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

PUBLIC UTILITIES COMMISSION
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February 26, 2013

Advice Letter 3353-G

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Subject: Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2013

Dear Mr. Cherry:

Advice Letter 3353-G is effective January 1, 2013.

Sincerely,

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Advice 3353-G
(Pacific Gas and Electric Company ID U 39 G)

Public Utilities Commission of the State of California

Subject: Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 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 January 1, 2013.

Purpose

This advice letter consolidates gas transportation and Public Purpose Program Surcharge rate changes authorized by the CPUC for implementation into rates effective January 1, 2013.

Background/Summary

On November 1, 2012, PG&E filed its Annual Gas True-Up ("AGT")[1] Advice Letter 3338-G, requesting approval to amortize forecast December 31, 2012 gas transportation balancing account balances in rates effective January 1, 2013.

This "Annual Gas True-Up: Consolidated Rate Update" advice letter consolidates forecast end-of-year gas balancing account balances with final authorized gas revenue requirement changes previously approved by the CPUC. In order to provide a more accurate forecast, this advice letter updates the forecast balancing account balances that were provided in Advice 3338-G using November 30, 2012 recorded balances as the starting point.[2]

In Advice 3338-G, PG&E provided a preview of its 2013 gas transportation revenue requirements, which at the time were estimated to be $1,933 million. In this advice letter, PG&E proposes to recover its final authorized 2013 gas transportation revenue

[1] The AGT is an annual process to update gas transportation balancing accounts as established in PG&E's 2005 Biennial Cost Allocation Proceeding ("BCAP") Decision 05-06-29, p. 10 and Finding of Fact 9.
[2] Advice Letter 3338-G used September 30, 2012 recorded balances as the starting point for December 31, 2012 forecast balancing account balances.

requirements totaling $1,891 million, which is a $121 million decrease compared to revenue requirements in present rates. The 2013 gas transportation revenue requirements include end-user transportation costs, gas PPP surcharges (which were submitted for Commission approval in Advice 3337-G-A), and gas transmission and storage (i.e., Gas Accord V) unbundled costs (See Table 1 below).

Table 1
Proposed Gas Transportation Revenue Requirements
Effective January 1, 2013
(in $ millions)[3]

Description	Currently in Rates	Proposed	Change
End-Use Gas Transportation	$1,564	$1,516	($48)
Gas Accord Unbundled Costs	$175	$168	($7)
Gas PPP Surcharges	$273	$207	($66)
Total Gas Transportation Revenue Requirements	**$2,012**	**$1,891**	**($121)**

Attachments 1 and 1A summarize the proposed 2013 gas transportation revenue requirements. Attachment 2 summarizes the gas transportation balancing accounts, which PG&E proposes to amortize in 2013. Attachments 3 through 6 provide rates and surcharges incorporating: (1) amounts previously authorized to be recovered in rates, effective January 1, 2013, and (2) the forecast December 31, 2012 account balances to be amortized in 2013.

Recovery of Transportation Balancing Accounts Already Approved for Amortization

As described in PG&E's Preliminary Statement C-*Gas Accounting Terms and Definitions*, Part 12.b, *Revision Dates*, the AGT updates the customer class charge components of transportation rates to recover all gas transportation-related balancing and memorandum account balances for costs that the Commission has authorized to be recovered in rates. PG&E determines the change in the customer class charge components of transportation rates, as follows:

1) December 31, 2012 balances are forecasted for each gas transportation balancing and memorandum account based on the November 30, 2012[4] recorded balances and a forecast of costs and revenues, including interest, through December 31, 2012; and

[3] This table does not include the 2013 gas procurement-related revenue requirement changes, which are being submitted in PG&E's monthly core procurement advice letter, Advice 3352-G.
[4] The PPP surcharge balancing accounts are included in the PPP surcharge proposed in Advice 3337-G-A. As a result, these PPP surcharge balancing accounts use September 30, 2012 recorded balances as the starting point of their respective December 31, 2012 forecast balances.

2) Customer class charge rate components are calculated by dividing the forecasted December 31, 2012 balancing account balances by PG&E's currently adopted BCAP throughput forecast (D.10-06-035).

Attachment 2 summarizes the forecast December 31, 2012 balances for gas transportation balancing accounts using recorded balances through November 30, 2012. The total December 31, 2012 gas transportation balancing account balances are projected to be undercollected by $106 million, as shown in Attachment 1, line 1, and Attachment 2, line 24. This represents a $62 million decrease in the gas transportation balancing account undercollections from those currently amortized in gas transportation rates. Because different balancing accounts are allocated differently to customer classes, the balancing account update results in a $54 million decrease in core transportation revenues and an $8 million decrease in noncore transportation revenues.

The remainder of this section describes the balancing accounts that will be amortized and consolidated in gas transportation rates through this advice letter, effective January 1, 2013.

Certain account balances are recovered in rates through the Core Fixed Cost Account ("CFCA") and/or Noncore Customer Class Charge Account ("NCA") rate components, as described below. For these accounts, PG&E will transfer the recorded December 31, 2012 balance to the appropriate subaccount of the CFCA and/or NCA, once this advice letter is approved.

Core Fixed Cost Account (CFCA) – (Attachment 2, Lines 1-3)

The CFCA records authorized General Rate Case ("GRC") distribution base revenue amounts (with credits and adjustments), certain other core transportation costs, and transportation revenue from core customers. The CFCA has three subaccounts:

(i) The Distribution Cost subaccount, which recovers the core distribution base revenue requirement adopted in PG&E's GRC (including Annual Attrition Adjustments) as well as changes adopted in the Cost of Capital Proceedings, and other core distribution-related costs authorized by the Commission. The Distribution Cost subaccount is allocated to core customer classes in proportion to their allocation of distribution base revenues;

(ii) The Core Cost subaccount, which recovers non-distribution-related costs, such as the Self-Generation Incentive Program ("SGIP") budget and Gas Accord local transmission revenue requirement, adopted by the Commission. The Core Cost subaccount is allocated to core transportation customers on an equal-cents-per-therm basis; and

(iii) The Winter Gas Savings Program ("WGSP") Transportation subaccount, which recovers transportation-related WGSP program credits and costs from core customer classes participating in the Program.

This advice letter includes a forecasted $5.7 million net undercollection in the CFCA, which results from:

(i) A forecasted $14.6 million undercollection in the Distribution Cost subaccount;

(ii) A forecasted $6.5 million overcollection in the Core Cost subaccount; and

(iii) A forecasted $2.4 million overcollection in the WGSP Transportation Subaccount.

Noncore Customer Class Charge Account (NCA) - (Attachment 2, Lines 5-6)

The NCA records noncore costs and revenues from noncore customers for balancing-account protected items such as SGIP. The NCA has two subaccounts:

(i) The Noncore subaccount, which recovers costs and balances from all noncore customers for non-distribution cost-related items and is allocated on an equal-cents-per-therm basis; and

(ii) The Interim Relief and Distribution subaccount, which recovers the noncore distribution portion of interim gas revenue requirement changes adopted in GRC decisions and other noncore distribution related costs and balances approved by the Commission. It is allocated to noncore classes in proportion to their allocation of distribution base revenues.

This advice letter includes a forecasted $7.6 million net overcollection in the NCA, which results from:

(i) A forecasted $6.7 million overcollection in the Noncore subaccount; and

(ii) A forecasted $0.9 million overcollection in the Interim Relief and Distribution subaccount.

Noncore Distribution Fixed Cost Account (NDFCA) - (Attachment 2, Line 4)

The NDFCA recovers the noncore distribution base revenue requirement. This advice letter includes a forecasted $22,000 overcollection in the NDFCA. The NDFCA balance is included in the Interim Relief and Distribution subaccount rate component of the NCA.

Core Brokerage Fee Balancing Account (CBFBA) - (Attachment 2, Line 7)

The CBFBA ensures that variations between the adopted forecast brokerage fee revenue requirement credits in core transportation rates and actual brokerage fee revenues collected from core procurement customers will flow through core transportation rates. This account was adopted in PG&E's 2005 BCAP decision (D.05-06-029). This advice letter includes a forecasted $0.5 million undercollection in the CBFBA. The CBFBA balance is included in the rate component of the Core Cost subaccount of the CFCA.

Liquefied Natural Gas Balancing Account (LNGBA) - (Attachment 2, Line 8)

The LNGBA records all transportation revenue from customers using experimental liquefied natural gas service. This advice letter forecasts a $0 balance in the LNGBA. The LNGBA balance is included in the rate component of the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA.

Hazardous Substance Mechanism (HSM) - (Attachment 2, Line 9)

The HSM provides a uniform methodology for allocating costs and related recoveries associated with covered hazardous substance-related activities, including hazardous substance clean-up and litigation, and related insurance recoveries, as set forth in D.94-05-020 (the original HSM decision) through the Hazardous Substance Cost Recovery Account ("HSCRA"). This advice letter forecasts a $39.1 million undercollection in the HSCRA. Once allocated, the HSCRA balance is included in the rate component of the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA.

Balancing Charge Account (BCA) - (Attachment 2, Line 10)

The BCA records the revenue and costs associated with providing gas balancing service, including charges and credits, as described in gas Schedule G-BAL and Gas Rule 14. This advice letter forecasts a $0.7 million undercollection in the BCA as of December 31, 2012.

Affiliate Transfer Fees Account (ATFA) - (Attachment 2, Line 11)

The ATFA records employee transfer fees paid to PG&E by its holding company, PG&E Corporation, and affiliates for future ratemaking treatment to ensure that PG&E's customers receive the fees, pursuant to the decision which approved for PG&E to become a wholly owned subsidiary of a holding company (D. 96-11-017). This advice letter forecasts a $29,000 overcollection in the ATFA, which represents activity in the account for 2012. The ATFA balance is included in the rate component of the Distribution Cost subaccount of the CFCA and the Interim Relief and Distribution Cost subaccount of the NCA.

Customer Energy Efficiency Incentive Account (CEEIA) - (Attachment 2, Line 12)

The CEEIA records the gas portion of any Energy Efficiency Risk Reward Incentive Mechanism ("RRIM") award or penalty that is authorized by the Commission to be recovered in rates. The forecast year-end balance incorporates the residual 2012 balance in the account and the gas portion of the 2010 RRIM claim as authorized by the CPUC on December 20, 2012. Interest does not accrue in this subaccount pursuant to D.07-09-043. This advice letter includes a forecasted $3.8 million undercollected balance, which will be collected through the CEE Incentive rate component.

SmartMeter™ Project Balancing Account-Gas (SBA-G) - (Attachment 2, Line 13)

The SBA-G recovers the incremental Operating and Maintenance ("O&M") and Administrative and General ("A&G") expenditures, capital-related costs, capital-related revenue requirements, benefits, and revenues associated with the SmartMeter™ Project, as authorized in D.06-07-027. This advice letter includes a forecasted $14.2 million undercollected balance in the SBA-G. The SBA-G is recovered through the SmartMeter**™** Project rate component.

California Solar Initiative Thermal Program Memorandum Account (CSITPMA) - (Attachment 2, Line 14)

Advice 3093-G established the CSITPMA to record expenses incurred by PG&E for implementing the CSI Thermal Program authorized by D.10-01-022. Customers who participate in the California Alternate Rates for Energy ("CARE") or Family Electric Rate Assistance ("FERA") Programs and customers who are currently exempt from funding the Self-Generation Incentive Program and customers exempt pursuant to Public Utilities Code Section 2863(b)(4) are exempt from CSI Thermal Program charges. This advice letter includes a forecasted $6.4 million undercollected balance in the CSITPMA as of December 31, 2012 and will be recovered in the CSITPMA rate component.

Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) – (Attachment 2, Line 15)

The AMCDOP records the difference in the revenue requirement associated with the costs determined in other proceedings and the revenue requirement based on placeholder costs included in the Gas Accord V Settlement Agreement as adopted in D.11-04-031. The AMCDOP consists of the following five subaccounts:

(i) The Administrative and General ("A&G") Subaccount, which tracks the amount of A&G expenses allocated to Gas Transmission & Storage ("GT&S") in the GRC against the allocation of A&G to GT&S services in the Gas Accord V Settlement Agreement;

(ii) The Uncollectibles Subaccount, which tracks the amount of uncollectibles expense based on the uncollectibles factor determined in the GRC against the uncollectible costs included in the Gas Accord V Settlement Agreement;

(iii) The Pension Subaccount, which tracks the amount of pension costs allocated to GT&S in the Pension Recovery proceeding against the pension costs allocated to GT&S services in the Gas Accord V Settlement Agreement;

(iv) The Cost of Capital Subaccount, which tracks the authorized cost of capital as determined in PG&E's cost of capital proceeding against the cost of capital used to set GT&S cost of service revenue requirements in the Gas Accord V Settlement Agreement; and

(v) The Other GRC Costs Subaccount, which tracks the amount of costs and policies determined to be allocated and applied to GT&S in the GRC (not already reflected in the preceding A&G and Uncollectibles subaccounts) against the allocation of costs and policies allocated and applied to GT&S services in the Gas Accord V Settlement Agreement.

This advice letter includes a forecasted net $0 balance in the AMCDOP. The AMCDOP is included in the rate component of the Core Cost subaccount of the CFCA and Noncore subaccount of the NCA. As further described in the "Gas Transmission and Storage Rates" section below, Attachment 6 contains the complete set of Gas Accord V rate tables updated for the impact of the 2013 cost of capital decision.

Non-Tariffed Products and Services Balancing Account (NTBA-G) - (Attachment 2, Line 16)

The NTBA-G is used to record the customer share of revenues net of costs and income taxes associated with new Non-Tariffed Products and Services ("NTP&S"), pursuant to CPUC Affiliate Transaction Rule VII. Costs and revenues are tracked for appropriate disbursement of revenues, net of expense, to customers and shareholders via the 50/50 sharing mechanism as approved by D.99-04-021. The NTBA-G does not apply to NTP&S in PG&E's existing NTP&S catalogue, which remains subject to Other Operating Revenue treatment, consistent with D.99-04-021. In Resolution G-3417, the Commission approved PG&E's proposal to (1) offer the Mover Services Program, (2) recover costs and disburse net revenues through the NTBA-G, (3) transfer the balance at the end of the year from the NTBA-G to the CFCA, and (4) include it in the AGT filing, in order to credit customer revenues pursuant to D.99.04-021. If the balance at the end of the year for any product or service category is undercollected, no transfer will be made for that product or service category, and the balance for that product or service category will be reset to zero at the beginning of the year. PG&E forecasts a $274,000 overcollected balance for this account, as of December 31, 2012, which will be transferred to the Distribution Cost subaccount of the CFCA.

Gas Meter Reading Costs Balancing Account (MRCBA-G) – Attachment 2, Line 18)

The MRCBA-G records and recovers gas meter reading costs, including Energy Delivery Services meter reading costs and severance costs, up to an annual combined electric and gas balancing accounts cap of $76.2 million, pursuant to D.11-05-018 in PG&E's 2011 GRC. The MRCBA-G is recovered through the Distribution Cost subaccount of the CFCA. This advice letter includes a forecasted $27.3 million undercollected balance in the MRCBA-G as of December 31, 2012. The 2013 Annual Electric True-Up ("AET") Advice 4096-E-A, which is expected to be filed December 31, 2012, will include a $35.0 million forecast for December 31, 2012, for the MRCBA-E, for a combined total of $62.3 million, within the cap.

Electricity Cost Balancing Account (ECBA) – (Attachment 2, Line 19)

The ECBA records 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. Created in compliance with D.11-04-031, the ECBA will record the differences between adopted revenue requirements and recorded expenses beginning January 1, 2011, and ending December 31, 2014. The balance in the ECBA will be recovered through the Core Cost Subaccount of the CFCA and the Noncore subaccount of the NCA. PG&E forecasts an $11.8 million undercollected balance in the ECBA as of December 31, 2012.

Pension Contribution Balancing Account (PCBA) - (Attachment 2, Line 20)

The PCBA includes the revenue requirement associated with the difference, if any, between adopted pension contributions and (i) lower contributions for any reason or (ii) federally mandated higher contributions, with the difference to be refunded to or recovered from customers. PG&E's contribution to the pension plan have matched the amounts adopted in D.06-06-014 and D.07-03-044. As a result, PG&E does not expect that the PCBA will have a balance on December 31, 2012.

TID Almond Power Plant Balancing Account (TIDBA) – (Attachment 2, Line 21)

The purpose of the TIDBA is to record the difference in revenue requirement based on the amount credited to rate base per the adopted Gas Accord V Settlement Agreement and the actual amount. The TIDBA balance is included in the rate component of the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA. This advice letter includes a forecasted $0.8 million overcollected balance in the TIDBA. In accordance with the Gas Accord V Settlement Agreement (Section 7.2.10), this balance is allocated to customers through the Customer Class Charge.

Revised Customer Energy Statement Balancing Account (RCESBA-G) – (Attachment 2, Line 22)

The RCESBA-G (Gas Preliminary Statement Part CV) tracks and records actual gas revenue requirements associated with authorized costs incurred to implement the Revised Customer Energy Statement Project, pursuant to D.12-03-015. The RCESBA-G will remain open until the test year of the GRC following PG&E’s 2014 General Rate Case (GRC), when any remaining cost recovery will be consolidated in the GRC. Disposition of the balance in the account shall be through the AGT advice letter process via the CFCA and the NCA, or through another proceeding as authorized by the Commission. This advice letter includes a forecasted $0.3 million undercollected balance in the RCESBA as of December 31, 2012.

Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) – (Attachment 2, Line 23)

The GTSRSM records the difference between the customer portion of recorded total revenue over- or under-collections (derived for backbone, local transmission and storage service) and the $30.0 million seed value embedded in rates as adopted in PG&E’s Gas Accord V Settlement Agreement. The over- or under-collections are determined by comparing revenue from implemented Gas Accord V rates with the revenue requirement used to determine those rates. The difference between the adopted revenue requirement in D.11-04-031 and the adjusted Gas Accord revenue requirement post-GRC and Pension decisions is tracked in the AMCDOP as discussed above. The GTSRSM consists of the following four subaccounts:

(i) The Backbone Subaccount, which records the difference between the adopted backbone revenue requirement (including the portion of the Local Transmission Bill Credits recovered through the surcharge on backbone rates) and recorded backbone revenues, whether an over-collection or an under-collection, to be shared 50 percent to customers and 50 percent to shareholders.

(ii) The Local Transmission Subaccount, which records the difference between the adopted local transmission revenue requirement (excluding the Local Transmission Bill Credits) and recorded local transmission revenues, whether an over-collection or an under-collection, to be shared 75 percent to customers and 25 percent to shareholders.

(iii) The Storage Subaccount, which records the difference between the adopted storage revenue requirement and recorded storage revenues, if an over-collection, to be shared 75 percent to customers and 25 percent to shareholders. PG&E is at risk for 100 percent of any net under-collections.

(iv) The Revenue Sharing Subaccount, which records the difference between the customer portion of recorded total over- or under-collections, as determined in the above three subaccounts, and the $30.0 million seed value embedded in rates.

In accordance with Preliminary Statement Part CP, the balances in the first three subaccounts[5] are transferred to the Revenue Sharing Subaccount as of September 30 of each year; and the Revenue Sharing Subaccount is transferred to the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA. This advice letter includes a forecasted $5.1 million undercollected balance in the GTSRSM.

Discussion of Recent CPUC Proceedings and Advice Letters

The following section highlights recent decisions and advice letter filings that impact PG&E's gas transportation revenue requirements and rates filed in this advice letter:

Attrition – (Attachment 1, Line 2)

On November 21, 2012, PG&E filed Advice Letter 3344-G, a Tier 1 compliance advice letter to implement the 2013 GRC attrition adjustments to its gas distribution revenue requirement. This revenue requirement adjustment is in compliance with the terms of the 2011 GRC Settlement Agreement approved by the Commission in D.11-05-018. The 2013 gas distribution adjustment is $35 million.

Cost of Capital – (Attachment 1, Lines 2-3)

On December 20, 2012, the CPUC approved D.12-12-034 which adopted changes to PG&E's 2013 Cost of Capital (A.12-04-018), ordered in D.09-10-016. Changes approved in D.12-12-034 are reflected in PG&E's 2013 gas distribution, Gas Accord, and pension revenue requirements and resulting 2013 rates submitted with this advice letter.

[5] If the storage subaccount is undercollected as of September 30, the balance will be transferred to earnings.

Pension – (Attachment 1, Line 3)

On November 21, 2012, PG&E filed Advice Letter 3344-G, a Tier 1 compliance advice letter to implement the 2013 pension adjustment to its gas distribution revenue requirement. This revenue requirement adjustment is made in compliance with the terms of the Pension Cost Recovery Mechanism Settlement Agreement approved by the Commission in D.09-09-020. As required in D.09-09-020, PG&E updated the 2011 through 2013 pension revenue requirement amounts to conform to the capitalization factor and the operations and maintenance ("O&M") labor allocations used in determining the 2011 GRC Settlement Agreement revenue requirements in D.11-05-018. Additionally, as provided in A.09-03-003, PG&E's Pension Recovery Mechanism Application,[6] PG&E's pension revenue requirement has been updated for changes to the adopted cost of capital approved by the CPUC on December 20, 2012.

Winter Gas Savings Program (WGSP) Costs – (Attachment 1, Line 8)

PG&E's Advice 3130-G-A, approved on September 28, 2010, requested that the CPUC approve a three-year WGSP beginning in 2011. The WGSP program proposed in Advice 3130-G-A is similar to prior year programs in that the purpose of the program is to encourage conservation among core gas customers by providing up to a 20 percent bill credit to those customers who reduce their cumulative weather-adjusted gas usage during the cold winter months. For the first year of this three-year WGSP cycle, the WGSP conservation program ran during January and February. For the second year of the program, PG&E filed Advice 3222-G, which among other things, changed the conservation program to run during December and January, which are the coldest months of the year in PG&E's service territory. PG&E requested a marketing and implementation budget of $4.3 million[7] for each year of the proposed three-year program. These costs, along with the estimated 2013 WGSP credits, will be recovered in gas transportation and procurement rates beginning on January 1, 2013, for commercial customers and from April 1 to October 31, 2013, for residential customers.

For ratemaking purposes, PG&E estimates that total 2013 WGSP bill credits will be approximately $40 million, compared to $42 million for the 2012 Program. The transportation-related portion included in this 2013 AGT Advice Letter Filing is forecasted to be 58 percent or $23 million. The actual credits provided to customers are tracked by class and by transportation/PPPS versus procurement origination as is the revenue recovery for the Program. The 2014 AGT will true-up credits provided to each participating core class (excluding Core NGV) with revenues received during 2013 for WGSP.

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[6] A.09-03-003, Prepared Testimony, Chapter 4, Page 4-2.
[7] $2.4 million of this amount relates to transportation, given the forecasted transportation/procurement split of 55 percent/45 percent.

In addition to the 2013 WGSP program costs, the gas transportation rates for January 1, 2013, includes the forecasted year-end 2012 balance in the WGSP Transportation subaccount of the CFCA and a true-up of the recorded 2012 WGSP credits versus revenue by class, both tracked based on procurement and transportation/PPPS origination.

Energy Efficiency 2013-2014 Portfolio– (Attachment 1, Line 19)

On November 8, 2012, the CPUC issued D.12-11-015, which approved PG&E's 2013-2014 Energy Efficiency portfolio. The 2013 EE annual program funding to be recovered from gas customers is $56.2 million. On November 16, 2012, PG&E filed Advice 3337-G-A to supplement its previously filed PPP Surcharge Advice Letter. The supplement incorporated the results of D.12-11-015.

Energy Efficiency Risk Reward Incentive Mechanism (RRIM) – (Attachment 2, Line 12)

On January 5, 2012, the Commission opened the Risk Reward Incentive Mechanism (RRIM) OIR R.12-01-005 to consider reforms considered in R.09-01-019 and to modify and streamline the design of incentives applied to energy efficiency activities. On December 20, 2012, the CPUC approved D.12-12-032 which adopted an incentive mechanism to reward 2010-2012 Energy Efficiency program activities. Decision 12-12-032 authorized PG&E to record its 2010 incentive award of $21.0 million, of which $3.8 million is allocated to gas customers based on the electric and gas allocation factors approved in Advice letter 3065 G-A/ 3563 E-A. PG&E will record the amount in the Customer Energy Efficiency Balancing Account for rate recovery effective January 1, 2013.

California Air Resources Board (CARB) Administration Fee – (Attachment 2, Line 17)

On August 2, 2010, PG&E filed a joint-IOU application A.10-08-002 to recover the California Air Resources Board's ("ARB") Assembly Bill ("AB") 32 Cost of Implementation Fee from its gas transportation customers excluding specific (mostly very large) customers who will be directly billed by the ARB. The ARB is responsible for, and these fees help fund, the implementation of AB 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions ("GHG") reduction goal into law. To date, PG&E has paid invoices from the ARB totaling approximately $16 million. The gas cost portion is currently being tracked in the AB32 – Cost of Implementation Fee Memorandum Account – Gas (AFMA-G), which was authorized by Advice 3180-G. On October 25, 2012, the Commission approved D.12-10-044 which granted the request in A.10-08-002 to recover AB 32 implementation costs recorded in the AFMA. The revenue requirement and resulting rates have not been included in this advice letter for the January 1, 2013 rate change. PG&E is in the process of determining billing system requirements related to this proceeding and plans to implement the results of D.12-10-044 in rates as soon as practical.

Lawrence Livermore National Laboratory

On July 18, 2011, PG&E, Southern California Edison Company (SCE), and San Diego Gas and Electric (SDG&E) (collectively, the "Joint Utilities"), filed a joint application (A.11-07-008) to recover costs for a public-private collaborative agreement with Lawrence Livermore National Laboratory, known as the "California Energy Systems for the 21st Century Project" (CES-21 Project). On December 20, 2012, the CPUC approved D.12-12-031. Decision 12-12-031 requires that the Joint Utilities file a Tier 3 advice letter within 90 days to approve the proposed CES-21 implementation plan and first year projects. Because PG&E will not have filed the Tier 3 advice letter by the end of 2012, the revenue requirement and resulting rates are not included in this AGT Consolidated Gas Rate Update advice letter.

Greenhouse Gas OIR – Compressor Station Compliance

On June 18, 2012, PG&E filed an application (A.12-06-010) to recover costs associated with the purchase of GHG compliance instruments to cover emissions associated with its gas compressor stations. As part of the AB32 legislation to reduce greenhouse gas emissions by 2020, the ARB adopted a Cap-and-trade regulation intended to establish a market-based price for GHG emissions. Compliance with the emissions cap begins in 2013 and is broken up into three compliance periods. The first compliance period, beginning on January 1, 2013, includes operators of facilities like PG&E's gas compressor stations. In A.12-06-010, PG&E has proposed a 2013 revenue requirement of $3.335 million to recover the forecasted cost to procure GHG compliance instruments. PG&E has proposed recovery of this revenue requirement through an adjustment to Backbone and Local Transmission rates. Because the CPUC did not issue a final decision in this proceeding by December 20, 2012, the revenue requirement and resulting rates have not been included in this advice letter.

Pipeline Safety Enhancement Plan

On August, 26, 2011, PG&E filed its Pipeline Safety Enhancement Plan ("Implementation Plan") in the Gas Pipeline Safety Rulemaking (OIR 11-02-019) in compliance with CPUC D.11-06-017. PG&E's proposed Implementation Plan includes four main components (Pipeline Modernization, Valve Automation, Pipeline Records Integration, and Interim Safety Enhancement Measures) with the goal of enhancing safety and improving operations. The Implementation Plan also includes a shareholder sharing proposal in which shareholders fund costs associated with complying with preexisting regulatory requirements, 2011 expenses, and 2011 capital-related revenues. The Implementation Plan also includes proposed mechanisms for Gas Pipeline Safety (GPS) revenue recovery and rates for the customer-funded portion of authorized Implementation Plan costs. The revenue requirements requested are: $247.279 million in 2012, $220.833 million in 2013, and $300.641 million in 2014. On December 20, 2012, the CPUC approved D.12-12-030 that authorized revenue requirements of: $2.913 million in 2012, $115.343 million in 2013, and $180.958 million in 2014.

The revenue requirement and resulting rates have not been included in this AGT advice letter for the January 1, 2013 rate change. PG&E is in the process of determining billing system requirements related to this proceeding and plans to include the results in rates on February 1, 2013, or as soon as practical thereafter.

Gas Public Purpose Program Authorized Funding

This AGT incorporates gas PPP surcharge changes that were filed in Advice Letter 3337-G-A on November 16, 2012. The gas PPP surcharge rate impacts on customers are shown in Attachment 1.

PU Code Sections 890-900 and D.04-08-010 authorize a gas surcharge rate to fund public purpose programs. The gas PPP Surcharge advice letter updates the natural gas PPP surcharge rates to fund authorized energy efficiency ("EE"), Energy Savings Assistance ("ESA") (formerly low income energy efficiency), CARE and public-interest research, development and demonstration ("RD&D") programs.

The gas PPP surcharges proposed include:

1) Total gas PPP authorized program funding of $135.0 million for EE, ESA, CARE administrative expenses, RD&D, and Board of Equalization administrative costs. This represents a $27.9 million decrease from 2012;

2) Amortization over 12 months of forecasted December 31, 2012 balances in the PPP surcharge balancing accounts totaling a $40.8 million overcollection; and

3) A projected 2013 CARE revenue shortfall of $112.4 million, which represents a $6.5 million decrease from the forecasted 2012 CARE customer discount. This shortfall is included in the PPP-CARE portion of the gas PPP surcharge rates for 2013 and accounted for as a reduction of net transportation revenue requirement in rates for a zero-sum impact on the total gas revenue requirement.

Gas Transmission and Storage Rates

Revenue Requirement Adjustment

The Commission adopted the Gas Accord V Settlement in D.11-04-031, dated April 14, 2011. Section 7.5 of the Settlement addresses treatment of costs determined in other PG&E proceedings. Section 7.5.3 specifically requires PG&E to apply Cost of Capital adjustments, as determined in PG&E's Cost of Capital proceedings, to the Gas Transmission and Storage (GT&S) rate base. As described above, on April 20, 2012, PG&E filed its Test-Year 2013 Cost of Capital

Application (A.12-04-018), ordered in D.09-10-016. On December 20, 2012, the CPUC approved D.12-12-034 authorizing changes to PG&E's Cost of Capital. The Cost of Capital changes approved in D.12-12-034 are reflected in the GT&S rates submitted with this advice letter.

The following table shows resulting total annual Settlement 2013 revenue requirement changes when compared with the total annual Settlement 2013 revenue requirements included in the 2013 Gas Transmission and Storage rates filed as of January 1, 2012 in advice letter 3257-G-A.

Annual Gas Transmission and Storage Revenue Requirements

2013

Adjusted to Reflect PG&E's 2013 Cost of Capital

($000)

GT&S 2013 Revenue Requirement (filed as of January 1, 2012 – Advice 3257-G-A)	$558,230
Add: 2013 Fractional Year Adder Project L-407 Phase 2 RRQ	$599
2013 GT&S RRQ included Fractional Year Adder Project	$558,829
Less: Cost of Capital Proposal	($22,571)
GT&S 2013 Revenue Requirement (including all adder & fractional year projects)	$536,258
Less: 2013 COC Adjusted Fractional Year Adder Project L-407 Phase 2 RRQ	($529)
GT&S 2013 Revenue Requirement	$535,729
Less: 2013 Local Transmission line 304 Project	($543)
Less: 2013 Local Transmission Line 407 Phase 1 project	($6,811)
Less: 2013 Backbone P02158-Topock K-Units Replacement-Ph1 Project	($7,829)
2013 GT&S Revenue Requirements (excluding non-operational projects)	$520,545

Attachment 6 provides an update of the GT&S revenue requirements and rates tables, included in Appendix A of the Gas Accord V Settlement, reflecting the impacts of PG&E's Test-Year 2013 Cost of Capital adjustments.

Backbone and Local Transmission Adder Project Rate Adjustments

Section 7.4 of the Gas Accord V Settlement addresses treatment of costs associated with various Backbone and Local Transmission adder projects. Under the terms of the Settlement, adder project costs are to be included in rates only if the project is actually built and only starting on January 1 following the project's in-service date. Two Local Transmission adder projects, Line 304 and Line 407 Phase 1, were scheduled to be, but were not, operational in 2012. Accordingly, Local Transmission rates effective January 1, 2013 have been adjusted to remove recovery of the Line 304 and Line 407 Phase 1 adder project revenue requirements.[8]

One Backbone Transmission adder project, P02158-Topock K-Units Replacement Phase 1, was scheduled to be, but was not, operational in 2012. Accordingly,

[8] The 2013 Line 304 adder project revenue requirement removed from Local Transmission rates is $543 thousand. The 2013 Line 407 Phase 1 adder project revenue requirement removed from Local Transmission rates is $6.811 million.

Backbone Transmission rates effective January 1, 2013 have been adjusted to remove recovery of the P02158-Topock K-Units Replacement Phase 1 adder project revenue requirement.[9]

Effective Date

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

Changes to core gas transportation rates will be incorporated into the monthly core procurement advice filing for rates effective January 1, 2013.

Protests

Anyone wishing to protest this advice letter may do so by sending a letter by **January 14, 2013**, which is 21 days[10] from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

CPUC Energy Division
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

[9] The 2013 P02158-Topock K-Units Replacement Phase 1 adder project revenue requirement removed from Backbone Transmission rates is $7.829 million.

[10] The 20 day protest period ends on a weekend. This is the next business day following that weekend.

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter. (General Order 96-B, Rule 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, Rule 3.11).

Notice

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

Brian Cherry /IG

Vice President – Regulatory Relations

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

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

Advice Letter (AL) #: **3353-G** **Tier: 1**

Subject of AL: **Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 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.05-06-029

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: **January 1, 2013** No. of tariff sheets: 37

Estimated system annual revenue effect (%): $1,891 million

Estimated system average rate effect (%): see advice letter

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-BAL G-CFS, G-LEND, G-LNG, G-NAA, G-NAAOFF, G-NAS, G-NFS, G-NFT, G-NFTOFF, G-PARK, G-SFS, G-SFT, G-XF, Gas Preliminary Statements Part B, Part C

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.

ATTACHMENT 1

PACIFIC GAS AND ELECTRIC COMPANY
2013 Annual Gas True-Up (AGT)

2013 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING
($ THOUSANDS)

		A	B	C	D	E	
Line No.		**Present in Rates as of April 2012**	**Proposed as of 1/1/2013**	**Total Change**	**Core**	**Noncore / Unbundled**	Line No.
	END-USE GAS TRANSPORTATION						
1	Gas Transportation Balancing Accounts	167,921	106,086	(61,835)	(53,836)	(7,999)	1
2	GRC Distribution Base Revenues (includes distribution portion of Cost of Capital) [1]	1,166,429	1,172,719	6,290	6,053	237	2
3	Pension	43,764	52,691	8,927	8,616	311	3
4	Self Generation Incentive Program Revenue Requirement	6,480	5,760	(720)	(285)	(435)	4
5	SmartMeter™ Project	82,514	79,202	(3,312)	(3,312)	-	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	2,355	2,474	119	119	-	8
9	Less CARE discount recovered in PPP surcharge from non-CARE customers	(118,884)	(112,382)	6,502	6,502	-	9
10	FF&U	3,419	2,563	(856)	(746)	(110)	10
11	Total Transportation RRQ with Adjustments and Credits	1,350,625	1,305,740	(44,885)	(36,889)	(7,996)	11
12	Procurement-Related G-10 Total	(1,070)	(1,025)	45	45	-	12
13	Procurement-Related G-10 Total Allocated	1,070	1,025	(45)	(18)	(27)	13
14	Total Transportation Revenue Requirements Reallocated	1,350,625	1,305,740	(44,885)	(36,862)	(8,023)	14
	Gas Accord Transportation Revenue Requirements						
15	Local Transmission	208,606	205,643	(2,963)	(4,159)	1,196	15
16	Customer Access	4,821	4,860	39	-	39	16
17	Total Gas Accord Transportation RRQ	213,427	210,503	(2,924)	(4,159)	1,235	17
18	**Total End Use Gas Transportation RRQ**	**1,564,052**	**1,516,243**	**(47,809)**	**(41,021)**	**(6,788)**	18
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING						
19	Energy Efficiency	80,280	56,178	(24,102)	(21,688)	(2,414)	19
20	Energy Savings Assistance	69,960	65,208	(4,752)	(4,276)	(476)	20
21	Research and Development and BOE Administrative Fees	10,717	10,882	165	105	60	21
22	CARE Administrative Expense	1,904	2,739	835	497	338	22
23	Total Authorized PPP Funding	162,861	135,007	(27,854)	(25,362)	(2,492)	23
24	PPP Surcharge Balancing Accounts	(8,657)	(40,827)	(32,170)	(21,040)	(11,130)	24
25	CARE discount recovered from non-CARE customers	118,884	112,382	(6,502)	(3,776)	(2,726)	25
26	**Total PPP Required Funding**	**273,088**	**206,562**	**(66,526)**	**(50,178)**	**(16,348)**	26
	GAS ACCORD UNBUNDLED COSTS						
27	Backbone Transmission	139,103	133,171	(5,932)	-	(5,932)	27
28	Storage	35,729	34,615	(1,114)	-	(1,114)	28
29	**Total Gas Accord Unbundled**	**174,832**	**167,786**	**(7,046)**	**-**	**(7,046)**	29
30	**TOTAL REVENUE REQUIREMENTS**	**2,011,972**	**1,890,591**	**(121,381)**	**(91,199)**	**(30,182)**	30

1. 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
2013 ANNUAL GAS TRUE-UP

2013 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING
($ THOUSANDS)

Line No.		Proposed as of 1/1/2013	Core	Noncore / Unbundled	Line No.
	END-USE GAS TRANSPORTATION				
1	Gas Transportation Balancing Accounts	106,086	77,137	28,949	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	2,563	2,117	446	10
11	Total Transportation RRQ with Adjustments and Credits	1,305,740	1,229,039	76,701	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	1,305,740	1,228,418	77,322	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	**Total End Use Transportation RRQ**	**1,516,243**	**1,361,272**	**154,971**	18
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING				
19	Energy Efficiency	56,178	50,551	5,627	19
20	Energy Savings Assistance	65,208	58,677	6,531	20
21	Research and Development and BOE Administrative Fees	10,882	6,948	3,934	21
22	CARE Administrative Expense	2,739	1,625	1,114	22
23	Total Authorized PPP Funding	135,007	117,801	17,205	23
24	PPP Surcharge Balancing Accounts	(40,827)	(28,057)	(12,770)	24
25	CARE discount recovered from non-CARE customers	112,382	66,681	45,701	25
26	**Total PPP Required Funding**	**206,562**	**156,425**	**50,137**	26
	GAS ACCORD UNBUNDLED COSTS				
27	Backbone Transmission	133,171	-	133,171	27
28	Storage	34,615	-	34,615	28
29	**Total Gas Accord Unbundled**	**167,786**	**-**	**167,786**	29
30	**TOTAL REVENUE REQUIREMENTS**	**1,890,591**	**1,517,697**	**372,894**	30

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

ATTACHMENT 2

PACIFIC GAS AND ELECTRIC COMPANY
2013 ANNUAL GAS TRUE-UP
BALANCING ACCOUNT FORECAST SUMMARY
($ 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	$3,925	$34	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	$0 *(4)*	$0	$0	$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)*	$1,993	$3,061	$0	$0	$0	23
24	**Subtotal Transportation Balancing Accounts**	**$106,086**	**$77,137**	**$28,949**	**$171,362**	**$135,030**	**$36,332**	24
	PUBLIC PURPOSE PROGRAM (PPP) SURCHARGE BALANCING ACCOUNTS							
25	PPP-Energy Efficiency *(5)*	($3,176)	($2,858)	($318)	$1,096	$986	$110	25
26	PPP-Low Income Energy Efficiency *(5)*	($9,229)	($8,305)	($924)	$518	$466	$52	26
27	PPP-Research Development and Demonstration *(5)*	($659)	($421)	($238)	($85)	($54)	($31)	27
28	California Alternate Rates for Energy Account *(5)*	($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**	**$65,259**	**$49,080**	**$16,179**	**$173,519**	**$136,800**	**$36,719**	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 will be transferred evenly (50/50) to the CFCA and NCA after the approval of the AGT advice letter.
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 balance is $15M, however a zero amount is indicated because PG&E is in the process of determining billing system requirements related to this proceeding and plans to implement the results of D.12-10-044 in rates as soon as practical.
5. These 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.

PACIFIC GAS AND ELECTRIC COMPANY
January 1, 2013 Filed Dec 24, 2012 - AL 3353-G
ATTACHMENT 3

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

Line No.	Customer Class	Rates Effective April 1, 2012 (A)			January 1, 2013 Filed Dec 24, 2012 - AL 3353-G (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)	$.611	$.086	**$.697**	$.593	$.066	**$.658**	(3.0%)	(24.0%)	(5.6%)
2	Small Commercial Non-CARE (4)	$.383	$.053	**$.436**	$.369	$.039	**$.408**	(3.7%)	(26.8%)	(6.5%)
3	Large Commercial	$.166	$.095	**$.261**	$.158	$.071	**$.230**	(4.9%)	(24.8%)	(12.1%)
4	NGV1 - (uncompressed service)	$.128	$.032	**$.160**	$.116	$.024	**$.140**	(9.5%)	(24.7%)	(12.5%)
5	NGV2 - (compressed service)	$1.351	$.032	**$1.383**	$1.362	$.024	**$1.386**	0.8%	(24.7%)	0.2%
	RETAIL NONCORE (1)									
6	Industrial - Distribution	$.142	$.047	**$.189**	$.134	$.036	**$.169**	(5.9%)	(24.6%)	(10.6%)
7	Industrial - Transmission	$.039	$.040	**$.079**	$.037	$.030	**$.067**	(4.0%)	(24.6%)	(14.4%)
8	Industrial - Backbone	$.012	$.040	**$.052**	$.012	$.030	**$.042**	(6.7%)	(24.6%)	(20.4%)
9	Electric Generation - Transmission (G-EG-D/LT)	$.032		**$.032**	$.030		**$.030**	(6.2%)		(6.2%)
10	Electric Generation - Backbone (G-EG-BB)	$.012		**$.012**	$.010		**$.010**	(14.8%)		(14.8%)
11	NGV 4 - Distribution (uncompressed service)	$.142	$.032	**$.174**	$.134	$.024	**$.158**	(5.9%)	(24.7%)	(9.4%)
12	NGV 4 - Transmission (uncompressed service)	$.032	$.032	**$.064**	$.031	$.024	**$.055**	(3.5%)	(24.7%)	(14.0%)
	WHOLESALE CORE AND NONCORE (G-WSL) (1)									
13	Alpine Natural Gas	$.034		**$.034**	$.032		**$.032**	(5.9%)		(5.9%)
14	Coalinga	$.035		**$.035**	$.033		**$.033**	(5.4%)		(5.4%)
15	Island Energy	$.053		**$.053**	$.051		**$.051**	(3.0%)		(3.0%)
16	Palo Alto	$.030		**$.030**	$.028		**$.028**	(6.0%)		(6.0%)
17	West Coast Gas - Castle	$.137		**$.137**	$.142		**$.142**	3.5%		3.5%
18	West Coast Gas - Mather Distribution	$.163		**$.163**	$.169		**$.169**	4.3%		4.3%
19	West Coast Gas - Mather Transmission	$.037		**$.037**	$.035		**$.035**	(4.6%)		(4.6%)

(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.

PACIFIC GAS AND ELECTRIC COMPANY
JANUARY 1, 2013 FILED DEC 24, 2012 - AL 3353-G
ATTACHMENT 4
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)	$.04238	$.04238	$.04238	$.04238	$.04238	$.01989	$.01989	$.00068	$.01989	$.01989	$.01989	$.00068
2 Self Generation Incentive Program	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080	$.00080
3 CPUC (3)	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00069	$.00003	$.00003
4 Balancing Accounts (2)	$.06987	$.04570	$.01843	$.02273	$.06610	$.00556	$.00776	$.00790	$.00556	$.00790	$.00629	$.00629
5 Distribution - Annual Average (6)	$.47917	$.22073	$.09153	$.04825	$1.25162	$.09911	$.00641		$.09911		$.00201	$.00201
6 **VOLUMETRIC RATE - Average Annual**	$.59291	$.31029	$.15383	$.11484	$1.36159	$.12605	$.03555	$.01007	$.12605	$.02928	$.02902	$.00981
7 **CUSTOMER ACCESS CHARGE - Class Average (4)**		$.05888	$.00449	$.00120	$.00000	$.00762	$.00180	$.00153	$.00762	$.00180	$.00106	$.00021
8 **CLASS AVERAGE TRANSPORTATION RATE**	$.59291	$.36918	$.15832	$.11604	$1.36159	$.13367	$.03735	$.01160	$.13367	$.03109	$.03008	$.01002
9 **PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)**	$.06551	$.03878	$.07137	$.02408	$.02408	$.03568	$.02990	$.02990	$.02408	$.02408		
10 **END-USE RATE (7)**	$.65842	$.40796	$.22969	$.14012	$1.38567	$.16935	$.06725	$.04150	$.15775	$.05517	$.03008	$.01002

	Wholesale						
			WC Gas Mather		Island		WC Gas
	Coalinga	Palo Alto	Dist.	Trans.	Energy	Alpine	Castle
TRANSPORTATION CHARGE COMPONENTS							
11 Local Transmission (1)	$.01989	$.01989	$.01989	$.01989	$.01989	$.01989	$.01989
12 Self Generation Incentive Program	WHOLESALE CUSTOMERS EXCEPT FROM SGIP RATE COMPONENT						
13 CPUC (3)							
14 Balancing Accounts (2)	$.00632	$.00632	$.00320	$.00632	$.00632	$.00632	$.00396
15 Distribution - Annual Average			$.13710				$.10354
16 **VOLUMETRIC RATE - Average Annual**	$.02621	$.02621	$.16019	$.02621	$.02621	$.02621	$.12739
17 **CUSTOMER ACCESS CHARGE - Class Average (4)**	$.00661	$.00173	$.00923	$.00923	$.02504	$.00590	$.01489
18 **CLASS AVERAGE TRANSPORTATION RATE**	$.03281	$.02794	$.16942	$.03543	$.05124	$.03211	$.14229
19 **PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)**							
20 **END-USE RATE**	$.03281	$.02794	$.16942	$.03543	$.05124	$.03211	$.14229

NOTES
(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2013 AGT AL 3353-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 AGT AL 3353-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
January 1, 2013 Filed Dec 24, 2012 - AL 3353-G
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	Line No.
1	Customer	659,284	575,206	76,655	1,640	67	0	653,568	4,058	231	0	1,427	0	0	0	0	0	0	0	5,716	1
2	Distribution	547,451	381,825	122,954	5,426	920	0	511,125	23,378	8,867	0	3,926	0	0	0	0	86	0	69	36,326	2
3	G-NGV2 Compression Cost	2,913	0	0	0	0	2,913	2,913	0	0	0	0	0	0	0	0	0	0	0	0	3
4	Allocation of Base Distribution Franchise Fees	11,959	9,461	1,973	70	10	29	11,543	271	90	0	53	0	0	0	0	1	0	1	416	4
5	Allocation of Base Distribution Uncollectibles Expense	3,804	3,010	628	22	3	9	3,673	86	29	0	17	0	0	0	0	0	0	0	132	5
6	Totals Before Core Averaging	1,225,410	969,503	202,209	7,158	1,000	2,951	1,182,821	27,794	9,216	0	5,423	0	0	0	0	87	0	69	42,589	6
7	Re-Allocation Due to Core Averaging*	(0)	(19,341)	19,341	0	0	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0	7
8	**Final Allocation of Distribution Revenue Requirement**	**1,225,410**	**950,162**	**221,551**	**7,158**	**1,000**	**2,951**	**1,182,821**	**27,794**	**9,216**	**0**	**5,423**	**0**	**0**	**0**	**0**	**87**	**0**	**69**	**42,589**	8
	Distribution-Level Revenue Requirement Allocation %	100.00000%	77.53824%	18.07972%	0.58410%	0.08160%	0.24081%	96.52447%	2.26813%	0.75211%	0.00000%	0.44253%	0.00000%	0.00000%	0.00000%	0.00000%	0.00709%	0.00000%	0.00567%	3.47553%	

Total Core Brokerage Fee (w/out FF&U) (6,498) (6,583) ←— With FF&U

Line No.	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	Line No.
9	Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount	14,608	11,735	2,736	88	12	36	14,608	0	0	0	0	0	0	0	0	0	0	0	0	9
10	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	10
11	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	11
12	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)	12
13	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)	13
14	NC Distribution Fixed Cost Acct.	(22)	0	0	0	0	0	0	(14)	(5)	0	(3)	0	0	0	0	(0)	0	(0)	(22)	14
15	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	15
16	Liquefied Natural Gas Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16
17	Hazardous Substance Balance	39,095	10,699	4,215	397	108	0	15,418	1,385	7,645	62	14,358	28	13	170	3	5	3	4	23,677	17
18	Non-Tariffed Products and Services	(274)	(190)	(75)	(7)	(2)	0	(274)	0	0	0	0	0	0	0	0	0	0	0	0	18
19	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	19
20	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	20
21	Affiliate Transfer Fee Account	(29)	(23)	(5)	(0)	(0)	(0)	(28)	(1)	(0)	0	(0)	0	0	0	0	(0)	0	(0)	(1)	21
22	Balancing Charge Account	742	203	80	8	2	0	293	26	145	1	272	1	0	3	0	0	0	0	449	22
23	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	23
24	Brokerage Fee Balance Account	501	347	137	13	3	0	501	0	0	0	0	0	0	0	0	0	0	0	0	24
25	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	25
26	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	26
27	TID Almond Power Plant	(773)	(212)	(83)	(8)	(2)	0	(305)	(27)	(151)	(1)	(284)	(1)	(0)	(3)	(0)	(0)	(0)	(0)	(468)	27
28	RCESBA-G	293	232	48	2	0	1	283	7	2	0	1	0	0	0	0	0	0	0	10	28
29	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	29
30	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	30
31	GT&S Revenue Sharing Mechanism	5,054	1,383	545	51	14	0	1,993	179	988	8	1,856	4	2	22	0	1	0	0	3,061	31
32	Gas Meter Reading Costs Balancing Account	27,266	21,903	5,107	165	23	68	27,266	0	0	0	0	0	0	0	0	0	0	0	0	32
33	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	33
34	Subtotals of Items Transferred to CFCA and NCA	112,748	62,146	16,487	840	157	105	79,735.832	1,611	12,139	100	18,888	45	15	200	4	4	4	3	33,012.58	34
35	Re-Allocation Due to Core Averaging	0	(561)	561	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35
36	Alloc. After Core Averaging	112,748	61,585	17,048	840	157	105	79,735.832	1,611	12,139	100	18,888	45	15	200	4	4	4	3	33,012.58	36
37	Franchise Fees and Uncoll. Exp. on Items Above	1,469	803	222	11	2	1	1,039	21	158	1	246	1	0	2	0	0	0	0	429	37
38	Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs	114,217	62,388	17,270	851	159	106	80,775	1,632	12,297	101	19,134	46	15	202	4	4	4	3	33,442	38
39	Total of Items Collected via CFCA, NCA, and NDFCA	1,339,627	1,012,549	238,821	8,009	1,159	3,057	1,263,596	29,426	21,514	101	24,557	46	15	202	4	91	4	72	76,032	39

Line No.	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	Line No.
40	CEE Incentive	3,757	3,278	437	9	0	0	3,724	23	1	0	8	0	0	0	0	0	0	0	33	40
41	Smart Meter™ Project Forecast Period Costs	79,202	63,623	14,835	479	265	0	79,202	0	0	0	0	0	0	0	0	0	0	0	0	41
42	SmartMeter™ Project Balancing Account (SBA-G)	14,200	11,407	2,660	86	47	0	14,200	0	0	0	0	0	0	0	0	0	0	0	0	42
43	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	43
44	Subtotals for Customer Class Charge Items	100,369	79,675	18,469	625	326	0	99,096	200	979	8	83	4	0	0	0	0	0	0	1,273	44
45	Re-Allocation Due to Core Averaging	0	(1,390)	1,390	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45
46	Allocation after Remaining Core Averaging	100,369	78,285	19,860	625	326	0	99,096	200	979	8	83	4	0	0	0	0	0	0	1,273	46
47	Franch. Fee and Uncoll. Exp. on Items Above	1,308	1,020	259	8	4	0	1,291	3	13	0	1	0	0	0	0	0	0	0	17	47
48	Subtotals of Other Costs	101,677	79,305	20,118	633	330	0	100,388	203	991	8	84	4	0	0	0	0	0	0	1,290	48
49	Allocation of Total Transportation Costs	1,441,304	1,091,855	258,939	8,642	1,490	3,057	1,363,983	29,629	22,505	109	24,641	49	15	202	4	91	4	72	77,321	49

Line No.	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	Line No.
50	WGSP-T Rebate Recovery (w/o FF&U)	(22,885)	(18,320)	(4,422)	(143)			(22,885)												0	50
51	Franchise Fees and Uncollectibles Expense	(298)	(239)	(58)	(2)			(298)												0	51
52	Total End-User Transportation Rev. Req. Excluding Gas Accord	1,418,121	1,073,296	254,460	8,498	1,490	3,057	1,340,800	29,629	22,505	109	24,641	49	15	202	4	91	4	72	77,321	52
	WGSP - T Marketing and Implementation	2,474	2,506 <—w F&U																		

Line No.	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	Line No.
53	Local Transmission	205,643	99,834	30,681	1,890	449		132,853	7,009	27,937		35,401	116	113	1,098	32	44	17	24	72,789	53
54	Customer Access Charge	4,860	0	0	0			0	0	2,562		2,192		17	55	4	9	11	10	4,860	54
55	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	55
56	Gross End-User Transportation Costs in Rates	1,628,624	1,173,130	285,141	10,387	1,938	3,057	1,473,654	36,638	53,004	109	63,234	165	144	1,355	39	144	32	106	154,970	56
57	Less Forecast CARE Discount recovered in PPP Surcharges	112,382	112,382					112,382												0	57
58	Net End-User Transportation Costs in Rates	1,516,241	1,060,747	285,141	10,387	1,938	3,057	1,361,271	36,638	53,004	109	63,234	165	144	1,355	39	144	32	106	154,970	58

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT 5 (continued)
January 1, 2013 Filed Dec 24, 2012 - AL 3353-G

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**	Noncore & Wholesale	Line No.
59	PPP-EE Surcharge	56,177.50	44,279	4,506	1,766	0		50,551	1,510	4,084	33		0							5,627	59
60	PPP-EE Balancing Account	(3,176.00000)	(2,503)	(255)	(100)	0		(2,858)	(85)	(231)	(2)		0							-318	60
61	PPP-ESA Surcharge	65,208.12	51,397	5,231	2,050	0		58,677	1,753	4,740	38		0							6,531	61
62	PPP-ESA Balancing Account	(9,229.00)	(7,274)	(740)	(290)	0		(8,305)	(248)	(671)	(5)		0							-924	62
63	PPP - RD&D Programs	10,559.04	4,707	1,823	170	42		6,742	592	3,187	26		12							3,817	63
64	PPP - RD&D Balancing Account	(659.00)	(294)	(114)	(11)	(3)		(421)	(37)	(199)	(2)		(1)							-238	64
65	PPP-CARE Discount Allocation Set Annually	112,382.3962	42,308	21,833	2,033	508		66,682	7,089	38,157	309		147							45,701	65
66	PPP-CARE Administration Expense	2,739.33	1,031	532	50	12		1,625	173	930	8		4							1,114	66
67	PPP-CARE Balancing Account	(27,763.00)	(10,452)	(5,394)	(502)	(125)		(16,473)	(1,751)	(9,426)	(76)		(36)							-11,290	67
68	PPP-Admin Cost for BOE and CPUC	322.49	144	56	5	1		206	18	97	1		0							117	68
69	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	50,136	69
70	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	0	70
71	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	50,136	71

Line No.				Line No.
72	Unbundled Gas Transmission and Storage Revenue Requirement	167,785		72
	TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES			
73	Total Transportation, PPPS,and Unbundled Costs	1,890,588	(Total of lines 58, 71, and 72)	73
74	Cross-check with Gas Revenue Requirement Table	1,890,591	(Total Row 31, Attachment 1)	74
75	Difference	3	(rounding due to allocating $)	75

* Residential and Small Commercial Classes are 15% averaged

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

Advice 3353-G
December 24, 2012

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 the 2013 Cost of Capital Decision issued 12/20/2012 D. 12-12-034.

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 January 1, 2013

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

Line		GA V Settlement	GA V with 2013 COC				GA V with 2013 COC, excluding Non-Operational Adder Projects.			
No.		2011 (9)	2011	2012	2013 (10)	2014 (11)	2011	2012	2013 (10)	2014 (11)
	Core Revenue Requirements									
1	Backbone Transmission Base (1) (2) (5) (6)	94,929	93,414	95,901	92,766	98,518	86,621	95,901	92,766	98,518
2	Backbone Transmission Adders	-	-	-	3,173	3,335	-	-	-	3,335
3	Subtotal Backbone Transmission	94,929	93,414	95,901	95,939	101,853	86,621	95,901	92,766	101,853
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	$283,035	$296,469	$254,444	$283,036	$275,111	$296,469
		53.4%	53.3%	53.0%	52.8%	53.7%	53.3%	53.0%	52.9%	53.7%
	Noncore / Unbundled Revenue Requirements									
10	Backbone Trans. Base w/o G-XF Contracts	124,818	123,774	132,655	127,238	123,053	114,758	132,655	127,238	123,053
11	Backbone Transmission Adders	-	-	-	4,656	5,158	-	-	-	5,158
12	Subtotal Backbone Transmission	124,818	123,774	132,655	131,895	128,211	114,758	132,655	127,238	128,211
13	G-XF Contracts	6,879	6,875	6,448	5,932	5,773	6,875	6,448	5,932	5,773
14	G-XF Contract Adders	-	-	-	-	43	-	-	-	43
15	G-XF Contracts Subtotal	6,879	6,875	6,448	5,932	5,816	6,875	6,448	5,932	5,816
16	Subtotal Backbone Transmission (5) (6)	131,698	130,648	139,103	137,827	134,027	121,633	139,103	133,171	134,027
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	$252,694	$255,820	$223,373	$251,246	$245,434	$255,820
		46.6%	46.7%	47.0%	47.2%	46.3%	46.7%	47.0%	47.1%	46.3%
	Total									
23	Backbone Transmission Base w/o G-XF Contracts	219,747	217,188	228,556	220,004	221,571	201,379	228,556	220,004	221,571
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	227,834	230,064	201,379	228,556	220,004	230,064
26	G-XF Contracts	6,879	6,875	6,448	5,932	5,773	6,875	6,448	5,932	5,773
27	G-XF Contract Adders	-	-	-	-	43	-	-	-	43
28	G-XF Contracts Subtotal	6,879	6,875	6,448	5,932	5,816	6,875	6,448	5,932	5,816
29	Subtotal Backbone Transmission (5) (6)	226,627	224,062	235,004	233,766	235,880	208,254	235,004	225,937	235,880
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	$535,729	$552,289	$477,817	$534,281	$520,545	$552,289
		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Appendix A
Effective January 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

(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. 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.

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Gas Accord V Settlement Agreement

Appendix A

Rates Effective January 1, 2013

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

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

(Topock Adder Projects In-Service 2013)

G-AFT: Annual Firm Transportation On-System

Line No.		Noncore Redwood 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	5.4087	5.4576	5.1339	5.0727		8.3095	8.3437	7.7904	7.6579	
3	Usage Charge	0.1038	0.1032	0.0952	0.0928		0.0084	0.0083	0.0079	0.0078	
4	Total Charge	0.2816	0.2826	0.2640	0.2596		0.2816	0.2826	0.2640	0.2596	
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	5.1339	5.2621		8.3095	8.3437	7.7904	7.9439	
29	Usage Charge	0.1038	0.1032	0.0952	0.0962		0.0084	0.0083	0.0079	0.0080	
30	Total Charge	0.2816	0.2826	0.2640	0.2692		0.2816	0.2826	0.2640	0.2692	

Line No.		Noncore 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	5.8930	6.0418	5.8209	5.9601		9.0536	9.2370	8.8327	8.9977	
3	Usage Charge	0.1129	0.1140	0.1076	0.1087		0.0089	0.0089	0.0086	0.0088	
4	Total Charge	0.3066	0.3126	0.2990	0.3046		0.3066	0.3126	0.2990	0.3046	
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	5.8209	6.1495		9.0536	9.2370	8.8327	9.2836	
29	Usage Charge	0.1129	0.1140	0.1076	0.1120		0.0089	0.0089	0.0086	0.0090	
30	Total Charge	0.3066	0.3126	0.2990	0.3142		0.3066	0.3126	0.2990	0.3142	

(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

(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. 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 January 1, 2013

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

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

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

Core 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	4.7466	4.6534	4.4009	4.3485		6.5162	6.4678	6.1720	6.1459	
3	Usage Charge	0.0684	0.0693	0.0672	0.0680		0.0102	0.0096	0.0090	0.0089	
4	Total Charge	0.2244	0.2223	0.2119	0.2110		0.2244	0.2223	0.2119	0.2110	
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	4.4009	4.5991		6.5162	6.4678	6.1720	6.5002	
29	Usage Charge	0.0684	0.0693	0.0672	0.0718		0.0102	0.0096	0.0090	0.0093	
30	Total Charge	0.2244	0.2223	0.2119	0.2230		0.2244	0.2223	0.2119	0.2230	

Core 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	5.2811	5.2883	5.1362	5.2867		7.2499	7.3504	7.2031	7.4720	
3	Usage Charge	0.0758	0.0784	0.0780	0.0822		0.0111	0.0106	0.0101	0.0103	
4	Total Charge	0.2494	0.2523	0.2469	0.2560		0.2494	0.2523	0.2469	0.2560	
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	$5.1362	$5.5373		7.2499	7.3504	$7.2031	$7.8262	
29	Usage Charge	0.0758	0.0784	$0.0780	$0.0859		0.0111	0.0106	$0.0101	$0.0107	
30	Total Charge	0.2494	0.2523	$0.2469	$0.2680		0.2494	0.2523	$0.2469	$0.2680	

(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

(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. 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 January 1, 2013

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

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

(Topock Adder Projects In-Service 2013)

G-AFT: Annual Firm Transportation On-System

		Silverado Path									
		MFV					SFV				
Line 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	3.1407	3.1506		4.8056	4.6413	4.4125	4.4208	
3	Usage Charge	0.0554	0.0545	0.0476	0.0475		0.0049	0.0059	0.0058	0.0058	
4	Total Charge	0.1628	0.1585	0.1508	0.1511		0.1628	0.1585	0.1508	0.1511	
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	3.1407	3.2921		4.8056	4.6413	4.4125	4.6279	
29	Usage Charge	0.0554	0.0545	0.0476	0.0498		0.0049	0.0059	0.0058	0.0059	
30	Total Charge	0.1628	0.1585	0.1508	0.1581		0.1628	0.1585	0.1508	0.1581	

(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

(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. 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 January 1, 2013

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

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

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

		Noncore Redwood Path									
		MFV					SFV				
Line 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	6.1607	6.0872		9.9714	10.0125	9.3484	9.1895	
3	Usage Charge	0.1245	0.1238	0.1142	0.1114		0.0101	0.0100	0.0094	0.0094	
4	Total Charge	0.3379	0.3392	0.3168	0.3115		0.3379	0.3392	0.3168	0.3115	
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	6.1607	6.3145		9.9714	10.0125	9.3484	9.5326	
29	Usage Charge	0.1245	0.1238	0.1142	0.1155		0.0101	0.0100	0.0094	0.0097	
30	Total Charge	0.3379	0.3392	0.3168	0.3231		0.3379	0.3392	0.3168	0.3231	

		Noncore 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	7.0717	7.2502	6.9850	7.1522		10.8643	11.0843	10.5992	10.7973	
3	Usage Charge	0.1354	0.1368	0.1291	0.1304		0.0107	0.0107	0.0103	0.0106	
4	Total Charge	0.3679	0.3752	0.3588	0.3655		0.3679	0.3752	0.3588	0.3655	
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	6.9850	7.3794		10.8643	11.0843	10.5992	11.1404	
29	Usage Charge	0.1354	0.1368	0.1291	0.1344		0.0107	0.0107	0.0103	0.0108	
30	Total Charge	0.3679	0.3752	0.3588	0.3771		0.3679	0.3752	0.3588	0.3771	

(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

(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. 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 January 1, 2013

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

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

(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	6.1634	6.3440		8.6999	8.6204	8.6438	8.9664	
3	Usage Charge	0.0910	0.0941	0.0936	0.0986		0.0133	0.0127	0.0121	0.0124	
4	Total Charge	0.2993	0.3027	0.2963	0.3072		0.2993	0.3027	0.2963	0.3072	
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	6.1634	6.6448		8.6999	8.6204	8.6438	9.3915	
29	Usage Charge	0.0910	0.0941	0.0936	0.1031		0.0133	0.0127	0.0121	0.0128	
30	Total Charge	0.2993	0.3027	0.2963	0.3216		0.2993	0.3027	0.2963	0.3216	

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	3.7967	3.7689	3.7807		5.7667	5.5695	5.2951	5.3049	
3	Usage Charge	0.0665	0.0654	0.0571	0.0571		0.0058	0.0071	0.0069	0.0069	
4	Total Charge	0.1954	0.1902	0.1810	0.1813		0.1954	0.1902	0.1810	0.1813	
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	3.7967	3.7689	3.9506		5.7667	5.5695	5.2951	5.5535	
29	Usage Charge	0.0665	0.0654	0.0571	0.0598		0.0058	0.0071	0.0069	0.0071	
30	Total Charge	0.1954	0.1902	0.1810	0.1897		0.1954	0.1902	0.1810	0.1897	

(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

(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. 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 January 1, 2013

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

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

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

Line No.		Redwood Path				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Usage Charge ($/Dth)**	0.3379	0.3392	0.3168	0.3115	
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	0.3168	0.3231	

Line No.		Baja Path				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
9	**Base Usage Charge ($/Dth)**	0.3679	0.3752	0.3588	0.3655	
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	0.3588	0.3771	

Line No.		Silverado Path				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
17	**Base Usage Charge ($/Dth)**	0.1954	0.1902	0.1810	0.1813	
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	0.1810	0.1897	

Line No.		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

(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. 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 January 1, 2013

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

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

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

Line No.		Redwood, Silverado and Mission (From City Gate) Off-System - Noncore				
		2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Usage Charge ($/Dth)**	0.3379	0.3392	0.3168	0.3115	
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	0.3168	0.3231	

		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	0.3588	0.3655	
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	0.3588	0.3771	

(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

(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. 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 January 1, 2013

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

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

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

Redwood, Silverado and Mission Paths Off-System

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	5.1339	5.0727		8.3095	8.3437	7.7904	7.6579	
3	Usage Charge	0.1038	0.1032	0.0952	0.0928		0.0084	0.0083	0.0079	0.0078	
4	Total Charge	0.2816	0.2826	0.2640	0.2596		0.2816	0.2826	0.2640	0.2596	
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	5.1339	5.2621		8.3095	8.3437	7.7904	7.9439	
29	Usage Charge	0.1038	0.1032	0.0952	0.0962		0.0084	0.0083	0.0079	0.0080	
30	Total Charge	0.2816	0.2826	0.2640	0.2692		0.2816	0.2826	0.2640	0.2692	

Baja Path Off-System

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	5.8209	5.9601		9.0536	9.2370	8.8327	8.9977	
3	Usage Charge	0.1129	0.1140	0.1076	0.1087		0.0089	0.0089	0.0086	0.0088	
4	Total Charge	0.3066	0.3126	0.2990	0.3046		0.3066	0.3126	0.2990	0.3046	
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	5.8209	6.1495		9.0536	9.2370	8.8327	9.2836	
29	Usage Charge	0.1129	0.1140	0.1076	0.1120		0.0089	0.0089	0.0086	0.0090	
30	Total Charge	0.3066	0.3126	0.2990	0.3142		0.3066	0.3126	0.2990	0.3142	

(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

(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. 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 January 1, 2013

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

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

G-XF: Pipeline Expansion Firm Intrastate Transportation Service

Line No.		Expansion Shippers (G-XF) SFV 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	0.0016	0.0016
4	Total Charge	0.2032	0.2059	0.1894	0.1843
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	0.0016	0.0016
13	Total Charge	0.2032	0.2059	0.1894	0.1857

(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

(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. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Gas Accord V Settlement Agreement

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

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

Gas Accord V Settlement Agreement

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 Billing 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.

A.09-09-013

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 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 and 2013 Cost of Capital

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path - Core (1)						
Reservation Charge	($/dth/mo)	4.3368	6.5162	6.4678	6.1720	6.5002
Usage Charge	($/dth)	0.0124	0.0102	0.0096	0.0090	0.0093
Total	($/dth @ Full Contract)	0.1550	0.2244	0.2223	0.2119	0.2230
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	9.2319	7.2499	7.3504	7.2031	7.8262
Usage Charge	($/dth)	0.0153	0.0111	0.0106	0.0101	0.0107
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2469	0.2680
Redwood Path - Noncore						
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.7904	7.9439
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0080
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2640	0.2692
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.8327	9.2836
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0086	0.0090
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.2990	0.3142
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	4.4828	4.8056	4.6413	4.4125	4.6279
Usage Charge	($/dth)	0.0060	0.0049	0.0059	0.0058	0.0059
Total	($/dth @ Full Contract)	0.1534	0.1628	0.1585	0.1508	0.1581

(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

(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. 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.

A.09-09-013

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 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 and 2013 Cost of Capit

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path - Core (1)						
Reservation Charge	($/dth/mo)	3.3290	4.7466	4.6534	4.4009	4.5991
Usage Charge	($/dth)	0.0455	0.0684	0.0693	0.0672	0.0718
Total	($/dth @ Full Contract)	0.1549	0.2244	0.2223	0.2119	0.2230
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	7.0037	5.2811	5.2883	5.1362	5.5373
Usage Charge	($/dth)	0.0885	0.0758	0.0784	0.0780	0.0859
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2469	0.2680
Redwood Path - Noncore						
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.1339	5.2621
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0952	0.0962
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2640	0.2692
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8209	6.1495
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1076	0.1120
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.2990	0.3142
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	3.0839	3.2679	3.1639	3.1407	3.2921
Usage Charge	($/dth)	0.0518	0.0554	0.0545	0.0476	0.0498
Total	($/dth @ Full Contract)	0.1532	0.1628	0.1585	0.1508	0.1581

(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.

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(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. 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 January 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 and 2013 Cost of Capital

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path						
Reservation Charge	($/dth/mo)	10.4795	9.9714	10.0125	9.3484	9.5326
Usage Charge	($/dth)	0.0082	0.0101	0.0100	0.0094	0.0097
Total	($/dth @ Full Contract)	0.3527	0.3379	0.3392	0.3168	0.3231
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	11.0784	8.6999	8.8204	8.6438	9.3915
Usage Charge	($/dth)	0.0183	0.0133	0.0127	0.0121	0.0128
Total	($/dth @ Full Contract)	0.3825	0.2993	0.3027	0.2963	0.3216
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	11.0784	10.8643	11.0843	10.5992	11.1404
Usage Charge	($/dth)	0.0183	0.0107	0.0107	0.0103	0.0108
Total	($/dth @ Full Contract)	0.3825	0.3679	0.3752	0.3588	0.3771
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	5.3794	5.7667	5.5695	5.2951	5.5535
Usage Charge	($/dth)	0.0071	0.0058	0.0071	0.0069	0.0071
Total	($/dth @ Full Contract)	0.1840	0.1954	0.1902	0.1810	0.1897

(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

(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. 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.

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 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 and 2013 Cost of Capital

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path						
Reservation Charge	($/dth/mo)	6.0840	6.4905	6.5491	6.1607	6.3145
Usage Charge	($/dth)	0.1528	0.1245	0.1238	0.1142	0.1155
Total	($/dth @ Full Contract)	0.3528	0.3379	0.3392	0.3168	0.3231
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	8.4044	6.3373	6.3460	6.1634	6.6448
Usage Charge	($/dth)	0.1063	0.0910	0.0941	0.0936	0.1031
Total	($/dth @ Full Contract)	0.3826	0.2993	0.3027	0.2963	0.3216
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	8.4044	7.0717	7.2502	6.9850	7.3794
Usage Charge	($/dth)	0.1063	0.1354	0.1368	0.1291	0.1344
Total	($/dth @ Full Contract)	0.3826	0.3679	0.3752	0.3588	0.3771
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	3.7008	3.9215	3.7967	3.7689	3.9506
Usage Charge	($/dth)	0.0622	0.0665	0.0654	0.0571	0.0598
Total	($/dth @ Full Contract)	0.1839	0.1954	0.1902	0.1810	0.1897

(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.

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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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Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 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 and 2013 Cost of Capital

		2010	GA IV	2011 (1)	2012	2013 (2)	2014 (3)
Redwood Path Usage Charge	($/dth)	0.3528		0.3379	0.3392	0.3168	0.3231
Baja Path Usage Charge	($/dth)	0.3826		0.3679	0.3752	0.3588	0.3771
Silverado Path Usage Charge	($/dth)	0.1839		0.1954	0.1902	0.1810	0.1897
Mission Path Usage Charge	($/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

(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. 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.

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Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 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 and 2013 Cost of Capital

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
SFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.7904	7.9439
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0080
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2640	0.2692
Baja Path Off-System						
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.8327	9.2836
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0086	0.0090
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.2990	0.3142
MFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.1339	5.2621
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0952	0.0962
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2640	0.2692
Baja Path Off-System						
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8209	6.1495
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1076	0.1120
Total	($/dth @ Full	0.3188	0.3066	0.3126	0.2990	0.3142
As-Available Service						
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore						
Usage Charge	($/dth)	0.3528	0.3379	0.3392	0.3168	0.3231
Mission Paths (From on-system storage) Off-System						
Usage Charge	($/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	0.3588	0.3771

(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

(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. 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 January 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 and 2013 Cost of Capital

		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	0.0016	0.0016
Total	($/dth @ Full Contract)	0.2096	0.2032	0.2059	0.1894	0.1857

(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

(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. 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 January 1, 2013

Table B-10

Storage Services

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

		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

(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. 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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Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2013

Table B-11

Local Transmission Rates
($/dth)

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

		GA IV 2010 (1)	2011 (2)	2012	2013 (3)	2014 (4)
Base Rates:						
Core Retail		0.3764	0.4118	0.4182	0.4072	0.4170
Noncore Retail and Wholesale		0.1628	0.2031	0.1933	0.1911	0.2041
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	0.4401	0.4628
Noncore Retail and Wholesale		0.1678	0.2139	0.2024	0.2065	0.2266

(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

(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. 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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Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2013

Table B-12

Customer Access Charges
($ per Month)

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

		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

(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. 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 January 1, 2013

Table B-13

Self Balancing Credit
$/dth

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

	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

(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. 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.**
30161-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 12	29448-G
30162-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 13	29449-G
30163-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 14	29450-G
30164-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 15	29451-G
30165-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 16	29452-G
30166-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 17	29453-G
30167-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 18	29454-G
30168-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 19	29455-G
30169-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 20	29620-G
30170-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 2	29457-G
30171-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 3	29458-G
30172-G*	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 4	29459-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
30173-G	GAS SCHEDULE G-AA AS AVAILABLE TRANSPORTATION ON-SYSTEM Sheet 2	29461-G
30174-G	GAS SCHEDULE G-AAOFF AS-AVAILABLE TRANSPORTATION OFF-SYSTEM Sheet 2	29462-G
30175-G	GAS SCHEDULE G-AFT ANNUAL FIRM TRANSPORTATION ON-SYSTEM Sheet 2	29463-G
30176-G	GAS SCHEDULE G-AFTOFF ANNUAL FIRM TRANSPORTATION OFF-SYSTEM Sheet 2	29464-G
30177-G	GAS SCHEDULE G-BAL GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS Sheet 4	29465-G
30178-G	GAS SCHEDULE G-CFS CORE FIRM STORAGE Sheet 1	29658-G
30179-G	GAS SCHEDULE G-EG GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION Sheet 1	29467-G
30180-G	GAS SCHEDULE G-LEND MARKET CENTER LENDING SERVICES Sheet 1	29468-G
30181-G	GAS SCHEDULE G-LNG EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE Sheet 1	29469-G
30182-G	GAS SCHEDULE G-NAS NEGOTIATED AS-AVAILABLE STORAGE SERVICE Sheet 1	29470-G

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
30183-G	GAS SCHEDULE G-NFS NEGOTIATED FIRM STORAGE SERVICE Sheet 1	29471-G
30184-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 1	29473-G
30185-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 2	29474-G
30186-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 1	29475-G
30187-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 2	29476-G
30188-G	GAS SCHEDULE G-PARK MARKET CENTER PARKING SERVICES Sheet 1	29477-G
30189-G	GAS SCHEDULE G-SFS STANDARD FIRM STORAGE SERVICE Sheet 1	29478-G
30190-G	GAS SCHEDULE G-SFT SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY Sheet 2	29479-G
30191-G	GAS SCHEDULE G-WSL GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS Sheet 1	29480-G

ATTACHMENT 1
Advice 3353-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
30192-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 1	29481-G
30193-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 2	29482-G
30194-G	GAS TABLE OF CONTENTS Sheet 1	30157-G
30195-G	GAS TABLE OF CONTENTS Sheet 2	30158-G
30196-G	GAS TABLE OF CONTENTS Sheet 3	30159-G
30197-G*	GAS TABLE OF CONTENTS Sheet 4	30160-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	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	-$0.00015	(R)	-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00642	(I)	$0.13816	(I)	$0.08809	(I)	$0.07786	(I)	$0.06986	(I)
TOTAL RATE	**0.03555**	(R)	**0.16507**	(R)	**0.11500**	(R)	**0.10477**	(R)	**0.09677**	(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	$0.00643	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (4)	$0.00068	(I)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00070	(I)	$0.18651	(I)	$0.11891	(I)	$0.10510	(I)	$0.09430	(I)
TOTAL RATE	**0.01007**	(R)	**0.21342**	(R)	**0.14582**	(R)	**0.13201**	(R)	**0.12121**	(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.)

	G-EG (3)**		G-EG BACKBONE	
NCA – NONCORE	$0.00713	(R)	$0.00713	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	-$0.00005	(R)	-$0.00005	(R)
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)	$0.01989	(R)	$0.00068	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00202	(I)	$0.00202	(I)
TOTAL RATE	**0.02902**	(R)	**0.00981**	(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

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	$0.00632	(R)	$0.00632	(R)	$0.00632	(R)	$0.00632	(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)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.00000		$0.00000		$0.00000	
TOTAL RATE	**0.02621**	(R)	**0.02621**	(R)	**0.02621**	(R)	**0.02621**	(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

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

	G-WSL					
	West Coast Mather-T		West Coast Mather-D		West Coast Castle-D	
NCA – NONCORE	$0.00632	(R)	$0.00632	(R)	$0.00632	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00198	(R)	-$0.00238	(R)
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)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.13596	(I)	$0.10356	(I)
TOTAL RATE	**0.02621**	(R)	**0.16019**	(I)	**0.12739**	(I)

* 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	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)	$0.00643	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.13816	(I)	$0.08809	(I)	$0.07786	(I)	$0.06986	(I)
TOTAL RATE	**0.02928**	(R)	**0.16507**	(R)	**0.11500**	(R)	**0.10477**	(R)	**0.09677**	(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

Sheet 18

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	$0.00643	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)	$0.00713	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)	-$0.00246	(R)
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)	$0.00157	(I)
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.00068	(I)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)	$0.01989	(R)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00070	(I)	$0.18651	(I)	$0.11891	(I)	$0.10510	(I)	$0.09430	(I)
TOTAL RATE	**0.01007**	(R)	**0.21342**		**0.14582**	(R)	**0.13201**	(R)	**0.12121**	(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	$0.16706	(R)
LOCAL TRANSMISSION (AT RISK)	$0.00000	
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000	
TOTAL RATE	**0.16775**	(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	$0.24444	(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	(R)	All Usage Levels	$4.95518
Schedule G-NGV1	$0.06382	(R)	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	(I)	0 to 5,000	$1.93578	(I)
Local Transmission	$0.00641	(I)	5,001 to 10,000	$5.76658	(I)
Backbone	$0.00000		10,001 to 50,000	$10.73293	(I)
			50,001 to 200,000	$14.08570	(I)
Schedule G-EG			200,001 to 1,000,000	$20.43715	(I)
Distribution	$0.00201	(I)	1,000,001 and above	$173.35956	(I)
Local Transmission	$0.00201	(I)			
Backbone	$0.00201	(I)			
Schedule G-NGV4					
Distribution	$0.09911	(I)			
Local Transmission	$0.00000				
Backbone	$0.00000				

(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

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
BASE REVENUES (incl. F&U) :					
Authorized GRC Distribution Base Revenue (1)					1,195,641 (I)
Pension (2)					52,691 (I)
Less: Other Operating Revenue					(22,922)
Authorized Distribution Revenues in Rates	1,182,821 (I)	42,589 (I)			1,225,410 (I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(1,025) (I)				(1,025) (I)
G-10 Procurement Discount Allocation	404 (R)	621 (R)			1,025 (R)
Less: Front Counter Closures	0				0
Core Brokerage Fee Credit	(6,583)				(6,583)
Distribution Base Revenue with Adj. and Credits	1,175,617 (I)	43,210 (I)			1,218,827 (I)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):					
Transportation Balancing Accounts	77,137 (R)	28,949 (R)			106,086 (R)
Self-Generation Incentive Program Revenue Requirement	2,283 (R)	3,477 (R)			5,760 (R)
CPUC Fee	1,970	1,240			3,210
					(D)
SmartMeter™ Project	79,202 (R)				79,202 (R)
Winter Gas Savings Plan (WGSP) – Transportation	2,474 (I)				2,474 (I)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,117 (R)	446 (R)			2,563 (R)
CARE Discount included in PPP Funding Requirement	(112,382) (I)				(112,382) (I)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	52,801 (R)	34,112 (R)			86,913 (R)
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):					
Local Transmission	132,854 (R)	72,789 (I)			205,643 (R)
Customer Access Charge – Transmission		4,860 (I)			4,860 (I)
Storage	47,513 (R)		34,083 (R)		81,596 (R)
Carrying Cost on PG&E Working Gas in Storage	1,978 (I)		532 (I)		2,510 (I)
Backbone Transmission/L-401	92,765 (R)		133,171(R)		225,936 (R)
Gas Accord Revenue Requirement	275,110 (R)	77,649 (I)	167,786 (R)		520,545 (R)

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2011, in General Rate Case D.11-05-018. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. This amount also includes the gas Distribution portion of the 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. (T)

(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. (T)

(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. (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				1,015,537 (R)	1,015,537 (R)	
Interstate and Canadian Capacity				188,107 (I)	188,107 (I)	
WGSP – Procurement – Residential				1,826 (R)	1,826 (R)	
F&U (on items above and Procurement Account Balances Below)				15,631 (R)	15,631 (R)	
Backbone Capacity (incl. F&U)	(64,098) (I)			64,098 (R)	0	
Backbone Volumetric (incl. F&U)	(28,668) (I)			28,668 (R)	0	
Storage (incl. F&U)	(47,513) (I)			47,513 (R)	0	
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(1,978) (R)			1,978 (I)	0	
Core Brokerage Fee (incl. F&U)				6,583	6,583	
Procurement Account Balances				(2,426) (R)	(2,426) (R)	
Illus. Core Procurement Revenue Requirement	(142,257) (I)			1,367,515 (R)	1,225,258 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**1,361,271** (R)	**154,971** (R)	**167,786** (R)	**1,367,515** (R)	**3,051,543** (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						
Energy Efficiency (EE)	50,551 (R)	5,627 (R)			56,178 (R)	
Energy Savings Assistance (ESA)	58,677 (R)	6,531 (R)			65,208 (R)	
Research, Demonstration and Development (RD&D)	6,742 (I)	3,817 (I)			10,559 (I)	
CARE Administrative Expense	1,625 (I)	1,114 (I)			2,739 (I)	
BOE and CPUC Administrative Cost	206 (I)	117 (I)			323 (I)	
PPP Balancing Accounts	(28,057) (R)	(12,770) (R)			(40,827) (R)	
CARE Discount Recovered from non-CARE customers	66,681 (R)	45,701 (R)			112,382 (R)	
Total PPP Funding Requirement in Rates	**156,425** (R)	**50,137** (R)			**206,562** (R)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**1,517,696** (R)	**205,108** (R)	**167,786** (R)	**1,367,515** (R)	**3,258,105** (R)	
Implementation Plan – Local Transmission not included in rates (7)	59,009	32,303			91,312	(N)
Implementation Plan – Backbone not included in rates (7)	9,542	12,873			22,415	(N)
Implementation Plan – Storage not included in rates (7)	950	666			1,616	(N)
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	**1,587,197** (R)	**250,950** (I)	**167,786** (R)	**1,367,515** (R)	**3,373,448** (R)	

(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. (T)

(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. (T) (T)

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030. These revenue requirements will be included in rates effective February 1, 2013, or as soon as practical thereafter, and are included in this presentation for illustrative purposes. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

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

3. COST ALLOCATION FACTORS:

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

	Factor			
Cost Category	Core	Noncore	Unbundled Storage and System Load Balancing	Total
Distribution Base Revenue Requirements	0.965245 (R)	0.034755 (I)		1.000000
Intervenor Compensation	0.965245 (R)	0.034755 (I)		1.000000
Other – Equal Distribution Based on All Transportation Volumes	0.394385 (R)	0.605615 (I)		1.000000
Carrying Cost on PG&E Working Gas in Storage	0.718750		0.281250	1.000000
ARB AB32 Cost of Implementation Fee	0.573069	0.426931		1.000000

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

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

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

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

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

(Continued)

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	$0.3168	(R)
Baja to On-System	$0.3588	(R)
Silverado to On-System	$0.1810	(R)
Mission to On-System	$0.0000	

2. Additional Charges:

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

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

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	$0.3168	(R)
Baja to Off-System	$0.3588	(R)
Silverado to Off-System	$0.3168	(R)
Mission to Off-System	$0.3168	(R)
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
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	$5.1339	(R)	$7.7904	(R)
Redwood to On-System (Core Procurement Groups only)	$4.4009	(R)	$6.1720	(R)
Baja to On-System	$5.8209	(R)	$8.8327	(R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$5.1362	(R)	$7.2031	(R)
Silverado to On-System (including Core Procurement Groups)	$3.1407	(R)	$4.4125	(R)
Mission to On-System (including Core Procurement Groups)	$3.1407	(R)	$4.4125	(R)

2. Usage Charge:

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

Path:	Usage Rate (Per Dth)			
	MFV Rates		SFV Rates	
Redwood to On-System	$0.0952	(R)	$0.0079	(R)
Redwood to On-System (Core Procurement Groups only)	$0.0672	(R)	$0.0090	(R)
Baja to On-System	$0.1076	(R)	$0.0086	(R)
Baja to On-System (N) (Core procurement Groups only) (N)	$0.0780	(R)	$0.0101	(R)
Silverado to On-System (including Core Procurement Groups)	$0.0476	(R)	$0.0058	(R)
Mission to On-System (including Core Procurement Groups)	$0.0476	(R)	$0.0058	(R)
Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only)	$0.0000		$0.0000	

(Continued)

GAS SCHEDULE G-AFTOFF

Sheet 2

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	$5.1339	(R)	$7.7904	(R)
Baja to Off-System	$5.8209	(R)	$8.8327	(R)
Silverado to Off-System	$5.1339	(R)	$7.7904	(R)
Mission to Off-System	$5.1339	(R)	$7.7904	(R)

2. Usage Charge:

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

Path:	Usage Rate (Per Dth)			
	MFV Rates		SFV Rates	
Redwood to Off-System	$0.0952	(R)	0.0079	(R)
Baja to Off-System	$0.1076	(R)	0.0086	(R)
Silverado to Off-System	$0.0952	(R)	0.0079	(R)
Mission to Off-System	$0.0952	(R)	0.0079	(R)

3. Additional Charges:

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

(Continued)

GAS SCHEDULE G-BAL

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MONTHLY BALANCING OPTIONS: (Cont'd.)

CASHOUT FOR MONTHLY BALANCING:

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

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

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

SELF-BALANCING OPTION:

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

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

SELF-BALANCING CREDIT:

The Self-Balancing option allows a Balancing Agent to receive a credit. The Self-Balancing credit is $0.0129 (R) per Decatherm multiplied by the actual recorded monthly usage. Credits will be provided to the Balancing Agent on a monthly basis, subject to adjustments.

LIMIT ON SELF-BALANCING PARTICIPATION:

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

(Continued)

GAS SCHEDULE G-CFS
CORE FIRM STORAGE

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

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

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

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

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

Reservation Charge per Dth per month	$0.1232 (R)

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

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

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

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

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

Injection and Withdrawal Capacities

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

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

(Continued)

GAS SCHEDULE G-EG
Sheet 1

GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

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

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

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

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

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

1. Customer Access Charge:

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

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

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: $0.00981 per therm (R)

b. All Other Customers: $0.02902 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.

(Continued)

GAS SCHEDULE G-LEND
MARKET CENTER LENDING SERVICES

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

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

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

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

Minimum Rate (per transaction): $57.00

Maximum Rate (per Dth per day): .... $1.0821 (R)

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

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

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

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

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

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

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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): $0.16775 (R)

LNG Gallon Equivalent: $0.13756 (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.

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

(Continued)

GAS SCHEDULE G-NAS
NEGOTIATED AS-AVAILABLE STORAGE SERVICE

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

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

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

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

	Maximum Rates (Per Dth/Day)
Injection	$5.9623 (R)
Withdrawal	$20.6428 (R)

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

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

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

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

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

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

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

GAS SCHEDULE G-NFS

NEGOTIATED FIRM STORAGE SERVICE

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

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

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

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

	Maximum Rates (Dth)	
Injection/Day	$5.9623	(R)
Inventory	$2.8489	(R)
Withdrawal/Day	$20.6428	(R)

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

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

(Continued)

GAS SCHEDULE G-NGV4

Sheet 1

NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

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

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

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

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

The following charges apply to service under this schedule:

1. Customer Access Charge:

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

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

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

(Continued)

GAS SCHEDULE G-NGV4

Sheet 2

NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

RATES: (Cont'd.)

2. Transportation Charge:

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

a. Backbone Level Rate:

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

Backbone Level Rate (per therm) .... $0.01007 (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)................................ $0.02928 (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	$0.16507	(R)	$0.21342	(R)
Tier 2: 20,834 to 49,999	$0.11500	(R)	$0.14582	(R)
Tier 3: 50,000 to 166,666	$0.10477	(R)	$0.13201	(R)
Tier 4: 166,667 to 249,999	$0.09677	(R)	$0.12121	(R)
Tier 5: 250,000 and above*	$0.02928	(R)	$0.02928	(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 1

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

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

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

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

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

1. Customer Access Charge:

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

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

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

(Continued)

GAS SCHEDULE G-NT
Sheet 2

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

RATES: (Cont'd.)

2. Transportation Charge:

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

a. Backbone Level Rate:

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

Backbone Level Rate (per therm): $0.01007 (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): $0.03555 (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	$0.16507	(R)	$0.21342	(R)
Tier 2: 20,834 to 49,999	$0.11500	(R)	$0.14582	(R)
Tier 3: 50,000 to 166,666	$0.10477	(R)	$0.13201	(R)
Tier 4: 166,667 to 249,999	$0.09677	(R)	$0.12121	(R)
Tier 5: 250,000 and above*	$0.03555	(R)	$0.03555	(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.

(Continued)

GAS SCHEDULE G-PARK

MARKET CENTER PARKING SERVICES

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

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

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

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

Minimum Rate (per transaction): $57.00

Maximum Rate (per Dth per day): .... $1.0821 (R)

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

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

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

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

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

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

(Continued)

GAS SCHEDULE G-SFS
STANDARD FIRM STORAGE SERVICE

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

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

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

1. Reservation Charges:

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

   Reservation Charge per Dth of Contract Inventory per month.......... $0.2374 (R)

2. Additional Charges:

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

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

(Continued)

GAS SCHEDULE G-SFT

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	$6.1607	(R)	$9.3484	(R)
Baja to On-System	$6.9850	(R)	$10.5992	(R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$6.1634	(R)	$8.6438	(R)
Silverado to On-System	$3.7689	(R)	$5.2951	(R)
Mission to On-System	$3.7689	(R)	$5.2951	(R)

2. Usage Charge:

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

Path:	Usage Rate (Per Dth)			
	MFV Rates		SFV Rates	
Redwood to On-System	$0.1142	(R)	$0.0094	(R)
Baja to On-System	$0.1291	(R)	$0.0103	(R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$0.0936	(R)	$0.0121	(R)
Silverado to On-System	$0.0571	(R)	$0.0069	(R)
Mission to On-System	$0.0571	(R)	$0.0069	(R)

3. Additional Charges:

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

(Continued)

GAS SCHEDULE G-WSL

Sheet 1

GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS

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

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

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

1. Customer Access Charge:

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

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto-T	$0.02621	(R)
Coalinga-T	$0.02621	(R)
West Coast Gas-Mather-T	$0.02621	(R)
West Coast-Mather-D	$0.16019	(I)
Island Energy-T	$0.02621	(R)
Alpine Natural Gas-T	$0.02621	(R)
West Coast Gas-Castle-D	$0.12739	(I)

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

(Continued)

GAS SCHEDULE G-XF

Sheet 1

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

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

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

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

1. Reservation Charge:

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

Reservation Rates:	Per Dth Per Month
SFV Rates:	5.7146 (R)

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

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

(Continued)

GAS SCHEDULE G-XF

Sheet 2

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:	0.0016 (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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GS	Multifamily Service	30153,29606,23215-G	
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G-CP	Gas Procurement Service to Core End-Use Customers	30143-G	
G-CPX	Crossover Gas Procurement Service To Core End-Use Customers	30116-G	
G-NT	Gas Transportation Service to Noncore End-Use Customers	**30186**, **30187**,22037,22038-G	(T)
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G-WSL	Gas Transportation Service to Wholesale/Resale Customers	**30191**, 28920,22045-G	(T)
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G-SFS	Standard Firm Storage Service	**30189**,22140,22141,22300-G	(T)
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G-SFT	Seasonal Firm Transportation On-System Only	24467,**30190**,22178-G	(T)
G-AA	As-Available Transportation On-System	24468,**30173**-G	(T)
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G-OEC	Gas Delivery To Off-System End-Use Customers	22263-22264-G	
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G-CRED	Billing Credits for CTA-Consolidated Billing	20063-G	
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Part C	Gas Accounting Terms and Definitions	28876, **30170,30171,30172***-G 28880-28883,28110,28884,28885,23351,29141-G	(T)
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Part V	California Alternate Rates For Energy Account	23358,28778-G	
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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
Ameresco
Anderson & Poole
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Bloomberg
Bloomberg New Energy Finance
Boston Properties
Braun Blaising McLaughlin, P.C.
Brookfield Renewable Power
CA Bldg Industry Association
CLECA Law Office
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Casner, Steve
Cenergy Power
Center for Biological Diversity
Chris, King
City of Palo Alto
City of Palo Alto Utilities
City of San Jose
City of Santa Rosa
Clean Energy Fuels
Clean Power
Coast Economic Consulting
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of General Services
Department of Water Resources
Dept of General Services
Douglass & Liddell
Downey & Brand
Duke Energy
Economic Sciences Corporation
Ellison Schneider & Harris LLP
Foster Farms
G. A. Krause & Assoc.
GLJ Publications
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Hitachi
In House Energy
International Power Technology
Intestate Gas Services, Inc.
Lawrence Berkeley National Lab
Los Angeles County Office of Education
Los Angeles Dept of Water & Power
MAC Lighting Consulting
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Merced Irrigation District
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
Morrison & Foerster LLP
NLine Energy, Inc.
NRG West
NaturEner
Norris & Wong Associates
North America Power Partners
North Coast SolarResources
Occidental Energy Marketing, Inc.
OnGrid Solar
PG&E
Praxair
R. W. Beck & Associates
RCS, Inc.
SCD Energy Solutions
SCE
SMUD
SPURR
San Francisco Public Utilities Commission
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Silo Energy LLC
Southern California Edison Company
Spark Energy, L.P.
Sun Light & Power
Sunrun Inc.
Sunshine Design
Sutherland, Asbill & Brennan
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Turlock Irrigation District
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation