STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298
Tel. No. (415) 703-1691

January 28, 2004

Advice Letter 2508-G

Ms Anita Smith, Rate Analyst
Pacific Gas and Electric Company
77 Beale Street, 10B Mail Code
San Francisco, CA 94177

Subject: January 1, 2004, Gas Accord II Tariff Revisions and Rate Changes

Dear Ms Smith:

Advice Letter 2508-G is effective January 1, 2004. A copy of the advice letter is sent herewith for your records.

Sincerely,

Paul Clanon

Director
Energy Division

Pacific Gas and
Electric Company

Karen A. Tomcala
Vice President
Regulatory Relations

77 Beale Street, Room 1065
San Francisco, CA 94105

Mailing Address
Mail Code B10A
P.O. Box 770000
San Francisco, CA 94177

415.972.5209
Internal: 222.5209
Fax: 415.972.5625
Internet: kat5@pge.com

December 23, 2003

ADVICE 2508-G
(Pacific Gas and Electric Company ID U39G)

Subject: January 1, 2004, Gas Accord II Tariff Revisions and Rate Changes (Noncore Gas Transportation and Backbone Transmission Tariffs)

Public Utilities Commission of the State of California

Purpose

The purpose of this filing is to submit proposed revisions to Pacific Gas and Electric Company's (PG&E's) gas tariffs for Commission-adopted changes effective **January 1, 2004.**[1] This filing updates noncore gas transportation rates, backbone transmission rates, and the gas revenue requirement resulting from Gas Accord II-2004 Decision (D.) 03-12-061 (or Gas Accord II decision), dated December 18, 2003. This filing also incorporates the noncore rates and gas revenue requirement filed in the Annual True-up Advice 2498-G, on November 14, 2003, and the CPUC fee adopted in Resolution (R.) M-4810, on December 18, 2003

This filing also includes tariff revisions in compliance with D. 03-12-061. The affected tariff sheets are included in Attachment I to this filing. Rate tables showing the consolidated impact on core and noncore rates, and the Gas Accord II adopted rates are included in Attachment II.

Core gas rates, effective January 1, 2004, are being filed concurrently in the core procurement monthly price Advice 2507-G to incorporate backbone, local transmission, and other rate revisions adopted in D. 03-12-061, the core rate changes filed in the Annual True-up Advice 2498-G, and the CPUC fee adopted in R. M-4810. The illustrative core rate changes are shown in Tables 15 and 16 of Attachment II.

[1] PG&E reserves all legal rights to challenge the decisions or statutes under which it has been required to make this advice filing, and nothing in this advice filing constitutes a waiver of such rights. Also, PG&E reserves any additional legal rights to challenge the requirement to make this advice filing by reason of its status as a debtor under Chapter 11 of the Bankruptcy Code, and nothing in this advice fling constitutes a waiver of such rights.

PG&E

Gas Accord II Rate and Revenue Requirement Changes

Gas Accord II D.03-12-061 adopts rates, terms and conditions of service for PG&E's natural gas transmission and storage system for 2004, and adopts the existing Gas Accord market structure for 2004 and 2005.[2] D. 03-12-061 adopts a revenue requirement for 2004 of $436,397,000. The adopted revenue requirement represents an increase of 2.94 percent over the adopted 2003 transmission and storage revenue requirement of $423,923,000.

This filing implements the rates for backbone, local transmission, customer access, as well as operations and balancing services, and other provisions that become effective January 1, 2004, pursuant to Ordering Paragraph (OP) 4 and OPs 6.a and 6.i of D. 03-12-061.

Storage rates, terms and services adopted in D. 02-08-070, dated August 22, 2002, remain in effect through March 31, 2004. Pursuant to OP 6.k of D. 03-12-061, PG&E will file tariffs reflecting the adopted storage and market service rates, and services, on or before January 20, 2004, to be effective April 1, 2004.[3]

The Gas Accord II decision also adopts rates and services for a single electric generation (EG) class to be implemented April 1, 2004. In accordance with OP 6.k, the tariffs reflecting the changes to Schedule G-EG and eliminating Schedule G-COG will be filed on or before January 20, 2004, in conjunction with the storage rates filing.

D. 03-12-061 continues the Core Procurement Incentive Mechanism (CPIM) through 2005[4], or until a revised CPIM is adopted by the CPUC.

The major provisions adopted by D. 03-12-061 and filed herein are summarized below. This filing implements the following provisions of the Gas Accord II decision effective January 1, 2004:

1. Updates backbone transmission rates using the adopted 77.02 percent load factor.
2. Updates noncore local transmission and customer access charges.

---

[2] D.03-12-061 adopts the Gas Accord market structure that was approved in D.97-08-055, as refined by D.00-02-050 and D.00-05-049, as extended by D.02-08-070, and as further refined by specific proposals adopted in D.03-12-061. The Gas Accord II decision also adopts storage rates and terms of service for the 2004/05 storage year beginning April 1, 2004, to March 31, 2005.

[3] OP 6.k states that PG&E will file an Advice letter within 30 days of December 18, 2003, the date D.03-12-061 was adopted, to implement adopted rates and changes to its affected gas schedules and rules associated with implementing the single electric generation class and storage provisions that will become effective April 1, 2004. January 17, 2004, falls on a weekend, and January 19, 2004, is a holiday; therefore, PG&E will submit this filing no later than January 20, 2004.

[4] PG&E assumes that D.03-12-061 continues the CPIM through the 2005/06 winter storage season ending March 31, 2006.

3. Revises core and noncore distribution rates to reflect the distribution marginal cost revenue allocation to the industrial transmission customer class and eliminates the shareholder-funded distribution shortfall.
4. Revises Schedule G-NT to simplify the eligibility for transmission-level rates by adding a 5^{th} tier to the distribution-level rates set equal to G-NT transmission-level rates. A similar change is made to Schedule G-NGV4.
5. Implements an interim rate design structure for Schedules G-EG and G-COG from January 1, 2004, through March 31, 2004, that applies the adopted 2004 revenue requirement allocated to electric generation and cogeneration customers to the existing rate design; also removes the 60-day lag between Schedules G-EG and G-COG. A single EG class begins April 1, 2004.
6. Eliminates the rate component to recover the Cogeneration Distribution Shortfall balancing account and includes the balance in the distribution rate component of Schedule G-EG and G-COG (see details in Annual True-up section below).
7. Revises Schedules G-AFT and G-AFT-OFF to allow offers for firm backbone transmission contracts with terms of up to 15 years.
8. Revises the commensurate discount rule shown on backbone transmission Schedules G-NFT and G-NAA to allow PG&E more discretion to discount Redwood-to-on-system service.
9. Revises Gas Rule 21 to implement new procedures for scheduling non-performance.
10. Revises Gas Rule 14 to add a provision for Local Curtailment noncompliance charges, adds a gas cost component to Operational Flow Order (OFO) and Emergency Flow Order (EFO) charges, applies OFO and EFO charges to California gas production; and changes the basis for measuring OFO and EFO noncompliance charges for Core Procurement Groups; Preliminary Statement Part L – *Balancing Charge Account (BCA)* is revised accordingly.
11. Revises Schedule G-BAL to change the index used to calculate cashout charges upon termination of the customer's gas transportation agreement, and to change the self-balancing noncompliance charges from a fixed charge to an index-based charge.
12. Eliminates the third-party trading platform and service adopted in D.00-05-049 and adopts PG&E's proposal to credit back $656,000 to the BCA for amounts previously authorized to implement the trading platform. Rule 21.2 is thereby eliminated and revisions to the BCA, Schedule G-BAL, and Gas Rule 14 reflect this change.
13. Revises Schedule G-CT to state that gas Energy Service Providers (gas ESPs) will not be able to reject any offered pipeline or storage capacities if the core transportation volume reaches 10 percent of the total core January load.

14. Updates the transmission and distribution shrinkage allowances as shown in Gas Rule 21.[5]

OP 6.i directs PG&E to file an advice letter, within ten days of approval of the Gas Accord II decision, that develops a rate table reflecting the CPUC's determination that rates for distribution-level electric generators are to remain as currently calculated. In compliance, PG&E is filing the requested table herein, as shown in Table 14, Attachment II.[6]

This filing updates noncore rates in Preliminary Statement Part B; and updates the Base Revenue amounts shown in Part C.2, Preliminary Statement Part C--*Accounting Terms and Definitions*, to reflect the annual revenue requirement adjustments resulting from the Gas Accord II decision, Advice 2498-G and R. M-4810.

This filing also includes minor changes to various rate schedules and rules for clarification and consistency.

Annual True-Up

On November 14, 2003, PG&E filed its Annual True-up Advice 2498-G, that updated the transportation balancing account balances in core and noncore transportation rates effective January 1, 2004. That filing incorporated the gas revenue requirement approved in Advice 2459-G resulting from the 1999 General Rate Case (GRC) Rehearing D. 03-04-002. That filing also updated the gas Public Purpose Program (PPP) balancing accounts and California Alternate Rates for Energy (CARE) subsidy which were filed in PPP Gas Surcharge Advice 2488-G/G-A and adopted in Resolution G-3361 on December 18, 2003 for January 1, 2004.

The rate changes resulting from the Annual True-up for noncore customer classes are incorporated herein, with one revision authorized in D. 03-12-061, as described below.

Pursuant to D. 03-12-061, Preliminary Statement Part W – *Cogeneration Distribution Shortfall Account (CDSA)* has been eliminated and the CDSA rate component removed from Preliminary Statement Part B. The November 2003 recorded balance in the CDSA of ($462,609) has been incorporated as a credit to

---

[5] OP 6.a orders PG&E to file the update in transmission and distribution shrinkage allowance on or before December 31, 2003, with an effective date of January 1, 2004. In addition, OP 6.b orders PG&E to file an advice letter to calculate an in-kind storage shrinkage allowance to be applied to all scheduled storage injection volumes on or before March 19, 2004, with an effective date of April 1, 2004.

[6] D. 03-12-061 adopts a single average distribution rate for cogeneration and electric generation customers for 2004. Table 14 filed in Attachment II herein, computes a single average distribution rate applicable to cogeneration and electric generation customers and effectively supercedes the segmented distribution rates presented in Appendix A, Table 15 of D. 03-12-061, which were not adopted.

the distribution rate component of the Schedules G-COG and G-EG rates with no balancing account treatment.

CPUC Fee

On December 18, 2003, the CPUC adopted Resolution M-4810 decreasing the CPUC fee from $.001988 per therm to $0.00076 per therm effective January 1, 2004. Preliminary Statement Part O and the footnote to Preliminary Statement Part B are updated to reflect this change.

Rate Changes

The following table summarizes the present and January 1, 2004, class average core and noncore gas transportation rates resulting from this advice filing. The core transportation class average rates shown below, are being filed concurrently this date in Advice 2507-G with the monthly core procurement rate effective January 1, 2004.

CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
CLASS AVERAGE RATES ($/th)

Customer Class	Present Rates	Rates 1/1/04	% Change (b)
TRANSPORT ONLY - Retail Core (a)			
Residential Non-CARE (G-CT)	$.318	$.315	-1.0%
Residential CARE (G-CT)	$.122	$.119	-2.2%
Small Commercial (G-CT)	$.315	$.313	-0.8%
Large Commercial (G-CT)	$.207	$.210	1.1%
TRANSPORT ONLY - Retail Noncore(a)			
Industrial Distribution (G-NT)	$.121	$.118	-2.6%
Industrial Transmission (G-NT)	$.045	$.054	22.2%
Cogeneration (G-COG)	$.025	$.026	7.5%
Electric Generation (G-EG)	$.025	$.026	7.5%
TRANSPORT ONLY - Wholesale Core and Noncore (a)			
Alpine Natural Gas	$.027	$.036	34.8%
Coalinga	$.027	$.036	33.4%
Island Energy	$.051	$.098	91.1%
Palo Alto	$.024	$.028	17.3%
West Coast Gas - Castle	$.030	$.043	45.7%
West Coast Gas - Mather	$.030	$.043	45.4%

(a) Transport-only rates exclude intrastate backbone transmission and storage charges.

(b) Differences due to rounding

The net rate impacts from Gas Accord II D. 03-12-061, updating balancing account balances and the 1999 GRC base revenue requirement in the Annual True-up Advice 2498-G, updating public purpose program costs as described in Advice 2488-G/G-A, and updating the CPUC fee pursuant to R. M-4810, vary by customer class. The net rate impact for each customer class is described below.

Residential and small commercial gas transportation rates decrease from 0.8 - 2.2 percent, on average, primarily due to changes in balancing account balances, the revision to the GRC base revenue requirement, decreases in the CPUC fee and distribution rate component, offset by an increase in the local transmission component.

Large commercial gas transportation rates increase 1.1 percent, on average, primarily due an increase in the local transmission component, offset by decreases in the CPUC fee, the distribution rate component, changes in balancing account balances and the revision to the GRC base revenue requirement.

Industrial distribution rates decrease 2.6 percent, on average, primarily due to changes in balancing account balances and the revision to the GRC base revenue requirement.

Industrial transmission rates increase 22.2 percent, on average, primarily due to increases in public purpose program costs, monthly fixed customer access charges and local transmission rates, offset by decreases in the CPUC fee and other balancing account balances.

Cogeneration and electric generation rates increase 7.5 percent primarily due to increases in customer access charges and local transmission rates, offset by decreases in the CPUC fee and other balancing account balances.

Wholesale customer rates increase from 17.3 to 91.1 percent primarily due to increases in monthly fixed customer access charges and local transmission rates, offset by decreases in other balancing account balances.

Effective Date

PG&E requests that this filing be approved effective **January 1, 2004**. In accordance with OP 4.b of D. 03-12-061, these rates shall remain in effect, even if protested, until a Commission resolution or decision rescinds, suspends, or changes the rate(s) or practices(s) described in the advice letter.

Protests

In accordance with OP 4.c, D. 03-12-061, anyone wishing to protest this filing may do so by sending a letter within 10 days of the date of this filing, which is **January 2, 2004**. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

IMC Branch Chief - Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: jjr@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4005 and Jerry Royer, Energy Division, at the address shown above. It is also requested that a copy of the protest be sent via postal mail and facsimile to Pacific Gas and Electric Company on the same date it is mailed or delivered to the Commission at the address shown below:

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

Facsimile: (415) 973-7226
E-mail: RxDd@pge.com

Notice

In accordance with General Order 96-A, Section III, Paragraph G, and OP 4.d of D. 03-12-061, a copy of this advice letter is being sent electronically and sent via U.S. mail to parties shown on the attached list and the service lists shown below. Supporting workpapers for this filing are available upon written request to: Pacific Gas and Electric Company, Regulatory Relations Department, Attention: Sandra Ciach, 77 Beale Street, Mail Code B10C, P.O. Box 770000, San Francisco, CA 94177. Address change requests should be directed to Ms. Ciach at (415) 973-7572. Advice letter filings can also be accessed electronically at:

http://www.pge.com/customer_services/business/tariffs/

Karen A. Tomcala/sa

Vice President – Regulatory Relations

Attachments

Service List – Gas Accord II (A. 01-10-011)

Cal. P.U.C. Sheet No.	Title of Sheet	Canceling Cal P.U.C. Sheet No.
	Preliminary Statement	
22015-G*	Part B—Default Tariff Rate Components - (Noncore p. 1)	21692-G
22016-G	Part B (Noncore p. 2) (Cont'd)	21693-G
22017-G	Part B (Noncore p. 3) (Cont'd)	21789-G
22018-G	Part B (Noncore p. 4) (Cont'd)	21390-G
22019-G	Part B (Noncore p. 5) (Cont'd)	21391-G
22020-G	Part B (Noncore p. 6) (Cont'd)	21695-G
22021-G	Part B (Noncore p. 7) (Cont'd)	21696-G
22022-G	Part B (Noncore p. 8) (Cont'd)	21697-G
22023-G	Part B Mainline Extension (Cont'd)	21018-G
22024-G	Part B (Footnotes) (Cont'd)	20842-G
22025-G	Part C—Gas Accounting Terms and Definitions	21429-G
22026-G	Part C (Cont'd)	21601-G
22027-G	Part C (Cont'd)	20844-G
22028-G	Part C (Cont'd)	18047-G
22029-G	Part C (Cont'd)	21395-G
22030-G	Part C (Cont'd)	21976-G
22031-G	Part L—Balancing Charge Account	20854-G
22032-G	Part L (Cont'd)	20030-G
22033-G	Part O --CPUC Reimbursement Fee	21360-G
Delete	Part W -- Cogeneration Distribution Shortfall Account	19203-G
	Rate Schedules	
22034-G	G-MHPS—Master-Metered Mobilehome Park Safety Surcharge	19986-G
22035-G	G-NT—Gas Transportation Service to Noncore End-Use Customers	21857-G
22036-G	G-NT (Cont'd)	21858-G
22037-G	G-NT (Cont'd)	18361-G
22038-G	G-NT (Cont'd)	20450-G
22039-G	G-COG—Gas Transportation Service to Cogeneration Facilities	19794-G
22040-G	G-EG-- Gas Transportation Service to Transmission Level Electric Generation	20292-G
22041-G	G-EG (Cont'd.)	21862-G
22042-G	G-30—Public Outdoor Lighting Service	20594-G
22043-G	G-WSL—Gas Transportation Service to Wholesale/Resale Customers	20759-G
22044-G	G-WSL (Cont'd)	19253-G
22045-G	G-WSL (Cont'd)	19253-G

Cal. P.U.C. Sheet No.	Title of Sheet	Canceling Cal P.U.C. Sheet No.
22046-G	G-BAL—Gas Balancing Service for Intrastate Transportation Customers	21866-G
22047-G	G-BAL (Cont'd.	21869-G
22048-G	G-BAL (Cont'd)	21870-G
22049-G	G-BAL (Cont'd)	20040-G
22050-G	G-BAL (Cont'd)	20041-G
22051-G	G-BAL (Cont'd)	20045-G
22052-G	G-AFT—Annual Firm Transportation On-System	21821-G
22053-G	G-AFT (Cont'd)	21822-G
22054-G	G-AFT (Cont'd)	21823-G
22055-G	G-AFTOFF—Annual Firm Transportation Off-System	21824-G
22056-G	G-AFTOFF (Cont'd)	21825-G
22057-G	G-AFTOFF (Cont'd)	21826-G
22058-G	G-SFT—Seasonal Firm Transportation On-System Only	20865-G
22059-G	G-SFT (Cont'd)	21828-G
22060-G	G-AA—As-Available Transportation On-System	21830-G
22061-G	G-AAOFF—As-Available Transportation Off-System	21832-G
22062-G	G-NFT—Negotiated Firm Transportation On-System	19084-G
22063-G	G-NFT (Cont'd)	21834-G
22064-G	G-NAA—Negotiated As-Available Transportation On ~~Off~~-System	18468-G
22065-G	G-XF—Pipeline Expansion Firm Intrastate Transportation Service	21880-G
22066-G	G-XF (Cont'd)	21881-G
22067-G	G-CT—Core Gas Aggregation Service	21884-G
22068-G	G-NGV4—Experimental Gas Transportation Service to Noncore Natural Gas Vehicles	21888-G
22069-G	G-NGV4 (Cont'd)	21701-G
22070-G	G-NGV4 (Cont'd)	21701-G
22071-G	G-LNG—Experimental Liquefied Natural Gas	21889-G
	Rules	
22072-G	Rule 14—Capacity Allocation and Constraint of Natural Gas	20064-G
22073-G	Rule 14 (Cont'd)	20065-G
22074-G	Rule 14 (Cont'd)	20458-G
22075-G	Rule 14 (Cont'd)	20067, 20068, 20069, 21892-G
22076-G	Rule 14 (Cont'd)	21537-G

Cal. P.U.C. Sheet No.	Title of Sheet	Canceling Cal P.U.C. Sheet No.
22077-G	Rule 14 (Cont'd)	20428-G
22078-G	Rule 14 (Cont'd)	20429-G
22079-G	Rule 14 (Cont'd)	20460-G
22080-G	Rule 14 (Cont'd)	19122-G
22081-G	Rule 14 (Cont'd)	19122-G
22082-G	Rule 21—Transportation of Natural Gas	21841-G
22083-G	Rule 21 (Cont'd)	21842-G
22084-G	Rule 21 (Cont'd)	21843-G
22085-G	Rule 21 (Cont'd)	21847-G
22086-G	Rule 21 (Cont'd)	21850-G
22087-G	Rule 21 (Cont'd)	21851-G
Delete	Rule 21.2—Customer Assignment of Intrastate Capacity	20070,20071-G
	Forms	
22088-G	Form No. 79-944—California Production Balancing Agreement	18302-G
	Tables of Contents	
22089-G	Table of Contents – Sample Forms	21551-G
22090-G	Table of Contents – Rules	20893-G
22091-G	Table of Contents – Preliminary Statements	22012-G
22092-G	Table of Contents (Cont'd)	20783-G
22093-G	Table of Contents	20784-G

PRELIMINARY STATEMENT
(Continued)

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

NONCORE p. 1

	G-NT TRANSMISSION		G-NT—DISTRIBUTION (1)*				
			SUMMER				
THERMS:			0- 20,833 (C)	20,834- 49,999 (C)	50,000- 166,666 (C)	166,667- 249,999***	(C)
NCA	0.00315	(I)	(0.00021) (R)	(0.00021) (R)	(0.00021) (R)	(0.00021) (R)	
DSM	0.00218	(R)	0.00339 (R)	0.00339 (R)	0.00339 (R)	0.00339 (R)	
GRC 2000 INTERIM ACCT	0.00000		0.00019 (I)	0.00019 (I)	0.00019 (I)	0.00019 (I)	
CARE	0.01547	(I)	0.01547 (I)	0.01547 (I)	0.01547 (I)	0.01547 (I)	
CPUC FEE**	0.00077	(R)	0.00077 (R)	0.00077 (R)	0.00077 (R)	0.00077 (R)	
EOR	0.00000		0.00001 (R)	0.00001 (R)	0.00001 (R)	0.00001 (R)	
CEE	0.00000		(0.00001) (R)	(0.00001) (R)	(0.00001) (R)	(0.00001) (R)	
EL PASO CAPACITY CHARGE	0.00616		0.00616	0.00616	0.00616	0.00616	
LOCAL TRANSMISSION (AT RISK)	0.01574	(I)	0.01574 (I)	0.01574 (I)	0.01574 (I)	0.01574 (I)	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00310	(I)	0.05597 (R)	0.04293 (R)	0.03995 (R)	0.03395 (R)	
TOTAL RATE	**0.04657**	**(I)**	**0.09748 (R)**	**0.08444 (R)**	**0.08146 (R)**	**0.07546 (R)**	

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). (R)

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

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

NONCORE p. 2

	G-NT—DISTRIBUTION (1)*			
	WINTER			
THERMS:	0- 20,833 (C)	20,834- 49,999 (C)	50,000- 166,666 (C)	166,667- 249,999*** (C)
NCA	(0.00027) (R)	(0.00027) (R)	(0.00028) (R)	(0.00028) (R)
DSM	0.00339 (R)	0.00339 (R)	0.00339 (R)	0.00339 (R)
GRC 2000 INTERIM ACCT	0.00026 (I)	0.00026 (I)	0.00026 (I)	0.00026 (I)
CARE	0.01547 (I)	0.01547 (I)	0.01547 (I)	0.01547 (I)
CPUC FEE**	0.00077 (R)	0.00077 (R)	0.00077 (R)	0.00077 (R)
EOR	0.00001 (R)	0.00001 (R)	0.00001 (R)	0.00001 (R)
CEE	(0.00001) (R)	(0.00001) (R)	(0.00001) (R)	(0.00001) (R)
EL PASO CAPACITY CHARGE	0.00616	0.00616	0.00616	0.00616
LOCAL TRANSMISSION (AT RISK)	0.01574 (I)	0.01574 (I)	0.01574 (I)	0.01574 (I)
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.07557 (R)	0.05797 (R)	0.05394 (R)	0.04585 (R)
TOTAL RATE	**0.11709 (R)**	**0.09949 (R)**	**0.09545 (R)**	**0.08736 (R)**

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). (R)

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

(Continued)

PRELIMINARY STATEMENT
(Continued)

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 3

	G-COG (3)*	G-EG (4)*	
NCA	0.00224 (I)	0.00224 (I)	
DSM	0.00000	0.00000	
GRC 2000 INTERIM ACCT	0.00000	0.00000	
CARE	0.00000	0.00000	
CPUC FEE **	0.00073 (R)	0.00073 (R)	
EOR	0.00000	0.00000	
CEE	0.00000	0.00000	
EL PASO CAPACITY CHARGE	0.00616	0.00616	(D)
LOCAL TRANSMISSION (AT RISK)	0.01574 (I)	0.01574 (I)	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00046 (I)	0.00046 (I)	
CUSTOMER ACCESS CHARGE (AT RISK)	0.00111 (I)	0.00111 (I)	
TOTAL RATE	**0.02644 (I)**	**0.02644 (I)**	

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). (R)

(Continued)

PRELIMINARY STATEMENT
(Continued)

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 4

	G-WSL							
	Palo Alto		Coalinga		Island Energy		Alpine	
NCA	0.00224	(I)	0.00224	(I)	0.00225	(I)	0.00224	(I)
DSM	0.00000		0.00000		0.00000		0.00000	
GRC 2000 INTERIM ACCT	0.00000		0.00000		0.00000		0.00000	
CARE	0.00000		0.00000		0.00000		0.00000	
CPUC Fee **	0.00000		0.00000		0.00000		0.00000	
EOR	0.00000	(R)	0.00000	(R)	0.00000	(R)	0.00000	(R)
CEE	0.00000		0.00000		0.00000		0.00000	
EL PASO CAPACITY CHARGE	0.00614		0.00614		0.00614		0.00614	
LOCAL TRANSMISSION (AT RISK)	0.01574	(I)	0.01574	(I)	0.01574	(I)	0.01574	(I)
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000		0.00000		0.00000		0.00000	
TOTAL RATE	**0.02412**	**(I)**	**0.02412**	**(I)**	**0.02413**	**(I)**	**0.02412**	**(I)**

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). It does not apply to customers on Schedule G-WSL. (R)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

	G-WSL	
	West Coast Mather	West Coast Castle
NCA	0.00224 (I)	0.00224 (I)
DSM	0.00000	0.00000
GRC 2000 INTERIM ACCT	0.00000	0.00000
CARE	0.00000	0.00000
CPUC FEE **	0.00000	0.00000
EOR	0.00000 (R)	0.00000 (R)
CEE	0.00000	0.00000
EL PASO CAPACITY CHARGE	0.00614	0.00614
LOCAL TRANSMISSION (AT RISK)	0.01574 (I)	0.01574 (I)
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000	0.00000
TOTAL RATE	**0.02412 (I)**	**0.02412 (I)**

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). It does not apply to customers on Schedule G-WSL. (R)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

NONCORE p. 6

	G-NGV4 TRANSMISSION		G-NGV4—DISTRIBUTION (1)* SUMMER			
THERMS:			0-20,833 (C)	20,834-49,999 (C)	50,000-166,666 (C)	166,667 249,999 (C)
NCA	0.00000		0.00000	0.00000	0.00000	0.00000
DSM	0.00000		0.00000	0.00000	0.00000	0.00000
GRC 2000 INTERIM ACCT	0.00000		0.00000	0.00000	0.00000	0.00000
CARE	0.00000		0.00000	0.00000	0.00000	0.00000
CPUC FEE **	0.00077	(R)	0.00077 (R)	0.00077 (R)	0.00077 (R)	0.00077 (R)
EOR	0.00000		0.00000	0.00000	0.00000	0.00000
CEE	0.00000		0.00000	0.00000	0.00000	0.00000
NGV BALANCING ACCOUNT	0.04580	(I)	0.09671 (R)	0.08367 (R)	0.08069 (R)	0.07469 (R)
EL PASO CAPACITY CHARGE	0.00000		0.00000	0.00000	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.00000		0.00000	0.00000	0.00000	0.00000
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000		0.00000	0.00000	0.00000	0.00000
TOTAL RATE	**0.04657**	**(I)**	**0.09748 (R)**	**0.08444 (R)**	**0.08146 (R)**	**0.07546 (R)**

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). (R)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

NONCORE p. 7

	G—NGV4-DISTRIBUTION (1)*			
	WINTER			
THERMS:	0- 20,833 (C)	20,834- 49,999 (C)	50,000- 166,666 (C)	166,667 249,999 (C)
NCA	0.00000	0.00000	0.00000	0.00000
DSM	0.00000	0.00000	0.00000	0.00000
GRC 2000 INTERIM ACCT	0.00000	0.00000	0.00000	0.00000
CARE	0.00000	0.00000	0.00000	0.00000
CPUC FEE**	0.00077 (R)	0.00077 (R)	0.00077 (R)	0.00077 (R)
EOR	0.00000	0.00000	0.00000	0.00000
CEE	0.00000	0.00000	0.00000	0.00000
NGV BALANCING ACCOUNT	0.11632 (R)	0.09872 (R)	0.09468 (R)	0.08659 (R)
EL PASO CAPACITY CHARGE	0.00000	0.00000	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.00000	0.00000	0.00000	0.00000
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000	0.00000	0.00000	0.00000
TOTAL RATE	**0.11709 (R)**	**0.09949 (R)**	**0.09545 (R)**	**0.08736 (R)**

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). (R)

(Continued)

PRELIMINARY STATEMENT
(Continued)

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 8

	G-LNG (1)*	
NCA	0.00000	
DSM	0.00000	
GRC 2000 INTERIM ACCT	0.00000	
CARE	0.00000	
CPUC Fee **	0.00077	(R)
EOR	0.00000	
CEE	0.00000	
NGV BALANCING ACCOUNT	0.19693	(I)
EL PASO CAPACITY CHARGE	0.00000	
LOCAL TRANSMISSION (AT RISK)	0.00000	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000	
TOTAL RATE	**0.19770 (I)**	

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

** The CPUC Fee includes $.00076 per therm as approved by the CPUC, plus an allowance for Franchise Fees and Uncollectible Expense (F&U). (R)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

MAINLINE EXTENSION FACTORS (1)

Core Schedules (2)	Mainline Extension Factor	
		(T)
Schedule G-NR1	0.23444 (I)	
Schedule G-NR2	0.09097 (I)	
Schedule G-NGV1	0.15354 (I)	
Schedule G-NGV2	0.15354 (I)	
Noncore Schedules		
Schedule G-NT		
Distribution	0.07680 (I)	
Transmission	0.00674 (I)	
Schedule G-COG	0.00119 (R)	
Schedule EG	0.00119 (R)	
Schedule G-NGV4		
Distribution	0.07680 (I)	
Transmission	0.00674 (I)	

(1) Mainline Extension Factors are required to support calculation of distribution-based revenues described in Rule 15.

(2) For all residential schedules, see Rule 15 for extension allowances.

(D)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

NONCORE (Cont'd.)

(1) All transportation revenue collected through this rate, less the amount for CPUC fee, will be booked to the Natural Gas Vehicle Balancing Account (NGVBA).

(2) See Preliminary Statement, Part K for EOR revenue accounting.

(D)

(3) The CPUC fee applies to all gas delivery service under Schedule G-EG, with the exception of interdepartmental sales and sales to electric public utilities. (See Preliminary Statement Part O.) (T)

PRELIMINARY STATEMENT
(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS

These accounting terms and definitions are used in the gas revenue requirement and 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.

   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.

2. BASE REVENUE AMOUNT: The Base Revenue Amount is comprised of GRC/BCAP Base Revenues, Public Purpose Program (PPP) Base Revenues and Gas Accord Base Revenues. The Base Revenue Amount shall be increased or decreased to incorporate changes in the level of authorized operating revenue specified in CPUC decisions. The currently effective Base Revenue Amount is shown in Table C.2.

   The GRC/BCAP Base Revenue Amount is the annual operating revenue, less other operating revenue adopted in the General Rate Case (GRC), and the Biennial Cost Allocation Proceeding (BCAP), or other proceedings.

   Credits to GRC/BCAP Base Revenues were approved in various CPUC decisions. In Decision 01-11-001, the CPUC adopted specific levels of Enhanced Oil Recovery (EOR) revenue. (T)
   In Decision 97-08-055, the CPUC adopted the core brokerage fee escalation adjustments. In |
   Decision 01-11-001, the CPUC also authorized allocation adjustments for G-10 employee (T)
   discounts.

   The PPP Base Revenues are the authorized amounts for Energy Efficiency (EE) and Low Income Energy Efficiency (LIEE) Programs, PPP Research, Development and Demonstration (RD&D), and California Alternate Rates for Energy (CARE) Administrative and General Expenses. The subsidy for CARE customers is not included in the PPP Base Revenues. PPP Base Revenues and CARE costs are recovered through the gas PPP surcharge, as authorized by Public Utilities Code Section 890 and Resolution G-3303.

   The Gas Accord Base Revenues are comprised of Local Transmission, Backbone Transmission, Storage and transmission-level customer access adopted in Gas Accord Decision 03-12-061. (T)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

2. BASE REVENUE AMOUNT: (Cont'd.)

Description	Core	Noncore	Unbundled	Total
	Amount ($000)			
GRC/BCAP BASE REVENUES (1):				
Authorized GRC Distribution Base Revenue	833,389 (R)	41,506 (I)		874,895
Less: Other Operating Revenue	(5,622) (R)	(236) (R)		(5,858)
Unescalated Customer Access Charge-Transmission (2)		(5,657)		(5,657)
Unescalated Customer Access Charge-UEG Gas Meters (2)		(868)		(868)
Authorized GRC Distribution Revenues in Rates	827,767 (R)	34,744 (I)		862,511 (I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:				
G-10 Allocated Employee Discount	642 (I)	994 (I)		1,636 (I)
EOR Revenue	(146) (I)	(6) (R)		(152)
Core Brokerage Fee	(6,869)	(6) (I)		(6,875) (I)
GRC/BCAP REVENUE REQUIREMENT	821,394 (R)	35,726 (I)	0	857,120 (I)
PUBLIC PURPOSE PROGRAM BASE REVENUES (excludes CARE Subsidy(3)):				
Energy Efficiency and Low Income Energy Efficiency Programs	38,536 (R)	4,289 (R)		42,825 (R)
CARE Administrative & General Expenses	963 (R)	673 (I)		1,636 (R)
PUBLIC PURPOSE PROGRAM REVENUE REQUIREMENT	39,499 (R)	4,963 (R)	0	44,461 (R)
GAS ACCORD BASE REVENUES				
Local Transmission	106,722 (I)	69,251 (I)		175,973 (I)
Customer Access Charge – Transmission		12,929 (I)		12,929 (I)
Storage (4)	38,911		11,216	50,127
Backbone Transmission (4)	52,586 (I)		50,787 (R)	103,373 (R)
L401 (PEP)			91,537 (R)	91,537 (R)
GAS ACCORD REVENUE REQUIREMENT	198,219 (I)	82,180 (I)	153,540 (R)	433,939 (I)
TOTAL BASE REVENUE REQUIREMENT	1,059,111 (I)	122,869 (I)	153,540 (R)	1,335,520 (I)

(1) The GRC/Biennial Cost Allocation Proceeding (BCAP) Base Revenue includes Distribution Base Revenues for core and noncore Customers, adopted in the General Rate Case and allocated in Cost Allocation Proceedings.

(D)

(2) Service line, regulator and meter costs for transmission-level customers were deducted from the 1999 authorized GRC base revenues and set in Gas Accord II D.03-12-061. (T)

(3) The Public Purpose Program (PPP) base revenue requirement includes 2004 PY LIEE program funding adopted in D.03-11-020 (unchanged from 2003 PY adopted in D.02-12-019), Energy Efficiency program funding adopted in D.03-08-067, CARE annual administration budget adopted in D.02-09-021, and Franchise Fees and Uncollectible Expense.

(4) The Gas Accord II D.03-12-061 adopted transmission revenues effective January 1, 2004. Storage revenues were set in Decision 02-08-070, through March 31, 2004. The Gas Accord II D.03-12-061 storage revenues will be effective April 1, 2004. (T)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

3. COST ALLOCATION FACTORS:

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

	Factor			
Cost Category	Core	Noncore	Unbundled Storage	Total
Intervenor Compensation	0.95972 (C)	0.04028 (C)		1.00000
Carrying Cost on Non-cycled Gas in Storage*	0.87500		0.12500	1.00000

(D)

* Excluding Non-cycled Gas in Storage which is allocated to system load balancing and recovered through transmission rates.

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.

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 Revenue Requirement, excluding the Revenue Requirement for Transmission and Storage, as described in Section C.10 below, is allocated between customer classes and included in rates. This proceeding is currently a biennial proceeding pursuant to CPUC Decision No. 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)

PRELIMINARY STATEMENT
(Continued)

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

8. CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE) REVENUE 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 Decision 03-12-061, and (T) 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 (T) Gas Accord base revenue amount,* load balancing storage costs, certain forecast amounts (T) 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. (T)

   b. The Storage Revenue Requirement includes the core and Unbundled Storage base revenue (T) amount,* carrying costs on noncycled gas in storage, and F&U.

---

* See Section C.2 for details.

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

10. REVENUE REQUIREMENT (Cont'd.)

c. Transportation Revenue Requirement (Cont'd.)

9) California Alternate Rates for Energy (CAREA) Balance: This is the forecast revision-date balance in the CAREA, described in Preliminary Statement, Part V, based on the latest recorded data available.

10) Natural Gas Vehicle Balancing Account (NGVBA) Balance: This is the forecast revision-date balance in the NGVBA, described in Preliminary Statement, Part X, based on the latest recorded data available.

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

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

13) Core Pipeline Demand Charge (CSPDC) Account: This is the forecast revision-date balance in the PG&E GT-NW Credit Subaccount and the Core Transport Interstate Transition Subaccount of the CPDCA, as described in Preliminary Statement, Part AE, based on the latest recorded data available.

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

(D)

15) El Paso Turned-Back Capacity Balancing Account (EPTCBA) Balance: This is the forecast revision-date balance in the EPTCBA described in Preliminary Statement, Part AZ, based on the latest recorded data available. (T)

16) 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.a. through C.10.c.15, above, by the applicable F&U factor. (T) (T)

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

11. REVISION DATES (Cont'd.)

c. In-Kind Shrinkage (N)

Pursuant to D.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.

D.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 effective January 1. The storage in-kind shrinkage allowance will change effective April 1. The in-kind shrinkage allowances are shown in Rule 21.

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. (N)

12. PIPELINE DEMAND CHARGE CREDITS

When PG&E brokers interstate capacity it will receive conditional credits from interstate pipelines which represent accrued revenues to the interstate pipelines from other parties who have acquired PG&E's brokered capacity. These credits may include other items such as reversed credits previously given to PG&E and late charges assessed per the interstate's FERC-approved tariffs.

(Continued)

PRELIMINARY STATEMENT
(Continued)

L. BALANCING CHARGE ACCOUNT (BCA)

1. PURPOSE: The purpose of the BCA is to record the revenue and cost associated with providing balancing service, including penalties and credits, as described in Schedule G-BAL, Rule 14, or as (T) otherwise authorized by the CPUC. The balance in this account will be incorporated into core and (T) noncore transportation rates as determined in PG&E's Biennial Cost Allocation Proceeding Decision 01-11-001.

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

2. APPLICABILITY: The BCA balance applies to all gas 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 BCA rate shall coincide with the revision date of the Cost Allocation Proceeding or at other times, as ordered by the CPUC.

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

5. BCA RATES: This account does not currently have a rate component.

6. ACCOUNTING PROCEDURE: PG&E shall maintain the BCA by making entries as follows:

   a. a debit entry equal to the cost of gas purchased under Schedule G-BAL as a result of over-deliveries; (T)

   b. a debit entry equal to the cost of gas purchased under a California Production Balancing Agreement (CPBA) as a result of overdeliveries;

   c. a debit entry equal to the cost of gas purchased by the transmission system to provide balancing service;

   d. a debit entry equal to the involuntary diversion credits to suppliers;

   e. a credit entry equal to revenues from the sale of gas commodity as a result of under-deliveries under Schedule G-BAL during the month, excluding the allowance for Franchise (T) Fees and Uncollectible Accounts Expense (F&U);

   f. a credit entry equal to the revenue from the sale of gas commodity as a result of underdeliveries under a CPBA, excluding the allowances for F&U;

(Continued)

PRELIMINARY STATEMENT
(Continued)

L. BALANCING CHARGE ACCOUNT (BCA) (Cont'd.)

6. ACCOUNTING PROCEDURE: (Cont'd.)

g. a credit entry equal to EFO and OFO noncompliance charges, excluding the allowance for F&U, as described in Gas Rule 14;

h. a credit entry equal to Self-Balancing noncompliance charges, as described in Schedule G-BAL;

i. a credit entry equal to the involuntary diversion usage charges excluding the allowance for F&U;

(D)

j. a credit entry equal to local curtailment noncompliance charges, excluding the allowance for F&U, as described in Gas Rule 14; (N) (N)

k. an entry equal to the interest on the average of the balance in the account at the beginning of the month and the balance in the account after the entries L.6.a through L.6.j, above, at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, G.13, or its successor.

PRELIMINARY STATEMENT
(Continued)

O. CPUC REIMBURSEMENT FEE

1. REIMBURSEMENT FEE

a. PURPOSE: The purpose of this provision is to set forth the Public Utilities Commission Reimbursement Fee (Chapter 323, Statutes of 1983) to be paid by utilities to fund regulation by the California Public Utilities Commission (CPUC) (Public Utilities Code, Sections 401-443). The fee is ordered by the CPUC under Section 433. Surcharge fees shall be forwarded to the CPUC on a quarterly basis between the 1st and the 15th days of October, January, April and July.

b. APPLICABILITY: This reimbursement fee applies to all gas delivery service rendered under all rate schedules and contracts authorized by the CPUC, with the exception of interdepartmental sales or transfers, and sales to electric, gas, or steam heat public utilities. It is applicable within the entire territory served by the company.

c. RATE: The current CPUC Reimbursement Fee Rate is $0.00076 per therm. This rate is included in all applicable schedules (see Preliminary Statement, Part B). (R)

2. MASTER-METERED MOBILEHOME PARK SAFETY PROGRAM SURCHARGE

a. PURPOSE: The purpose of this provision is to set forth the CPUC Mobilehome Park Safety Inspection and Enforcement Program Surcharge to be paid by mobilehome park operators with master-metered natural gas distribution systems. The surcharge will recover the CPUC's costs to implement and maintain a safety inspection and enforcement program as mandated by the CPUC under the authority granted by Public Utility Code Sections 4351-4358. Surcharge fees shall be forwarded to the CPUC on a quarterly basis between the 1st and 15th days of October, January, April and July.

b. APPLICABILITY: This surcharge applies to all gas delivery service provided to all master-metered mobilehome parks on Schedules GM, GML, GT, GTL and G-NR1.

c. RATE: The Master-Metered Mobilehome Park Safety Program Surcharge is $0.00691 per installed space per day ($0.21 per installed space per month). This rate is included in Schedule G-MHPS.

SCHEDULE G-MHPS—MASTER-METERED MOBILEHOME PARK SAFETY SURCHARGE

APPLICABILITY: This schedule applies to all master-metered mobilehome parks served under Schedules GM, GML, GT, GTL, and G-NR1 pursuant to the California Public Utilities Commission's (CPUC) Master-Metered Mobilehome Park Gas Safety Inspection and Enforcement Program in Public Utilities Code Sections 4351-4358. To fund the program, effective July 1, 1991, a surcharge will be collected by PG&E from master-metered mobilehome park operators owning their own distribution system. The CPUC is solely responsible for making the final determination as to whether a mobilehome park is exempt from this surcharge.

TERRITORY: Schedule G-MHPS applies everywhere within PG&E's natural gas Service Territory. (T)

RATES: MASTER-METERED MOBILEHOME PARK SAFETY SURCHARGE:

For each mobilehome park, per installed space per day $0.00691

SURCHARGE RECOVERY: The mobilehome park operator is allowed under law to recover the surcharge from the park's tenants on a monthly basis. The surcharge to any tenant shall not exceed $0.30 per month for the period from July 1, 1991, until July 1, 1992 and shall not exceed $0.00821 per day thereafter. However, if the CPUC establishes the surcharge at a lesser amount, the surcharge to any tenant cannot exceed that lesser amount.

TERMINATION OF SERVICE: Failure on the part of a mobilehome park operator to comply with the terms and conditions of this tariff may result in termination of service by PG&E under the terms and conditions of Rule 11*. The terms and conditions of all other gas tariffs still apply.

---

* PG&E's gas tariffs are available on-line at www.pge.com. (T)

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 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 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. (T)

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. (T)

(D)

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. (N)

Average Monthly Use (Therms)	Per Day	
0 to 5,000	$ 0.99010	(I)
5,001 to 10,000	$ 7.80073	I
10,001 to 50,000	$ 29.59388	I
50,001 to 200,000	$ 78.00975	I
200,001 to 1,000,000	$111.69084	I
1,000,001 and above	$324.67266	(I)

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

(Continued)

SCHEDULE G-NT—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.

Transmission-Level Rate: (T)

Transmission-Level Rates apply to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi). (T)

Transmission-Level Rate (Per Therm) $0.04657 (I)

Distribution-Level Rates: (T)

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	$0.09748	(R)	$0.11709	(R)	
Tier 2: 20,834 to 49,999	$0.08444	|	$0.09949	|	
Tier 3: 50,000 to 166,666	$0.08146	|	$0.09545	|	
Tier 4: 166,667 to 249,999	$0.07546	(R)	$0.08736	(R)	(T)
Tier 5: 250,000 and above*	$0.04657		$0.04657		(N)

See Preliminary Statement Part B for Default Tariff Rate Components.

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. (T) (T)

* Tier 5 Summer and Winter rates are the same. (N)

(Continued)

SCHEDULE G-NT—GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS
(Continued)

NEGOTIABLE RATES: Rates under this schedule may be negotiated. (L)

NEGOTIATED RATE GUIDELINES:

1. Standard tariff rates and terms are available to all Customers.

2. PG&E may distinguish between parties in offering negotiated rates by evaluating differences in circumstances and conditions, including, but not limited to, differences occurring upstream of, downstream of, or at, the Customer's location, and differences affecting either cost of service to the Customer or Customer's market alternatives. Negotiations with Customers under this rate schedule will be conducted without undue preference or undue discrimination to the Customer or to any third party. Negotiated rates for G-NT service shall not be less than PG&E's short-run marginal cost of providing the service.

3. PG&E will issue monthly reports to the Commission listing all negotiated contracts including those negotiated under G-NT. PG&E will make the report available to others upon request. Customer names will not be provided in the report. The report will show the negotiated rates and dates of service. (L)

SEASONS: Summer season is from April 1 through October 31. Winter Season is from November 1 through March 31. (N)

SERVICE AGREEMENT: A Natural Gas Service Agreement (NGSA) (Form No. 79-756) is required for service under this schedule. The initial term of the NGSA will be for one (1) year. (L)

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

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

(D)

(Continued)

SCHEDULE G-NT—GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS
(Continued)

CURTAILMENT OF SERVICE:	Service under this schedule may be curtailed. See Rule 14* for details.	
BALANCING SERVICE:	Service hereunder shall be subject to all the applicable terms, conditions and obligations of Schedule G-BAL.	
ENERGY EFFICIENCY ADJUSTMENT:	A Customer who implements measures to improve energy efficiency on or after January 1, 1992, may be eligible to receive an energy efficiency adjustment and therefore qualify to take service under this schedule. The following qualifications must be met by the Customer: 1) Customer's service was established prior to January 1, 1992, and 2) the efficiency measures reduce the Customer's natural gas usage to the point that the Customer would no longer be eligible for service under this schedule. Qualifying Customers must execute an Agreement for Adjustment for Natural Gas Energy Efficiency Measures (Form No. 79-788) with PG&E prior to receiving an energy efficiency adjustment.	
BACKBONE TRANSMISSION TRANSPORTATION SERVICE:	Transportation service on PG&E's Backbone Transmission System may be taken in conjunction with this schedule under Schedule G-AFT, G-SFT, G-AA, G-NFT, or G-NAA. A separate Gas Transmission Service Agreement (GTSA) (Form 79-866) must be executed for such service. The GTSA can be held by the Customer or by another party, such as the Customer's gas supplier.	(T) (T)

(D)

SCHEDULE G-COG—GAS TRANSPORTATION SERVICE TO COGENERATION FACILITIES

APPLICABILITY: This rate schedule* applies to the transportation of natural gas on PG&E's Local Transmission and/or Distribution System to cogeneration facilities and solar electric generation projects, as defined herein. This rate schedule also applies to Customers previously served under Schedule G-EPO.

To qualify for service under this schedule, a Customer must be a cogeneration facility which sequentially uses natural gas to produce electricity and useful thermal energy, as specified in the California Public Utilities Code Section 218.5,** or a solar electric generation project as defined herein.

Customers receive service under this schedule in conjunction with the rate schedule that would otherwise apply if the Customer did not meet the requirements to qualify as a cogeneration facility. All provisions in the otherwise-applicable schedule will be binding on the Customer unless superseded by the provisions in this schedule.

TERRITORY: Schedule G-COG applies everywhere within PG&E's natural gas Service Territory. (T)

RATES: The following transportation charges do not include charges for service on PG&E's Backbone Transmission System. These rates apply to volumes up to the Limitation of Gas Use, described herein.

Customers taking service under this schedule will be billed for transportation under the lower of the following rates:

1. The Schedule G-EG transportation rate, including discounts to PG&E's utility steam-electricity generating plants. (T)

	Per Therm
The Transportation Charge is:	$0.02644 (I)

or,

2. The rate specified in the Customer's otherwise-applicable rate schedule.

Noncore End-Use customers must procure gas supply from PG&E or from a supplier other than PG&E.

Core End-Use Customers will pay the procurement charge under their otherwise-applicable rate schedule, unless they purchase gas from a third-party supplier.

---

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

** Efficiency Standards: In accordance with PU Code Section 218.5, 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)

SCHEDULE G-EG—GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

APPLICABILITY: This rate schedule* applies to the transportation of natural gas on PG&E's Local Transmission System. The following Customer loads will be served under Schedule G-EG: (a) PG&E-owned gas-fired electric generation plants, (b) gas-fired electric generation plants formerly owned by PG&E which have been divested pursuant to electric industry restructuring, (c) existing or new gas-fired electric generation facilities owned by municipalities, irrigation districts, joint power authorities or other state or local governmental entities that would otherwise qualify for Transmission rates under Schedule G-NT, and (d) merchant power plants and independent power production facilities that would otherwise qualify for Transmission rates under Schedule G-NT. This schedule does not apply to gas transported to non-electric generation loads, or to cogeneration loads.

TERRITORY: Schedule G-EG applies everywhere within PG&E's natural gas Service Territory. (T)

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

Transportation Charge (per therm): $0.02644 (I)

Customers may be required to pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details.) (N)

In addition, the Customer will also be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of gas supplied from a source other than PG&E from intra- or interstate sources.

See Preliminary Statement, Part B for Default Tariff Rate Components.

NEGOTIABLE RATES: Rates under this schedule may be negotiated.

NEGOTIATED RATE GUIDELINES:

1. Standard tariff rates and terms are available to all Customers.
2. PG&E may distinguish between parties in offering negotiated rates by evaluating differences in circumstances and conditions, including, but not limited to, differences occurring upstream of, downstream of, or at, the Customer's location, and differences affecting either cost of service to the Customer or Customer's market alternatives. Negotiations with Customers under this rate schedule will be conducted without undue preference or undue discrimination to the Customer or to any third party. Negotiated rates for G-EG service shall not be less than PG&E's short-run marginal cost of providing the service.
3. PG&E will issue monthly reports to the Commission listing all negotiated contracts, including those negotiated under G-EG. PG&E will make the report available to others upon request. Customer names, including PG&E's affiliates and other departments, will not be provided in the report. However, the report will indicate whether a particular transaction was with an affiliate. The report will show the negotiated rates and dates of service.

---

* PG&E's gas tariffs are available on-line at www.pge.com. (T)

(Continued)

SCHEDULE G-EG—GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION
(Continued)

ELECTRIC DEPARTMENT NOTIFICATIONS: During Open Seasons for PG&E's intrastate services, PG&E will notify on-system cogenerators of PG&E's Electric Generation (EG) Department's elections for service three (3) business days prior to the date that cogenerators must make their service elections. PG&E will also notify cogenerators of EG's other elections for intrastate services as they may occur from time to time. This provision will apply to EG service agreements which have terms exceeding one (1) calendar month or thirty (30) days for contracts beginning on other than the first day of the month, and to EG service agreements with automatic renewal provisions where the total contract term would exceed one (1) calendar month or thirty (30) days.

SERVICE AGREEMENT: A Natural Gas Service Agreement (NGSA) (Form 79-756) is required for service under this schedule. The initial term of the NGSA will be for 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 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 the applicable terms, conditions and obligations of Schedule G-BAL.

BACKBONE TRANSMISSION TRANSPORTATION SERVICE: Transportation service on PG&E's Backbone Transmission System must be taken in conjunction with this schedule under Schedule G-AFT, G-SFT, G-AA, G-NFT, or G-NAA. A separate Gas Transmission Service Agreement (GTSA) (Form 79-866) and appropriate exhibits must be executed for such service. The GTSA can be held by the Customer or by another party, such as the Customer's gas supplier. (N)

SCHEDULE G-30—PUBLIC OUTDOOR LIGHTING SERVICE

APPLICABILITY: This rate schedule* is applicable to unmetered firm gas service available for continuous use by groups of customer-owned gas lights installed in a consecutive and contiguous arrangement along or adjacent to public thoroughfares and constituting a lighting system. Service under this schedule to be conditional upon arrangements mutually satisfactory to the Customer and PG&E for connection of Customers' gas lights to PG&E's facilities and is available only for groups of gas lights approved by PG&E. This schedule was closed to new installations as of June 20, 1973.

TERRITORY: Schedule G-30 applies everywhere PG&E provides natural gas service.

RATES:

	Per Group of Lights Per Month
First 10 lights or less	$108.70 (I)
For each additional gas light	$10.88 (I)
For each cubic foot per hour of total rated capacity for the group in excess of either 1.5 cubic foot per hour per light or 15.0 cubic feet per hour for the group, whichever is greater	$6.50 (I)

See Preliminary Statement, Part B for the Default Tariff Rate Components, applicable to this schedule.

SPECIAL CONDITIONS:

1. A contract on Form No. 62-4897 will be required for a term of three years when service is first rendered under this schedule and continuing thereafter until cancelled by either party by thirty days' advance written notice.

2. All gas lights for public outdoor lighting will be owned and installed by the Customer. The gas light shall consist of a PG&E approved post, base, and luminaire with one or more mantles.

3. PG&E maintenance includes service to "no light" reports, burner and regulator adjustment, and it includes glassware cleaning at the time other maintenance work is being performed. Mantle replacements, not to exceed annually the total number of mantles installed, will be made at PG&E expense. Replacement glassware provided by the Customer will be installed by PG&E.

4. The service tap assembly and service pipe for each gas light will be owned, installed, and maintained by PG&E. The estimated installed cost shall be paid by the Customer to PG&E in advance of construction.

5. The rated capacity of each gas light shall be determined by PG&E to the nearest one-tenth cubic foot per hour from the name plate rating or by test, at PG&E's option.

---

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

(Continued)

SCHEDULE G-WSL—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. Customers electing to use the Storage options described in this rate schedule must pay the applicable Storage Charge.

1. Customer Access Charge:

	Per Day	
Palo Alto	$366.39715	(I)
Coalinga	$ 85.75463	|
West Coast Gas-Mather	$ 62.29808	|
Island Energy	$ 46.75003	|
Alpine Natural Gas	$ 17.24219	|
West Coast Gas-Castle	$ 40.22137	(I)

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto	$0.02412	(I)
Coalinga	$0.02412	|
West Coast Gas-Mather	$0.02412	|
Island Energy	$0.02413	|
Alpine Natural Gas	$0.02412	|
West Coast Gas-Castle	$0.02412	(I)

3. Storage Charge:

Customers may take storage service under Schedule(s) G-FS, G-NFS, and/or G-NAS, if available.

---

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

(Continued)

SCHEDULE G-WSL—GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS
(Continued)

RATES: (Cont'd.) (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.

(D)

Existing Wholesale Customers will have a one-time option prior to April 1, 2004 to subscribe, on behalf of their core Customers, for firm capacity on the Redwood to on-system as specified below. Capacity will be offered only for the core portion of the Customer's load. (T)

Customer	Redwood (MDth)
Alpine	0.087
Coalinga	0.609
Island Energy	0.072
Palo Alto	5.433
West Coast Gas (Castle)	0.072
West Coast Gas (Mather)	0.227

(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. (T)

(D)

(Continued)

SCHEDULE G-WSL—GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS
(Continued)

(D)

SERVICE AGREEMENT:	A Natural Gas Service Agreement (NGSA) (Form No. 79-756) is required for service under this schedule. The initial term of the NGSA will be one (1) year.	
SHRINKAGE:	Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.	
NOMINATIONS:	Nominations are required for gas supplies delivered under this schedule. See Rule 21 for details.	
CURTAILMENT OF SERVICE:	Service under this schedule may be curtailed. Service under this schedule for the core portion of the Customer's load receives priority comparable to PG&E's core load. See Rule 14 for details.	
BALANCING:	Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.	
GAS OWNERSHIP:	Quantities of gas transported under this schedule may include gas owned by authorized end-users on the Customer's gas distribution system.	
BACKBONE TRANSMISSION TRANS-PORTATION SERVICE:	Transportation service on PG&E's Backbone Transmission System must be taken in conjunction with this schedule under Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA. A separate Gas Transmission Service Agreement (GTSA) (Form No. 79-866) and appropriate exhibits must be executed for such service. The GTSA can be held by the Customer or by another party, such as the Customer's gas supplier.	(T) (T) (T)

(Continued)

SCHEDULE G-BAL—GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

APPLICABILITY: This rate schedule* provides the terms and conditions pursuant to which PG&E will endeavor to balance volumes of gas it receives into its pipeline system with the volume it delivers to End-Use Customers and to Off-System Delivery Points. In addition, this schedule provides for balancing PG&E's Market Center volumes. Under this schedule, PG&E will calculate, maintain, and carry imbalances; provide incentives for Customers to avoid and minimize imbalances; facilitate elimination of imbalances; and cash out imbalances. Schedule G-BAL applies to PG&E's Core Procurement Department transactions on behalf of PG&E's core procurement Customers, and to all Customers taking services under Schedules G-CT (or other core rate schedule(s) where procurement service is provided by a third party), to Schedules G-NT, G-EG, G-COG, G-NGV4, G-WSL, G-LNG, G-AFT, G-SFT, G-NFT, G-AA, G-NAA, G-AFTOFF, G-AAOFF, G-NFTOFF, G-NAAOFF, G-PARK, and G-LEND.

Imbalances generally will be maintained at the delivery point.

This schedule is the default supply schedule for Noncore End-Use Customers who do not execute a Natural Gas Service Agreement (NGSA) (Form No. 79-756), pursuant to the terms of Schedules G-NT or G-COG.

TERRITORY: Schedule G-BAL applies everywhere within PG&E's natural gas Service Territory. (T)

BALANCING AGGREGATION: Noncore End-Use Customers may elect to aggregate Cumulative Imbalances for multiple premises, or they may assign their balancing obligations to a Balancing Agent, as described below. If the Cumulative Imbalances are aggregated or assigned to a Balancing Agent, PG&E will aggregate individual Balancing Service accounts into a single Balancing Service account, with both the usage and the deliveries aggregated. A single Tolerance Band, as defined below, shall apply to the aggregated quantities.

BALANCING AGENT: The Balancing Agent is the party financially responsible for managing and clearing imbalances described in Schedule G-BAL. The Balancing Agent shall be responsible for all applicable balancing and Rule 14 Operational Flow Order, Emergency Flow Order (T)
and diversion noncompliance charges. The following are Balancing Agents: Core (T)
Transportation Agent (CTA), PG&E Core Procurement Department, Noncore Balancing Aggregation Agreement (NBAA) Agent, a Noncore End-Use Customer or Wholesale Customer that is not part of an NBAA. All Balancing Agents are subject to creditworthiness requirements.

For deliveries to a Core Transportation Group, the CTA will be responsible for any imbalances. For deliveries to storage and to off-system points, the Customer holding the Gas Transmission Service Agreement (GTSA) (Form No. 79-866) will be responsible for imbalances.

For deliveries made to Noncore End-Use Customers, the Noncore End-Use Customer will be responsible for imbalances; however, Noncore End-Use Customers may designate a Balancing Agent to manage and assume responsibility for the Noncore End-Use Customer's obligations under this schedule.

A Noncore End-Use Customer may change its Balancing Agent no more than once per month.

---

* PG&E's gas tariffs are available on-line at www.pge.com. (T)

(Continued)

SCHEDULE G-BAL—GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS
(Continued)

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 $0.0096 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)

SCHEDULE G-BAL—GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS
(Continued)

SELF-BALANCING OPTION: (Cont'd.)

DAILY IMBALANCE LIMITS FOR SELF-BALANCING:

A Balancing Agent electing Self-Balancing will be subject to two (2) imbalance limits each day:

1. The Daily Imbalance cannot exceed plus or minus ten percent (±10%) of that day's metered usage for an NBAA or 24-hour forecast usage for a CTA Group, except on OFO or EFO days. On OFO or EFO days the applicable OFO or EFO tolerance band and noncompliance charge will apply.

2. A Balancing Agent must also maintain an Accumulated Daily Imbalance less than, or equal to, plus or minus one percent (±1%) of the Pre-Determined Monthly Usage for that month.

The Pre-Determined Monthly Usage (PDMU) for Noncore End-Use Customers will be equal to the Monthly Contract Quantity specified in the Exhibit B of their NGSA. PG&E will provide the Self-Balancing CTA with a PDMU at least 5 days prior to the first of each month. The PDMU for CTA Groups will be determined by PG&E as a function of the sum of the actual usage of the End-Use Customers within the CTA Group in the same month of the prior year. Adjustments may be applied for missing usage information for the prior year, mid-month starts and stops of service by the Balancing Agent, and for weather effects.

SELF-BALANCING NONCOMPLIANCE CHARGES:

Self-Balancing Noncompliance charges will be calculated as the sum of the following:

1. Daily Noncompliance Charge: For each non-OFO or non-EFO day, a noncompliance charge equal to fifty percent (50%) of the Monthly Citygate Index (MCI) per Decatherm for the portion of the daily imbalance that exceeds plus or minus ten percent (±10%) of the daily metered usage for customers in an NBAA or 24-hour forecast usage for a CTA Group per day. The MCI is the higher of the highest daily price during the month, or the monthly PG&E Citygate Index price published in *Gas Daily*, rounded up to the next whole dollar. If no price is published on a given day, the previously published price will be applied. On OFO or EFO days the corresponding tolerance band and OFO or EFO charge will apply. (T) (T) (T) | | (T)

2. Accumulated Daily Imbalance Noncompliance Charge: For each day, including OFO and EFO days, a noncompliance charge equal to fifty percent (50%) of the Monthly Citygate Index (MCI) per Decatherm per day for each day when the Accumulated Daily Imbalance exceeds plus or minus one percent (±1%) of the Pre-Determined Monthly Usage. The MCI is the higher of the highest daily price during the month, or the monthly PG&E Citygate Index price published in *Gas Daily*, rounded up to the next whole dollar. If no price is published on a given day, the previously published price will be applied. (See gas Rule 14 for possible exemptions from noncompliance charges on OFO days.) (T) (T) (T) | | (T)

(Continued)

SCHEDULE G-BAL—GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS
(Continued)

IMBALANCE TRADING: (Cont'd.)

IMBALANCE TRADING PERIOD:

PG&E will issue Cumulative Imbalance statements no later than the fifteenth (15) day of the first subsequent month following the month in which the Cumulative Imbalance occurred. PG&E will issue Operating Imbalance Statements no later than the fifteenth (15) day of the second subsequent month following the month in which the Cumulative Imbalance Statement for the same period was issued. Thereafter, Balancing Agents may trade all or a portion of their Cumulative and/or Operating Imbalance quantity by executing an imbalance trade by 5:00 p.m. Pacific Time on the closing date for New York Mercantile Exchange (NYMEX) Henry Hub Gas Futures contracts for the following month. If necessary, PG&E will extend the Cumulative and Operating Imbalance trading deadline beyond the NYMEX close date to ensure that the trading period lasts a minimum of five (5) business days.

TRADING IMBALANCES USING STORAGE ACCOUNTS:

During the imbalance Trading Period, Balancing Agents may manage both Cumulative and Operating Imbalances by trading into or out of storage accounts at on-system storage facilities. The owner of the storage account is not required to purchase storage injection or storage withdrawal capacity from PG&E to effect an imbalance trade. (D)

The owner of the storage account must have, at the time of the trade, the inventory capacity to accept a trade into storage or the gas in inventory to trade out of storage. A gas ESP that uses its core storage account for managing Cumulative or Operating Imbalances must adhere to the end-of-month inventory target levels, as specified in Schedule G-CT. Owners of a third-party storage account must provide documentation of their inventory capacity or gas in inventory. Subject to system load balancing and/or operational constraints, Balancing Agents may trade as much of their Cumulative and/or Operating Imbalance quantity as their storage inventory/capacity allows. (T)

(D)

For the purpose of accepting trades into or out of storage, PG&E will review its pipeline operations and will establish an Imbalance Trade Operating Band (OP BAND) prior to the Imbalance Trading Period. PG&E, prior to the beginning of the Imbalance Trading Period, will electronically post the OP BAND. PG&E will accept Cumulative and/or Operating Imbalance trades, using storage accounts, on a first-come, first-served basis, during the Imbalance Trading Period, within the OP BAND. Cumulative and/or Operating Imbalance trades not accepted because of the limit from the OP BAND will be retained and processed at a later time within the current Imbalance Trading Period, if trades from the Customers allow room in the OP BAND, unless the trade is canceled by the Customer or the Imbalance Trading Period closes.

(Continued)

SCHEDULE G-BAL—GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS
(Continued)

IMBALANCE TRADING: (Cont'd.)

Usage Charges specified in Schedule G-FS, or any negotiated Usage Charges under Schedule G-NFS, will apply to trades into or out of a PG&E storage account.

MANAGING REMAINING IMBALANCES AFTER TRADING:

After the imbalance trading deadline, any remaining Cumulative Imbalance, within the Tolerance Band, and any Operating Imbalance Carryover, as specified below, will be considered the first transaction during the calendar month following the just-completed trading period. Any remaining Cumulative Imbalance in excess of the Tolerance Band will be automatically cashed out. Cashouts will include a Commodity Cashout component and a Transmission Cashout component.

After the imbalance trading deadline, any remaining Operating Imbalance will be managed as follows:

1. The Operating Imbalance remaining after trading will be added to the Operating Imbalance Carryover.

2. One-twelfth (1/12) of the Operating Imbalance Carryover will be considered part of the first transaction for the CP Group during the calendar month following the just completed trading period.

3. A CP Group may also make a monthly election to clear its entire Operating Imbalance Carryover if it is less than 5,000 Dth. This will be considered the first transaction during the calendar month following PG&E's receipt of written notification, and will set the Operating Imbalance Carryover to zero.

(D)
|
|
|
|
(D)

(Continued)

SCHEDULE G-BAL—GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS
(Continued)

ACCOUNTING ADJUSTMENTS: If subsequent accounting adjustments change a previous Cumulative or Operating Imbalance, then:

1. If any portion of the adjusted quantity was previously subject to an imbalance cashout, the adjusted portion of the cashout will be reversed.
2. For noncore Cumulative Imbalances, any remaining adjustment quantity will be considered the first transaction during the calendar month following the date of notification of the adjustment, and reported on the Cumulative Imbalance Statement, unless otherwise agreed to by PG&E.
3. For Core Procurement Groups, adjustment quantities will be included in the Operating Imbalance Carryover.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. Details are provided in gas Rule 14.

TERMINATION: Upon termination of a Customer's GTSA, NGSA, NBAA, CTA Agreement, and/or CPBA, any remaining Cumulative Imbalance and/or Operating Imbalance Carryover must be traded, toward zero, during the first Imbalance Trading Period following notice of termination. Following the Trading Period, any remaining negative Cumulative and Operating Imbalances will be cashed out at the applicable MCI. The MCI is the higher of the highest daily price during the month, or the monthly PG&E Citygate Index Price of gas in the daily range, as published in *Gas Daily*, rounded up to the next whole dollar. If there is no price published on a given day the previously published price will be applied. Any remaining positive Cumulative and Operating Imbalances will be cashed out at the applicable Lowest Citygate Index (LCI). The LCI is the lower of the lowest daily price during the month, or the monthly PG&E Citygate Index Price as published in *Gas Daily*, rounded down to the next whole dollar. If there is no price published on a given day the previously published price will be applied. (N)

(Continued)

SCHEDULE G-AFT—ANNUAL FIRM TRANSPORTATION ON-SYSTEM

APPLICABILITY: This rate schedule* applies to the firm transportation of natural gas on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a PG&E G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: G-CT, G-NT, C-COG, G-EG, G-NGV4, or G-WSL. To arrange for the further transportation and delivery of natural gas to an Off-System Delivery Point, one of the following additional rate schedules must be utilized: G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

TERRITORY: Schedule G-AFT is available only for the transportation of natural gas within PG&E's service territory on the specific paths described herein.

PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in the exhibits to the Customer's Gas Transmission Service Agreement (GTSA) (Form No. 79-866).

Receipt Point(s) available for service under this schedule are as follows:

Path:	Receipt Point(s):
Redwood to On-System	Malin or other receipt points north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Daggett, High Desert Lateral, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities, or a third party's storage facilities located in PG&E's service territory

Delivery Point(s):

Any Delivery Point(s) to which gas is transported under this rate schedule must be On-System Delivery Point(s).

TERM: The minimum term for service under this rate schedule is one (1) year, and the (T)
maximum term is fifteen (15) years. (T)

---

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

(Continued)

SCHEDULE G-AFT—ANNUAL FIRM TRANSPORTATION ON-SYSTEM
(Continued)

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	$5.3574 (I)	$9.0598 (I)
Redwood to On-System (Core Procurement Groups only)	$2.9624 (I)	$3.8462 (I)
Baja to On-System (including Core Procurement Groups)	$4.4678 (I)	$5.7218 (I)
Silverado to On-System (including Core Procurement Groups)	$2.4975 (I)	$3.4518 (I)
Mission to On-System (including Core Procurement Groups)	$2.4975 (I)	$3.4518 (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	$0.1236 (I)	$0.0019 (R)
Redwood to On-System (Core Procurement Groups only)	$0.0313 (R)	$0.0023 (R)
Baja to On-System (including Core Procurement Groups)	$0.0448 (R)	$0.0036 (R)
Silverado to On-System (including Core Procurement Groups)	$0.0328 (R)	$0.0014 (R)
Mission to On-System (including Core Procurement Groups)	$0.0328 (R)	$0.0014 (R)

(Continued)

SCHEDULE G-AFT—ANNUAL FIRM TRANSPORTATION ON-SYSTEM
(Continued)

RATES: (Cont'd.)

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.

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

ELECTRIC DEPARTMENT/ COGENERATOR PARITY RATES: Schedule G-COG Customers who take service under this schedule will be eligible for the provisions of the Cogeneration Rate Parity Exhibit of the Customer's GTSA.

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 (T)
one (1) year. (T)

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.

CAPACITY LIMITATION: Long-term standard firm contracts for terms of five (5) years or greater are subject to a (N)
capacity limitation of 400 MDth/day on the Redwood Path and 200 MDth/day on the |
Baja Path. (N)

SCHEDULE G-AFTOFF—ANNUAL FIRM TRANSPORTATION OFF-SYSTEM

APPLICABILITY: This rate schedule* applies to the firm transportation of natural gas on PG&E's Backbone Transmission System to the Off-System Delivery Points.

TERRITORY: Schedule G-AFTOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described herein for off-system deliveries.

PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in the exhibits to the Customer's Gas Transmission Service Agreement (GTSA) (Form No. 79-866).

Receipt Point(s) available for service under this schedule are as follows:

Path:	Receipt Point(s):
Redwood to Off-System	Malin or other receipt points north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Daggett, High Desert Lateral, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities, or a third-party's storage facilities located in PG&E's service territory

Firm Off-System Delivery Points:

Kern River Station to Southern California Gas Company
Fremont Peak to Kern River Gas Transmission

Backhaul Off-System Delivery Points:

All off-system interconnection points are available as backhaul delivery points under this schedule if the upstream pipeline accepts backhaul nominations. Backhaul service is limited to the quantities of gas being delivered from the upstream pipeline.

Alternative Delivery Points:

If the Customer elects the Modified Fixed Variable (MFV) rate structure under G-AFTOFF, the Delivery Point under this schedule shall be limited to a Firm Off-System Delivery Point.

If the Customer elects the Straight Fixed Variable (SFV) rate structure under G-AFTOFF, the Customer may specify an On-System Delivery Point within the transmission path contracted by Customer as an alternate delivery point.

TERM: The minimum term for service under this rate schedule is one (1) year, and the maximum term is fifteen (15) years. (T) (T)

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

(Continued)

SCHEDULE G-AFTOFF—ANNUAL FIRM TRANSPORTATION OFF-SYSTEM
(Continued)

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	\$5.3574 (I)	\$9.0598 (R)
Baja to Off-System	\$4.4678 (I)	\$5.7218 (I)
Silverado to Off-System	\$5.3574 (I)	\$9.0598 (R)
Mission to Off-System	\$5.3574 (I)	\$9.0598 (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	\$0.1236 (R)	\$0.0019 (R)
Baja to Off-System	\$0.0448 (R)	\$0.0036 (R)
Silverado to Off-System	\$0.1236 (R)	\$0.0019 (R)
Mission to Off-System	\$0.1236 (R)	\$0.0019 (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)

SCHEDULE G-AFTOFF—ANNUAL FIRM TRANSPORTATION OFF-SYSTEM
(Continued)

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.	(T)
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.	
CAPACITY LIMITATION:	Long-term standard firm contracts for terms of five (5) years or greater are subject to a capacity limitation of 400 MDth/day on the Redwood Path and 200 MDth/day on the Baja Path	(N) | (N)

SCHEDULE G-SFT—SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY
(Continued)

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 (T)
to the Customer's GTSA. The Reservation Charge is payable each month (T)
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	$6.4282 (I)	$10.8710 (I)
Baja to On-System	$5.3610 (I)	$6.8657 (I)
Silverado to On-System	$2.9967 (I)	$4.1419 (I)
Mission to On-System	$2.9967 (I)	$4.1419 (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	$0.1483 (I)	$0.0023 (R)
Baja to On-System	$0.0538 (R)	$0.0043 (R)
Silverado to On-System	$0.0393 (R)	$0.0017 (R)
Mission to On-System	$0.0393 (R)	$0.0017 (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)

SCHEDULE G-SFT—SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY
(Continued)

TERM: The minimum term for service for an exhibit to the GTSA under this rate schedule is three (3) consecutive months in any one season. For exhibits that straddle seasons, the minimum term of service is six (6) months, covering at least three (3) consecutive months in each season. The maximum term is two (2) years. (T)

For purposes of this rate schedule, there are two (2) seasons per year; Winter and Summer. The Winter season extends for five (5) months beginning November 1 and ending March 31. The Summer season extends for seven (7) months, beginning April 1 and ending October 31.

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

ELECTRIC DEPARTMENT/ COGENERATOR PARITY RATES: Schedule G-COG Customers who take service under this schedule will be eligible for the provisions of the Cogeneration Rate Parity Exhibit of the Customer's GTSA.

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 under this schedule. The minimum term for service under the GTSA is one (1) year. (T)

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.

SCHEDULE G-AA—AS AVAILABLE TRANSPORTATION ON-SYSTEM
(Continued)

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	$0.3597 (I)
Baja to On-System	$0.2300 (I)
Silverado to On-System	$0.1379 (R)
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.

ELECTRIC DEPARTMENT/ COGENERATOR PARITY RATES: Schedule G-COG Customers who take service under this schedule will be eligible for the provisions of the Cogeneration Rate Parity Exhibit of the Customer's GTSA.

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. (T)

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.

SCHEDULE G-AAOFF—AS-AVAILABLE TRANSPORTATION OFF-SYSTEM
(Continued)

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	$0.3597 (R)
Baja to Off-System	$0.2300 (I)
Silverado to Off-System	$0.3597 (R)
Mission to Off-System	$0.3597 (R)

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: 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.

(L)

SCHEDULE G-NFT—NEGOTIATED FIRM TRANSPORTATION ON-SYSTEM
(Continued)

RATES:

The term, take requirement,** and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under G-NFT will be capped at 120 percent of the tariffed rate for G-AFT on a particular path, as follows: the negotiated rate (including all surcharges, costs and/or fees), converted to a volumetric-only rate at 100 percent load factor, shall be no greater than 120 percent of the G-AFT tariffed rate (including all surcharges, costs and/or fees), converted to a volumetric-only rate at 100 percent load factor under the Modified Fixed Variable (MFV) rate structure.

At PG&E's sole option, firm On-System capacity may be available hereunder at less than the rates in Schedule G-AFT. At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted.

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.

NEGOTIATED RATE GUIDELINES:

1. Standard tariff rates and terms are available to all Customers, in lieu of negotiated rates and terms.

2. PG&E may distinguish between parties in offering negotiated rates by evaluating differences in circumstances and conditions, including, but not limited to, differences occurring upstream of, downstream of, or at, the Customer's location, and differences affecting either cost of service to the Customer or the Customer's market alternatives. Negotiations with Customers under this rate schedule will be conducted without undue preference or undue discrimination to the Customer or to any third party.

3. Whenever PG&E offers a rate under this rate schedule which is below the tariff rate cap for Schedule G-AFT on its Redwood to On-System path, PG&E shall (T) contemporaneously offer a commensurate discount (i.e., the same penny for penny discount up to the specified quantity and up to the specified term in any discounted contract with any Redwood to On-System shipper) to all prospective (T) shippers for firm service from the tariffed rate cap for Schedule G-NFT for the Baja to On-System and Silverado to On-System paths, to the extent that capacity is available up to an equivalent volume in aggregate to the discount offered for (T) Redwood to On-System service. (T)

4. PG&E will issue monthly reports to the CPUC listing all negotiated contracts, including those negotiated under G-NFT. PG&E will make the report available to others upon request. Customer names, including PG&E's affiliates and other departments, will not be provided in the report. However, the report will indicate whether a particular transaction was with an affiliate. The report will show the negotiated rates and dates of service. PG&E shall contemporaneously report on its electronic bulletin board commensurate discounts available to prospective shippers on its Baja to On-System and Silverado to On-System paths when PG&E has offered or made known its intent to offer a discount to shippers on its Redwood to On-System path.

** A take requirement (also known as a transport-or-pay requirement) is an obligation to pay for a specified quantity of transportation pursuant to the terms of the applicable GTSA exhibit and shall be unaffected by the quantity of gas transported by PG&E to the Customer's Delivery Point(s).

(Continued)

SCHEDULE G-NFT—NEGOTIATED FIRM TRANSPORTATION ON-SYSTEM
(Continued)

NEGOTIATED RATE GUIDELINES (Cont'd.)

5. The CPUC's complaint procedure will be available to address any claims of undue discrimination in providing service hereunder.

6. Negotiated transmission contracts under G-NFT will not require submission to the CPUC for approval. Unless otherwise provided in the applicable GTSA, or exhibit thereto, the application of Sections IX and X of General Order 96-A is waived by the CPUC.

ELECTRIC DEPARTMENT/ COGENERATOR PARITY RATES: Schedule G-COG Customers who take service under this schedule will be eligible for the provisions of the Cogeneration Rate Parity Exhibit of the Customer's GTSA.

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 under this schedule. The minimum term for service under the GTSA is one (1) year. (T)

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 obligation under Schedule G-BAL.

SCHEDULE G-NAA—NEGOTIATED AS-AVAILABLE TRANSPORTATION ON-SYSTEM (T)
(Continued)

RATES:

The term, take requirement,* and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under G-NAA will be capped at 120 percent of the tariffed rate for G-AA on a particular path.

At PG&E's sole option, As-available On-System capacity may be available hereunder at less than the rates in Schedule G-AA. At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted.

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.

NEGOTIATED RATE GUIDELINES:

1. Standard tariff rates and terms are available to all Customers, in lieu of negotiated rates and terms.

2. PG&E may distinguish between parties in offering negotiated rates by evaluating differences in circumstances and conditions, including, but not limited to, differences occurring upstream of, downstream of, or at, the Customer's location, and differences affecting either cost of service to the Customer or the Customer's market alternatives. Negotiations with Customers under this rate schedule will be conducted without undue preference or undue discrimination to the Customer or to any third party.

3. Whenever PG&E offers a rate under this rate schedule which is below the tariff rate cap for Schedule G-AA on its Redwood to On-System path, PG&E shall (T) contemporaneously offer a commensurate discount (i.e., the same penny for penny discount up to the specified quantity and up to the specified term in any discounted contract with any Redwood to On-System shipper) to all prospective (T) shippers for as-available service from the tariffed rate cap for Schedule G-NAA for the Baja to On-System and Silverado to On-System paths up to an equivalent (T) volume in aggregate to the discount offered for Redwood to On-System service. (T)

4. PG&E will issue monthly reports to the CPUC listing all negotiated contracts, including those negotiated under G-NAA. PG&E will make the report available to others upon request. Customer names, including PG&E's affiliates and other departments, will not be provided in the report. However, the report will indicate whether a particular transaction was with an affiliate. The report will show the negotiated rates and dates of service. PG&E shall contemporaneously report on its electronic bulletin board commensurate discounts available to prospective shippers on its Baja to On-System and Silverado to On-System paths when PG&E has offered or made known its intent to offer a discount to shippers on its Redwood to On-System path.

5. The CPUC's complaint procedure will be available to address any claims of undue discrimination in providing service hereunder.

6. Negotiated transmission contracts under G-NAA will not require submission to the CPUC for approval. Unless otherwise provided in the applicable GTSA, or exhibit thereto, the application of Sections IX and X of General Order No. 96-A is waived by the CPUC.

(Continued)

SCHEDULE G-XF—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
	(D)
SFV Rates:	$7.8996 (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.

---

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

(Continued)

SCHEDULE G-XF—PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE
(Continued)

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	
		(D)
SFV Rates:	$0.0011 (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.

SCHEDULE G-CT—CORE GAS AGGREGATION SERVICE

APPLICABILITY: This schedule*applies to transportation of natural gas for Core End-Use Customers (as defined in Rule 1*) ("Customer") who aggregate their gas volumes and who obtain natural gas supply service from parties other than PG&E. The provisions of Schedule G-CT apply to Core End-Use Customers and to the party who supplies them with natural gas and provides or obtains services necessary to deliver such gas to PG&E's Distribution System. Rule 23 also sets forth terms and conditions applicable to Core Gas Aggregation Service.

A group of Core End-Use Customers who aggregate their gas volumes shall comprise a Core Transport Group (Group). The minimum aggregate gas volume for a Group is 12,000 decatherms per year. The Customer must designate a Core Transport Agent (CTA), who is responsible for providing gas aggregation services to Customers in the Group as described herein and in Rule 23. Aggregation of multiple loads at a single facility or aggregation of loads at multiple facilities shall not change the otherwise-applicable rate schedule for a specific facility. Customers electing service under this schedule must request such service for one hundred (100) percent of the core load served by the meter. Schedule G-CT must be taken in conjunction with a core rate schedule.

Core volumes are eligible for service under this schedule, whether or not noncore volumes are also delivered to the same premises. However, core volumes cannot be aggregated with noncore volumes in order to meet the minimum therm requirement for noncore service. Service to core volumes associated with noncore volumes under this schedule applies to all core volumes on the noncore premises.

CTAs, on behalf of a Group, may receive service on PG&E's Backbone Transmission System by utilizing Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA.

TERRITORY: This schedule applies everywhere within PG&E's natural gas Service Territory. (T)

RATES: Customers taking service under Schedule G-CT will receive and pay for service under their otherwise-applicable core rate schedule; except that Customers who procure their own gas supply will not pay the Procurement Charge specified on their otherwise-applicable core rate schedule.

Pursuant to Schedule G-SUR, Customers will be subject to a franchise fee surcharge for gas volumes purchased from parties other than PG&E and transported by PG&E. Customers will also be responsible for any applicable costs, taxes and/or fees incurred by PG&E in receiving gas to be delivered to such Customers.

See Preliminary Statement, Part B for the Default Tariff Rate Components.

---

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

(Continued)

SCHEDULE G-NGV4—EXPERIMENTAL GAS TRANSPORTATION SERVICE TO NONCORE NATURAL GAS VEHICLES

APPLICABILITY: This rate schedule* applies to the transportation of gas to customer-owned natural gas vehicle fueling stations on PG&E's 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. (T)

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. (N)

(D)

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. (N)

Average Monthly Use (Therms)	Per Day
0 to 5,000	$0.99010 (I)
5,001 to 10,000	$7.80073 (I)
0,001 to 50,000	$29.59388 (I)
50,001 to 200,000	$78.00975 (I)
200,001 to 1,000,000	$111.69084 (I)
1,000,001 and above	$324.67266 (I)

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

(Continued)

SCHEDULE G-NGV4—EXPERIMENTAL GAS TRANSPORTATION SERVICE TO NONCORE NATURAL GAS VEHICLES
(Continued)

RATES: (Cont'd.)

2. Transportation Charge:

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

Transmission-Level Rate: (T)

Transmission-Level Rates apply to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi). (T)

Transmission-Level Rate (Per Therm) $0.04657 (I)

Distribution-Level Rates:

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. (T)

Average Monthly Use (Therms)	Summer (Per Therm)	Winter (Per Therm)	
Tier 1: 0 to 20,833	$0.09748 (R)	$0.11709 (R)	
Tier 2: 20,834 to 49,999	$0.08444 (R)	$0.09949 (R)	
Tier 3: 50,000 to 166,666	$0.08146 (R)	$0.09545 (R)	
Tier 4: 166,667 to 249,999	$0.07546 (R)	$0.08736 (R)	(T)
Tier 5: 250,000 and above*	$0.04657	$0.04657	(N)

See Preliminary Statement Part B for Default Tariff Rate Components.

FEES AND TAXES:

Customer may pay a franchise fee surcharge for gas volumes transported by PG&E. (T)
(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. (T)

* Tier 5 Summer and Winter rates are the same. (N)

(Continued)

SCHEDULE G-NGV4—EXPERIMENTAL GAS TRANSPORTATION SERVICE TO NONCORE NATURAL GAS VEHICLES
(Continued)

SEASONS: Summer season is from April 1 through October 31. Winter season is from November 1 through March 31.

SERVICE AGREEMENT: A Natural Gas Service Agreement (NGSA) (Form No. 79-756) is required for service under this schedule. The initial term of the NGSA will be for 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 schedule. See Rule 21 for details.

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

BACKBONE TRANSMISSION TRANS-PORTATION SERVICE: Transportation service on PG&E's Backbone Transmission System may be taken in conjunction with this schedule under Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA. A separate Gas Transmission Service Agreement (GTSA) (Form No. 79-866) must be executed for such service. The GTSA can be held by the Customer or by another party, such as the Customer's gas supplier. (T) (T)

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):	$0.19770 (I)
LNG Gallon Equivalent: (Conversion factor - One LNG Gallon = 0.82 Therms)	$0.16211 (I)

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.

---

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

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE

E. OPERATIONAL FLOW ORDERS (OFO)

In order to protect the integrity of its pipeline system, PG&E will issue and implement system-wide, local, or Customer-specific Operational Flow Orders (OFO). PG&E will issue an OFO for a Gas Day if, on the day prior to this Gas Day, PG&E's forecast of pipeline inventory for the Gas Day is either below the Lower Pipeline Inventory Limit or above the Upper Pipeline Inventory Limit. At such time as PG&E issues an OFO, Balancing Agents will be required to balance supply and demand on a daily basis within a specified tolerance band or be subject to charges for noncompliance. PG&E may elect not to issue an OFO for a Gas Day if the forecast of pipeline inventory for the day following that Gas Day indicates the pipeline inventory will return to within the Pipeline Inventory Limits without the assistance of an OFO.

The Lower and Upper Pipeline Inventory Limits may be revised as needed by PG&E to maintain the safety and reliability of the pipeline system. These changes, along with a supporting explanation, will be posted to the Pipe Ranger Web site.

The tolerance band will be a percentage of the usage, as defined below.

PG&E may implement multi-stage OFO provision charges, as follows:

	Tolerance Band	Noncompliance Charge Per Decatherm	
			(T)
Stage 1:	up to +/-25%	$0.025	
Stage 2:	up to +/-20%	$0.10	
Stage 3:	up to +/-15%	$0.50	
Stage 4:	up to +/-5%	$2.50	
Stage 5:	up to +/-5%	$25.00 plus DCI*	(N)

* The DCI is the PG&E Daily Citygate Index Price as published in Gas Daily, rounded up to the next whole dollar. If the price is not published on a given day, the previous published price will apply. (N)

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

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

PG&E has the option, and would normally expect, to issue and implement an OFO with a one-sided tolerance band, and related non-compliance charges in one direction only (i.e., an OFO with a –25 percent (-25%) tolerance band and $0.25 per Decatherm noncompliance charge for supply being less than usage but no (T) tolerance band in the positive direction—supply greater than usage). Generally an initial OFO event will start at Stage 1 with a noncompliance charge of $0.25 per (T) Decatherm; however, an OFO event may begin at any stage with the corresponding (T) noncompliance charge as deemed appropriate by PG&E.

A specific Balancing Agent may start at an elevated charge level if that Balancing Agent has a history of noncompliance with prior PG&E requests or orders for the Balancing Agent to balance supply with demands. A history of noncompliance will be defined as being at least three days in any thirty-day period that a Balancing Agent has not met with prior balancing orders. The amount of the charge will be announced when PG&E issues an OFO. An OFO will normally be ordered with at least twelve (12) hours notice prior to the beginning of the gas day, or as necessary as dictated by operating conditions. Charges for the first day of the OFO event will not be imposed if notice is given after 6:00 p.m. Pacific Time the day prior to the start of the OFO event.

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

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 for any month, the noncompliance charge will be exempted and the charge will be zero. If the noncompliance charge is greater than $1,000, the Balancing Agent will be responsible for the full noncompliance charge; i.e., $1,000 will not be deducted from the calculated noncompliance charge. This exemption provision only applies to OFO noncompliance charges. (T)

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 average daily metered usage for the affected premises will be substituted for the actual 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)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

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

3. For a Core Procurement Group (which includes PG&E's Core Procurement Department and Core Transport Groups) (CP Group), compliance during an OFO and calculation of any OFO noncompliance charges will be based on the Determined Usage forecast as defined in Schedule G-BAL provided on the designated OFO day. If the Determined Usage is not posted by 7:15 a.m., the most recent previous forecast will be used. (N)

4. For a California Production Balancing Agreement (CPBA), (Form 79-944) compliance with an OFO and calculation of any OFO noncompliance charges will be based on the difference between scheduled deliveries and actual deliveries. (N)

Should PG&E's implementation of an OFO prove to be inadequate to ensure system integrity, PG&E may implement other measures including, but not limited to, implementing an Emergency Flow Order (EFO).

OFOs and SELF-BALANCING

On OFO days, any Balancing Agent who has selected the Self-Balancing Option, pursuant to Schedule G-BAL, will be required to comply with the tolerance band specified for that OFO day. The Self-Balancing plus or minus ten percent (±10%) daily Imbalance tolerance will not apply on days when an OFO is in effect. A Self-Balancing Agent will not be subject to Accumulated Daily Imbalance Noncompliance Charges on high inventory OFO days if the Accumulated Daily Imbalance is negative, or on any low inventory OFO days if the Accumulated Daily Imbalance is positive. However, any imbalance that occurs on that OFO day will be included as part of the Customer's ongoing Accumulated Daily Imbalance calculation.

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

F. EMERGENCY FLOW ORDERS (EFO)

PG&E may invoke Emergency Flow Orders (EFO) when a forecast or an actual supply and/or capacity shortage threatens deliveries to End-Use Customers.

During an EFO, End-Use Customers' usage must be less than or equal to supply for a gas day (i.e., supply must be equal to or greater than usage). With the one exception specified herein, EFOs will have a zero (0) percent tolerance and a (T)
noncompliance charge of $50.00 plus DCI for each Decatherm of usage in excess of (T)
supply.

As ordered in Decision 01-02-049, PG&E shall waive any EFO 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.

EFO COMPLIANCE

EFO 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 EG Department, compliance during an EFO will be based on actual daily metered usage and the calculation after the EFO 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 EFO 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 EFO event will be based on one of the following, whichever results in the lesser charge:

   (1) the Customer's ADQ, or

   (2) the Customer's actual daily metered usage, or

   (3) when Customer's actual daily metered usage is not available, the average daily metered usage for the affected premises will be substituted for the actual 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)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

F. EMERGENCY FLOW ORDERS (EFO) (Cont'd.)

3. For a Core Procurement Group (CP Group), compliance during an EFO and calculation of any EFO noncompliance charges will be based on the Determined Usage forecast provided on the designated EFO day, or the end-of-flow day core demand estimate, whichever results in a lower noncompliance charge. If the Determined Usage is not posted by 7:15 a.m., the most recent previous forecast will be used. (N)

4. For a CPBA, compliance during an EFO and calculation of any EFO noncompliance charges will be based on the difference between scheduled deliveries and actual deliveries. (N)

With the exception of the EFO noncompliance charge waiver specified above, if PG&E invokes an involuntary supply diversion (see Section G, below) in conjunction with an EFO, an additional $50.00 per Decatherm diversion usage charge will apply. (T)

An EFO will normally be invoked following an Operational Flow Order (OFO), but PG&E may invoke an EFO without previously invoking an OFO if, in PG&E's judgment, emergency operating conditions exist. There shall be no minimum notice period for EFOs; however, PG&E will attempt to provide as much notification to Customers as practicable under the circumstances.

PG&E may implement other measures to ensure system integrity should an EFO fail to alleviate the emergency condition.

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

G. DIVERSION OF CUSTOMER-OWNED GAS (Cont'd.)

1. INVOLUNTARY DIVERSIONS

PG&E may divert gas supplies from Backbone Transmission System Customers. Firm transportation to off-system is not subject to diversion. Diversions will occur in the following order:

a. Supply scheduled under As-Available transmission service will be diverted in order of increasing transmission contract price and on a pro rata basis for all volumes transported under the same price. However, supply under scheduled deliveries from storage using As-Available transmission service will be treated as the highest priority Firm transmission service. (See G.1.c., below.)

b. Supply scheduled to Noncore End-User Customers under Firm transmission service is diverted on a pro rata basis.

c. Scheduled deliveries from storage using Firm or As-Available transmission service will be treated as the highest priority Firm transmission service and will be diverted on a pro rata basis.

2. INVOLUNTARY DIVERSION COMPLIANCE AND CHARGES

All Customers who use more gas during an involuntary diversion than their post-diverted supply, whether or not their gas is subject to an involuntary diversion, will be assessed involuntary diversion charges. Those customers will be deemed to be receiving involuntarily diverted supply, and therefore will be assessed a $50.00 per Decatherm diversion usage charge, in addition to the (T)
EFO noncompliance charge. See Section F, above, for conditional waiver of |
only the EFO noncompliance charges for certain core customers during an (T)
involuntary diversion.

Involuntary diversion compliance and charges will be based on the following:

a. For a Noncore End-Use Customer with automated meter reading (AMR) capability, compliance and the calculation after the involuntary diversion event of any involuntary diversion charge will be based on actual daily metered usage and the post-diverted supply. (Post-diverted supply is the original scheduled supply less the diverted volumes.)

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

G. DIVERSION OF CUSTOMER-OWNED GAS (Cont'd.)

2. INVOLUNTARY DIVERSION COMPLIANCE AND CHARGES (Cont'd)

   b. For a Noncore End-Use Customer without AMR capability (all or part non-AMR capability) at their premises and PG&E's Electric Generation (EG) department, compliance and the calculation after the involuntary diversion event of any noncompliance charge will be based on actual usage and the post-diverted supply.

   c. For a Core Procurement Group (CP Group), compliance and the calculation after the involuntary diversion event of any involuntary diversion charge will be based on the latest available forecast from the core load forecast model for the CP Group prior to the time the event is called, up to and including a 5:00 p.m. Pacific Time Forecast, and the CP Group's original supply before involuntary diversion.

3. COMPENSATION FOR INVOLUNTARILY DIVERTED GAS

Firm transmission service Customers whose gas supply is involuntarily diverted will receive a $50.00 per Decatherm diversion credit. (T)

As-Available transmission service Customers whose gas supply is involuntarily diverted will receive a diversion credit based on the current market price of the diverted supply on the day it was diverted.

The current market price will be based on an average of the published price data from Natural Gas Intelligence (NGI) and the BTU Daily Gas Wire for the PG&E interconnect points of Malin (Line 400) and Topock (Southern California Border), weighted by the supply mix of all gas received at Malin and Topock for on-system End-Use Customers for that day.

(Continued)

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

G. DIVERSION OF CUSTOMER-OWNED GAS (Cont'd.)

3. COMPENSATION (Cont'd.)

If no published daily price is reported on a given day, the prior published daily price from that index service will continue to apply for that day. If an index service is no longer available, PG&E reserves the right to choose another nationally recognized index to replace it.

H. LOCAL CURTAILMENT (N)

In the event of localized constraints, PG&E may curtail Noncore End-Use Customers in a localized area. When a local curtailment is announced, Noncore End-Use Customers will be provided a maximum allowed usage for the designated curtailment period. (N) Compliance with the local curtailment is the responsibility of the Noncore End-Use Customer and may not be assigned to a Balancing Agent. (L) Noncore End-Use Customers that exceed the maximum allowed usage will be subject to a noncompliance charge. (N)

Local Curtailment noncompliance charges for each decatherm of usage in excess of designated maximum allowed usage shall equal $50.00 plus the DCI. In order to protect its system, PG&E may temporarily shut off gas service to any Customer that fails to comply with the local curtailment.

In the event that an OFO or EFO is in effect simultaneously with a local curtailment, OFO or EFO noncompliance charges may apply in addition to any local curtailment noncompliance charges. (N)

I. SERVICE FROM OFF-SYSTEM STORAGE FACILITIES (T)

Gas from off-system storage facilities is treated equally with any other gas delivered at that specific PG&E interconnection. (T)

J. WHOLESALE/RESALE SERVICE

Service under wholesale/resale service agreements, in which the gas is resold to customers of other utilities within PG&E's service territory, shall be subject to Operational Flow Orders, Emergency Flow Orders, and diversion of Customer-owned gas in the same manner as if such Customers were Customers of PG&E.

RULE 14—CAPACITY ALLOCATION AND CONSTRAINT OF NATURAL GAS SERVICE
(Continued)

K. CORE END-USE CUSTOMERS (T) (L)

In an emergency situation, non-residential Core End-Use Customers may be asked to reduce usage prior to residential Core End-Use Customers.

L. CONFLICTS WITH OTHER TARIFFS AND/OR CONTRACTS

Each of the gas rate schedules, agreements, and rules governing the sale and transportation of natural gas by PG&E on file with the CPUC, shall be deemed amended to the extent that they are or may be inconsistent or in conflict with the priorities of service as listed in this rule.

M. NBAA AND CTA GROUP IMBALANCES MAY NOT BE COMBINED (T)

OFO, EFO, and Diversion compliance calculations for Noncore Balancing Aggregation Groups (NBAA) and Core Transportation groups (CTA) are performed separately, according to the terms contained in this rule. Suppliers may not combine NBAA group and CTA group usage and supplies in an effort to comply with an OFO, EFO, or Diversion. (L)

RULE 21—TRANSPORTATION OF NATURAL GAS

This Rule describes the general terms and conditions that apply whenever PG&E transports Customer-owned gas over its system. Customers who wish to transport gas must sign the applicable Agreement.

A. GENERAL

1. NATURE OF SERVICE

Customers or their designated Agent or Core Transport Agent hereinafter referred to as "Customer" and meaning Customer and/or their Agent will deliver or have delivered to PG&E quantities of gas, and PG&E will deliver equivalent quantities of gas adjusted for In-Kind Shrinkage Allowance, on a Btu-for-Btu basis, to the Customer's Delivery Point. Customers must endeavor to ensure that daily gas deliveries match daily gas usage. The gas that PG&E delivers to the Customer's Delivery Point will not necessarily be the gas that the Customer delivered to PG&E.

2. GAS SPECIFICATIONS

Unless otherwise agreed to by both parties, the gas delivered to PG&E must meet the quality specifications detailed in Section C, below. The minimum and maximum heating value and the pressure of the gas must be such that the gas can be integrated into PG&E's system at the Receipt Point(s).

B. QUANTITIES OF GAS

1. IN-KIND SHRINKAGE ALLOWANCE

The in-kind shrinkage quantities represent the unaccounted-for gas and the utility fuel use attributable to the volume of natural gas received by PG&E for backbone transmission, distribution, and storage service. (T)

(Continued)

RULE 21—TRANSPORTATION OF NATURAL GAS
(Continued)

B. QUANTITIES OF GAS (Cont'd.)

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

a. Backbone Transmission Shrinkage (T)

A Customer transporting gas over PG&E's Backbone Transmission System shall deliver each day at the Receipt Point to PG&E an additional in-kind quantity of natural gas supply equal to a percent of total volume of natural gas to be delivered at the Receipt Point. Thus, the quantity to be nominated at the Receipt Point equals the quantity desired at the Delivery Point divided by (1 - x) where x is the decimal equivalent of the Backbone Transmission System In-Kind Shrinkage Allowance percentage, based on the transmission path utilized as follows:

Path	In-Kind Shrinkage Allowance	In-Kind Shrinkage Credit	Effective In-Kind Shrinkage Allowance	(T)
Redwood to Off-System	1.11 percent	–	1.11 percent	
Mission to On-System	0	–	0	
Mission to Off-System	0	–	0	
All other transmission	1.2 percent (C)	0 percent	1.2 percent (C)	

Provided, however, that PG&E and the Customer shall not be prohibited under this Rule, where shrinkage requirements support a different shrinkage allowance, from mutually agreeing to a different shrinkage allowance for transportation over PG&E's Backbone Transmission System.

(Continued)

RULE 21—TRANSPORTATION OF NATURAL GAS
(Continued)

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 (T) to PG&E at the Citygate an additional in-kind quantity of natural gas supply (T) 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	In-Kind Shrinkage Allowance	In-Kind Shrinkage Credit	Effective In-Kind Shrinkage Allowance	(T)
Core	2.4 percent (C)	0 percent	2.4 percent (C)	
Noncore Distribution	0.2 percent (C)	0 percent	0.2 percent (C)	
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.

(Continued)

RULE 21—TRANSPORTATION OF NATURAL GAS
(Continued)

B. QUANTITIES OF GAS (Cont'd.)

3. NOMINATIONS (Cont'd.)

f. Evening Nomination Cycle

An Evening Nomination must be received by PG&E no later than 4:00 p.m. one day prior to the gas day for which the Customer requests service. Evening Nominations will be effective at 7:00 a.m. the following morning. Evening Nominations will be confirmed and scheduled after Timely Nominations are confirmed and scheduled.

PG&E will provide to the Customer a confirmed nomination report indicating the nomination quantities which have been received and confirmed for transport on PG&E's system and which have been communicated to the upstream and/or downstream pipeline(s) and/or operator(s). Subject to PG&E receiving notification from the applicable upstream and/or downstream pipeline(s) and/or operator(s), PG&E will provide to the Customer a scheduled quantities report. PG&E will attempt, but cannot guarantee, delivery of these two reports by 7:00 p.m. and 8:00 p.m., respectively.

Evening Nomination summary

- Nominations submitted: No later than 4:00 p.m.
- Flow will be effective: 7:00 a.m. the following morning

Evening Nominations will be confirmed and scheduled by priority of service among all Evening Nominations PG&E has received and in accordance with Rule 14.

An Evening Nomination either may be the Customer's first nomination for service for the following day or may modify a Timely Nomination for the following day. An Evening Nomination may increase or decrease previously scheduled quantities subject to Section B.3.b. and scheduling non-performance in Section B.4. An Evening Nomination does not carry over to the following gas day. (T)

(Continued)

RULE 21—TRANSPORTATION OF NATURAL GAS
(Continued)

B. QUANTITIES OF GAS (Cont'd.)

4. SCHEDULING NON-PERFORMANCE

An excess of confirmed nominations relative to scheduled nominations for a given gas day for a given Customer and a particular As-Available transportation exhibit to the Gas Transmission Service Agreement (GTSA) shall be deemed to be scheduling non-performance. This section sets forth how PG&E will manage excess As-Available volumes and reduce a Customer's ability to engage in scheduling non-performance. (T)

(D)

1. PG&E may limit the Maximum Daily Quantity (MDQ) of an As-Available contract to the expected usage of that contract by an entity. Expected usage is the Customer's highest actual usage in the past twelve (12) months.

2. PG&E may reduce an As-Available contract's MDQ on a daily basis to the previous day's actual usage if scheduling non-performance occurs.

3. If an entity's load increases, the entity may contact PG&E to increase the MDQ.

(Continued)

RULE 21—TRANSPORTATION OF NATURAL GAS
(Continued)

B. QUANTITIES OF GAS (Cont'd.)

5. IMBALANCES IN DELIVERIES

a. On any given day the Customer shall bring in a quantity of Customer-Owned Gas, adjusted for In-Kind Shrinkage Allowance, to be delivered to the Customer, approximately equal to the quantity of gas received by PG&E for transportation to the Customer that day.

Any day-to-day imbalance will be handled and resolved through Schedule G-BAL.

b. Procedures for balancing the Customer's account when PG&E receives Customer-Owned Gas for transportation but, because of constraints or diversions, does not deliver it to the Customer, are covered in Rule 14.

c. A transmission Customer's Imbalance, defined in Schedule G-BAL, refers to a difference between a Customer's final scheduled quantity and the quantity of gas actually delivered at the Receipt Point on behalf of that Customer for a given gas day. (T)

6. TRANSPORT OF CALIFORNIA PRODUCTION GAS

PG&E may receive gas from California production supply for transport by a Customer from various Receipt Points on PG&E's system. As of April 1, 1998, nominations shall be accepted by PG&E only from California production Receipt Points which are designated in a California Production Balancing Agreement (Form No. 79-944) which has been executed between a California producer's Authorized Agent and PG&E.

(Continued)

PACIFIC GAS AND ELECTRIC COMPANY
CALIFORNIA PRODUCTION BALANCING AGREEMENT
FORM NO. 79-944 (1/04) (T)
(ATTACHED)

Contract No.________________
Date______________________

PACIFIC GAS & ELECTRIC COMPANY
CALIFORNIA PRODUCTION BALANCING AGREEMENT

This California Production Balancing Agreement (CPBA) is made by and between Pacific Gas & Electric Company (PG&E), a California corporation, and ______________________________ ____________ hereafter referred to as Authorized Agent (AA), a(n) ____________________________________. PG&E and the AA are each also referred to herein as "Party" and together as "Parties".

PURPOSE
This CPBA establishes the terms and conditions for the resolution of imbalances on PG&E's gas transportation system (the PG&E System) caused by volumes of gas, delivered into the PG&E System from California production wells, which volumes exceed or are insufficient to match the nominations made for the deliveries into the PG&E System.

The AA requests that PG&E recognize (1) the AA's authority to represent and act on behalf of the parties (party) who own(s) or control(s) gas produced from certain California production wells (Producer(s)) and who deliver that gas into the PG&E System, for transportation, at the point(s) of interconnection where gas is measured before delivery into the PG&E System (Receipt Point(s)), which is (are) specified in Attachment 2 "Receipt Point(s)" (Attachment 2); and (2) that the AA has been duly appointed to act as agent for the Producer(s) pursuant to Attachment 1 "Appointment of Authorized Agent" (Attachment 1).

This CPBA is not intended to be an agreement for transportation services. PG&E provides transportation services pursuant to applicable rules, schedules, tariffs, and agreements.

This CPBA does not apply to gas volumes delivered at the Receipt Point(s) specified in Attachment 2 for procurement by PG&E under a traditional procurement contract executed prior to December, 1989, and such deliveries shall not be included in the Cumulative Imbalance calculation applicable to gas nominated by the AA under this CPBA.

AGREEMENT
The Parties intending to be legally bound agree as follows:

REPRESENTATIONS
By entering into this CPBA, the AA accepts the obligations of the AA hereunder. The AA represents that (1) the AA is the exclusive agent for one or more Producer(s), who are supplying gas to the Receipt Point(s) listed in Attachment 2 of this CPBA, for the purpose of nominating volumes of that gas for transport by PG&E under PG&E's standard nomination procedures; balancing those nominations against actual deliveries at the Receipt Point(s); allocating, prorating and handling administrative matters concerning Receipt Point(s); giving and receiving payments, notices and requests; and taking such action and exercising such powers as agent on behalf of the Producer(s) as set forth in Attachment 1; and (2) the AA is

duly authorized and has all necessary legal rights and powers to enter into this CPBA and to perform all of the obligations of the AA set forth herein, to grant to PG&E the rights set forth herein, and to bind the Producer(s) to all obligations, acts and omissions of the AA under this CPBA; and (3) the AA will comply with all of the obligations set forth in this CPBA, notwithstanding any agency relationship between the AA and the Producer(s) or other third party.

WARRANTIES

The AA represents and warrants that (1) it has the right and is duly authorized to nominate all gas delivered to PG&E at the Receipt Point(s); (2) it has or can transfer good title to such gas, and all such gas is delivered free from all liens, encumbrances and adverse claims of any kind; (3) it will comply with all federal, state and local reporting requirements and other applicable laws or regulations; and (4) PG&E may conclusively rely upon any and all nominations made and information provided by the AA hereunder as correct.

TARIFFS

The Parties agree to abide by the applicable sections of PG&E's tariffs as they may change from time to time, as well as the terms and conditions stated in this CPBA and its Attachments. Such tariffs include but are not limited to the Operational Flow Order (OFO) and Emergency Flow Order (EFO) provisions of gas Rule 14.

TERM OF AGREEMENT

This CPBA will become effective as of the effective service date of______________________
and will remain in effect until terminated by the AA or PG&E pursuant to this CPBA.

ATTACHMENTS

Attachments, as listed below, are hereby made a part of this CPBA and specify terms and conditions under which PG&E will recognize the authority of the AA and the Receipt Point(s) for which the AA is responsible.

(1) Appointment of Authorized Agent (Attachment 1). Appoints the exclusive agent of the Producer(s) for all purposes stated in this CPBA including, without limitation, all applicable nominating, balancing, paying, allocating, prorating, and other administrative matters with respect to the gas to be delivered at the Receipt Point(s) specified in Attachment 2 of this CPBA.

(2) Receipt Point(s) (Attachment 2). Lists the Receipt Point(s), and their maximum daily production cap(s), for which the AA will be responsible.

(3) Communications and Operations Contact (Attachment 3). Specifies the notice requirements applicable to this CPBA.

NOMINATIONS AND SCHEDULED DELIVERIES

The AA shall place nominations with PG&E for transportation of gas from each Receipt Point consistent with PG&E's nomination procedures. PG&E shall process nominations in accordance with PG&E's normal scheduling procedures and communicate the resulting confirmed nominations to the AA pursuant to Attachment 3.

The AA shall verify with the well operator that the confirmed nomination quantity of gas shall be delivered to each Receipt Point each day for which the gas is nominated. If the delivered quantity is estimated to be less than the confirmed nomination, the AA shall provide PG&E with an estimate of the delivered quantity. This estimated quantity, which may not exceed the volume of gas already confirmed by PG&E, shall become the volume of gas scheduled for delivery and shall be communicated by PG&E to the AA, by facsimile or other electronic means, on the day the gas is transported.

PG&E, in its sole discretion, may review the maximum daily production cap volume(s) for the Receipt Point(s) specified on Attachment 2, and may reduce such volume(s) to better match actual delivered volume(s) into the PG&E System. PG&E may also revise a maximum daily production cap upward, if the AA provides PG&E with recent well test documentation for increased production to be delivered to a Receipt Point.

REFUSAL OF GAS

PG&E, in its sole judgment, shall have the right, without incurring any liability to the AA or to the Producer(s), to refuse acceptance of gas at the Receipt Point(s) when:

(a) the AA fails to comply with a provision of this CPBA, becomes insolvent or subject to a bankruptcy proceeding, or fails to establish creditworthiness if requested by PG&E; or

(b) any agreement required by PG&E in connection with the transportation of gas on PG&E's System has not been executed, has been terminated, or has expired; or

(c) PG&E deems it necessary or desirable to curtail acceptance of the gas in order to operate, preserve, or protect the integrity and safety of PG&E's gas system including, without limitation, gas quality, gas supply, and/or gas system facilities. PG&E shall use reasonable efforts to give the AA advance notice of any such curtailment.

ADDING POINTS OF RECEIPT TO THE CPBA

The AA shall notify PG&E in writing of any Receipt Point(s) to be added to or deleted from Attachment 2. Changes will take effect on the first day of the month following PG&E's receipt of a written notification from the AA of an addition or deletion of a Receipt Point if received by PG&E no later than ten (10) business days prior to the first day of the month in which the change is to take effect. The AA shall not nominate or deliver gas to an added Receipt Point until PG&E notifies the AA that the Receipt Point is included in Attachment 2 by written amendment.

CALCULATING IMBALANCES

At the end of each month, PG&E shall calculate the difference between the actual delivery and the scheduled delivery at each Receipt Point listed on Attachment 2. The total net difference for all Receipt Points, plus any uncleared prior imbalance allowed under the provisions of this CPBA, shall be the "Cumulative Imbalance", which shall be maintained in a "Cumulative Imbalance Account" until cleared under the provisions of this CPBA.

Actual deliveries greater than the scheduled deliveries for all Receipt Point(s) shall be a positive Cumulative Imbalance. Actual deliveries less than the scheduled deliveries for all Receipt Point(s) shall be a negative Cumulative Imbalance. PG&E shall issue a "Cumulative Imbalance Statement" no later than the 15th day of the first month subsequent to the month in which the Cumulative Imbalance occurred.

TOLERANCE BAND

The Tolerance Band is equal to plus or minus 150 decatherms of the Cumulative Imbalance for the month in which the imbalance occurred.

CLEARING IMBALANCES

A Cumulative Imbalance may be cleared by nominating to or from the AA's Cumulative Imbalance Account or by trading the Cumulative Imbalance.

1. Cumulative Imbalance Account Nominations: Following issuance of the Cumulative Imbalance Statement, the AA may clear a negative Cumulative Imbalance by nominating, consistent with PG&E's nominating procedures, In-Kind (an equivalent amount of gas from the Receipt Point(s) listed on Attachment 2) to the Cumulative Imbalance Account; or the AA may clear a positive Cumulative Imbalance by nominating from the Cumulative Imbalance Account to a Delivery Point, on or before the closing date for trading imbalances as described below.

2. Trading Imbalances: Following issuance of the Cumulative Imbalance Statement, the AA may trade its Cumulative Imbalance with another AA under a CPBA that has a Cumulative Imbalance from the same calendar month. Any imbalance trade shall move the trading party's Cumulative Imbalance toward zero or result in an imbalance that is within the Tolerance Band. The AA may trade all or a portion of its Cumulative Imbalance by executing an imbalance trade on or before the last business day of the first month subsequent to the month in which the Cumulative Imbalance occurred. Executing an imbalance trade consists of both parties to the trade completing a California Production Cumulative Imbalance Trading Form (No. 79-946) or electronic equivalent, and submitting the form to PG&E.

REMAINING IMBALANCES

After the imbalance trading deadline, a remaining Cumulative Imbalance within the Tolerance Band will be carried forward to the following month's Cumulative Imbalance. A remaining Cumulative Imbalance greater than the Tolerance Band will be automatically cashed out in its entirety, resulting in a zero imbalance.

CASHOUT

The Commodity cashout prices for each month are established for the following four (4) imbalance categories: Over-deliveries and under-deliveries in the imbalance range of greater than zero (0) percent and less than or equal to ten (10) percent of actual deliveries (Tier 1 Cashout), plus over-deliveries and under-deliveries in the imbalance range of greater than ten (10) percent of actual deliveries (Tier II Cashout).

Each cashout price is based on a two step calculation: First a cashout index is determined based on an average of the published price date from Natural Gas Intelligence (NGI) and the BTU Daily Gas Wire for the PG&E interconnect points of Malin (Line 400) and Topock (Southern California Border). Second, that index is adjusted to arrive at the cashout price for that imbalance category.

Imbalances greater than zero (0) percent and less than or equal to ten (10) percent of actual deliveries (Tier I Cashout):

1) Over-deliveries
   a) The Weighted Over Delivery (WOD) Index equals the lower of the Bid Week monthly index price or the average of the five (5) lowest average published daily prices, weighted by the supply mix of all gas received at Malin and Topock for on-system End-Use Customers during the month in which the imbalance occurred.

   b) The cashout price equals ninety five (95) percent of the WOD Index.

2) Under-deliveries:
   a) The Weighted Under Delivery (WUD) Index equals the higher of the Bid Week monthly index price or the average of the five highest average published daily prices, weighted by the supply mix of all gas received at Malin and Topock for on-system End-Use Customers during the month in which the imbalance occurred.

   b) The cashout price equals one hundred five (105) percent of the WUD Index.

Imbalances Greater than 10% of Actual Deliveries (Tier II Cashout):

1) Over-deliveries:
   a) The Over Delivery (OD) Index equals the lowest average published daily price at either Malin or Topock.

   b) The cashout price equals fifty (50) percent of the OD Index.

2) Under-deliveries:
   a) The Under Delivery (UD) Index is defined as the highest average published daily price at either Malin or Topock.

   b) The cashout price equals one hundred fifty (150) percent of the UD Index.

If no published daily price is reported on a given day, the prior published daily price from that index service will continue to apply for that day. If an index service is no longer available, PG&E reserves the right to choose another nationally recognized index to replace it.

PAYMENTS
The AA shall pay PG&E for all charges associated with balancing service on behalf of the Producer(s) supplying gas to any Receipt Point. Details for payment are provided in PG&E's tariffs. All payments shall be made by wire transfer or check to the address for "Payments" set forth in Attachment 3.

DISPUTED CASHOUT STATEMENTS
In the event of a dispute as to the amount of a cashout, OFO or EFO Noncompliance Charge under this CPBA, payment shall nonetheless be made in a timely manner as specified in PG&E's tariffs. Such payment shall not be deemed to be a waiver of any rights to recoup any amounts in dispute, if a written statement setting forth the nature of the dispute is sent along with payment to the PG&E Statements address in Attachment 3. Any rights to recoup such amounts may be treated as waived if said written statement is not sent within 6 months of the

date of the cashout, OFO or EFO Noncompliance Charge statement. If the cashout statement is determined to be incorrect after PG&E is notified hereunder, PG&E will issue a corrected statement. Neither PG&E nor the AA shall be obligated to pay interest on a corrected cashout statement.

ADJUSTMENTS

If an error is discovered in a Cumulative Imbalance Statement, cashout statement, or OFO or EFO Noncompliance Charge statement, then an appropriate correction shall be made by PG&E. Claims for errors by either Party shall be made promptly to the other Party, but in no event more than 6 months after the month in which the statement was issued. Notwithstanding the provisions of this paragraph, any adjustment resulting from the orders, rules, or regulations issued by any governmental agency having jurisdiction shall be made promptly by the appropriate Party, regardless of the 6-month time limitation stated in this paragraph.

Each Party shall have the right, during normal business hours, to receive copies of the records of the other Party, to the extent necessary to verify the accuracy of any statement, charge, computation, payment, refund, or demand, made under this CPBA.

CREDITWORTHINESS

If the AA fails to pay two (2) cashout amounts by the due date for payment within a twelve (12) month period, PG&E shall have the right to require the AA to establish creditworthiness pursuant to PG&E's tariff.

SUCCESSION

The AA acknowledges and agrees that the Producer(s) may appoint a successor AA from time to time, by mailing to PG&E an "Appointment of Authorized Agent" executed by the majority of Producer(s) pursuant to Attachment 1 to this CPBA. The effective date of such a succession of an AA shall be the first day of the month following the date on which PG&E confirms in writing its receipt of the new Appointment of Authorized Agent (Attachment 1). A succession of the AA, or an assignment or termination of this CPBA by either Party, shall not release the AA from any of its obligations or liabilities for costs, payments, and damages, due or incurred prior to the effective date of the succession, assignment or termination, or resulting from acts or omissions of the AA which occurred prior to that date. Payment of amounts that the previous AA owes PG&E as of such effective date shall be made no later than fifteen (15) days thereafter.

ASSIGNMENT

The respective rights or obligations under this CPBA shall not be assigned or delegated by either Party without the written consent of the other Party; provided, however, that only a notice is required if an assignment of PG&E's rights is made concurrently with a delegation of PG&E's obligations hereunder to a parent or affiliate of PG&E, or to an entity acquiring the business properties or the portion of PG&E's gathering system where the Receipt Point(s) specified in Attachment 2 is/are located. Any successor to or assignee of the rights of a Party, whether by voluntary transfer, judicial sale, foreclosure sale, or otherwise, shall be subject to and bound by all terms and conditions of this CPBA to the same extent as though such successor or assignee were an original Party. An assignment or delegation of rights or obligations under this CPBA which is not in conformance with the provisions of this paragraph shall be null and void.

TERMINATION

Either Party may terminate this CPBA upon thirty (30) days written notice, or immediately upon notice if: (1) the other Party is in breach of this CPBA; or (2) the CPUC or the FERC at any time asserts regulation that may prevent PG&E from complying with this CPBA. Upon termination of this CPBA, PG&E shall have the right to refuse nominations for deliveries of gas into the PG&E System.

INDEMNIFICATION

The AA shall indemnify and hold PG&E harmless from and against all losses, costs, damages, claims and liabilities, resulting from a breach of any of the representations or warranties set forth in this CPBA, and from and against any payments received from or owed to PG&E by the AA with respect to any gas nominated or delivered by the AA at the Receipt Point(s). The provisions of this paragraph shall survive the termination of this CPBA by either Party or the appointment of a successor AA, notwithstanding any other provision of this CPBA.

MISCELLANEOUS

With the exception of Commission-approved tariff and rule changes, no subsequent waiver, modification or amendment of this CPBA or of any of its provisions shall be of any effect unless in writing and signed by a duly authorized representative of each Party.

This CPBA does not change the obligations, restrictions or rights contained in other agreements between the Parties unless expressly indicated in this CPBA.

The waiver by either Party of any breach of any term, covenant or condition contained in this CPBA, or any default in the performance of any obligations under this CPBA, shall not be deemed to be a waiver of any other breach or default of the same or any other term, covenant, condition or obligation. Nor shall any waiver of any incident of breach or default constitute a continuing waiver of the same.

Neither Party shall be liable for any special, punitive, consequential, incidental, or indirect damages, whether arising in contract, tort, including negligence or otherwise, related to this CPBA.

This CPBA shall be interpreted under the laws of the State of California.

This CPBA and the obligations of the Parties are subject to all valid laws, orders, rules, and regulations of the authorities having jurisdiction over this CPBA (or the successors of those authorities).

PG&E shall have the right to terminate this CPBA immediately if the continued performance of this CPBA or of related services could reasonably be determined to jeopardize continuance of PG&E's Hinshaw Exemptions pursuant to Section 1 (c) of the Natural Gas Act.

Pacific Gas & Electric Company	**Authorized Agent**
	Company
Signature	Signature
Print Name	Print Name
Title	Title
Date	Date

Attachments:

Attachment 1: "Appointment of Authorized Agent"
Attachment 2: "Receipt Points"
Attachment 3: "Communications and Operations Contact"
Gas Rule 14

Contract No.____________________
Date ________________________

ATTACHMENT 1
CALIFORNIA PRODUCTION BALANCING AGREEMENT

APPOINTMENT OF AUTHORIZED AGENT

PURPOSE OF THIS DOCUMENT

The parties (party) who own(s) or control(s) gas produced from certain California production wells (Producer(s)) and who delivers that gas into the PG&E system (the PG&E System) for transport by PG&E, at the point(s) of interconnection where gas is measured before delivery into the PG&E System (Receipt Point(s),wishes/wish to appoint an Authorized Agent (AA), of the Producer(s), to enter into a California Production Balancing Agreement (CPBA) with PG&E, and to act for and on behalf of the Producer(s) as its/their managing agent in matters relating to the delivery of gas into the PG&E System at certain Receipt Point(s).

AGENCY AUTHORIZATION

Each Producer who executes this document on behalf of itself and of its successors and assignees hereby appoint(s) and authorize(s) ____________________________ to act as its exclusive agent, for all purposes stated in the CPBA with respect to the gas to be delivered at the Receipt Point(s) specified in Attachment 2 of the CPBA. The powers and authority to act for the Producer delegated to the AA hereunder shall include without limitation:

(a) execution and performance of the CPBA and all other agreements and documents as may be necessary or desirable for purposes of or in connection with gas deliveries to the PG&E System for transportation and the administration thereof, including nominating volumes of gas under PG&E's standard nomination procedures; and
(b) balancing, allocating and prorating the Producer's share of gas; and
(c) any other act or function required to perform the obligations of the AA or the Producer set forth in the CPBA.

The aforestated appointment and delegation of authority shall be irrevocable except as stated in the paragraph "APPOINTMENT OF SUCCESSOR AA" below.

REPRESENTATIONS AND OBLIGATIONS OF PRODUCER(S) TO PG&E

To the extent that obligations assumed by the AA pursuant to this document or the CPBA, or any other agreements of or executed by the AA in connection with the CPBA, are part of an existing contract between the Producer(s) and PG&E, the Producer(s) shall continue to be liable to PG&E for the performance of such obligations, and nothing contained in this document or the CPBA shall release the Producer(s) from its/their obligations under any contracts with PG&E.

Notwithstanding any other provision contained in this document, the Producer(s) agrees/agree that where an obligation, promise, responsibility, commitment, risk, liability, warranty, or representation of the AA is stated in the CPBA, the term "AA" shall mean the AA and the Producer(s) jointly.

Each of the undersigned Producers represents to PG&E that it has read and understood all of the provisions contained in the CPBA which is incorporated herein by this reference and agrees to be bound thereby.

The Producer(s) specifically authorizes PG&E to rely on the AA for nominations and allocations related to transport of gas by PG&E, and for all other purposes in connection with the CPBA, and to conclusively rely upon any and all information provided by the AA under the CPBA as correct. The Producer(s) will indemnify PG&E and hold it harmless, against all claims, suits, actions, liabilities, debts, accounts, damages, costs, losses and expenses, including attorney's fees, arising from or out of: PG&E's reliance upon or use of nominations or other information provided by the AA; any acts, omissions, performance or failure to perform of the AA under the CPBA or other agreements; any failure to comply with any federal, state or local reporting requirement or other laws or regulations; or the breach of any warranty or representation stated in the CPBA or herein.

PG&E'S RIGHT TO REFUSE ACCEPTANCE OF GAS

The Producer(s) agree(s) that PG&E, in its sole judgment, shall have the right, without incurring any liability to the Producer(s) to refuse acceptance of gas for transportation at the Receipt Point(s) when:

(a) the AA fails to comply with a provision of the CPBA, becomes insolvent or subject to a bankruptcy proceeding, or fails to establish creditworthiness if requested by PG&E; or
(b) any agreement required by PG&E in connection with the transportation of gas on PG&E's gas system has not been executed, has been terminated, or has expired; or
(c) PG&E deems it necessary or desirable to curtail acceptance of the gas in order to operate, preserve, or protect the integrity and safety of PG&E's gas system including but not limited to, gas quality, gas supply, and /or gas system facilities. PG&E shall use reasonable efforts to give the AA advance notice of any curtailment.

In the event of any of the occurrences enumerated in items (a) through (c) above or in the event that at any given time there is no AA appointed and accepted pursuant to the conditions hereof, the Producer(s) shall, upon five (5) days' notice by PG&E, disconnect the flow into PG&E's gas system of all gas intended for transportation. In the event of such a notice, all gas flow into PG&E's gas system (through the Receipt Point(s) following the five (5) day period shall be deemed to be delivered to PG&E at the applicable Cash-Out price.

DAMAGES

The Producer who executes this document agrees on behalf of itself and of its successors and assignees that PG&E shall not be liable to the Producer or to its successors or assignees for any special, indirect, incidental or consequential damages arising out of or in connection with the CPBA or this Appointment of Authorized Agent, whether based in contract, tort (including negligence) or otherwise.

SUPERSEDING DOCUMENT

This document supersedes any previous appointment by the Producer(s) of an agent, for the purposes set forth herein or in the CPBA, and shall not be modified except by a written notice to PG&E, as described in the paragraph "APPOINTMENT OF SUCCESSOR AUTHORIZED AGENT" below, executed by the majority of the Producer(s) signatories to this Agreement. This document shall be binding on all successors and assigns of the interest(s) of the

Producer(s) in the gas wells(s) associated with the Receipt Point(s) listed in Attachment 2 of the CPBA.

APPOINTMENT OF SUCCESSOR AUTHORIZED AGENT

The Producer(s) may appoint a successor AA from time to time, by mailing to PG&E an Appointment of Authorized Agent (in the form of this document) executed by the majority of the Producers which are signatories to this document. The Producer(s) agree to be bound by any such majority appointment of a successor AA, regardless of whether each Producer supports the change of AA. Each Producer signatory to this Agreement hereby appoints the other Producer signatories to this Agreement as the Producer's agent with authority to appoint a successor AA by majority vote to act on behalf of the Producers as set forth in this document and in the CPBA. Each Producer agrees to be bound by such an appointment, if the majority of the other Producer signatories to this Agreement appoint a successor AA pursuant to these provisions. Such change (succession) shall not be effective until the newly appointed AA: (1) signed the new Appointment of Authorized Agent, whereby the new AA assumes all of the obligations of the AA set forth therein; and (2) has been approved by PG&E, which approval shall not be unreasonably withheld. When all of the aforestated conditions have been met, the new (successor) AA shall succeed to and become vested with all the rights and obligations of the retiring AA.

ASSIGNMENT

The rights and obligations of a Producer under this Appointment of Authorized Agent may be assigned and delegated concurrently to a successor to the rights of the Producer in the gas delivered at the Receipt Point(s) set forth in Attachment 2 of the CPBA, provided that the assignment and delegation shall not become effective until PG&E has received from the Producer's successor a written acceptance of all of the obligations of the assignor Producer; and provided further that such an assignment and delegation shall not release the assignor Producer from its obligations under this Appointment of Authorized Agent, the CPBA, or any other agreements to which the assignor Producer and PG&E are parties, to the extent that the assignee Producer fails to perform such obligations. PG&E may assign its rights under this document to a parent or affiliate of PG&E or an entity acquiring the portion of PG&E's gathering system where the Receipt Point(s) specified in Attachment 2 are located.

THIRD PARTY BENEFICIARY

PG&E shall be a third party beneficiary of this Appointment of Authorized Agent.

AA'S AGREEMENT

By signing this document in the space titled "Acceptance by Authorized Agent," the AA accepts the terms and conditions hereof and agrees to act as the Producer(s) agent as set forth herein.

EFFECTIVE DATE

This Appointment of Authorized Agent shall become effective following execution by the Producer(s) and by the AA, and shall continue in effect for the term of the CPBA; provided that PG&E has accepted the AA by executing a CPBA with the AA and accepting the Appointment of Authorized Agent concurrently therewith.

COUNTERPARTS

This document may be executed in counterparts, and if executed in that manner shall have the same effect as if the Producer(s) and the AA had executed the same document. The AA and each other party executing a counterpart to this document shall deliver an executed copy of that counterpart to PG&E.

In Witness Whereof, The Producer(s) and the AA have executed this Appointment of Authorized Agent, and each signatory to this document represents that the person executing it is duly authorized to do so.

Producer:____________________

By: ____________________
Signature

____
Full Name

____
Title

____
Date

____

Producer:____________________

By:____________________
Signature

____
Full Name

____
Title

____
Date

____

Producer:____________________

By: ____________________
Signature

____
Full Name

____
Title

____
Date

____

Producer:____________________

By:____________________
Signature

____
Full Name

____
Title

____
Date

____

Accepted by Authorized Agent:
Company Name:

By:____________________
Signature

____
Full Name

____
Title

____
Date

____

Accepted by PG&E:

By:____________________
Signature

____
Full Name

____
Title

____
Date

____

Contract No.____________________
Date________________________

ATTACHMENT 2
CALIFORNIA PRODUCTION BALANCING AGREEMENT

RECEIPT POINTS

Receipt Point Meter No.	Maximum Daily Production Cap

Contract No____________________________
Date____________________________

ATTACHMENT 3
CALIFORNIA PRODUCTION BALANCING AGREEMENT
COMMUNICATIONS AND OPERATIONS CONTACT

Attachment 3 designates the formal contact names, mailing addresses, telephone and telecopier numbers for the Parties. Either Party may from time to time change or designate any other name or address for such purposes by providing the other Party with a revised Attachment 3. The revised Attachment 3 shall be effective upon receipt by the other Party. Any notice, request, demand, cashout, OFO or EFO Noncompliance Charge statement shall be in writing and shall be deemed to have been given when deposited in the United States, mail, postage prepaid, or transmitted and confirmed via telecopier. Routine operations may be exclusively communicated by facsimile or other electronic means.

	To PG&E	**To AA**
Gas Nominations		
Business Name:	Pacific Gas & Electric Company	________________________
Mailing Address:	P. O. Box 770000, Mail Code B16A	________________________
	San Francisco, CA 94177	________________________
Attention:	Gas Scheduling	________________________
Telephone Number:	(415) 973-2424	(____)__________________
Telecopy Number:	(415) 973-0649	(____)__________________
Notifications and Trades		
Business Name:	Pacific Gas & Electric Company	________________________
Mailing Address:	P. O. Box 770000, Mail Code B16A	________________________
	San Francisco, CA 94177	________________________
Attention:	Balancing Coordinator	________________________
Telephone Number:	(415) 972-5295	(____)__________________
Telecopy Number:	(415) 973-0750	(____)__________________
Payments By Wire		
Business Name:	Wells Fargo Bank, N.A.	
Address:	San Francisco, CA 93177	
ABA Routing Number	121000248	
Account Name	Pacific Gas & Electric Co.	
Account Number:		
Payments By Check		
Business Name:	Pacific Gas & Electric Company	
Mailing Address:	P. O. Box 770000, Mail Code B5A	
	San Francisco, CA 94177	
Attention:	Customer Billing Department	

For maximum protection of PG&E's system in case of operational conditions and emergencies, the AA shall notify PG&E's Gas System Operations in writing of its Physical Operator's name, telephone and facsimile numbers. Notification of physical operation of the Receipt Point by a Physical Operator shall not constitute a delegation of the AA's obligations and shall not in any way limit, diminish, or otherwise affect the AA's obligations under this Agreement, which the AA shall fully perform.

	Physical Operator
Business Name:	________________________
Mailing Address:	________________________
	________________________
Attention:	________________________
Telephone Number:	(____)__________________
Telecopy Number;	(____)__________________

TABLE OF CONTENT
(Continued)

SAMPLE FORMS (Cont'd.)

TABLE OF CONTENTS
(Continued)

RULES

(Continued)

TABLE OF CONTENTS
(Continued)

PRELIMINARY STATEMENTS

(Continued)

TABLE OF CONTENTS
(Continued)

NONRESIDENTIAL (Cont'd.)

OTHER

EXPERIMENTAL

(Continued)

TABLE OF CONTENTS

RATE SCHEDULES

RESIDENTIAL

NONRESIDENTIAL

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ATTACHMENT II: TABLE 1
ILLUSTRATIVE GAS RATES
CLASS AVERAGE RATES ($/th)

Line No.	Customer Class	Present Rates August-03 (A)	Effective Rates January-04 (B)	% Change (c) (C)
	BUNDLED - Retail Core (a)			
1	Residential Non-CARE	$.918	$.922	.4%
2	Residential CARE	$.722	$.724	.3%
3	Small Commercial	$.857	$.862	.6%
4	Large Commercial	$.732	$.741	1.3%
	TRANSPORT ONLY - Retail Core (b)			
5	Residential Non-CARE (G-CT)	$.318	$.315	-1.0%
6	Residential CARE (G-CT)	$.122	$.119	-2.2%
7	Small Commercial (G-CT)	$.315	$.313	-0.8%
8	Large Commercial (G-CT)	$.207	$.210	1.1%
	TRANSPORT ONLY - Retail Noncore(b)			
9	Industrial Distribution (G-NT)	$.121	$.118	-2.6%
10	Industrial Transmission (G-NT)	$.045	$.054	22.2%
11	Cogeneration (G-COG)	$.025	$.026	7.5%
12	Electric Generation (G-EG)	$.025	$.026	7.5%
	TRANSPORT ONLY - Wholesale Core and Noncore (b)			
13	Alpine Natural Gas	$.027	$.036	34.8%
14	Coalinga	$.027	$.036	33.4%
15	Island Energy	$.051	$.098	91.1%
16	Palo Alto	$.024	$.028	17.3%
17	West Coast Gas - Castle	$.030	$.043	45.7%
18	West Coast Gas - Mather	$.030	$.043	45.4%

(a) Bundled retail core rates include interstate and intrastate transmission, storage, and an illustrative annual average WACOG of $.463 per therm.
(b) Transport-only rates exclude intrastate backbone transmission and storage charges.
(c) Rates are rounded to 3 decimals for viewing ease. Percentage rate changes are calculated on a 5-digit basis.

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ATTACHMENT II: TABLE 2
SUMMARY OF RATES BY MAJOR COMPONENT
($/dth; Illustrative)

		Core Retail			Noncore Retail				Wholesale					
		Non-CARE Residential	Sml Com.	Lg. Comm.	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Coalinga	Palo Alto	WC Gas Mather	Island Energy	Alpine	WC Gas Castle
	TRANSPORTATION CHARGE COMPONENTS													
1	Local Transmission (1)	$.3674	$.3674	$.3674	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574
2	Customer Class Charge (2)	$.1440	$.1457	$.1495	$.0576	$.0899	$.0840	$.0840	$.0838	$.0838	$.0838	$.0839	$.0838	$.0838
3	Public Purpose Program Charges	$.3018	$.2664	$.6690	$.1920	$.1796								
4	CPUC Fee (3)	$.0077	$.0077	$.0077	$.0077	$.0077	$.0073	$.0073						
3	Customer Access Charge (Volumetric CAC only) (4)						$.0111	$.0111						
4	Distribution - Annual Average (5)	$2.8581	$1.9865	$.8397	$.4789	$.0310	$.0046	$.0046						
5	**VOLUMETRIC RATE - Average Annual**	$3.6790	$2.7736	$2.0334	$.8935	$.4657	$.2644	$.2644	$.2412	$.2412	$.2412	$.2413	$.2412	$.2412
6	**CUSTOMER ACCESS CHARGE - Class Average**		$.3580	$.0699	$.2892	$.0792			$.1145	$.0347	$.1892	$.7368	$.1222	$.1912
7	**CLASS AVERAGE TRANSPORTATION RATE**	$3.6790	$3.1316	$2.1033	$1.1827	$.5449	$.2644	$.2644	$.3557	$.2759	$.4305	$.9781	$.3634	$.4324
	INTRASTATE BACKBONE TRANSMISSION													
8	AFT BAJA INTRASTATE @ 100% Load Factor (6)				$.1917	$.1917	$.1917	$.1917	$.1917	$.1917	$.1917	$.1917	$.1917	$.1917
9	AFT REDWOOD INTRASTATE @ 100% Load Factor (6)				$.2998	$.2998	$.2998	$.2998	$.1287	$.1287	$.1287	$.1287	$.1287	$.1287
	PROCUREMENT (Illustrative) - Bundled Retail Core Service Only (7)													
10	Core Intrastate Backbone Transmission (8)	$.1332	$.1284	$.0855										
11	Interstate Pipeline Demand Charge	$.1900	$.1831	$.1219										
12	Procurement-Other (Incl. Illust. Avg. WACOG)	$5.0394	$5.0350	$4.9961										
13	Storage (9)	$.1444	$.1372	$.1000										
14	PROCUREMENT CHARGE	$5.5070	$5.4837	$5.3035										
15	**TOTAL TRANSPORT RATE W/ AFT BAJA**				$1.3744	$.7366	$.4561	$.4561	$.5474	$.4676	$.6222	$1.1698	$.5551	$.6241
16	**TOTAL TRANSPORT RATE W/ AFT REDWOOD**				$1.4825	$.8447	$.5642	$.5642	$.4844	$.4046	$.5592	$1.1068	$.4921	$.5611

LINE NOTES
1. Decision 03-12-061, Table 11
2. Based on recorded 9/30/03 balancing accounts and forecasted to 12/31/03.
3. Resolution M-4810, effective January 1, 2004.
4. Decision 03-12-061, Table 14, adopted an interim volumetric CAC charge, effective January 1, 2004 - March 31, 2004.
5. Decision 03-12-061. EG and Cogeneration rates are based on Table 14 distribution rate of $0.0043/dth, net of closing balance in cogen distribution shortfall account
6. Decision 03-12-061, Tables 3 & 4
7. From Table 15, Procurement Rates.
8. Decision 03-12-061. Rates are based on a forecast of total backbone reservation costs for all transmission paths, allocated to customer classes based on average year January throughput (D. 01-11-001). See Table 15, Procurement R
9. Core Storage costs adopted in Decision 03-12-061 are allocated to customer classes based on average year January throughput (D. 01-11-001). See Table 15, Procurement rates

Table 3
Adopted 2004
Firm Backbone Transportation
Annual Rates (AFT) -- SFV Rate Design
On-System Transportation Service

		GA II 2003	Adopted 2004	$ Change
Redwood - Core				
Reservation Charge	($/dth/mo)	3.517	3.846	0.330
Usage Charge	($/dth)	0.009	0.002	(0.007)
Total	($/dth @ Full Contract)	0.125	0.129	0.004
Redwood Path				
Reservation Charge	($/dth/mo)	7.961	9.060	1.099
Usage Charge	($/dth)	0.007	0.002	(0.006)
Total	($/dth @ Full Contract)	0.269	0.300	0.031
Baja Path				
Reservation Charge	($/dth/mo)	5.192	5.722	0.530
Usage Charge	($/dth)	0.004	0.004	(0.000)
Total	($/dth @ Full Contract)	0.175	0.192	0.017
Silverado and Mission Paths				
Reservation Charge	($/dth/mo)	3.426	3.452	0.026
Usage Charge	($/dth)	0.003	0.001	(0.002)
Total	($/dth @ Full Contract)	0.116	0.115	(0.001)

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 77.02 percent load factor.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Rates are subject to change pursuant to D.03-12-061

Table 4
Adopted 2004
Firm Backbone Transportation
Annual Rates (AFT) -- MFV Rate Design
On-System Transportation Service

		GA II 2003	Adopted 2004	$ Change
Redwood - Core				
Reservation Charge	($/dth/mo)	2.414	2.962	0.548
Usage Charge	($/dth)	0.045	0.031	(0.014)
Total	($/dth @ Full Contract)	0.125	0.129	0.004
Redwood Path				
Reservation Charge	($/dth/mo)	4.687	5.357	0.670
Usage Charge	($/dth)	0.115	0.124	0.009
Total	($/dth @ Full Contract)	0.269	0.300	0.031
Baja Path				
Reservation Charge	($/dth/mo)	3.910	4.468	0.558
Usage Charge	($/dth)	0.046	0.045	(0.001)
Total	($/dth @ Full Contract)	0.175	0.192	0.017
Silverado and Mission Paths				
Reservation Charge	($/dth/mo)	2.328	2.498	0.170
Usage Charge	($/dth)	0.039	0.033	(0.007)
Total	($/dth @ Full Contract)	0.116	0.115	(0.001)

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 77.02 percent load factor.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Rates are subject to change pursuant to D.03-12-061

Table 5
Adopted 2004
Firm Backbone Transportation
Seasonal Rates (SFT) -- SFV Rate Design
On-System Transportation Service

		GA II 2003	Adopted 2004	$ Change
Redwood Path				
Reservation Charge	($/dth/mo)	9.553	10.871	1.318
Usage Charge	($/dth)	0.009	0.002	(0.007)
Total	($/dth @ Full Contract)	0.323	0.360	0.037
Baja Path				
Reservation Charge	($/dth/mo)	6.231	6.866	0.635
Usage Charge	($/dth)	0.005	0.004	(0.000)
Total	($/dth @ Full Contract)	0.210	0.230	0.021
Silverado Path				
Reservation Charge	($/dth/mo)	4.111	4.142	0.031
Usage Charge	($/dth)	0.004	0.002	(0.002)
Total	($/dth @ Full Contract)	0.139	0.138	(0.001)

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Rates are subject to change pursuant to D.03-12-061

Table 6
Adopted 2004
Firm Backbone Transportation
Seasonal Rates (SFT) -- MFV Rate Design
On-System Transportation Service

		GA II 2003	Adopted 2004	$ Change
Redwood Path				
Reservation Charge	($/dth/mo)	5.625	6.428	0.803
Usage Charge	($/dth)	0.138	0.148	0.010
Total	($/dth @ Full Contract)	0.323	0.360	0.037
Baja Path				
Reservation Charge	($/dth/mo)	4.692	5.361	0.669
Usage Charge	($/dth)	0.055	0.054	(0.001)
Total	($/dth @ Full Contract)	0.210	0.230	0.021
Silverado Path				
Reservation Charge	($/dth/mo)	2.793	2.997	0.204
Usage Charge	($/dth)	0.047	0.039	(0.008)
Total	($/dth @ Full Contract)	0.139	0.138	(0.001)

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Rates are subject to change pursuant to D.03-12-061

Table 7
Adopted 2004
As-Available Backbone Transportation
On-System Transportation Service

		GA II 2003	Adopted 2004	$ Change
Redwood Path				
Usage Charge	($/dth)	0.323	0.360	0.037
Baja Path				
Usage Charge	($/dth)	0.210	0.230	0.021
Silverado Path				
Usage Charge	($/dth)	0.139	0.138	(0.001)
Mission Path				
Usage Charge	($/dth)	0.000	0.000	0.000

Notes:

a) As-Available rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.

d) Rates are subject to change pursuant to D.03-12-061

Table 8
Adopted 2004
Firm Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries

		GA II 2003	Adopted 2004	$ Change
SFV Rate Design				
Redwood, Silverado and Mission Paths Off-System				
Reservation Charge	($/dth/mo)	9.825	9.060	(0.765)
Usage Charge	($/dth)	0.004	0.002	(0.002)
Total	($/dth @ Full Contract)	0.327	0.300	(0.027)
Baja Path Off-System				
Reservation Charge	($/dth/mo)	5.192	5.722	0.530
Usage Charge	($/dth)	0.004	0.004	(0.000)
Total	($/dth @ Full Contract)	0.175	0.192	0.017
MFV Rate Design				
Redwood, Silverado and Mission Paths Off-System				
Reservation Charge	($/dth/mo)	5.182	5.357	0.176
Usage Charge	($/dth)	0.165	0.124	(0.041)
Total	($/dth @ Full Contract)	0.335	0.300	(0.036)
Baja Path Off-System				
Reservation Charge	($/dth/mo)	3.910	4.468	0.558
Usage Charge	($/dth)	0.046	0.045	(0.001)
Total	($/dth @ Full Contract)	0.175	0.192	0.017
As-Available Service				
Redwood, Silverado and Mission Paths Off-System				
Usage Charge	($/dth)	0.403	0.360	(0.044)
Baja Path Off-System				
Usage Charge	($/dth)	0.210	0.230	0.021

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 77.02 percent load factor.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

e) Rates are subject to change pursuant to D.03-12-061

Table 9
Adopted 2004
Firm Transportation
Expansion Shippers -- Annual Rates (G-XF)
SFV Rate Design
Off-System Deliveries

		GA II 2003	Adopted 2004	$ Change
SFV Rate Design				
Reservation Charge	($/dth/mo)	9.825	7.900	(1.926)
Usage Charge	($/dth)	0.004	0.001	(0.003)
Total	($/dth @ Full Contract)	0.327	0.261	(0.066)

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.

d) Rates are subject to change pursuant to D.03-12-061

Table 10
Adopted 2004
Storage Services (Effective April 1, 2004)

		GA II 2003	Adopted April 1, 2004	$ Change
Core Firm Storage (G-CFS)				
Reservation Charge	($/dth/mo)	0.108	0.096	(0.012)
Standard Firm Storage (G-SFS)				
Reservation Charge	($/dth/mo)	n/a	0.118	
Capacity Charge		0.070	n/a	
Withdrawl Charge		0.910	n/a	
Negotiated Firm Storage (G-NFS)				
Injection	($/dth/d)	9.223	13.707	4.485
Inventory	($/dth/mo)	1.295	1.421	0.126
Withdrawal	($/dth/d)	5.572	10.334	4.763
Negotiated As-Available Storage (G-NAS) - Maximum Rate				
Injection	($/dth/d)	9.223	13.707	4.485
Withdrawal	($/dth/d)	5.572	10.334	4.763
Market Center Services (Parking and Lending Services)				
Usage Charge:				
Maximum Daily Charge ($/Dth/day)		1.004	0.820	(0.184)
Minimum Rate (per transaction)		$ 57.00	$ 57.00	0.000

Notes:

a) Rates for storage services are based on the costs of storage injection, inventory and withdrawal.

b) Core Firm Storage (G-CFS) and Standard Firm Storage (G-SFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.

c) Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.

d) Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.

e) Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g. inventory, injection, or withdrawal). The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.

f) Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.

g) The maximum charge for parking and lending is based on the annual cost of cycling one dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season.

h) Gas Storage shrinkage will be applied in-kind on storage injections.

i) Rates are subject to change pursuant to D.03-12-061

Table 11
Adopted 2004
Local Transmission Rates
($/dth)

Annual Usage (millions of Therms/year)	GA II 2003	Adopted 2004	$ Change
Core Retail	0.287	0.367	0.080
Noncore (including Wholesale)	0.149	0.157	0.009

Notes:
a) Rates are subject to change pursuant to D.03-12-061

Table 12
Adopted 2004
Customer Access Charges Using GA I Structure

		GA II 2003	Adopted 2004	$ Change
G-EG and G-COG ($/therm) (a)		$0.00080	$0.00111	$0.00031
G-NT ($/month)				
Transmission and Distribution	(Therms/Month)			
Tier 1	0 to 5,000	$11.87	$ 30.12	$18.25
Tier 2	5,001 to 10,000	$93.52	$ 237.27	$143.75
Tier 3	10,001 to 50,000	$354.79	$ 900.15	$545.36
Tier 4	50,001 to 200,000	$935.23	$ 2,372.80	$1,437.57
Tier 5	200,001 to 1,000,000	$1,339.02	$ 3,397.26	$2,058.24
Tier 6	1,000,001 and above	$3,892.38	$ 9,875.46	$5,983.08
Wholesale ($/month)				
Alpine		$206.71	$ 524.45	$317.74
Coalinga		$1,028.08	$ 2,608.37	$1,580.29
Island Energy		$560.47	$ 1,421.98	$861.51
Palo Alto		$4,392.60	$11,144.58	$6,751.98
West Coast Gas - Castle		$482.20	$ 1,223.40	$741.20
West Coast Gas - Mather		$746.87	$ 1,894.90	$1,148.03

Notes:

a) Gas Accord II - 2004 D. 03-12-061 adopts a single average volumetric customer access charge applicable to both G-COG and G-EG customers during the interim period, January 1, 2004 - March 31, 2004, and a 6 tier rate structure applicable to the single EG class (Schedule G-EG), beginning April 1, 2004.

b) Rates are subject to change pursuant to D.03-12-061

Table 13
Adopted 2004
Self Balancing Credit
$/dth

	GA II 2003	Adopted 2004	$ Change
Self Balancing Credit	0.005	0.010	0.005

Notes:

a) Storage balancing costs are bundled in backbone rates. Customers or Balancing Agents who elect self balancing on a daily basis can opt out of PG&E's monthly balancing program and receive a self-balancing credit.

b) Rates are subject to change pursuant to D.03-12-061

Table 14

EG and Cogeneration - 2004 Distribution Rates (Note 1) and Interim Period (1/1/04 - 3/31/04) Customer Access Charges

Interim Customer Access Charges, effective January 1, 2004 - March 31, 2004

EG-T Customer Access Charge Annual Revenue Requirement Calculation

	IND-T + EG-T 2004 Bills By Tier/Mo.	IND-T 2004 Bills By Tier/Mo.	EG-T 2005 Bills By Tier/Mo.	Adopted Monthly 2004 Charges	EG-T Annual CAC Revenue Req
Tier 1	19	14	5	$30.12	$1,709
Tier 2	16	10	6	$237.27	$16,027
Tier 3	105	72	33	$900.15	$359,097
Tier 4	109	99	10	$2,372.80	$280,342
Tier 5	99	78	21	$3,397.26	$866,899
Tier 6	37	24	13	$9,875.46	$1,494,845
Totals/Averages	385	297	87		**$3,018,918**

Interim Period Volumetric EG and Cogeneration Customer Access Charge Calculation

Adopted EG-T CAC Revenue Requirement (M$)	$3,018.918
Adopted EG/COG Volumes (Mdth) (D. 03-12-061)	272,101
Volumetric Customer Access Charge ($/dtherm)	**$ 0.0111**

2004 Distribution Rate Component Calculation (1)

Adjusted (Advice 2508-G) Annual Distribution-Level Costs Allocated to Distribution-level Cogen D.(	$1,747
EG/COG Volumes per D. 01-11-001 (Mdth)	276,320
Distribution Rate Component ($/dtherm)	**$ 0.0063**

(1) Decision 03-12-061 adopts a single average distribution rate component applicable to electric generators and cogenerators during the interim period, January 1, 2004 - March 31, 2004, and applicable to the single electric generation class beginning April 1, 2004. PG&E submits this Table 14, in compliance with OP 6.i, directing PG&E to file an advice letter within ten days of D. 03-12-061, that develops a rate table that reflects the CPUC's determination that rates for distribution-level electric generators are to remain as currently designed and calculated. The calculation above complies with this directive.

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ALLOCATION OF PROCUREMENT COSTS BY CLASS (Illustrative two year totals; $000)
ATTACHMENT II: TABLE 15

LINE No.		CORE Residential	CORE Sm Comrcl	CORE Lrg Comrcl	NGV*	TOTAL
1	SUMMER VOLUMES (mth)		553,945	25,020		
2	WINTER VOLUMES (mth)		713,111	21,907		
3	TOTAL VOLUMES (mth)	4,421,103	1,267,056	46,927	15,852	5,750,939
4	WACOG ($/therm) **	$.46202	$.46202	$.46202	$.46202	$.46202
5	WACOG REVENUE ($ 000)	$2,042,638	$585,405	$21,681	$7,324	$2,657,049
6	INTRASTATE BACKBONE CAPACITY	$58,889	$16,264	$401	$0	$75,554
7	REVENUES - BAJA PATH WINTER RESERVATION		$3,058	$75		
8	BACKBONE FORMERLY COLLECTED IN SUMMER		$13,206	$326		
9	INTERSTATE PIPELINE CAPACITY	$83,994	$23,198	$572	$0	$107,764
10	CANADIAN BALANCES	$0	$0	$0	$0	$0
11	ANG & NOVA Period Costs	$50,898	$14,057	$347	$0	$65,301
12	CANADIAN CHARGES INCL F&U	$50,898	$14,057	$347	$0	$65,301
13	BROKERAGE FEES INCL F&U	$10,611	$3,041	$113	$0	$13,764
14	SHRINKAGE REVENUE	$81,264	$23,290	$863	$291	$105,708
15	CARRYING CST CYCLED GAS IN STOR	$2,409	$690	$26	$9	$3,133
16	CORE STORAGE BASE REVENUE INCLUDING F&U (000's)	$57,323	$15,606	$421	$0	$73,350
17	CARRYING COST ON NONCYCLED GAS IN STORAGE (000'S	$6,504	$1,771	$48	$0	$8,323
18	FRANCHISE FEES AND UNCOLLECTIBLES EXPENSE	$40,170	$11,486	$417	$135	$52,208
19	TOTAL PROCUREMENT REVENUES	$2,434,700	$694,808	$24,888	$7,759	$3,162,155
20	F&U FACTOR	1.77140%	1.77140%	1.77140%	1.77140%	

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ILLUSTRATIVE PROCUREMENT RATES (first year rates; $/therm)
(residential/small commercial after being de-averaged by 30 %)

LINE No.		CORE Residential	CORE Sm Comrcl	CORE Lrg Comrcl	NGV	Avg. Rate
1	WACOG and Balances***	$.46202	$.46202	$.46202	$.46202	$.46202
2	INTRASTATE TRANSMISSION CHARGE	$.01332	$.01284	$.00855	$.00000	$.01314
3	Summer		$.01284	$.00855		
4	Winter		$.01284	$.00855		
5	INTERSTATE PLD COMPONENT	$.01900	$.01831	$.01219	$.00000	$.01874
6	CANADIAN CHARGES RATE	$.01151	$.01109	$.00739	$.00000	$.01135
7	BROKERAGE FEE RATE	$.00240	$.00240	$.00240	$.00000	$.00239
8	SHRINKAGE RATE	$.01838	$.01838	$.01838	$.01838	$.01838
9	CARRYING COST OF GAS COMPONENT	$.00054	$.00054	$.00054	$.00054	$.00054
10	CORE STORAGE BASE REVENUE INCLUDING F&U (000's)	$.01297	$.01232	$.00898	$.00000	$.01275
11	CARRYING COST ON NONCYCLED GAS IN STORAGE (000'S	$.00147	$.00140	$.00102	$.00000	$.00145
12	CS PHASEOUT SURCHARGE RATE					
13	FRANCHISE FEES AND UNCOLLECTIBLES EXPENSE	$.00909	$.00907	$.00888	$.00852	$.00908
14	PROCUREMENT RATE	$.55070	$.54837	$.53035	$.48946	$.53564
15	Summer		$.54837	$.53035		
16	Winter		$.54837	$.53035		

* NGV rates shown above are for revenue accounting purposes only; a separate run is necessary to calculate NGV procurement rates as th
and not allocated fixed costs.
** Procurement rates include an illustrative WACOG of $.46 per therm.

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
CORE RATES AND REVENUES (Illustrative)
ATTACHMENT II: TABLE 16

		PRESENT RATES AND REVENUES August 1, 2003 (Uncoll. Factor Change)			PROPOSED RATES & REVENUES January 1, 2004			PROPOSED CHANGE IN RATES	
	RATE CLASS	ADJ. BILLING DETERMINANT	RATE OR CHARGE	TEST PERIOD REVENUE	ADJ. BILLING DETERMINANT	RATE OR CHARGE	TEST PERIOD REVENUE		
Line		Mth or # of Customers	$/therm or $/cust. mo.	($ 000)	Mth or # of Customers	$/therm or $/cust. mo.	($ 000)	$/therm or $/cust. mo.	%
No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	ILLUSTRATIVE AVERAGES FOR BUNDLED CUSTOMERS								
	NON-CARE RESIDENTIAL	3,123,289			3,123,289				
1	Tier I (Baseline)	2,672,526	$.85374	2,281,642	2,672,526	$.85822	2,293,625	$.00448	.53%
2	Tier II	1,128,478	$1.07124	1,208,871	1,128,478	$1.07349	1,211,411	$.00225	.21%
3	Non-CARE Subtotal	3,801,005	$.91831	3,490,514	3,801,005	$.92213	3,505,036	$.00382	.42%
	CARE RESIDENTIAL	504,653			504,653				
4	Tier I (Baseline)	404,290	$.66473	268,743	404,290	$.66969	270,747	$.00496	.75%
5	Tier II	209,866	$.83337	174,896	209,866	$.83007	174,204	($.00330)	-.40%
6	CARE Subtotal	614,156	$.72236	443,640	614,156	$.72449	444,951	$.00214	.30%
7	Pre-GS/GT Discount Residential Subtotal	4,415,161	$.89106	3,934,153	4,415,161	$.89464	3,949,987	$.00359	.40%
8	GS and GT Discount			-11,643			-11,649		
9	TOTAL BUNDLED RESIDENTIAL	4,415,161	$.88842	3,922,510	4,415,161	$.89200	3,938,338	$.00358	.40%
	SMALL COMMERCIAL (G-NR1)								
10	Customer Charge (Average)	164,113	$11.52	45,355	164,113	$11.52	45,355	$0.00	.00%
11	Smr Volumetric Tier A (0-4000 th/mo.)	473,585	$.80219	379,907	473,585	$.80754	382,440	$.00535	.67%
12	Smr Volumetric Tier B (4001+ th/mo.)	80,360	$.71049	57,095	80,360	$.72131	57,964	$.01082	1.52%
13	Wtr Volumetric Tier A (0-4000 th/mo.)	589,315	$.86521	509,878	589,315	$.86834	511,726	$.00313	.36%
14	Wtr Volumetric Tier B (4001+ th/mo.)	123,796	$.75140	93,020	123,796	$.76188	94,318	$.01048	1.39%
15	BUNDLED SML. COMM. TOT.	1,267,056	$.85652	1,085,256	1,267,056	$.86168	1,091,803	$.00517	.60%
	LARGE COMMERCIAL (G-NR2)								
16	Customer Charge	91	$150.72	328	91	$150.72	328	$0.00	.00%
17	Smr Volumetric Tier A (0-4000 th/mo.)	3,095	$.78487	2,429	3,095	$.78952	2,444	$.00465	.59%
18	Smr Volumetric Tier B (4001+ th/mo.)	21,925	$.69317	15,198	21,925	$.70329	15,420	$.01012	1.46%
19	Wtr Volumetric Tier A (0-4000 th/mo.)	2,607	$.84789	2,210	2,607	$.85032	2,217	$.00243	.29%
20	Wtr Volumetric Tier B (4001+ th/mo.)	19,300	$.73408	14,168	19,300	$.74386	14,356	$.00978	1.33%
21	BUNDLED LRG. COMM. TOT.	46,927	$.73163	34,333	46,927	$.74082	34,765	$.00919	1.26%
22	TOTAL BUNDLED COMMERCIAL	1,313,983	$.85206	1,119,589	1,313,983	$.85737	1,126,567	$.00531	.62%
23	TOTAL BUNDLED CORE	5,729,144	$.88008	5,042,100	5,729,144	$.88406	5,064,905	$.00398	.45%
	ILLUSTRATIVE AVERAGES FOR TRANSPORT-ONLY CUSTOMERS								
	NON-CARE RESIDENTIAL	49,792			49,792				
24	Tier I (Baseline)	58,614	$.31073	18,213	58,614	$.30752	18,025	($.00321)	-1.03%
25	Tier II	1,982	$.52823	1,047	1,982	$.52279	1,036	($.00544)	-1.03%
26	Non-CARE Subtotal	60,596	$.31784	19,260	60,596	$.31456	19,061	($.00328)	-1.03%
	CARE RESIDENTIAL	863			863				
27	Tier I (Baseline)	1,050	$.12172	128	1,050	$.11899	125	($.00273)	-2.25%
28	Tier II	1	$.29036	0	1	$.27937	0	($.01099)	-3.78%
29	CARE Subtotal	1,051	$.12185	128	1,051	$.11911	125	($.00274)	-2.25%
30	Pre-GS/GT Discount Residential Subtotal	61,647	$.31450	19,388	61,647	$.31123	19,187	($.00327)	-1.04%
31	GS and GT Discount			-163			-163		
32	TOTAL TRANSPORT-ONLY RES.	61,647	$.31187	19,226	61,647	$.30859	19,024	($.00327)	-1.05%
	SMALL COMMERCIAL (G-NR1)								
33	Customer Charge (Average)	40,728	$11.52	11,256	40,728	$11.52	11,256	$0.00	.00%
34	Smr Volumetric Tier A (0-4000 th/mo.)	121,375	$.26144	31,733	121,375	$.25917	31,457	($.00227)	-.87%
35	Smr Volumetric Tier B (4001+ th/mo.)	20,595	$.16974	3,496	20,595	$.17294	3,562	$.00320	1.88%
36	Wtr Volumetric Tier A (0-4000 th/mo.)	142,532	$.32446	46,245	142,532	$.31997	45,606	($.00449)	-1.38%
37	Wtr Volumetric Tier B (4001+ th/mo.)	29,941	$.21065	6,307	29,941	$.21351	6,393	$.00286	1.36%
38	TRANSPORT-ONLY SML. COMM.	314,443	$.31496	99,037	314,443	$.31253	98,273	($.00243)	-.77%
	LARGE COMMERCIAL (G-NR2)								
39	Customer Charge	21	$150.72	77	21	$150.72	77	$0.00	.00%
40	Smr Volumetric Tier A (0-4000 th/mo.)	750	$.26144	196	750	$.25917	194	($.00227)	-.87%
41	Smr Volumetric Tier B (4001+ th/mo.)	5,310	$.16974	901	5,310	$.17294	918	$.00320	1.88%
42	Wtr Volumetric Tier A (0-4000 th/mo.)	588	$.32446	191	588	$.31997	188	($.00449)	-1.38%
43	Wtr Volumetric Tier B (4001+ th/mo.)	4,353	$.21065	917	4,353	$.21351	929	$.00286	1.36%
44	TRANSPORT-ONLY LRG. COMM.	11,000	$.20744	2,282	11,000	$.20972	2,307	$.00228	1.10%
45	TOT. TRANSPORT-ONLY COMM.	325,443	$.31132	101,318	325,443	$.30906	100,580	($.00227)	-.73%
46	TOT. TRANSPORT-ONLY CORE	387,090	$.31141	120,544	387,090	$.30898	119,604	($.00243)	-.78%
47	TOTAL RESIDENTIAL VOL. and REV.	4,476,808		3,941,736	4,476,808		3,957,362	15,626	.40%
48	TOTAL COMMERCIAL VOL. and REV.	1,639,426		1,220,908	1,639,426		1,227,147	6,239	.51%
49	TOTAL CORE VOLUMES & REVENUES	6,116,234		5,162,644	6,116,234		5,184,509	21,865	.42%

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ATTACHMENT II: TABLE 17
SEASONAL VOLUMETRIC RATES FOR DISTRIBUTION SERVICE CUSTOMERS

Class		Rate Component		Rates ($/th)			Winter to
				Summer	Winter	Average	Summer Ratio
CORE							
	Small Commercial	Distribution Only		$.16609	$.22423	$.19865	1.35
		Total Volumetric		$.79503	$.84986	$.82589	1.07
	Large Commercial	Distribution Only		$.07225	$.09754	$.08397	1.35
		Total Volumetric		$.71396	$.75653	$.73383	1.06
NONCORE							
	Industrial Distribution	Distribution Only					
			Tier 1	$.05601	$.07562	$.06623	1.35
			Tier 2	$.04298	$.05802	$.04997	1.35
			Tier 3	$.03999	$.05399	$.04604	1.35
			Tier 4	$.03399	$.04589	$.03928	1.35
		Total Volumetric					
			Tier 1	$.09748	$.11709	$.10770	1.20
			Tier 2	$.08444	$.09949	$.09143	1.18
			Tier 3	$.08146	$.09545	$.08750	1.17
			Tier 4	$.07546	$.08736	$.08075	1.16

Notes:
Rates exclude monthly customer charge.
Total core volumetric rates include distribution, bundled storage, backbone and local transmission, customer class charge and procurement.
Core commercial rates are the weighted average of Tier A and Tier B seasonal rates.
Noncore Distribution rates are the distribution-only cost components
Noncore Total Volumetric include distribution, customer class charge, and local transmission.

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ATTACHMENT II: TABLE 18
NGV RATES AND REVENUES

Line No.	Rate Class	PRESENT RATES AND REVENUES August 1, 2003 (Uncoll. Factor Change)			PROPOSED RATES & REVENUES January-04			PROPOSED CHANGE IN RATES Change	
		Adj Billing Determinant	RATE OR CHARGE	TEST PERIOD REVENUE	Adj Billing Determinant	RATE OR CHARGE	TEST PERIOD REVENUE		
		# of Cust. or Mth	$/therm or $/cust. mo.	$ (000)	# of Cust. or Mth	$/therm or $/cust. mo.	$ (000)	$/therm or $/cust. mo.	%
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	G-NGV1								
1	Customer Charge	109	$13.42	$35	109	$13.42	$35	$.00	0.00%
2	Volumetric Rate	11,221	$.70028	$7,858	11,221	$.68981	$7,740	($.01047)	-1.50%
3	G-NGV1	11,221	$.70341	$7,893	11,221	$.69294	$7,776	($.01047)	-1.49%
	G-NGV2								
4	Volumetric Rate	4,631	$1.29739	$5,950	4,631	$1.26388	$5,853	($.03351)	-2.58%
5	Total Core NGV	15,852	$.87323	$13,843	15,852	$.85974	$13,629	($.01349)	-1.55%

Rates include an illustrative WACOG of $.462 per therm.

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ATTACHMENT II: TABLE 19
AVERAGE ANNUAL DISTRIBUTION REVENUE REQUIREMENT ALLOCATION BY CUSTOMER CLASS*
($000)

Line No.	Component	TOTAL	Residential	Small Commercial	Large Commercial	Subtotal Core	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Total Wholesale	Total Noncore & Wholesale
1	Customer	482,638	441,561	34,603	797	476,961	5,030	0	647	0	0	5,677
2	Distribution	364,861	255,862	78,745	1,792	336,398	22,651	4,742	1,070	0	0	28,463
3	Allocation of Franchise Fees	12,710	10,459	1,700	39	12,198	415	71	26	0	0	512
4	Allocation of Uncollectibles Expense	2,303	1,895	308	7	2,210	75	13	5	0	0	93
5	Totals Before Averaging	862,512	709,777	115,355	2,635	827,767	28,171	4,826	1,747	0	0	34,744
6	Re-Allocation Due to Averaging*	(0)	(70,030)	70,030	0	(0)	0	0	(1,130)	1,130	0	(0)
7	Final Allocation of Distribution Revenue Requirement	862,512	639,747	185,385	2,635	827,767	28,171	4,826	617	1,130	0	34,744

AVERAGE ANNUAL ALLOCATION BY CUSTOMER CLASS OF CORE FIXED COST ACCOUNT AND NONCORE CUSTOMER CLASS CHARGE AND ITEMS TRANSFERRED TO THESE ACCOUNTS

Line No.	Component	TOTAL	Residential	Small Commercial	Large Commercial	Subtotal Core	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Total Wholesale	Total Noncore & Wholesale
8	Core Fixed Cost Account	24,507	17,938	6,337	232	24,507	0	0	0	0	0	0
9	Noncore Customer Class Charge Account (incl. Subaccounts)	(376)	0	0	0	0	(963)	790	(71)	(130)	(3)	(376)
10	NGV expenses	3,970	1,141	403	15	1,559	187	794	497	911	22	2,411
11	Natural Gas Vehicle Account Balance	2,881	828	292	11	1,131	136	576	361	661	16	1,750
12	Hazardous Substance Balance	10,554	3,033	1,071	39	4,144	497	2,109	1,322	2,422	60	6,410
13	EOR Credit to Base Rev.	(152)	(125)	(20)	(0)	(146)	(5)	(1)	(0)	0	0	(6)
14	Gas Brokerage Proc. Credit (Core Brok. Fee)	(5,793)	(4,240)	(1,498)	(55)	(5,793)	0	0	0	0	0	0
15	Sales/Marketing Credit (Core Brokerage Fee)	(1,089)	(996)	(78)	(2)	(1,076)	(11)	0	(1)	0	0	(13)
16	Affiliate Transfer Fee Account	19	16	3	0	18	1	0	0	0	0	1
17	Balancing Charge Account	(1,310)	(376)	(133)	(5)	(514)	(62)	(262)	(164)	(301)	(7)	(796)
18	G-10 Procurement Allocation	1,636	470	166	6	642	77	327	205	376	9	994
19	Brokerage Fee Balance Acct. (Core only)	551	403	142	5	551	0	0	0	0	0	0
20	Subtotals of Items Transferred to CFCA and NCCCCA	35,398	18,091	6,686	246	25,023	(144)	4,333	2,149	3,939	97	10,375
21	Re-Allocation Due to Averaging	0	152	(152)	0	0	0	0	1	(1)	0	(0)
22	Alloc. After Averaging of Items Transferred to CFCA and NCCCCA	35,398	18,243	6,533	246	25,023	(144)	4,333	2,150	3,939	97	10,375
23	Franchise Fees and Uncoll. Exp. on Non-Base CFCA and NCA	627	323	116	4	443	(3)	77	38	70	1	184
24	Subtotals with FF&U	36,025	18,567	6,649	251	25,466	(146)	4,410	2,188	4,008	99	10,559
25	Total of Items Collected via CFCA and NCCCCA	898,537	658,314	192,034	2,885	853,234	28,025	9,236	2,805	5,139	99	45,303

* Residential and Small Commercial Classes are 70% averaged; COG and EG are 100% averaged

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
CONSOLIDATED RATE CHANGES EFFECTIVE JANUARY 1, 2004
ATTACHMENT II: TABLE 20
AVERAGE ANNUAL ALLOCATION BY CUSTOMER CLASS OF NON-BASE, NON-PPP TRANSPORTATION REVENUE REQUIREMENT COSTS*
($000)

	Component	TOTAL	Residential	Small Commercial	Large Commercial	Subtotal Core	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Total Wholesale	Total Noncore & Wholesale
1	EOR Balancing Account	87	54	20	2	76	3	3	1	3	0	11
2	CEE Incentive	(502)	-459	-36	-1	(496)	-5	0	-1	0	0	(6)
3	Core Transport Interstate Transition Subaccount of the CPDCA	309	226	80	3	309	0	0	0	0	0	0
4	reserved for future use	0	0	0	0	0	0	0	0	0	0	0
5	El Paso Capacity Charge	47,146	13,549	4,786	175	18,511	2,220	9,423	5,906	10,819	267	28,635
6	Cogeneration Distribution Shortfall Account - Closeout	(463)	0	0	0	(0)	0	0	-163	-299	0	(463)
7	CPUC FEE	5,762	1,701	601	22	2,324	279	1,183	742	1,235	0	3,438
8	Subtotals	52,339	15,071	5,452	201	20,724	2,497	10,609	6,485	11,757	267	31,616
9	Re-Allocation Due to Averaging	0	66	-66	0	(0)	0	0	-43	43	0	(0)
10	Allocation after Averaging	52,339	15,137	5,386	201	20,724	2,497	10,609	6,442	11,801	267	31,616
11	Franch. Fee and Uncoll. Exp. on Non-CFCA, Non-NCA, Non-PPP	926	268	95	4	367	44	188	114	209	4	559
12	Totals	53,266	15,405	5,481	205	21,091	2,541	10,797	6,556	12,010	271	32,175

PUBLIC PURPOSE PROGRAMS (ENERGY EFFICIENCY AND CARE)
($000)

	COMPONENT	TOTAL	Residential	Small Commercial	Large Commercial	Subtotal Core	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Total Wholesale	Total Noncore & Wholesale
13	PPP - Energy Efficiency Programs	42,080	33,167	3,375	1,323	37,865	1,131	3,084	0	0	0	4,215
14	PPP-EE Balancing Account	4,235	3,338	340	133	3,811	114	310	0	0	0	424
15	PPP-CARE Subsidy Allocation	55,256	22,825	9,348	342	32,516	4,336	18,404	0	0	0	22,740
16	PPP-CARE A&G Allocation	1,607	664	272	10	946	126	535	0	0	0	661
17	PPP-CARE Balancing Account	15,442	6,379	2,612	96	9,087	1,212	5,143	0	0	0	6,355
18	Subtotal	118,619	66,373	15,947	1,904	84,224	6,919	27,476	0	0	0	34,395
19	Re-Allocation Due to Averaging	0	(4,749)	4,749	0	0	0	0	0	0	0	0
20	Allocation after Averaging	118,619	61,624	20,696	1,904	84,224	6,919	27,476	0	0	0	34,395
21	Franchise and Uncollectibles on PPP	2,101	1,092	367	34	1,492	123	487	0	0	0	609
22	Total PPP with FF&U	120,720	62,715	21,063	1,938	85,716	7,042	27,963	0	0	0	35,005
23	LESS: CARE Discount Provided to Residential CARE Customers	(55,256)	(55,256)			(55,256)			0	0	0	0
24	Net Allocation of PPP by Class	65,465	7,460	21,063	1,938	30,460	7,042	27,963	0	0	0	35,005
25	**Net Totals of Transportation Costs**	**1,017,267**	**681,179**	**218,578**	**5,028**	**904,785**	**37,608**	**47,996**	**9,361**	**17,149**	**369**	**112,483**

ᴾGE Gas Advice Filing
.ist
ɜeneral Order 96-A, Section III(G)

ıBAG Power Pool
ıccent Energy
ıglet Consumer Alliance
ıgnews Developmental Center
ıhmed, Ali
ılcantar & Elsesser
ıpplied Power Technologies
ırter & Hadden LLP
ıvista Corp
ıarkovich & Yap, Inc.
ıART
ılue Ridge Gas
ıP Energy Company
ıraun & Associates
; & H Sugar Co.
:A Bldg Industry Association
:A Cotton Ginners & Growers Assoc.
:A League of Food Processors
:A Water Service Group
:alifornia Energy Commission
:alifornia Farm Bureau Federation
:alifornia Gas Acquisition Svcs
:alifornia ISO
:alpine
:alpine Corp
:alpine Gilroy Cogen
:ambridge Energy Research Assoc
:ameron McKenna
:ardinal Cogen
:hevron USA Production Co.
:hildress, David A.
:ity of Glendale
:ity of Palo Alto
:ity of Redding
:LECA Law Office
:onstellation New Energy
:PUC
:reative Technology
:ross Border Inc
:rossborder Inc
:SC Energy Services
:avis, Wright Tremaine LLP
:avis, Wright, Tremaine, LLP
:efense Fuel Support Center
:epartment of the Army
:epartment of Water & Power City
:GS Natural Gas Services
:MM Customer Services
:owney, Brand, Seymour & Rohwer
:uke Energy
:uke Energy North America
:uncan, Virgil E.
:utcher, John
:ynegy Inc.
:llison Schneider
:nergy Law Group LLP
:nron Energy Services
Exelon Energy Ohio, Inc
Exeter Associates
Foster Farms
Foster, Wheeler, Martinez
Franciscan Mobilehome
Future Resources Associates, Inc
G. A. Krause & Assoc
GLJ Energy Publications
Goodin, MacBride, Squeri, Schlotz &
Grueneich Resource Advocates
Hanna & Morton
Heeg, Peggy A.
Hogan Manufacturing, Inc
House, Lon
Integrated Utility Consulting Group
International Power Technology
Interstate Gas Services, Inc.
J. R. Wood, Inc
JTM, Inc
Kaiser Cement Corp
Korea Elec Power Corp
Luce, Forward, Hamilton & Scripps
Marcus, David
Masonite Corporation
Matthew V. Brady & Associates
Maynor, Donald H.
McKenzie & Assoc
McKenzie & Associates
Meek, Daniel W.
Meyer, Joseph
Mirant California, LLC
Modesto Irrigation Dist
Morrison & Foerster
Morse Richard Weisenmiller & Assoc.
Navigant Consulting
New United Motor Mfg, Inc
Norris & Wong Associates
Northern California Power Agency
Office of Energy Assessments
Palo Alto Muni Utilities
PG&E National Energy Group
Pinnacle CNG Company
PITCO
Plurimi, Inc.
PPL EnergyPlus, LLC
Price, Roy
Product Development Dept
Provost Pritchard
R. M. Hairston & Company
R. W. Beck & Associates
Recon Research
Regional Cogeneration Service
RMC Lonestar
Sacramento Municipal Utility District
SCD Energy Solutions
Seattle City Light
Sempra
Sempra Energy
Sequoia Union HS Dist
SESCO
Sierra Pacific Power Company
Silicon Valley Power
Simpson Paper Company
Smurfit Stone Container Corp
Southern California Edison
SPURR
St. Paul Assoc
Stanford University
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tansev and Associates
Tecogen, Inc
TFS Energy
TJ Cross Engineers
Transwestern Pipeline Co
U S Borax, Inc
United Cogen Inc.
URM Groups
Utility Cost Management LLC
Utility Resource Network
Wellhead Electric Company
Western Hub Properties, LLC
White & Case
WMA