**	**191,486 (I)**	**167,493 (R)**	**1,495,026 (R)**	**3,296,181 (I)**
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	**1,442,176 (I)**	**191,486 (I)**	**167,493 (R)**	**1,495,026 (R)**	**3,296,181 (I)**

(5) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3130-G-A, will be recovered in residential rates effective April 1, 2011.

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2010 PPP surcharge AL 3057-G and includes LIEE program funding adopted in D.08-11-031, EE program funding adopted in D.08-10-027, CARE annual administrative expense adopted in D.08-11-031, and excludes F&U per D.04-08-010.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

3. COST ALLOCATION FACTORS:

a. General: These factors are derived from the allocation policies adopted in the last Cost Allocation Proceeding and are used to allocate recorded costs to customer classes.

	Factor				
Cost Category	Core	Noncore	Unbundled Storage and System Load Balancing	Total	(N) I (N)
Distribution Base Revenue Requirements	0.965284	0.034716		1.000000	
Intervenor Compensation	0.965284	0.034716		1.000000	
Other – Equal Distribution Based on All Transportation Volumes	0.394384	0.605616		1.000000	
Carrying Cost on PG&E Working Gas in Storage	0.718750 (R)		0.281250 (I)	1.000000	(N) (N)

b. Pacific Gas and Electric Gas Transmission Northwest (PG&E GT-NW) and Intrastate Pipeline Demand Charges: Factors are derived based on the procedures defined in Decisions 91-11-025 and 97-05-093. (D)

1) The core procurement factor will be equal to the capacity reserved for core procurement customers on each pipeline divided by the total capacity held by PG&E on that pipeline.

2) The core transport factor will be equal to the capacity reserved for core transport customers on each pipeline divided by the total capacity held by PG&E on that pipeline.

4. COST ALLOCATION PROCEEDING: The proceeding in which the Transportation Revenue Requirement, as described in Section C.10.c below, and the gas PPP authorized funding, as described in Section C.11. below, is allocated between customer classes. This proceeding is currently a biennial proceeding pursuant to CPUC Decision 90-09-089.

5. FORECAST PERIOD OR TEST PERIOD: The 24-month period, beginning with the revision date as specified in the Cost Allocation Proceeding.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

8. CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE) SHORTFALL: This shall be computed by subtracting CARE customers' monthly revenues from the revenues that would have been recovered from CARE customers had they been paying standard transportation and procurement rates.

9. MEMORANDUM ACCOUNT: In the context of this tariff, a memorandum account operates similar to a balancing account except that interest may be excluded and the under- or overcollection may or may not be amortized in future rates.

10. REVENUE REQUIREMENT: The revenue requirement consists of the sum of the Transmission and Storage Revenue Requirement which is set in PG&E's Gas Accord Decisions, and the Transportation and Procurement Revenue Requirements which are allocated in the Cost Allocation Proceeding, and are defined below. Rates will be established to recover all items in the revenue requirement.

    a. The Transmission System Revenue Requirement includes the Transmission portion of the Gas Accord base revenue amount,* load balancing storage costs, the balance from the Topock Adder Projects Balancing Account (TAPBA) described in Preliminary Statement Part CN, certain forecast amounts and F&U. Amounts to be included in the Customer Class Charge paid by Transmission Service customers are allocated in the Cost Allocation Proceeding and described under Transportation Revenue Requirement, below. (N) I (N)

    b. The Storage Revenue Requirement includes the core and Unbundled Storage base revenue amount,* carrying costs on PG&E working gas in storage, load balancing gas, and F&U. (N)

* See Section C.2 for details.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

c. The Transportation Revenue Requirement includes the core and noncore GRC Distribution Base Revenue Amounts (with credits and adjustments)*, forecast expenses, and balancing and memorandum account balances, with interest, as listed below. These amounts are recovered through distribution rates and the Customer Class Charge.

1) GRC Distribution Base Revenue Amount (with credits and adjustments): This shall be the GRC Distribution Base Revenue amount, with credits and adjustments as shown in Section C.2.

2) CPUC Reimbursement Fee Expense: This is the amount equal to the CPUC-adopted reimbursement rate, described in Preliminary Statement, Part O, multiplied by the total forecast period deliveries excluding interdepartmental, wholesale, interutility, and UEG deliveries.

3) Core Fixed Cost Account (CFCA) Balance: This is the forecast revision date balance in the CFCA, described in Preliminary Statement, Part F, based on the latest recorded data available.

4) Noncore Distribution Fixed Cost Account (NDFCA) Balance: This is the forecast revision-date balance in the NDFCA, described in Preliminary Statement Part BL, based on the latest recorded data available.

5) Noncore Customer Class Charge Account (NCA) Balance: This is the forecast revision-date balance in the NCA, described in Preliminary Statement, Part J, based on the latest recorded data available.

6) Liquefied Natural Gas Balancing Account (LNGBA) Balance: This is the forecast revision-date balance in the LNGBA, described in Preliminary Statement part X. based on the latest recorded data available. (D)/(N) I (D)/(N)

7) Hazardous Substance Mechanism (HSM) Balance: This is the forecast revision-date balance in the HSM, as described in Preliminary Statement, Part AN, based on the latest recorded data available. (N) I (N)

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

c. Transportation Revenue Requirement (Cont'd.)

8) Customer Energy Efficiency Incentive Account (CEEIA) Balance: This is the forecast revision-date balance in the CEEIA, as described in Preliminary Statement, Part Y, based on the latest recorded data available. (D)/(T) (D) (D)

9) Core Brokerage Fee Balancing Account (CBFA) Balance: This is the forecast revision-date balance in the CBFA described in Preliminary Statement, Part U, based on the latest recorded data available. (T)/(D) (D) (D)

10) Affiliate Transfer Fees Account (ATFA) Balance: This is the forecast revision-date balance in the ATFA described in Preliminary Statement Part Q, based on the latest recorded data available. (T)

11) Self-Generation Program Memorandum Account (SGIP) Balance: This is the forecast revision-date balance in the SGIP described in Preliminary Statement, Part AW, based on the latest recorded data available. (T)

12) Gas Reimbursable Fees Balancing Account (GRFBA) Balance: This is the forecast revision-date balance in the GRFBA described in Preliminary Statement Part BF, based on the latest recorded data available. (T)

13) Franchise Fees and Uncollectible Accounts Expense (F&U): The amount to be added for F&U shall be determined by multiplying the sum of Sections C.10.c.4.a through C.10.c.13, above, by the applicable F&U factor. (T)

14) TID Almond Power Plant Balancing Account (TIDBA) Balance: This is the forecast revision date balance in the TIDBA described in Preliminary Statement Part CK, based on the latest recorded data available. (N)

15) Integrity Management Expense Balancing Account (IMEBA) Balance: This is the forecast revision-date balance in the IMEBA described in Preliminary Statement Part CL, based on the latest recorded data available.

16) Electricity Cost Balancing Account (ECBA) Balance: This is the forecast revision-date balance in the ECBA described in Preliminary Statement Part CM, based on the latest recorded data available.

17) Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) Balance: This is the forecast revision date balance in the AMCDOP described in Preliminary Statement Part CO, based on the latest recorded data available.

18) Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) Balance: This is the forecast revision-date balance in the GTSRSM described in Preliminary Statement Part CP, based on the latest recorded data available. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

d. Procurement Revenue Requirement includes the cost of gas from the Gas Supply Portfolio, pipeline capacity costs, intrastate transmission costs, the forecast revision-date balance in the Purchased Gas Account, and other procurement balancing accounts, the brokerage fee and core storage revenue requirements, plus F&U, as applicable.

1) Procurement Cost of Gas (Sales Only): The Procurement Cost of Gas is determined by multiplying the forecast core sales volume by the Weighted Average Cost of Gas (WACOG).

2) Procurement Cost of Gas (Shrinkage only): This cost-of-gas component shall be determined by multiplying the forecast shrinkage (LUAF & GDU) quantities for core procurement and core subscription customers by the weighted average cost of gas (WACOG). Customers who procure their own supplies are not responsible for this cost component; rather, they deliver shrinkage in-kind.

3) Pipeline Demand Charges: Pipeline Demand Charges include fixed demand and capacity charges from Canadian and FERC-regulated interstate pipelines.

4) Intrastate Transmission Charges: Intrastate Transmission Charges include capacity charges reserved for Core Portfolio customers on PG&E's Backbone Transmission System at the Modified Fixed Variable (MFV) tariff rate for core customers.

5) Carrying Cost on PG&E Working Gas in Storage: The Carrying Cost on PG&E Working Gas in Storage shall be determined by multiplying the forecast value of gas in storage during this forecast period, excluding gas owned by third parties, by the current interest rate on three-month Commercial Paper, as reported in the Federal Reserve Statistical Release, H.15, or its successor. (D)/(N)

6) Carrying Cost on Core's Cycled Gas in Storage: The Carrying Cost on Core's Cycled Gas in Storage shall be determined by multiplying the forecast value of gas in storage during this forecast period, excluding gas owned by third parties, by the current interest rate on three-month Commercial Paper, as reported in the Federal Reserve Statistical Release, H.15, or its successor. (N)

7) Purchased Gas Account (PGA): The revenue requirement will include the forecast revision-date balance in the PGA, described in Preliminary Statement, Part D, based on the latest recorded data available.

8) Core Pipeline Demand Charge Account (CPDCA): The revenue requirement will include the forecast revision-date balance in the CPDCA, described in Preliminary Statement, Part AE, based on the latest recorded data available.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

12. REVISION DATES: PG&E's application for the Biennial Cost Allocation Proceeding (BCAP) shall be filed based on a schedule set forth by the CPUC. PG&E's Procurement rate shall be updated monthly.

a. Core Procurement Rate Change

Per Decision 97-10-065, an advice filing to change core procurement rates will be filed monthly. The filing will update certain forecasted procurement costs and the amortization component of the procurement rate. PG&E will continue to provide a Weighted Average Cost of Gas (WACOG) forecast in its BCAP for ratemaking purposes.

Per Decision 03-12-008, noncore customers switching to core service are subject to a crossover procurement rate, as specified in Schedule G-CPX, for the first twelve (12) regular monthly billing periods. Schedule G-CPX is filed by advice letter monthly.

b. Annual Gas True-up of Balancing Accounts (AGT)

Per Decision 05-06-029, an advice filing to change core and noncore transportation rates will be filed 45 days prior to the end of each calendar year for rates effective January 1. The filing will update the customer class charge components of transportation rates to recover all transportation-related balancing and memorandum account balances for costs that the Commission has authorization to be recovered in rates.

To determine the change in the customer charge components of transportation rates, PG&E will rely on the following:

1) The December 31 forecasted balance for each transportation balancing and memorandum account to be updated in the AGT will be determined based on the most recent recorded balance plus a forecast of the costs and revenues, including interest, through December 31. The exceptions are the GTSRSM balance (see 10.c), which will be determined on a recorded basis as of September 30 of each year during the Gas Accord V term (January 1, 2011 through December 31, 2014): and the IMEBA balance (see 10.c.), which will not be determined annually, but will be determined in aggregate for the Gas Accord V four-year term ending December 31, 2014. (N)

2) The customer class charge components will be calculated by dividing the balancing account balances as determined in 12.b.1 above by the annual average adjusted BCAP throughput. For four balancing accounts, the balance will first be allocated to the Core and Noncore classes, as described below, then divided by the Core and Noncore annual average adjusted BCAP throughput. (D) (N)

i) TID Almond Power Plant Balancing Account (TIDBA) - - Allocate balance to Core and Noncore classes based on Cold-year January throughput.

ii) Integrity management Expenses Balancing Account (IMEBA) - - Allocate balance 50% to Core and 50% to Noncore.

iii) Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) - - Allocate balance 50% to Core and 50% to Noncore.

iv) Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) -- Allocate balance 50% to Core and 50% to Noncore. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

12. REVISION DATES (Cont'd.)

c. In-Kind Shrinkage

Pursuant to Decision 03-12-061, an in-kind shrinkage allowance will be applied to all scheduled storage injection volumes beginning April 1, 2004. The in-kind shrinkage quantity will be calculated by dividing the total storage-related GDU and LUAF by the forecast annual storage-cycle quantity.

Decision 03-12-061 authorizes PG&E to update its in-kind shrinkage allowances on an annual basis through an advice letter compliance filing. The in-kind shrinkage allowances for backbone transmission and distribution will change annually effective November 1. The (N)
storage in-kind shrinkage allowance will change effective April 1. Pursuant to Gas Accord I
D.11-04-031, the core distribution in-kind shrinkage allowance will be seasonal, with separate I
allowances for summer (April-October) and winter (November-March).The in-kind shrinkage I
allowances are shown in Rule 21. (N)

If necessary, PG&E may make separate advice letter filings to adjust in-kind shrinkage allowances at other times of the year in order to better match the actual shrinkage experience on PG&E's system. The BCAP shall continue to be the proceeding in which the pipeline shrinkage calculation methodology, and the proportion of LUAF and GDU that are to be assigned to transmission and distribution shrinkage, is determined.

d. PPP Surcharge Rates

1) **Timing and Frequency**: Per Decision 04-08-010, an advice filing to change core and noncore gas PPP surcharges will be filed by October 31 of each year to be effective January 1 of the next year. The PPP surcharge rates will include a forecast of the December 31 balance for each PPP balancing account, in accordance with prevailing Commission balancing account amortization policies. The forecast will be based on the most recent recorded balance, plus a forecast of the costs and revenues, including interest, through December 31. The forecasted balance for the PPP-RDD account will exclude interest until further direction from the CPUC.

   PG&E may request a change in gas PPP surcharge rates during the year if failure to make the rate change would result in a forecasted total rate increase of 10 percent or more on January 1 of the next year. Requested rate changes will be by advice letter filing and be filed at least 40 days prior to the beginning of the next quarter with an effective date to be determined by the Energy Division in consultation with the California State Board Of Equalization (BOE).

   If the current year program budget for CARE subsidy costs has not been adopted by the CPUC, PG&E will use forecasts of expected CARE subsidy costs based upon estimated future gas prices (using a credible, published source) and CARE penetration rates to calculate the surcharge. Amortization of balances in the applicable PPP balancing accounts will be in accordance with CPUC-established policies for the treatment of these funds.

2) **Information due dates**: By October 31, Energy Division will provide the allocation of RDD, BOE and CPUC administrative costs, and interstate pipeline customer gas volumes used for setting surcharge rates.

(Continued)

GAS PRELIMINARY STATEMENT PART F
CORE FIXED COST ACCOUNT

Sheet 3

6. ACCOUNTING PROCEDURE: (Cont'd.)

   b. Core Cost Subaccount (Cont'd.)

      4) a debit entry equal to one-twelfth of the core portion of the authorized local transmission revenue requirement, excluding the allowance for F&U;

      5) a debit or credit entry, as appropriate, to record the transfer of amounts from other accounts to this subaccount for recovery in rates, upon approval by the CPUC;

      6) an entry equal to 65.907 percent of the local transmission revenue shortfall or over-recovery resulting from a change in customers qualifying for backbone-level end-use service, and associated throughput reduction or increase, as applicable; (D)(N)

      7) a debit or credit entry equal to any amounts authorized by the CPUC to be recorded in this subaccount;

      8) a debit entry equal to one-twelfth of the core portion of the current year Self Generation Incentive Program (SGIP) revenue requirement authorized by the CPUC;

      9) an entry equal to the core portion of the gain or loss on the sale of a gas transmission non-depreciable asset, as approved by the Commission;

      10) a debit entry equal to the core gas portion of incremental administrative costs and amounts written off as uncollectible associated with the payment deferral plan for qualifying citrus and other agricultural growers pursuant to Resolution E-4065; and

      11) an entry equal to interest on the average of the balance in the account at the beginning of the month and the balance in the account after entries F.6.b.1 through F.6.b.10 above, are made, at a rate equal to one-twelfth the interest rate of the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release. H.15, or its successor.

   c. Winter Gas Savings Program Transportation Subaccount

      The following entries will be made to this subaccount each month or as applicable:

      1) a debit entry to record the transportation portion of WGSP credits;

      2) a debit entry, as appropriate, to record the transportation portion of the actual WGSP marketing, outreach, and implementation costs up to the amount authorized by the CPUC;

      3) a credit entry equal to the revenue from the WGSP – Transportation rate component, excluding the allowance for F&U;

      4) a debit or credit entry equal to any other amounts authorized by the CPUC to be recorded in this subaccount; and

      5) an entry equal to interest on the average of the balance in the account at the beginning of the month and the balance in the account after entries F.6.c.1 through F.6.c.4 are made, at a rate equal to one-twelfth the interest rate of the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

GAS PRELIMINARY STATEMENT PART J Sheet 2
NONCORE CUSTOMER CLASS CHARGE ACCOUNT

J. NONCORE CUSTOMER CLASS CHARGE ACCOUNT (NCA) (Cont'd.)

6. ACCOUNTING PROCEDURE: (Cont'd.)

a. Noncore Subaccount

The following entries will be made to this subaccount each month, or as applicable:

1) a debit entry equal to one-twelfth of the noncore portion of the procurement-related G-10 employee discount allocation shown on Preliminary Statement Part C.2;

2) a debit entry equal to the noncore portion of intervenor compensation and any other expense adopted by the CPUC as a cost to be included in this subaccount;

3) a credit entry equal to the NCA-Noncore revenue, excluding the allowance for Franchise Fees and Uncollectible Accounts Expense (F&U);

4) an debit or credit entry, as appropriate, to record the transfer of amounts from other accounts to this subaccount for recovery in rates, upon approval by the CPUC;

5) an entry equal to 34.093 percent of the local transmission revenue shortfall or over-recovery resulting from a change in customers qualifying for backbone-level end-use service, and associated throughput reduction or increase, as applicable; (D)/(N)

6) a debit entry equal to one-twelfth of the noncore portion of the current year Self Generation Incentive Program (SGIP) revenue requirement authorized by the CPUC;

7) an entry equal to the noncore portion of the gain or loss on the sale of a gas transmission non-depreciable asset, as approved by the Commission;

8) a debit entry equal to the noncore gas portion of incremental administrative costs and amounts written off as uncollectible associated with the payment deferral plan for qualifying citrus and other agricultural growers pursuant to Resolution E-4065; and

9) an entry equal to interest on the average of the balance in the subaccount at the beginning of the month and the balance after entries from J.6.a.1 through J.6.a.8 above, are made, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

(Continued)

GAS PRELIMINARY STATEMENT PART AG
CORE FIRM STORAGE ACCOUNT

AG. CORE FIRM STORAGE ACCOUNT (CFSA)

1. PURPOSE: The purpose of the CFSA is to record the costs and revenues associated with firm storage capacity allocated to core customers as adopted in Decision (D.) 03-12-061. The balance in this account will be incorporated into core procurement rates.

   Descriptions of the terms and definitions used in this section are found in Preliminary Statement, Part C or in Rule 1.

2. APPLICABILITY: The CFSA applies to all core procurement rate schedules and contracts subject to the jurisdiction of the CPUC, except for those schedules and contracts specifically excluded by the CPUC.

3. REVISION DATE: The revision date applicable to the CFSA rate shall coincide with the revision date of the monthly core procurement rate or at other times, as ordered by the CPUC.

4. FORECAST PERIOD: The forecast test period will be as specified in the current Cost Allocation Proceeding.

5. CFSA RATES: CFSA rates are included in the effective rates set forth in each gas procurement rate schedule (see Preliminary Statement, Part B), as applicable.

6. ACCOUNTING PROCEDURE: PG&E shall make the following entries to the CFSA at the end of each month or when applicable:

   a. a debit entry equal to one-twelfth of the total core firm storage revenue requirement, which is the amount accepted by CTAs, plus the remainder allocated to core procurement customers, under the provisions of Schedule G-CFS, excluding the allowance for franchise fees and uncollectible accounts expense (F&U);

   b. a debit entry equal to the core portion of the recorded carrying cost on PG&E working gas in (D)/(N)
   storage; (N)

   c. a credit entry equal to the core firm storage revenue from core procurement customers for the month, excluding the allowance for F&U;

   d. a credit entry equal to the revenue from CTAs pursuant to Schedule G-CFS, excluding the allowance for F&U;

   e. a credit entry equal to the revenue received from the sale of released core storage capacity by PG&E's Core Procurement Department; and

   f. an entry equal to the interest on the average of the balance in the account at the beginning of the month and the balance after entries 6.a. and 6.e., above, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

GAS PRELIMINARY STATEMENT PART CK
TID ALMOND POWER PLANT BALANCING ACCOUNT

Sheet 1 (N)
(N)

CK. TID Almond Power Plant Balancing Account (TIDBA) (N)

1. PURPOSE: PG&E will receive a customer deposit for the TID Almond Power Plant project. The actual customer deposit, less the income tax component of contribution, will be credited to rate base simultaneously with the inclusion of the project costs in rate base and may increase or decrease in the future depending on whether the customer's load is less than or greater than initially forecasted. The purpose of the TID Almond Power Plant Balancing Account (TIDBA) is to record the difference in revenue requirement based on the amount credited to rate base per the Gas Accord V Settlement Agreement and the actual amount. The TIDBA is created in compliance with Decision 11-04-031, and will record the differences between adopted revenue requirements and actual revenue requirements beginning January 1, 2011 and ending December 31, 2014. (N)

   The deposit amount will be subject to a Gas Rules 15.H.3 and 16.H Exceptional Case filing with the CPUC. Other parties will have an opportunity to protest the Exceptional Case filing, including without limitation the amount of the customer deposit.

2. APPLICABILITY: The TIDBA shall apply to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATES: Disposition of the balances in this account shall be through the Customer Class Charge in PG&E's Annual Gas True-up advice letter process. (N)

4. RATES: The TIDBA does not have a separate rate component.

(Continued)

GAS PRELIMINARY STATEMENT PART CK Sheet 2 (N)
TID ALMOND POWER PLANT BALANCING ACCOUNT (N)

CK. TID Almond Power Plant Balancing Account (TIDBA)(Ctd.) (N)

5. ACCOUNTING PROCEDURE: The following entries shall be made to the account each month or as applicable: (N)

   a. A credit entry equal to one-twelfth of the annual revenue requirement (excluding FF&U) based on the amount credited to rate base adopted in PG&E's Gas Accord V Settlement Agreement.

   b. A debit entry equal to the monthly revenue requirement (excluding FF&U) based on the actual amount credited to rate base.

   c. An annual entry to transfer any over- or under-collected balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution between core and noncore will be based on the cold year January throughput forecast as adopted in PG&E's 2010 Biennial Cost Proceeding (BCAP).

   d. An entry equal to the interest on the average balance in the account at the beginning of the month and the balance after entries 5.a through 5.c, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

GAS PRELIMINARY STATEMENT PART CL Sheet 1 (N)
INTEGRITY MANAGEMENT EXPENSE BALANCING ACCOUNT (N)

CL. Integrity Management Expense Balancing Account (IMEBA) (N)

1. PURPOSE: The purpose of the Integrity Management Expense Balancing Account (IMEBA) is to track the aggregate amount of integrity management expenses incurred during the term of the Gas Accord V Settlement Agreement (2011 through 2014). The IMEBA is created in compliance with Decision 11-04-031, and will record the differences between adopted revenue requirements and recorded expenses for the Settlement Period beginning January 1, 2011 and ending December 31, 2014. The IMEBA is a one-way balancing account. (N)

2. APPLICABILITY: The IMEBA shall apply to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATES: Disposition of the balances in this account shall be through the Customer Class Charge in PG&E's Annual Gas True-up advice letter process.

4. RATES: The IMEBA does not have a separate rate component.

5. ACCOUNTING PROCEDURE: The following entries shall be made to the account each month or as applicable:

   a. A credit entry equal to one-twelfth of the annual revenue requirement for the integrity management (excluding FF&U) adopted in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031. The 2011 amount is $22.0 million in FERC dollars and escalates by 2.6% in 2012, 2.3% in 2013, and 2.6% in 2014.

   b. A debit entry equal to the actual integrity management expenses incurred for the current month.

   c. If the accumulated balance is a credit at December 31, 2014, a debit entry to transfer the December 31, 2014 accumulated balance to the Core Cost subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution of the balance will be 50% to core and 50% to noncore. If the accumulated balance is a debit at December 31, 2014, a credit entry to transfer the December 31, 2014 accumulated balance to earnings.

   d. An entry equal to the interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

GAS PRELIMINARY STATEMENT PART CM Sheet 1 (N)
ELECTRICITY COST BALANCING ACCOUNT (N)

CM. Electricity Cost Balancing Account (ECBA) (N)

1. PURPOSE: The purpose of the Electricity Cost Balancing Account (ECBA) is to record the difference between the cost of electricity used to provide gas transmission and storage services adopted in PG&E's Gas Accord V Settlement Agreement, and PG&E's recorded cost of electricity used to provide gas transmission and storage services. The ECBA is created in compliance with Decision 11-04-031, and will record the differences between adopted revenue requirements and recorded expenses beginning January 1, 2011 and ending December 31, 2014. (N)

2. APPLICABILITY: The Electricity Cost Balancing Account shall apply to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATES: Disposition of the balances in the subaccounts of this account shall be through the Customer Class Charge in the Annual Gas True-up advice letter process.

4. RATES: The ECBA does not have a separate rate component.

5. ACCOUNTING PROCEDURE: The following entries shall be made to the account:

   a. A credit entry each month equal to one-twelfth of the annual revenue requirement for electricity costs (excluding FF&U) as adopted in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031. The 2011 annual amount is $5.3 million in FERC dollars and escalates by 2.3% in 2012, 2.3% in 2013, and 2.6% in 2014.

   b. A debit entry each month equal to the actual expense incurred for the current month.

   c. An annual entry to transfer the accumulated balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution between core and noncore will be based on equal cents per therm as stated in the annual year throughput forecast as adopted in PG&E's Biennial Cost Allocation Proceeding (BCAP).

   d. An entry each month equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

GAS PRELIMINARY STATEMENT PART CN — Sheet 1 (N)
TOPOCK ADDER PROJECTS BALANCING ACCOUNT (N)

CN. Topock Adder Projects Balancing Account (TAPBA) (N)

1. PURPOSE: The purpose of the Topock Adder Projects Balancing Account (TAPBA) is to recover the revenue requirements of the Topock Adder projects between their in-service dates and the following January 1, when they will be put into rates. (N)

   There are three Topock Adder projects: Topock K-units Phase 1, Topock K-units Phase II, and Topock P-units. The capital expenditures on which the Topock Adder Projects capital-related revenue requirements are based are subject to a cap for ratemaking purposes during the Gas Accord V Settlement Period (2011-2014). The capital-related revenue requirement for each adder project is based on the lower of the actual capital expenditures or the following applicable caps: $60.0 million for Topock K-units Phase 1, and $100.0 million for all three Adder projects collectively.

2. APPLICABILITY: The TAPBA shall apply to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATES: Disposition of the balances in this account shall be through backbone rates in PG&E's Annual Gas True-up advice letter process during the calendar year following the in-service date of each project. This will be accomplished by increasing the otherwise applicable backbone Adder rate during the first year that the project is included in rates.

4. RATES: The TAPBA does not have a separate rate component.

5. ACCOUNTING PROCEDURE: The following entries shall be made to the account each month or as applicable:

   a. A debit entry equal to the actual capital-related revenue requirement calculated for the current month for any Topock Adder project that goes into service. Capital-related revenue requirements include depreciation expense, the return on investment (including return on equity and cost of debt), federal and state income taxes, and property taxes associated with the costs of installed equipment and exclude Franchise Fees and Uncollectible (FF&U) Accounts expense.

   b. Beginning January 1 when the Topock Adder project revenue requirement is included in rates, a credit entry equal to the revenue requirement amount included in rates.

   c. An entry equal to the interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

PRELIMINARY STATEMENT PART CO
ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS

Sheet 1 (N) (N)

CO. Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) (N)

1. PURPOSE: The purpose of the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) is to record the difference in the revenue requirement associated with the costs determined in other proceedings and the revenue requirement based on placeholder costs included in the Gas Accord V Settlement Agreement. (N)

2. APPLICABILITY: The AMCDOP shall apply to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATES: Disposition of the balances in the subaccounts of this account shall be through the Customer Class Charge in PG&E's Annual Gas True-up (AGT) advice letter process.

4. RATES: The AMCDOP does not have a separate rate component.

5. ACCOUNTING PROCEDURE: The AMCDOP consists of the following five subaccounts:

   ADMINISTRATIVE & GENERAL (A&G) SUBACCOUNT: The purpose of the A&G subaccount is to track the amount of A&G expenses allocated to Gas Transmission & Storage (GT&S) in the General Rate Case (GRC) against the allocation of A&G to GT&S services in the Gas Accord V Settlement Agreement.

   UNCOLLECTIBLES SUBACCOUNT: The purpose of the Uncollectibles subaccount is to track the amount of uncollectibles expenses based on the uncollectibles factor determined in the GRC against the uncollectible costs included in the Gas Accord V Settlement Agreement.

   PENSION SUBACCOUNT: The purpose of the Pension subaccount is to track the amount of pension costs allocated to GT&S in the Pension Recovery proceeding against the pension costs allocated to GT&S services in the Gas Accord V Settlement Agreement.

   COST OF CAPITAL SUBACCOUNT: The purpose of the Cost of Capital subaccount is to track the authorized cost of capital as determined in PG&E's cost of capital proceeding (or annual adjustment mechanism) against the cost of capital used to set GT&S cost of service revenue requirements in the Gas Accord V settlement agreement.

   OTHER GRC COSTS SUBACCOUNT: The purpose of the Other GRC Costs subaccount is to track the amount of costs and policies determined to be allocated and applied to GT&S in the GRC (not already reflected in the preceding A&G and Uncollectibles subaccounts) against the allocation of costs and policies allocated and applied to GT&S services in the Gas Accord V Settlement Agreement. (N)

(Continued)

PRELIMINARY STATEMENT PART CO Sheet 2 (N)
ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS (N)

5. ACCOUNTING PROCEDURE (Ctd.) (N)

a. Administrative & General (A&G) Subaccount (N)

The following entries shall be made to this subaccount at the end of each month, as applicable:

1) A credit entry equal to one-twelfth of the annual placeholder A&G revenue requirement (excluding Franchise Fees & Uncollectibles (FF&U)) based on the adopted revenue requirement in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031.

2) A debit entry equal to one-twelfth of the annual A&G revenue requirement (excluding FF&U) adopted for GT&S Services in PG&E's GRC.

3) An annual entry to transfer any over- or under-collected balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution of the balance will be 50% to core and 50% to noncore.

4) An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

b. Pension Subaccount

The following entries shall be made to this subaccount at the end of each month, as applicable:

1) A credit entry equal to one-twelfth of the annual placeholder Pension revenue requirement (excluding FF&U) based on the adopted revenue requirement in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031.

2) A debit entry equal to one-twelfth of the annual revenue requirement (excluding FF&U) adopted and allocated to GT&S Services in PG&E's Pension Recovery Mechanism.

3) An annual entry to transfer any over- or under-collected balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution of the balance will be 50% to core and 50% to noncore.

4) An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

(Continued)

PRELIMINARY STATEMENT PART CO Sheet 3 (N)
ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS (N)

5. ACCOUNTING PROCEDURE (Ctd.) (N)

c. Uncollectibles Subaccount (N)

The following entries shall be made to this subaccount at the end of each month, as applicable:

1) A credit entry equal to one-twelfth of the annual placeholder Uncollectibles revenue requirement based on the adopted revenue requirement in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031.

2) A debit entry equal to one-twelfth of the annual Uncollectibles revenue requirement based on the uncollectibles factor adopted in PG&E's GRC.

3) An annual entry to transfer any over- or under-collected balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution of the balance will be 50% to core and 50% to noncore.

4) An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

d. Cost of Capital Subaccount

The following entries shall be made to this subaccount at the end of each month, as applicable:

1) A credit entry equal to one-twelfth of the annual placeholder cost of capital revenue requirement (excluding FF&U) based on the adopted revenue requirement in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031.

2) A debit entry equal to one-twelfth of the annual cost of capital revenue requirement (excluding FF&U) for GT&S Services based on authorized rate base in the Gas Accord V Settlement Agreement and the rate of return on rate base adopted in PG&E's current cost of capital proceeding or annual cost of capital adjustment mechanism.

3) An annual entry to transfer any over- or under-collected balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge account (NCA). The distribution of the balance will be 50% to core and 50% to noncore.

4) An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

(Continued)

PRELIMINARY STATEMENT PART CO Sheet 4 (N)
ADJUSTMENT MECHANISM FOR COSTS DETERMINED IN OTHER PROCEEDINGS (N)

5. ACCOUNTING PROCEDURE (Ctd.) (N)

e. Other GRC Costs Subaccount (N)

The following entries shall be made to this subaccount at the end of each month, as applicable:

1) A credit or debit entry equal to the increase or decrease in the GT&S revenue requirement, as adopted in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031, as a result of costs and policies determined in PG&E's GRC to be allocated and applied to GT&S. Such costs and polices are described in 7.5.1 of the Gas Accord V Settlement Agreement. Amounts recorded to this subaccount would exclude those amounts already recorded to the A&G or uncollectibles subaccount of this account.

2) An annual entry to transfer any over- or under-collected balance in the account to the Core Cost Subaccount of the Core Fixed Cost Account (CFCA) and the Noncore Subaccount of the Noncore Customer Class Charge (NCA). The distribution of the balance will be 50% to core and 50% to noncore.

3) An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

GAS PRELIMINARY STATEMENT PART CP Sheet 1 (N)
GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM (N)

CP. Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) (N)

1. PURPOSE: The purpose of the Gas Transmission & Storage (GT&S) Revenue Sharing Mechanism (GTSRSM) is to record the difference between the customer portion of recorded total revenue over- or under-collections (derived for backbone, local transmission and storage) and the $30.0 million seed value embedded in rates (as allocated to backbone and local transmission) as adopted in PG&E's Gas Accord V Settlement Agreement. The GTSRSM is created in compliance with Decision 11-04-031. This mechanism will be effective beginning January 1, 2011 and will exist beyond the Gas Accord V Settlement Period (2011-2014) to the extent necessary to recover balances accumulated in the account through the calendar year 2014. The disposition of this account will be the 12-month period from October 1 through September 30. (N)

2. APPLICABILITY: The revenue sharing mechanism shall apply to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATES: Disposition of the balances in the subaccounts of this account shall be through the Customer Class Charge in the Annual Gas True-up (AGT) advice letter process.

4. RATES: The GTSRSM does not have a separate rate component.

5. ACCOUNTING PROCEDURE: The revenue sharing mechanism consists of the following four subaccounts:

   BACKBONE SUBACCOUNT: The purpose of backbone subaccount is to record the difference between the adopted backbone revenue requirement (including the portion of the Local Transmission Bill Credits recovered through the surcharge on backbone rates) and recorded backbone revenues, whether an over-collection or an under-collection, to be shared 50% to customers and 50% to shareholders. [Note: Core Reservation is balancing account protected and therefore not included in this calculation. Rate Schedule G-XF is subject to incremental ratemaking and therefore also not included.]

   LOCAL TRANSMISSION SUBACCOUNT: The purpose of the local transmission subaccount is to record the difference between the adopted local transmission revenue requirement (excluding the Local Transmission Bill Credits) and recorded local transmission revenues, whether an over-collection or an under-collection, to be shared 75% to customers and 25% to shareholders. [Note: Core Local Transmission is balancing account protected and therefore not included in this calculation.] (N)

(Continued)

GAS PRELIMINARY STATEMENT PART CP Sheet 2 (N)
GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM (N)

5. ACCOUNTING PROCEDURE (Ctd.): (N)

STORAGE SUBACCOUNT: The purpose of the storage subaccount is to record the difference between the adopted storage revenue requirement and recorded storage revenues, if resulting in an over-collection, to be shared 75% to customers and 25% to shareholders. PG&E is at risk for 100% of any net under-collections. [Note: Core Storage is balancing account protected and therefore not included in this calculation.] (N)

If PG&E identifies and wishes to make incremental additions to its storage facilities or operations that are expected to produce incremental storage revenues during the Settlement Period, PG&E will file an advice letter with the CPUC to show the expected costs and the expected revenues of the project. In the advice letter, PG&E will ask to add the revenue requirements associated with the project to the adopted storage revenue requirements only for purposes of administering the revenue sharing mechanism. PG&E will also include all recorded revenues in the sharing mechanism, including incremental revenues obtained because of the new storage project.

REVENUE SHARING SUBACCOUNT: The purpose of the revenue sharing subaccount is to record the difference between the customer portion of recorded total revenue over- or under-collections, as determined in the subaccounts described above, and the $30.0 million seed value embedded in rates.

a. Backbone Subaccount

The following entries shall be made to this subaccount, as applicable:

1) A monthly debit equal to 50% of one-twelfth of the authorized backbone revenue requirement.

2) A monthly credit equal to 50% of the recorded backbone revenue.

3) A monthly credit entry equal to 50% of one-twelfth of the seed value embedded in backbone rates.

4) On September 30 of each year, an annual debit or credit entry to transfer the accumulated balance to the Revenue Sharing Subaccount of this balancing account.

5) A monthly entry equal to interest on the average balance in the subaccount at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART CP Sheet 3 (N)
GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM (N)

5. ACCOUNTING PROCEDURE (Ctd.): (N)
   b. Local Transmission Subaccount (N)

   The following entries shall be made to this subaccount, as applicable:

   1) A monthly debit equal to 75% of one-twelfth of the authorized local transmission revenue requirement.

   2) A monthly credit equal to 75% of the recorded local transmission revenue.

   3) A monthly credit entry equal to 75% of one-twelfth of the seed value embedded in local transmission rates.

   4) On September 30 of each year, an annual debit or credit entry to transfer the accumulated balance to the Revenue Sharing Subaccount of this balancing account.

   5) A monthly entry equal to interest on the average balance in the subaccount at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

   c. Storage Subaccount

   The following entries shall be made to this subaccount, as applicable:

   1) A monthly debit entry equal to 75% of one-twelfth of the authorized storage revenue requirement.

   2) A monthly credit entry equal to 75% of the recorded storage revenue.

   3) A monthly credit entry equal to 75% of one-twelfth of the seed value embedded in storage rates.

   4) If the balance is over-collected, on September 30 each year, a debit entry to transfer the accumulated balance to the Revenue Sharing Subaccount of this balancing account. If the balance is under-collected, PG&E is at risk and will transfer the balance to earnings.

   5) A monthly entry equal to interest on the average balance in the subaccount at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART CP Sheet 4 (N)
GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM (N)

5. ACCOUNTING PROCEDURE (Ctd.): (N)

d. Revenue Sharing Subaccount (N)

The following entries shall be made to this subaccount, as applicable:

1) A monthly debit entry equal to one-twelfth of the seed value embedded in rates ($30.0 million annually).

2) On September 30 of each year, a debit or credit entry to transfer the accumulated balances in the Backbone Subaccount and Local Transmission Subaccount to this subaccount.

3) If the Storage Subaccount balance is over-collected, on September 30 of each year, a credit entry to transfer the accumulated balance in the Storage Subaccount to this subaccount.

4) An annual entry to transfer the balance in this subaccount as of September 30 of each year to the Core subaccount of the Core Fixed Cost Account (CFCA) and the Noncore subaccount of the Noncore Customer Class Charge Account (NCA). The distribution of the balance will be 50% to core and 50% to noncore. (N)

GAS SCHEDULE G-AA
AS AVAILABLE TRANSPORTATION ON-SYSTEM

RATES: The Customer shall pay a Usage Charge for each decatherm equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

1. Usage Charge:

Path:	Usage Rate (Per Dth)
Redwood to On-System	$0.3379 (R)
Baja to On-System	$0.3679 (R)
Silverado to On-System	$0.1954 (I)
Mission to On-System	$0.0000

2. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

CREDIT-WORTHINESS: Customer must meet the creditworthiness requirements specified in Rule 25.

SERVICE AGREEMENT AND TERM: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) is required for service on this schedule. The minimum term for service under the GTSA is one (1) year.

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

NOMINATIONS: Nominations are required for gas transported under this rate schedule. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

BALANCING: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

GAS SCHEDULE G-AAOFF
AS-AVAILABLE TRANSPORTATION OFF-SYSTEM

RATES: The Customer shall pay a Usage Charge for each decatherm equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

1. Usage Charge:

Path:	Usage Rate (Per Dth)
Redwood to Off-System	$0.3379 (R)
Baja to Off-System	$0.3679 (R)
Silverado to Off-System	$0.3379 (R)
Mission to Off-System	$0.3379 (R)
Mission to Off-System Storage Withdrawals	$0.00000

2. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

STORAGE WITHDRAWAL OPTIONS (MISSION TO OFF-SYSTEM): Storage withdrawals to PG&E's Backbone Transmission System may be nominated for off-system delivery under the Mission Off-System As-Available service for no additional charge.

CREDIT-WORTHINESS: Customer must meet the creditworthiness requirements specified in Rule 25.

SERVICE AGREEMENT: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) is required for service under this schedule. The minimum term for service under the GTSA is one (1) year.

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

NOMINATIONS: Nominations are required for gas transported under this rate schedule. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

BALANCING: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

GAS SCHEDULE G-AFT

Sheet 2

ANNUAL FIRM TRANSPORTATION ON-SYSTEM

RATES: Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will then be specified in the exhibits to the Customer's GTSA.

1. Reservation Charge:

The Reservation Charge shall be the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the exhibits to the Customer's GTSA. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

Path:	Reservation Rate (Per Dth per month)	
	MFV Rates	SFV Rates
Redwood to On-System	$5.4087 (I)	$8.3095 (R)
Redwood to On-System (Core Procurement Groups only)	$4.7466 (I)	$6.5162 (I)
Baja to On-System	$5.8930 (I)	$9.0536 (R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$5.2811 (N)	$7.2499 (N)
Silverado to On-System (including Core Procurement Groups)	$3.2679 (I)	$4.8056 (I)
Mission to On-System (including Core Procurement Groups)	$3.2679 (I)	$4.8056 (I)

2. Usage Charge:

The Usage Charge shall be equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Path:	Usage Rate (Per Dth)	
	MFV Rates	SFV Rates
Redwood to On-System	$0.1038 (R)	$0.0084 (I)
Redwood to On-System (Core Procurement Groups only)	$0.0684 (I)	$0.0102 (R)
Baja to On-System	$0.1129 (I)	$0.0089 (R)
Baja to On-System (N) (Core procurement Groups only) (N)	$0.0758 (N)	$0.0111 (N)
Silverado to On-System (including Core Procurement Groups)	$0.0554 (I)	$0.0049 (R)
Mission to On-System (including Core Procurement Groups)	$0.0554 (I)	$0.0049 (R)
Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only)	$0.0000	$0.0000

(Continued)

GAS SCHEDULE G-AFTOFF

ANNUAL FIRM TRANSPORTATION OFF-SYSTEM

RATES: Customer has the option to elect either the MFV or the SFV rate structure, which will then be specified in the exhibits to the Customer's GTSA.

1. Reservation Charge:

   The Reservation Charge shall be the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the exhibits to the Customer's GTSA. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

Path:	Reservation Rate (Per Dth per month)	
	MFV Rates	SFV Rates
Redwood to Off-System	$5.4087 (I)	$8.3095 (R)
Baja to Off-System	$5.8930 (R)	$9.0536 (R)
Silverado to Off-System	$5.4087 (I)	$8.3095 (R)
Mission to Off-System	$5.4087 (I)	$8.3095 (R)

2. Usage Charge:

   The Usage Charge shall be equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Path:	Usage Rate (Per Dth)	
	MFV Rates	SFV Rates
Redwood to Off-System	$0.1038 (R)	$0.0084 (I)
Baja to Off-System	$0.1129 (I)	$0.0089 (R)
Silverado to Off-System	$0.1038 (R)	$0.0084 (I)
Mission to Off-System	$0.1038 (R)	$0.0084 (I)

3. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

(Continued)

GAS SCHEDULE G-BAL

Sheet 4

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MONTHLY BALANCING OPTIONS: (Cont'd.)

CASHOUT FOR MONTHLY BALANCING:

Monthly imbalances after trading is completed, which exceed the Monthly Tolerance Band are cashed out for both the commodity component and the transportation component.

The Commodity Cashout for each month is based on the following four (4) imbalance categories: Over-deliveries and under-deliveries in the imbalance range of greater than five percent (5%) and less than or equal to ten percent (10%) of usage (Tier I Cashout), and over-deliveries and under-deliveries in the imbalance range of greater than ten percent (10%) of usage (Tier II Cashout). The amount of gas in each category is multiplied by the appropriate price as determined below to calculate the commodity cashout portion of the bill.

The Transportation Cashout for each month is based only on the under or over-delivery greater than five percent (5%). This amount is multiplied by the appropriate transportation cashout price as determined below to calculate the transportation cashout portion of the bill. In the case of an overdelivery, this will be a credit.

SELF-BALANCING OPTION:

The Self-Balancing option requires daily balancing within specified limits. To participate in Self-Balancing, the Balancing Agent must have an NBAA or CTA Group.

To elect Self-Balancing, the Balancing Agent must sign a Self-Balancing Amendment (Form No. 79-971) and the NBAA or the Core Gas Aggregation Service Agreement (CTA Agreement) will be subject to the terms of Self-Balancing for the period identified in the Amendment.

SELF-BALANCING CREDIT:

The Self-Balancing option allows a Balancing Agent to receive a credit. The Self-Balancing credit is $0.0130 per Decatherm multiplied by the actual recorded monthly usage. Credits will be provided to the Balancing Agent on a monthly basis, subject to adjustments. (I)

LIMIT ON SELF-BALANCING PARTICIPATION:

When a Balancing Agent elects Self-Balancing, their share of the balancing storage assets will be assigned to and marketed through PG&E's at-risk unbundled storage program. The amount of storage assets allocated to PG&E's at-risk unbundled storage program is based on the Balancing Agent's End-Use Customer's annual average usage as a percentage of PG&E's average annual system usage. PG&E will allow the election of Self-Balancing until the storage balancing assets of 1.1 Bcf of inventory, 25 MMcf per day of injection and 35 MMcf per day of withdrawal are reached. If these limits are reached, PG&E will restrict further elections for Self-Balancing until capacity is made available or the OFO Forum raises the limits.

(Continued)

GAS SCHEDULE G-CFS
CORE FIRM STORAGE

APPLICABILITY: This rate schedule* provides the rates and charges associated with core firm storage capacity (Assigned Storage) assigned to Core Procurement Groups (CPGs), which include Core Transport Agents (CTAs) and PG&E's Core Procurement Department, pursuant to the core firm storage provisions of Schedule G-CT.

This schedule also provides the methodology for determining the quantity of gas inventory that may be sold to or purchased from a CTA by PG&E's Core Procurement Department, as amounts of Assigned Storage change during the Storage Year. In addition, this schedule describes the calculation of the prices to be paid when such gas inventory is transferred.

The CPG may also take storage service under Schedule(s), G-SFS, G-NFS and/or G-NAS in conjunction with service under this rate schedule.

TERRITORY: Schedule G-CFS applies to the firm use of PG&E's storage facilities.

ASSIGNED STORAGE MONTHLY CHARGE: CPGs holding an assignment of core firm storage (Assigned Storage), pursuant to the provisions of Schedule G-CT, will be billed each month based upon the amount of Assigned Storage held for the current month. The monthly charge is calculated by multiplying the applicable monthly rate, shown below, by the inventory quantity associated with CPG's Assigned Storage for that month.

Reservation Charge per Dth per month $0.1293 (I)

SHRINKAGE: In-kind storage shrinkage is applicable to all injection quantities in accordance with gas Rule 21.

SERVICE AGREEMENT: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) and applicable exhibit are required for CTAs taking service under this rate schedule.

NOMINATIONS: Nominations are required for injections and withdrawals. See Rule 21 for details.

INJECTION/ WITHDRAWAL: This schedule provides for firm injection and withdrawal for CPGs. It also specifies month-end minimum inventory targets for CPGs.

Firm injection is available from April 1 through October 31. Firm withdrawal is available from November 1 through March 31. In addition, firm summer withdrawal and winter injection are also available, as specified below.

Injection and Withdrawal Capacities

For CPGs that hold up to 1,000,000 Dth of Annual Inventory (AI), fixed injection and withdrawal capacities are assigned pursuant to Schedule G-CT.

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-EG
GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

APPLICABILITY: This rate schedule* applies to the transportation of natural gas used in: (a) electric generation plants served directly from PG&E gas facilities that have a maximum operation pressure greater than sixty pounds per square inch (60 psi); (b) all Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 216.6**; (c) solar electric generation plants, defined herein and (d) Advanced Electrical Distributed Generation technology that meets all of the conditions specified in Public Utilities Code Section 379.8, as defined in Rule 1, and are first operational at a site prior to January 1, 2014. This schedule does not apply to gas transported to non-electric generation loads.

Customers on Schedule G-EG permanently classified as Noncore End-Use Customers, per Rule 1 must procure gas supply from a third-party gas supplier, not from a Core Procurement Group, as defined in Rule 1.

Certain noncore customers served under this rate schedule may be restricted from converting to a core rate schedule. See Rule 12 for details on core and noncore reclassification.

TERRITORY: Schedule G-EG applies everywhere within PG&E's natural gas Service Territory.

RATES: The following charges apply to this schedule. They do not include charges for service on PG&E's Backbone Transmission System:

1. Customer Access Charge:

   The applicable Per-Day Customer Access Charge specified below is based on the Customer's Average Monthly Use, as defined in Rule 1. Usage through multiple noncore meters on a single premises will be combined to determine Average Monthly Usage. Customers taking service under this schedule who also receive service under other noncore rate schedules at the same premises will be charged a single Customer Access Charge under this schedule.

Average Monthly Use (Therms)	Per Day	
0 to 5,000 therms	$ 1.78652	(R)
5,001 to 10,000 therms	$ 5.32175	I
10,001 to 50,000 therms	$ 9.90477	I
50,001 to 200,000 therms	$ 12.99912	I
200,001 to 1,000,000 therms	$ 18.86038	I
1,000,001 and above therms	$159.98499	(R)

2. Transportation Charge:

   Customers will pay one of the following rates for gas delivered in the current billing period:

   a. The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

      Backbone Level Rate: $0.00713 per therm (I)

   b. All Other Customers: $0.02787 per therm (I)

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* PG&E's gas tariffs are available on-line at www.pge.com.

** Efficiency Standard: In accordance with PU Code Section 216.6, at least 5 percent of the facility's total output must be in the form of useful thermal energy. Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output must equal no less than 42.5 percent of any natural gas and oil energy input.

(Continued)

GAS SCHEDULE G-LEND
MARKET CENTER LENDING SERVICES

APPLICABILITY: This rate schedule* applies to the gas lending service offered to Customers as part of PG&E's Golden Gate Market Center Services. Gas lending is the temporary loan of gas from the PG&E gas transmission system. This service is provided on an interruptible basis only, and is the lowest priority transmission service offered by PG&E.

The Customer shall be responsible for arranging and paying for interstate and intrastate transportation service, as applicable, for transportation into and out of their Market Center accounts.

TERRITORY: The points of service for lending under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Rates will be negotiated on a transaction-by-transaction basis and shall be within the range set forth below:

Minimum Rate (per transaction): $57.00

Maximum Rate (per Dth per day): .... $1.1053 (I)

The minimum rate reflects PG&E's minimum costs to offer and operate the service.

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements specified in Rule 25.

SERVICE AGREEMENT: Service under this schedule is available to Customers who have executed a Gas Transmission Service Agreement (GTSA) (Form No. 79-866) with PG&E.

NOMINATIONS: Notice is required for service under this schedule, as agreed to by PG&E and the customer.

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-LNG
EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE

APPLICABILITY: This rate schedule* applies to experimental natural gas liquefaction service provided by PG&E to noncore End-Use Customers. This experimental liquefaction service is limited and PG&E will provide this service on a first-come first-served basis.

TERRITORY: Schedule G-LNG applies to the PG&E experimental Liquefied Natural Gas (LNG) facility located in Sacramento, California.

RATES: The following charges will apply to per therm liquefied natural gas service under this rate schedule:

Liquefaction Charge (Per Therm): $0.16571 (I)

LNG Gallon Equivalent: $0.13588 (I)
(Conversion factor - One LNG Gallon = 0.82 Therms)

Public Purpose Program Surcharge:
Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

METERING: For metering and billing purposes, the number of LNG gallons dispensed will be compiled from a summary of transactions recorded at the dispensing unit for the Customer during a calendar month. Delivery and custody transfer of LNG shall be at the point where LNG is dispensed into the Customer's LNG transport vehicle. LNG will be weighed and converted to LNG gallons. Vehicles must be weighed at an authorized weigh station prior to receiving LNG and again after filling. Weight information must be provided to PG&E within 5 business days. LNG gallons delivered will be converted to therms and billed. LNG usage that occurs during a billing period, but which is not recorded in that billing period, will be deferred to a future billing period.

The rate includes local transportation costs from the PG&E Citygate to the LNG Facility. These charges do not include transportation service on PG&E's Backbone Transmission System, which must be arranged for separately

See Preliminary Statement, Part B for the default tariff rate components.

LNG COMPOSITION: The resulting LNG product delivered will contain amounts equal to or greater than ninety-six percent (96%) methane and amounts equal to or less than four percent (4%) ethane.

SERVICE AGREEMENT: The Customer must execute a Natural Gas Service Agreement (NGSA) Form No. 79-756 to receive service under this schedule.

NOMINATIONS: Customers who take service under this schedule must arrange for the delivery of natural gas to the PG&E LNG facility in quantities necessary to equal the amount of LNG fuel dispensed to the customer. Nominations are required for gas transported under this schedule. See Rule 21 for details.

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* PG&E's gas tariffs are on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NAS

Sheet 1

NEGOTIATED AS-AVAILABLE STORAGE SERVICE

APPLICABILITY: This rate schedule* applies to the As-available use of PG&E's storage facilities. Storage injection and withdrawal may be taken separately under this schedule. Core Transport Agents, or PG&E, on behalf of Core Customers, may take storage service in excess of that provided by the core storage allocation.

TERRITORY: The rate schedule applies to use of PG&E's storage facilities. The points of service for storage under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Customers taking service under this rate schedule will pay monthly Usage Charges for any injection and/or withdrawal services utilized during the billing period. Any injections and/or withdrawals occurring during a billing period, but not recorded in that billing period, shall be deferred to a future billing period.

Negotiated rates for service under this rate schedule shall not be less than PG&E's marginal cost of providing the service and shall not exceed a price which will collect 100 percent of PG&E's total revenue requirement for the Unbundled Storage Program under both subfunctions (e.g., injection or withdrawal), as shown below. Customers will be billed on a monthly basis.

	Maximum Rates (Per Dth/Day)
Injection	$6.1656 (R)
Withdrawal	$21.3468 (I)

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

SHRINKAGE: In-kind storage shrinkage is available to all injection quantities in accordance with gas Rule 21.

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements as specified in Rule 25.*

SERVICE AGREEMENT: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) and storage exhibit thereto are required for service under this rate schedule.

NOMINATIONS: Notice is required for injections and withdrawals as agreed to by PG&E and the customer. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

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* PG&E's gas tariffs are available on-line at www.pge.com.

GAS SCHEDULE G-NFS
NEGOTIATED FIRM STORAGE SERVICE

APPLICABILITY: This rate schedule* applies to the firm use of PG&E's storage facilities, subject to rates negotiated by the Customer and PG&E. Fixed amounts of firm storage inventory, injection, and withdrawal service may be procured separately or in combination under this rate schedule. Core Transport Agents and PG&E, on behalf of Core Customers, may take storage service under this rate schedule for storage in excess of that provided by their core storage allocation.

TERRITORY: This rate schedule applies to firm use of PG&E's storage facilities. The points of service for storage under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Rates under this schedule are negotiable and may be structured as one-part rates (Usage or Reservation Charge) or two-part rates (both Reservation and Usage Charges), as negotiated between the Customer and PG&E. Reservation Charges, if applicable, shall be based on the injection, inventory, and/or withdrawal quantities specified in the Gas Transmission Service Agreement (GTSA) (Form No. 79-866). Any Usage Charges shall be equal to the applicable effective rate in the GTSA multiplied by the actual injection, inventory, or withdrawal quantities occurring during that billing period, including volumes traded pursuant to Schedule G-BAL. Any injections and withdrawals which occur during a billing period, but which are not recorded in that billing period, will be deferred to a future billing period.

Negotiated rates, for service under this schedule, are subject to minimum and maximum rates. Negotiated rates for storage service shall not be less than PG&E's marginal cost of providing the service. Negotiated rates for storage service will be capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three (3) subfunctions (i.e., injection, inventory or withdrawal), as listed below.

	Maximum Rates (Dth)	
Injection/Day	$6.1656	(R)
Inventory	$2.9461	(I)
Withdrawal/Day	$21.3468	(I)

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

* PG&E'S gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NGV4
NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

APPLICABILITY: This rate schedule* applies to the transportation of gas to customer-owned natural gas vehicle fueling stations on PG&E's Backbone, Local Transmission and/or Distribution Systems. To qualify for service under this schedule, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential Customer must have maintained an average monthly use, through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. See Rule 12 for details on core and noncore reclassification.

Customers must procure gas supply from a supplier other than PG&E.

TERRITORY: Schedule G-NGV4 applies everywhere within PG&E's natural gas Service Territory.

RATES: The applicable Customer Access Charges and Distribution Level Transportation Rate specified below is based on the Customer's Average Monthly Usage, as defined in Rule 1. Usage through multiple noncore gas meters on a single premises will be combined to determine Average Monthly Usage.

The following charges apply to service under this schedule:

1. Customer Access Charge:

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

Average Monthly Use (Therms)	Per Day	
0 to 5,000	$ 1.78652	(R)
5,001 to 10,000	$ 5.32175	I
10,001 to 50,000	$ 9.90477	I
50,001 to 200,000	$ 12.99912	I
200,001 to 1,000,000	$ 18.86038	I
1,000,001 and above	$159.98499	(R)

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NGV4 Sheet 2

NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

RATES: (Cont'd.)

2. Transportation Charge:

A customer will pay one of the following rates for gas delivered in the current billing month.

a. Backbone Level Rate:

The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

Backbone Level Rate (per therm) .... $0.00599 (I)

b. Transmission-Level Rate:

The Transmission-Level Rate applies to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi) that do not qualify for the Backbone Level Rate.

Transmission-Level Rate (per therm)................................ $0.02673 (I)

c. Distribution-Level Rate:

The Distribution-Level Rate applies to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate specified above.

Average Monthly Use (Therms)	Summer (Per Therm)	Winter (Per Therm)
Tier 1: 0 to 20,833	$0.15074 (I)	$0.19485 (I)
Tier 2: 20,834 to 49,999	$0.10506 (I)	$0.13318 (I)
Tier 3: 50,000 to 166,666	$0.09573 (I)	$0.12058 (I)
Tier 4: 166,667 to 249,999	$0.08843 (I)	$0.11073 (I)
Tier 5: 250,000 and above*	$0.02673 (I)	$0.02673 (I)

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES FEES AND TAXES:

Customer may pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details.) The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

Public Purpose Program Surcharge:
Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

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* Tier 5 Summer and Winter rates are the same.

(Continued)

GAS SCHEDULE G-NT

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

APPLICABILITY: This rate schedule* applies to the transportation of natural gas to Noncore End-Use Customers on PG&E's Backbone, Local Transmission and/or Distribution Systems. To qualify for service under this schedule, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential Customer must have maintained an average monthly use, through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. Certain noncore customers served under this schedule may be restricted from converting to a core rate schedule. See Rule 12 for details on core and noncore reclassification.

Customers on Schedule G-NT must procure gas supply from a supplier other than PG&E.

TERRITORY: Schedule G-NT applies everywhere within PG&E's natural gas Service Territory.

RATES: The applicable Customer Access Charges and Distribution Level Transportation Rate specified below is based on the Customer's Average Monthly Usage, as defined in Gas Rule 1. Usage through multiple noncore gas meters on a single premises will be combined to determine Average Monthly Usage.

1. Customer Access Charge:

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

Average Monthly Use (Therms)	Per Day	
0 to 5,000	$ 1.78652	(R)
5,001 to 10,000	$ 5.32175	I
10,001 to 50,000	$ 9.90477	I
50,001 to 200,000	$ 12.99912	I
200,001 to 1,000,000	$ 18.86038	I
1,000,001 and above	$159.98499	(R)

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NT

Sheet 2

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

RATES: (Cont'd.)

2. Transportation Charge:

A customer will pay one of the following rates for gas delivered in the current billing month.

a. Backbone Level Rate:

The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

Backbone Level Rate (per therm): $0.00599 (I)

b. Transmission-Level Rate:

The Transmission-Level Rate applies to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi) that do not qualify for the Backbone Level Rate.

Transmission-Level Rate (per therm): $0.03246 (I)

c. Distribution-Level Rate:

The Distribution-Level Rate applies to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate specified above.

Average Monthly Use (Therms)	Summer (Per Therm)	Winter (Per Therm)
Tier 1: 0 to 20,833	$0.15074 (I)	$0.19485 (I)
Tier 2: 20,834 to 49,999	$0.10506 (I)	$0.13318 (I)
Tier 3: 50,000 to 166,666	$0.09573 (I)	$0.12058 (I)
Tier 4: 166,667 to 249,999	$0.08843 (I)	$0.11073 (I)
Tier 5: 250,000 and above*	$0.03246 (I)	$0.03246 (I)

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES, FEES AND TAXES:

Customer may pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details.) The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

* Tier 5 Summer and Winter rates are the same.

(Continued)

GAS SCHEDULE G-PARK
MARKET CENTER PARKING SERVICES

APPLICABILITY: This rate schedule applies to the gas parking service offered to Customers as part of PG&E's Golden Gate Market Center Services. Gas parking is the temporary storage of gas on the PG&E gas transmission system. This service is provided on an interruptible basis only, and is the lowest priority transmission service offered by PG&E.

The Customer shall be responsible for arranging and paying for interstate and intrastate transportation service, as applicable, for transportation into and out of their Market Center accounts.

TERRITORY: The points of service for parking under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Rates will be negotiated on a transaction-by-transaction basis and shall be within the range set forth below:

Minimum Rate (per transaction): $57.00

Maximum Rate (per Dth per day): .... $1.1053 (I)

The minimum rate reflects PG&E's minimum costs to offer and operate the service.

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements specified in Rule 25.*

SERVICE AGREEMENT: Service under this schedule is available to Customers who have executed a Gas Transmission Service Agreement (GTSA) (Form No. 79-866) with PG&E.

NOMINATIONS: Notice is required for service under this schedule, as agreed to by PG&E and the customer.

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-SFS
STANDARD FIRM STORAGE SERVICE

APPLICABILITY: This rate schedule* applies to the firm use of PG&E's storage facilities. This rate schedule provides a combination of firm storage injection, inventory and withdrawal service. Service under this rate schedule is available to any Customer including Core Procurement Groups (CPGs) on behalf of Core Customers for storage service in addition to that provided under Schedule G-CFS.

TERRITORY: This rate schedule applies to firm use of PG&E's storage facilities.

RATES: Rates under this schedule consist of Reservation Charges. The Reservation Charge is based upon the amount of inventory capacity held by the Customer (Contract Inventory). Contract Inventory is shown per Decatherm (Dth).

1. Reservation Charges:

   The Reservation Charges shall be based on the quantities specified in Exhibit J of the Customer's Gas Transmission Service Agreement (GTSA) (Form No. 79-866). The Reservation Charge includes inventory, injection and withdrawal rights. The monthly charge is calculated by multiplying the applicable monthly rate shown below by the inventory specified in the GTSA (Contract Inventory).

   Reservation Charge per Dth of Contract Inventory per month .... $0.3008 (I)

2. Additional Charges:

   The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

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* PG&E's gas tariffs are available on-line at www.pge.com

(Continued)

GAS SCHEDULE G-SFT

SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY

RATES: Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will then be specified in the Customer's GTSA.

1. Reservation Charge:

   The Reservation Charge shall be the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the Exhibit to the Customer's GTSA. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

Path:	Reservation Rate (Per Dth per month)	
	MFV Rates	SFV Rates
Redwood to On-System	$6.4905 (I)	$9.9714 (R)
Baja to On-System	$7.0717 (R)	$10.8643 (R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$6.3373 (N)	$8.6999 (N)
Silverado to On-System	$3.9215 (I)	$5.7667 (I)
Mission to On-System	$3.9215 (I)	$5.7667 (I)

2. Usage Charge:

   The Usage Charge shall be equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Path:	Usage Rate (Per Dth)	
	MFV Rates	SFV Rates
Redwood to On-System	$0.1245 (R)	$0.0101 (I)
Baja to On-System	$0.1354 (I)	$0.0107 (R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$0.0910 (N)	$0.0133 (N)
Silverado to On-System	$0.0665 (I)	$0.0058 (R)
Mission to On-System	$0.0665 (I)	$0.0058 (R)

3. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

(Continued)

GAS SCHEDULE G-WSL

Sheet 1

GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS

APPLICABILITY: This rate schedule* applies to the transportation of natural gas for resale. Service under this schedule is available to the Customers listed below, and any new wholesale Customer. Customers must procure gas supply from a supplier other than PG&E.

LOAD FORECAST: For planning purposes, Customers may provide PG&E an annual forecast of the core and noncore portion of its load. If the Customer elects not to provide an annual forecast, PG&E will use the forecast adopted in the most recent Cost Allocation Proceeding.

RATES: Customers pay a Customer Access Charge and a Transportation Charge.

1. Customer Access Charge:

	Per Day	
Palo Alto	$138.97907	(R)
Coalinga	$ 41.68274	I
West Coast Gas-Mather	$ 22.12767	I
Island Energy	$ 28.24142	I
Alpine Natural Gas	$ 9.42444	I
West Coast Gas-Castle	$ 24.21337	(R)

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto-T	$0.02514	(I)
Coalinga-T	$0.02514	(I)
West Coast Gas-Mather-T	$0.02514	(I)
West Coast-Mather-D	$0.11702	(I)
Island Energy-T	$0.02514	(I)
Alpine Natural Gas-T	$0.02514	(I)
West Coast Gas-Castle-D	$0.09453	(I)

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-WSL

Sheet 2

GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS

RATES: (Cont'd.)

See Preliminary Statement, Part B for the default tariff rate components applicable to this schedule.

Customers will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

The existing Wholesale Customers listed below will have a one-time option prior to June 1, 2011, to subscribe, on behalf of their core Customers, for firm capacity on the Redwood to on-system and Baja to on-system paths as specified below. Capacity will be offered only for the core portion of the Customer's load.

Customer	Redwood (MDth)		Baja – Annual (MDth)		Baja – Seasonal (MDth)		
							(N)
Alpine	0.098	(N)	0.056	(N)	0.052	(N)	I
Coalinga	0.552	(N)	0.316	(N)	0.291	(N)	I
Island Energy	0.064	(N)	0.037	(N)	0.034	(N)	I
Palo Alto	5.898	(N)	3.372	(N)	3.110	(N)	I
West Coast Gas (Castle)	0.051	(N)	0.029	(N)	0.027	(N)	I
West Coast Gas (Mather)	0.171	(N)	0.098	(N)	0.090	(N)	I
							(N)

This intrastate capacity will be offered to the G-WSL Customers specified above at the rates specified for Core Procurement Groups in Schedule G-AFT. G-WSL Customers must execute a Gas Transmission Service Agreement (GTSA) (Form No. 79-866) and associated exhibits in order to exercise a preferential right to this intrastate capacity. In addition, G-WSL Customers, at their option, may execute a GTSA and associated exhibits for additional intrastate transmission pipeline capacity that will not be offered at the rates specified for Core Procurement Groups in Schedule G-AFT.

(Continued)

GAS SCHEDULE G-XF

Sheet 1

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

APPLICABILITY: This rate schedule* is available to any Customer who holds a Pipeline Expansion Firm Transportation Service Agreement (FTSA) (Form No. 79-791) approved by the CPUC. This schedule is closed to new Customers. This schedule may also be taken in conjunction with Schedule G-STOR, G-FS, G-NFS, G-NAS, G-PARK, or G-LEND.

TERRITORY: Schedule G-XF applies to pre-existing Pipeline Expansion firm transportation service.

RATES: The following charges apply to intrastate natural gas transportation service under this schedule. In addition, Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from inter- or intrastate sources and any other applicable charges.

1. Reservation Charge:

The monthly Reservation Charge shall be the applicable reservation rate multiplied by the Customer's Maximum Daily Quantity (MDQ), as specified in the Customer's FTSA.

Reservation Rates:	Per Dth Per Month
SFV Rates:	$6.1394 (R)

Customer's obligation to pay the Reservation Charge each month is absolute and unconditional and is independent of Customer's ability to obtain export authorization from the National Energy Board of Canada, Canadian provincial removal authority, and/or import authorization from the United States Department of Energy. Customer's obligation to pay the Reservation Charge shall be unaffected by the quantity of gas transported by PG&E to Customer's Delivery Point(s) on the Pipeline Expansion.

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* PG&E's gas tariffs are on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-XF

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

RATES: (Cont'd.)

2. Usage Charge:

In addition to the Reservation Charge described above, Customer shall pay a usage charge for each decatherm equal to the applicable usage rate times the quantity of gas received on the Customer's behalf, less the applicable shrinkage allowance in the current month.

Usage Rates:	Per Dth
SFV Rates:	\$0.0013 (R)

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements set forth in Rule 25.

SERVICE AGREEMENT: Customer must have executed a Pipeline Expansion Firm Transportation Service Agreement (Form No. 79-791) prior to the implementation date of the Gas Accord Settlement on March 1, 1998, in order to qualify for service under this schedule.

NOMINATIONS: Nominations are required for gas supplies delivered under this rate schedule. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

TEMPORARY ASSIGNMENT OF CAPACITY RIGHTS: Customer may assign all or a portion of its long-term firm capacity on the Pipeline Expansion to another party, subject to the creditworthiness requirements set forth in Rule 25. In order to assign capacity, Customer must provide PG&E written notice, using the Assignment of Gas Transmission Services (Form No. 79-867).

RECEIPT POINTS: PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specified in Exhibit A to the FTSA. On any given day, the total amount of gas nominated for firm transportation service at all Receipt Points may not exceed Customer's MDQ, as specified in the FTSA.

DELIVERY POINTS: Customer may nominate only to the Delivery Point set forth in Exhibit A to the Customer's FTSA. Customer is responsible for separately arranging for transportation of its gas between the Delivery Point and the ultimate end-use destination(s).

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

BALANCING: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

GAS RULE NO. 14 Sheet 16
CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE

E. OPERATIONAL FLOW ORDERS (OFO) (Cont'd.)

OFO NONCOMPLIANCE CHARGE EXEMPTION:

If a Balancing Agent's OFO noncompliance charge is calculated to be less than or equal to 1,000 Dth for an OFO, the noncompliance charge will be exempted and the charge will be zero. If the noncompliance charge is greater than 1,000 Dth, the Balancing Agent will be responsible for the full noncompliance charge; i.e., 1,000 Dth will not be deducted from the calculated noncompliance charge. This exemption provision only applies to OFO noncompliance charges. (D)/(N)
I
I
(D)/(N)

As ordered in Decision 01-02-049, PG&E shall waive any OFO noncompliance charges incurred by core customers whose gas is procured by PG&E if: 1) PG&E has implemented an Involuntary Diversion of noncore gas supplies (see Section G, below; and 2) due to PG&E's lack of credit, PG&E is unable to procure sufficient core gas supplies directly from suppliers.

OFO COMPLIANCE

OFO compliance and charges will be based on the following:

1. For a Noncore End-Use Customer with automated meter reading (AMR) capability and for PG&E's Electric Generation (EG) Department, compliance during an OFO will be based on actual daily metered usage, and the calculation after the OFO event of any applicable noncompliance charge will be based on actual daily metered usage.

2. For a Noncore End-Use Customer without AMR capability (all or part non-AMR capability at their premises), or for Noncore End-Use Customers with non-functioning AMR meters, compliance during an OFO will be based on the average daily quantity (ADQ) as specified in the Customer's NGSA. The calculation of any applicable noncompliance charges after the OFO event will be based on one of the following, whichever results in the lesser charge:

   a) the Customer's ADQ; or

   b) the Customer's actual daily metered usage; or

   c) when Customer's actual daily metered usage is not available (e.g., due to meter failure), the <u>average</u> daily metered usage for the affected premises will be substituted for the <u>actual</u> daily metered usage. The average daily metered usage is calculated by dividing the recorded monthly usage by the number of days in the billing period.

(Continued)

GAS RULE NO. 21 Sheet 3
TRANSPORTATION OF NATURAL GAS

B. QUANTITIES OF GAS (Cont'd.)

1. IN-KIND SHRINKAGE ALLOWANCE (Cont'd.)

b. Distribution Shrinkage

For transportation on PG&E's Distribution System, an additional In-Kind Shrinkage Allowance shall apply, which is separate from backbone transmission and storage shrinkage. The Customer shall deliver each day to PG&E at the Citygate an additional in-kind quantity of natural gas supply equal to a percent of the total volume of natural gas flowing through the End-Use Customer's meter. Thus, the quantity to be nominated at the Citygate equals the quantity to be flowed through the meter multiplied by (1 + *y*) where *y* is the decimal equivalent of the Distribution System In-Kind Shrinkage Allowance percentage, as follows:

End-Use Customer	Percentage of In-Kind Shrinkage Base Allowance	Percentage of In-Kind Shrinkage Adjustment	Percentage of Effective In-Kind Shrinkage Allowance	
Core – Summer Season (April - October)	1.3 (R)	(0.4) (R)	0.9 (R)	(N)
Core – Winter Season (November – March)	2.0 (N)	(0.4) (N)	1.6 (N)	(N)
Noncore Distribution	0.2	0	0.2	
Noncore Transmission*	–	–	–	

As an example, for a Core End-Use Customer being served via the Redwood Path, the amount to be nominated at Malin is calculated as:

Receipt Point Quantity = Est. Metered Usage x (1 + y) / (1 - x)

Where: x = decimal equivalent of the Backbone Shrinkage percentage, and

y = decimal equivalent of the Distribution Shrinkage percentage

* Noncore Transmission Level End-Use Customers or Agents require no Distribution System In-Kind Shrinkage Allowance.

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GAS TABLE OF CONTENTS

Sheet 6

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ATTACHMENT 2

ATTACHMENT 2

PACIFIC GAS AND ELECTRIC COMPANY
May 1, 2011 Gas Accord V
TABLE 1

AVERAGE END-USER GAS TRANSPORTATION RATES AND PUBLIC PURPOSE PROGRAM SURCHARGES (2)
($/th; Annual Class Averages)

Line No.	Customer Class	Rates Effective April 1, 2011 (A)			May 1, 2011 Gas Accord V (B)			% Change (3) (C)		
		Transportation	G-PPPS (2)	Total	Transportation	G-PPPS (2)	Total	Transportation	G-PPPS (2)	Total
	RETAIL CORE (1)									
1	Residential Non-CARE (4)	$.534	$.084	$.618	$.539	$.084	$.623	0.9%	0.0%	0.8%
2	Small Commercial Non-CARE (4)	$.345	$.051	$.396	$.350	$.051	$.401	1.4%	0.0%	1.2%
3	Large Commercial	$.144	$.094	$.238	$.149	$.094	$.242	3.4%	0.0%	2.1%
4	NGV1 - (uncompressed service)	$.109	$.027	$.136	$.114	$.027	$.141	4.5%	0.0%	3.6%
5	NGV2 - (compressed service)	$1.337	$.027	$1.364	$1.342	$.027	$1.369	0.4%	0.0%	0.4%
	RETAIL NONCORE (1)									
6	Industrial - Distribution	$.118	$.043	$.161	$.122	$.043	$.165	3.9%	0.0%	2.9%
7	Industrial - Transmission	$.030	$.035	$.065	$.034	$.035	$.069	13.8%	0.0%	6.4%
8	Industrial - Backbone	$.008	$.035	$.043	$.007	$.035	$.042	(7.7%)	0.0%	(1.4%)
9	Electric Generation - Transmission (G-EG-D/LT)	$.024		$.024	$.029		$.029	19.4%		19.4%
10	Electric Generation - Backbone (G-EG-BB)	$.008		$.008	$.007		$.007	(7.8%)		(7.8%)
11	NGV 4 - Distribution (uncompressed service)	$.118	$.027	$.144	$.122	$.027	$.149	3.9%	0.0%	3.2%
12	NGV 4 - Transmission (uncompressed service)	$.024	$.027	$.051	$.028	$.027	$.055	17.0%	0.0%	8.1%
	WHOLESALE CORE AND NONCORE (G-WSL) (1)									
13	Alpine Natural Gas	$.030		$.030	$.026		$.026	(13.8%)		(13.8%)
14	Coalinga	$.029		$.029	$.026		$.026	(11.1%)		(11.1%)
15	Island Energy	$.050		$.050	$.027		$.027	(44.7%)		(44.7%)
16	Palo Alto	$.022		$.022	$.025		$.025	13.6%		13.6%
17	West Coast Gas - Castle	$.120		$.120	$.096		$.096	(20.2%)		(20.2%)
18	West Coast Gas - Mather Distribution	$.122		$.122	$.118		$.118	(3.2%)		(3.2%)
19	West Coast Gas - Mather Transmission	$.030		$.030	$.026		$.026	(13.0%)		(13.0%)

(1) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable). Transport only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

(2) D. 04-08-010 authorized PG&E to remove the gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, energy efficiency, Research Development and Demonstration program and BOE/CPUC Administration costs from transportation rates and into its own separate surcharge tariff. Certain customers are exempt from paying the PPP surcharge; see tariff G-PPPS for details. G-PPPS rates are determined annually in PG&E's PPP Filing.

(3) Rates are rounded to 3 decimals for viewing ease. Percentage rate changes are calculated on a 5-digit basis.

(4) CARE Customers receive a 20% discount off of the total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates.

ATTACHMENT 2

PACIFIC GAS AND ELECTRIC COMPANY
MAY 1, 2011 GAS ACCORD V
TABLE 2
SUMMARY OF RATES (excluding procurement) BY CLASS BY MAJOR ELEMENTS
($/th; Annual Class Averages)

		Core Retail					Noncore Retail						
							Industrial			G-NGV 4		Electric Generation	
		Non-CARE Residential	Sml Com.	Lg. Comm.	G-NGV1 (Uncompressed)	G-NGV2 (Compressed)	Distribution	Transmission	BB-Level Serv.	Distribution	Transmission	Dist./Trans.	BB-Level Serv.
	TRANSPORTATION CHARGE COMPONENTS												
1	Local Transmission (1)	$.04367	$.04367	$.04367	$.04367	$.04367	$.02139	$.02139	$.00065	$.02139	$.02139	$.02139	$.00065
2	Self Generation Incentive Program	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090
3	CPUC Fee (3)	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00003	$.00003
4	Balancing Accounts (2)	$.05888	$.04204	$.01588	$.02376	$.04816	$.00175	$.00363	$.00376	$.00175	$.00376	$.00372	$.00372
5	Distribution - Annual Average (6)	$.43516	$.20384	$.08318	$.04395	$1.24869	$.09042	$.00586		$.09042		$.00183	$.00183
6	VOLUMETRIC RATE - Average Annual	$.53929	$.29113	$.14432	$.11296	$1.34211	$.11515	$.03246	$.00599	$.11515	$.02674	$.02787	$.00713
7	CUSTOMER ACCESS CHARGE - Class Average (4)		$.05888	$.00449	$.00120	$.00000	$.00703	$.00166	$.00141	$.00703	$.00166	$.00102	$.00020
8	CLASS AVERAGE TRANSPORTATION RATE	$.53929	$.35002	$.14881	$.11416	$1.34211	$.12218	$.03413	$.00740	$.12218	$.02840	$.02889	$.00733
9	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)	$.08400	$.05078	$.09366	$.02674	$.02674	$.04314	$.03489	$.03489	$.02674	$.02674		
10	END-USE RATE	$.62329	$.40080	$.24247	$.14090	$1.36885	$.16532	$.06902	$.04229	$.14892	$.05514	$.02889	$.00733

		Wholesale						
				WC Gas Mather				
		Coalinga	Palo Alto	Dist.	Trans.	Island Energy	Alpine	WC Gas Castle
	TRANSPORTATION CHARGE COMPONENTS							
11	Local Transmission (1)	$.02139	$.02139	$.02139	$.02139	$.02139	$.02139	$.02139
12	Self Generation Incentive Program							
13	CPUC Fee (3)							
14	Balancing Accounts (2)	$.00375	$.00375	$.00169	$.00375	$.00375	$.00375	$.00219
15	Distribution - Annual Average			$.09394				$.07094
16	VOLUMETRIC RATE - Average Annual	$.02514	$.02514	$.11702	$.02514	$.02514	$.02514	$.09453
17	CUSTOMER ACCESS CHARGE - Class Average (4)	$.00063	$.00016	$.00084	$.00084	$.00229	$.00055	$.00136
18	CLASS AVERAGE TRANSPORTATION RATE	$.02577	$.02530	$.11787	$.02599	$.02743	$.02569	$.09589
19	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)							
20	END-USE RATE	$.02577	$.02530	$.11787	$.02599	$.02743	$.02569	$.09589

NOTES
(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11 adjusted for late implementation of Gas Accord V Settlement rates effective May 1, 2011.
(2) Based on November 2010 recorded balances and forecasted through December.
(3) CPUC Fee based on Resolution M-4819, effective July 1, 2007 (including FF&U).
(4) Adopted in Decision 11-04-031 based on Appendix B, Table 12 adjusted for late implementation of Gas Accord V Settlement rates effective May 1, 2011.
(5) Decision 04-08-010 ordered the removal of PPP cost recovery from transportation rates. On March 1, 2005 PG&E began to treat PPP as a tax. AL 3161-G updated PG&E's 2011 PPP Surcharges effective January 1, 2011.
(6) The G-NGV2 Distribution rate component incudes the cost of compression, station operations and maintanance, and state/federal gas excise taxes.

ATTACHMENT 2
PACIFIC GAS AND ELECTRIC COMPANY
TABLE 3
May 1, 2011 Gas Accord V
ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES
($000)

Line No.	GAS GRC, ATTRITION, PENSION & COST OF CAPITAL DISTRIBUTION-LEVEL REVENUE REQUIREMENTS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore & Wholesale
1	Customer	602,477	525,644	70,050	1,499	61	0	597,254	3,709	211	0	1,304	5,224
2	Distribution	500,244	348,925	112,359	4,958	841	0	467,084	21,364	8,103	0	3,588	33,161
3	G-NGV2 Compression Cost	2,919	0	0	0	0	2,919	2,919	0	0	0	0	0
4	Allocation of Base Distribution Franchise Fees	10,610	8,392	1,750	62	9	28	10,241	241	80	0	47	368
5	Allocation of Base Distribution Uncollectibles Expense	2,825	2,235	466	16	2	7	2,727	64	21	0	12	98
6	Totals Before Core Averaging	1,119,075	885,197	184,626	6,535	913	2,954	1,080,225	25,377	8,415	0	4,951	38,850
7	Re-Allocation Due to Core Averaging*	(0)	(23,546)	23,546	0	0	0	(0)	0	0	0	0	0
8	**Final Allocation of Distribution Revenue Requirement**	**1,119,075**	**861,650**	**208,172**	**6,535**	**913**	**2,954**	**1,080,226**	**25,377**	**8,415**	**0**	**4,951**	**38,850**
	Distribution-Level Revenue Requirement Allocation %	100.00000%	76.99666%	18.60214%	0.58398%	0.08158%	0.26399%	96.52835%	2.26768%	0.75196%	0.00000%	0.44245%	3.47165%
	CUSTOMER CLASS COSTS WITHOUT RATE COMPONENTS	**TOTAL**	**Residential***	**Small Commercial***	**Large Commercial**	**Core NGV**	**Compression Cost for G-NGV2**	**Subtotal Core**	**Industrial Distribution**	**Industrial Transmission**	**Industrial Backbone**	**Electric Gen**	**Noncore & Wholesale**
9	Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount	22,137	17,658	4,266	134	19	61	22,137	0	0	0	0	0
10	Core Fixed Cost Acct. Bal. - Core Cost Subaccount - ECPT	7,558	5,245	2,066	194	53	0	7,558	0	0	0	0	0
11	CFCA-Winter Gas Savings Program Transportation Portion	20,312	16,260	3,928	123	0	0	20,312	0	0	0	0	0
12	Noncore Customer Class Charge Account - ECPT	(24)	0	0	0	0	0	0	(1)	(8)	(0)	(15)	(24)
13	Noncore Customer Class Charge Account - Interim Relief	200	0	0	0	0	0	0	131	43	0	25	200
14	NC Distribution Fixed Cost Acct.	(1,038)	0	0	0	0	0	0	(678)	(225)	0	(132)	(1,038)
15	CA Solar Hot Water Heating	0	0	0	0	0	0	0	0	0	0	0	0
16	LNG Account Balance	0	0	0	0	0	0	0	0	0	0	0	0
17	Hazardous Substance Balance	26,880	7,356	2,898	273	74	0	10,601	952	5,256	43	9,872	16,279
18	Non-Tariffed Products and Services	(223)	(155)	(61)	(6)	(2)	0	(223)	0	0	0	0	0
19	Core Brokerage Fee Credit (Gas Brokerage Costs w/o FF&U)	(5,475)	(3,799)	(1,497)	(141)	(38)	0	(5,475)	0	0	0	0	0
20	Core Brokerage Fee Credit (Sales/Marketing Costs w/o FF&U)	(1,029)	(906)	(121)	(3)	(0)	0	(1,029)	0	0	0	0	0
21	Affiliate Transfer Fee Account	(153)	(121)	(25)	(1)	(0)	(0)	(148)	(3)	(1)	0	(1)	(5)
22	Balancing Charge Account	(679)	(186)	(73)	(7)	(2)	0	(268)	(24)	(133)	(1)	(249)	(411)
23	G-10 Procurement-related Employee Discount Allocated	1,128	309	122	11	3	0	445	40	221	2	414	683
24	Brokerage Fee Balance Account	1,150	798	314	30	8	0	1,150	0	0	0	0	0
25	G-10 Procurement-related Employee Discount	(1,128)	(1,128)	0	0	0	0	(1,128)	0	0	0	0	0
26	2007 GRC Office Closure (net of FF&U)	(351)	(280)	(68)	(2)	(0)	(1)	(351)	0	0	0	0	0
27	Gas Reimburseable Fees Account Balance	0	0	0	0	0	0	0	0	0	0	0	0
28	WGSP Balancing Account	(9,102)	(8,276)	(768)	(58)	0	0	(9,102)	0	0	0	0	0
29	Climate Protection Tariff	0	0	0	0	0	0	0	0	0	0	0	0
30	Self Gen Incentive Program Forecast Period Cost	6,480	1,782	702	66	17.921	0	2,569	231	1,274	10	2,392	3,911
31	Subtotals of Items Transferred to CFCA and NCA	66,643	34,558	11,684	614	132	59	47,048	647	6,428	53	12,307	19,595
32	Re-Allocation Due to Core Averaging	(0)	15	(15)	0	0	0	(0)	0	0	0	0	0
33	Alloc. After Core Averaging	66,643	34,573	11,670	614	132	59	47,048	647	6,428	53	12,307	19,595
34	Franchise Fees and Uncoll. Exp. on Items Above	809	420	142	7	2	1	572	8	78	1	150	238
35	Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs	67,452	34,993	11,811	622	134	60	47,620	655	6,506	54	12,457	19,833
36	Total of Items Collected via CFCA, NCA, and NDFCA	1,186,527	896,643	219,983	7,157	1,047	3,014	1,127,844	26,032	14,921	54	17,408	58,683
	CUSTOMER CLASS COSTS WITH THEIR OWN RATE COMPONENTS	**TOTAL**	**Residential***	**Small Commercial***	**Large Commercial**	**Core NGV**	**Compression Cost for G-NGV2**	**Subtotal Core**	**Industrial Distribution**	**Industrial Transmission**	**Industrial Backbone**	**Electric Gen**	**Noncore & Wholesale**
37	EOR Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0
38	CEE Incentive	5,568	4,858	647	14	1	0	5,520	34	2	0	12	48
39	AB32 ARB Implementation Fee	0	0	0	0	0	0	0	0	0	0	0	0
40	Smart Meter™ Project Forecast Period Costs	45,997	36,690	8,864	278	165	0	45,997	0	0	0	0	0
41	SmartMeter™ Project Balancing Account (SBA-G)	54,491	43,465	10,501	330	195	0	54,491	0	0	0	0	0
42	CPUC FEE	3,210	1,368	538	51	13.751	0	1,970	177	977	8	75	1,240
43	Subtotals for Customer Class Charge Items	109,266	86,381	20,550	672	374	0	107,978	211.353	979	8	87	1,289
44	Re-Allocation Due to Core Averaging	0	-1,934	1,934	0	0	0	0	0	0	0	0	0
45	Allocation after Remaining Core Averaging	109,266	84,446	22,484	672	374	0	107,978	211	979	8	87	1,289
46	Franch. Fee and Uncoll. Exp. on Items Above	1,328	1,026	273	8	5	0	1,312	3	12	0	1	16
47	Subtotals of Other Costs	110,594	85,473	22,758	681	379	0	109,290	214	991	8	88	1,304
48	Allocation of Total Transportation Costs	1,297,121	982,116	242,741	7,837	1,425	3,014	1,237,134	26,246	15,912	62	17,496	59,988
	RECONCILIATION WITH REVENUE REQUIREMENTS TABLE FOR END-USER TRANSPORTATION TOTALS	**TOTAL**	**Residential***	**Small Commercial***	**Large Commercial**	**Core NGV**	**Compression Cost for G-NGV2**	**Subtotal Core**	**Industrial Distribution**	**Industrial Transmission**	**Industrial Backbone**	**Electric Gen**	**Noncore & Wholesale**
49	WGSP-T Rebate Recovery (w/o FF&U)	(18,133)	(14,516)	(3,507)	(110)			(18,133)					0
50	Franchise Fees and Uncollectibles Expense	(220)	(176)	(43)	(1)			(220)					0
51	Total End-User Transportation Rev. Req. Excluding Gas Accord	1,278,769	967,424	239,191	7,726	1,425	3,014	1,218,781	26,246	15,912	62	17,496	59,988

ATTACHMENT 2
PACIFIC GAS AND ELECTRIC COMPANY
TABLE 3 (continued)

May 1, 2011 Gas Accord V
ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES
($000)

	ADOPTED REVENUE REQUIREMENTS ALLOCATIONS FOR GAS ACCORD ITEMS IN TRANSPORTATION	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore & Wholesale
52	Local Transmission	197,833	98,790	29,349	1,836	411		130,386	6,810	27,090		32,140	67,447
53	Customer Access Charge	4,691	0	0	0			0	0	2,473		2,116	4,691
54	Total End-User Gas Accord Transportation Costs	202,524	98,790	29,349	1,836	411	0	130,386	6,810	29,563	0	34,256	72,138
55	Gross End-User Transportation Costs in Rates	1,481,293	1,066,214	268,541	9,562	1,836	3,014	1,349,167	33,056	45,475	62	51,752	132,126
56	Less Forecast CARE Discount recovered in PPP Surcharges	110,499	110,499					110,499					0
57	Net End-User Transportation Costs in Rates	1,370,794	955,715	268,541	9,562	1,836	3,014	1,238,668	33,056	45,475	62	51,752	132,126

	ALLOCATION OF PUBLIC PURPOSE PROGRAM SURCHARGES UNDER PER PG&E AL 3161-G	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore & Wholesale
58	PPP-EE Surcharge	77,850	61,361	6,245	2,447	0		70,052	2,092	5,659	46		7,798
59	PPP-EE Balancing Account	12,076	9,519	969	380	0		10,867	325	878	7		1,210
60	PPP-LIEE Surcharge	64,284	50,668	5,156	2,021	0		57,845	1,728	4,673	38		6,439
61	PPP-LIEE Balancing Account	(262)	(206)	(21)	(8)	0		(235)	(7)	(19)	(0)		-26
62	PPP - RD&D Programs	10,349	4,598	1,782	166	41		6,586	578	3,147	25		3,762
63	PPP - RD&D Balancing Account	(76)	(34)	(13)	(1)	(0)		(48)	(4)	(23)	(0)		-28
64	PPP-CARE Discount Allocation Set Annually	110,499	41,631	21,339	1,983	494		65,447	6,918	37,686	305		45,052
65	PPP-CARE Administration Expense	1,904	717	368	34	9		1,128	119	649	5		776
66	PPP-CARE Balancing Account	(14,040)	(5,289)	(2,711)	(252)	(63)		(8,315)	(879)	(4,788)	(39)		-5,724
67	PPP-Admin Cost for BOE and CPUC	284	126	49	5	1		181	16	86	1		103
68	Subtotal	262,869	163,090	33,162	6,773	482		203,507	10,886	47,948	388	0	59,362
69	Re-Allocation Due to Core Averaging	(0)	(6,359)	6,359	0	0		(0)	0	0	0	0	0
70	Allocation after Remaining Averaging	262,869	156,731	39,521	6,773	482		203,507	10,886	47,948	388	0	59,362

	ILLUSTRATIVE ALLOCATION OF GAS PROCUREMENT REVENUE REQUIREMENTS	TOTAL	Residential	Small Commercial	Large Commercial	Core NGV		Subtotal Core
71	llustrative Core Bundled Cost of Gas, Shrinkage, and FF&U	1,164,084	875,611	257,534	21,998	8,940		1,164,084
72	Illustrative Interstate and Canadian Capacity Charges	180,374	142,699	34,998	1,921	756		180,374
73	Intrastate Volumetric and Backbone	90,279	70,325	18,283	1,194	477		90,279
74	Cycled Carrying Cost of Gas in Storage	1,662	1,250	368	31	13		1,662
75	Core Storage and Noncycled Carrying Cost of Gas in Storage	51,949	40,966	10,152	601	229		51,949
76	Brokerage Fees	6,583	4,952	1,456	124	51		6,583
77	Winter Gas Savings Program	(1,861)	(1,424)	(318)	(120)	0		(1,861)
78	Subtotal	1,493,069	1,134,380	322,474	25,749	10,465		1,493,069
79	Re-allocation Due to Core Averaging	0	(1,726)	1,726	0.0	0		0
80	Total Illustrative Procurement for Rate Making Purposes	1,493,069	1,132,654	324,200	25,749	10,465		1,493,069
81	Core Proc BB Seed Value for Reconciliation with Total RRQ	4,650	3,678	902	50	19		4,650
82	Storage Late Implementation RRQ for Reconciliation with Total RRQ	(2,693)	(2,124)	(526)	(31)	(12)		(2,693)
83	Total Authorized Illustrative Procurement RRQ	1,495,026	1,134,209	324,576	25,767	10,473	0	1,495,026

84	Unbundled Gas Transmission and Storage Revenue Requirement	167,493

	TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES		
85	Total Transportation, PPPS, Procurement, and Unbundled Costs	3,296,182	(Total of lines 57, 70, 83 and 84)

* Residential and Small Commercial Classes are 20% averaged

** Wholesale Customer West Coast Gas is allocated 60 % of its full Distribution Cost allocation as of January 1, 2011

PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

AT&T
Alcantar & Kahl LLP
Ameresco
Anderson & Poole
Arizona Public Service Company
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Bloomberg
Bloomberg New Energy Finance
Boston Properties
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California League of Food Processors
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Calpine
Casner, Steve
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City of Palo Alto
City of Palo Alto Utilities
Clean Energy Fuels
Coast Economic Consulting
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Intestate Gas Services, Inc.
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MBMC, Inc.
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North Coast SolarResources
Occidental Energy Marketing, Inc.
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Praxair
R. W. Beck & Associates
RCS, Inc.
Recurrent Energy
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SCE
SMUD
SPURR
San Francisco Public Utilities Commission
Santa Fe Jets
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
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Southern California Edison Company
Spark Energy, L.P.
Sun Light & Power
Sunshine Design
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Turlock Irrigation District
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation