STATE OF CALIFORNIA Edmund G. Brown Jr., *Governor*

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

June 19, 2013

Advice Letter 3374-G

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

SUBJECT: Gas Transportation Rate Changes Effective April 1, 2013

Dear Mr. Cherry:

Advice Letter 3374-E is effective as of April 1, 2013.

Sincerely,

Edward Randolph

Edward F. Randolph, Director
Energy Division

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

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

Fax: 415.973.7226

March 25, 2013

Advice 3374-G
(Pacific Gas and Electric Company ID U 39 G)

Public Utilities Commission of the State of California

<u>Subject:</u> **Gas Transportation Rate Changes effective April 1, 2013**

Pacific Gas and Electric Company ("PG&E") hereby submits for approval by the California Public Utilities Commission ("Commission" or "CPUC") revisions to PG&E's gas tariff schedules effective April 1, 2013. The effective tariffs are included in Attachment 7 to this filing.

Purpose

The purpose of this advice letter is to submit changes to PG&E's tariffs effective April 1, 2013. Specifically, this filing:

1) Revises residential and small commercial gas transportation rates for an additional 5% annual phase-in of core deaveraging in compliance with PG&E's 2010 Biennial Cost Allocation (BCAP) Decision (D.) 10-06-035;
2) Revises PG&E's core gas transportation rates to recover 2013 Winter Gas Savings Program (WGSP) costs from residential customers during the summer season, as filed and approved in Advice Letters (AL) 3222-G and 3353-G;
3) Revises PG&E's local transmission and unbundled backbone transmission rates for the recovery of AB32-related gas compressor station costs, as authorized in D.13-03-017;
4) Renames PG&E's Preliminary Statement, Part CM, from the "Electric Cost Balancing Account" (ECBA) to the "Gas Operations Balancing Account" (GOBA), as ordered in D.13-03-017; and
5) Revises core and noncore transportation rates associated with the GT&S Revenue Sharing Mechanism account balance implemented in PG&E's 2013 Annual Gas True-Up (AGT) AL 3353-G.

Attachments 1 and 1A summarize the proposed 2013 gas transportation revenue requirements collected in rates effective April 1, 2013. Attachment 2 summarizes the gas transportation balancing accounts amortized in 2013 rates. Attachments 3 through

5 provide rates and surcharges incorporating PG&E's authorized 2013 revenue requirements. Attachment 6 provides an update of Gas Accord V Settlement tables including AB32-related gas compressor station costs.

Phased-in Core Deaveraging

PG&E's 2010 BCAP, D. 10-06-035, adopted the continued phase-out of PG&E's then remaining 30 percent core averaging between residential and small commercial rates. An initial change of 5 percent deaveraging was implemented upon adoption of D. 10-06-035 with an additional 5 percent deaveraging on April 1st of each succeeding year until PG&E's core rates are fully deaveraged.

In this advice letter, PG&E's core rates are modified so that the remaining 15 percent core averaging is deaveraged by another 5 percent, thus resulting in 10 percent core averaging remaining effective April 1, 2013.

Recovery of 2013 WGSP Residential Transportation Costs

Consistent with implementation of PG&E's 2013 WGSP, as authorized in AL 3222-G and AL 3353-G, the residential gas transportation rates in this filing include forecasted 2013 residential transportation-related WGSP marketing and implementation costs and program bill credits totaling $20.6 million. These WGSP costs are recovered in PG&E's residential transportation rates between April and October 2013. The actual bill credits earned by residential customers in the 2013 WGSP will be trued-up with recorded revenue in the 2014 AGT.

Recovery of AB32 Compressor Station Emission Allowance Compliance Costs

D.13-03-017 allows PG&E to recover costs incurred by PG&E to purchase Greenhouse Gas (GHG) emission allowance for six gas compressor stations that emit over 25,000 MT CO2e per year, as required by Assembly Bill (AB) 32. Specifically, the decision authorizes PG&E to increase its natural gas rates to recover an estimated $3.335 million in 2013 (Ordering Paragraph (OP) 1). Accordingly, PG&E has revised its local transmission and unbundled backbone transmission rates to reflect this authorized cost recovery. Attachment 6 provides an update of the tables included in Appendix A of the Gas Accord V Settlement to show revenue requirements and rates that include authorized AB32 compressor station emission allowance costs.

D.13-03-017 allows PG&E to track and recover actual costs of AB 32 compliance for its gas compressor stations. The decision orders PG&E to revise the name of Preliminary Statement, Part CM – "Electricity Cost Balancing Account" to the "Gas Operational Cost Balancing Account" (GOBA) (OP 5). The renamed account will be used to track both the electric operating costs of compressor stations as well as the emission allowance costs related to the compressor stations on PG&E's gas transmission system.

Accordingly, PG&E requests approval of PG&E's proposed Gas Preliminary Statement, Part CM – "Gas Operational Balancing Account." PG&E's proposed GOBA consists of two subaccounts: 1) the "Electricity Cost Subaccount" used to track PG&E's electric operating costs for compressor stations; and 2) the "Compressor Station GHG Cost Subaccount" used to track GHG emission allowance costs related to the compressor stations on PG&E's gas transmission system.

PG&E will record the difference between the adopted forecast and actual AB 32 compliance costs incurred in 2013[1] and 2014 in the GOBA. These costs will be trued-up in PG&E's Annual Gas True-Up (AGT) advice letters (D.13-03-017, OP 6).

Allocation of the GT&S Sharing Mechanism Account Balance between Core and Noncore classes

This advice letter corrects the allocation between core and noncore customers of the $5 million balance in the GT&S Revenue Sharing Mechanism account, as implemented in AL 3353-G on January 1, 2013. The balance was misallocated resulting in core transportation rates that were too low by approximately $0.00019 per therm and noncore transportation rates that were too high by approximately $0.00012 per therm. This has resulted in an estimated under collection from core customers of $192 thousand and an estimated over collection from noncore customers of $121 thousand during the January 1 through March 31, 2013 time period. This AL corrects the allocation and resulting rates going forward as of April 1.

The core under collection and the noncore over collection during the first three months of 2013 is reflected in the Core Fixed Cost Account – Core Cost Subaccount and the Noncore Customer Class Account – Noncore Subaccount, respectively, and will be trued-up in PG&E's 2014 AGT advice letter.

<u>Effective Date</u>

PG&E requests that this Tier 1 advice filing be approved effective **April 1, 2013**.

Changes to core gas transportation rates will be incorporated into PG&E's monthly core procurement advice filing (AL 3373-G) with rates effective April 1, 2013.

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[1] Recovery of PG&E's AB 32 compliance costs will be recorded beginning on the effective date of D.13-03-017 (pg. 10). Consequently, actual costs recorded in 2013 will not include costs incurred between January 1, 2013 and March 20, 2013.

PG&E will also adjust the 2013 Backbone Transmission revenue requirement included in PG&E's Gas Transmission and Storage Revenue Sharing Mechanism to include the 2013 GHG emission allowance revenue requirement adopted in D.13-03-017 adjusted to exclude the time period between January 1, 2013 and March 20, 2013.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than 21 days after the date of this filing, which is **April 15, 2013**[2]. Protests must be submitted to:

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

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

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

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

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

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

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter. (General Order 96-B, Section 7.4.) The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

[2] The 20-day protest period concludes on a weekend, therefore, PG&E is moving this date to the following business day.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes to the General Order 96-B service list should be directed to e-mail PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian Cherry /IG

Vice President – Regulatory Relations

Attachments

cc: 2009 Biennial Cost Allocation Proceeding (BCAP) (A.09-05-026)
Gas PPP Surcharge (R.02-10-001)
2011 Gas Transmission and Storage Proceeding (A.09-09-013)
Eugene Cadenasso, Energy Division
Richard Myers, Energy Division

Attachments

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

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

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 G)**

Utility type:	Contact Person: Igor Grinberg
☐ ELC ☑ GAS	Phone #: 415-973-8580
☐ PLC ☐ HEAT ☐ WATER	E-mail: ixg8@pge.com and PGETariffs@pge.com

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

Advice Letter (AL) #: **3374-G** **Tier:** 1

Subject of AL: **Gas Transportation Rate Changes effective April 1, 2013**

Keywords (choose from CPUC listing): Transportation Rates, Balancing Accounts, Non-Core, Compliance

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.10-06-035 & D.13-03-017

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

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Is AL requesting confidential treatment? No.

If so, what information is the utility seeking confidential treatment for: N/A

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

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

Resolution Required? ☐ Yes ☑No

Requested effective date: **April 1, 2013** No. of tariff sheets: 28

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

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

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

Tariff schedules affected: G-NT, G-EG, G-WSL, G-NGV4, G-AA, G-AAOFF, G-AFT, G-AFTOFF, G-LNG, G-SFT, G-XF, Gas Preliminary Statements Part B, Part C & CM

Service affected and changes proposed: Rate value changes per the advice letter and attachments and minor text updates.

Protests, dispositions, and all other correspondence regarding this AL are due no later than 21[1] days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

[1] The 20-day protest period concludes on a weekend, therefore, PG&E is moving this date to the following business day.

ATTACHMENTS

PACIFIC GAS AND ELECTRIC COMPANY

ADVICE 3374-G

MARCH 25, 2013

Attachment #	Attachment Title
1)	2013 Annual End-Use Transportation, Gas Accord Revenue Requirements, and Public Purpose Programs Authorized Funding Change
1A)	2013 Annual End-Use Transportation, Gas Accord Revenue Requirements, and Public Purpose Programs Authorized Funding Core/Noncore/Unbundled Allocation
2)	Balancing Account Forecast Summary
3)	Average End-User Gas Transportation Rates and Public Purpose Program Surcharges
4)	Summary of Rates by Major Elements
5)	Allocation of Gas End-Use Transportation Revenue Requirement and Public Purpose Program Surcharge Revenues Across Classes
6)	Gas Accord V Settlement – Appendix A (Updated)
7)	Tariffs

ATTACHMENT 1

PACIFIC GAS AND ELECTRIC COMPANY
APRIL 2013 AB32-RELATED GAS COMPRESSOR STATION COSTS IMPLEMENTATION [1]
2013 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING CHANGE
($ THOUSANDS)

		A	B	C	D	E	
Line No.		Present in Rates as of February 2013	Proposed as of 4/1/2013	Total Change	Core	Noncore / Unbundled	Line No.
	END-USE GAS TRANSPORTATION						
1	Gas Transportation Balancing Accounts	121,520	121,520	-	534	(534)	1
2	GRC Distribution Base Revenues (includes distribution portion of Cost of Capital) [2]	1,172,719	1,172,719	-	-	-	2
3	Pension	52,691	52,691	-	-	-	3
4	Self Generation Incentive Program Revenue Requirement	5,760	5,760	-	-	-	4
5	SmartMeter™ Project	79,202	79,202	-	-	-	5
6	CPUC Fee	3,210	3,210	-	-	-	6
7	Core Brokerage Fee Credit	(6,583)	(6,583)	-	-	-	7
8	Winter Gas Savings Program - Transportation	2,474	2,474	-	-	-	8
9	Less CARE discount recovered in PPP surcharge from non-CARE customers	(112,382)	(112,382)	-	-	-	9
10	FF&U	2,764	2,764	-	7	(7)	10
11	Total Transportation RRQ with Adjustments and Credits	1,321,375	1,321,375	-	541	(541)	11
12	Procurement-Related G-10 Total	(1,025)	(1,025)	-	-	-	12
13	Procurement-Related G-10 Total Allocated	1,025	1,025	-	-	-	13
14	Total Transportation Revenue Requirements Reallocated	1,321,375	1,321,375	-	541	(541)	14
	Gas Accord Transportation Revenue Requirements						
15	Local Transmission	205,643	205,643	-	-	-	15
16	Customer Access	4,860	4,860	-	-	-	16
17	Total Gas Accord Transportation RRQ	210,503	210,503	-	-	-	17
18	Implementation Plan Revenue Requirements						18
19	Implementation Plan - Local Transmission	91,312	91,312	-	-	-	19
20	Implementation Plan - Backbone	22,415	22,415	-	-	-	20
21	Implementation Plan - Storage	1,616	1,616	-	-	-	21
22	Total Implementation Plan	115,343	115,343	-	-	-	22
23	**Total End Use Gas Transportation RRQ**	**1,647,221**	**1,647,221**	**-**	**541**	**(541)**	23
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING						
24	Energy Efficiency	56,178	56,178	-	-	-	24
25	Energy Savings Assistance	65,208	65,208	-	-	-	25
26	Research and Development and BOE Administrative Fees	10,882	10,882	-	-	-	26
27	CARE Administrative Expense	2,739	2,739	-	-	-	27
28	Total Authorized PPP Funding	135,007	135,007	-	-	-	28
29	PPP Surcharge Balancing Accounts	(40,827)	(40,827)	-	-	-	29
30	CARE discount recovered from non-CARE customers	112,382	112,382	-	-	-	30
31	**Total PPP Required Funding**	**206,562**	**206,562**	**-**	**-**	**-**	31
	GAS ACCORD UNBUNDLED COSTS						
32	Backbone Transmission	133,171	134,765	1,594	-	1,594	32
33	Storage	34,615	34,615	-	-	-	33
34	**Total Gas Accord Unbundled**	**167,786**	**169,380**	**1,594**	**-**	**1,594**	34
35	**TOTAL REVENUE REQUIREMENTS**	**2,021,569**	**2,023,163**	**1,594**	**541**	**1,053**	35

1. Includes correction for the allocation of the GTSRSM balance implemented in the AGT AL 3353-G (see change in lines 1 & 10)
2. The 2013 change consists of a $35M increase for GRC Attrition and a $28.71M decrease for 2013 Cost of Captial.

Notes:
A positive balance represents an under-collection. A negative balance represents an over-collection.

ATTACHMENT 1A

PACIFIC GAS AND ELECTRIC COMPANY
APRIL 2013 AB32-RELATED GAS COMPRESSOR STATION COSTS IMPLEMENTATION[1]
2013 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING ALLOCATION TO CORE/NONCORE/UNBUNDLED
($ THOUSANDS)

Line No.		Proposed as of 4/1/2013	Core	Noncore / Unbundled	Line No.
	END-USE GAS TRANSPORTATION				
1	Gas Transportation Balancing Accounts	121,520	86,516	35,004	1
2	GRC Distribution Base Revenues	1,172,719	1,131,961	40,758	2
3	Pension	52,691	50,860	1,831	3
4	Self Generation Incentive Program Revenue Requirement	5,760	2,283	3,477	4
5	SmartMeter™ Project	79,202	79,202	-	5
6	CPUC Fee	3,210	1,970	1,240	6
7	Core Brokerage Fee Credit	(6,583)	(6,583)	-	7
8	Winter Gas Savings Program - Transportation	2,474	2,474	-	8
9	Less CARE discount recovered in PPP surcharge from non-CARE customers	(112,382)	(112,382)	-	9
10	FF&U	2,764	2,239	525	10
11	Total Transportation RRQ with Adjustments and Credits	1,321,375	1,238,540	82,835	11
12	Procurement-Related G-10 Total	(1,025)	(1,025)	-	12
13	Procurement-Related G-10 Total Allocated	1,025	404	621	13
14	Total Transportation Revenue Requirements Reallocated	1,321,375	1,237,919	83,456	14
	Gas Accord Transportation Revenue Requirements				
15	Local Transmission	205,643	132,854	72,789	15
16	Customer Access	4,860	-	4,860	16
17	Total Gas Accord Transportation RRQ	210,503	132,854	77,649	17
18	Implementation Plan Revenue Requirements				18
19	Implementation Plan - Local Transmission	91,312	59,009	32,303	19
20	Implementation Plan - Backbone	22,415	9,542	12,873	20
21	Implementation Plan - Storage	1,616	950	666	21
22	Total Implementation Plan	115,343	69,501	45,842	22
23	**Total End Use Transportation RRQ**	**1,647,221**	**1,440,274**	**206,947**	23
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING				
24	Energy Efficiency	56,178	50,551	5,627	24
25	Energy Savings Assistance	65,208	58,677	6,531	25
26	Research and Development and BOE Administrative Fees	10,882	6,948	3,934	26
27	CARE Administrative Expense	2,739	1,625	1,114	27
28	Total Authorized PPP Funding	135,007	117,801	17,205	28
29	PPP Surcharge Balancing Accounts	(40,827)	(28,057)	(12,770)	29
30	CARE discount recovered from non-CARE customers	112,382	66,681	45,701	30
31	**Total PPP Required Funding**	**206,562**	**156,425**	**50,137**	31
	GAS ACCORD UNBUNDLED COSTS				
32	Backbone Transmission	134,765	-	134,765	32
33	Storage	34,615	-	34,615	33
34	**Total Gas Accord Unbundled**	**169,380**	-	**169,380**	34
35	**TOTAL REVENUE REQUIREMENTS**	**2,023,163**	**1,596,699**	**426,464**	35

1. Includes correction for the allocation of the GTSRSM balance implemented in the AGT AL 3353-G (included in lines 1 & 10)

Notes:
A positive balance represents an under-collection. A negative balance represents an over-collection.

ATTACHMENT 2

PACIFIC GAS AND ELECTRIC COMPANY
APRIL 2013 AB32-RELATED GAS COMPRESSOR STATION COSTS IMPLEMENTATION
BALANCING ACCOUNT FORECAST SUMMARY

UPDATED With AB32 ARB Cost of Implementation D.12-10-044 (implemented in Feb 2012 AL 3360-G) and CORRECTION of GTSRSM Balance Allocation
($ THOUSANDS)

Line No.		Balance: Nov. 2012 Recorded Dec. 2012 Forecast	Allocation: Core	Allocation: Noncore	Balance: December 2011 Recorded (1)	Allocation: Core	Allocation: Noncore	Line No.
		A	B	C	D	E	F	
	GAS TRANSPORTATION BALANCING ACCOUNTS							
1	CFCA - Distribution Cost Subaccount	$14,608	$14,608	$0	($9,631)	($9,631)	$0	1
2	CFCA - Core Cost Subaccount	($6,543)	($6,543)	$0	$13,811	$13,811	$0	2
3	CFCA - Winter Gas Savings Subaccount - Transportation	($2,372)	($2,372)	$0	$16,875	$16,875	$0	3
4	Noncore Distribution Fixed Cost Account	($22)	$0	($22)	$2,411	$0	$2,411	4
5	NC Customer Class Charge (Noncore Subaccount)	($6,656)	$0	($6,656)	$9,108	$0	$9,108	5
6	NC Customer Class Charge (Interim Relief and Distribution Subaccount)	($946)	$0	($946)	($1,094)	$0	($1,094)	6
7	Core Brokerage Fee Balancing Account	$501	$501	$0	$40	$40	$0	7
8	Liquefied Natural Gas Balancing Account	$0	$0	$0	($3)	($1)	($2)	8
9	Hazardous Substance Mechanism	$39,095	$15,418	$23,677	$39,990	$15,771	$24,219	9
10	Balancing Charge Account	$742	$293	$449	($705) (3)	($278)	($427)	10
11	Affiliate Transfer Fee Account	($29)	($28)	($1)	($22)	($21)	($1)	11
12	Customer Energy Efficiency Incentive Recovery Account - Gas	$3,757	$3,724	$33	$3,959	$3,924	$35	12
13	SmartMeter™ Project Balancing Account	$14,200	$14,200	$0	$60,465	$60,465	$0	13
14	California Solar Initiative Thermal Program Memoradum Account	$6,365	$3,711	$2,654	$3,678	$1,451	$2,227	14
15	Adjustment Mechanism of Costs Determined in Other Proceedings	$0	$0	$0	($6,390)	($2,520)	($3,870)	15
16	Non-Tariffed Products and Services Balancing Account	($274)	($274)	$0	($184)	($184)	$0	16
17	AB 32 Cost of Implementation Fee Memorandum Account	$15,434 (4)	$8,845	$6,589	$0	$0	$0	17
18	Gas Meter Reading Costs Balancing Account	$27,266	$27,266	$0	$32,901	$32,901	$0	18
19	Electricity Cost Balancing Account	$11,820	$4,662	$7,158	$4,709	$1,857	$2,852	19
20	Pension Contribution Balancing Account	$0	$0	$0	$0	$0	$0	20
21	TID Almond Power Plant Balancing Account	($773)	($305)	($468)	$1,444	$569	$875	21
22	Revised Customer Energy Statement Balancing Account	$293	$283	$10	$0	$0	$0	22
23	GT&S Revenue Sharing Mechanism	$5,054 (2)	*$2,527*	*$2,527*	$0	$0	$0	23
24	**Subtotal Transportation Balancing Accounts**	**$121,520**	**$86,516**	**$35,004**	**$171,362**	**$135,029**	**$36,333**	24
	PUBLIC PURPOSE PROGRAM (PPP) SURCHARGE BALANCING ACCOUNTS (5)							
25	PPP-Energy Efficiency	($3,176)	($2,858)	($318)	$1,096	$986	$110	25
26	PPP-Low Income Energy Efficiency	($9,229)	($8,305)	($924)	$518	$466	$52	26
27	PPP-Research Development and Demonstration	($659)	($421)	($238)	($85)	($54)	($31)	27
28	California Alternate Rates for Energy Account	($27,763)	($16,473)	($11,290)	$628	$372	$256	28
29	**Subtotal Public Purpose Program Balancing Accounts**	**($40,827)**	**($28,057)**	**($12,770)**	**$2,157**	**$1,770**	**$387**	29
30	**TOTAL BALANCING ACCOUNTS**	**$80,693**	**$58,459**	**$22,234**	**$173,519**	**$136,799**	**$36,720**	30

Footnotes:

1. These balances are the recorded balances as of December 2011. The 12/11 ending balances that were provided in the 2012 AGT AL 3257-G-A were the forecasted balances (based on recorded balances through November 2011).
2. The balance shown is the September 30, 2012 balance, which was transferred evenly (50/50) to the CFCA and NCA after the approval of the AGT advice letter. Attachment 2 in the AGT AL 3353-G presented an incorrect core/noncore allocation of the balance. That allocation is corrected in this table.
3. The December 31, 2011 balance is $805k of which $705k was transferred to the CFCA and NCA. $100k was retained in the BCA to enable the purchase of gas for balancing.
4. The $15M balance shown was implemented in 2/1/13 rates (AL 3360-G). In 2013 AGT AL 3353-G, a zero amount was indicated as CPUC authorization for recovery in rates was still pending at that time.
5. The PPP-related balances (based on Sept 2012 recorded) were included in the 2013 PPP Gas Surcharge filed in AL 3337-G-A on November 16, 2012.

Notes:
A positive balance represents an under-collection. A negative balance represents an over-collection.
Some numbers may not add precisely due to rounding.

ATTACHMENT 3

PACIFIC GAS AND ELECTRIC COMPANY

APRIL 1, 2013 FILING - CORE DEAVERAGING, RESIDENTIAL WGSP, AB32 COMPRESSOR STATION, GT&S SHARING MECHANISM CORRECTION

AVERAGE END-USER GAS TRANSPORTATION RATES AND PUBLIC PURPOSE PROGRAM SURCHARGES (2)

($/th; Annual Class Averages)

Line No.	Customer Class	Rates Effective February 1, 2013 (A)			APRIL 1, 2013 FILING - CORE DEAVERAGING, RESIDENTIAL WGSP, AB32 COMPRESSOR STATION, (B)			% Change (3) (C)		
		Transportation	G-PPPS (2)	Total	Transportation	G-PPPS (2)	Total	Transportation	G-PPPS (2)	Total
	RETAIL CORE (1)									
1	Residential Non-CARE (4)	$.620	$.066	$.685	$.624	$.066	**$.689**	0.7%	0.0%	0.6%
2	Small Commercial Non-CARE (4)	$.396	$.039	$.435	$.387	$.039	**$.425**	(2.4%)	0.0%	(2.2%)
3	Large Commercial	$.185	$.071	$.257	$.185	$.071	**$.257**	0.1%	0.0%	0.1%
4	NGV1 - (uncompressed service)	$.143	$.024	$.167	$.143	$.024	**$.167**	0.1%	0.0%	0.1%
5	NGV2 - (compressed service)	$1.396	$.024	$1.420	$1.397	$.024	**$1.421**	0.0%	0.0%	0.0%
	RETAIL NONCORE (1)									
6	Industrial - Distribution	$.149	$.036	$.185	$.149	$.036	**$.185**	(0.1%)	0.0%	(0.1%)
7	Industrial - Transmission	$.053	$.030	$.083	$.053	$.030	**$.083**	(0.2%)	0.0%	(0.1%)
8	Industrial - Backbone	$.018	$.030	$.047	$.017	$.030	**$.047**	(0.7%)	0.0%	(0.3%)
9	Electric Generation - Transmission (G-EG-D/LT)	$.046		$.046	$.045		**$.045**	(0.2%)		(0.2%)
10	Electric Generation - Backbone (G-EG-BB)	$.016		$.016	$.016		**$.016**	(0.8%)		(0.8%)
11	NGV 4 - Distribution (uncompressed service)	$.149	$.024	$.173	$.149	$.024	**$.173**	(0.1%)	0.0%	(0.1%)
12	NGV 4 - Transmission (uncompressed service)	$.047	$.024	$.071	$.046	$.024	**$.070**	(0.2%)	0.0%	(0.2%)
	WHOLESALE CORE AND NONCORE (G-WSL) (1)									
13	Alpine Natural Gas	$.044		$.044	$.044		**$.044**	(0.2%)		(0.2%)
14	Coalinga	$.045		$.045	$.045		**$.045**	(0.2%)		(0.2%)
15	Island Energy	$.064		$.064	$.063		**$.063**	(0.2%)		(0.2%)
16	Palo Alto	$.040		$.040	$.040		**$.040**	(0.3%)		(0.3%)
17	West Coast Gas - Castle	$.155		$.155	$.155		**$.155**	(0.1%)		(0.1%)
18	West Coast Gas - Mather Distribution	$.182		$.182	$.182		**$.182**	(0.1%)		(0.1%)
19	West Coast Gas - Mather Transmission	$.048		$.048	$.048		**$.048**	(0.2%)		(0.2%)

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

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

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

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

ATTACHMENT 4
PACIFIC GAS AND ELECTRIC COMPANY
APRIL 1, 2013 FILING - CORE DEAVERAGING, RESIDENTIAL WGSP, AB32 COMPRESSOR STATION, GT&S SHARING MECHANISM CORRECTION
SUMMARY OF RATES (excluding procurement) BY CLASS BY MAJOR ELEMENTS
($/th; Annual Class Averages)

		Core Retail					Noncore Retail						
		Non-CARE			G-NGV1	G-NGV2	Industrial			G-NGV 4		Electric Generation	
		Residential	Sml Com.	Lg. Comm.	(Uncompressed)	(Compressed)	Distribution	Transmission	BB-Level Serv.	Distribution	Transmission	Dist./Trans.	BB-Level Serv.
	TRANSPORTATION CHARGE COMPONENTS												
1	Local Transmission (1)	$.04241	$.04241	$.04241	$.04241	$.04241	$.01990	$.01990	$.00068	$.01990	$.01990	$.01990	$.00068
2	Self Generation Incentive Program	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080
3	CPUC (3)	$.00378	$.00378	$.00378	$.00378	$.00378	$.00378	$.00378	$.00378	$.00378	$.00378	$.00312	$.00312
4	Balancing Accounts (2)	$.07072	$.04421	$.01862	$.02299	$.06663	$.00544	$.00764	$.00778	$.00544	$.00778	$.00617	$.00617
5	PSEP	$.02384	$.02384	$.02384	$.02384	$.02384	$.01234	$.01234	$.00288	$.01234	$.01234	$.01234	$.00288
6	Distribution - Annual Average (6)	$.48237	$.21258	$.09153	$.04825	$1.25911	$.09911	$.00641		$.09911		$.00201	$.00201
7	VOLUMETRIC RATE - Average Annual	$.62392	$.32762	$.18098	$.14207	$1.39658	$.14137	$.05087	$.01592	$.14137	$.04460	$.04434	$.01566
8	CUSTOMER ACCESS CHARGE - Class Average (4)		$.05888	$.00449	$.00120		$.00762	$.00180	$.00153	$.00762	$.00180	$.00106	$.00021
9	CLASS AVERAGE TRANSPORTATION RATE	$.62392	$.38651	$.18547	$.14326	$1.39658	$.14899	$.05267	$.01745	$.14899	$.04640	$.04540	$.01587
10	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)	$.06551	$.03878	$.07137	$.02408	$.02408	$.03568	$.02990	$.02990	$.02408	$.02408		
11	END-USE RATE (7)	$.68943	$.42529	$.25684	$.16734	$1.42066	$.18467	$.08257	$.04735	$.17307	$.07048	$.04540	$.01587

		Wholesale						
				WC Gas Mather		Island		WC Gas
		Coalinga	Palo Alto	Dist.	Trans.	Energy	Alpine	Castle
	TRANSPORTATION CHARGE COMPONENTS							
12	Local Transmission (1)	$.01990	$.01990	$.01990	$.01990	$.01990	$.01990	$.01990
13	Self Generation Incentive Program	WHOLESALE CUSTOMERS EXCEPT FROM SGIP RATE COMPONENT						
14	CPUC (3)							
15	Balancing Accounts (2)	$.00620	$.00620	$.00308	$.00620	$.00620	$.00620	$.00384
16	PSEP	$.01234	$.01234	$.01234	$.01234	$.01234	$.01234	$.01234
17	Distribution - Annual Average			$.13710				$.10354
18	VOLUMETRIC RATE - Average Annual	$.03844	$.03844	$.17242	$.03844	$.03844	$.03844	$.13962
19	CUSTOMER ACCESS CHARGE - Class Average (4)	$.00661	$.00173	$.00923	$.00923	$.02504	$.00590	$.01489
20	CLASS AVERAGE TRANSPORTATION RATE	$.04504	$.04017	$.18165	$.04766	$.06347	$.04434	$.15451
21	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)							
22	END-USE RATE	$.04504	$.04017	$.18165	$.04766	$.06347	$.04434	$.15451

NOTES
(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2013 GHG Compressor Station Allowance Cost Impementation AL 3374-G Attachment 6, Appendix B, Table 11.
(2) Based on November recorded balances and forecasted through December.
(3) CPUC Fee based on Resolution M-4819, effective July 1, 2007 (including FF&U). G-EG customers pay a reduced CPUC fee per the 2010 BCAP D.10-06-035.
(4) Adopted in Decision 11-04-031 based on Appendix B, Table 12; updated in the 2013 GHG Compressor Station Allowance Cost Implementation AL 3374-G Attachment 6, Appendix B, Table 12.
(5) Decision 04-08-010 ordered the removal of PPP cost recovery from transportation rates. On March 1, 2005 PG&E began to treat PPP as a tax. AL 3337-G-A updated PG&E's 2013 PPP Surcharges effective January 1, 2013.
(6) The G-NGV2 Distribution rate component incudes the cost of compression, station operations and maintanance, and state/federal gas excise taxes, and the average A-10 electric rate.
(7) CARE Customers receive a 20% discount off of PG&E's total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates and cost recovery of the California Solar Initiative Thermal Program.

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT 5
APRIL 1, 2013 FILING - CORE DEAVERAGING, RESIDENTIAL WGSP, AB32 COMPRESSOR STATION, GT&S SHARING MECHANISM CORRECTION
ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES
($000)

Line No.	GAS GRC, ATTRITION, PENSION & COST OF CAPITAL DISTRIBUTION-LEVEL REVENUE REQUIREMENTS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Noncore & Wholesale
1	Customer	659,274	575,198	76,654	1,640	67	0	653,558	4,058	231	0	1,427	0	0	0	0	0	0	0	5,716
2	Distribution	547,442	381,819	122,952	5,425	920	0	511,117	23,376	8,867	0	3,926	0	0	0	0	86	0	69	36,325
3	G-NGV2 Compression Cost	2,931	0	0	0	0	2,931	2,931	0	0	0	0	0	0	0	0	0	0	0	0
4	Allocation of Base Distribution Franchise Fees	11,959	9,461	1,873	70	10	29	11,543	271	90	0	53	0	0	0	0	1	0	1	416
5	Allocation of Base Distribution Uncollectibles Expense	3,804	3,010	628	22	3	9	3,673	86	28	0	17	0	0	0	0	0	0	0	132
6	Totals Before Core Averaging	1,225,410	969,488	202,206	7,158	1,000	2,969	1,182,821	27,794	9,216	0	5,423	0	0	0	0	87	0	69	42,589
7	Re-Allocation Due to Core Averaging*	(0)	(12,894)	12,894	0	0	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0
8	**Final Allocation of Distribution Revenue Requirement**	**1,225,410**	**956,594**	**215,100**	**7,158**	**1,000**	**2,969**	**1,182,821**	**27,794**	**9,216**	**0**	**5,423**	**0**	**0**	**0**	**0**	**87**	**0**	**69**	**42,589**
9	**Distribution-Level Revenue Requirement Allocation %**	100.00000%	78.06319%	17.55334%	0.58409%	0.08160%	0.24231%	96.52452%	2.26810%	0.75209%	0.00000%	0.44253%	0.00000%	0.00000%	0.00000%	0.00000%	0.00709%	0.00000%	0.00567%	3.47548%
	CUSTOMER CLASS COSTS WITHOUT RATE COMPONENTS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Noncore & Wholesale
10	Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount	14,608	11,814	2,657	88	12	37	14,608	0	0	0	0	0	0	0	0	0	0	0	0
11	Core Fixed Cost Acct. Bal. - Core Cost Subaccount - ECPT	-6,543	-4,540	-1,789	-168	-46	0	-6,543	0	0	0	0	0	0	0	0	0	0	0	0
12	CFCA-Winter Gas Savings Program Transportation Portion	25,359	20,300	4,904	154	0	0	25,359	0	0	0	0	0	0	0	0	0	0	0	0
13	Noncore Customer Class Charge Account - ECPT	-6,656	0	0	0	0	0	0	-389	-2,149	-17	-4,036	-8	-4	-48	-1	-2	-1	-1	-6,656
14	Noncore Customer Class Charge Account - Interim Relief	-946	0	0	0	0	0	0	-617	-205	0	-120	0	0	0	0	-2	0	-2	-946
15	NC Distribution Fixed Cost Acct.	-22	0	0	0	0	0	0	-14	-5	0	-3	0	0	0	0	0	0	0	-22
16	CA Solar Hot Water Heating	6,365	2,338	1,226	115	31	0	3,711	403	2,224	18	0	8	0	0	0	0	0	0	2,654
17	LNG Balancing Account & Lawrence Livermore Lab	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Hazardous Substance Balance	39,095	10,699	4,215	397	106	0	15,418	1,385	7,645	62	14,358	28	13	170	3	5	3	4	23,677
19	Non-Tariffed Products and Services	-274	-190	-75	-7	-2	0	-274	0	0	0	0	0	0	0	0	0	0	0	0
20	Core Brokerage Fee Credit (Gas Brokerage Costs w/o FF&U)	-5,470	-3,796	-1,495	-141	-38	0	-5,470	0	0	0	0	0	0	0	0	0	0	0	0
21	Core Brokerage Fee Credit (Sales/Marketing Costs w/o FF&U)	-1,028	-905	-121	-3	0	0	-1,028	0	0	0	0	0	0	0	0	0	0	0	0
22	Affiliate Transfer Fee Account	-29	-23	-5	0	0	0	-28	-1	0	0	0	0	0	0	0	0	0	0	-1
23	Balancing Charge Account	742	203	80	8	2	0	293	26	145	1	272	1	0	3	0	0	0	0	449
24	G-10 Procurement-related Employee Discount Allocated	1,025	280	110	10	3	0	404	36	200	2	376	1	0	4	0	0	0	0	621
25	Brokerage Fee Balance Account	501	347	137	13	3	0	501	0	0	0	0	0	0	0	0	0	0	0	0
26	Adjust. Mechanism Costs Determined Other Proceedings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	G-10 Procurement-related Employee Discount	-1,025	-1,025	0	0	0	0	-1,025	0	0	0	0	0	0	0	0	0	0	0	0
28	TID Almond Power Plant	-773	-212	-63	-8	-2	0	-305	-27	-151	-1	-284	-1	0	-3	0	0	0	0	-468
29	RCESBA-G	293	232	48	2	0	1	283	7	2	0	1	0	0	0	0	0	0	0	10
30	Electricity Cost Balancing Account	11,820	3,235	1,274	120	33	0	4,662	419	2,311	19	4,341	8	4	51	1	2	1	1	7,158
31	WGSP Balancing Account	-2,372	-1,403	-953	-15	0	0	-2,372	0	0	0	0	0	0	0	0	0	0	0	0
32	GT&S Revenue Sharing Mechanism	5,054	1,754	691	65	18	0	2,527	148	816	7	1,532	3	1	18	0	1	0	0	2,527
33	Gas Meter Reading Costs Balancing Account	27,266	22,051	4,958	165	23	68	27,266	0	0	0	0	0	0	0	0	0	0	0	0
34	Self Gen Incentive Program Forecast Period Cost	5,760	1,584	624	59	16	0	2,283	205	1,132	9	2,126	4	0	0	0	0	0	0	3,477
35	Subtotals of Items Transferred to CFCA and NCA	112,748	62,744	16,405	854	161	106	80,270	1,580	11,967	98	18,564	44	15	196	4	4	4	3	32,479
36	Re-Allocation Due to Core Averaging	0	-397	397	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Alloc. After Core Averaging	112,748	62,348	16,801	854	161	106	80,270	1,580	11,967	98	18,564	44	15	196	4	4	4	3	32,479
38	Franchise Fees and Uncoll. Exp. on Items Above	1,469	812	219	11	2	1	1,046	21	156	1	242	1	0	2	0	0	0	0	423
39	Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs	114,217	63,160	17,020	865	163	107	81,316	1,601	12,123	100	18,806	45	15	198	4	4	4	3	32,901
40	Total of Items Collected via CFCA, NCA, and NDFCA	1,339,627	1,019,754	232,121	8,023	1,163	3,076	1,264,137	29,394	21,339	100	24,229	45	15	198	4	91	4	72	75,490
	CUSTOMER CLASS COSTS WITH THEIR OWN RATE COMPONENTS ALLOCATED USING BCAP THROUGHPUT	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Noncore & Wholesale
41	Unused	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	CEE Incentive	3,757	3,278	437	9	0	0	3,724	23	1	0	8	0	0	0	0	0	0	0	33
43	AB32 ARB Implementation Fee	15,434	6,137	2,418	227	62	0	8,845	794	4,385	35	1,359	16	0	0	0	0	0	0	6,589
44	Smart Meter™ Project Forecast Period Costs	79,202	64,054	14,403	479	266	0	79,202	0	0	0	0	0	0	0	0	0	0	0	0
45	SmartMeter™ Project Balancing Account (SBA-G)	14,200	11,484	2,582	86	48	0	14,200	0	0	0	0	0	0	0	0	0	0	0	0
46	SmartMeter Opt-Out	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	CPUC FEE	3,210	1,368	538	51	14	0	1,970	177	977	8	75	4	0	0	0	0	0	0	1,240
48	Subtotals for Customer Class Charge Items	115,803	86,321	20,378	853	389	0	107,941	994	5,363	43	1,442	20	0	0	0	0	0	0	7,862
49	Re-Allocation Due to Core Averaging	0	-978	978	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50	Allocation after Remaining Core Averaging	115,803	85,343	21,356	853	389	0	107,941	994	5,363	43	1,442	20	0	0	0	0	0	0	7,862
51	Franch. Fee and Uncoll. Exp. on Items Above	1,509	1,112	278	11	5	0	1,407	13	70	1	19	0	0	0	0	0	0	0	102
52	Subtotals of Other Costs	117,312	86,455	21,634	864	394	0	109,347	1,007	5,433	44	1,461	20	0	0	0	0	0	0	7,965
53	Allocation of Total Transportation Costs	1,456,939	1,106,210	253,755	8,886	1,557	3,076	1,373,484	30,401	26,772	144	25,690	65	15	198	4	91	4	72	83,455
	CUSTOMER CLASS COST FOR PIPELINE SAFETY ENHANCEMENT ALLOCATED BASED ON GAS ACCORD THROUGHPUT	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Noncore & Wholesale
54	Local Transmission Expense (Forecast Period Cost)	91,313	40,959	15,970	1,641	440	0	59,009	2,507	13,633	0	15,759	53	24	302	6	9	4	6	32,303
55	Local Transmission Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
56	Backbone Transmission Expense (Forecast Period Cost)	22,415	6,623	2,582	265	71	0	9,542	727	3,952	31	8,046	15	7	88	2	3	1	2	12,873
57	Backbone Transmission Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
58	Storage (Forecast Period Cost)	1,616	659	257	26	7	0	950	38	205	2	416	1	0	5	0	0	0	0	666
59	Storage Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	Subtotal of Pipeline Safety Enhacement Cost	115,343	48,241	18,809	1,932	518	0	69,501	3,271	17,789	33	24,221	69	31	394	8	12	6	8	45,842
	RECONCILIATION WITH REVENUE REQUIREMENTS TABLE FOR END-USER TRANSPORTATION TOTALS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Noncore & Wholesale
61	WGSP-T Rebate Recovery (w/o FF&U)	(22,885)	(18,320)	(4,422)	(143)			(22,885)												0
62	Franchise Fees and Uncollectibles Expense	(298)	(239)	(58)	(2)			(298)												0
63	Total End-User Transportation Rev. Req. Excluding Gas Accord	1,549,099	1,135,892	268,084	10,674	2,076	3,076	1,419,802	33,672	44,561	177	49,911	134	46	592	12	103	9	80	129,297
	ADOPTED REVENUE REQUIREMENTS ALLOCATIONS FOR GAS ACCORD ITEMS IN TRANSPORTATION	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Noncore & Wholesale
64	Local Transmission	205,643	99,834	30,681	1,890	449		132,853	7,009	27,937		36,401	116	113	1,088	32	44	17	24	72,789
65	Customer Access Charge	4,860	0	0	0			0	0	2,562		2,192		17	55	4	9	11	10	4,860
66	Total End-User Gas Accord Transportation Costs	210,502	99,834	30,681	1,890	449	0	132,853	7,009	30,499	0	38,593	116	129	1,153	35	53	28	34	77,649
67	Gross End-User Transportation Costs in Rates	1,759,602	1,235,725	298,766	12,564	2,524	3,076	1,552,656	40,681	75,060	177	88,504	250	175	1,745	47	156	37	114	206,946
68	Less Forecast CARE Discount recovered in PPP Surcharges	112,382	112,382					112,382												0
69	Net End-User Transportation Costs in Rates	1,647,219	1,123,343	298,766	12,564	2,524	3,076	1,440,273	40,681	75,060	177	88,504	250	175	1,745	47	156	37	114	206,946

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT 5 (continued)
APRIL 1, 2013 FILING - CORE DEAVERAGING, RESIDENTIAL WGSP, AB32 COMPRESSOR STATION, GT&S SHARING MECHANISM CORRECTION
ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES
($000)

Line No.	ALLOCATION OF PUBLIC PURPOSE PROGRAM SURCHARGES UNDER PER PG&E AL 3161-G	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**
70	PPP-EE Surcharge	56,178	44,279	4,506	1,766	0		50,551	1,510	4,084	33		0						
71	PPP-EE Balancing Account	(3,176)	(2,503)	(255)	(100)	0		(2,858)	(85)	(231)	(2)		0						
72	PPP-ESA Surcharge	65,208	51,397	5,231	2,050	0		58,677	1,753	4,740	38		0						
73	PPP-ESA Balancing Account	(9,229)	(7,274)	(740)	(290)	0		(8,305)	(248)	(671)	(5)		0						
74	PPP - RD&D Programs	10,559	4,707	1,823	170	42		6,742	592	3,187	26		12						
75	PPP - RD&D Balancing Account	(659)	(294)	(114)	(11)	(3)		(421)	(37)	(199)	(2)		(1)						
76	PPP-CARE Discount Allocation Set Annually	112,382	42,308	21,833	2,033	508		66,682	7,089	38,157	309		147						
77	PPP-CARE Administration Expense	2,739	1,031	532	50	12		1,625	173	930	8		4						
78	PPP-CARE Balancing Account	(27,763)	(10,452)	(5,394)	(502)	(125)		(16,473)	(1,751)	(9,426)	(76)		(36)						
79	PPP-Admin Cost for BOE and CPUC	322	144	56	5	1		206	18	97	1		0						
80	Subtotal	206,561.87	123,342	27,479	5,170	436		156,426	9,013	40,668	329	0	126	0	0	0	0	0	0
81	Re-Allocation Due to Core Averaging	0.00	(2,701)	2,701	0	0		0	0	0	0	0	0	0	0	0	0	0	0
82	Allocation after Remaining Averaging	206,561.87	120,641	30,180	5,170	436		156,426	9,013	40,668	329	0	126	0	0	0	0	0	0

Line No.		
83	Unbundled Gas Transmission and Storage Revenue Requirement	169,380

Line No.	TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES	
84	Total Transportation, PPPS,and Unbundled Costs	2,023,161
85	Cross-check with Gas Revenue Requirement Table	2,023,161
86	Difference	0

* Residential and Small Commercial Classes are 10% averaged

** Wholesale Customer West Coast Gas is allocated 80% of its full distribution costs as of January 2013.

Advice 3374-G
March 25, 2013

GAS ACCORD V SETTLEMENT

(A.09-09-013)

Attachment 6 - Appendix A

Updated

2011 Rates – Reflects (May 1, 2011) Late Implementation of GA V Settlement as filed in Advice 3200-G and 3201-G.

2012 Rates – Reflects treatment of costs as determined in PG&E's 2011 General Rate Case in Advice Letter 3257-G-A.

2013-2014 Rates – Reflects treatment of costs as determined in PG&E's 2013 Cost of Capital decision issued 12/20/2012 (D.12-12-034) and PG&E's compressor station GHG Emissions allowance cost recovery decision issued 03/21/2013 (D.13-03-017).

A.09-09-013

Gas Accord V Settlement Agreement

Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-1
Core and Core Wholesale
Delivery Point Backbone Capacity Assignments/Options

		Gas Accord IV	Gas Accord V			
Line No.		Core Redwood Annual Capacity (MDth/d)	Allocation Factors	Core Redwood Annual Capacity (MDth/d)	Core Baja Annual Capacity (MDth/d)	Core Baja Seasonal Capacity (MDth/d)
1	CORE and CTAs	608.766	98.89%	608.766	348.000	321.000
2	WHOLESALE - Core					
3	Palo Alto	5.898	0.96%	5.898	3.372	3.110
4	Coalinga	0.552	0.09%	0.552	0.316	0.291
5	West Coast Gas-Mather	0.171	0.03%	0.171	0.098	0.090
6	Island Energy	0.064	0.01%	0.064	0.037	0.034
7	Alpine Natural Gas	0.098	0.02%	0.098	0.056	0.052
8	West Coast Gas-Castle	0.051	0.01%	0.051	0.029	0.027
9	Subtotal	6.834	1.11%	6.834	3.907	3.604
10	TOTAL	615.600	100.00%	615.600	351.907	324.604

A.09-09-013

Gas Accord V Settlement Agreement

Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-2

Firm Storage Capacity Assignments
Core, Load Balancing, and Market Storage Services

Line No.	Service	Annual Injection Storage Units	Inventory	Annual Withdrawal Storage Units
1	Monthly Balancing Service	76	4.1	76
2	Core Firm Storage	157	33.5	1,111
3	Core Firm Storage Counter Cyclical	50	0	50
4	Market Storage (Traditional)	194	9.0	300
5	Market Storage Counter Cyclical (Traditional)	194	0	300
6	Market Storage (Gill Ranch)	62	3.2	105

A.09-09-013

Gas Accord V Settlement Agreement

Appendix A
Effective April 1, 2013

Table A-3
GT&S Revenue Requirement
<u>Including Core and Noncore Revenue Responsibility</u>
($ Thousand)

Line No.		GA V Settlement 2011 (9)	GA V with 2013 COC and GHG Compressor Cost 2011	2012	2013 (10)	2014 (11)	GA V with 2013 COC and GHG Compressor Cost, excluding Non-Operational Adder Projects. 2011	2012	2013 (10)	2014 (11)
	Core Revenue Requirements									
1	Backbone Transmission Base (1) (2) (5) (6)	94,929	93,414	95,901	94,506	100,728	86,621	95,901	94,506	100,728
2	Backbone Transmission Adders	-	-	-	3,173	3,335	-	-	-	3,335
3	Subtotal Backbone Transmission	94,929	93,414	95,901	97,679	104,063	86,621	95,901	94,506	104,063
4	Local Transmission Base	124,872	122,972	131,618	128,003	130,693	113,620	131,618	128,003	130,693
5	Local Transmission Adder (3) (7)	5,514	5,514	5,785	9,602	13,319	5,514	5,395	4,850	13,319
6	Subtotal Local Transmission	130,386	128,486	137,403	137,605	144,013	119,134	137,013	132,853	144,013
7	Storage (4) (8)	49,255	48,689	50,121	49,492	50,603	48,689	50,121	49,492	50,603
8	Customer Access Charge	-	-	-	-	-	-	-	-	-
9	Total Core (12)	$274,571	$270,589	$283,425	$284,776	$298,679	$254,444	$283,036	$276,851	$298,679
		53.4%	53.3%	53.0%	52.8%	53.7%	53.3%	53.0%	52.8%	53.7%
	Noncore / Unbundled Revenue Requirements									
10	Backbone Trans. Base w/o G-XF Contracts	124,818	123,774	132,655	128,787	125,053	114,758	132,655	128,787	125,053
11	Backbone Transmission Adders	-	-	-	4,656	5,158	-	-	-	5,158
12	Subtotal Backbone Transmission	124,818	123,774	132,655	133,444	130,211	114,758	132,655	128,787	130,211
13	G-XF Contracts	6,879	6,875	6,448	5,978	5,831	6,875	6,448	5,978	5,831
14	G-XF Contract Adders	-	-	-	-	43	-	-	-	43
15	G-XF Contracts Subtotal	6,879	6,875	6,448	5,978	5,874	6,875	6,448	5,978	5,874
16	Subtotal Backbone Transmission (5) (6)	131,698	130,648	139,103	139,422	136,085	121,633	139,103	134,765	136,085
17	Local Transmission Base	64,594	63,623	68,774	70,132	74,223	58,784	68,774	70,132	74,223
18	Local Transmission Adder (3) (7)	2,853	2,853	3,023	5,261	7,564	2,853	2,819	2,657	7,564
19	Subtotal Local Transmission	67,447	66,476	71,797	75,392	81,787	61,637	71,593	72,789	81,787
20	Storage (4) (8)	35,795	35,513	35,729	34,615	34,980	35,513	35,729	34,615	34,980
21	Customer Access Charge	4,691	4,590	4,821	4,860	5,026	4,590	4,821	4,860	5,026
22	Total Noncore / Unbundled (12)	$239,631	$237,227	$251,449	$254,288	$257,878	$223,373	$251,246	$247,029	$257,878
		46.6%	46.7%	47.0%	47.2%	46.3%	46.7%	47.0%	47.2%	46.3%
	Total									
23	Backbone Transmission Base w/o G-XF Contracts	219,747	217,188	228,556	223,294	225,781	201,379	228,556	223,294	225,781
24	Backbone Transmission Adders	-	-	-	7,829	8,493	-		-	8,493
25	Subtotal Backbone Trans. w/o G-XF Contracts	219,747	217,188	228,556	231,123	234,274	201,379	228,556	223,294	234,274
26	G-XF Contracts	6,879	6,875	6,448	5,978	5,831	6,875	6,448	5,978	5,831
27	G-XF Contract Adders	-	-	-	-	43	-	-	-	43
28	G-XF Contracts Subtotal	6,879	6,875	6,448	5,978	5,874	6,875	6,448	5,978	5,874
29	Subtotal Backbone Transmission (5) (6)	226,627	224,062	235,004	237,101	240,148	208,254	235,004	229,271	240,148
30	Local Transmission Base	189,466	186,595	200,392	198,135	204,916	172,404	200,392	198,135	204,916
31	Local Transmission Adder (less 5%) (3) (7)	8,367	8,367	8,808	14,862	20,884	8,367	8,214	7,508	20,884
32	Subtotal Local Transmission	197,833	194,962	209,200	212,997	225,800	180,771	208,606	205,643	225,800
33	Storage (4) (8)	85,051	84,202	85,850	84,106	85,583	84,202	85,850	84,106	85,583
34	Customer Access Charge	4,691	4,590	4,821	4,860	5,026	4,590	4,821	4,860	5,026
35	Total GT&S (12)	$514,202	$507,817	$534,874	$539,064	$556,557	$477,817	$534,281	$523,880	$556,557
		100.0%	100.0%	100.0%	100.0%	100.0%				

Appendix A

Effective April 1, 2013

Table A-3 (continued)
GT&S Revenue Requirement
Including Core and Noncore Revenue Responsibility
($ Thousand)

Notes

(1) 2010-2014 Core Backbone revenue responsibility assumes an average 100% load factor.

(2) Beginning in 2011, Core eliminated its annual Silverado capacity holdings.

(3) The Gas Accord V adopted 2011 local transmission rate includes a base rate component plus a rate adder for the Line 406 adder project.

(4) 2010-2014 storage revenue requirements include carrying costs on noncycled working gas and cycle gas.

(5) Backbone revenue requirements do not reflect the impact of PG&E's proposed revenue sharing mechanism.

(6) Backbone rates include load balancing costs.

(7) The Gas Accord V Settlement local transmission revenue requirements have been reduced by the following amounts that represent the fractional-year revenue requirements associated with local transmission adder projects: 2011 - $145 thousand; 2012 - $614 thousand; 2013 - $529 thousand.

(8) The Gas Accord V Settlement storage revenue requirements include the following non-base revenues for carrying costs on noncycled working gas and and cycled gas for storage balancing: 2011 - $1,852 million; 2012 - $2,867 million; 2013 - $3,042 million; 2014 - $3,584 million.

(9) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(10) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(11) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

(12) Totals may not agree with the sum of the numbers shown due to rounding.

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-AFT: Annual Firm Transportation On-System

Noncore Redwood Path

Line No.		MFV 2011 (2)	MFV 2012	MFV 2013 (3)	MFV 2014 (4)	MFV 2015	SFV 2011 (2)	SFV 2012	SFV 2013 (3)	SFV 2014 (4)	SFV 2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.4087	5.4576	5.2084	5.1676		8.3095	8.3437	7.9034	7.8013	
3	Usage Charge	0.1038	0.1032	0.0965	0.0945		0.0084	0.0083	0.0079	0.0079	
4	Total Charge	0.2816	0.2826	0.2678	0.2644		0.2816	0.2826	0.2678	0.2644	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0076		—	—	—	0.0115	
8	Usage Charge	—	—	—	0.0001		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0004		—	—	—	0.0004	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0175		—	—	—	0.0264	
12	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0009		—	—	—	0.0009	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1643		—	—	—	0.2481	
20	Usage Charge	—	—	—	0.0029		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0083		—	—	—	0.0083	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0817	—	—	—	—	0.1233
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.4087	5.4576	5.2084	5.3570		8.3095	8.3437	7.9034	8.0872	
29	Usage Charge	0.1038	0.1032	0.0965	0.0979		0.0084	0.0083	0.0079	0.0082	
30	Total Charge	0.2816	0.2826	0.2678	0.2740		0.2816	0.2826	0.2678	0.2740	

Noncore Baja Path

Line No.		MFV 2011 (2)	MFV 2012	MFV 2013 (3)	MFV 2014 (4)	MFV 2015	SFV 2011 (2)	SFV 2012	SFV 2013 (3)	SFV 2014 (4)	SFV 2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.8930	6.0418	5.8953	6.0551		9.0536	9.2370	8.9457	9.1411	
3	Usage Charge	0.1129	0.1140	0.1090	0.1104		0.0089	0.0089	0.0087	0.0089	
4	Total Charge	0.3066	0.3126	0.3028	0.3094		0.3066	0.3126	0.3028	0.3094	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0076		—	—	—	0.0115	
8	Usage Charge	—	—	—	0.0001		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0004		—	—	—	0.0004	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0175		—	—	—	0.0264	
12	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0009		—	—	—	0.0009	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1643		—	—	—	0.2481	
20	Usage Charge	—	—	—	0.0029		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0083		—	—	—	0.0083	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0817	—	—	—	—	0.1233
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.8930	6.0418	5.8953	6.2445		9.0536	9.2370	8.9457	9.4270	
29	Usage Charge	0.1129	0.1140	0.1090	0.1137		0.0089	0.0089	0.0087	0.0091	
30	Total Charge	0.3066	0.3126	0.3028	0.3190		0.3066	0.3126	0.3028	0.3190	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-AFT: Annual Firm Transportation On-System

		Core Redwood Path									
Line		MFV					SFV				
No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	4.7466	4.6534	4.4923	4.4638		6.5162	6.4678	6.3001	6.3089	
3	Usage Charge	0.0684	0.0693	0.0685	0.0697		0.0102	0.0096	0.0091	0.0091	
4	Total Charge	0.2244	0.2223	0.2162	0.2165		0.2244	0.2223	0.2162	0.2165	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0214		—	—	—	0.0303	
8	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0010		—	—	—	0.0010	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0375	—	—	—	—	0.0530
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0001
17	Total Charge	—	—	—	—	0.0018	—	—	—	—	0.0018
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.2292		—	—	—	0.3239	
20	Usage Charge	—	—	—	0.0035		—	—	—	0.0003	
21	Total Charge	—	—	—	0.0110		—	—	—	0.0110	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.1139	—	—	—	—	0.1610
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0002
25	Total Charge	—	—	—	—	0.0055	—	—	—	—	0.0055
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	4.7466	4.6534	4.4923	4.7144		6.5162	6.4678	6.3001	6.6632	
29	Usage Charge	0.0684	0.0693	0.0685	0.0735		0.0102	0.0096	0.0091	0.0095	
30	Total Charge	0.2244	0.2223	0.2162	0.2285		0.2244	0.2223	0.2162	0.2285	

		Core Baja Path									
		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.2811	5.2883	5.2276	5.4020		7.2499	7.3504	7.3313	7.6350	
3	Usage Charge	0.0758	0.0784	0.0794	0.0839		0.0111	0.0106	0.0102	0.0105	
4	Total Charge	0.2494	0.2523	0.2512	0.2615		0.2494	0.2523	0.2512	0.2615	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0214		—	—	—	0.0303	
8	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0010		—	—	—	0.0010	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0375	—	—	—	—	0.0530
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0001
17	Total Charge	—	—	—	—	0.0018	—	—	—	—	0.0018
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.2292		—	—	—	0.3239	
20	Usage Charge	—	—	—	0.0035		—	—	—	0.0003	
21	Total Charge	—	—	—	0.0110		—	—	—	0.0110	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.1139	—	—	—	—	0.1610
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0002
25	Total Charge	—	—	—	—	0.0055	—	—	—	—	0.0055
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.2811	5.2883	$5.2276	$5.6526		7.2499	7.3504	$7.3313	$7.9892	
29	Usage Charge	0.0758	0.0784	$0.0794	$0.0877		0.0111	0.0106	$0.0102	$0.0109	
30	Total Charge	0.2494	0.2523	$0.2512	$0.2735		0.2494	0.2523	$0.2512	$0.2735	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-AFT: Annual Firm Transportation On-System

Line		Silverado Path									
		MFV					SFV				
No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	3.2679	3.1639	3.1425	3.1527		4.8056	4.6413	4.4150	4.4238	
3	Usage Charge	0.0554	0.0545	0.0495	0.0500		0.0049	0.0059	0.0077	0.0082	
4	Total Charge	0.1628	0.1585	0.1528	0.1536		0.1628	0.1585	0.1528	0.1536	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	----	----	----	0.0057		----	----	----	0.0083	
8	Usage Charge	----	----	----	0.0001		----	----	----	0.0000	
9	Total Charge	----	----	----	0.0003		----	----	----	0.0003	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	----	----	----	0.0130		----	----	----	0.0191	
12	Usage Charge	----	----	----	0.0002		----	----	----	0.0000	
13	Total Charge	----	----	----	0.0006		----	----	----	0.0006	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	----	----	----	----	0.0201	----				
16	Usage Charge	----	----	----	----	0.0003	----				
17	Total Charge	----	----	----	----	0.0010	----				
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	----	----	----	0.1228		----	----	----	0.1797	
20	Usage Charge	----	----	----	0.0020		----	----	----	0.0001	
21	Total Charge	----	----	----	0.0060		----	----	----	0.0060	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	----	----	----	----	0.0611	----	----	----	----	0.0893
24	Usage Charge	----	----	----	----	0.0010	----	----	----	----	0.0001
25	Total Charge	----	----	----	----	0.0030	----	----	----	----	0.0030
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	3.2679	3.1639	3.1425	3.2942		4.8056	4.6413	4.4150	4.6309	
29	Usage Charge	0.0554	0.0545	0.0495	0.0523		0.0049	0.0059	0.0077	0.0083	
30	Total Charge	0.1628	0.1585	0.1528	0.1606		0.1628	0.1585	0.1528	0.1606	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-SFT: Seasonal Firm Transportation On-System Only

Noncore Redwood Path

Line		MFV					SFV				
No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	6.4905	6.5491	6.2501	6.2012		9.9714	10.0125	9.4840	9.3616	
3	Usage Charge	0.1245	0.1238	0.1159	0.1134		0.0101	0.0100	0.0095	0.0095	
4	Total Charge	0.3379	0.3392	0.3213	0.3173		0.3379	0.3392	0.3213	0.3173	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0091		—	—	—	0.0138	
8	Usage Charge	—	—	—	0.0002		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0005		—	—	—	0.0005	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0209		—	—	—	0.0316	
12	Usage Charge	—	—	—	0.0004		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0011		—	—	—	0.0011	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0322	—	—	—	—	0.0487
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0016	—	—	—	—	0.0016
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1972		—	—	—	0.2977	
20	Usage Charge	—	—	—	0.0035		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0100		—	—	—	0.0100	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0980	—	—	—	—	0.1480
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0050	—	—	—	—	0.0050
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	6.4905	6.5491	6.2501	6.4284		9.9714	10.0125	9.4840	9.7047	
29	Usage Charge	0.1245	0.1238	0.1159	0.1175		0.0101	0.0100	0.0095	0.0098	
30	Total Charge	0.3379	0.3392	0.3213	0.3288		0.3379	0.3392	0.3213	0.3288	

Noncore Baja Path

Line		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	7.0717	7.2502	7.0744	7.2661		10.8643	11.0843	10.7348	10.9693	
3	Usage Charge	0.1354	0.1368	0.1308	0.1324		0.0107	0.0107	0.0104	0.0107	
4	Total Charge	0.3679	0.3752	0.3633	0.3713		0.3679	0.3752	0.3633	0.3713	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0091		—	—	—	0.0138	
8	Usage Charge	—	—	—	0.0002		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0005		—	—	—	0.0005	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0209		—	—	—	0.0316	
12	Usage Charge	—	—	—	0.0004		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0011		—	—	—	0.0011	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0322	—	—	—	—	0.0487
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0016	—	—	—	—	0.0016
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1972		—	—	—	0.2977	
20	Usage Charge	—	—	—	0.0035		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0100		—	—	—	0.0100	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0980	—	—	—	—	0.1480
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0050	—	—	—	—	0.0050
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	7.0717	7.2502	7.0744	7.4934		10.8643	11.0843	10.7348	11.3124	
29	Usage Charge	0.1354	0.1368	0.1308	0.1365		0.0107	0.0107	0.0104	0.0109	
30	Total Charge	0.3679	0.3752	0.3633	0.3828		0.3679	0.3752	0.3633	0.3828	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

A.09-09-013

Gas Accord V Settlement Agreement

Appendix A

Rates Effective April 1, 2013

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)

G-SFT: Seasonal Firm Transportation On-System Only

Core Baja Path

		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	6.3373	6.3460	6.2731	6.4824		8.6999	8.8204	8.7976	9.1620	
3	Usage Charge	0.0910	0.0941	0.0952	0.1007		0.0133	0.0127	0.0122	0.0126	
4	Total Charge	0.2993	0.3027	0.3015	0.3138		0.2993	0.3027	0.3015	0.3138	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0257		—	—	—	0.0364	
8	Usage Charge	—	—	—	0.0004		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0012		—	—	—	0.0012	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0450	—	—	—	—	0.0636
16	Usage Charge	—	—	—	—	0.0007	—	—	—	—	0.0001
17	Total Charge	—	—	—	—	0.0022	—	—	—	—	0.0022
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.2750		—	—	—	0.3887	
20	Usage Charge	—	—	—	0.0041		—	—	—	0.0004	
21	Total Charge	—	—	—	0.0132		—	—	—	0.0132	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.1367	—	—	—	—	0.1932
24	Usage Charge	—	—	—	—	0.0021	—	—	—	—	0.0002
25	Total Charge	—	—	—	—	0.0066	—	—	—	—	0.0066
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	6.3373	6.3460	6.2731	6.7832		8.6999	8.8204	8.7976	9.5870	
29	Usage Charge	0.0910	0.0941	0.0952	0.1052		0.0133	0.0127	0.0122	0.0130	
30	Total Charge	0.2993	0.3027	0.3015	0.3282		0.2993	0.3027	0.3015	0.3282	

Silverado Path

		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	3.9215	3.7987	3.7710	3.7832		5.7667	5.5695	5.2980	5.3085	
3	Usage Charge	0.0665	0.0654	0.0594	0.0600		0.0058	0.0071	0.0092	0.0098	
4	Total Charge	0.1954	0.1902	0.1834	0.1844		0.1954	0.1902	0.1834	0.1844	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0068		—	—	—	0.0100	
8	Usage Charge	—	—	—	0.0001		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0003		—	—	—	0.0003	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0157		—	—	—	0.0229	
12	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0008		—	—	—	0.0008	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0241	—	—	—	—	0.0353
16	Usage Charge	—	—	—	—	0.0004	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0012	—	—	—	—	0.0012
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1474		—	—	—	0.2157	
20	Usage Charge	—	—	—	0.0024		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0072		—	—	—	0.0072	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0733	—	—	—	—	0.1072
24	Usage Charge	—	—	—	—	0.0012	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0036	—	—	—	—	0.0036
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	3.9215	3.7987	3.7710	3.9531		5.7667	5.5695	5.2980	5.5571	
29	Usage Charge	0.0665	0.0654	0.0594	0.0628		0.0058	0.0071	0.0092	0.0100	
30	Total Charge	0.1954	0.1902	0.1834	0.1927		0.1954	0.1902	0.1834	0.1927	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

A.09-09-013

Gas Accord V Settlement Agreement

Appendix A

Rates Effective April 1, 2013

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-AA: As Available Transportation On-System

		Redwood Path				
Line No.		2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Usage Charge ($/Dth)**	0.3379	0.3392	0.3213	0.3173	
2	**Adder Rates**					
3	Delevan K3/Gerber - L400	----	----	----	0.0005	—
4	Delevan K3/Gerber - L401	----	—	----	0.0011	—
5	P03107 Topock, P-Units Replacement	—	—	----	----	0.0016
6	P02158-Topock K-Units Replacement-Ph 1	----	----	----	0.0100	—
7	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
8	**Total Base Usage Charge Plus Adders (1)**	0.3379	0.3392	0.3213	0.3288	

		Baja Path				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
9	**Base Usage Charge ($/Dth)**	0.3679	0.3752	0.3633	0.3713	
10	**Adder Rates**					
11	Delevan K3/Gerber - L400	----	----	----	0.0005	
12	Delevan K3/Gerber - L401	----	----	----	0.0011	
13	P03107 Topock, P-Units Replacement	—	----	----	----	0.0016
14	P02158-Topock K-Units Replacement-Ph 1	----	----	----	0.0100	
15	P02158-Topock K-Units Replacement-Ph 2	----	----	—	----	0.0050
16	**Total Base Usage Charge Plus Adders (1)**	0.3679	0.3752	0.3633	0.3828	

		Silverado Path				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
17	**Base Usage Charge ($/Dth)**	0.1954	0.1902	0.1834	0.1844	
18	**Adder Rates**					
19	Delevan K3/Gerber - L400	----	----	----	0.0003	
20	Delevan K3/Gerber - L401	----	----	—	0.0008	
21	P03107 Topock, P-Units Replacement	----	----	----	----	0.0012
22	P02158-Topock K-Units Replacement-Ph 1	----	----	----	0.0072	
23	P02158-Topock K-Units Replacement-Ph 2	----	----	—	----	0.0036
24	**Total Base Usage Charge Plus Adders (1)**	0.1954	0.1902	0.1834	0.1927	

		Mission Path				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
25	**Usage Charge ($/Dth)**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Gas Accord V Settlement Agreement
Appendix A
Rates Effective April 1, 2013

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-AAOFF: As Available Transportation Off-System

		Redwood, Silverado and Mission (From City Gate) Off-System - Noncore				
Line No.		2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Usage Charge ($/Dth)**	0.3379	0.3392	0.3213	0.3173	
2	**Adder Rates**					
3	Delevan K3/Gerber - L400	----	----	----	0.0005	
4	Delevan K3/Gerber - L401	----	----	----	0.0011	
5	P03107 Topock, P-Units Replacement	----	----	----	----	0.0016
6	P02158-Topock K-Units Replacement-Ph 1	----	----	----	0.0100	
7	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
8	**Total Base Usage Charge Plus Adders (1)**	0.3379	0.3392	0.3213	0.3288	

		Mission Path (From On-System Storage) Off-System				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
9	**Usage Charge ($/Dth)**	0.0000	0.0000	0.0000	0.0000	

		Baja Path Off-System - Noncore				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
10	**Base Usage Charge ($/Dth)**	0.3679	0.3752	0.3633	0.3713	
11	**Adder Rates**					
12	Delevan K3/Gerber - L400	----	----	----	0.0005	
13	Delevan K3/Gerber - L401	----	----	----	0.0011	
14	P03107 Topock, P-Units Replacement	----	----	----	----	0.0016
15	P02158-Topock K-Units Replacement-Ph 1	----	----	----	0.0100	
16	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
17	**Total Base Usage Charge Plus Adders (1)**	0.3679	0.3752	0.3633	0.3828	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Gas Accord V Settlement Agreement

Appendix A

Rates Effective April 1, 2013

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2013)
G-AFTOFF: Annual Firm Transportation Off-System

Line No.		Redwood, Silverado and Mission Paths Off-System: MFV 2011 (2)	MFV 2012	MFV 2013 (3)	MFV 2014 (4)	MFV 2015	SFV 2011 (2)	SFV 2012	SFV 2013 (3)	SFV 2014 (4)	SFV 2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.4087	5.4576	5.2084	5.1676		8.3095	8.3437	7.9034	7.8013	
3	Usage Charge	0.1038	0.1032	0.0965	0.0945		0.0084	0.0083	0.0079	0.0079	
4	Total Charge	0.2816	0.2826	0.2678	0.2644		0.2816	0.2826	0.2678	0.2644	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0076		—	—	—	0.0115	
8	Usage Charge	—	—	—	0.0001		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0004		—	—	—	0.0004	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0175		—	—	—	0.0264	
12	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0009		—	—	—	0.0009	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1643		—	—	—	0.2481	
20	Usage Charge	—	—	—	0.0029		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0083		—	—	—	0.0083	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0817	—	—	—	—	0.1233
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.4087	5.4576	5.2084	5.3570		8.3095	8.3437	7.9034	8.0872	
29	Usage Charge	0.1038	0.1032	0.0965	0.0979		0.0084	0.0083	0.0079	0.0082	
30	Total Charge	0.2816	0.2826	0.2678	0.2740		0.2816	0.2826	0.2678	0.2740	

Line No.		Baja Path Off-System: MFV 2011 (2)	MFV 2012	MFV 2013 (3)	MFV 2014 (4)	MFV 2015	SFV 2011 (2)	SFV 2012	SFV 2013 (3)	SFV 2014 (4)	SFV 2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.8930	6.0418	5.8953	6.0551		9.0536	9.2370	8.9457	9.1411	
3	Usage Charge	0.1129	0.1140	0.1090	0.1104		0.0089	0.0089	0.0087	0.0089	
4	Total Charge	0.3066	0.3126	0.3028	0.3094		0.3066	0.3126	0.3028	0.3094	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	0.0076		—	—	—	0.0115	
8	Usage Charge	—	—	—	0.0001		—	—	—	0.0000	
9	Total Charge	—	—	—	0.0004		—	—	—	0.0004	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	0.0175		—	—	—	0.0264	
12	Usage Charge	—	—	—	0.0003		—	—	—	0.0000	
13	Total Charge	—	—	—	0.0009		—	—	—	0.0009	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	0.1643		—	—	—	0.2481	
20	Usage Charge	—	—	—	0.0029		—	—	—	0.0002	
21	Total Charge	—	—	—	0.0083		—	—	—	0.0083	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0817	—	—	—	—	0.1233
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.8930	6.0418	5.8953	6.2445		9.0536	9.2370	8.9457	9.4270	
29	Usage Charge	0.1129	0.1140	0.1090	0.1137		0.0089	0.0089	0.0087	0.0091	
30	Total Charge	0.3066	0.3126	0.3028	0.3190		0.3066	0.3126	0.3028	0.3190	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Appendix A

Rates Effective April 1, 2013

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

G-XF: Pipeline Expansion Firm Intrastate Transportation Service

		Expansion Shippers (G-XF)			
		SFV			
Line No.		2011 (2)	2012	2013 (3)	2014 (4)
1	**Base Rates ($/Dth)**				
2	Reservation Charge	6.1394	6.2159	5.7146	5.5594
3	Usage Charge	0.0013	0.0015	0.0031	0.0035
4	Total Charge	0.2032	0.2059	0.1910	0.1863
5	**Adder Rates**				
6	Delevan K3/Gerber - L401				
7	Reservation Charge	----	----	----	0.0415
8	Usage Charge	----	----	----	0.0000
9	Total Charge	----	----	----	0.0014
10	**Total Base Rates Plus Adders (1)**				
11	Reservation Charge	6.1394	6.2159	5.7146	5.6008
12	Usage Charge	0.0013	0.0015	0.0031	0.0035
13	Total Charge	0.2032	0.2059	0.1910	0.1877

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Appendix A
(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-5
On-System Demand Forecast (Mdth/d)

Line No.	Service	2011	2012	2013	2014
1	Core	800	802	799	797
2	Industrial and Noncore NGV	468	473	472	472
3	Cogeneration	198	198	198	198
4	Power Plants and Miscellaneous EG				
5	Backbone Level Service	333	371	367	387
6	Local Transmission Level Service	188	231	259	251
7	Subtotal Power Plants and Miscellaneous EG	520	602	626	638
8	Wholesale	10	10	10	10
9	Total	1,996	2,085	2,106	2,115

Gas Accord V Settlement Agreement

Appendix A
(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-6
Billing Units for Cost Allocation

Line No.	Service	Annual Injection Storage Units	Inventory	Annual Withdrawal Storage Units
1	Core Firm Storage	41,074.4	33,477.7	178,601.0
2	Monthly Balancing Service	27,785.6	4,100.0	27,785.6
3	Market Storage (Traditional)	53,454.3	9,000.0	64,766.7
4	Market Storage (Gill Ranch)	17,180.6	3,150.0	22,668.3

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Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-7

Local Transmission Bill Credits and Funding Mechanism for Bill Credit Recovery

Line No.		GA IV 2010	2011	2012	2013	2014
1	Moss Landing Units 1 & 2 Local Transmission Bill Credit					
2	Annual, $000	$2,164	$2,500	$2,550	$2,601	$2,653
3	Monthly, $	$180,336	$208,333	$212,500	$216,750	$221,085
4	City of Redding Local Transmission Bill Credit					
5	Annual, $000	$52	$65	$66	$68	$69
6	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
7	Modesto Irrigation District Local Transmission Bill Credit					
8	Annual, $000	$52	$65	$66	$68	$69
9	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
10	Turlock Irrigation District Local Transmission Bill Credit					
11	Annual, $000	$52	$65	$66	$68	$69
12	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
13	City of Santa Clara (Silicon Valley Power) Local Transmission Bill Credit					
14	Annual, $000	$52	$65	$66	$68	$69
15	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
16	Total NCGC Local Transmission Billing Credit					
17	Annual, $000	$208	$260	$265	$271	$276
18	**Total Local Transmission Billling Credit**					
	Annual, $000	$2,372	$2,760	$2,815	$2,872	$2,929
19	Revenue Recovered Through Backbone Rates, $000					
20	Responsibility for Moss Landing 1&2, $000	$1,623	$1,800	$1,836	$1,873	$1,910
21	Backbone Annual AFT Surcharge Rate, $ per Dth	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
22	Backbone Seasonal SFT & As-Available AA Surcharge Rate, $ per Dth	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029
23	Revenue Recovered Through Backbone-Level End-Use G-NT and G-EG Rates, $000					
24	Responsibility for Moss Landing 1&2, $000	$541	$600	$612	$624	$637
25	Responsibility for NCGC, $000	$104	$130	$133	$135	$138
26	Total Revenue Responsibility	$645	$730	$745	$759	$775
27	Surcharge Rate, $ per Dth	$0.0053	$0.0065	$0.0067	$0.0068	$0.0069
28	Surcharge Rate, $ per Therm	$0.00053	$0.00065	$0.00067	$0.00068	$0.00069
29	**Total Revenue Responsibilty From Surcharges (a)**					
30	Annual, $000	$2,268	$2,530	$2,581	$2,632	$2,685
31	PG&E Shareholder Revenue Responsibility					
32	Moss Landing 1&2	$0	$100	$102	$104	$106
33	NCGC	$104	$130	$133	$135	$138
34	Total Shareholder Revenue Responsibility	$104	$230	$235	$239	$244

(a) PG&E is at risk for collecting the difference between the non-shareholder funded portion of the bill credit and the total revenue responsibility used to calculate the surcharge rates.

Gas Accord V Settlement Agreement

Appendix B

Rates Effective April 1, 2013

Table B-3

Firm Backbone Transportation
Annual Rates (AFT) -- SFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2013)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path - Core (1)						
Reservation Charge	($/dth/mo)	4.3368	6.5162	6.4678	6.3001	6.6632
Usage Charge	($/dth)	0.0124	0.0102	0.0096	0.0091	0.0095
Total	($/dth @ Full Contract)	0.1550	0.2244	0.2223	0.2162	0.2285
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	9.2319	7.2499	7.3504	7.3313	7.9892
Usage Charge	($/dth)	0.0153	0.0111	0.0106	0.0102	0.0109
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2512	0.2735
Redwood Path - Noncore						
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.9034	8.0872
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0082
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2740
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.9457	9.4270
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0087	0.0091
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3190
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	4.4828	4.8056	4.6413	4.4150	4.6309
Usage Charge	($/dth)	0.0060	0.0049	0.0059	0.0077	0.0083
Total	($/dth @ Full Contract)	0.1534	0.1628	0.1585	0.1528	0.1606

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Gas Accord V Settlement Agreement

Appendix B

Rates Effective April 1, 2013

Table B-4

Firm Backbone Transportation
Annual Rates (AFT) -- MFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2013)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path - Core (1)						
Reservation Charge	($/dth/mo)	3.3290	4.7466	4.6534	4.4923	4.7144
Usage Charge	($/dth)	0.0455	0.0684	0.0693	0.0685	0.0735
Total	($/dth @ Full Contract)	0.1549	0.2244	0.2223	0.2162	0.2285
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	7.0037	5.2811	5.2883	5.2276	5.6526
Usage Charge	($/dth)	0.0885	0.0758	0.0784	0.0794	0.0877
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2512	0.2735
Redwood Path - Noncore						
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.2084	5.3570
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0965	0.0979
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2740
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8953	6.2445
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1090	0.1137
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3190
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	3.0839	3.2679	3.1639	3.1425	3.2942
Usage Charge	($/dth)	0.0518	0.0554	0.0545	0.0495	0.0523
Total	($/dth @ Full Contract)	0.1532	0.1628	0.1585	0.1528	0.1606

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Appendix B

Rates Effective April 1, 2013

Table B-5

Firm Backbone Transportation
Seasonal Rates (SFT) -- SFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2013)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path						
Reservation Charge	($/dth/mo)	10.4795	9.9714	10.0125	9.4840	9.7047
Usage Charge	($/dth)	0.0082	0.0101	0.0100	0.0095	0.0098
Total	($/dth @ Full Contract)	0.3527	0.3379	0.3392	0.3213	0.3288
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	11.0784	8.6999	8.8204	8.7976	9.5870
Usage Charge	($/dth)	0.0183	0.0133	0.0127	0.0122	0.0130
Total	($/dth @ Full Contract)	0.3825	0.2993	0.3027	0.3015	0.3282
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	11.0784	10.8643	11.0843	10.7348	11.3124
Usage Charge	($/dth)	0.0183	0.0107	0.0107	0.0104	0.0109
Total	($/dth @ Full Contract)	0.3825	0.3679	0.3752	0.3633	0.3828
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	5.3794	5.7667	5.5695	5.2980	5.5571
Usage Charge	($/dth)	0.0071	0.0058	0.0071	0.0092	0.0100
Total	($/dth @ Full Contract)	0.1840	0.1954	0.1902	0.1834	0.1927

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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 any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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 include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

g) Dollar difference are due to rounding.

Appendix B

Rates Effective April 1, 2013

Table B-6

Firm Backbone Transportation
Seasonal Rates (SFT) -- MFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2013)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path						
Reservation Charge	($/dth/mo)	6.0840	6.4905	6.5491	6.2501	6.4284
Usage Charge	($/dth)	0.1528	0.1245	0.1238	0.1159	0.1175
Total	($/dth @ Full Contract)	0.3528	0.3379	0.3392	0.3213	0.3288
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	8.4044	6.3373	6.3460	6.2731	6.7832
Usage Charge	($/dth)	0.1063	0.0910	0.0941	0.0952	0.1052
Total	($/dth @ Full Contract)	0.3826	0.2993	0.3027	0.3015	0.3282
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	8.4044	7.0717	7.2502	7.0744	7.4934
Usage Charge	($/dth)	0.1063	0.1354	0.1368	0.1308	0.1365
Total	($/dth @ Full Contract)	0.3826	0.3679	0.3752	0.3633	0.3828
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	3.7008	3.9215	3.7967	3.7710	3.9531
Usage Charge	($/dth)	0.0622	0.0665	0.0654	0.0594	0.0628
Total	($/dth @ Full Contract)	0.1839	0.1954	0.1902	0.1834	0.1927

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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 any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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 include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

g) Dollar difference are due to rounding.

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Appendix B

Rates Effective April 1, 2013

Table B-7

As-Available Backbone Transportation
On-System Transportation Service
(Topock Adder Projects In-Service 2013)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		2010	GA IV	2011 (1)	2012	2013 (2)	2014 (3)
Redwood Path							
Usage Charge	($/dth)	0.3528		0.3379	0.3392	0.3213	0.3288
Baja Path							
Usage Charge	($/dth)	0.3826		0.3679	0.3752	0.3633	0.3828
Silverado Path							
Usage Charge	($/dth)	0.1839		0.1954	0.1902	0.1834	0.1927
Mission Path							
Usage Charge	($/dth)	0.0000		0.0000	0.0000	0.0000	0.0000

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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 any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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 include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Gas Accord V Settlement Agreement

Appendix B

Rates Effective April 1, 2013

Table B-8

Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries
(Topock Adder Projects In-Service 2013)

G-AFT: Annual Firm Transportation On-System

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
SFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.9034	8.0872
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0082
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2740
Baja Path Off-System						
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.9457	9.4270
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0087	0.0091
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3190
MFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.2084	5.3570
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0965	0.0979
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2740
Baja Path Off-System						
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8953	6.2445
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1090	0.1137
Total	($/dth @ Full	0.3188	0.3066	0.3126	0.3028	0.3190
As-Available Service						
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore						
Usage Charge	($/dth)	0.3528	0.3379	0.3392	0.3213	0.3288
Mission Paths (From on-system storage) Off-System						
Usage Charge	($/dth)	0.0000	0.0000	0.0000	0.0000	0.0000
Baja Path Off-System - Noncore						
Usage Charge	($/dth)	0.3826	0.3679	0.3752	0.3633	0.3828

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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) California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Appendix B

Rates Effective April 1, 2013

Table B-9

Firm Transportation
Expansion Shippers -- Annual Rates (G-XF)
SFV Rate Design

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
SFV Rate Design						
Reservation Charge	($/dth/mo)	6.3182	6.1394	6.2159	5.7146	5.6008
Usage Charge	($/dth)	0.0019	0.0013	0.0015	0.0031	0.0035
Total	($/dth @ Full Contract)	0.2096	0.2032	0.2059	0.1910	0.1877

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other 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 include the Delevan/Gerber L-401 backbone adder project. Base G-XF backbone transmission rates and individual adder project rates are shown in Appendix A, Table A-4.

e) Dollar difference are due to rounding.

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Appendix B

Rates Effective April 1, 2013

Table B-10

Storage Services

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
Core Firm Storage (G-CFS)						
Reservation Charge	($/dth/mo)	0.1092	0.1293	0.1248	0.1232	0.1260
Standard Firm Storage (G-SFS)						
Reservation Charge	($/dth/mo)	0.1350	0.3008	0.2451	0.2374	0.2399
Negotiated Firm Storage (G-NFS)						
Injection	($/dth/d)	15.6336	6.1656	6.1542	5.9623	6.0252
Inventory	($/dth)	1.6205	2.9461	2.9407	2.8489	2.8790
Withdrawal	($/dth/d)	11.7865	21.3468	21.3075	20.6428	20.8607
Negotiated As-Available Storage (G-NAS) - Maximum Rate						
Injection	($/dth/d)	15.6336	6.1656	6.1542	5.9623	6.0252
Withdrawal	($/dth/d)	11.7865	21.3468	21.3075	20.6428	20.8607
Market Center Services (Parking and Lending Services)						
Maximum Daily Charge ($/Dth/d)		0.9702	1.1053	1.1136	1.0821	1.0986
Minimum Rate (per transaction)		$ 57.00	57.00	57.00	57.00	57.00

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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) Dollar difference are due to rounding.

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Appendix B

Rates Effective April 1, 2013

Table B-11

Local Transmission Rates
($/dth)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010 (1)	2011 (2)	2012	2013 (3)	2014 (4)
Base Rates:						
Core Retail		0.3764	0.4118	0.4182	0.4074	0.4173
Noncore Retail and Wholesale		0.1628	0.2031	0.1933	0.1912	0.2043
Rate Adders:						
Core						
	L-304		0.0000	0.0013	0.0012	0.0012
	L-406	0.0115	0.0248	0.0185	0.0166	0.0160
	L-407 Phase 1		0.0000	0.0000	0.0151	0.0144
	L-407 Phase 2		0.0000	0.0000	0.0000	0.0142
	Total	0.0115	0.0248	0.0198	0.0330	0.0458
Noncore Retail & Wholesale						
	L-304		0.0000	0.0006	0.0006	0.0006
	L-406	0.0050	0.0108	0.0085	0.0078	0.0078
	L-407 Phase 1		0.0000	0.0000	0.0071	0.0071
	L-407 Phase 2		0.0000	0.0000	0.0000	0.0070
	Total	0.0050	0.0108	0.0091	0.0155	0.0224
Total Base plus Adder:						
Core Retail		0.3879	0.4367	0.4380	0.4404	0.4631
Noncore Retail and Wholesale		0.1678	0.2139	0.2024	0.2066	0.2267

(1) The 2010 Local Transmission rates was escalated 2 percent and also includes the 2011 L-406 adder rate adopted in Gas Accord IV.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) The Gas Accord IV adopted 2010 local transmission rate includes a base rate component plus a rate adder for 2 of 5 of the specific local transmission capital projects designated in Section 8.4 of the Gas Accord IV Settlement Agreement. (Core rate adder: Line 138 adder of $0.0173 per Dth + Line 108 adder of $0.0152 per Dth = $0.0325 per Dth) (Noncore rate adder: Line 138 adder of $0.0075 per Dth + Line 108 adder of $0.0066 per Dth = $0.0141 per Dth)

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Appendix B

Rates Effective April 1, 2013

Table B-12

Customer Access Charges
($ per Month)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
G-EG / G-NT ($/month)						
Transmission and Distribution						
	(Therms/Month)					
Tier 1	0 to 5,000	$61.85	$54.34	$58.41	$58.88	$60.90
Tier 2	5,001 to 10,000	$184.23	$161.87	$174.00	$175.40	$181.41
Tier 3	10,001 to 50,000	$342.89	$301.27	$323.85	$326.46	$337.64
Tier 4	50,001 to 200,000	$450.01	$395.39	$425.02	$428.44	$443.12
Tier 5	200,001 to 1,000,000	$652.92	$573.67	$616.67	$621.63	$642.93
Tier 6	1,000,001 and above	$5,538.45	$4,866.21	$5,230.96	$5,273.02	$5,453.67
Wholesale ($/month)						
Alpine		$333.28	$286.66	$310.56	$313.06	$323.79
Coalinga		$1,474.03	$1,267.85	$1,373.51	$1,384.55	$1,431.99
Island Energy		$998.71	$859.01	$930.61	$938.09	$970.23
Palo Alto		$4,914.73	$4,227.28	$4,579.59	$4,616.40	$4,774.56
West Coast Gas - Castle		$856.26	$736.49	$797.87	$804.28	$831.84
West Coast Gas - Mather		$782.50	$673.05	$729.14	$735.00	$760.18

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) The 2011-2014 CAC revenue requirements are established in this GT&S Rate Case proceeding. The rate design for the customer access charge may be addressed in PG&E's Biennial Cost Allocation Proceedings (BCAP).

Gas Accord V Settlement Agreement

Appendix B

Rates Effective April 1, 2013

Table B-13

Self Balancing Credit
$/dth

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

	GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
Self Balancing Credit	($0.0096)	($0.0130)	($0.0131)	($0.0129)	($0.0132)

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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.

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
30373-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 12	30241-G
30374-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 13	30242-G
30375-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 14	30243-G
30376-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 15	30244-G
30377-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 16	30245-G
30378-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 17	30246-G
30379-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 18	30247-G
30380-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 19	30248-G
30381-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 20	30249-G
30382-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 2	30250-G
30383-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 3	30251-G

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
30384-G	GAS PRELIMINARY STATEMENT PART CM GAS OPERATIONAL COST BALANCING ACCOUNT Sheet 1	28892-G
30385-G	GAS PRELIMINARY STATEMENT PART CM GAS OPERATIONAL COST BALANCING ACCOUNT Sheet 2	
30386-G	GAS SCHEDULE G-AA AS AVAILABLE TRANSPORTATION ON-SYSTEM Sheet 2	30173-G
30387-G	GAS SCHEDULE G-AAOFF AS-AVAILABLE TRANSPORTATION OFF-SYSTEM Sheet 2	30174-G
30388-G	GAS SCHEDULE G-AFT ANNUAL FIRM TRANSPORTATION ON-SYSTEM Sheet 2	30175-G
30389-G	GAS SCHEDULE G-AFTOFF ANNUAL FIRM TRANSPORTATION OFF-SYSTEM Sheet 2	30176-G
30390-G	GAS SCHEDULE G-EG GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION Sheet 1	30337-G
30391-G	GAS SCHEDULE G-LNG EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE Sheet 1	30253-G
30392-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 2	30254-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
30393-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 2	30338-G
30394-G	GAS SCHEDULE G-SFT SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY Sheet 2	30190-G
30395-G	GAS SCHEDULE G-WSL GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS Sheet 1	30256-G
30396-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 2	30193-G
30397-G	GAS TABLE OF CONTENTS Sheet 1	30369-G
30398-G	GAS TABLE OF CONTENTS Sheet 2	30370-G
30399-G	GAS TABLE OF CONTENTS Sheet 3	30371-G
30400-G	GAS TABLE OF CONTENTS Sheet 4	30372-G

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 12

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

	G-NT TRANSMISSION		G-NT—DISTRIBUTION SUMMER							
THERMS:			0-20,833		20,834-49,999		50,000-166,666		166,667-249,999***	
NCA – NONCORE	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	-$0.00015		-$0.00246		-$0.00246		-$0.00246		-$0.00246	
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157		$0.00157		$0.00157		$0.00157		$0.00157	
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00642		$0.13816		$0.08809		$0.07786		$0.06986	
NCA - ARB AB32 COI	$0.00309		$0.00309		$0.00309		$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	**0.05087**	(R)	**0.18039**	(R)	**0.13032**	(R)	**0.12009**	(R)	**0.11209**	(R)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts Expense (F&U)

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

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 13

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

	G-NT BACKBONE		G-NT—DISTRIBUTION WINTER							
THERMS:			0-20,833		20,834-49,999		50,000-166,666		166,667-249,999***	
NCA – NONCORE	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000		-$0.00246		-$0.00246		-$0.00246		-$0.00246	
CPUC FEE	0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		$0.00157		$0.00157		$0.00157		$0.00157	
CEE INCENTIVE	0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	0.00068		$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000		$0.18650	(R)	$0.11891		$0.10510		$0.09430	
NCA - ARB AB32 COI	0.00309		$0.00309		$0.00309		$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	0.00000		$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN - BB	0.00274		$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN - Storage	0.00014		$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	**0.01592**	(R)	**0.22873**	(R)	**0.16114**	(R)	**0.14733**	(R)	**0.13653**	(R)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts Expense (F&U)

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

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

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

NONCORE p. 3

	G-EG (3)**		G-EG BACKBONE	
NCA – NONCORE	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	-$0.00005		-$0.00005	
CPUC FEE	$0.00003		$0.00003	
CSI- SOLAR THERMAL PROGRAM	$0.00000		$0.00000	
CEE INCENTIVE	$0.00000		$0.00000	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	$0.01990	(I)	$0.00068	
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00202		$0.00202	
NCA - ARB AB32 COI	$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00000	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN - Storage	$0.00014		$0.00014	
TOTAL RATE	**0.04434**	(R)	**0.01566**	(R)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts Expense (F&U)

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 15

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

NONCORE p. 4

	G-WSL							
	Palo Alto-T		Coalinga-T		Island Energy-T		Alpine-T	
NCA – NONCORE	$0.00620	(R)	$0.00620	(R)	$0.00620	(R)	$0.00620	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		$0.00000		$0.00000		$0.00000	
CPUC FEE**	$0.00000		$0.00000		$0.00000		$0.00000	
CSI- SOLAR THERMAL PROGRAM	$0.00000		$0.00000		$0.00000		$0.00000	
CEE INCENTIVE	$0.00000		$0.00000		$0.00000		$0.00000	
LOCAL TRANSMISSION (AT RISK)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.00000		$0.00000		$0.00000	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	**0.03844**	(R)	**0.03844**	(R)	**0.03844**	(R)	**0.03844**	(R)

* All tariff rate components on this sheet include an allowance for Franchise Fees only.

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 16

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

	G-WSL					
	West Coast Mather-T		West Coast Mather-D		West Coast Castle-D	
NCA – NONCORE	$0.00620	(R)	$0.00620	(R)	$0.00620	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00198		-$0.00238	
CPUC FEE**	$0.00000		$0.00000		$0.00000	
CSI- SOLAR THERMAL PROGRAM	$0.00000		$0.00000		$0.00000	
CEE INCENTIVE	$0.00000		$0.00000		$0.00000	
LOCAL TRANSMISSION (AT RISK)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.13596		$0.10356	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014	
TOTAL RATE	**0.03844**	(R)	**0.17242**	(R)	**0.13962**	(R)

* All tariff rate components on this sheet include an allowance for Franchise Fees only.

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 17

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

NONCORE p. 6

	G-NGV4 TRANSMISSION		G-NGV4—DISTRIBUTION SUMMER							
THERMS:			0- 20,833		20,834- 49,999		50,000- 166,666		166,667- 249,999	
NCA – NONCORE	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246		-$0.00246		-$0.00246		-$0.00246	
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157		$0.00157		$0.00157		$0.00157		$0.00157	
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.13816		$0.08809		$0.07786		$0.06986	
NCA - ARB AB32 COI	$0.00309		$0.00309		$0.00309		$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	**0.04460**	(R)	**0.18039**	(R)	**0.13032**	(R)	**0.12009**	(R)	**0.11209**	(R)

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* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts.

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

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

	G-NGV4 BACKBONE		G—NGV4-DISTRIBUTION WINTER							
THERMS:			0-20,833		20,834-49,999		50,000-166,666		166,667-249,999	
NCA – NONCORE	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246		-$0.00246		-$0.00246		-$0.00246	
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157		$0.00157		$0.00157		$0.00157		$0.00157	
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.00068		$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.18650	(R)	$0.11891		$0.10510		$0.09430	
NCA - ARB AB32 COI	$0.00309		$0.00309		$0.00309		$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00000		$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	**0.01592**	(R)	**0.22873**	(R)	**0.16114**	(R)	**0.14733**	(R)	**0.13653**	(R)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts.

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

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

	G-LNG (1)*	
NCA – NONCORE	$0.00000	
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000	
CPUC Fee	$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00000	
CEE	$0.00000	
LNGV BALANCING ACCOUNT	$0.18238	(R)
LOCAL TRANSMISSION (AT RISK)	$0.00000	
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000	
NONCORE IMPLEMENTATION PLAN – LT	$0.00000	
NONCORE IMPLEMENTATION PLAN – BB	$0.00000	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00000	
TOTAL RATE	**0.18307**	**(R)**

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts.

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

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

MAINLINE EXTENSION RATES (1)

Core Schedules (2)	Mainline Extension Rate (Per Therm) (T)		Core Customer Charges (3) ADU (therms) (4)	Per Day
Schedule G-NR1	$0.23518	(R)	0 – 5.0	$0.27048
			5.1 to 16.0	$0.52106
			16.1 to 41.0	$0.95482
			41.1 to 123.0	$1.66489
			123.1 & Up	$2.14936
Schedule G-NR2	$0.09911		All Usage Levels	$4.95518
Schedule G-NGV1	$0.06389		All Usage Levels	$0.44121
Schedule G-NGV2	N/A		All Usage Levels	N/A

Noncore Schedules	Mainline Extension Rate (Per Therm) (T)	Noncore Customer Access Charges (5) Average Monthly Use (Therms)	Per Day
Schedule G-NT			
Distribution	$0.09911	0 to 5,000	$1.93578
Local Transmission	$0.00641	5,001 to 10,000	$5.76658
Backbone	$0.00000	10,001 to 50,000	$10.73293
		50,001 to 200,000	$14.08570
Schedule G-EG		200,001 to 1,000,000	$20.43715
Distribution	$0.00201	1,000,001 and above	$173.35956
Local Transmission	$0.00201		
Backbone	$0.00201		
Schedule G-NGV4			
Distribution	$0.09911		
Local Transmission	$0.00000		
Backbone	$0.00000		

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

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

(3) The Core Customer Charge is in addition to the core Mainline Extension Rates specified above.

(4) The applicable Schedule G-NR1 Customer Charge is based on the customer's highest Average Daily Usage (ADU) determined from among the billing periods occurring within the last twelve (12) months, including the current billing period. PG&E calculates the ADU for each billing period by dividing the total usage by the number of days in the billing period.

(5) The Noncore Customer Access Charge is in addition to the noncore Mainline Extension Rates specified above.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

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

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

	Amount ($000)				
Description	Core	Noncore	Unbundled	Core Procurement	Total
BASE REVENUES (incl. F&U) :					
Authorized GRC Distribution Base Revenue (1)					1,195,641
Pension (2)					52,691
Less: Other Operating Revenue					(22,922)
Authorized Distribution Revenues in Rates	1,182,821	42,589			1,225,410
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(1,025)				(1,025)
G-10 Procurement Discount Allocation	404	621			1,025
Less: Front Counter Closures	0				0
Core Brokerage Fee Credit	(6,583)				(6,583)
Distribution Base Revenue with Adj. and Credits	1,175,617	43,210			1,218,827
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):					
Transportation Balancing Accounts	86,516 (I)	35,004 (R)			121,520
Self-Generation Incentive Program Revenue Requirement	2,283	3,477			5,760
CPUC Fee	1,970	1,240			3,210
SmartMeter™ Project	79,202				79,202
Winter Gas Savings Plan (WGSP) – Transportation	2,474				2,474
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,239 (I)	525 (R)			2,764
CARE Discount included in PPP Funding Requirement	(112,382)				(112,382)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	62,302 (I)	40,246 (R)			102,548
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):					
Local Transmission	132,854	72,789			205,643
Customer Access Charge – Transmission		4,860			4,860
Storage	47,513		34,083		81,596
Carrying Cost on PG&E Working Gas in Storage	1,978		532		2,510
Backbone Transmission/L-401	94,506 (I)	0	134,765 (I)		229,271 (I)
Gas Accord Revenue Requirement	276,851 (I)	77,649	169,380 (I)		523,880 (I)

(1) The amount includes the authorized distribution base revenue and F&U approved effective January 1, 2011, in GRC D.11-05-018 and changes to PG&E's cost of capital authorized in D.12-12-034. (T)

(2) PG&E's 2013 pension revenue requirement was updated and approved by the Energy Division in Advice Letter 3344-G/4147-E. These revenue requirement adjustments are in compliance with the terms of the Pension Cost Recovery Mechanism Settlement Agreement approved by the Commission in D.09-09-020. This adjusted amount was updated: (1) to conform to the capitalization factor and the operations and maintenance labor allocations used in determining the 2011 GRC revenue requirement adopted in D.11-05-018 and (2) for changes to the adopted cost of capital authorized by D.12-12-034.

(3) -The total 2013 SGIP revenue requirement (RRQ) was approved in D.11-12-030.
-D.06-07-027 authorized Advanced Metering Infrastructure ("AMI")/SmartMeter™ Project deployment. The Energy Division approved PG&E's AL 3210-G which included a revised 2013 revenue requirement.
-The Energy Division approved PG&E's AL 3222-G to continue PG&E's Winter Gas Savings Program (WGSP). The approved marketing, outreach and administration costs are shown here allocated between transportation and procurement.

(4) The Gas Accord V RRQ effective January 1, 2013, was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates. Some amounts include changes to PG&E's cost of capital authorized in D.12-12-034. The backbone transmission amounts include the implementation of the AB32-related gas compressor station costs. (D.13-03-017) (T)

*Some numbers may not add precisely due to rounding.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

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

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

	Amount ($000)					
Description	Core	Noncore	Unbundled	Core Procurement	Total	
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):						
Illustrative Gas Supply Portfolio				1,015,555 (I)	1,015,555 (I)	
Interstate and Canadian Capacity				188,107	188,107	
WGSP – Procurement – Residential				1,826	1,826	
F&U (on items above and Procurement Account Balances Below)				15,632 (I)	15,632 (I)	
Backbone Capacity (incl. F&U)	(65,300) (R)			65,300 (I)	0	
Backbone Volumetric (incl. F&U)	(29,206) (R)			29,206 (I)	0	
Storage (incl. F&U)	(47,513)			47,513	0	
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(1,978)			1,978	0	
Core Brokerage Fee (incl. F&U)				6,583	6,583	
Procurement Account Balances				(2,426)	(2,426)	
Illus. Core Procurement Revenue Requirement	(143,997) (R)			1,369,274 (I)	1,225,277 (I)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**1,370,773** (I)	**161,105** (R)	**169,380** (I)	**1,369,274** (I)	**3,070,531** (I)	
IMPLEMENTATION PLAN REVENUE REQUIREMENT (7)						(T)
Implementation Plan – Local Transmission	59,009	32,303			91,312	I
Implementation Plan – Backbone	9,542	12,873			22,415	I
Implementation Plan – Storage	950	666			1,616	(T)
Total Implementation Plan	**69,501**	**45,842**			**115,343**	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						
Energy Efficiency (EE)	50,551	5,627			56,178	
Energy Savings Assistance (ESA)	58,677	6,531			65,208	
Research, Demonstration and Development (RD&D)	6,742	3,817			10,559	
CARE Administrative Expense	1,625	1,114			2,739	
BOE and CPUC Administrative Cost	206	117			323	
PPP Balancing Accounts	(28,057)	(12,770)			(40,827)	
CARE Discount Recovered from non-CARE customers	66,681	45,701			112,382	
Total PPP Funding Requirement in Rates	**156,425**	**50,137**			**206,562**	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**1,596,699** (I)	**257,084** (R)	**169,380** (I)	**1,369,274** (I)	**3,392,437** (I)	

(5) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3222-G, is recovered in residential rates effective April 1, 2013.

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2013 PPP surcharge AL 3337-G-A; and includes ESA program funding adopted in D.12-08-044, EE program funding adopted in D.12-11-015, CARE annual administrative expense adopted in D.12-08-044, and excludes F&U per D.04-08-010.

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030. These revenue requirements are included in rates effective February 1, 2013.

(Continued)

GAS PRELIMINARY STATEMENT PART CM

Sheet 1

GAS OPERATIONAL COST BALANCING ACCOUNT (N)

CM. Gas Operational Cost Balancing Account (GOBA) (T)

1. PURPOSE: The purpose of the Gas Operational Cost subaccount is to record the difference between PG&E's authorized and actual cost associated with the cost of electricity used to provide gas transmission and storage services to its customers and Greenhouse Gas (GHG) cost associated with PG&E's gas compressor stations. (T)

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

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

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

5. ACCOUNTING PROCEDURE: The GOBA consists of the following two subaccounts:

   ELECTRICITY COST SUBACCOUNT: The purpose of this subaccount is to record the difference between the cost of electricity used to provide gas transmission and storage services adopted in PG&E's Gas Accord V Settlement Agreement, and PG&E's recorded cost of electricity used to provide gas transmission and storage services. This subaccount is created in compliance with Decision (D.) 11-04-031, and records the differences between adopted revenue requirements and recorded expenses beginning January 1, 2011 and ending December 31, 2014.

   COMPRESSOR STATION GREEN HOUSE GAS (GHG) COST SUBACCOUNT: The purpose of this subaccount is to record the difference between the Commission-adopted forecast and PG&E's actual GHG cost associated with its gas compressor stations, as authorized in D.13-03-017.

   I. Electricity Cost Subaccount

   The following entries shall be made to the account, each month, as applicable:

   a. A credit entry each month equal to one-twelfth of the annual revenue requirement for electricity costs (excluding FF&U) as adopted in PG&E's Gas Accord V Settlement Agreement per Decision 11-04-031. The 2011 annual amount is $5.3 million in FERC dollars and escalates by 2.3% in 2012, 2.3% in 2013, and 2.6% in 2014. (T)

(Continued)

GAS PRELIMINARY STATEMENT PART CM Sheet 2 (N)
GAS OPERATIONAL COST BALANCING ACCOUNT (N)

CM. Gas Operational Cost Balancing Account (GOBA) (T)

I. Electricity Cost Subaccount (Cont'd.) (T) (L)

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

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

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

II. Compressor Station GHG Cost Subaccount (N)

The following entries shall be made to the account, each month, as applicable:

a. A credit entry each month equal to one-twelfth of the forecast annual revenue requirement for GHG costs associated with the compressor stations (excluding FF&U) as authorized by the Commission.

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

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

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

GAS SCHEDULE G-AA

AS AVAILABLE TRANSPORTATION ON-SYSTEM

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

1. Usage Charge:

Path:	Usage Rate (Per Dth)	
Redwood to On-System	$0.3213	(I)
Baja to On-System	$0.3633	(I)
Silverado to On-System	$0.1834	(I)
Mission to On-System	$0.0000	

2. Additional Charges:

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

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

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

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

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

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

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

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

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

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

1. Usage Charge:

Path:	Usage Rate (Per Dth)	
Redwood to Off-System	$0.3213	(I)
Baja to Off-System	$0.3633	(I)
Silverado to Off-System	$0.3213	(I)
Mission to Off-System	$0.3213	(I)
Mission to Off-System Storage Withdrawals	$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.

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

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

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

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

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

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

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

GAS SCHEDULE G-AFT

Sheet 2

ANNUAL FIRM TRANSPORTATION ON-SYSTEM

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

1. Reservation Charge:

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

Path:	Reservation Rate (Per Dth per month)			
	MFV Rates		SFV Rates	
Redwood to On-System	$5.2084	(I)	$7.9034	(I)
Redwood to On-System (Core Procurement Groups only)	$4.4923	(I)	$6.3001	(I)
Baja to On-System	$5.8953	(I)	$8.9457	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$5.2276	(I)	$7.3313	(I)
Silverado to On-System (including Core Procurement Groups)	$3.1425	(I)	$4.4150	(I)
Mission to On-System (including Core Procurement Groups)	$3.1425	(I)	$4.4150	(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	$0.0965	(I)	$0.0079	
Redwood to On-System (Core Procurement Groups only)	$0.0685	(I)	$0.0091	(I)
Baja to On-System	$0.1090	(I)	$0.0087	(I)
Baja to On-System (N) (Core procurement Groups only) (N)	$0.0794	(I)	$0.0102	(I)
Silverado to On-System (including Core Procurement Groups)	$0.0495	(I)	$0.0077	(I)
Mission to On-System (including Core Procurement Groups)	$0.0495	(I)	$0.0077	(I)
Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only)	$0.0000		$0.0000	

(Continued)

GAS SCHEDULE G-AFTOFF
ANNUAL FIRM TRANSPORTATION OFF-SYSTEM

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

1. Reservation Charge:

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

Path:	Reservation Rate (Per Dth per month)			
	MFV Rates		SFV Rates	
Redwood to Off-System	$5.2084	(I)	$7.9034	(I)
Baja to Off-System	$5.8953	(I)	$8.9457	(I)
Silverado to Off-System	$5.2084	(I)	$7.9034	(I)
Mission to Off-System	$5.2084	(I)	$7.9034	(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 Off-System	$0.0965	(I)	0.0079	
Baja to Off-System	$0.1090	(I)	0.0087	(I)
Silverado to Off-System	$0.0965	(I)	0.0079	
Mission to Off-System	$0.0965	(I)	0.0079	

3. Additional Charges:

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

(Continued)

GAS SCHEDULE G-EG
GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

Sheet 1

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

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

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

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

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

1. Customer Access Charge:

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

Average Monthly Use (Therms)	Per Day
0 to 5,000 therms	$1.93578
5,001 to 10,000 therms	$5.76658
10,001 to 50,000 therms	$10.73293
50,001 to 200,000 therms	$14.08570
200,001 to 1,000,000 therms	$20.43715
1,000,001 and above therms	$173.35956

2. Transportation Charge:

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

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

      Backbone Level Rate: $0.01566 per therm (R)

   b. All Other Customers: $0.04434 per therm (R)

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

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

Note: Customers who are directly billed by Air Resources Board (ARB) for ARB AB32 Administration Fees are exempt from PG&E's ARB AB32 Cost of Implementation (COI) rate component. Customers on the Directly Billed list, as provided annually by the ARB, may change from year to year. The exemption credit will be equal to PG&E's currently-effective ARB AB32 COI per-therm rate component (as shown in PG&E's Preliminary Statement, Part B – "Default Tariff Rate Components"), times the customer's billed volumes (therms) for each billing period.

(Continued)

GAS SCHEDULE G-LNG

EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE

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

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

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

Liquefaction Charge (Per Therm): $0.18307 (R)

LNG Gallon Equivalent: $0.15012 (R)
(Conversion factor - One LNG Gallon = 0.82 Therms)

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

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

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

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

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

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

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

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

(Continued)

GAS SCHEDULE G-NGV4

NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES

RATES: (Cont'd.)

2. Transportation Charge:

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

a. Backbone Level Rate:

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

Backbone Level Rate (per therm) .... $0.01592 (R)

b. Transmission-Level Rate:

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

Transmission-Level Rate (per therm)............................... $0.04460 (R)

c. Distribution-Level Rate:

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

Average Monthly Use (Therms)	Summer (Per Therm)		Winter (Per Therm)	
Tier 1: 0 to 20,833	$0.18039	(R)	$0.22873	(R)
Tier 2: 20,834 to 49,999	$0.13032	(R)	$0.16114	(R)
Tier 3: 50,000 to 166,666	$0.12009	(R)	$0.14733	(R)
Tier 4: 166,667 to 249,999	$0.11209	(R)	$0.13653	(R)
Tier 5: 250,000 and above*	$0.04460	(R)	$0.04460	(R)

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES FEES AND TAXES:

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

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

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* Tier 5 Summer and Winter rates are the same.

(Continued)

GAS SCHEDULE G-NT

Sheet 2

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

RATES: (Cont'd.)

2. Transportation Charge:

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

a. Backbone Level Rate:

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

Backbone Level Rate (per therm): $0.01592 (R)

b. Transmission-Level Rate:

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

Transmission-Level Rate (per therm): $0.05087 (R)

c. Distribution-Level Rate:

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

Average Monthly Use (Therms)	Summer (Per Therm)		Winter (Per Therm)	
Tier 1: 0 to 20,833	$0.18039	(R)	$0.22873	(R)
Tier 2: 20,834 to 49,999	$0.13032	(R)	$0.16114	(R)
Tier 3: 50,000 to 166,666	$0.12009	(R)	$0.14733	(R)
Tier 4: 166,667 to 249,999	$0.11209	(R)	$0.13653	(R)
Tier 5: 250,000 and above*	$0.05087	(R)	$0.05087	(R)

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES, FEES AND TAXES:

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

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

* Tier 5 Summer and Winter rates are the same.

Note: Customers who are directly billed by Air Resources Board (ARB) for ARB AB32 Administration Fees are exempt from PG&E's ARB AB32 Cost of Implementation (COI) rate component. Customers on the Directly Billed list, as provided annually by the ARB, may change from year to year. The exemption credit will be equal to PG&E's currently-effective ARB AB32 COI per-therm rate component (as shown in PG&E's Preliminary Statement, Part B – "Default Tariff Rate Components"), times the customer's billed volumes (therms) for each billing period. (N)
I
I
(N)

(Continued)

GAS SCHEDULE G-SFT
Sheet 2

SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY

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

1. Reservation Charge:

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

Path:	Reservation Rate (Per Dth per month)			
	MFV Rates		SFV Rates	
Redwood to On-System	$6.2501	(I)	$9.4840	(I)
Baja to On-System	$7.0744	(I)	$10.7348	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$6.2731	(I)	$8.7976	(I)
Silverado to On-System	$3.7710	(I)	$5.2980	(I)
Mission to On-System	$3.7710	(I)	$5.2980	(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	$0.1159	(I)	$0.0095	(I)
Baja to On-System	$0.1308	(I)	$0.0104	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$0.0952	(I)	$0.0122	(I)
Silverado to On-System	$0.0594	(I)	$0.0092	(I)
Mission to On-System	$0.0594	(I)	$0.0092	(I)

3. Additional Charges:

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

(Continued)

GAS SCHEDULE G-WSL

Sheet 1

GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS

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

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

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

1. Customer Access Charge:

	Per Day
Palo Alto	$151.77205
Coalinga	$45.51945
West Coast Gas-Mather	$24.16438
Island Energy	$30.84132
Alpine Natural Gas	$10.29238
West Coast Gas-Castle	$26.44208

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto-T	$0.03844	(R)
Coalinga-T	$0.03844	(R)
West Coast Gas-Mather-T	$0.03844	(R)
West Coast-Mather-D	$0.17242	(R)
Island Energy-T	$0.03844	(R)
Alpine Natural Gas-T	$0.03844	(R)
West Coast Gas-Castle-D	$0.13962	(R)

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

(Continued)

GAS SCHEDULE G-XF

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

RATES: (Cont'd.)

2. Usage Charge:

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

Usage Rates:	Per Dth
SFV Rates:	0.0031 (I)

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.

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

1st Light Energy
AT&T
Alcantar & Kahl LLP
Anderson & Poole
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Bear Valley Electric Service
Braun Blaising McLaughlin, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
Calpine
Casner, Steve
Cenergy Power
Center for Biological Diversity
City of Palo Alto
City of San Jose
Clean Power
Coast Economic Consulting
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Dept of General Services
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
G. A. Krause & Assoc.
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
In House Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Lawrence Berkeley National Lab
Linde
Los Angeles Dept of Water & Power
MAC Lighting Consulting
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.
North America Power Partners
Occidental Energy Marketing, Inc.
OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
SCE
SPURR
San Francisco Public Utilities Commission
Seattle City Light
Sempra Utilities
SoCalGas
Southern California Edison Company
Sun Light & Power
Sunshine Design
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Utility Cost Management
Utility Power Solutions
Utility Specialists
Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)