STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

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

Tel. No. (415) 703-1691

March 18, 2004

Advice Letter 2515-G/A/B

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

Subject: February 1, 2004 noncore tariff revisions and rate changes to eliminate El Paso capacity charge, add Schedule G-COG

Dear Ms Smith:

Advice Letter 2515-G/A/B is effective February 1, 2004. A copy of the advice letter is returned herewith for your records.

Sincerely,

Paul Clanon

Paul Clanon, Director
Energy Division

jjr

Pacific Gas and Electric Company

Karen A. Tomcala
Vice President
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January 26, 2004

Advice 2515-G
(Pacific Gas and Electric Company ID U 39 G)

Subject: **Cost Allocation for El Paso Turned Back Capacity (D. 04-01-047) (Effective February 1, 2004)**

Public Utilities Commission of the State of California

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

Purpose

The purpose of this filing is to reduce PG&E's noncore transportation rates effective **February 1, 2004**, by eliminating the El Paso Natural Gas Company (El Paso) Capacity Charge component in accordance with Decision (D.) 04-01-047—Opinion Establishing Cost Allocation for El Paso Turned Back Capacity, dated January 22, 2004. The decision, among other things, provides that PG&E should remove the costs of El Paso turned back capacity from core and noncore transportation rates and recover these costs in core procurement rates. The affected tariff sheets are included in Attachment 1 to this filing.

PG&E will remove the El Paso Capacity Charge from core transportation rates in conjunction with its February 6, 2004 monthly core procurement rate changes to be filed on January 30, 2004.

PG&E will supplement this filing to revise Schedule G-CT in order to make El Paso and Transwestern capacity available to core aggregation customers, in accordance with this decision and the Gas Accord II D. 03-12-061 dated December 23, 2003.

Background

On July 27, 2002, the Commission issued D. 02-07-037 in Rulemaking 02-06-041, requiring natural gas and large electric utilities to acquire turned back capacity, made available by a Federal Energy Regulatory Commission order allowing marketers currently serving California to turn back up to 725 MMcf/day of firm capacity on El Paso's pipeline. Utilities were required to sign up for a proportionate amount of turned back capacity not subscribed to by replacement shippers serving California.

PG&E acquired 203 MMcf/day of firm El Paso capacity and began charging the cost of the capacity, including prepayments required as a result of PG&E's bankruptcy status, to core customers as part of monthly core procurement rates. However, in Resolution (R.) G-3339, adopted December 17, 2002, the Commission ordered PG&E to refund amounts collected from core procurement customers for the capacity charges, and instead charge the costs to all customers on an equal-cents-per-therm basis, subject to reallocation following a decision on cost allocation in Phase II of the proceeding.

In accordance with R. G-3339, PG&E filed Advice 2434-G to establish Preliminary Statement Part AZ -- *El Paso Turned-Back Capacity Balancing Account,* and Advice 2437-G to begin recovery of El Paso costs on an equal cents per therm basis in all core and noncore transportation rates effective March 1, 2003.

Decision 04-01-047, adopted January 22, 2004, finds that PG&E uses its turned back capacity to serve its core market and should recover the costs of this capacity from its core procurement customers (Finding of Fact No. 8). The decision also orders PG&E to provide refunds to noncore and core aggregation customers for the costs they have paid for PG&E's turned back El Paso capacity. Core procurement customers are to be responsible for the refunded costs (Ordering Paragraph No 8).[1]

Tariff Revisions

PG&E is revising Preliminary Statement Part B—*Default Tariff Rate Components*, and transportation rate Schedules G-NT, G-EG, G-WSL, G-NGV4 and G-LNG to remove the El Paso Capacity Charge component from noncore transportation rates. This reduces noncore transportation rates by approximately $0.00615 per therm. Supporting rate tables are attached to this filing.

PG&E is revising Preliminary Statement Part C—*Gas Accounting Terms and Definitions*, to delete language in Section 7—Gas Supply Portfolio, referring to inclusion of the costs of Transwestern capacity forecast to Core Portfolio customers, in response to a stipulation with TURN.[2]

[1] The decision confers the cost responsibility for El Paso costs to PG&E's core customers, excluding core aggregation customers; that is, those core customers that purchase gas from PG&E, or PG&E's core procurement customers.

[2] Effective February 2004, Transwestern and El Paso capacity costs will be recorded the same as other core procurement interstate demand charges in the Core Pipeline Demand Charge Account.

PG&E's El Paso and Transwestern costs will be included in PG&E's monthly core procurement rates, to be filed January 30, 2004, and effective February 6, 2004. The El Paso Capacity Charge will be removed from PG&E's core transportation rates in conjunction with the February 2004 monthly core procurement rate change.

In accordance with Ordering Paragraph 9, PG&E will file a separate advice letter on or before March 22, 2004 setting forth mechanisms for refunding El Paso turned back capacity costs, plus interest, that has been previously paid by noncore and core aggregation customers, and for placing the refunded costs into rates for PG&E's core procurement customers.

Protests

Anyone wishing to protest this filing may do so by sending a letter by **February 17, 2004**, which is 22 days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

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

Protests also should be sent by e-mail and facsimile to Mr. Jerry Royer, Energy Division, as shown above, and by U.S. mail to Mr. Royer at the above address.

The protest should be sent via both e-mail and facsimile to PG&E on the same date it is mailed or delivered to the Commission at the address shown below.

Pacific Gas and Electric Company
Attention: Brian 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

Effective Date

PG&E requests that this advice filing become effective **February 1, 2004**, to eliminate the El Paso Capacity Charges for PG&E's noncore customers, as set forth in D. 04-01-047.

Notice

In accordance with General Order 96-A, Section III, Paragraph G, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list, and the parties on the service list for R. 02-06-041. Address changes should be directed to Sandra Ciach at (415) 973-7572. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs

Karen A. Tomcala/ss

Vice President - Regulatory Relations

Attachments

cc: Service List – R. 02-06-041

ATTACHMENT I
ADVICE 2515-G

Cal. P.U.C. Sheet No.	Title of Sheet	Canceling Cal P.U.C. Sheet No.
	Preliminary Statement	
22199-G	Part B—Default Tariff Rate Components - (Noncore p. 1)	22015-G
22200-G	Part B (Noncore p. 2) (Cont'd)	22016-G
22201-G	Part B (Noncore p. 3) (Cont'd)	22017-G
22202-G	Part B (Noncore p. 4) (Cont'd)	22018-G
22203-G	Part B (Noncore p. 5) (Cont'd)	22019-G
22204-G	Part B (Noncore p. 6) (Cont'd)	22020-G
22205-G	Part B (Noncore p. 7) (Cont'd)	22021-G
22206-G	Part B (Noncore p. 8) (Cont'd)	22022-G
22207-G	Part C—Gas Accounting Terms and Definitions	21698-G
	Rate Schedules	
22208-G	G-NT—Gas Transportation Service to Noncore End-Use Customers	22036-G
22209-G	G-EG-- Gas Transportation Service to Transmission Level Electric Generation	22040-G
22210-G	G-WSL—Gas Transportation Service to Wholesale/Resale Customers	22043-G
22211-G	G-NGV4—Experimental Gas Transportation Service to Noncore Natural Gas Vehicles	22069-G
22212-G	G-LNG—Experimental Liquefied Natural Gas	22071-G
	Tables of Contents	
22213-G	Table of Contents – Preliminary Statements	22091-G
22214-G	Table of Contents (Cont'd)	22092-G
22215-G	Table of Contents	22093-G

PRELIMINARY STATEMENT
(Continued)

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

	G-NT	G-NT—DISTRIBUTION (1)*				
	TRANSMISSION	SUMMER				
THERMS:		0-20,833	20,834-49,999	50,000-166,666	166,667-249,999***	
NCA	0.00316 (I)	(0.00020) (I)	(0.00020) (I)	(0.00021)	(0.00020) (I)	
DSM	0.00218	0.00339	0.00339	0.00339	0.00339	
GRC 2000 INTERIM ACCT	0.00000	0.00019	0.00019	0.00019	0.00019	
CARE	0.01547	0.01547	0.01547	0.01547	0.01547	
CPUC FEE**	0.00077	0.00077	0.00077	0.00077	0.00077	
EOR	0.00000	0.00001	0.00001	0.00001	0.00001	
CEE	0.00000	(0.00001)	(0.00001)	(0.00001)	(0.00001)	
						(D)
LOCAL TRANSMISSION (AT RISK)	0.01574	0.01574	0.01574	0.01574	0.01574	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00310	0.05597	0.04293	0.03995	0.03395	
TOTAL RATE	**0.04042 (R)**	**0.09133 (R)**	**0.07829 (R)**	**0.07530 (R)**	**0.06931 (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).

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

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

	G-NT—DISTRIBUTION (1)*				
	WINTER				
THERMS:	0-20,833	20,834-49,999	50,000-166,666	166,667-249,999***	
NCA	(0.00027) (R)	(0.00027)	(0.00027) (I)	(0.00028)	
DSM	0.00339	0.00339	0.00339	0.00339	
GRC 2000 INTERIM ACCT	0.00026	0.00026	0.00026	0.00026	
CARE	0.01547	0.01547	0.01547	0.01547	
CPUC FEE**	0.00077	0.00077	0.00077	0.00077	
EOR	0.00001	0.00001	0.00001	0.00001	
CEE	(0.00001)	(0.00001)	(0.00001)	(0.00001)	
					(D)
LOCAL TRANSMISSION (AT RISK)	0.01574	0.01574	0.01574	0.01574	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.07557	0.05797	0.05394	0.04585	
TOTAL RATE	**0.11093 (R)**	**0.09333 (R)**	**0.08930 (R)**	**0.08120 (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).

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

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PRELIMINARY STATEMENT
(Continued)

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

	G-COG (3)*	G-EG (4)*
NCA	0.00225 (I)	0.00225 (I)
DSM	0.00000	0.00000
GRC 2000 INTERIM ACCT	0.00000	0.00000
CARE	0.00000	0.00000
CPUC FEE **	0.00073	0.00073
EOR	0.00000	0.00000
CEE	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.01574	0.01574
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00046	0.00046
CUSTOMER ACCESS CHARGE (AT RISK)	0.00111	0.00111
TOTAL RATE	**0.02029 (R)**	**0.02029 (R)**

(D)

* 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).

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

NONCORE p. 4

	G-WSL							
	Palo Alto		Coalinga		Island Energy		Alpine	
NCA	0.00225	(I)	0.00225	(I)	0.00225	(I)	0.00225	(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		0.00000		0.00000		0.00000	
CEE	0.00000		0.00000		0.00000		0.00000	
								(D)
LOCAL TRANSMISSION (AT RISK)	0.01574		0.01574		0.01574		0.01574	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000		0.00000		0.00000		0.00000	
TOTAL RATE	**0.01799**	**(R)**	**0.01799**	**(R)**	**0.01799**	**(R)**	**0.01799**	**(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). It does not apply to customers on Schedule G-WSL.

(Continued)

PRELIMINARY STATEMENT
(Continued)

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) NONCORE p. 5

	G-WSL	
	West Coast Mather	West Coast Castle
NCA	0.00224 (I)	0.00225 (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	0.00000
CEE	0.00000	0.00000
LOCAL TRANSMISSION (AT RISK)	0.01574	0.01574
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000	0.00000
TOTAL RATE	**0.01798 (R)**	**0.01799 (R)**

(D)

* 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.

(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	20,834-49,999	50,000-166,666	166,667 249,999
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		0.00077	0.00077	0.00077	0.00077
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	0.03965	(R)	0.09056 (R)	0.07752 (R)	0.07453 (R)	0.06854 (R)
						(D)
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	**0.04042**	**(R)**	**0.09133 (R)**	**0.07829 (R)**	**0.07530 (R)**	**0.06931 (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).

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

	G—NGV4-DISTRIBUTION (1)*				
	WINTER				
THERMS:	0- 20,833	20,834- 49,999	50,000- 166,666	166,667 249,999	
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	0.00077	0.00077	0.00077	
EOR	0.00000	0.00000	0.00000	0.00000	
CEE	0.00000	0.00000	0.00000	0.00000	
NGV BALANCING ACCOUNT	0.11016 (R)	0.09256 (R)	0.08853 (R)	0.08043 (R)	
					(D)
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	**0.11093 (R)**	**0.09333 (R)**	**0.08930 (R)**	**0.08120 (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).

(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	
EOR	0.00000	
CEE	0.00000	
NGV BALANCING ACCOUNT	0.19078	(R)
		(D)
LOCAL TRANSMISSION (AT RISK)	0.00000	
DISTRIBUTION & BASE REVENUE CREDITS (AT RISK)	0.00000	
TOTAL RATE	**0.19155 (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).

(Continued)

PRELIMINARY STATEMENT
(Continued)

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

6. FRANCHISE FEES AND UNCOLLECTIBLE ACCOUNTS EXPENSE (F&U): F&U refers to that portion of rates designed to recover PG&E's authorized expenses for both the use of public rights-of-way (franchise fees) and bad debts (uncollectible accounts expense). Rates for retail customers include a component for F&U, as determined in PG&E's 1999 General Rate Case, Decisions 00-02-046 and 01-10-031. Rates for wholesale customers include a component for the franchise fees only, per Decision 87-12-039. Rates for UEG and cogeneration include uncollectibles expense and a reduced component for franchise fees. Since UEG is exempt from franchise fees, the franchise fee rate for UEG and cogeneration is reduced to account for the UEG franchise fee exemption while maintaining UEG/cogeneration parity in accordance with Public Utility Code 454.4.

The F&U factor is equal to..1.01771

7. GAS SUPPLY PORTFOLIO: This portfolio includes the cost of gas procured by PG&E for its Core Portfolio (Core Procurement) customers. Gas Supply Portfolio costs are recovered through the Procurement Revenue Requirement described in Section C.10.d.

Costs incurred for the portfolio include the cost of volumetric transportation, incremental pipeline capacity costs, imbalance transactions, hub services, incremental storage services, voluntary diversions, and emergency flow order (EFO) and operational flow order (OFO) charges. These costs may be offset by revenue or gains from risk management tools such as derivative financial instruments (net of transaction costs), and out-of-state sales. Other transactions such as net revenue from imbalance transactions and byproducts extraction and expenses/losses from risk management tools are included in the portfolio.

(D)

The net cost of the "flowing supply" is the result of the transactions listed above. This portfolio also includes gas withdrawn from storage and excludes gas injected into storage for Core Procurement customers using the core storage reservation.

(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:

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).

Transmission-Level Rate (Per Therm) $0.04042 (R)

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.

Average Monthly Use (Therms)	Summer (Per Therm)		Winter (Per Therm)	
Tier 1: 0 to 20,833	$0.09133	(R)	$0.11093	(R)
Tier 2: 20,834 to 49,999	$0.07829	I	$0.09333	I
Tier 3: 50,000 to 166,666	$0.07530	I	$0.08930	I
Tier 4: 166,667 to 249,999	$0.06931	I	$0.08120	I
Tier 5: 250,000 and above*	$0.04042	(R)	$0.04042	(R)

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.

* Tier 5 Summer and Winter rates are the same.

(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.

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): $0.02029 (R)

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

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.

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* PG&E's gas tariffs are available 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
Coalinga	$ 85.75463
West Coast Gas-Mather	$ 62.29808
Island Energy	$ 46.75003
Alpine Natural Gas	$ 17.24219
West Coast Gas-Castle	$ 40.22137

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto	$0.01799	(R)
Coalinga	$0.01799	I
West Coast Gas-Mather	$0.01798	I
Island Energy	$0.01799	I
Alpine Natural Gas	$0.01799	I
West Coast Gas-Castle	$0.01799	(R)

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-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:

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).

Transmission-Level Rate (Per Therm) $0.04042 (R)

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.

Average Monthly Use (Therms)	Summer (Per Therm)	Winter (Per Therm)
Tier 1: 0 to 20,833	$0.09133 (R)	$0.11093 (R)
Tier 2: 20,834 to 49,999	$0.07829 I	$0.09333 I
Tier 3: 50,000 to 166,666	$0.07530 I	$0.08930 I
Tier 4: 166,667 to 249,999	$0.06931 I	$0.08120 I
Tier 5: 250,000 and above*	$0.04042 (R)	$0.04042 (R)

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.

* Tier 5 Summer and Winter rates are the same.

(Continued)

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):	$0.19155 (R)
LNG Gallon Equivalent: (Conversion factor - One LNG Gallon = 0.82 Therms)	$0.15707 (R)

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

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

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

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

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

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

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

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RATE SCHEDULES

RESIDENTIAL

NONRESIDENTIAL

PACIFIC GAS AND ELECTRIC COMPANY
IMPLEMENTATION OF EL PASO CAPACITY OIR DECISION

ILLUSTRATIVE NONCORE GAS TRANSPORTATION RATES
CLASS AVERAGE RATES ($/th)

Line No.	Customer Class	Present Rates January-04 (A)	Effective Rates February-04 (B)	% Change (b) (C)
	TRANSPORT ONLY - Retail Noncore(a)			
1	Industrial Distribution (G-NT)	$.118	$.112	-5.2%
2	Industrial Transmission (G-NT)	$.054	$.048	-11.3%
3	Cogeneration (G-COG)	$.026	$.020	-23.3%
4	Electric Generation (G-EG)	$.026	$.020	-23.3%
	TRANSPORT ONLY - Wholesale Core and Noncore (a)			
5	Alpine Natural Gas	$.036	$.030	-16.9%
6	Coalinga	$.036	$.029	-17.3%
7	Island Energy	$.098	$.092	-6.3%
8	Palo Alto	$.028	$.021	-22.2%
9	West Coast Gas - Castle	$.043	$.037	-14.2%
10	West Coast Gas - Mather	$.043	$.037	-14.3%

(a) Transport-only rates exclude intrastate backbone transmission and storage charges.
(b) 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
IMPLEMENTATION OF EL PASO CAPACITY OIR DECISION

SUMMARY OF RATES BY MAJOR COMPONENT
($/dth; Illustrative)

		Noncore Retail				Wholesale					
		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)	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574	$.1574
2	Customer Class Charge (2)	($.0040)	$.0284	$.0225	$.0225	$.0225	$.0225	$.0224	$.0225	$.0225	$.0225
3	Public Purpose Program Charges	$.1920	$.1796								
4	CPUC Fee (3)	$.0077	$.0077	$.0073	$.0073						
3	Customer Access Charge (Volumetric CAC only) (4)			$.0111	$.0111						
4	Distribution - Annual Average (5)	$.4789	$.0310	$.0046	$.0046						
5	**VOLUMETRIC RATE - Average Annual**	$.8320	$.4042	$.2029	$.2029	$.1799	$.1799	$.1798	$.1799	$.1799	$.1799
6	**CUSTOMER ACCESS CHARGE - Class Average**	$.2892	$.0792			$.1145	$.0347	$.1892	$.7368	$.1222	$.1912
7	**CLASS AVERAGE TRANSPORTATION RATE**	$1.1211	$.4834	$.2029	$.2029	$.2944	$.2145	$.3691	$.9167	$.3021	$.3710
	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

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 $0.0065/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 (I
   See Table 15, Procurement Rates
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

PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE GAS RATES
IMPLEMENTATION OF EL PASO CAPACITY OIR DECISION

SEASONAL VOLUMETRIC RATES FOR DISTRIBUTION SERVICE CUSTOMERS

Class		Rate Component		Rates ($/th) Summer	Winter	Average	Winter to Summer Ratio
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	$.09133	$.11093	$.10155	1.21
			Tier 2	$.07829	$.09333	$.08528	1.19
			Tier 3	$.07530	$.08930	$.08135	1.19
			Tier 4	$.06931	$.08120	$.07459	1.17

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.

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General Order 96-A, Section III(G)

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Navigant Consulting
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