STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

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

December 17, 2014

**Advice Letter: 3529-G**

Pacific Gas and Electric Company
Attention: Meredith Allen
Senior Director, Regulatory Relations
77 Beale Street, Mail Code B10C
San Francisco, CA 94177

**SUBJECT: ANNUAL GAS TRUE-UP OF GAS TRANSPORTATION BALANCING ACCOUNTS FOR RATES EFFECTIVE JANUARY 1, 2015**

Dear Ms. Allen:

Advice Letter 3529-G is approved as of December 17, 2014, for rates effective January 1, 2015. Pursuant to recommendations by the California State Auditor, Energy Division staff is currently conducting in-depth reviews of three PG&E gas balancing accounts. Balances in all accounts authorized for recovery are subject to audit, verification and adjustment.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

Pacific Gas and Electric Company®

**Meredith Allen**
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November 4, 2014

**Advice 3529-G**
(Pacific Gas and Electric Company ID U 39 G)

Public Utilities Commission of the State of California

**Subject:** **Annual Gas True-Up of Gas Transportation Balancing Accounts for Rates Effective January 1, 2015**

## Purpose

Pacific Gas and Electric Company (PG&E) submits this Annual Gas True-Up (AGT) of its Gas Transportation Balancing Accounts to amortize account balances in core and noncore gas transportation rates effective January 1, 2015. This advice letter also provides a *preliminary* estimate of projected gas transportation rate and gas Public Purpose Program (PPP) Surcharge rate changes authorized by, or currently pending before and expected to be authorized by the California Public Utilities Commission (Commission or CPUC) effective January 1, 2015.

Consistent with prior years, this AGT advice letter does not include the 2015 gas procurement-related revenue requirement changes, which will be submitted in PG&E's monthly core procurement advice letter in late December 2014.

PG&E respectfully requests approval of this Tier 2 AGT advice letter to amortize balancing account balances[1] within 30 days (by December 4, 2014), with an effective date of January 1, 2015. PG&E will file a separate advice letter in December to consolidate all final authorized revenue requirement changes and update forecast end-of-year gas transportation balancing accounts.[2]

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[1] As described in further detail below and consistent with prior years, this advice letter uses actual recorded balances as of September 30, 2014, as the starting point for December 31, 2014 forecast balances.

[2] Consistent with prior years, the December advice letter will use November 30, 2014 actual recorded balances as the starting point for December 31, 2014 forecast balances.

**Background/Summary**

The AGT is an annual process to change core and noncore gas transportation rates, as established in PG&E's 2005 Biennial Cost Allocation Proceeding (BCAP) Decision (D.) 05-06-029.[3] This advice letter requests approval to amortize forecast December 31, 2014 gas transportation balancing account balances in rates effective January 1, 2015. This AGT advice letter forecasts December 31, 2014 balancing account balances using September 30, 2014 recorded balances as the starting point. In late December, PG&E will file a separate advice letter to consolidate in transportation rates these forecast end-of- year balancing account balances with all final authorized revenue requirement changes. In order to provide a more accurate forecast, the December advice letter will update these forecast balancing account balances using November 30, 2014 recorded balances as the starting point.

In this advice letter, PG&E provides a preliminary estimate of its 2015 gas transportation revenue requirements totaling $2,684 million, which is a $182 million increase compared to present rates. The 2015 gas transportation revenue requirements include end-user transportation costs, gas PPP surcharges (which were submitted for Commission approval in a separate advice letter on October 31, 2014, and gas transmission and storage (i.e., Gas Accord V or GAV) unbundled costs (See Table 1 below).

**Table 1**
**Proposed Gas Transportation Revenue Requirements**
**Effective January 1, 2015**
**(in $ millions)[4]**

| Description | Currently in Rates | Proposed | Change |
|---|---|---|---|
| End-Use Gas Transportation | $2,076 | $2,238 | $162 |
| GAV Unbundled Costs | $170 | $174 | $4 |
| Gas PPP Surcharges | $256 | $272 | $16 |
| **Total Gas Transportation Revenue Requirements** | **$2,502** | **$2,684** | **$182** |

Attachment 1 summarizes the proposed 2015 gas transportation revenue requirements. Attachment 2 summarizes the gas transportation balancing accounts, which PG&E proposes to amortize in 2015. In order to provide the CPUC with a preliminary estimate of gas transportation rates and gas PPP surcharges to be effective on January 1, 2015, PG&E includes Attachments 3 through 5 to provide illustrative rates and surcharges incorporating: (1) amounts previously authorized to

[3] D.05-06-029, p. 10 and Finding of Fact 9.
[4] This table does not include the 2014 gas procurement-related revenue requirement changes, which will be submitted in PG&E's monthly core procurement advice letter in late December 2014.

be recovered in rates, effective January 1, 2015, (2) the forecast December 31, 2014 account balances to be amortized in 2015, and (3) gas transportation rate changes being considered in a number of pending proceedings and advice letters that would result in rate changes effective January 1, 2015, should decisions be issued prior to the separate December advice filing mentioned above.

**Recovery of Transportation Balancing Accounts Already Approved for Amortization in the 2015 AGT**

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) Forecasting the December 31, 2014 balance for each gas transportation balancing and memorandum account to be updated in the AGT based on the September 30, 2014 recorded balances and a forecast of costs and revenues, including interest, through December 31, 2014; and

2) Calculating the customer class charge components by dividing the forecasted December 31, 2014 balancing account balance by PG&E's currently adopted BCAP throughput forecast (D.10-06-035).

Attachment 2 summarizes the forecast December 31, 2014 balances for gas transportation balancing accounts using recorded balances through September 30, 2014. The total December 31, 2014 gas transportation balancing account balances are projected to be undercollected by $416 million, as shown in Attachment 1, line 1, and Attachment 2, line 26. This represents a $241 million increase in the gas transportation balancing account undercollections from those currently amortized in gas transportation rates.

The remainder of this section describes: (1) the balancing accounts that will be amortized through this AGT advice letter, (2) the recent CPUC decisions impacting the balancing account balances, and (3) PG&E's proposals to recover the forecasted balances in rates, effective January 1, 2015.

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, 2014 balance to the appropriate subaccount of the CFCA and/or NCA, once the AGT is approved.

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

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 and 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 Assembly Bill (AB) 32 Cost of Implementation Fee Core subaccount, which recovers the gas cost portion of California Air Resources Board's (ARB) AB 32 Cost of Implementation Fee, allocated to PG&E's core transportation customers.

The AGT includes a forecasted $391.4 million net undercollection in the CFCA, excluding the AB 32 Cost of Implementation Fee Core subaccount, which is described separately below. The net undercollection in the CFCA results from:

(i) A forecasted $376.4 million undercollection in the Distribution Cost subaccount. On August 14, 2014, the CPUC issued D.14-08-032, which adopted among other things, PG&E's gas distribution revenue requirement for the 2014-2016 GRC period, effective January 1, 2014.[5] On August 25, 2014, PG&E filed Advice 3505-G, to implement the resulting rate change, effective September 1, 2014. Because the GRC decision was not implemented until September 1, 2014, the CFCA and NCA forecast year-end balances reflect the increased amounts that PG&E was not able to collect through rates between January 1 and August 31, 2014; and

(ii) A forecasted $14.9 million undercollection in the Core Cost subaccount.

[5] On April 18, 2013, the CPUC issued D. 13-04-023 granting PG&E's request to make its 2014 GRC revenue requirement effective January 1, 2014, including interest.

**Noncore Customer Class Charge Account - (Attachment 2, Lines 3-4)**

The NCA records noncore costs and revenues from noncore customers for balancing account protected items such as SGIP. The NCA has three 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;

(ii) The 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; and

(iii) The AB 32 Cost of Implementation Fee Noncore subaccount, which recovers the gas cost portion of the AB 32 cost of implementation fee, allocated to PG&E's noncore transportation customers.

The AGT includes a forecasted $8.5 million net overcollection in the NCA, excluding the AB 32 Cost of Implementation Fee Noncore subaccount, which is described separately below. The net overcollection in the NCA results from:

(i) A forecasted $14.1 million overcollection in the Noncore subaccount; and

(ii) A forecasted $5.6 million undercollection in the Distribution subaccount.

**AB 32 Cost of Implementation Fee – (Attachment 2, Line 14)**

As described above, the AB 32 Cost of Implementation (COI) Fee consists of two subaccounts: 1) the core subaccount of the CFCA recovers the gas cost portion of the AB 32 COI Fee allocated to core customers; and 2) the noncore subaccount of the NCA recovers the gas cost portion of the AB 32 COI Fee allocated to noncore customers. In accordance with D.12-10-044 and Advice 3348-G, the AB 32 COI Fee is allocated to all non-exempt customers on an equal-cents-per-therm basis. As indicated in Advice 3348-G, the ARB provides PG&E with an invoice and a list of PG&E customers who pay the COI fee directly to the ARB. These customers paying the COI fee directly to the ARB are exempt from paying for COI fee costs through PG&E's rates. PG&E has updated the volumes used to calculate PG&E's 2015 COI rates to reflect a reduction of the volumes associated with exempt customers. The AGT balance proposed to be amortized in 2015 rates consists of a forecasted $2.8 million net undercollection in the AB 32 Cost of Implementation Fee subaccounts. This balance is the sum of COI invoice costs received from the ARB recorded during 2014 plus a small forecast undercollection of the adopted COI costs included in 2014 rates.

**Core Brokerage Fee Balancing Account (CBFBA) - (Attachment 2, Line 5)**

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). The AGT includes a forecasted $1.4 million undercollection in the CBFBA. The CBFBA balance is included in the rate component of the Core Cost subaccount of the CFCA.

**Hazardous Substance Mechanism (HSM) - (Attachment 2, Line 6)**

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 AGT forecasts a $46.6 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 7)**

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. PG&E currently forecasts a $421,000 undercollection in the BCA as of December 31, 2014.

**Affiliate Transfer Fees Account (ATFA) - (Attachment 2, Line 8)**

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 approving PG&E to become a wholly owned subsidiary of a holding company (D.96-11-017). This AGT forecasts a $162,000 overcollection in the ATFA, which represents activity in the account for 2014. The ATFA balance is included in the rate component of the Distribution Cost subaccount of the CFCA and the Distribution Cost subaccount of the NCA.

**Customer Energy Efficiency Incentive Account (CEEIA) - (Attachment 2, Line 9)**

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 requested earnings for program year 2012 and the first part of the 2013 EE incentive award. Interest does not accrue in this subaccount pursuant to D.07-09-043. This AGT includes a forecasted $7.3 million undercollected balance, which will be recovered through the CEE Incentive rate component. See further discussion below in the "Recent, Pending and Anticipated CPUC Proceedings and Advice Letters" section.

**SmartMeter™ Opt-Out Program Balancing Account (SOPBA-G) – (Attachment 2, Line 10)**

On September 29, 2014, in accordance with D.14-08-032, PG&E filed Advice 3519-G to establish the SOPBA-G. Decision 14-08-032 was issued by the CPUC on August 14, 2014 and approved PG&E's GRC base revenue requirements. Additionally, D.14-08-032 required PG&E to file a Tier 1 advice letter to implement a two-way balancing account to track revenues and costs associated with the SmartMeter™ Opt-Out Program. In accordance with Gas Preliminary Statement Part DF, the SOPBA-G records the difference between actual revenue requirements related to PG&E's SmartMeter™ Opt-Out Program and the Program's adopted revenue requirements approved in D.14-08-032, pursuant to Ordering Paragraph 23 of D.14-08-032. The Program's actual revenue requirements include the incremental expenditures required to manage PG&E's SmartMeter™ Opt-Out Program and the associated revenues from fees received from Opt-Out Program participants. Costs that can be attributed specifically to gas service will be recorded to this account. General costs that cannot be attributed specifically either to providing gas service or electric service shall be allocated 55 percent electric and 45 percent gas. This advice letter includes a forecasted $7.8 million undercollected balance in the SOPBA-G.

**California Solar Initiative Thermal Program Memorandum Account (CSITPMA) - (Attachment 2, Line 11)**

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 SGIP and customers exempt pursuant to Public Utilities Code Section 2863(b)(4) are exempt from CSI Thermal Program charges. This AGT includes a forecasted $6.2 million undercollected balance in the CSITPMA as of December 31, 2014, and will be recovered in the CSITPMA rate component.

**Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) – (Attachment 2, Line 12)**

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 GAV 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 GAV 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 GAV 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 GAV 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 GAV 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 GAV Settlement Agreement.

The AGT includes a forecasted net $23.9 million undercollection 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 GAV rate tables.

**Non-Tariffed Products and Services Balancing Account (NTBA-G) - (Attachment 2, Line 13)**

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 offer the Mover Services Program; to recover costs and disburse net revenues through the NTBA-G; to transfer the balance at the end of the year from the NTBA-G to the CFCA; and to 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 $33,000 overcollected balance for this account, as of December 31, 2014; which will be transferred to the Distribution Cost subaccount of the CFCA.

**Gas Pipeline Expense and Capital Balancing Account (GPECBA) – (Attachment 2, Line 15)**

The GPECBA tracks the aggregate revenue requirements associated with the expense and capital costs of PG&E's Pipeline Safety Enhancement Plan, as authorized by the Commission in D.12-12-030, and any other subsequent Commission decisions. The GPECBA records the difference between adopted forecast revenue requirements and capital and expense revenue requirements based on actual costs for the Plan through 2014. The GPECBA is a one-way balancing account. Any unspent funds (i.e., overcollected balance) at the end of 2014 shall be returned to customers. The GPECBA has two subaccounts:

(i) The CPUC Reimbursement Subaccount, which records PG&E's reimbursements to the Commission associated with implementing and complying with D.12-12-030, up to $15 million. This AGT includes a forecasted $0 balance in the CPUC Reimbursement Subaccount as of December 31, 2014.

(ii) The Program Expense and Capital Subaccount, which records the revenue requirements associated with the actual expense and capital cost PG&E incurred to implement the programs authorized in D.12-12-030. The 2012-2014 revenue requirement recorded in this subaccount is capped at $299.2 million or $295.4 million (without franchise fees and uncollectibles or FF&U) under D.12-12-030. On October 16, 2014, the CPUC issued a Proposed Decision Adopting the Settlement Agreement among PG&E, the Office of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN). The Proposed Decision adopts a reduced PSEP revenue requirement of $223.2 million.[6] This $76 million reduction ($299.2 million less $223.2 million) has been reflected in the forecast balancing account balances of the Core Gas Pipeline Safety Balancing Account and the Noncore Gas Pipeline Safety Balancing Account, which are discussed below. Disposition of the balance in the Program Expense and Capital Subaccount shall be determined in the AGT at the end of 2014, or as otherwise authorized by the Commission. The Program Expense and Capital Subaccount is forecast to be

[6] The revenue requirements may be reduced further in the December 2014 AGT Consolidated Gas Rate Update advice letter by the cost of any project deferred or cancelled and not replaced with a higher priority project.

undercollected as of December 31, 2014. Because this is a one-way balancing account, this amount will not be collected from customers.

(iii) In accordance with Section 4.5 of the Settlement Agreement, the December 31, 2014 forecast balancing account balances for the CFCA and NCA have been reduced for capital projects that will not be operational in 2014.

**Gas Leak Survey and Repair Balancing Account (GLSRBA) – (Attachment 2, Line 16)**

On September 29, 2014, in accordance with D.14-08-032, PG&E filed Advice 3518-G to establish the GLSRBA. The GLSRBA tracks and adjusts for the difference between authorized and recorded expenses for the following cost categories: 1) Natural Gas Distribution Leak Survey, 2) Leak Repair, 3) Meter Set Leak Repair, 4) Atmospheric Corrosion Inspection and 5) Tee Cap Repair. The GSLRBA excludes costs recovered through the Catastrophic Event Memorandum Account (CEMA). This AGT includes a forecast $18.0 million net overcollection in the GLSRBA.

**Gas Operational Cost Balancing Account (GOBA) – (Attachment 2, Line 17)**

The GOBA records the difference between PG&E's authorized and actual cost associated with the cost of electricity used to provide gas transmission and storage services to its customers and Greenhouse Gas (GHG) cost associated with PG&E's gas compressor stations. The GOBA has two subaccounts:

(i) The Electricity Cost Subaccount, which records the difference between the cost of electricity used to provide gas transmission and storage services adopted in PG&E's GAV Settlement Agreement, and PG&E's recorded cost of electricity used to provide gas transmission and storage services; and

(ii) The Compressor Station Greenhouse Gas Cost subaccount, which records the difference between the Commission's forecast and PG&E's actual GHG costs associated with its gas compressor stations, as authorized in D.13-03-017.

This AGT includes a forecasted $10.3 million net undercollection in the GOBA. The GOBA is recovered through the Core Cost subaccount of the CFCA and Noncore subaccount of the NCA.

**Pension Contribution Balancing Account (PCBA) - (Attachment 2, Line 18)**

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, 2014.

**TID Almond Power Plant Balancing Account (TIDBA) – (Attachment 2, Line 19)**

The purpose of the TIDBA is to record the difference in revenue requirement based on the amount credited to rate base per the adopted GAV 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 AGT includes a forecasted $898,000 overcollected balance in the TIDBA. In accordance with the GAV Settlement Agreement (Section 7.2.10), this balance is allocated to customers through the Customer Class Charge in the AGT.

**Revised Customer Energy Statement Balancing Account (RCESBA-G) – (Attachment 2, Line 20)**

The RCESBA-G 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. Advice 3287-G filed in compliance with D.12-03-015 provided that the disposition of the balance in the account shall be through the AGT via the CFCA and the NCA, or through another proceeding as authorized by the Commission. This AGT includes a forecasted $2.5 million undercollected balance in the RCESBA as of December 31, 2014.

**Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) – (Attachment 2, Line 21)**

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 the GAV Settlement Agreement. The over- or under-collections are determined by comparing revenue from implemented GAV 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 GAV 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[7] 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 $4.9 million undercollected balance in the GTSRSM.

**Core Gas Pipeline Safety Balancing Account (CGPSBA) – (Attachment 2, Line 22)**

The purpose of the CGPSBA is to record and recover the core customers' portion of adopted forecast expense and, capital-related revenue requirements and revenues associated with Phase 1 and any subsequent phases of PG&E's Implementation Plan, as authorized by the Commission in D.12-12-030 and any other subsequent Commission decisions. The CGPSBA consists of the following three subaccounts:

(i) The Backbone Subaccount, which records the difference between the adopted backbone revenue requirements and recorded backbone revenues related to PG&E's Implementation Plan;

(ii) The Local Transmission Subaccount, which records the difference between the adopted local transmission revenue requirements and recorded local transmission revenues related to PG&E's Implementation Plan; and

(iii) The Storage Subaccount, which records the difference between the adopted storage revenue requirements and recorded storage revenues related to PG&E's Implementation Plan.

This AGT includes a forecasted $37.1 million overcollected balance in the CGPSBA. As discussed in further detail below, on October 16, 2014, the CPUC issued a proposed decision adopting the PSEP Update Settlement Agreement,

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

which proposed a reduction in PG&E's authorized PSEP revenue requirements for the period from 2012 through 2014. This reduction has been included in the December 31, 2014 forecast balancing account balance for the CGPSBA. If the CPUC issues a final decision by December 1, 2014, PG&E will include the final authorized December 31, 2014 forecast balance in the CGPSBA in the December AGT advice letter that consolidates all final authorized 2015 revenue requirements and forecast end-of-year gas transportation balancing account balances.

**Noncore Gas Pipeline Safety Balancing Account (NGPSBA) – (Attachment 2, Line 23)**

The purpose of the NGPSBA is to record and recover the noncore customers' portion of adopted forecast expense and, capital-related revenue requirements and revenues associated with Phase 1 and any subsequent phases of PG&E's Implementation Plan, as authorized by the Commission in D.12-12-030 and any other subsequent Commission decisions. The NGPSBA consists of the following three subaccounts:

(i) The Backbone Subaccount, which records the difference between the adopted backbone revenue requirements and recorded backbone revenues related to PG&E's Implementation Plan;

(ii) The Local Transmission Subaccount, which records the difference between the adopted local transmission revenue requirements and recorded local transmission revenues related to PG&E's Implementation Plan; and

(iii) The Storage Subaccount, which records the difference between the adopted storage revenue requirements and recorded storage revenues related to PG&E's Implementation Plan.

This AGT includes a forecasted $25.2 million overcollected balance in the NGPSBA. As discussed in further detail below, on October 16, 2014, the CPUC issued a proposed decision adopting the PSEP Update Settlement Agreement, which proposed a reduction in PG&E's authorized PSEP revenue requirements for the period from 2012 through 2014. This reduction has been included in the December 31, 2014 forecast balancing account balance for the NGPSBA. If the CPUC issues a final decision by December 1, 2014, PG&E will include the final authorized December 31, 2014 forecast balance in the NGPSBA in the December AGT advice letter that consolidates all final authorized 2015 revenue requirements and forecast end-of-year gas transportation balancing account balances.

**Integrity Management Expense Balancing Account (IMEBA) – (Attachment 2, Line 24)**

The IMEBA tracks the aggregate amount of integrity management expenses incurred during the term of the GAV Settlement Agreement (2011 through 2014). The IMEBA was created in compliance with D.11-04-031 and records the difference between adopted revenue requirements and recorded expenses for the Settlement Period beginning January 1, 2011 and ending December 31, 2014. If the accumulated balance is a credit at December 31, 2014, a debit entry to transfer the December 31, 2014 accumulated balance to the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA. The distribution of the balance will be 50 percent to core and 50 percent to noncore. The IMEBA is forecasted to be undercollected in December 2014. The IMEBA is a one-way account, thus no balance will be collected from customers.

**Mobile Home Park Balancing Account – Gas (MHPBA) – (Attachment 2, Line 25)**

The MHPBA records and recovers actual incurred costs of implementing the voluntary program to convert the gas master-meter/submeter service at mobile home parks and manufactured housing communities to direct service by PG&E, pursuant to D.14-03-021. Advice 3473-G provided that the disposition of the balance in the account shall be through the AGT, via the CFCA and NCA, or other venues as approved by the Commission. This AGT includes a forecast $54,000 undercollected balance in the MHPBA.

## Discussion of Recent, Pending and Anticipated CPUC Proceedings and Advice Letters

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

**2014 General Rate Case – (Attachment 1, Lines 2-3, 8)**

On August 14, 2014, the CPUC issued D.14-08-032 in PG&E's 2014 GRC Application (A.12-11-009). Decision 14-08-032 adopted a new method for calculating the uncollectibles factor that will be revised annually. PG&E will file an advice letter to update its 2015 uncollectibles factor by the end of the year.

**Energy Efficiency Risk Reward Incentive Mechanism (RRIM) – (Attachment 2, Line 9)**

PG&E filed Advice 3492-G/4451-E on June 30, 2014, and supplemental Advice 3492-G-A/4451-E-A on August 20, 2014, requesting approval of PG&E's 2012 and the first part of the 2013 EE incentive award in the amount of $37,338,440. These advice letters comply with OP 8 of D.12-12-032, and OPs 4 and 6 of D.13-09-023. The gas portion of the total amount is $6.7 million based on the gas portion of the net benefit factor of 18 percent approved for the 2010-2012 portfolio in Advice 3065-G-A/3562E-A and 3065-G-B/3562-E-B and for the 2013-2014 portfolio in Advice 3356-G-A/4176-E-A. The December 31, 2014 forecast balance includes this pending $6.7 million amount plus the residual balance in the account.

**Self Generation Incentive Program Cost Recovery – (Attachment 1, Line 4)**

Senate Bill (SB) 861, signed by Governor Brown on June 20, 2014, authorized the extension of the SGIP at the current annual funding level for an additional five years. Through the passage of this bill, PG&E expects to recover $36 million in 2015. The Commission will need to act and implement the provisions of this bill in order for PG&E to begin recovery. The gas portion of $6.5 million is 18 percent of the total based on the adopted EE net benefit split adopted in Advice 3356-G-A/ 4176-E-A. The split is subject to approval of PG&E's 2015 EE Funding request that maintained the currently adopted allocation.

**GHG Natural Gas Application**

On July 25, 2014, PG&E, ORA, Southwest Gas Corporation, Southern California Gas Company and San Diego Gas and Electric Company filed a joint motion to adopt a settlement to resolve high-priority issues identified as necessary for natural gas utilities' compliance obligations pursuant to AB 32, which begin January 1, 2015. The settlement addressed natural gas utilities' procurement authority, purchasing rules, and cost forecasting and recovery. In the settlement, PG&E forecasts 2015 GHG compliance costs and an associated revenue requirement of $63.46 million, including FF&U. PG&E proposes to establish a new two-way balancing account to track and record the costs of complying with its obligations as a natural gas supplier and for operating company facilities (e.g., gas compressor stations) subject to direct regulation under AB 32. The settlement specifies that each utility will recover compliance costs on a forecast basis through separate filings in June and updated in October of each compliance year, subject to annual true up. PG&E is currently awaiting a proposed decision on "Phase 1" issues identified by the Commission in its July 7, 2014 scoping memo, which projected a proposed decision in November 2014. Policies regarding the return of revenue from the sale of allowances to customers will be addressed in the second phase of the proceeding, which is expected to begin after Phase 1 concludes. PG&E is in the process of determining billing system requirements related to this proceeding and plans to return the cost of compliance into rates as soon as practical and when authorized to do so by the Commission.

**Pipeline Safety Enhancement Plan – (Attachment 1, Lines 17-20, and Attachment 2, Lines 22-23)**

On December 28, 2012, the CPUC issued D.12-12-030, approving PG&E's Pipeline Modernization scope of work and ordering PG&E to file an application after the completion of its Maximum Allowable Operating Pressure (MAOP) Validation Project and records search to present the results of those efforts, and update its authorized revenue requirements and related budgets. On October 29, 2013, PG&E filed its Pipeline Safety Enhancement Program (PSEP) Update Application, A.13-10-017. On July 25, 2014, PG&E, ORA, and TURN filed a Joint Motion for approval of a PSEP Update Settlement Agreement (Settlement Agreement). Although PG&E's scope of work proposed in A.13-10-017 will not be reduced as a result of the July 2014 PSEP Update Settlement Agreement, the settling parties agreed to a reduction in the revenue requirement for 2012-2014. On October 16, 2014, the CPUC issued a proposed decision which approves the reduction in the revenue requirement proposed in the Settlement Agreement. Based on OP 2 of the proposed decision, the reduced revenue requirement should be reflected in the PSEP balancing accounts. As a result, PG&E has reflected this $76 million reduction in the authorized revenue requirement that is currently in rates and the amount approved in the Settlement Agreement in Lines 22 and 23 of Attachment 2 of this advice letter. In accordance with Footnote 2 of the Settlement Agreement, post-2014 recovery of ongoing PSEP revenue requirements related to capital expenditures will be addressed in PG&E's 2015 GT&S Rate Case, A.13-12-012. Because the CPUC will not issue a decision on A.13-12-012 by December 2014, the ongoing 2015 PSEP revenue requirements included in PG&E's 2015 GT&S rate case have not been included in this AGT advice letter.

**Presiding Officer's Decisions on PG&E's Natural Gas Order Instituting Investigations (OIIs)**

On September 2, 2014, the Commission issued four Presiding Officers' Decisions (PODs) in the Commission's OIIs regarding PG&E's gas transmission system. On October 2, 2014, PG&E and other parties filed appeals of the PODs. PG&E will implement any changes to its gas department revenues required by the Commission's decisions once these cases have been resolved.

## <u>Gas Public Purpose Program Authorized Funding</u>

This AGT incorporates gas PPP surcharge changes that will be filed in a separate advice letter on October 31, 2014. The gas PPP surcharge rate impacts on customers are shown in Attachment 1.

Public Utilities 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 $159.6 million for EE, ESA, CARE administrative expenses, RD&D, Board of Equalization,

CPUC administrative costs and Statewide Marketing Education & Outreach administrative costs. This represents a $3.4 million increase from 2014;

2) Amortization over 12 months of forecasted December 31, 2014 balances in the PPP surcharge balancing accounts totaling a $1.7 million overcollection; and

3) A projected 2014 CARE revenue shortfall of $113.9 million, which represents a $5.0 million increase from the forecasted 2014 CARE customer discount. This shortfall is included in the PPP-CARE portion of the gas PPP surcharge rates for 2015 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 GAV Settlement in D.11-04-031, dated April 14, 2011. The rates submitted with this advice letter implement the 2015 interim rate provisions established in the GAV Settlement. Pursuant to Section 2.4, interim 2015 rates are set equal to the rates in effect on December 31, 2014, plus a 2 percent escalator for non G-XF backbone transmission, local transmission, storage, and customer access charge rates. The 2 percent escalation of non-G-XF backbone transmission and local transmission rates is applied to December 31, 2014 rates adjusted to remove the $30 million revenue sharing mechanism seed value credit adopted in Section 10.1.2 of the GAV Settlement.[8]

The following table shows resulting total annual 2015 revenue requirement changes.

[8] The revenue sharing mechanism was established to apply from 2011 through 2014, the term of the GAV Settlement (Section 10.1).

**Annual Gas Transmission and Storage Revenue Requirements**

**2015**

**($000)**

| Total Annual GT&S Revenue Requirements | GT&S 2014 | GT&S Interim 2015 | % Change |
|---|---|---|---|
| Total Backbone | $231,612 | $236,128 | 1.9% |
| Total Local Transmission | $212,200 | $216,444 | 2.0% |
| Total Storage | $ 85,583 | $ 87,295 | 2.0% |
| Total Customer Access Charge | $ 5,026 | $ 5,127 | 2.0% |
| Total GT&S | $534,421 | $544,993 | 2.0% |

Attachment 6 provides an update of the GT&S revenue requirements and rates tables, included in Appendix A of the GAV Settlement.

**Backbone and Local Transmission Adder Project Rate Adjustments**

Section 7.4 of the GAV Settlement addresses treatment of costs associated with various Backbone and Local Transmission adder projects. Under the terms of the GAV 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. Three Local Transmission adder projects, Line 304, Line 407 Phase 1, and Line 407 Phase 2, were scheduled to be, but were not, operational in 2013 nor in 2014. Accordingly, Local Transmission rates effective January 1, 2014, have been adjusted to remove recovery of the Line 304, Line 407 Phase 1, and Line 407 Phase 2 adder project revenue requirements.[9]

The GAV Settlement identified three backbone transmission adder projects. None of these projects became operational during the Settlement period. The revenue requirements associated with these backbone transmission adder projects are not included in the revenue requirements proposed to be collected through 2015 backbone transmission rates.[10]

[9] The 2014 Line 304 adder project revenue requirement removed from Local Transmission rates is $539,000. The 2014 Line 407 Phase 1 adder project revenue requirement removed from Local Transmission rates is $6.576 million. The 2014 Line 407 Phase 2 adder project revenue requirement removed from Local Transmission rates is $6.484 million.

[10] The 2014 P02158-Topock K-Units Replacement Phase 1 adder project revenue requirement removed from Backbone Transmission rates is $7.525 million. The Delevan K3/Gerber – Line 400 adder project revenue requirement removed from Backbone Transmission rates is $493,000. The Delevan K3/Gerber – Line 401 adder project revenue requirement removed from Backbone Transmission rates is $518,000.

## Effective Date

PG&E requests that this Tier 2 filing be approved within 30 days of filing (by December 4, 2014), with an effective date of January 1, 2015.

As noted above, illustrative average rates are shown on Attachments 3 through 5 of this filing. PG&E will submit final rates and preliminary statement changes in a separate December 2014 advice letter that will consolidate all year-end gas transportation rate changes authorized to be effective on January 1, 2015.[11] Changes to core gas transportation rates will be incorporated into the monthly core procurement advice filing for rates effective January 1, 2015.

## Protests

Anyone wishing to protest this advice letter may do so by sending a letter by November 24, 2014, which is 20 days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

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:

Meredith Allen
Senior Director, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

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

[11] The advice letter for monthly core gas procurement rates will be submitted in a separate advice letter in December 2014.

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.

/S/
Meredith Allen
Senior Director – Regulatory Relations

cc: 2009 Biennial Cost Allocation Proceeding (BCAP) (A.09-05-026)
Gas PPP Surcharge (R.13-11-005 (EE) and A.11-05-019 (ESA/CARE))
2011 Gas Transmission and Storage Proceeding (A.09-09-013)
2014 GRC Phase I (A.12-11-009)
AB 32 Natural Gas Supplier Cost Recovery (A.13-09-015)
PSEP Update (A.13-10-017)
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: Kingsley Cheng |
|---|---|
| ☐ ELC ☑ GAS | Phone #: (415) 973-5265 |
| ☐ PLC ☐ HEAT ☐ WATER | E-mail: k2c0@pge.com and PGETariffs@pge.com |

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

Advice Letter (AL) #: **3529-G** **Tier: 2**

Subject of AL: **Annual Gas True-Up of Gas Transportation Balancing Accounts for Rates Effective January 1, 2015**

Keywords (choose from CPUC listing): Compliance, Surcharges

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? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________

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

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

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

Resolution Required? ☐Yes ☑No

Requested effective date: **January 1, 2015** No. of tariff sheets: N/A

Estimated system annual revenue effect (%): $2,684 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: N/A

Service affected and changes proposed: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

**California Public Utilities Commission**
**Energy Division**
**EDTariffUnit**
**505 Van Ness Ave., 4th Flr.**
**San Francisco, CA 94102**
**E-mail: EDTariffUnit@cpuc.ca.gov**

**Pacific Gas and Electric Company**
**Attn: Meredith Allen**
**Senior Director, Regulatory Relations**
**77 Beale Street, Mail Code B10C**
**P.O. Box 770000**
**San Francisco, CA 94177**
**E-mail: PGETariffs@pge.com**

**ATTACHMENT 1**

**PACIFIC GAS AND ELECTRIC COMPANY**
**2015 ANNUAL GAS TRUE-UP**

**2015 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 9/1/14** | **Proposed as of 1/1/2015** | **Total Change** | **Core** | **Noncore / Unbundled** | Line No. |
| | **END-USE GAS TRANSPORTATION** | | | | | | |
| 1 | Gas Transportation Balancing Accounts | 174,813 | 415,544 | 240,731 | 264,603 | (23,872) | 1 |
| 2 | GRC Distribution Base Revenues (includes distribution portion of Cost of Capital) | 1,559,047 | 1,652,881 | 93,834 | 90,538 | 3,296 | 2 |
| 3 | Pension | 46,015 | 50,422 | 4,407 | 4,254 | 153 | 3 |
| 4 | Self Generation Incentive Program Revenue Requirement | 6,480 | 6,525 | 45 | 18 | 27 | 4 |
| 5 | CPUC Fee | 3,210 | 3,210 | - | - | - | 5 |
| 6 | Core Brokerage Fee Credit | (6,583) | (6,583) | - | - | - | 6 |
| 7 | Less CARE discount recovered in PPP surcharge from non-CARE customers | (108,850) | (113,888) | (5,038) | (5,038) | - | 7 |
| 8 | FF&U | 3,207 | 8,509 | 5,302 | 5,275 | 27 | 8 |
| 9 | Total Transportation RRQ with Adjustments and Credits | 1,677,339 | 2,016,620 | 339,281 | 359,650 | (20,369) | 9 |
| 10 | Procurement-Related G-10 Total | (1,047) | (1,035) | 12 | 12 | - | 10 |
| 11 | Procurement-Related G-10 Total Allocated | 1,047 | 1,035 | (12) | (4) | (8) | 11 |
| 12 | Total Transportation Revenue Requirements Reallocated | 1,677,339 | 2,016,620 | 339,281 | 359,658 | (20,377) | 12 |
| | Gas Accord Transportation Revenue Requirements | | | | | | |
| 13 | Local Transmission | 212,200 | 216,444 | 4,244 | 2,707 | 1,537 | 13 |
| 14 | Customer Access | 5,026 | 5,127 | 101 | - | 101 | 14 |
| 15 | Total Gas Accord Transportation RRQ | 217,226 | 221,571 | 4,345 | 2,707 | 1,638 | 15 |
| 16 | Implementation Plan Revenue Requirements | | | | | | 16 |
| 17 | Implementation Plan - Local Transmission | 134,616 | - | (134,616) | (85,881) | (48,735) | 17 |
| 18 | Implementation Plan - Backbone | 40,770 | - | (40,770) | (17,462) | (23,308) | 18 |
| 19 | Implementation Plan - Storage | 5,572 | - | (5,572) | (3,291) | (2,281) | 19 |
| 20 | Total Implementation Plan Revenue Requirements | 180,958 | - | (180,958) | (106,634) | (74,324) | 20 |
| 21 | **Total End Use Gas Transportation RRQ** | **2,075,523** | **2,238,191** | **162,668** | **255,731** | **(93,063)** | 21 |
| | **PUBLIC PURPOSE PROGRAMS (PPP) FUNDING** | | | | | | |
| 22 | Energy Efficiency | 74,077 | 77,296 | 3,219 | 2,897 | 322 | 22 |
| 23 | Energy Savings Assistance | 67,982 | 68,858 | 876 | 788 | 88 | 23 |
| 24 | Research and Development and BOE/CPUC Admin Fees | 11,079 | 10,900 | (179) | (113) | (66) | 24 |
| 25 | CARE Administrative Expense | 2,806 | 3,001 | 195 | 133 | 62 | 25 |
| 26 | Statewide Marketing, Education & Outreach - EE Flex Alert | 255 | (477) | (732) | (659) | (73) | 26 |
| 27 | Total Authorized PPP Funding | 156,199 | 159,578 | 3,379 | 3,046 | 333 | 27 |
| 28 | PPP Surcharge Balancing Accounts | (9,295) | (1,740) | 7,555 | 7,232 | 323 | 28 |
| 29 | CARE discount recovered from non-CARE customers | 108,850 | 113,888 | 5,038 | 3,661 | 1,377 | 29 |
| 30 | **Total PPP Required Funding** | **255,754** | **271,726** | **15,972** | **13,939** | **2,033** | 30 |
| | **GAS ACCORD UNBUNDLED COSTS** | | | | | | |
| 31 | Backbone Transmission | 135,405 | 137,996 | 2,591 | - | 2,591 | 31 |
| 32 | Storage | 34,980 | 35,679 | 699 | - | 699 | 32 |
| 33 | **Total Gas Accord Unbundled** | **170,385** | **173,675** | **3,290** | **-** | **3,290** | 33 |
| 34 | **TOTAL REVENUE REQUIREMENTS** | **2,501,662** | **2,683,592** | **181,930** | **269,670** | **(87,740)** | 34 |

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

**ATTACHMENT 1A**

**PACIFIC GAS AND ELECTRIC COMPANY**
**2015 ANNUAL GAS TRUE-UP**

**2015 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING ALLOCATION TO CORE/NONCORE/UNBUNDLED**
**($ THOUSANDS)**

| Line No. | | Proposed as of 1/1/2015 | Core | Noncore / Unbundled | Line No. |
|---|---|---|---|---|---|
| | **END-USE GAS TRANSPORTATION** | | | | |
| 1 | Gas Transportation Balancing Accounts | 415,544 | 397,010 | 18,534 | 1 |
| 2 | GRC Distribution Base Revenues | 1,652,881 | 1,595,347 | 57,534 | 2 |
| 3 | Pension | 50,422 | 48,667 | 1,755 | 3 |
| 4 | Self Generation Incentive Program Revenue Requirement | 6,525 | 2,587 | 3,938 | 4 |
| 5 | CPUC Fee | 3,210 | 1,970 | 1,240 | 5 |
| 6 | Core Brokerage Fee Credit | (6,583) | (6,583) | - | 6 |
| 7 | Less CARE discount recovered in PPP surcharge from non-CARE customers | (113,888) | (113,888) | - | 7 |
| 8 | FF&U | 8,509 | 7,645 | 864 | 8 |
| 9 | Total Transportation RRQ with Adjustments and Credits | 2,016,620 | 1,932,755 | 83,865 | 9 |
| 10 | Procurement-Related G-10 Total | (1,035) | (1,035) | - | 10 |
| 11 | Procurement-Related G-10 Total Allocated | 1,035 | 408 | 627 | 11 |
| 12 | Total Transportation Revenue Requirements Reallocated | 2,016,620 | 1,932,128 | 84,492 | 12 |
| | Gas Accord Transportation Revenue Requirements | | | | |
| 13 | Local Transmission | 216,444 | 138,046 | 78,398 | 13 |
| 14 | Customer Access | 5,127 | - | 5,127 | 14 |
| 15 | Total Gas Accord Transportation RRQ | 221,571 | 138,046 | 83,525 | 15 |
| 16 | Implementation Plan Revenue Requirements | | | | 16 |
| 17 | Implementation Plan - Local Transmission | - | - | - | 17 |
| 18 | Implementation Plan - Backbone | - | - | - | 18 |
| 19 | Implementation Plan - Storage | - | - | - | 19 |
| 20 | Total Implementation Plan | - | - | - | 20 |
| 21 | **Total End Use Gas Transportation RRQ** | **2,238,191** | **2,070,174** | **168,017** | 21 |
| | **PUBLIC PURPOSE PROGRAMS (PPP) FUNDING** | | | | |
| 22 | Energy Efficiency | 77,296 | 69,554 | 7,742 | 22 |
| 23 | Energy Savings Assistance | 68,858 | 61,961 | 6,897 | 23 |
| 24 | Research and Development and BOE/CPUC Admin Fees | 10,900 | 6,975 | 3,925 | 24 |
| 25 | CARE Administrative Expense | 3,001 | 1,811 | 1,190 | 25 |
| 26 | Statewide Marketing, Education & Outreach - EE Flex Alert | (477) | (429) | (48) | 26 |
| 27 | Total Authorized PPP Funding | 159,578 | 139,872 | 19,706 | 27 |
| 28 | PPP Surcharge Balancing Accounts | (1,740) | 4,526 | (6,266) | 28 |
| 29 | CARE discount recovered from non-CARE customers | 113,888 | 68,733 | 45,155 | 29 |
| 30 | **Total PPP Required Funding** | **271,726** | **213,131** | **58,595** | 30 |
| | **GAS ACCORD UNBUNDLED COSTS** | | | | |
| 31 | Backbone Transmission | 137,996 | - | 137,996 | 31 |
| 32 | Storage | 35,679 | - | 35,679 | 32 |
| 33 | **Total Gas Accord Unbundled** | **173,675** | **-** | **173,675** | 33 |
| 34 | **TOTAL REVENUE REQUIREMENTS** | **2,683,592** | **2,283,305** | **400,287** | 34 |

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

ATTACHMENT 2

**PACIFIC GAS AND ELECTRIC COMPANY**
**2015 ANNUAL GAS TRUE-UP**
**BALANCING ACCOUNT FORECAST SUMMARY**

**($ THOUSANDS)**

| Line No. | | Balance: Sept. 2014 Recorded Dec. 2014 Forecast | Allocation: Core | Allocation: Noncore | Balance: December 2013 Recorded (1) | Allocation: Core | Allocation: Noncore | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | A | B | C | D | E | F | |
| | **GAS TRANSPORTATION BALANCING ACCOUNTS** | | | | | | | |
| 1 | Core Fixed Cost Account (CFCA) - Distribution Cost Subaccount | $376,432 | $376,432 | $0 | $55,850 | $55,850 | $0 | 1 |
| 2 | CFCA - Core Cost Subaccount | $14,936 | $14,936 | $0 | $4,994 | $4,994 | $0 | 2 |
| 3 | Noncore Customer Class Charge Account (NCA) - Noncore Subaccount | ($14,090) | $0 | ($14,090) | ($3,652) | $0 | ($3,652) | 3 |
| 4 | NCA - Distribution Subaccount | $5,623 | $0 | $5,623 | ($896) | $0 | ($896) | 4 |
| 5 | Core Brokerage Fee Balancing Account | $1,426 | $1,426 | $0 | $764 | $764 | $0 | 5 |
| 6 | Hazardous Substance Mechanism | $46,555 | $18,360 | $28,195 | $51,039 | $20,129 | $30,910 | 6 |
| 7 | Balancing Charge Account | $421 | $166 | $255 | ($80) | ($32) | ($48) | 7 |
| 8 | Affiliate Transfer Fee Account | ($162) | ($157) | ($5) | $0 | $0 | $0 | 8 |
| 9 | Customer Energy Efficiency Incentive Recovery Account - Gas | $7,270 | $7,207 | $63 | $3,983 | $3,948 | $35 | 9 |
| 10 | SmartMeter™ Opt-Out Balancing Account | $7,830 | $7,557 | $273 | $0 | $0 | $0 | 10 |
| 11 | California Solar Initiative Thermal Program Memoradum Account | $6,200 | $3,669 | $2,531 | $4,931 | $1,945 | $2,986 | 11 |
| 12 | Adjustment Mechanism of Costs Determined in Other Proceedings | $23,868 | $11,934 | $11,934 | $0 | $0 | $0 | 12 |
| 13 | Non-Tariffed Products and Services Balancing Account | ($33) | ($33) | $0 | ($267) | ($267) | $0 | 13 |
| 14 | AB 32 Cost of Implementation Fee | $2,794 *(2)* | $1,597 | $1,197 | $4,815 | $4,122 | $693 | 14 |
| 15 | GPECBA - CPUC Reimbursement Subaccount | $0 | $0 | $0 | $0 | $0 | $0 | 15 |
| 16 | Gas Leak Survey and Repair Balancing Account | ($18,002) | ($17,375) | ($627) | $0 | $0 | $0 | 16 |
| 17 | Gas Operational Cost Balancing Account | $10,267 | $4,049 | $6,218 | $9,551 | $3,767 | $5,784 | 17 |
| 18 | Pension Contribution Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | 18 |
| 19 | TID Almond Power Plant Balancing Account | ($898) | ($580) | ($318) | ($1,265) | ($499) | ($766) | 19 |
| 20 | Revised Customer Energy Statement Balancing Account | $2,502 | $2,415 | $87 | ($4,204) | ($1,658) | ($2,546) | 20 |
| 21 | GT&S Revenue Sharing Mechanism | $4,867 *(3)* | $2,433 | $2,434 | $10,985 *(4)* | $5,493 | $5,492 | 21 |
| 22 | Core Gas Pipeline Safety Balancing Account | ($37,078) | ($37,078) | $0 | $0 | $0 | $0 | 22 |
| 23 | Noncore Gas Pipeline Safety Balancing Account | ($25,238) | $0 | ($25,238) | $0 | $0 | $0 | 23 |
| 24 | Integrity Management Expense Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | 24 |
| 25 | Mobile Home Park Balancing Account | $54 | $52 | $2 | $0 | $0 | $0 | 25 |
| 26 | **Subtotal Transportation Balancing Accounts** | **$415,544** | **$397,010** | **$18,534** | **$136,548** | **$98,556** | **$37,992** | 26 |
| | **PUBLIC PURPOSE PROGRAM (PPP) SURCHARGE BALANCING ACCOUNTS (5)** | | | | | | | |
| 27 | PPP-Energy Efficiency | $11,323 | $10,189 | $1,134 | $11,836 | $10,651 | $1,185 | 27 |
| 28 | PPP-Low Income Energy Efficiency | $7,466 | $6,719 | $747 | $4,938 | $4,442 | $496 | 28 |
| 29 | PPP-Research Development and Demonstration | $194 | $124 | $70 | $194 | $124 | $70 | 29 |
| 30 | California Alternate Rates for Energy Account | ($20,723) | ($12,506) | ($8,217) | ($21,550) | ($12,883) | ($8,667) | 30 |
| 31 | **Subtotal Public Purpose Program Balancing Accounts** | **($1,740)** | **$4,526** | **($6,266)** | **($4,582)** | **$2,334** | **($6,916)** | 31 |
| 32 | **TOTAL BALANCING ACCOUNTS** | **$413,804** | **$401,536** | **$12,268** | **$131,966** | **$100,890** | **$31,076** | 32 |

**Footnotes:**

1. These balances are the recorded balances as of December 2013. The 12/13 ending balances that were provided in the 2014 AGT AL 3447-G were the forecasted balances (based on recorded balances through November 2013).
2. This amount reflects the total forecast balance of the AB 32 Cost of Implementation Fee Core subaccount in the CFCA and the Noncore subaccount of the NCA. The total forecast balance is allocated on an equal-cents-per therm basis.
3. The balance shown is the September 30, 2014 recorded balance, which will be transferred evenly (50/50) to the CFCA and NCA after the approval of the AGT advice letter.
4. This amount represents the September 30, 2013 recorded balance which was transferred to CFCA and NCA evenly.
5. The PPP-related balances (based on Sept 2014 recorded) were included in the 2015 PPP Gas Surcharge filed in AL 3528-G on October 31, 2014.

**Notes:**

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

ATTACHMENT 3
PACIFIC GAS AND ELECTRIC COMPANY
January 1, 2015 AGT/GT&S escalated 2% November Filing
AVERAGE END-USER GAS TRANSPORTATION RATES AND PUBLIC PURPOSE PROGRAM SURCHARGES
($/th; Annual Class Averages)(3)

| Line No. | Customer Class | Sept 1, 2014 GRC Implementation (A) | | | January 1, 2015 AGT/GT&S escalated 2% November Filing | | | Percentage Change From September 1, 2014 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Transportation(1) | G-PPPS (2) | Total | Transportation | G-PPPS | Total | Transportation | G-PPPS | Total |
| | RETAIL CORE | | | | | | | | | |
| 1 | Residential Non-CARE (4) | $.766 | $.084 | **$.850** | $.882 | $.090 | **$.972** | 15.1% | 7.2% | 14.3% |
| 2 | Small Commercial Non-CARE (4) | $.459 | $.044 | **$.504** | $.509 | $.045 | **$.553** | 10.7% | 0.7% | 9.8% |
| 3 | Large Commercial | $.227 | $.092 | **$.319** | $.219 | $.097 | **$.317** | (3.4%) | 6.4% | (0.6%) |
| 4 | NGV1 - (uncompressed service) | $.164 | $.026 | **$.189** | $.140 | $.026 | **$.166** | (14.8%) | 1.9% | (12.5%) |
| 5 | NGV2 - (compressed service) | $1.445 | $.026 | **$1.470** | $1.651 | $.026 | **$1.677** | 14.3% | 1.9% | 14.1% |
| | RETAIL NONCORE | | | | | | | | | |
| 6 | Industrial - Distribution | $.191 | $.042 | **$.232** | $.191 | $.043 | **$.234** | 0.1% | 4.3% | 0.9% |
| 7 | Industrial - Transmission | $.064 | $.034 | **$.098** | $.040 | $.035 | **$.075** | (36.8%) | 3.5% | (22.9%) |
| 8 | Industrial - Backbone | $.020 | $.034 | **$.054** | $.010 | $.035 | **$.045** | (49.0%) | 3.5% | (16.4%) |
| 9 | Electric Generation - Transmission (G-EG-D/LT) | $.056 | | **$.056** | $.031 | | **$.031** | (44.8%) | | (44.8%) |
| 10 | Electric Generation - Backbone (G-EG-BB) | $.020 | | **$.020** | $.010 | | **$.010** | (50.2%) | | (50.2%) |
| 11 | NGV 4 - Distribution (uncompressed service) | $.191 | $.026 | **$.216** | $.191 | $.026 | **$.217** | 0.1% | 1.9% | 0.3% |
| 12 | NGV 4 - Transmission (uncompressed service) | $.056 | $.026 | **$.081** | $.031 | $.026 | **$.057** | (44.9%) | 1.9% | (30.2%) |
| | WHOLESALE CORE AND NONCORE (G-WSL) (1) | | | | | | | | | |
| 13 | Alpine Natural Gas | $.056 | | **$.056** | $.031 | | **$.031** | (44.7%) | | (44.7%) |
| 14 | Coalinga | $.057 | | **$.057** | $.032 | | **$.032** | (44.0%) | | (44.0%) |
| 15 | Island Energy | $.076 | | **$.076** | $.051 | | **$.051** | (32.3%) | | (32.3%) |
| 16 | Palo Alto | $.052 | | **$.052** | $.027 | | **$.027** | (48.3%) | | (48.3%) |
| 17 | West Coast Gas - Castle | $.215 | | **$.215** | $.237 | | **$.237** | 10.4% | | 10.4% |
| 18 | West Coast Gas - Mather Distribution | $.257 | | **$.257** | $.295 | | **$.295** | 14.5% | | 14.5% |
| 19 | West Coast Gas - Mather Transmission | $.060 | | **$.060** | $.035 | | **$.035** | (41.8%) | | (41.8%) |

(1) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable), distribution costs (where applicable), and AB32 Cost of Implementation Fee (wholesale and certain large customers are directly billed by the Air Resource board, and are exempt from PG&E's AB32 COI rate component of $0.00056 per therm). Transport only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

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

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

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

Attachment 4
PACIFIC GAS AND ELECTRIC COMPANY
JANUARY 1, 2015 AGT/GT&S ESCALATED 2% NOVEMBER FILING
SUMMARY OF RATES (excluding procurement) BY CLASS BY MAJOR ELEMENTS
($/th; Annual Class Averages)(9)

| | | 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) | $.04749 | $.04749 | $.04749 | $.04749 | $.04749 | $.0232500 | $.02325 | $.00000 | $.02325 | $.02325 | $.02325 | $.00000 |
| 2 | Self Generation Incentive Program | $.00091 | $.00091 | $.00091 | $.00091 | $.00091 | $.0009080 | $.00091 | $.00091 | $.00091 | $.00091 | $.00091 | $.00091 |
| 3 | CPUC and AB32 Cost of Implementation Fee (3)(8) | $.00125 | $.00125 | $.00125 | $.00125 | $.00125 | $.0012525 | $.00125 | $.00125 | $.00125 | $.00125 | $.00059 | $.00059 |
| 4 | Balancing Accounts (2) | $.17202 | $.10539 | $.04903 | $.03407 | $.31505 | $.0233253 | $.01037 | $.00963 | $.02333 | $.00963 | $.00833 | $.00833 |
| 5 | PSEP | ($.01275) | ($.01275) | ($.01275) | ($.01275) | ($.01275) | ($.0062730) | ($.00627) | ($.00296) | ($.00627) | ($.00627) | ($.00627) | ($.00296) |
| 6 | Distribution - Annual Average (6) | $.67276 | $.30737 | $.12906 | $.06758 | $1.29942 | $.1404092 | $.00892 | | $.14041 | | $.00279 | $.00279 |
| 7 | VOLUMETRIC RATE - Average Annual | $.88168 | $.44966 | $.21499 | $.13855 | $1.65137 | $.18287 | $.03843 | $.00883 | $.18287 | $.02877 | $.02960 | $.00967 |
| 8 | CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4) | | $.05888 | $.00449 | $.00120 | | $.00804 | $.00190 | $.00161 | $.00804 | $.00190 | $.00111 | $.00020 |
| 9 | CLASS AVERAGE TRANSPORTATION RATE | $.88168 | $.50854 | $.21947 | $.13974 | $1.65137 | $.19091 | $.04033 | $.01044 | $.19091 | $.03067 | $.03071 | $.00986 |
| 10 | PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5) | $.08989 | $.04472 | $.09743 | $.02602 | $.02602 | $.04349 | $.03488 | $.03488 | $.02602 | $.02602 | | |
| 11 | END-USE RATE (7) | $.97157 | $.55326 | $.31690 | $.16576 | $1.67739 | $.23440 | $.07521 | $.04532 | $.21693 | $.05669 | $.03071 | $.00986 |

| | | Wholesale | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | WC Gas Mather | | Island | | WC Gas |
| | | Coalinga | Palo Alto | Dist. | Trans. | Energy | Alpine | Castle |
| | TRANSPORTATION CHARGE COMPONENTS | | | | | | | |
| 12 | Local Transmission (1) | $.02325 | $.02325 | $.02325 | $.02325 | $.02325 | $.02325 | $.02325 |
| 13 | Self Generation Incentive Program | WHOLESALE CUSTOMERS EXCEPT FROM SGIP, AB32 COI, and CPUC FEE RATE COMPONENT | | | | | | |
| 14 | CPUC and AB32 Cost of Implementation Fee (3)(8) | | | | | | | |
| 15 | Balancing Accounts (2) | $.00790 | $.00795 | $.02984 | $.00795 | $.00798 | $.00788 | $.02442 |
| 16 | PSEP | ($.00627) | ($.00627) | ($.00627) | ($.00627) | ($.00627) | ($.00627) | ($.00627) |
| 17 | Distribution - Annual Average | | | $.23831 | | | | $.17997 |
| 18 | VOLUMETRIC RATE - Average Annual | $.02488 | $.02493 | $.28513 | $.02493 | $.02496 | $.02485 | $.22137 |
| 19 | CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4) | $.00683 | $.00183 | $.00973 | $.00973 | $.02641 | $.00597 | $.01571 |
| 20 | CLASS AVERAGE TRANSPORTATION RATE | $.03171 | $.02676 | $.29486 | $.03466 | $.05137 | $.03082 | $.2370788 |
| 21 | PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5) | | | | | | | |
| 22 | END-USE RATE | $.03171 | $.02676 | $.29486 | $.03466 | $.05137 | $.03082 | $.23708 |

NOTES
(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2015 Annual Gas True-Up Filing AL 3529-G Attachment 6, Appendix B, Table 11.
(2) Based on September 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 2015 Annual Gas True-Up Filing AL 3529-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 3528-G updated PG&E's 2015 PPP Surcharges effective January 1, 2015.
(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.
(8) AB32 provides the Air Resource Board recovery of its administration costs associated with the implementation of AB32. Wholesale and certain large customers are directly billed by the ARB, and are exempt from PG&E's cost of implementation component of $0.00056 per therm
(9) Rates are unrounded

# Attachment 5

**PACIFIC GAS AND ELECTRIC COMPANY**

**January 1, 2015 AGT/GT&S escalated 2% November Filing**

**ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES**

**($000)**

| Line No. | GAS GRC, ATTRITION, PENSION & COST OF CAPITAL DISTRIBUTION-LEVEL REVENUE REQUIREMENTS | TOTAL | Residential* | Small Commercial* | Large Commercial | Core NGV | Compression Cost for G-NGV2 | Subtotal Core | Industrial Distribution | Industrial Transmission | Industrial Backbone | Electric Gen | Noncore NGV | Coalinga | Palo Alto | Alpine Natural Gas | WC Gas Mather** | Island Energy | WC Gas Castle** | Noncore & Wholesale |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Customer | $912,963 | $796,534 | $106,150 | $2,271 | $92 | $0 | $905,047 | $5,620 | $320 | $0 | $1,976 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $7,916 |
| 2 | + Distribution | $758,152 | $528,744 | $170,264 | $7,513 | $1,275 | $0 | $707,795 | $32,373 | $12,279 | $0 | $5,437 | $0 | $0 | $0 | $0 | $149 | $0 | $119 | $50,357 |
| 3 | + G-NGV2 Compression Cost | $2,969 | $0 | $0 | $0 | $0 | $2,969 | $2,969 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | Allocation of Base Distribution Franchise Fees | $23,556 | $18,648 | $3,889 | $138 | $19 | $42 | $22,736 | $535 | $177 | $0 | $104 | $0 | $0 | $0 | $0 | $2 | $0 | $2 | $820 |
| 5 | Allocation of Base Distribution Uncollectibles Expense | $5,663 | $4,484 | $935 | $33 | $5 | $10 | $5,467 | $129 | $43 | $0 | $25 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $196 |
| 6 | Totals Before Core Averaging | $1,703,303 | $1,348,410 | $281,238 | $9,955 | $1,391 | $3,021 | $1,644,015 | $38,657 | $12,818 | $0 | $7,542 | $0 | $0 | $0 | $0 | $151 | $0 | $121 | $59,289 |
| 7 | Re-Allocation Due to Core Averaging* | ($0) | ($8,968) | $8,968 | $0 | $0 | $0 | ($0) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | **Final Allocation of Distribution Revenue Requirement** | **$1,703,303** | **$1,339,442** | **$290,206** | **$9,955** | **$1,391** | **$3,021** | $1,644,015 | **$38,657** | **$12,818** | **$0** | **$7,542** | **$0** | **$0** | **$0** | **$0** | **$151** | **$0** | **$121** | $59,289 |
| 9 | **Distribution-Level Revenue Requirement Allocation %** | 100.00000% | 78.63791% | 17.03783% | 0.58445% | 0.08165% | 0.17735% | 96.51919% | 2.26950% | 0.75256% | 0.00000% | 0.44280% | 0.00000% | 0.00000% | 0.00000% | 0.00000% | 0.00886% | 0.00000% | 0.00709% | 3.48081% |

Total Core Brokerage Fee (w/out F&U) (6,470) (6,583) With F&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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount | $376,432 | $306,694 | $66,449 | $2,279 | $318 | $692 | $376,432 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 | Core Fixed Cost Acct. Bal. - Core Cost Subaccount - ECPT | $14,936 | $10,364 | $4,083 | $384 | $104 | $0 | $14,936 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12 | *Mobile Home Parks Balancing Account* | $54 | $43 | $9 | $0 | $0 | $0 | $52 | $1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2 |
| 13 | Noncore Customer Class Charge Account - ECPT | ($14,090) | $0 | $0 | $0 | $0 | $0 | $0 | ($824) | ($4,550) | ($37) | ($8,545) | ($17) | ($8) | ($101) | ($2) | ($3) | ($2) | ($2) | ($14,090) |
| 14 | Noncore Customer Class Charge Account - Distribution Subacct | $5,623 | $0 | $0 | $0 | $0 | $0 | $0 | $3,667 | $1,216 | $0 | $715 | $0 | $0 | $0 | $0 | $14 | $0 | $11 | $5,623 |
| 15 | *Gas Leak Survey & Repair Balancing Account* | ($18,002) | ($14,251) | ($2,972) | ($105) | ($15) | ($32) | ($17,375) | ($409) | ($135) | $0 | ($80) | $0 | $0 | $0 | $0 | ($2) | $0 | ($1) | ($627) |
| 16 | SmartMeter™ Opt-Out Balancing Account | $7,830 | $6,198 | $1,293 | $46 | $6 | $14 | $7,557 | $178 | $59 | $0 | $35 | $0 | $0 | $0 | $0 | $1 | $0 | $1 | $273 |
| 17 | Placeholder | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 18 | Hazardous Substance Balance | $46,555 | $12,740 | $5,020 | $472 | $128 | $0 | $18,360 | $1,650 | $9,104 | $74 | $17,099 | $33 | $15 | $202 | $4 | $6 | $4 | $4 | $28,195 |
| 19 | Non-Tariffed Products and Services | ($33) | ($23) | ($9) | ($1) | ($0) | $0 | ($33) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 | Core Brokerage Fee Credit (Gas Brokerage Costs w/o FF&U) | ($5,446) | ($3,779) | ($1,489) | ($140) | ($38) | $0 | ($5,446) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 21 | Core Brokerage Fee Credit (Sales/Marketing Costs w/o FF&U) | ($1,024) | ($901) | ($120) | ($3) | ($0) | $0 | ($1,024) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 22 | Affiliate Transfer Fee Account | ($162) | ($128) | ($27) | ($1) | ($0) | ($0) | ($157) | ($4) | ($1) | $0 | ($1) | $0 | $0 | $0 | $0 | ($0) | $0 | ($0) | ($6) |
| 23 | Balancing Charge Account | $421 | $115 | $45 | $4 | $1 | $0 | $166 | $15 | $82 | $1 | $155 | $0 | $0 | $2 | $0 | $0 | $0 | $0 | $255 |
| 24 | G-10 Procurement-related Employee Discount Allocated | $1,035 | $283 | $112 | $11 | $3 | $0 | $408 | $37 | $202 | $2 | $380 | $1 | $0 | $4 | $0 | $0 | $0 | $0 | $627 |
| 25 | Brokerage Fee Balance Account | $1,426 | $989 | $390 | $37 | $10 | $0 | $1,426 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 26 | Adjust. Mechanism Costs Determined Other Proceedings | $23,868 | $8,261 | $3,263 | $307 | $83 | $0 | $11,934 | $698 | $3,853 | $31 | $7,237 | $14 | $6 | $86 | $2 | $3 | $2 | $2 | $11,934 |
| 27 | G-10 Procurement-related Employee Discount | ($1,035) | ($1,035) | $0 | $0 | $0 | $0 | ($1,035) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 28 | TID Almond Power Plant | ($898) | ($436) | ($134) | ($8) | ($2) | $0 | ($580) | ($31) | ($122) | $0 | ($159) | ($1) | ($0) | ($5) | ($0) | ($0) | ($0) | ($0) | ($318) |
| 29 | RCESBA-G | $2,502 | $1,961 | $413 | $15 | $2 | $4 | $2,415 | $57 | $19 | $0 | $11 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $87 |
| 30 | Gas Operational Cost Balancing Account | $10,267 | $2,810 | $1,107 | $104 | $28 | $0 | $4,049 | $364 | $2,008 | $16 | $3,771 | $7 | $3 | $45 | $1 | $1 | $1 | $1 | $6,218 |
| 31 | WGSP Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 32 | GT&S Revenue Sharing Mechanism | $4,867 | $1,669 | $665 | $63 | $17 | $0 | $2,433 | $142 | $786 | $6 | $1,476 | $3 | $1 | $17 | $0 | $1 | $0 | $0 | $2,433 |
| 33 | Gas Meter Reading Costs Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 34 | Self Gen Incentive Program Forecast Period Cost | $6,525 | $1,795 | $707 | $67 | $18 | $0 | $2,587 | $232 | $1,283 | $10 | $2,409 | $5 | $0 | $0 | $0 | $0 | $0 | $0 | $3,939 |
| 35 | Subtotals of Items Transferred to CFCA and NCA | $461,653 | $333,429 | $78,804 | $3,530 | $665 | $678 | $417,106 | $5,773 | $13,804 | $103 | $24,504 | $46 | $19 | $250 | $5 | $22 | $5 | $16 | $44,547 |
| 36 | Re-Allocation Due to Core Averaging | $0 | ($1,900) | $1,900 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 37 | Alloc. After Core Averaging | $461,653 | $331,529 | $80,704 | $3,530 | $665 | $678 | $417,106 | $5,773 | $13,804 | $103 | $24,504 | $46 | $19 | $250 | $5 | $22 | $5 | $16 | $44,547 |
| 38 | Franchise Fees and Uncoll. Exp. on Items Above | $8,057 | $5,787 | $1,409 | $62 | $12 | $12 | $7,280 | $101 | $241 | $2 | $428 | $1 | $0 | $4 | $0 | $0 | $0 | $0 | $776 |
| 39 | Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs | $469,710 | $337,316 | $82,113 | $3,592 | $676 | $690 | $424,386 | $5,874 | $14,045 | $105 | $24,932 | $47 | $19 | $254 | $5 | $22 | $5 | $16 | $45,323 |
| 40 | Total of Items Collected via CFCA, NCA, and NDFCA | $2,173,013 | $1,676,758 | $372,319 | $13,547 | $2,067 | $3,711 | $2,068,401 | $44,530 | $26,864 | $105 | $32,474 | $47 | $19 | $254 | $5 | $173 | $5 | $137 | $104,612 |

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | CEE Incentive | $7,270 | $6,343 | $845 | $18 | $1 | $0 | $7,207 | $45 | $3 | $0 | $16 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $63 |
| 42 | AB32 ARB Implementation Fee | $2,794 | $1,108 | $437 | $41 | $11 | $0 | $1,597 | $143 | $792 | $6 | $253 | $3 | $0 | $0 | $0 | $0 | $0 | $0 | $1,197 |
| 43 | CA Solar Hot Water Heating | $6,200 | $2,360 | $1,170 | $110 | $30 | $0 | $3,669 | $384 | $2,122 | $17 | $0 | $8 | $0 | $0 | $0 | $0 | $0 | $0 | $2,531 |
| 44 | SmartMeter™ Project Balancing Account (SBA-G) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 45 | 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 |
| 46 | Subtotals for Customer Class Charge Items | $19,474 | $11,178 | $2,989 | $220 | $55 | $0 | $14,443 | $749 | $3,893 | $31 | $343 | $14 | $0 | $0 | $0 | $0 | $0 | $0 | $5,032 |
| 47 | Re-Allocation Due to Core Averaging | $0 | ($59) | $59 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 48 | Allocation after Remaining Core Averaging | $19,474 | $11,119 | $3,049 | $220 | $55 | $0 | $14,443 | $749 | $3,893 | $31 | $343 | $14 | $0 | $0 | $0 | $0 | $0 | $0 | $5,032 |
| 49 | Franch. Fee and Uncoll. Exp. on Items Above | $340 | $194 | $53 | $4 | $1 | $0 | $252 | $13 | $68 | $1 | $6 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $88 |
| 50 | Subtotals of Other Costs | $19,814 | $11,313 | $3,102 | $224 | $56 | $0 | $14,695 | $763 | $3,961 | $32 | $349 | $14 | $0 | $0 | $0 | $0 | $0 | $0 | $5,119 |
| 51 | Allocation of Total Transportation Costs | $2,192,827 | $1,688,071 | $375,421 | $13,771 | $2,123 | $3,711 | $2,083,096 | $45,293 | $30,825 | $137 | $32,823 | $61 | $19 | $254 | $5 | $173 | $5 | $137 | $109,732 |

| Line No. | CUSTOMER CLASS COST FOR PIPELINE SAFETY ENHANCEMENT ALLOCATED BASED ON GAS ACCORD THROUGHPUT | TOTAL | Residential* | Small Commercial* | Large Commercial | Core NGV | Compression Cost for G-NGV2 | Subtotal Core | Industrial Distribution | Industrial Transmission | Industrial Backbone | Electric Gen | Noncore NGV | Coalinga | Palo Alto | Alpine Natural Gas | WC Gas Mather** | Island Energy | WC Gas Castle** | Noncore & Wholesale |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 52 | Local Transmission Expense (Forecast Period Cost) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 53 | Local Transmission Balancing Account | ($27,713) | ($11,413) | ($4,488) | ($462) | ($128) | $0 | ($16,489) | ($862) | ($4,765) | $0 | ($5,433) | ($19) | ($9) | ($106) | ($2) | ($3) | ($1) | ($2) | ($11,224) |
| 54 | Backbone Transmission Expense (Forecast Period Cost) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 55 | Backbone Transmission Balancing Account | ($29,672) | ($12,219) | ($4,805) | ($494) | ($137) | $0 | ($17,655) | ($675) | ($3,847) | ($29) | ($7,556) | ($15) | ($7) | ($81) | ($2) | ($2) | ($1) | ($2) | ($12,017) |
| 56 | Storage (Forecast Period Cost) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 57 | Storage Balancing Account | ($4,931) | ($2,030) | ($798) | ($82) | ($23) | $0 | ($2,934) | ($112) | ($606) | ($5) | ($1,256) | ($2) | ($1) | ($13) | ($0) | ($0) | ($0) | ($0) | ($1,997) |
| 58 | Subtotal of Pipeline Safety Enhacement Cost | ($62,315) | ($25,662) | ($10,091) | ($1,038) | ($287) | $0 | ($37,078) | ($1,670) | ($9,019) | ($34) | ($14,245) | ($36) | ($16) | ($200) | ($4) | ($6) | ($3) | ($4) | ($25,238) |
| 59 | Net End-User Transportation Excluding LT and CAC | $2,130,512 | $1,662,408 | $365,330 | $12,733 | $1,837 | $3,711 | $2,046,018 | $43,623 | $21,806 | $103 | $18,578 | $25 | $3 | $53 | $1 | $167 | $2 | $133 | $84,494 |

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 60 | Local Transmission | 216,444 | 103,489 | 32,107 | 1,969 | 480 | | 138,046 | 7,303 | 28,845 | | 40,752 | 124 | 119 | 1,134 | 34 | 46 | 17 | 25 | 78,398 |
| 61 | Customer Access Charge | 5,127 | 0 | 0 | 0 | | | 0 | 0 | 2,703 | 0 | 2,313 | | 18 | 58 | 4 | 9 | 12 | 10 | 5,127 |
| 62 | Total End-User Gas Accord Transportation Costs | 221,571 | 103,489 | 32,107 | 1,969 | 480 | 0 | 138,046 | 7,303 | 31,547 | 0 | 43,064 | 124 | 136 | 1,193 | 38 | 55 | 29 | 35 | 83,525 |
| 63 | Gross End-User Transportation Costs in Rates | 2,352,083 | 1,765,897 | 397,437 | 14,702 | 2,317 | 3,711 | 2,184,064 | 50,926 | 53,353 | 103 | 61,643 | 149 | 139 | 1,246 | 39 | 222 | 31 | 168 | 168,019 |
| 64 | Less Forecast CARE Discount recovered in PPP Surcharges | 113,888 | 113,888 | | | | | 113,888 | | | | | | | | | | | | 0 |
| 65 | Net End-User Transportation Costs in Rates | 2,238,195 | 1,652,009 | 397,437 | 14,702 | 2,317 | 3,711 | 2,070,176 | 50,926 | 53,353 | 103 | 61,643 | 149 | 139 | 1,246 | 39 | 222 | 31 | 168 | 168,019 |

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT 5 (continued)
January 1, 2015 AGT/GT&S escalated 2% November Filing
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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 66 | PPP-EE Surcharge | 76,819 | 60,548 | 6,162 | 2,415 | 0 | | 69,124 | 2,065 | 5,584 | 45 | | 0 | | | | | | | 7,694 |
| 67 | PPP-EE Balancing Account | 11,323 | 8,925 | 908 | 356 | 0 | | 10,189 | 304 | 823 | 7 | | 0 | | | | | | | 1,134 |
| 68 | PPP-ESA Surcharge | 68,858 | 54,273 | 5,523 | 2,164 | 0 | | 61,961 | 1,851 | 5,006 | 40 | | 0 | | | | | | | 6,897 |
| 69 | PPP-ESA Balancing Account | 7,466 | 5,885 | 599 | 235 | 0 | | 6,719 | 201 | 543 | 4 | | 0 | | | | | | | 748 |
| 70 | PPP - RD&D Programs | 10,494 | 4,687 | 1,817 | 169 | 42 | | 6,715 | 591 | 3,151 | 25 | | 12 | | | | | | | 3,779 |
| 71 | PPP - RD&D Balancing Account | 194 | 87 | 34 | 3 | 1 | | 124 | 11 | 58 | 0 | | 0 | | | | | | | 70 |
| 72 | PPP-CARE Discount Allocation Set Annually | 113,888 | 44,500 | 21,707 | 2,019 | 507 | | 68,733 | 7,056 | 37,649 | 305 | | 146 | | | | | | | 45,156 |
| 73 | PPP-CARE Administration Expense | 3,001 | 1,173 | 572 | 53 | 13 | | 1,811 | 186 | 992 | 8 | | 4 | | | | | | | 1,190 |
| 74 | PPP-CARE Balancing Account | (20,723) | (8,097) | (3,950) | (367) | (92) | | (12,506) | (1,284) | (6,850) | (55) | | (27) | | | | | | | -8,216 |
| 75 | PPP-Admin Cost for BOE and CPUC | 406 | 161 | 70 | 7 | 2 | | 260 | 23 | 122 | 1 | | 0 | | | | | | | 146 |
| 76 | Subtotal | 271,726.35 | 172,161 | 33,442 | 7,053 | 473 | | 213,129 | 11,003 | 47,077 | 381 | 0 | 136 | 0 | 0 | 0 | 0 | 0 | 0 | 58,597 |
| 77 | Re-Allocation Due to Core Averaging | (0) | (1,359) | 1,359 | 0 | 0 | | (0) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 78 | Allocation after Remaining Averaging | $271,726 | $170,802 | $34,801 | $7,053 | $473 | | $213,129 | $11,003 | $47,077 | $381 | $0 | $136 | $0 | $0 | $0 | $0 | $0 | $0 | $58,597 |

| Line No. | | | |
|---|---|---|---|
| 79 | Unbundled Gas Transmission and Storage Revenue Requirement | $173,675 | |
| | TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES | | |
| 80 | Total Transportation, PPPS,and Unbundled Costs | 2,683,596 | [Total of lines 65, 78, and 79\) |
| 81 | Cross-check with Gas Revenue Requirement Table | 2,683,592 | Attachment 1 Row 34 |
| 82 | Difference | -4 | [Off due to rounding in Attachment 1} |

* Residential and Small Commercial Classes are 5% averaged

** Wholesale Customer West Coast Gas is allocated 100% of its full distribution costs as of January 2015.

Advice 3529-G
November 4, 2014

# Gas Accord V Settlement

## D.11-04-031

# Attachment 6 - Appendix A

## 2015 Interim Rate Update

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

2012 - 2014 Rates - Reflect treatment of costs as determined in PG&E's 2011 General Rate Case in Advice 3257-G-A.

2013 - 2014 Rates - Reflect treatment of costs as proposed in PG&E's 2013 Cost of Capital Proceeding (A.12-04-018).

2015 Rates - Reflect interim rates as in PG&E's Gas Accord V Settlement Agreement D.11-04-031

*D.11-04-031*

# *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**

| Line No. | | Gas Accord IV: Core Redwood Annual Capacity (MDth/d) | Gas Accord V: Allocation Factors | Gas Accord V: Core Redwood Annual Capacity (MDth/d) | Gas Accord V: Core Baja Annual Capacity (MDth/d) | Gas Accord V: 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 |

*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 |

*Gas Accord V Settlement Agreement*

**Appendix A**

**Effective January 1, 2015**

**Table A-3**

**GT&S Revenue Requirement**

**Including Core and Noncore Revenue Responsibility**

**($ Thousand)**

| Line No. | | GA IV 2010 | GA V with 2013 COC and GHG Compressor Cost 2011 | 2012 | 2013 | 2014 | GA V with 2013 COC and GHG Compressor Cost, excluding adder projects that did not go in effect in 2012, 2013 and 2014 2011 | 2012 | 2013 | 2014 | Interim 2015 | 2015 Escalator |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Core Revenue Requirements** | | | | | | | | | | | |
| 1 | Backbone Transmission Base (1) (2) (5) (6) | 86,138 | 93,414 | 95,901 | 94,506 | 96,208 | 93,414 | 95,901 | 94,506 | 96,208 | 98,132 | 2.0% |
| 2 | Backbone Transmission Adders | - | - | - | 3,173 | 3,335 | - | - | - | - | - | |
| 3 | Subtotal Backbone Transmission | 86,138 | 93,414 | 95,901 | 97,679 | 99,543 | 93,414 | 95,901 | 94,506 | 96,208 | 98,132 | 2.0% |
| 4 | Local Transmission Base | 104,752 | 122,972 | 131,618 | 128,003 | 130,693 | 122,972 | 131,618 | 128,003 | 130,693 | 133,307 | 2.0% |
| 5 | Local Transmission Adder (3) (7) | 10,102 | 5,514 | 5,785 | 9,602 | 13,319 | 5,514 | 5,395 | 4,850 | 4,646 | 4,739 | 2.0% |
| 6 | Subtotal Local Transmission | 114,854 | 128,486 | 137,403 | 137,605 | 144,013 | 128,486 | 137,013 | 132,853 | 135,339 | 138,046 | 2.0% |
| 7 | Storage (4) (8) | 43,850 | 48,689 | 50,121 | 49,492 | 50,603 | 48,689 | 50,121 | 49,492 | 50,603 | 51,615 | 2.0% |
| 8 | Customer Access Charge | - | - | - | - | - | - | - | - | - | - | |
| 9 | Total Core (9) | $244,843 | $270,589 | $283,425 | $284,776 | $294,159 | $270,589 | $283,036 | $276,851 | $282,150 | $287,793 | 2.0% |
| | **Noncore / Unbundled Revenue Requirements** | | | | | | | | | | | |
| 10 | Backbone Trans. Base w/o G-XF Contracts | 147,825 | 123,774 | 132,655 | 128,787 | 129,574 | 123,774 | 132,655 | 128,787 | 129,574 | 132,165 | 2.0% |
| 11 | Backbone Transmission Adders | - | - | - | 4,656 | 5,158 | - | - | - | - | - | |
| 12 | Subtotal Backbone Transmission | 147,825 | 123,774 | 132,655 | 133,444 | 134,732 | 123,774 | $ 132,655 | $ 128,787 | $ 129,574 | $ 132,165 | 2.0% |
| 13 | G-XF Contracts | | 6,875 | 6,448 | 5,978 | 5,831 | 6,875 | $ 6,448 | $ 5,978 | $ 5,831 | $ 5,831 | 0.0% |
| 14 | G-XF Contract Adders | | - | - | - | 43 | - | - | - | - | - | |
| 15 | G-XF Contracts Subtotal | 7,024 | 6,875 | 6,448 | 5,978 | 5,874 | 6,875 | 6,448 | 5,978 | 5,831 | 5,831 | 0.0% |
| 16 | Subtotal Backbone Transmission (5) (6) | 154,849 | 130,648 | 139,103 | 139,422 | 140,606 | 130,648 | 139,103 | 134,765 | 135,405 | 137,996 | 1.9% |
| 17 | Local Transmission Base | 44,823 | 63,623 | 68,774 | 70,132 | 74,223 | 63,623 | 68,774 | 70,132 | 74,223 | 75,707 | 2.0% |
| 18 | Local Transmission Adder (3) (7) | 4,323 | 2,853 | 3,023 | 5,261 | 7,564 | 2,853 | 2,819 | 2,657 | 2,638 | 2,691 | 2.0% |
| 19 | Subtotal Local Transmission | 49,146 | 66,476 | 71,797 | 75,392 | 81,787 | 66,476 | 71,593 | 72,789 | 76,861 | 78,398 | 2.0% |
| 20 | Storage (4) (8) | 7,750 | 35,513 | 35,729 | 34,615 | 34,980 | 35,513 | 35,729 | 34,615 | 34,980 | 35,679 | 2.0% |
| 21 | Customer Access Charge | 5,174 | 4,590 | 4,821 | 4,860 | 5,026 | 4,590 | 4,821 | 4,860 | 5,026 | 5,127 | 2.0% |
| 22 | Total Noncore / Unbundled (9) | $216,919 | $237,227 | $251,449 | $254,288 | $262,398 | $237,227 | $251,246 | $247,029 | $252,271 | $257,200 | 2.0% |
| | **Total** | | | | | | | | | | | |
| 23 | Backbone Transmission Base w/o G-XF Contracts | 233,963 | 217,188 | 228,556 | 223,294 | 225,781 | 217,188 | 228,556 | 223,294 | 225,781 | 230,297 | 2.0% |
| 24 | Backbone Transmission Adders | - | - | - | 7,829 | 8,493 | - | - | - | - | - | |
| 25 | Subtotal Backbone Trans. w/o G-XF Contracts | $233,963 | 217,188 | 228,556 | 231,123 | 234,274 | 217,188 | $228,556 | $223,294 | $225,781 | $230,297 | 2.0% |
| 26 | G-XF Contracts | | 6,875 | 6,448 | 5,978 | 5,831 | 6,875 | $6,448 | $5,978 | $5,831 | $5,831 | 0.0% |
| 27 | G-XF Contract Adders | | - | - | - | 43 | - | $0 | $0 | $0 | $0 | |
| 28 | G-XF Contracts Subtotal | 7,024 | 6,875 | 6,448 | 5,978 | 5,874 | 6,875 | 6,448 | 5,978 | 5,831 | 5,831 | 0.0% |
| 29 | Subtotal Backbone Transmission (5) (6) | 240,987 | 224,062 | 235,004 | 237,101 | 240,148 | 224,062 | 235,004 | 229,271 | 231,612 | 236,128 | 1.9% |
| 30 | Local Transmission Base | 149,576 | 186,595 | 200,392 | 198,135 | 204,916 | 186,595 | 200,392 | 198,135 | 204,916 | 209,014 | 2.0% |
| 31 | Local Transmission Adder (less 5%) (3) (7) | 14,424 | 8,367 | 8,808 | 14,862 | 20,884 | 8,367 | 8,214 | 7,508 | 7,284 | 7,430 | 2.0% |
| 32 | Subtotal Local Transmission | 164,000 | 194,962 | 209,200 | 212,997 | 225,800 | 194,962 | 208,606 | 205,643 | 212,200 | 216,444 | 2.0% |
| 33 | Storage (4) (8) | 51,600 | 84,202 | 85,850 | 84,106 | 85,583 | 84,202 | 85,850 | 84,106 | 85,583 | 87,295 | 2.0% |
| 34 | Customer Access Charge | 5,174 | 4,590 | 4,821 | 4,860 | 5,026 | 4,590 | 4,821 | 4,860 | 5,026 | 5,127 | 2.0% |
| 35 | Total GT&S (9) | $461,761 | $507,817 | $534,874 | $539,064 | $556,557 | $507,817 | $534,281 | $523,880 | $534,421 | $544,993 | 2.0% |

*D.11-04-031*

*Gas Accord V Settlement Agreement*

*Appendix A*
*Effective January 1, 2015*

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

**Notes**

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

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

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

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

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

(6) Backbone rates include load balancing costs.

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

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

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

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

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

(13) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S revenue requirement for backbone, local transmission, storage, and customer access charges are escalated 2%. Schedule G-XF revenue requirement continues to be based on Line 401 incremental costs.

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

# *Gas Accord V Settlement Agreement*

**Appendix A**

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

**Table A-4**

**Designated Local and BackboneTransmission Projects**

**Revenue Requirement Caps and Rates**

**Local Transmission Projects**

| Line No. | Project (Planned Operation Date) | Estimated Capital ($ million) | Local Transmission Revenue Requirement Caps, ($000) per year: Core 2011 | Core 2012 | Core 2013 | Core 2014 | Noncore 2011 | Noncore 2012 | Noncore 2013 | Noncore 2014 | Total 2011 | Total 2012 | Total 2013 | Total 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Line 304, 4.6 miles 12" pipe, Stockton Area (September 2011) | $4.7 | ---- | 390 | 351 | 344 | ---- | 204 | 192 | 195 | ---- | 593 | 543 | 539 |
| 3 | Line 406, 2 miles 8" pipe, Merced Area (November 2010) | $58.6 | 5,514 | 5,395 | 4,850 | 4,646 | 2,853 | 2,819 | 2,657 | 2,638 | 8,367 | 8,214 | 7,508 | 7,284 |
| 4 | Line 407 Phase 1 , 12 miles 30" pipe, Roseville Area (November 2012) | $51.9 | ---- | ---- | 4,400 | 4,194 | ---- | ---- | 2,411 | 2,382 | ---- | ---- | 6,811 | 6,576 |
| 5 | Line 407 Phase 2, 14.3 miles 30" pipe, Yolo Area (November 2013) | $51.0 | ---- | ---- | ---- | 4,136 | ---- | ---- | ---- | 2,349 | ---- | ---- | ---- | 6,484 |
| 6 | Total | $166.2 | 5,514 | 5,785 | 9,602 | 13,319 | 2,853 | 3,023 | 5,261 | 7,564 | 8,367 | 8,808 | 14,862 | 20,884 |

| Line | Project | Local Transmission Rate Adder, $ per Dth: Core 2011 | Core 2012 | Core 2013 | Core 2014 | Noncore 2011 | Noncore 2012 | Noncore 2013 | Noncore 2014 |
|---|---|---|---|---|---|---|---|---|---|
| 8 | Line 304, 4.6 mile 12" pipe | ---- | 0.0013 | 0.0012 | 0.0012 | ---- | 0.0006 | 0.0006 | 0.0006 |
| 9 | Line 406, 2 miles 8" pipe | 0.0189 | 0.0185 | 0.0166 | 0.0160 | 0.0091 | 0.0085 | 0.0078 | 0.0078 |
| 10 | Line 407 Phase 1 , 12 miles 30" pipe | ---- | ---- | 0.0151 | 0.0144 | ---- | ---- | 0.0071 | 0.0071 |
| 11 | Line 407 Phase 2, 14.3 miles 30" pipe | ---- | ---- | ---- | 0.0142 | ---- | ---- | ---- | 0.0070 |
| 12 | Total | 0.0189 | 0.0198 | 0.0330 | 0.0458 | 0.0091 | 0.0091 | 0.0155 | 0.0224 |

**Backbone Transmission Projects**

| Line | Project | Capital | Total: 2011 | 2012 | 2013 | 2014 | 2015 (1) |
|---|---|---|---|---|---|---|---|
| 13 | Delevan K3/Gerber - L400, NOx Emissions, Selective Catalytic Reduction System (December 2013) | $4.1 | ---- | ---- | ---- | 493 | ---- |
| 14 | Delevan K3/Gerber - L401, NOx Emissions, Selective Catalytic Reduction System (Decenber 2013) | $4.0 | ---- | ---- | ---- | 516 | ---- |
| 15 | P03107 Topock, P-Units Replacement, Rebuild of compressor station power units (June 2014) | $10.0 | ---- | ---- | ---- | ---- | 1,230 |
| 16 | P02158-Topock K-Units Replacement-Ph 1, NOx Emissions, Compressor Engine Replacement (December 2012) | $60.0 | ---- | ---- | 7,829 | 7,525 | ---- |
| 17 | P02158-Topock K-Units Replacement-Ph 2 (September 2014) | $30.0 | ---- | ---- | ---- | ---- | 3,741 |
| 18 | Total | $108.1 | ---- | ---- | 7,829 | 8,536 | 4,971 |

(1) Consistent with Gas Accord V Settlement Agreement, Section 2.4 - "Interim Rates" should approved rates not be in place for GT&S services by January 1, 2015, pursuant to a Commission order in the next GT&S Ratecase, a rate adjustment will be made for designated backbone and local transmission "Adder" project that may go into service in 2014.

# 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 |

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*Appendix A*

*Effective January 1, 2015*

**Table B-3**

**Firm Backbone Transportation**
**Annual Rates (AFT) -- SFV Rate Design**
**On-System Transportation Service**
**2015 Interim Rates**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (2) | 2012 | 2013 (3) | 2014 (4) | Excluding Seed 2014 (5) | Escalated 2% Interim 2015 (5) |
|---|---|---|---|---|---|---|---|---|
| **Redwood Path - Core (1)** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 4.3368 | 6.5162 | 6.4678 | 6.3001 | 6.3780 | 6.8816 | 7.0192 |
| Usage Charge | ($/dth) | 0.0124 | 0.0102 | 0.0096 | 0.0091 | 0.0092 | 0.0073 | 0.0074 |
| Total | ($/dth @ Full Contract) | 0.1550 | 0.2244 | 0.2223 | 0.2162 | 0.2188 | 0.2335 | 0.2382 |
| **Baja Path - Core (1)** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 9.2319 | 7.2499 | 7.3504 | 7.3313 | 7.5567 | 8.0603 | 8.2215 |
| Usage Charge | ($/dth) | 0.0153 | 0.0111 | 0.0106 | 0.0102 | 0.0104 | 0.0085 | 0.0087 |
| Total | ($/dth @ Full Contract) | 0.3188 | 0.2494 | 0.2523 | 0.2512 | 0.2588 | 0.2735 | 0.2790 |
| **Redwood Path - Noncore** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 8.7329 | 8.3095 | 8.3437 | 7.9034 | 7.8577 | 8.4518 | 8.6209 |
| Usage Charge | ($/dth) | 0.0070 | 0.0084 | 0.0083 | 0.0079 | 0.0080 | 0.0060 | 0.0061 |
| Total | ($/dth @ Full Contract) | 0.2941 | 0.2816 | 0.2826 | 0.2678 | 0.2663 | 0.2839 | 0.2896 |
| **Baja Path - Noncore** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 9.2319 | 9.0536 | 9.2370 | 8.9457 | 9.0486 | 9.6427 | 9.8356 |
| Usage Charge | ($/dth) | 0.0153 | 0.0089 | 0.0089 | 0.0087 | 0.0088 | 0.0069 | 0.0070 |
| Total | ($/dth @ Full Contract) | 0.3188 | 0.3066 | 0.3126 | 0.3028 | 0.3063 | 0.3239 | 0.3304 |
| **Silverado and Mission Paths** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 4.4828 | 4.8056 | 4.6413 | 4.4150 | 4.4293 | 4.7527 | 4.8477 |
| Usage Charge | ($/dth) | 0.0060 | 0.0049 | 0.0059 | 0.0077 | 0.0082 | 0.0062 | 0.0063 |
| Total | ($/dth @ Full Contract) | 0.1534 | 0.1628 | 0.1585 | 0.1528 | 0.1538 | 0.1625 | 0.1657 |

(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 True-up (AGT) filing.

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

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

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

**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) Dollar difference are due to rounding.

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*Appendix A*

*Effective January 1, 2015*

**Table B-4**

**Firm Backbone Transportation**
**Annual Rates (AFT) -- MFV Rate Design**
**On-System Transportation Service**
***2015 Interim Rates***

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (2) | 2012 | 2013 (3) | 2014 (4) | Excluding Seed 2014 (5) | Escalated 2% Interim 2015 (5) |
|---|---|---|---|---|---|---|---|---|
| **Redwood Path - Core (1)** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 3.3290 | 4.7466 | 4.6534 | 4.4923 | 4.5126 | 4.8690 | 4.9663 |
| Usage Charge | ($/dth) | 0.0455 | 0.0684 | 0.0693 | 0.0685 | 0.0705 | 0.0735 | 0.0749 |
| Total | ($/dth @ Full Contract) | 0.1549 | 0.2244 | 0.2223 | 0.2162 | 0.2188 | 0.2335 | 0.2382 |
| **Baja Path - Core (1)** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 7.0037 | 5.2811 | 5.2883 | 5.2276 | 5.3466 | 5.7029 | 5.8170 |
| Usage Charge | ($/dth) | 0.0885 | 0.0758 | 0.0784 | 0.0794 | 0.0831 | 0.0860 | 0.0878 |
| Total | ($/dth @ Full Contract) | 0.3188 | 0.2494 | 0.2523 | 0.2512 | 0.2588 | 0.2735 | 0.2790 |
| **Redwood Path - Noncore** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 5.0700 | 5.4087 | 5.4576 | 5.2084 | 5.2050 | 5.5985 | 5.7105 |
| Usage Charge | ($/dth) | 0.1274 | 0.1038 | 0.1032 | 0.0965 | 0.0952 | 0.0998 | 0.1018 |
| Total | ($/dth @ Full Contract) | 0.2941 | 0.2816 | 0.2826 | 0.2678 | 0.2663 | 0.2839 | 0.2896 |
| **Baja Path - Noncore** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 7.0037 | 5.8930 | 6.0418 | 5.8953 | 5.9939 | 6.3874 | 6.5151 |
| Usage Charge | ($/dth) | 0.0885 | 0.1129 | 0.1140 | 0.1090 | 0.1093 | 0.1139 | 0.1162 |
| Total | ($/dth @ Full Contract) | 0.3188 | 0.3066 | 0.3126 | 0.3028 | 0.3063 | 0.3239 | 0.3304 |
| **Silverado and Mission Paths** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 3.0839 | 3.2679 | 3.1639 | 3.1425 | 3.1566 | 3.3867 | 3.4544 |
| Usage Charge | ($/dth) | 0.0518 | 0.0554 | 0.0545 | 0.0495 | 0.0500 | 0.0511 | 0.0522 |
| Total | ($/dth @ Full Contract) | 0.1532 | 0.1628 | 0.1585 | 0.1528 | 0.1538 | 0.1625 | 0.1657 |

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

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

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

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

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

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**Table B-5**

**Firm Backbone Transportation**
**Seasonal Rates (SFT) -- SFV Rate Design**
**On-System Transportation Service**
***2015 Interim Rates***

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (2) | 2012 | 2013 (3) | 2014 (4) | Excluding Seed 2014 (5) | Escalated 2% Interim 2015 (5) |
|---|---|---|---|---|---|---|---|---|
| **Redwood Path** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 10.4795 | 9.9714 | 10.0125 | 9.4840 | 9.4293 | 10.1422 | 10.3450 |
| Usage Charge | ($/dth) | 0.0082 | 0.0101 | 0.0100 | 0.0095 | 0.0096 | 0.0072 | 0.0074 |
| Total | ($/dth @ Full Contract) | 0.3527 | 0.3379 | 0.3392 | 0.3213 | 0.3196 | 0.3407 | 0.3475 |
| **Baja Path - Core (1)** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 11.0784 | 8.6999 | 8.8204 | 8.7976 | 9.0680 | 9.6723 | 9.8658 |
| Usage Charge | ($/dth) | 0.0183 | 0.0133 | 0.0127 | 0.0122 | 0.0125 | 0.0102 | 0.0104 |
| Total | ($/dth @ Full Contract) | 0.3825 | 0.2993 | 0.3027 | 0.3015 | 0.3106 | 0.3282 | 0.3348 |
| **Baja Path - Noncore** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 11.0784 | 10.8643 | 11.0843 | 10.7348 | 10.8584 | 11.5713 | 11.8027 |
| Usage Charge | ($/dth) | 0.0183 | 0.0107 | 0.0107 | 0.0104 | 0.0106 | 0.0082 | 0.0084 |
| Total | ($/dth @ Full Contract) | 0.3825 | 0.3679 | 0.3752 | 0.3633 | 0.3676 | 0.3887 | 0.3964 |
| **Silverado and Mission Paths** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 5.3794 | 5.7667 | 5.5695 | 5.2980 | 5.3151 | 5.7032 | 5.8173 |
| Usage Charge | ($/dth) | 0.0071 | 0.0058 | 0.0071 | 0.0092 | 0.0098 | 0.0075 | 0.0076 |
| Total | ($/dth @ Full Contract) | 0.1840 | 0.1954 | 0.1902 | 0.1834 | 0.1846 | 0.1950 | 0.1989 |

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

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

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

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

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

**Table B-6**

**Firm Backbone Transportation**
**Seasonal Rates (SFT) -- MFV Rate Design**
**On-System Transportation Service**
**2015 Interim Rates**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (2) | 2012 | 2013 (3) | 2014 (4) | Excluding Seed 2014 (5) | Escalated 2% Interim 2015 (5) |
|---|---|---|---|---|---|---|---|---|
| **Redwood Path** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 6.0840 | 6.4905 | 6.5491 | 6.2501 | 6.2460 | 6.7182 | 6.8526 |
| Usage Charge | ($/dth) | 0.1528 | 0.1245 | 0.1238 | 0.1159 | 0.1142 | 0.1198 | 0.1222 |
| Total | ($/dth @ Full Contract) | 0.3528 | 0.3379 | 0.3392 | 0.3213 | 0.3196 | 0.3407 | 0.3475 |
| **Baja Path - Core (1)** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 8.4044 | 6.3373 | 6.3460 | 6.2731 | 6.4159 | 6.8435 | 6.9804 |
| Usage Charge | ($/dth) | 0.1063 | 0.0910 | 0.0941 | 0.0952 | 0.0997 | 0.1032 | 0.1053 |
| Total | ($/dth @ Full Contract) | 0.3826 | 0.2993 | 0.3027 | 0.3015 | 0.3106 | 0.3282 | 0.3348 |
| **Baja Path - Noncore** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 8.4044 | 7.0717 | 7.2502 | 7.0744 | 7.1926 | 7.6649 | 7.8182 |
| Usage Charge | ($/dth) | 0.1063 | 0.1354 | 0.1368 | 0.1308 | 0.1311 | 0.1367 | 0.1394 |
| Total | ($/dth @ Full Contract) | 0.3826 | 0.3679 | 0.3752 | 0.3633 | 0.3676 | 0.3887 | 0.3964 |
| **Silverado and Mission Paths** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 3.7008 | 3.9215 | 3.7967 | 3.7710 | 3.7879 | 4.0640 | 4.1453 |
| Usage Charge | ($/dth) | 0.0622 | 0.0665 | 0.0654 | 0.0594 | 0.0601 | 0.0614 | 0.0626 |
| Total | ($/dth @ Full Contract) | 0.1839 | 0.1954 | 0.1902 | 0.1834 | 0.1846 | 0.1950 | 0.1989 |

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

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

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

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

(4) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

**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) Dollar difference are due to rounding.

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**Table B-7**

**As-Available Backbone Transportation**
**On-System Transportation Service**
**2015 Interim Rates**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | 2010 | 2011 (1) | 2012 | 2013 (2) | 2014 (3) | Excluding Seed 2014 (4) | Escalated 2% Interim 2015 (4) |
|---|---|---|---|---|---|---|---|---|
| **Redwood Path** Usage Charge | ($/dth) | 0.3528 | 0.3379 | 0.3392 | 0.3213 | 0.3196 | 0.3407 | 0.3475 |
| **Baja Path** Usage Charge | ($/dth) | 0.3826 | 0.3679 | 0.3752 | 0.3633 | 0.3676 | 0.3887 | 0.3964 |
| **Silverado Path** Usage Charge | ($/dth) | 0.1839 | 0.1954 | 0.1902 | 0.1834 | 0.1846 | 0.1950 | 0.1989 |
| **Mission Path** Usage Charge | ($/dth) | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |

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

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

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

(4) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

**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) Dollar difference are due to rounding.

**Table B-8**

**Backbone Transportation**
**Annual Rates (AFT-Off)**
**Off-System Deliveries**
**2015 Interim Rates**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (1) | 2012 | 2013 (2) | 2014 (3) | Excluding Seed 2014 (4) | Escalated 2% Interim 2015 (4) |
|---|---|---|---|---|---|---|---|---|
| **SFV Rate Design** | | | | | | | | |
| **Redwood, Silverado and Mission Paths Off-System** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 8.7329 | 8.3095 | 8.3437 | 7.9034 | 7.8577 | 8.4518 | 8.6209 |
| Usage Charge | ($/dth) | 0.0070 | 0.0084 | 0.0083 | 0.0079 | 0.0080 | 0.0060 | 0.0061 |
| Total | ($/dth @ Full Contract) | 0.2941 | 0.2816 | 0.2826 | 0.2678 | 0.2663 | 0.2839 | 0.2896 |
| **Baja Path Off-System** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 9.2319 | 9.0536 | 9.2370 | 8.9457 | 9.0486 | 9.6427 | 9.8356 |
| Usage Charge | ($/dth) | 0.0153 | 0.0089 | 0.0089 | 0.0087 | 0.0088 | 0.0069 | 0.0070 |
| Total | ($/dth @ Full Contract) | 0.3188 | 0.3066 | 0.3126 | 0.3028 | 0.3063 | 0.3239 | 0.3304 |
| **MFV Rate Design** | | | | | | | | |
| **Redwood, Silverado and Mission Paths Off-System** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 5.0700 | 5.4087 | 5.4576 | 5.2084 | 5.2050 | 5.5985 | 5.7105 |
| Usage Charge | ($/dth) | 0.1274 | 0.1038 | 0.1032 | 0.0965 | 0.0952 | 0.0998 | 0.1018 |
| Total | ($/dth @ Full Contract) | 0.2941 | 0.2816 | 0.2826 | 0.2678 | 0.2663 | 0.2839 | 0.2896 |
| **Baja Path Off-System** | | | | | | | | |
| Reservation Charge | ($/dth/mo) | 7.0037 | 5.8930 | 6.0418 | 5.8953 | 5.9939 | 6.3874 | 6.5151 |
| Usage Charge | ($/dth) | 0.0885 | 0.1129 | 0.1140 | 0.1090 | 0.1093 | 0.1139 | 0.1162 |
| Total | ($/dth @ Full | 0.3188 | 0.3066 | 0.3126 | 0.3028 | 0.3063 | 0.3239 | 0.3304 |
| **As-Available Service** | | | | | | | | |
| **Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore** | | | | | | | | |
| Usage Charge | ($/dth) | 0.3528 | 0.3379 | 0.3392 | 0.3213 | 0.3196 | 0.3407 | 0.3475 |
| **Mission Paths (From on-system storage) Off-System** | | | | | | | | |
| Usage Charge | ($/dth) | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| **Baja Path Off-System - Noncore** | | | | | | | | |
| Usage Charge | ($/dth) | 0.3826 | 0.3679 | 0.3752 | 0.3633 | 0.3676 | 0.3887 | 0.3964 |

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

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

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

(4) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

*D.11-04-031*

*Gas Accord V Settlement Agreement*

*Appendix A*
*Effective January 1, 2015*

**Table B-9**

**Firm Transportation**
**Expansion Shippers -- Annual Rates (G-XF)**
**SFV Rate Design**
**2015 Interim Rates**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (1) | 2012 | 2013 (2) | 2014 (3) | 2015 (4) |
|---|---|---|---|---|---|---|---|
| **SFV Rate Design** | | | | | | | |
| Reservation Charge | ($/dth/mo) | 6.3182 | 6.1394 | 6.2159 | 5.7146 | 5.5594 | 5.5594 |
| Usage Charge | ($/dth) | 0.0019 | 0.0013 | 0.0015 | 0.0031 | 0.0035 | 0.0035 |
| Total | ($/dth @ Full Contract) | 0.2096 | 0.2032 | 0.2059 | 0.1910 | 0.1863 | 0.1863 |

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

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

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

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, schedule G-XF 2015 interim rates continues to be based on Line 401 incremental costs.

**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) Dollar difference are due to rounding.

*D.11-04-031*

## *Gas Accord V Settlement Agreement*

**Appendix A**

**Effective January 1, 2015**

**Table B-10**

**Storage Services**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (1) | 2012 | 2013 (2) | 2014 (3) | 2015 (4) |
|---|---|---|---|---|---|---|---|
| **Core Firm Storage (G-CFS)** | | | | | | | |
| Reservation Charge | ($/dth/mo) | 0.1092 | 0.1293 | 0.1248 | 0.1232 | 0.1260 | 0.1285 |
| **Standard Firm Storage (G-SFS)** | | | | | | | |
| Reservation Charge | ($/dth/mo) | 0.1350 | 0.3008 | 0.2451 | 0.2374 | 0.2399 | 0.2447 |
| **Negotiated Firm Storage (G-NFS)** | | | | | | | |
| Injection | ($/dth/d) | 15.6336 | 6.1656 | 6.1542 | 5.9623 | 6.0252 | 6.1457 |
| Inventory | ($/dth) | 1.6205 | 2.9461 | 2.9407 | 2.8489 | 2.8790 | 2.9366 |
| Withdrawal | ($/dth/d) | 11.7865 | 21.3468 | 21.3075 | 20.6428 | 20.8607 | 21.2779 |
| **Negotiated As-Available Storage (G-NAS) - Maximum Rate** | | | | | | | |
| Injection | ($/dth/d) | 15.6336 | 6.1656 | 6.1542 | 5.9623 | 6.0252 | 6.1457 |
| Withdrawal | ($/dth/d) | 11.7865 | 21.3468 | 21.3075 | 20.6428 | 20.8607 | 21.2779 |
| **Market Center Services (Parking and Lending Services)** | | | | | | | |
| Maximum Daily Charge ($/Dth/d) | | 0.9702 | 1.1053 | 1.1136 | 1.0821 | 1.0986 | 1.1206 |
| Minimum Rate (per transaction) | | $ 57.00 | 57.00 | 57.00 | 57.00 | 57.00 | 57.00 |

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

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

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

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S 2015 interim storage rates are escalated 2%.

**Not**

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.

*D.11-04-031*

## *Gas Accord V Settlement Agreement*

**Appendix A**

**Effective January 1, 2015**

**Table B-11**

**Local Transmission Rates**

**($/dth)**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 (1) | 2011 (2) | 2012 | 2013 (3) | 2014 (4) | Excluding Seed 2014 (5) | Escalated 2% 2015 (5) |
|---|---|---|---|---|---|---|---|---|
| **Base Rates:** | | | | | | | | |
| Core Retail | | 0.3764 | 0.4118 | 0.4182 | 0.4074 | 0.4173 | 0.4496 | 0.4586 |
| Noncore Retail and Wholesale | | 0.1628 | 0.2031 | 0.1933 | 0.1912 | 0.2043 | 0.2201 | 0.2245 |
| **Rate Adders:** | | | | | | | | |
| Core | | | | | | | | |
| | L-304 | | 0.0000 | 0.0013 | 0.0012 | 0.0012 | 0.0012 | 0.0012 |
| | L-406 | 0.0115 | 0.0248 | 0.0185 | 0.0166 | 0.0160 | 0.0160 | 0.0163 |
| | L-407 Phase 1 | | 0.0000 | 0.0000 | 0.0151 | 0.0144 | 0.0144 | 0.0147 |
| | L-407 Phase 2 | | 0.0000 | 0.0000 | 0.0000 | 0.0142 | 0.0142 | 0.0145 |
| | Total | 0.0115 | 0.0248 | 0.0198 | 0.0330 | 0.0458 | 0.0458 | 0.0467 |
| Noncore Retail & Wholesale | | | | | | | | |
| | L-304 | | 0.0000 | 0.0006 | 0.0006 | 0.0006 | 0.0006 | 0.0006 |
| | L-406 | 0.0050 | 0.0108 | 0.0085 | 0.0078 | 0.0078 | 0.0078 | 0.0080 |
| | L-407 Phase 1 | | 0.0000 | 0.0000 | 0.0071 | 0.0071 | 0.0071 | 0.0072 |
| | L-407 Phase 2 | | 0.0000 | 0.0000 | 0.0000 | 0.0070 | 0.0070 | 0.0071 |
| | Total | 0.0050 | 0.0108 | 0.0091 | 0.0155 | 0.0224 | 0.0224 | 0.0229 |
| **Total Base plus Adder:** | | | | | | | | |
| Core Retail | | 0.3879 | 0.4367 | 0.4380 | 0.4404 | 0.4631 | 0.4954 | 0.5053 |
| Noncore Retail and Wholesale | | 0.1678 | 0.2139 | 0.2024 | 0.2066 | 0.2267 | 0.2425 | 0.2474 |

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

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

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

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

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

**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)

*D.11-04-031*

## *Gas Accord V Settlement Agreement*

**Appendix A**

**Effective January 1, 2015**

**Table B-12**

**Customer Access Charges**
**($ per Month)**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | | GA IV 2010 | 2011 (1) | 2012 | 2013 (2) | 2014 (3) | 2015 (4) |
|---|---|---|---|---|---|---|---|
| **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 | $62.12 |
| Tier 2 | 5,001 to 10,000 | $184.23 | $161.87 | $174.00 | $175.40 | $181.41 | $185.04 |
| Tier 3 | 10,001 to 50,000 | $342.89 | $301.27 | $323.85 | $326.46 | $337.64 | $344.40 |
| Tier 4 | 50,001 to 200,000 | $450.01 | $395.39 | $425.02 | $428.44 | $443.12 | $451.98 |
| Tier 5 | 200,001 to 1,000,000 | $652.92 | $573.67 | $616.67 | $621.63 | $642.93 | $655.79 |
| Tier 6 | 1,000,001 and above | $5,538.45 | $4,866.21 | $5,230.96 | $5,273.02 | $5,453.67 | $5,562.75 |
| **Wholesale ($/month)** | | | | | | | |
| Alpine | | $333.28 | $286.66 | $310.56 | $313.06 | $323.79 | $330.27 |
| Coalinga | | $1,474.03 | $1,267.85 | $1,373.51 | $1,384.55 | $1,431.99 | $1,460.63 |
| Island Energy | | $998.71 | $859.01 | $930.61 | $938.09 | $970.23 | $989.63 |
| Palo Alto | | $4,914.73 | $4,227.28 | $4,579.59 | $4,616.40 | $4,774.56 | $4,870.05 |
| West Coast Gas - Castle | | $856.26 | $736.49 | $797.87 | $804.28 | $831.84 | $848.48 |
| West Coast Gas - Mather | | $782.50 | $673.05 | $729.14 | $735.00 | $760.18 | $775.38 |

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

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

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

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S 2015 interim customer access charges are escalated 2%.

**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 A**

**Effective January 1, 2015**

**Table B-13**

**Self Balancing Credit**
**$/dth**

**Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates**

| | GA IV 2010 | 2011 (1) | 2012 | 2013 (2) | 2014 (3) | 2015 (4) |
|---|---|---|---|---|---|---|
| **Self Balancing Credit** | ($0.0096) | ($0.0130) | ($0.0131) | ($0.0129) | ($0.0132) | ($0.0135) |

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

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

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

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S 2015 interim self balancing credit are escalated 2%.

**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.

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

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