STATE OF CALIFORNIA

EDMUND G. BROWN JR., *Governor*

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

June 21, 2018

Erik Jacobson
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c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Advice Letter 3919-G/ 3919-G-A

**Subject: Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2018**

Dear Mr. Jacobson:

Pacific Gas and Electric Company (PG&E) Advice Letter 3919-G and 3919-G-A is approved as of June 21, 2018 and is effective January 1, 2018. Pursuant to recommendations by the California State Auditor, Energy Division staff continues to conduct in-depth reviews of PG&E gas balancing accounts. Balances in all accounts authorized for recovery are subject to audit, verification and adjustment.

Sincerely,

FOR

Edward Randolph
Director, Energy Division

Pacific Gas and Electric Company®

**Erik Jacobson**
Director
Regulatory Relations

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December 21, 2017

**Advice 3919-G**
(Pacific Gas and Electric Company ID U 39G)

Public Utilities Commission of the State of California

**Subject** **Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2018**

## Purpose

Pacific Gas and Electric Company (PG&E) submits for approval by the California Public Utilities Commission (Commission or CPUC) revisions to PG&E's gas tariff schedules effective January 1, 2018.

Consistent with prior years, this Annual Gas True-Up (AGT) advice letter does not include the 2018 gas procurement-related revenue requirement changes, which are being submitted concurrently in PG&E's monthly core procurement advice letter.

## Overview

On November 3, 2017, PG&E filed its AGT[1] Advice 3903-G, requesting approval to amortize forecast December 31, 2017 gas transportation balancing account balances in rates effective January 1, 2018. On December 15, 2017, the Energy Division approved Advice 3903-G, effective January 1, 2017.

This "Annual Gas True-Up: Consolidated Gas Rate Update" advice letter consolidates forecast end-of-year gas balancing account balances with final authorized gas revenue requirement changes previously approved by the CPUC. In order to provide a more accurate forecast, this advice letter updates the forecast balancing account balances that were provided in Advice 3903-G using November 30, 2017 recorded balances as the starting point.[2]

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1 The AGT is an annual process to update gas transportation balancing accounts as established in PG&E's 2005 Biennial Cost Allocation Proceeding (BCAP) Decision (D.) 05-06-029, p.10 and Finding of Fact 9.

2 Advice 3903-G used September 30, 2017 recorded balances as the starting point for December 31, 2017 forecast balancing account balances.

In Advice 3903-G, PG&E provided a preliminary estimate of its 2018 gas transportation revenue requirements, which at the time were estimated to be $3,573 million. In this advice letter, PG&E proposes to recover its final authorized 2018 gas transportation revenue requirements totaling $3,652 million, which is a $209 million increase compared to revenue requirements in present rates. The 2018 gas transportation revenue requirements include end-user transportation costs, gas Public Purpose Program (PPP) surcharges (which were submitted for Commission approval in Advice 3901-G), and gas transmission and storage unbundled costs (See Table 1 below).

**Table 1**
**Proposed Gas Transportation Revenue Requirements**
**Effective January 1, 2018**
**($ millions)[3]**

| Description | Currently in Rates | Proposed | Change |
|---|---|---|---|
| End-Use Gas Transportation | $2,957 | $3,173 | $216 |
| Storage and Backbone Unbundled Costs | 218 | 231 | 13 |
| Gas PPP Surcharges [4] | 268 | 248 | (20) |
| **Total Gas Transportation Revenue Requirements** | **$3,443** | **$3,652** | **$209** |

Attachment 1 summarizes the proposed 2018 gas transportation revenue requirements. Attachment 2 summarizes the forecast December 31, 2017 balances for gas transportation balancing accounts using recorded balances through November 30, 2017. The total December 31, 2017 gas transportation balancing account balances are projected to be undercollected by $401 million, as shown in Attachment 1, line 1, and Attachment 2, line 22. This represents a $34 million increase in the gas transportation balancing account undercollections from those currently amortized in gas transportation rates. Finally, Attachments 3 through 6 provide rates and surcharges resulting from the amounts summarized in Attachments 1 and 2.

## Background

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:

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[3] This table does not include 2018 gas procurement-related revenue requirement changes, which will be submitted concurrently in PG&E's monthly core procurement advice letter.

[4] Submitted for Commission approval in Advice 3901-G, which was filed on October 31, 2017**.**

1) Forecasting the December 31, 2017 balance for each gas transportation balancing and memorandum account to be updated in the AGT based on the November 30, 2017 recorded balances plus a forecast of costs and revenues, including interest, through December 31, 2017; and,

2) Calculating the customer class charge components by dividing the forecasted December 31, 2017 balancing account balance by PG&E's currently adopted BCAP throughput forecast (D. 10-06-035).

**Transportation Balancing Accounts Already Approved for Amortization in the 2018 AGT**

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, 2018.

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, 2017 balances 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 Phase I (GRC) gas 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) Distribution Cost subaccount recovers the core distribution base revenue requirements adopted in GRCs, including annual attrition adjustments, adjustments resulting from 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 adopted allocation of distribution base revenues;

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

(iii) Assembly Bill (AB) 32 Cost of Implementation Fee Core subaccount recovers the gas portion of California Air Resources Board's (ARB) AB 32

Cost of Implementation Fee, allocated to PG&E's applicable core transportation customers.

The AGT includes a forecasted $231.8 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 $218.7 million undercollection in the Distribution Cost subaccount; and

(ii) A forecasted $13.1 million undercollection in the Core Cost subaccount.

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

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

(i) The Noncore subaccount 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 recovers the noncore distribution portion of gas revenue requirements 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 adopted 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 applicable noncore transportation customers.

The AGT includes a forecasted $1.1 million net overcollection in the NCA, excluding the AB 32 Cost of Implementation Fee Noncore subaccount, which is described separately below. The net undercollection in the NCA results from:

(i) A forecasted $2.4 million undercollection in the Noncore subaccount; and

(ii) A forecasted $3.5 million overcollection in the Distribution subaccount.

**AB 32 Cost of Implementation Fee – (Attachment 2, Line 13)**

As described above, the AB 32 Cost of Implementation (COI) Fee is recovered in 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. 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 2018 COI rates to reflect a reduction of the volumes associated with exempt customers. The AGT balance proposed to be amortized in 2018 rates consists of a forecasted $6.2 million net undercollection in the AB 32 Cost of Implementation Fee subaccounts.

**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 $1.1 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). The Commission has approved an allocation of Hazardous Substance Mechanism costs on an equal cents per therm basis[5]. This AGT forecasts an $83.5 million balance for collection 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. According to Gas Preliminary Statement Part L, the balance in this account will be incorporated into core and noncore transportation rates as determined in PG&E's Biennial Cost Allocation Proceeding Decision 01-11-001. PG&E currently forecasts a $482,000 undercollection in the BCA. The BCA balance is included in the rate component of the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA.

[5] See also gas Preliminary Statement Part AN.

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

The CEEIA records the gas portion of any Efficiency Savings Performance Incentive (ESPI) award authorized by the Commission to be recovered in rates. The forecast year-end balance incorporates the requested earnings for the first part of the Program Year 2016 EE incentive award and the second part of the Program Year 2015 EE incentive award as requested in Advice 3880-G-A. Interest does not accrue in this subaccount pursuant to D. 07-09-043. This AGT includes a forecasted $182,000 undercollected balance, which will be recovered through the CEE Incentive rate component. See further discussion below in the "Discussion of Recent CPUC Proceedings and Advice Letters" section.

**California Solar Initiative Thermal Program Memorandum Account (CSITPMA) - (Attachment 2, Line 10)**

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 $6.7 million undercollected balance in the CSITPMA, and will be recovered in the CSITPMA rate component.

**Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) – (Attachment 2, Line 11)**

The AMCDOP was approved by the Commission in D.11-04-031 (approving the Gas Accord V Settlement, and continued in PG&E's 2015 GT&S rate case, D.16-06-056). The purpose of the AMCDOP is to record the difference in the revenue requirement associated with costs determined in other proceedings and the revenue requirements based on placeholder costs included in PG&E's GT&S filings. Examples of "other proceedings" are PG&E's General Rate Case, the Cost of Capital Proceeding, and the Pension Recovery Proceeding. The AMCDOP is governed by Gas Preliminary Statement Part CO, which specifies that the AMCDOP shall apply to all customer classes. According to the Preliminary Statement, 50% of the costs are allocated to core customers and 50% to noncore customers through the customer class charge.

The 2017 GRC revenue requirements adopted in D. 17-05-013 include adopted administrative and general (A&G) costs, payroll taxes, common costs, revenue fees and uncollectibles (RF&U) that are different from those used as placeholders in calculating the 2017 GT&S revenue requirements in the 2015 GT&S rate case decision. In addition, the 2017 GRC decision also adopted different common cost allocation percentages compared to those percentages used in the 2015 GT&S decision. As a result, the 2017 GT&S revenue requirements determined in the 2015 GT&S decision were revised to account for these cost and cost allocation differences and recorded in the AMCDOP. This AGT includes a forecast $49.6 million undercollected balance in the AMCDOP.

**Non-Tariffed Products and Services Balancing Account (NTBA-G) - (Attachment 2, Line 12)**

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 $131,000 overcollected balance for this account, which will be transferred to the Distribution Cost subaccount of the CFCA.

**Gas Pipeline Expense Reimbursement Balancing Account (GPERBA) – (Attachment 2, Line 14)**

The GPERBA records PG&E's reimbursements to the Commission associated with implementing and complying with D. 12-12-030, up to $15 million. PG&E forecasts a balance of $3.3 million undercollection in this account.

**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, 2017.

**Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) – (Attachment 2, Line 20)**

Originally adopted as part of the Gas Accord V Settlement Agreement, the GTSRSM records the difference between adopted noncore and unbundled revenue requirements and recorded noncore and unbundled revenues to be shared between customers and shareholders, as further described below. The GTSRSM consists of the following four subaccounts:

(i) The Backbone subaccount, which records the difference between the adopted unbundled backbone revenue requirement and the portion of backbone revenues allocated to core customers that are collected volumetrically 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 noncore local transmission revenue requirement 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 unbundled storage revenue requirement and recorded unbundled 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.

In accordance with Preliminary Statement Part CP, the balances in the first three subaccounts[6] 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 upon approval of the December AGT advice letter[7]. This advice letter includes a $12.8 million undercollected balance in the GTSRSM.

**Mobile Home Park Balancing Account – Gas (MHPBA) – (Attachment 2, Line 21)**

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

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

7 According to Gas Preliminary Statement Part CP, balances are allocated 50% to core customers and 50% to noncore customers through the customer class charge.

venues as approved by the Commission. This AGT includes a forecast $6.7 million undercollected balance in the MHPBA[8].

**Discussion of Recent CPUC Proceedings and Advice Letters**

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

**2018 General Rate Case (GRC) Annual Adjustments (Attachment 1, Line 2)**

On October 20, 2017, PG&E filed Advice 3896-G/5162-E to implement Decision 17-05-013 to: (1) include the GRC adopted 2018 increases in its gas distribution revenue requirement; (2) Cost of Capital[9]; and (3) update its 2018 RF&U. The 2018 gas distribution attrition increase and currently effective RF&U[10] are included in Attachment 1, line 2.

**CPUC User Fee – (Attachment 1, Line 6)**

On December 14, 2017, the CPUC approved Resolution M-4832 that adopts an increase to the current CPUC fee to better align the collection with expenditures needed by the CPUC to ensure the provision of safe, reliable utility service and infrastructure at reasonable rates.

**Efficiency Savings and Performance Incentive Mechanism (ESPI) – (Attachment 2, Line 9)**

PG&E submitted Advice Letter 3880-G/5136-E to the CPUC on September 1, 2017, to request approval of its ESPI award for the second part of 2015 and first part of 2016 in the total amount of $24.8 million. PG&E's Advice Letter requested an offset to the award of $5.8 million consistent with a settlement of the 2006-2008 Risk/Reward Incentive Mechanism (RRIM) approved in D. 16-09-019. On September 28, 2017, PG&E submitted Supplemental Advice Letter 3880-G-A/5136-E-A. The Supplemental Advice letter requested to further reduce PG&E's award claim by satisfying the remaining offset required by Decision 16-09-019. On December 14, 2017, the CPUC issued Resolution E-4897, approving Advice 3880-G-A/5136-E-A with modifications. The Resolution determined that PG&E was entitled to a total award of $21.9 million. The Resolution granted PG&E's request to offset as much of the remaining balance of the RRIM settlement as possible. The full $21.9 million award was offset due to the RRIM settlement, leaving a remaining

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8 According to Gas Preliminary Statement Part DB, balances are to be allocated through distribution rates paid by all core and noncore distribution customers

9 On September 29, 2017, PG&E filed Advice 3887-G to update its Cost of Capital as adopted in D. 17-07-005. The Commission approved Advice 3887-G on October 26, 2017.

10 The RF&U included in this advice letter is 0.013411, as filed in Advice 3894-G on October 12, 2017. The Commission approved Advice 3894-G on November 14, 2017.

RRIM settlement balance of $1.38 million to be offset as part of PG&E's next ESPI claim.

**GT&S IRS Private Letter Ruling**

In D. 16-12-010, *Decision Regarding $850 Million Penalty Allocation for PG&E for Gas Pipeline Safety Enhancements*, the Commission created a regulatory liability in the amount of $688.5 million ($379.3 million relating to capital costs incurred in 2015 and $309.2 million relating to capital costs incurred in 2016) as an offset to rate base without adjusting for the rate base impact of the corresponding deferred taxes. To address PG&E's concern that the approach adopted could violate the normalization rules of the Internal Revenue Service (IRS), the Commission expressed its intention that PG&E comply with normalization rules and allowed PG&E to establish a Tax Normalization Memorandum Account to track relevant costs.

On October 2, 2017, PG&E received a Private Letter Ruling (PLR) from the IRS concluding that the omission of the reduction in deferred income taxes violates the normalization requirements of the Internal Revenue Code. As provided for in D. 16-12-010, PG&E filed Advice 3909-G on November 14, 2017, requesting to increase its 2015-2018 GT&S revenue requirements. Advice 3909-G has not yet been approved, therefore, PG&E has not reflected the additional costs associated with the rate base true-up. PG&E will include as soon as practical after Advice 3909-G is approved.

**Ex Parte Order Instituting Investigation**

On September 1, 2017, the Commission issued a Proposed Decision (PD) in its Ex Parte Order Instituting Investigation (OII) (I.15-11-015). If approved by the Commission, the PD would adopt a modified settlement and result in both non-financial and financial remedies. Under the terms of the Settlement, PG&E would additionally forgo collection of $63.5 million in revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million) as determined in its 2015 Gas Transmission and Storage rate case and implemented through the Annual Gas True Up Advice filing. On November 30, 2017, the CPUC extended the statutory deadline in the Ex Parte OII until June 29, 2018, to allow the CPUC additional time to issue a new Proposed Decision. In this advice letter, PG&E has not reflected the revenue requirement reduction, but will include these decreases as soon as practical after the Decision is approved.

**Natural Gas Leak Abatement Program**

On January 22, 2015, the CPUC opened Order Instituting Rulemaking (R.) 15-01-008 to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525). SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities. On June 15, 2017, the Commission issued D. 17-06-015 which identified 26 Best Practices related to policies and procedures, recordkeeping, training, leak detection, leak repair, and leak prevention.

Additionally, D. 17-06-015 provides for the creation of three new PG&E accounts to record and recover the incremental costs associated with implementation of the 26 Best Practices. The Commission approved Advice 3855-G/G-A which: (1) established a New Environmental Regulations Balancing Account (NERBA) for incremental Natural Gas Leak Abatement Program expenditures; (2) created a Memorandum Account for incremental administrative costs associated with the Natural Gas Leak Abatement Program expenditures; and, (3) created a new Natural Gas Leak Abatement Program one-way balancing account for the costs of Pilot Projects and Research and Development activities.

The Commission has not adopted revenue forecasts for the incremental costs of the 26 Best Practices implementation at this time. Pursuant to D. 17-16-015, PG&E filed a Tier 3 advice letter[11] with cost forecasts for each best practice on October 31, 2017. PG&E plans to supplement this advice letter with the associated revenue requirements for the Natural Gas Leak Abatement Program which will be recorded to the NERBA and the NGLAPBA. In compliance with D. 17-06-015, once the supplemental advice letter is approved, PG&E will file an advice letter within 60 days of approval to implement in 2018 rates.

**Greenhouse Gas (GHG) Natural Gas Costs and Revenue Return – (Attachment 7)**

Under California's Cap-and-Trade Program, PG&E and other natural gas suppliers are required to procure compliance instruments, including allowances and offsets, beginning January 1, 2015, to cover GHG emissions from end-use natural gas customers not directly regulated by the ARB. The Commission initiated proceeding R.14-03-003 on March 14, 2014, to address natural gas utilities' compliance obligations under the Cap-and-Trade Program and subsequently split the proceeding into two phases to address high-priority issues immediately necessary for the utilities' participation beginning January 1, 2015. The Commission addressed phase one issues in D.14-12-040.

On October 23, 2015, the Commission issued D. 15-10-032 addressing the remaining phase two issues related to the natural gas utilities' participation in the Cap-and-Trade program. The decision specified that recovery of GHG costs from core and non-core customers, excluding customers who have a direct compliance obligation to ARB, was to begin on April 1, 2016. The decision also ordered utilities to return revenue from the sale of GHG allowances to all residential customers as a non-volumetric credit one time per year beginning in April 2016.

However, on April 12, 2016, the Commission issued D. 16-04-013, which granted limited rehearing of D. 15-10-032 and "vacated" the provisions to begin recovering

[11] Advice Letter 3902-G, filed October 31, 2017

GHG costs and returning related allowance revenues on April 1, 2016. On October 16, 2017, the Commission issued a PD modifying Decision 15-10-032. The PD specifies the mechanisms for reconciling GHG costs and revenues accrued from 2015-2017. The PD also specifies that GHG cost recovery should begin in March 2018 and the California Climate Credit should be distributed in April 2018. Therefore, PG&E has not reflected rate impacts for gas GHG costs and allowance revenues in this filing. If and when the PD is approved, in its current form or as modified, PG&E will submit its 2015-2017 costs and revenues in the filings in compliance with the Commission's final decision, as well as any recovery of applicable Climate Credit amounts.

**Gas Public Purpose Program Authorized Funding**

This AGT incorporates gas PPP surcharge changes that were filed in Advice 3901-G on October 31, 2017. 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 program (ESA), Statewide Marketing Education and Outreach (SWME&O) (for EE and ESA), CARE, public-interest research, development and demonstration (RD&D) programs and Board of Equalization (BOE) administrative costs.

The gas PPP surcharges proposed include:

1) Total gas PPP authorized program funding of $159.7 million for EE, ESA, CARE administrative expenses, RD&D, BOE administrative costs and SWME&O administrative costs. This represents a $2.1 million decrease from 2017;

2) Amortization over 12 months of forecasted December 31, 2017 balances in the PPP surcharge balancing accounts totaling a $28.5 million overcollection. This represents an $11.6 million decrease from 2017; and

3) A projected 2018 CARE revenue shortfall of $116.8 million, which represents a $6.2 million decrease from the forecasted 2017 CARE customer discount. This shortfall is included in the PPP-CARE portion of the gas PPP surcharge rates for 2018 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

The following table shows resulting total annual 2018 revenue requirements authorized by Decision 16-12-010 compared to 2017 amounts currently in rates. A portion of the backbone and the storage revenue requirements shown below are recovered in PG&E's core procurement rates and from Core Transport Agents and are not included in the revenue requirement tables or rates provided in this advice letter. Recovery of these portions of the backbone and storage revenue requirements shown below will occur in PG&E's monthly procurement advice letters effective during 2018.

**Annual 2018 Gas Transmission and Storage Revenue Requirements**

**($ thousands)**

| Total Annual GT&S Revenue Requirements | GT&S 2017 | GT&S 2018 |
|---|---|---|
| Total Backbone | $324,189 | $347,453 |
| Total Local Transmission | 712,503 | 792,339 |
| Total Storage | 88,810 | 90,651 |
| Total Customer Access Charge | 2,630 | 2,507 |
| Total GT&S[12] | $1,128,133 | $1,232,950 |

In addition to these 2018 revenue requirements, in this advice letter, PG&E will include $176.7 million[13] in rates on January 1, 2018 related to the net undercollection.

Attachment 6 provides the GT&S revenue requirements and rates tables included in Appendix J of Decision 16-12-010.

## Confidentiality

Per GO 66-C, Section 583 of the Public Utilities Code, and D. 15-10-032, specific values in Attachment 7 are confidential as described in the attached confidentiality declaration.

## Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than January 10, 2018, which is 20 days after the date of this filing. Protests must be submitted to:

[12] Totals may not tie due to rounding.
[13] See line 21 of Attachment 1.

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:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

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

**Effective Date**

PG&E requests that this Tier 1 filing be approved effective January 1, 2018.

Changes to core gas transportation rates will be incorporated into the monthly core procurement advice filing for rates effective January 1, 2018.

**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 parties on the service list for A.09-05-026, R.02-10-001, A.13-12-012, A.15-09-001, A.13-09-

015, and R.14-03-003. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

**Attachments**

Attachment 1: 2018 Revenue Requirements
Attachment 1A: 2018 Revenue Requirements Allocation to Core/Noncore/Unbundled
Attachment 2: Balancing Account Forecast Summary
Attachment 3: Average End-User Gas Transportation Rates and Public Purpose Program Surcharges
Attachment 4: Summary of Rates by Class by Major Elements
Attachment 5: Allocation of Gas End-Use Transportation Revenue Requirements and Public Purpose Program Surcharge Revenues across Classes
Attachment 6: Gas Transmission and Storage Rates
Attachment 7: Confidential: PG&E's 2018 Natural Gas GHG Limit
Attachment 8: Confidentiality Declaration
Attachment 9: Tariffs

cc: 2009 Biennial Cost Allocation Proceeding (BCAP) (A.09-05-026) (Public Version)
Gas PPP Surcharge (R.02-10-001) (Public Version)
2015 Gas Transmission and Storage Proceeding (A.13-12-012) (Public Version)
2017 GRC Phase I (A.15-09-001) (Public Version)
AB 32 Natural Gas Supplier Cost Recovery (A.13-09-015) (Public Version)
Greenhouse Gas Natural Gas OIR (R.14-03-003) (Public Version)
Eugene Cadenasso, Energy Division (Public and Confidential Versions)

# 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: Annie Ho |
|---|---|
| ☐ ELC ☑ GAS | Phone #: (415) 973-8794 |
| ☐ PLC ☐ HEAT ☐ WATER | E-mail: AMHP@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) #: **3919-G** **Tier: 1**

Subject of AL: **Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2018**

Keywords (choose from CPUC listing): Compliance, Agreements

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: Yes. See the attached matrix that identifies all of the confidential information

Confidential information will be made available to those who have executed a nondisclosure agreement: ☑ Yes ☐ No

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: _____Leslie Almond (415) 973-1803_______________________________

Resolution Required? ☐Yes ☑No

Requested effective date: **January 1, 2018** No. of tariff sheets: **39**

Estimated system annual revenue effect (%): $3,652 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: **Gas Preliminary Statement B, Gas Preliminary Statement C, Gas Preliminary Statement O, Gas Rate Schedule G-EG, G-LNG, G-NGV4, G-NT, G-WSL, G-AA, G-AAOFF, G-AFT, G-AFTOFF, G-BAL, G-CFS, G-LEND, G-NAA, G-NAAOFF, G-NAS, G-NFS, G-NFT, G-NETOFF, G-PARK, G-SFS, G-SFT, G-XF**

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: Erik Jacobson**
**Director, Regulatory Relations**
**c/o Megan Lawson**
**77 Beale Street, Mail Code B13U**
**P.O. Box 770000**
**San Francisco, CA 94177**
**E-mail: PGETariffs@pge.com**

**ATTACHMENT 1**

**PACIFIC GAS AND ELECTRIC COMPANY**
**JANUARY 1, 2018 RATE CHANGE**

**2018 ANNUAL END-USE TRANSPORTATION, GAS TRANSMISSION AND STORAGE REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING**
**($ THOUSANDS)**

| | | A | B | C | D | E | |
|---|---|---|---|---|---|---|---|
| Line No. | | **Present in Rates as of 7/1/17** | **Proposed as of 1/1/2018** | **Total Change** | **Core** | **Noncore / Unbundled** | Line No. |
| | **END-USE GAS TRANSPORTATION** | | | | | | |
| 1 | Gas Transportation Balancing Accounts | 367,144 | 401,033 | 33,889 | (35,241) | 69,129 | 1 |
| 2 | GRC Distribution Base Revenues (includes distribution portion of Cost of Capital) | 1,738,483 | 1,825,859 | 87,376 | 84,328 | 3,048 | 2 |
| 3 | Pension - Distribution | 46,980 | 51,922 | 4,942 | 4,770 | 172 | 3 |
| 4 | Pension - Gas Transmission & Storage | 17,741 | 19,607 | 1,866 | 1,207 | 659 | 4 |
| 5 | Self Generation Incentive Program Revenue Requirement | 12,989 | 12,990 | 1 | - | 1 | 5 |
| 6 | CPUC Fee | 6,562 | 7,837 | 1,275 | 782 | 493 | 6 |
| 7 | Core Brokerage Fee Credit | (6,583) | (6,583) | - | - | - | 7 |
| 8 | Less CARE discount recovered in PPP surcharge from non-CARE customers | (122,975) | (116,811) | 6,164 | 6,164 | - | 8 |
| 9 | RF&U | 5,172 | 5,655 | 483 | (448) | 931 | 9 |
| 10 | Total Transportation RRQ with Adjustments and Credits | 2,065,513 | 2,201,509 | 135,996 | 61,562 | 74,433 | 10 |
| 11 | Procurement-Related G-10 Total | (886) | (664) | 222 | 222 | - | 11 |
| 12 | Procurement-Related G-10 Total Allocated | 886 | 664 | (222) | (88) | (135) | 12 |
| 13 | Total Transportation Revenue Requirements Reallocated | 2,065,513 | 2,201,509 | 135,996 | 61,697 | 74,298 | 13 |
| | Gas Transmission & Storage (GT&S) Transportation Revenue Requirements (RRQ) | | | | | | |
| 14 | Local Transmission | 712,503 | 792,339 | 79,836 | 54,054 | 25,782 | 14 |
| 15 | Customer Access | 2,630 | 2,507 | (123) | - | (122) | 15 |
| 16 | Total GT&S Transportation RRQ | 715,133 | 794,846 | 79,713 | 54,054 | 25,660 | 16 |
| 17 | 2015 GT&S Late Implementation | | | | | | 17 |
| 18 | Local Transmission | 176,147 | 176,147 | - | - | - | 18 |
| 19 | Backbone | 5,316 | 5,316 | - | - | - | 19 |
| 20 | Storage | (4,728) | (4,728) | - | - | - | 20 |
| 21 | Total 2015 GT&S Late Implementation | 176,735 | 176,735 | - | - | - | 21 |
| 22 | **Total End-Use Gas Transportation RRQ** | **2,957,381** | **3,173,090** | **215,710** | **115,751** | **99,958** | 22 |
| | **PUBLIC PURPOSE PROGRAMS (PPP) FUNDING** | | | | | | |
| 23 | Energy Efficiency | 77,417 | 68,030 | (9,387) | (8,447) | (940) | 23 |
| 24 | Energy Savings Assistance | 68,858 | 75,703 | 6,845 | 6,160 | 686 | 24 |
| 25 | Research and Development and BOE/CPUC Admin Fees | 11,216 | 11,098 | (118) | (29) | (89) | 25 |
| 26 | CARE Administrative Expense | 3,177 | 3,696 | 519 | 289 | 230 | 26 |
| 27 | Statewide Marketing, Education & Outreach | 1,113 | 1,139 | 26 | 23 | 3 | 27 |
| 28 | Total Authorized PPP Funding | 161,781 | 159,666 | (2,115) | (2,004) | (111) | 28 |
| 29 | PPP Surcharge Balancing Accounts | (16,818) | (28,450) | (11,632) | (8,062) | (3,570) | 29 |
| 30 | CARE discount recovered from non-CARE customers | 122,975 | 116,811 | (6,164) | (2,804) | (3,361) | 30 |
| 31 | **Total PPP Required Funding** | **267,938** | **248,027** | **(19,911)** | **(12,869)** | **(7,042)** | 31 |
| | **GT&S UNBUNDLED COSTS** | | | | | | |
| 32 | Backbone Transmission | 203,757 | 217,083 | 13,326 | - | 13,326 | 32 |
| 33 | Storage | 14,073 | 13,783 | (290) | - | (290) | 33 |
| 34 | **Total GT&S Unbundled** | **217,830** | **230,866** | **13,036** | **-** | **13,036** | 34 |
| 35 | **TOTAL REVENUE REQUIREMENTS** | **3,443,149** | **3,651,983** | **208,835** | **102,882** | **105,952** | 35 |

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

**ATTACHMENT 1A**

**PACIFIC GAS AND ELECTRIC COMPANY**
**JANUARY 1, 2018 RATE CHANGE**

**2018 ANNUAL END-USE TRANSPORTATION, GAS TRANSMISSION AND STORAGE REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING ALLOCATION TO CORE/NONCORE/UNBUNDLED**
**($ THOUSANDS)**

| Line No. | | Proposed as of 1/1/2018 | Core | Noncore / Unbundled | Line No. |
|---|---|---|---|---|---|
| | **END-USE GAS TRANSPORTATION** | | | | |
| 1 | Gas Transportation Balancing Accounts | 401,033 | 313,386 | 87,646 | 1 |
| 2 | GRC Distribution Base Revenues | 1,825,859 | 1,762,294 | 63,565 | 2 |
| 3 | Pension - Distribution | 51,922 | 50,114 | 1,808 | 3 |
| 4 | Pension - Gas Transmission & Storage | 19,607 | 12,448 | 7,159 | 4 |
| 5 | Self Generation Incentive Program Revenue Requirement | 12,990 | 5,149 | 7,841 | 5 |
| 6 | CPUC Fee | 7,837 | 4,808 | 3,028 | 6 |
| 7 | Core Brokerage Fee Credit | (6,583) | (6,583) | - | 7 |
| 8 | Less CARE discount recovered in PPP surcharge from non-CARE customers | (116,811) | (116,811) | - | 8 |
| 9 | FF&U | 5,655 | 4,331 | 1,324 | 9 |
| 10 | Total Transportation RRQ with Adjustments and Credits | 2,201,509 | 2,029,137 | 172,372 | 10 |
| 11 | Procurement-Related G-10 Total | (664) | (664) | - | 11 |
| 12 | Procurement-Related G-10 Total Allocated | 664 | 262 | 402 | 12 |
| 13 | Total Transportation Revenue Requirements Reallocated | 2,201,509 | 2,028,735 | 172,773 | 13 |
| | Gas Transmission & Storage (GT&S) Transportation Revenue Requirements (RRQ) | | | | |
| 14 | Local Transmission | 792,339 | 536,850 | 255,490 | 14 |
| 15 | Customer Access | 2,507 | - | 2,507 | 15 |
| 16 | Total GT&S Transportation RRQ | 794,846 | 536,850 | 257,998 | 16 |
| 17 | 2015 GT&S Late Implementation | | | | 17 |
| 18 | Local Transmission | 176,147 | 121,559 | 54,588 | 18 |
| 19 | Backbone | 5,316 | (1,764) | 7,080 | 19 |
| 20 | Storage | (4,728) | 6,774 | (11,502) | 20 |
| 21 | Total 2015 GT&S Late Implementation | 176,735 | 126,569 | 50,166 | 21 |
| 22 | **Total End-Use Gas Transportation RRQ** | **3,173,090** | **2,692,154** | **480,937** | 22 |
| | **PUBLIC PURPOSE PROGRAMS (PPP) FUNDING** | | | | |
| 23 | Energy Efficiency | 68,030 | 61,216 | 6,814 | 23 |
| 24 | Energy Savings Assistance | 75,703 | 68,121 | 7,583 | 24 |
| 25 | Research and Development and BOE/CPUC Admin Fees | 11,098 | 6,349 | 4,750 | 25 |
| 26 | CARE Administrative Expense | 3,696 | 1,969 | 1,727 | 26 |
| 27 | Statewide Marketing, Education & Outreach | 1,139 | 1,025 | 114 | 27 |
| 28 | Total Authorized PPP Funding | 159,666 | 138,680 | 20,987 | 28 |
| 29 | PPP Surcharge Balancing Accounts | (28,450) | (19,316) | (9,134) | 29 |
| 30 | CARE discount recovered from non-CARE customers | 116,811 | 62,231 | 54,579 | 30 |
| 31 | **Total PPP Required Funding** | **248,027** | **181,595** | **66,432** | 31 |
| | **GT&S UNBUNDLED COSTS** | | | | |
| 32 | Backbone Transmission | 217,083 | - | 217,083 | 32 |
| 33 | Storage | 13,783 | - | 13,783 | 33 |
| 34 | **Total GT&S Unbundled** | **230,866** | **-** | **230,866** | 34 |
| 35 | **TOTAL REVENUE REQUIREMENTS** | **3,651,983** | **2,873,750** | **778,235** | 35 |

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

**ATTACHMENT 2**



**PACIFIC GAS AND ELECTRIC COMPANY**
**JANUARY 1, 2018 RATE CHANGE**
**BALANCING ACCOUNT FORECAST SUMMARY**

**($ THOUSANDS)**

| Line No. | | Balance: Nov. 2017 Recorded Dec. 2017 Forecast | Allocation: Core | Allocation: Noncore | Balance: December 2016 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 | $218,650 | $218,650 | $0 | $327,056 | $327,056 | $0 | 1 |
| 2 | CFCA - Core Cost Subaccount | $13,122 | $13,122 | $0 | $29,464 | $29,464 | $0 | 2 |
| 3 | Noncore Customer Class Charge Account (NCA) - Noncore Subaccount | $2,409 | $0 | $2,409 | ($896) | $0 | ($896) | 3 |
| 4 | NCA - Distribution Subaccount | ($3,530) | $0 | ($3,530) | ($1,906) | $0 | ($1,906) | 4 |
| 5 | Core Brokerage Fee Balancing Account | $1,113 | $1,113 | $0 | $1,464 | $1,464 | $0 | 5 |
| 6 | Hazardous Substance Mechanism | $83,469 | $32,918 | $50,551 | $46,826 | $18,467 | $28,359 | 6 |
| 7 | Balancing Charge Account | $482 | $190 | $292 | 3,724 | $1,469 | $2,255 | 7 |
| 8 | Affiliate Transfer Fee Account | $0 **(2)** | $0 | ($1) | (498) | ($480) | ($17) | 8 |
| 9 | Customer Energy Efficiency Incentive Recovery Account - Gas | $182 | $180 | $2 | 2,314 | $2,294 | $20 | 9 |
| 10 | California Solar Initiative Thermal Program Memoradum Account | $6,722 | $3,983 | $2,740 | 9,350 | $5,540 | $3,810 | 10 |
| 11 | Adjustment Mechanism of Costs Determined in Other Proceedings | $49,576 | $24,788 | $24,788 | - | $0 | $0 | 11 |
| 12 | Non-Tariffed Products and Services Balancing Account | ($131) | ($131) | $0 | (204) | ($204) | $0 | 12 |
| 13 | AB 32 Cost of Implementation Fee | $6,226 **(3)** | $3,790 | $2,434 | $3,652 | $5,224 | ($1,572) | 13 |
| 14 | Gas Pipeline Expense Reimbursement Balancing Account | $3,323 | $1,977 | $1,346 | 2,420 | $1,440 | $980 | 14 |
| 15 | Gas Leak Survey and Repair Balancing Account | $0 **(2)** | $0 | $0 | (18,535) | ($17,890) | ($645) | 15 |
| 16 | Natural Gas Leak Abatement Program Balancing Account | $0 | $0 | $0 | - | $0 | $0 | 16 |
| 17 | New Environmental Regulations Balancing Account | $0 | $0 | $0 | - | $0 | $0 | 17 |
| 18 | Pension Contribution Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | 18 |
| 19 | Revised Customer Energy Statement Balancing Account | $0 **(2)** | $0 | ($1) | 1,599 | $1,543 | $56 | 19 |
| 20 | GT&S Revenue Sharing Mechanism | $12,767 **(4)** | $6,384 | $6,384 | (45,938) | ($22,969) | ($22,970) | 20 |
| 21 | Mobile Home Park Balancing Account | $6,653 | $6,422 | $232 | 2,097 | $2,024 | $73 | 21 |
| 22 | **Subtotal Transportation Balancing Accounts** | **$401,033** | **$313,386** | **$87,646** | **$361,989** | **$354,443** | **$7,548** | 22 |
| | **PUBLIC PURPOSE PROGRAM (PPP) SURCHARGE BALANCING ACCOUNTS (5)** | | | | | | | |
| 23 | PPP-Energy Efficiency | ($11,345) | ($10,208) | ($1,136) | $2,891 | $2,602 | $289 | 23 |
| 24 | PPP-Low Income Energy Efficiency | $39 | $35 | $4 | $8,729 | $7,858 | $871 | 24 |
| 25 | PPP-Research Development and Demonstration | ($258) | ($147) | ($111) | $683 | $376 | $307 | 25 |
| 26 | California Alternate Rates for Energy Account | ($16,886) | ($8,996) | ($7,891) | ($14,268) | ($7,545) | ($6,723) | 26 |
| 27 | **Subtotal Public Purpose Program Balancing Accounts** | **($28,450)** | **($19,316)** | **($9,134)** | **($1,964)** | **$3,291** | **($5,256)** | 27 |
| 28 | **TOTAL BALANCING ACCOUNTS** | **$372,583** | **$294,070** | **$78,512** | **$360,025** | **$357,734** | **$2,292** | 28 |

**Footnotes:**

1. These balances are the recorded balances as of December 2016. The December 2016 ending balances that were provided in the 2017 AGT AL 3791-G were the forecasted balances (based on recorded balances through November 2016).
2. Decision 17-05-013 authorized closure of the Affiliate Transfer Fees Account, the Gas Leak Survey and Repair Balancing Account, and the Revised Customer Energy Statement Balancing Account (RCESBA).
3. 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.
4. The balance shown is the September 30, 2017 recorded balance, which will be transferred evenly (50/50) to the CFCA and NCA after the approval of the AGT advice letter.
5. The PPP-related balances (based on Sept 2017 recorded) were included in the 2018 PPP Gas Surcharge filed in AL 3901-G on October 31, 2017.

**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**
**1/1/2018 - December AGT Final**

**AVERAGE END-USER GAS TRANSPORTATION RATES AND PUBLIC PURPOSE PROGRAM SURCHARGES**
**($/th; Annual Class Averages)[3]**

| Line No. | Customer Class | 7/1/2017 GRC & SGIP (A) Transportation[1] | G-PPPS[2] | Total | 1/1/2018 - December AGT Final Transportation | G-PPPS | Total | Percentage Change From July 1, 2017 Transportation | G-PPPS | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | **RETAIL CORE** | | | | | | | | | |
| 1 | Residential Non-CARE [4] | $1.0722 | $.0959 | **$1.168** | $1.112 | $.088 | **$1.200** | 3.7% | (7.7%) | 2.7% |
| 2 | Small Commercial Non-CARE [4] | $.6763 | $.0467 | **$.723** | $.713 | $.042 | **$.756** | 5.5% | (9.4%) | 4.5% |
| 3 | Large Commercial | $.4033 | $.0975 | **$.501** | $.439 | $.091 | **$.530** | 8.8% | (6.6%) | 5.8% |
| 4 | NGV1 - (uncompressed service) | $.3235 | $.0310 | **$.354** | $.358 | $.028 | **$.386** | 10.7% | (10.6%) | 8.9% |
| 5 | NGV2 - (compressed service) | $1.7890 | $.0310 | **$1.820** | $1.762 | $.028 | **$1.790** | (1.5%) | (10.6%) | (1.7%) |
| | **RETAIL NONCORE** | | | | | | | | | |
| 6 | Industrial - Distribution | $.2513 | $.0466 | **$.298** | $.283 | $.042 | **$.326** | 12.8% | (9.2%) | 9.3% |
| 7 | Industrial - Transmission | $.1132 | $.0372 | **$.150** | $.138 | $.034 | **$.172** | 22.1% | (9.6%) | 14.3% |
| 8 | Industrial - Backbone | $.0104 | $.0372 | **$.048** | $.026 | $.034 | **$.060** | 152.9% | (9.6%) | 26.0% |
| 9 | Electric Generation - Transmission (G-EG-D/LT) | $.1031 | | **$.103** | $.128 | | **$.128** | 24.5% | | 24.5% |
| 10 | Electric Generation - Backbone (G-EG-BB) | $.0089 | | **$.009** | $.026 | | **$.026** | 187.7% | | 187.7% |
| 11 | NGV 4 - Distribution (uncompressed service) | $.2513 | $.0310 | **$.282** | $.283 | $.028 | **$.311** | 12.8% | (10.6%) | 10.2% |
| 12 | NGV 4 - Transmission (uncompressed service) | $.1043 | $.0310 | **$.135** | $.129 | $.028 | **$.157** | 23.6% | (10.6%) | 15.8% |
| | **WHOLESALE CORE AND NONCORE (G-WSL) (1)** | | | | | | | | | |
| 13 | Alpine Natural Gas | $.1003 | | **$.100** | $.125 | | **$.125** | 24.3% | | 24.3% |
| 14 | Coalinga | $.1007 | | **$.101** | $.125 | | **$.125** | 24.2% | | 24.2% |
| 15 | Island Energy | $.1123 | | **$.112** | $.136 | | **$.136** | 21.2% | | 21.2% |
| 16 | Palo Alto | $.0980 | | **$.098** | $.122 | | **$.122** | 25.0% | | 25.0% |
| 17 | West Coast Gas - Castle | $.2845 | | **$.284** | $.318 | | **$.318** | 11.7% | | 11.7% |
| 18 | West Coast Gas - Mather Distribution | $.3391 | | **$.339** | $.375 | | **$.375** | 10.7% | | 10.7% |
| 19 | West Coast Gas - Mather Transmission | $.1018 | | **$.102** | $.126 | | **$.126** | 23.9% | | 23.9% |

( 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 $0.00133 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**
**1/1/2018 - DECEMBER AGT FINAL**
**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) | $.18988 | $.18988 | $.18988 | $.18988 | $.18988 | $.08286 | $.08286 | $.00000 | $.08286 | $.08286 | $.08286 | $.00000 |
| 2 | Self Generation Incentive Program | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 | $.00180 |
| 3 | CPUC Fee (3) | $.00168 | $.00168 | $.00168 | $.00168 | $.00168 | $.00168 | $.00168 | $.00168 | $.00168 | $.00168 | $.00007 | $.00007 |
| 4 | AB32 Air Resource Board Cost of Implementation Fee (8) | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 | $.00133 |
| 5 | AB32 Greenhouse Gas Compliance & Obligation Cost | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 |
| 6 | Balancing Accounts (2) | $.12055 | $.07702 | $.04640 | $.03744 | $.19435 | $.01287 | $.02074 | $.02124 | $.01287 | $.02124 | $.01946 | $.01946 |
| 7 | 2015 GT&S Late Implementation Shortfall Amortization | $.04598 | $.04598 | $.04598 | $.04598 | $.04598 | $.01716 | $.01716 | ($.00102) | $.01716 | $.01716 | $.01716 | ($.00102) |
| 8 | GT&S Pension | $.00429 | $.00429 | $.00429 | $.00429 | $.00429 | $.00195 | $.00195 | $.00060 | $.00195 | $.00195 | $.00195 | $.00060 |
| 9 | Distribution - Annual Average (6) | $.74601 | $.33247 | $.14276 | $.07463 | $1.32270 | $.15931 | $.00983 | | $.15931 | | $.00308 | $.00308 |
| 10 | **VOLUMETRIC RATE - Average Annual** | $1.11153 | $.65446 | $.43413 | $.35704 | $1.76203 | $.27896 | $.13735 | $.02563 | $.27896 | $.12801 | $.12770 | $.02533 |
| 11 | **CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4)** | | $.05888 | $.00449 | $.00120 | | $.00436 | $.00092 | $.00074 | $.00436 | $.00092 | $.00063 | $.00019 |
| 12 | **CLASS AVERAGE TRANSPORTATION RATE** | $1.11153 | $.71334 | $.43862 | $.35823 | $1.76203 | $.28333 | $.13827 | $.02638 | $.28333 | $.12894 | $.12833 | $.02552 |
| 13 | **PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)** | $.08849 | $.04232 | $.09104 | $.02770 | $.02770 | $.04228 | $.03359 | $.03359 | $.02770 | $.02770 | | |
| 14 | **END-USE RATE (7)** | $1.20002 | $.75566 | $.52966 | $.38593 | $1.78973 | $.32561 | $.17186 | $.05997 | $.31103 | $.15664 | $.12833 | $.02552 |

| | | Wholesale | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | WC Gas Mather | | Island | | WC Gas |
| | | Coalinga | Palo Alto | Dist. | Trans. | Energy | Alpine | Castle |
| | **TRANSPORTATION CHARGE COMPONENTS** | | | | | | | |
| 15 | Local Transmission (1) | $.08286 | $.08286 | $.08286 | $.08286 | $.08286 | $.08286 | $.08286 |
| 16 | Self Generation Incentive Program | WHOLESALE CUSTOMERS EXCEMPT FROM SGIP, AB32 COI, and CPUC FEE RATE COMPONENTS | | | | | | |
| 17 | CPUC Fee (3) | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 |
| 18 | AB32 Air Resource Board Cost of Implementation Fee (8) | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 |
| 19 | AB32 Greenhouse Gas Compliance & Obligation Cost | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 | $.00000 |
| 20 | Balancing Accounts (2) | $.01955 | $.01955 | $.00617 | $.01955 | $.01955 | $.01955 | $.00944 |
| 21 | 2015 GT&S Late Implementation Shortfall Amortization | $.01716 | $.01716 | $.01716 | $.01716 | $.01716 | $.01716 | $.01716 |
| 22 | GT&S Pension | $.00195 | $.00195 | $.00195 | $.00195 | $.00195 | $.00195 | $.00195 |
| 23 | Distribution - Annual Average | | | $.26273 | | | | $.19841 |
| 24 | **VOLUMETRIC RATE - Average Annual** | $.12152 | $.12152 | $.37086 | $.12152 | $.12152 | $.12152 | $.30982 |
| 25 | **CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4)** | $.00350 | $.00093 | $.00454 | $.00454 | $.01464 | $.00317 | $.00787 |
| 26 | **CLASS AVERAGE TRANSPORTATION RATE** | $.12502 | $.12245 | $.37540 | $.12606 | $.13616 | $.12469 | $.31769 |
| 27 | **PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)** | Wholesale Customers Exempt from Public Purpose Program Surcharge | | | | | | |
| 28 | **END-USE RATE** | $.12502 | $.12245 | $.37540 | $.12606 | $.13616 | $.12469 | $.31769 |

NOTES
(1) Adopted in Decision 16-12-010 filed with Advice Letter 3788-G Attachment 6 Appendix J Table 22
(2) Based on November recorded balances and forecasted through December.
(3) CPUC Fee based on Resolution M-4832, effective January 1, 2018 (including FF&U). G-EG customers pay a reduced CPUC fee per the 2010 BCAP D.10-06-035.
(4) Adopted in Decision 16-12-010 filed with Advice Letter 3788-G Attachment 6 Appendix J Table 23
(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 3901-G updated PG&E's 2018 PPP Surcharges effective January 1, 2018.
(6) The G-NGV2 Distribution rate component incudes the cost of compression, station operations and maintenance, 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 $0.00133 per therm

(9) Rates are unrounded

# Attachment 5

**PACIFIC GAS AND ELECTRIC COMPANY**

**1/1/2018 - December AGT Final**

**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** | All Other Wholesale | Noncore & Wholesale |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Customer | $1,010,643 | $881,757 | $117,507 | $2,514 | $102 | $0 | $1,001,880 | $6,221 | $354 | $0 | $2,187 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $8,762 |
| 2 | + Distribution | $839,268 | $585,315 | $188,480 | $8,317 | $1,411 | $0 | $783,523 | $35,837 | $13,593 | $0 | $6,019 | $0 | $0 | $0 | $0 | $165 | $0 | $132 | $0 | $55,745 |
| 3 | + G-NGV2 Compression Cost | $3,020 | $0 | $0 | $0 | $0 | $3,020 | $3,020 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | Allocation of Base Distribution Franchise Fees | $18,417 | $14,582 | $3,041 | $108 | $15 | $30 | $17,776 | $418 | $139 | $0 | $82 | $0 | $0 | $0 | $0 | $2 | $0 | $1 | $0 | $641 |
| 5 | Allocation of Base Distribution Uncollectibles Expense | $6,432 | $5,093 | $1,062 | $38 | $5 | $10 | $6,209 | $146 | $48 | $0 | $28 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $223 |
| 6 | **Final Allocation of Distribution Revenue Requirement** | **$1,877,780** | **$1,486,747** | **$310,091** | **$10,976** | **$1,533** | **$3,061** | **$1,812,409** | **$42,622** | **$14,133** | **$0** | **$8,316** | **$0** | **$0** | **$0** | **$0** | **$166** | **$0** | **$133** | **$0** | **$65,371** |
| 7 | **Distribution-Level Revenue Requirement Allocation %** | 100.00000% | 79.17578% | 16.51371% | 0.58454% | 0.08166% | 0.16299% | 96.51869% | 2.26983% | 0.75267% | 0.00000% | 0.44287% | 0.00000% | 0.00000% | 0.00000% | 0.00000% | 0.00886% | 0.00000% | 0.00709% | 0.00000% | 3.48131% |

Total Core Brokerage Fee (w/out F&U) (6,496) (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** | All Other Wholesale | Noncore & Wholesale |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount | $218,650 | $179,362 | $37,410 | $1,324 | $185 | $369 | $218,650 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **$0** | $0 |
| 9 | Core Fixed Cost Acct. Bal. - Core Cost Subaccount - ECPT (2016 PSEF | $13,122 | $9,106 | $3,588 | $338 | $92 | $0 | $13,122 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **$0** | $0 |
| 10 | Mobile Home Parks Balancing Account | $6,653 | $5,268 | $1,099 | $39 | $5 | $11 | $6,422 | $151 | $50 | $0 | $29 | $0 | $0 | $0 | $0 | $1 | $0 | $0 | $0 | $232 |
| 11 | Noncore Customer Class Charge Account - ECPT | $2,409 | $0 | $0 | $0 | $0 | $0 | $0 | $141 | $778 | $6 | $1,461 | $3 | $1 | $17 | $0 | $1 | $0 | $0 | $19 | $2,409 |
| 12 | Noncore Customer Class Charge Account - Distribution Subacct | ($3,530) | $0 | $0 | $0 | $0 | $0 | $0 | ($2,301) | ($763) | $0 | ($449) | $0 | $0 | $0 | $0 | ($9) | $0 | ($7) | $0 | ($3,530) |
| 13 | Gas Leak Survey & Repair Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14 | SmartMeter™ Opt-Out Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15 | Gas Pipeline Expense & Capital BA (2016 is for CPUC Reimb sub) | $3,323 | $1,372 | $540 | $51 | $14 | $0 | $1,977 | $79 | $434 | $4 | $816 | $2 | $1 | $10 | $0 | $0 | $0 | $0 | $11 | $1,346 |
| 16 | Hazardous Substance Balance | $83,469 | $22,842 | $9,000 | $847 | $230 | $0 | $32,918 | $2,958 | $16,323 | $132 | $30,656 | $59 | $27 | $362 | $7 | $11 | $7 | $8 | $404 | $50,551 |
| 17 | Non-Tariffed Products and Services | ($131) | ($91) | ($36) | ($3) | ($1) | $0 | ($131) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 18 | Core Brokerage Fee Credit (Gas Brokerage Costs w/o FF&U) | ($5,468) | ($3,794) | ($1,495) | ($141) | ($38) | $0 | ($5,468) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 19 | Core Brokerage Fee Credit (Sales/Marketing Costs w/o FF&U) | ($1,028) | ($904) | ($121) | ($3) | ($0) | $0 | ($1,028) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 20 | Affiliate Transfer Fee Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 21 | Balancing Charge Account | $482 | $132 | $52 | $5 | $1 | $0 | $190 | $17 | $94 | $1 | $177 | $0 | $0 | $2 | $0 | $0 | $0 | $0 | $2 | $292 |
| 22 | G-10 Procurement-related Employee Discount Allocated | $664 | $182 | $72 | $7 | $2 | $0 | $262 | $24 | $130 | $1 | $244 | $0 | $0 | $3 | $0 | $0 | $0 | $0 | $3 | $402 |
| 23 | Brokerage Fee Balance Account | $1,113 | $772 | $304 | $29 | $8 | $0 | $1,113 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 24 | Adjust. Mechanism Costs Determined Other Proceedings | $49,576 | $17,201 | $6,777 | $638 | $173 | $0 | $24,788 | $1,450 | $8,004 | $65 | $15,033 | $29 | $13 | $178 | $3 | $6 | $3 | $4 | $198 | $24,788 |
| 25 | G-10 Procurement-related Employee Discount Applied to Res Class | ($664) | ($664) | $0 | $0 | $0 | $0 | ($664) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 26 | TID Almond Power Plant | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 27 | RCESBA-G | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 28 | Gas Operational Cost Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 29 | Noncore Gas Pipeline Safety Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 30 | GT&S Revenue Sharing Mechanism | $12,767 | $4,430 | $1,745 | $164 | $45 | $0 | $6,384 | $374 | $2,061 | $17 | $3,871 | $8 | $3 | $46 | $1 | $1 | $1 | $1 | $51 | $6,384 |
| 31 | Core Gas Pipeline Safety Balancing Account | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 32 | Self Gen Incentive Program Forecast Period Cost | $12,990 | $3,573 | $1,408 | $132 | $36 | $0 | $5,149 | $463 | $2,553 | $21 | $4,795 | $9 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $7,841 |
| 33 | Subtotals of Items Transferred to CFCA and NCA | $394,398 | $238,786 | $60,342.28 | $3,425.92 | $750.62 | $380 | $303,684 | $3,354.01 | $29,664.51 | $245.71 | $56,633.20 | $110.57 | $46.87 | $617.79 | $11.87 | $11.07 | $11.42 | $6.27 | $688 | $90,713 |
| 34 | Franchise Fees and SF Gross Receipts and Uncoll. Exp. on Items Abov | $5,287 | $3,202 | $809 | $46 | $10 | $5 | $4,073 | $45 | $398 | $3 | $759 | $1 | $0 | $6 | $0 | $0 | $0 | $0 | $7 | $1,214 |
| 35 | Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs | $399,684 | $241,988 | $61,152 | $3,472 | $761 | $385 | $307,757 | $3,399 | $30,062 | $249 | $57,393 | $112 | $47 | $624 | $12 | $11 | $12 | $6 | $695 | $91,927 |
| 36 | Total of Items Collected via CFCA, NCA, and NDFCA | $2,277,465 | $1,728,735 | $371,243 | $14,448 | $2,294 | $3,446 | $2,120,166 | $46,021 | $44,196 | $249 | $65,709 | $112 | $47 | $624 | $12 | $178 | $12 | $139 | $695 | $157,299 |

| 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** | All Other Wholesale | Noncore & Wholesale |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 37 | CEE Incentive | $182 | $159 | $21 | $0 | $0 | $0 | $180 | $1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2 |
| 38 | AB32 ARB Implementation Fee | $6,226 | $2,631 | $1,036 | $97 | $26 | $0 | $3,790 | $340 | $1,874 | $15 | $199 | $7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,435 |
| 39 | CA Solar Hot Water Heating | $6,722 | $2,566 | $1,266 | $119 | $32 | $0 | $3,983 | $416 | $2,296 | $19 | $0 | $8 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,739 |
| 40 | CPUC FEE | $7,837 | $3,338 | $1,313 | $124 | $34 | $0 | $4,808 | $432 | $2,386 | $19 | $182 | $9 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,028 |
| 41 | Subtotals for Customer Class Charge Items | $20,967 | $8,694 | $3,636 | $341 | $92 | $0 | $12,762 | $1,189 | $6,556 | $53 | $382 | $24 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $8,204 |
| 42 | Franchise Fees and SF Gross Receipts and Uncoll. Exp. on Items Abov | $281 | $117 | $49 | $5 | $1 | $0 | $171 | $16 | $88 | $1 | $5 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $110 |
| 43 | Subtotals of Other Costs | $21,248 | $8,810 | $3,685 | $345 | $94 | $0 | $12,934 | $1,205 | $6,644 | $54 | $387 | $24 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $8,314 |
| 44 | Allocation of Total Transportation Costs prior to GT&S-related Costs | $2,298,712 | $1,737,545 | $374,927 | $14,793 | $2,388 | $3,446 | $2,133,099 | $47,227 | $50,840 | $303 | $66,096 | $136 | $47 | $624 | $12 | $178 | $12 | $139 | $695 | $165,613 |

## Attachment 5 (continued)

| Line No. | | 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** | All Other Wholesale | Noncore & Wholesale |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **CUSTOMER CLASS COST FOR 2015 GTS LISA ALLOCATED BASED ON 2017 GT&S 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** | All Other Wholesale | Noncore & Wholesale |
| 45 | 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 | $0 |
| 46 | Local Transmission Balancing Account | $176,147 | $82,756 | $34,250 | $3,359 | $1,194 | $0 | $121,559 | $4,483 | $28,489 | $0 | $20,895 | $69 | $44 | $560 | $11 | $18 | $7 | $12 | $623 | $54,588 |
| 47 | 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 | $0 |
| 48 | Backbone Transmission Balancing Account | $5,316 | ($1,201) | ($497) | ($49) | ($17) | $0 | ($1,764) | $403 | $2,561 | $30 | $4,022 | $6 | $4 | $50 | $1 | $2 | $1 | $1 | $56 | $7,080 |
| 49 | Storage (Forecast Period Cost) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 50 | Storage Balancing Account | ($4,728) | $4,612 | $1,909 | $187 | $67 | $0 | $6,774 | ($655) | ($4,160) | ($48) | ($6,534) | ($10) | ($6) | ($82) | ($2) | ($3) | ($1) | ($2) | ($91) | ($11,502) |
| 51 | Subtotal of 2015 GTS LISA in 2016 Rates | $176,735 | $86,167 | $35,662 | $3,497 | $1,243 | $0 | $126,570 | $4,231 | $26,889 | ($18) | $18,383 | $65 | $42 | $529 | $10 | $17 | $7 | $11 | $588 | $50,166 |
| | **GT&S Pension** | $0 | 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** | All Other Wholesale | Noncore & Wholesale |
| 56 | GT&S Pension Including FF&U | $19,607 | $8,638 | $3,403 | $320 | $87 | $0 | $12,448 | $507 | $2,796 | $7 | $3,767 | $10 | $5 | $62 | $1 | $2 | $1 | $1 | $69 | $7,159 |
| 57 | Net End-User Transportation Excluding LT and CAC | $2,495,055 | $1,832,350 | $413,992 | $18,611 | $3,718 | $3,446 | $2,272,117 | $51,964 | $80,525 | $291 | $88,246 | $211 | $94 | $1,215 | $24 | $197 | $19 | $152 | $1,352 | $222,938 |
| | **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** | All Other Wholesale | Noncore & Wholesale |
| 58 | Local Transmission (w/applied seed value) | 771,375 | 355,812 | 147,258 | 14,442 | 5,133 | | 522,645 | 20,426 | 129,810 | | 95,207 | 313 | 203 | 2,552 | 51 | 83 | 33 | 53 | 2,838 | 248,730 |
| 59 | Customer Access Charge | 2,507 | 0 | 0 | 0 | | | 0 | 0 | 1,465 | 13 | 975 | | 9 | 29 | 2 | 5 | 6 | 5 | 45 | 2,507 |
| 60 | Total End-User Gas Accord Transportation Costs | 773,882 | 355,812 | 147,258 | 14,442 | 5,133 | 0 | 522,645 | 20,426 | 131,275 | 13 | 96,182 | 313 | 211 | 2,581 | 53 | 88 | 39 | 58 | 2,883 | 251,237 |
| 61 | Gross End-User Transportation Costs in Rates | 3,268,937 | 2,188,162 | 561,250 | 33,053 | 8,851 | 3,446 | 2,794,762 | 72,390 | 211,800 | 305 | 184,428 | 524 | 305 | 3,795 | 76 | 284 | 58 | 209 | 4,235 | 474,175 |
| 62 | Less Forecast CARE Discount recovered in PPP Surcharges | 116,811 | 116,811 | | | | | 116,811 | | | | | | | | | | | | | 0 |
| 63 | Net End-User Transportation Costs in Rates | 3,152,126 | 2,071,351 | 561,250 | 33,053 | 8,851 | 3,446 | 2,677,951 | 72,390 | 211,800 | 305 | 184,428 | 524 | 305 | 3,795 | 76 | 284 | 58 | 209 | 4,235 | 474,175 |
| 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** | All Other Wholesale | Noncore & Wholesale |
| 64 | PPP-EE Surcharge | 69,168 | 54,518 | 5,548 | 2,174 | 0 | | 62,240 | 1,859 | 5,028 | 41 | | 0 | | | | | | | | 6,928 |
| 65 | PPP-EE Balancing Account | (11,345) | (8,942) | (910) | (357) | 0 | | (10,208) | (305) | (825) | (7) | | 0 | | | | | | | | -1,136 |
| 66 | PPP-ESA Surcharge | 75,703 | 59,669 | 6,072 | 2,380 | 0 | | 68,121 | 2,035 | 5,503 | 45 | | 0 | | | | | | | | 7,583 |
| 67 | PPP-ESA Balancing Account | 39 | 31 | 3 | 1 | 0 | | 35 | 1 | 3 | 0 | | 0 | | | | | | | | 4 |
| 68 | PPP - RD&D Programs | 10,682 | 4,134 | 1,749 | 158 | 69 | | 6,111 | 588 | 3,940 | 32 | | 11 | | | | | | | | 4,571 |
| 69 | PPP - RD&D Balancing Account | (258) | (100) | (42) | (4) | (2) | | (147) | (14) | (95) | (1) | | (0) | | | | | | | | -110 |
| 70 | PPP-CARE Discount Allocation Set Annually | 116,811 | 38,720 | 20,799 | 1,889 | 823 | | 62,231 | 7,015 | 47,049 | 381 | | 135 | | | | | | | | 54,580 |
| 71 | PPP-CARE Administration Expense | 3,696 | 1,225 | 658 | 60 | 26 | | 1,969 | 222 | 1,489 | 12 | | 4 | | | | | | | | 1,727 |
| 72 | PPP-CARE Balancing Account | (16,886) | (5,597) | (3,007) | (273) | (119) | | (8,996) | (1,014) | (6,801) | (55) | | (19) | | | | | | | | -7,890 |
| 73 | PPP-Admin Cost for BOE and CPUC | 416 | 161 | 68 | 6 | 3 | | 238 | 23 | 153 | 1 | | 0 | | | | | | | | 178 |
| 74 | Subtotal of Public Purpose Program Surcharges | $248,027.130 | $143,819 | $30,939 | $6,035 | $800 | $0 | $181,593 | $10,410 | $55,445 | $448 | $0 | $131 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $66,434 |
| 75 | Totals by End-User Customer Class (excludes Unbundled GT&S) | $3,400,153 | $2,215,170 | $592,190 | $39,088 | $9,651 | $3,446 | $2,859,544 | $82,800 | $267,245 | $753 | $184,428 | $655 | $305 | $3,795 | $76 | $284 | $58 | $209 | $4,235 | $540,609 |
| 76 | Unbundled Gas Transmission and Storage Revenue Requirement | $230,866 | | | | | | | | | | | | | | | | | | | |
| | | Total RRQ | 2,898,437 | 781,099 | 53,413 | 15,418 | 3,446 | 3,751,812 | 82,800 | 267,245 | 753 | 184,428 | 655 | 305 | 3,795 | 76 | 284 | 58 | 209 | 4,235 | 540,609 |

| Line No. | **TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES** | | |
|---|---|---|---|
| 77 | Total Transportation, PPPS,and Unbundled Costs | $3,631,019 | (Total of lines 75 + 76) |
| 78 | Cross-check with Gas Revenue Requirement Table | $3,651,983 | Attachment 1 Line 35 |
| 79 | Difference | 20,965 | |
| 80 | Reconciliation Due to Local Transmission Seed Credit | 20,965 | |
| 81 | Difference | 0 | |

| **Cal P.U.C. Sheet No.** | **Title of Sheet** | **Cancelling Cal P.U.C. Sheet No.** |
|---|---|---|
| 33923-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 12 | 33525-G |
| 33924-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 13 | 33526-G |
| 33925-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 14 | 33527-G |
| 33926-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 15 | 33528-G |
| 33927-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 16 | 33529-G |
| 33928-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 17 | 33530-G |
| 33929-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 18 | 33531-G |
| 33930-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 19 | 33532-G |
| 33931-G | GAS PRELIMINARY STATEMENT PART B<br>DEFAULT TARIFF RATE COMPONENTS<br>Sheet 20 | 33533-G |
| 33932-G | GAS PRELIMINARY STATEMENT PART C<br>GAS ACCOUNTING TERMS & DEFINITIONS<br>Sheet 2 | 33534-G |
| 33933-G | GAS PRELIMINARY STATEMENT PART C<br>GAS ACCOUNTING TERMS & DEFINITIONS<br>Sheet 3 | 33535-G |
| 33934-G | GAS PRELIMINARY STATEMENT PART C<br>GAS ACCOUNTING TERMS & DEFINITIONS<br>Sheet 4 | 33536-G |
| 33935-G | GAS PRELIMINARY STATEMENT PART C<br>GAS ACCOUNTING TERMS & DEFINITIONS<br>Sheet 5 | 33537-G |
| 33936-G | GAS PRELIMINARY STATEMENT PART O<br>CPUC REIMBURSEMENT FEE<br>Sheet 1 | 33487-G |

| Cal P.U.C. Sheet No. | Title of Sheet | Cancelling Cal P.U.C. Sheet No. |
|---|---|---|
| 33937-G | GAS SCHEDULE G-AA<br>AS AVAILABLE TRANSPORTATION ON-SYSTEM<br>Sheet 2 | 33085-G |
| 33938-G | GAS SCHEDULE G-AAOFF<br>AS-AVAILABLE TRANSPORTATION OFF-SYSTEM<br>Sheet 2 | 33086-G |
| 33939-G | GAS SCHEDULE G-AFT<br>ANNUAL FIRM TRANSPORTATION ON-SYSTEM<br>Sheet 2 | 33087-G |
| 33940-G | GAS SCHEDULE G-AFTOFF<br>ANNUAL FIRM TRANSPORTATION OFF-SYSTEM<br>Sheet 2 | 33088-G |
| 33941-G | GAS SCHEDULE G-BAL<br>GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS<br>Sheet 4 | 33089-G |
| 33942-G | GAS SCHEDULE G-CFS<br>CORE FIRM STORAGE<br>Sheet 1 | 33090-G |
| 33943-G | GAS SCHEDULE G-EG<br>GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION<br>Sheet 1 | 33120-G |
| 33944-G | GAS SCHEDULE G-EG<br>GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION<br>Sheet 2 | 33538-G |
| 33945-G | GAS SCHEDULE G-LEND<br>MARKET CENTER LENDING SERVICES<br>Sheet 1 | 33091-G |
| 33946-G | GAS SCHEDULE G-LNG<br>EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE<br>Sheet 1 | 33539-G |
| 33947-G | GAS SCHEDULE G-NAS<br>NEGOTIATED AS-AVAILABLE STORAGE SERVICE<br>Sheet 1 | 33092-G |
| 33948-G | GAS SCHEDULE G-NFS<br>NEGOTIATED FIRM STORAGE SERVICE<br>Sheet 1 | 33093-G |
| 33949-G | GAS SCHEDULE G-NGV4<br>NONCORE NATURAL GAS SERVICE<br>FOR COMPRESSION ON CUSTOMERS' PREMISES<br>Sheet 1 | 33123-G |

| **Cal P.U.C. Sheet No.** | **Title of Sheet** | **Cancelling Cal P.U.C. Sheet No.** |
|---|---|---|
| 33950-G | GAS SCHEDULE G-NGV4<br>NONCORE NATURAL GAS SERVICE<br>FOR COMPRESSION ON CUSTOMERS' PREMISES<br>Sheet 2 | 33540-G |
| 33951-G | GAS SCHEDULE G-NT<br>GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS<br>Sheet 1 | 33125-G |
| 33952-G | GAS SCHEDULE G-NT<br>GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS<br>Sheet 2 | 33541-G |
| 33953-G | GAS SCHEDULE G-PARK<br>MARKET CENTER PARKING SERVICES<br>Sheet 1 | 33094-G |
| 33954-G | GAS SCHEDULE G-SFS<br>STANDARD FIRM STORAGE SERVICE<br>Sheet 1 | 33095-G |
| 33955-G | GAS SCHEDULE G-SFT<br>SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY<br>Sheet 2 | 33096-G |
| 33956-G | GAS SCHEDULE G-WSL<br>GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS<br>Sheet 1 | 33542-G |
| 33957-G | GAS SCHEDULE G-XF<br>PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE<br>Sheet 1 | 33097-G |
| 33958-G | GAS TABLE OF CONTENTS<br>Sheet 1 | 33919-G |
| 33959-G | GAS TABLE OF CONTENTS<br>Sheet 2 | 33920-G |
| 33960-G | GAS TABLE OF CONTENTS<br>Sheet 3 | 33921-G |
| 33961-G | GAS TABLE OF CONTENTS<br>Sheet 4 | 33922-G |

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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

NONCORE
p. 1

| THERMS: | G-NT TRANSMISSION | | G-NT—DISTRIBUTION SUMMER 0-20,833 | | 20,834-49,999 | | 50,000-166,666 | | 166,667-249,999*** | |
|---|---|---|---|---|---|---|---|---|---|---|
| NCA – NONCORE | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00934 | (I) | 0.21367 | (I) | 0.13318 | (I) | 0.11674 | (I) | 0.10388 | (I) |
| CPUC FEE | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) |
| CSI- SOLAR THERMAL PROGRAM | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) |
| CEE INCENTIVE | 0.00000 | | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) |
| LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) |
| NCA - ARB AB32 COI | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.13735** | (I) | **0.34168** | (I) | **0.26119** | (I) | **0.24475** | (I) | **0.23189** | (I) |

* All tariff rate components on the sheet include an allowance for Revenue Fees and Uncollectible (RF&U) accounts expense.

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

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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

| | G-NT BACKBONE | | G-NT—DISTRIBUTION WINTER | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| THERMS: | | | 0-20,833 | | 20,834-49,999 | | 50,000-166,666 | | 166,667-249,999*** | |
| NCA – NONCORE | 0.02203 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00000 | | 0.29138 | (I) | 0.18272 | (I) | 0.16052 | (I) | 0.14317 | (I) |
| CPUC FEE | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) |
| CSI- SOLAR THERMAL PROGRAM | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) |
| CEE INCENTIVE | 0.00000 | | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) |
| LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3) | 0.00000 | | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) |
| NCA - ARB AB32 COI | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.00000 | | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.02563** | (I) | **0.41939** | (I) | **0.31073** | (I) | **0.28853** | (I) | **0.27118** | (I) |

* All tariff rate components on the sheet include an allowance for Revenue Fees and Uncollectible (RF&U) accounts expense.

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

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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



| | G-EG (2)** | | G-EG BACKBONE | |
|---|---|---|---|---|
| NCA – NONCORE | 0.02337 | (I) | 0.02202 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00292 | (I) | 0.00294 | (I) |
| CPUC FEE | 0.00007 | (I) | 0.00007 | (I) |
| CSI- SOLAR THERMAL PROGRAM | 0.00000 | | 0.00000 | |
| CEE INCENTIVE | 0.00000 | | 0.00000 | |
| LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3) | 0.08286 | (I) | 0.00000 | |
| NCA - ARB AB32 COI | 0.00133 | (I) | 0.00133 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.01818 | | 0.00000 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.12770** | (I) | **0.02533** | (I) |

* All tariff rate components on the sheet include an allowance for Revenue Fees and Uncollectible (RF&U) accounts expense.

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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

NONCORE p. 4

| | G-WSL | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Palo Alto-T | | Coalinga-T | | Island Energy-T | | Alpine-T | |
| NCA – NONCORE | 0.02151 | (I) | 0.02151 | (I) | 0.02151 | (I) | 0.02151 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00000 | | 0.00000 | | 0.00000 | | 0.00000 | |
| CPUC FEE** | 0.00000 | | 0.00000 | | 0.00000 | | 0.00000 | |
| CSI- SOLAR THERMAL PROGRAM | 0.00000 | | 0.00000 | | 0.00000 | | 0.00000 | |
| CEE INCENTIVE | 0.00000 | | 0.00000 | | 0.00000 | | 0.00000 | |
| LOCAL TRANSMISSION (AT RISK) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.12152** | (I) | **0.12152** | (I) | **0.12152** | (I) | **0.12152** | (I) |

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

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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

| | G-WSL | | | | | |
|---|---|---|---|---|---|---|
| | West Coast Mather-T | | West Coast Mather-D | | West Coast Castle-D | |
| NCA – NONCORE | 0.02151 | (I) | 0.02150 | (I) | 0.02150 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00000 | | 0.24935 | (I) | 0.18831 | (I) |
| CPUC FEE** | 0.00000 | | 0.00000 | | 0.00000 | |
| CSI- SOLAR THERMAL PROGRAM | 0.00000 | | 0.00000 | | 0.00000 | |
| CEE INCENTIVE | 0.00000 | | 0.00000 | | 0.00000 | |
| LOCAL TRANSMISSION (AT RISK) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.01818 | | 0.01818 | | 0.01818 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.12152** | (I) | **0.37086** | (I) | **0.30982** | (I) |

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

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)* NONCORE p. 6

| | G-NGV4 TRANSMISSION | | G-NGV4—DISTRIBUTION SUMMER | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| THERMS: | | | 0-20,833 | | 20,834-49,999 | | 50,000-166,666 | | 166,667-249,999 | |
| NCA – NONCORE | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00000 | | 0.21367 | (I) | 0.13318 | (I) | 0.11674 | (I) | 0.10388 | (I) |
| CPUC FEE | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) |
| CSI- SOLAR THERMAL PROGRAM | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) |
| CEE INCENTIVE | 0.00000 | | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) |
| LOCAL TRANSMISSION (AT RISK) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) |
| NCA - ARB AB32 COI | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.12801** | (I) | **0.34168** | (I) | **0.26119** | (I) | **0.24475** | (I) | **0.23189** | (I) |

* All tariff rate components on the sheet include an allowance for Revenue Fees and Uncollectible (RF&U) accounts expense.

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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

NONCORE p. 7

| | G-NGV4 BACKBONE | | G—NGV4-DISTRIBUTION WINTER | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| THERMS: | | | 0-20,833 | | 20,834-49,999 | | 50,000-166,666 | | 166,667-249,999 | |
| NCA – NONCORE | 0.02203 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) | 0.02337 | (I) |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00000 | | 0.29138 | (I) | 0.18272 | (I) | 0.16052 | (I) | 0.14317 | (I) |
| CPUC FEE | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | (I) | 0.00168 | | 0.00168 | (I) |
| CSI- SOLAR THERMAL PROGRAM | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) | 0.00162 | (R) |
| CEE INCENTIVE | 0.00000 | | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) | 0.00000 | (R) |
| LOCAL TRANSMISSION (AT RISK) | 0.00000 | | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) | 0.08286 | (I) |
| NCA - ARB AB32 COI | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) | 0.00133 | (I) |
| 2015 GT&S LATE IMPLEMENTATION AMORT – LT | 0.00000 | | 0.01818 | | 0.01818 | | 0.01818 | | 0.01818 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – BB | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | | 0.00163 | |
| 2015 GT&S LATE IMPLEMENTATION AMORT – Storage | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | | (0.00266) | |
| **TOTAL RATE** | **0.02563** | (I) | **0.41939** | (I) | **0.31073** | (I) | **0.28853** | (I) | **0.27118** | (I) |

* All tariff rate components on the sheet include an allowance for Revenue Fees and Uncollectible (RF&U) accounts expense.

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

(Continued)

**GAS PRELIMINARY STATEMENT PART B**
DEFAULT TARIFF RATE COMPONENTS



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



| | G-LNG (1)* | |
|---|---|---|
| NCA – NONCORE | 0.00000 | |
| NCA – DISTRIBUTION SUBACCOUNT | 0.00000 | |
| CPUC Fee | 0.00168 | (I) |
| CSI- SOLAR THERMAL PROGRAM | 0.00000 | |
| CEE INCENTIVE | 0.00000 | |
| LNG BALANCING ACCOUNT | 0.26370 | (I) |
| LOCAL TRANSMISSION (AT RISK) | 0.00000 | |
| **TOTAL RATE** | **0.26538** | **(I)** |

* All tariff rate components on the sheet include an allowance for Revenue Fees and Uncollectible (RF&U) accounts expense.

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

(Continued)

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

**MAINLINE EXTENSION RATES (1)**

| Core Schedules (2) | Mainline Extension Rate (Per Therm) (T) | | Core Customer Charges (3) ADU (therms) (4) | Per Day |
|---|---|---|---|---|
| Schedule G-NR1 | $0.33247 | (I) | 0 – 5.0 | $0.27048 |
| | | | 5.1 to 16.0 | $0.52106 |
| | | | 16.1 to 41.0 | $0.95482 |
| | | | 41.1 to 123.0 | $1.66489 |
| | | | 123.1 & Up | $2.14936 |
| Schedule G-NR2 | $0.14276 | (I) | All Usage Levels | $4.95518 |
| Schedule G-NGV1 | $0.07478 | (I) | All Usage Levels | $0.44121 |
| Schedule G-NGV2 | N/A | | All Usage Levels | N/A |

| Noncore Schedules | Mainline Extension Rate (Per Therm) (T) | |
|---|---|---|
| Schedule G-NT | | |
| Distribution | $0.15931 | (I) |
| Local Transmission | $0.00983 | (I) |
| Backbone | $0.00000 | |
| Schedule G-EG | | |
| Distribution | $0.00308 | (I) |
| Local Transmission | $0.00308 | (I) |
| Backbone | $0.00308 | (I) |
| Schedule G-NGV4 | | |
| Distribution | $0.15931 | (I) |
| Local Transmission | $0.00000 | |
| Backbone | $0.00000 | |

| Noncore Customer Access Charges (5) Average Monthly Use (Therms) | Per Day | |
|---|---|---|
| 0 to 5,000 | $1.10893 | (R) |
| 5,001 to 10,000 | $3.30279 | (R) |
| 10,001 to 50,000 | $6.14729 | (R) |
| 50,001 to 200,000 | $8.06762 | (R) |
| 200,001 to 1,000,000 | $11.70542 | (R) |
| 1,000,001 and above | $99.29227 | (R) |

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

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

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

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

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

(Continued)

## GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

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

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

Amount ($000)

| Description | Core | | Noncore | | Unbundled | Core Procurement | Total | |
|---|---|---|---|---|---|---|---|---|
| BASE REVENUES (incl. RF&U) : | | | | | | | | (T) |
| Authorized GRC Distribution Base Revenue (1) | | | | | | | 1,853,950 | (I) |
| Pension - Distribution (2) | | | | | | | 51,922 | (I) |
| Less: Other Operating Revenue | | | | | | | (28,091) | |
| **Authorized Distribution Revenues** | 1,812,409 | (I) | 65,371 | (I) | | | 1,877,780 | (I) |
| BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE: | | | | | | | | |
| G-10 Procurement-Related Employee Discount | (664) | (I) | | | | | (664) | (I) |
| G-10 Procurement Discount Allocation | 262 | (R) | 402 | (R) | | | 664 | (R) |
| Core Brokerage Fee Credit | (6,583) | | | | | | (6,583) | |
| **Distribution Base Revenue with Adj. and Credits** | 1,805,424 | (I) | 65,773 | (I) | | | 1,871,197 | (I) |
| TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3): | | | | | | | | |
| Transportation Balancing Accounts | 313,389 | (R) | 87,644 | (I) | | | 401,033 | (I) |
| Self-Generation Incentive Program Revenue Requirement | 5,149 | | 7,841 | (I) | | | 12,990 | (I) |
| CPUC Fee | 4,808 | (I) | 3,027 | (I) | | | 7,835 | (I) |
| Pension – Gas Transmission & Storage (GT&S) | 12,448 | (I) | 7,160 | (I) | | | 19,608 | (I) |
| Revenue Fees and Uncollectible (RF&U) accounts expense (on items above) | 4,331 | (R) | 1,324 | (I) | | | 5,655 | (I) |
| CARE Discount included in PPP Funding Requirement | (116,811) | (I) | | | | | (116,811) | (I) |
| CARE Discount not included in PPP Surcharge Rates | 0 | | | | | | 0 | |
| **Transportation Forecast Period Costs & Balancing Account Balances** | 223,314 | (R) | 106,996 | (I) | | | 330,310 | (I) |
| GT&S REVENUE REQUIREMENT (incl. RF&U) (4): | | | | | | | | |
| Local Transmission | 536,850 | (I) | 255,490 | (I) | | | 792,340 | (I) |
| Customer Access Charge – Transmission | | | 2,507 | (R) | | | 2,507 | (R) |
| Storage | 74,593 | (I) | | | 13,762 | | 88,355 | (I) |
| Carrying Cost on PG&E Working Gas in Storage | 2,275 | (I) | | | 21 | | 2,296 | (I) |
| Backbone Transmission/L-401 | 130,370 | (I) | | | 217,083 | | 347,453 | (I) |
| **GT&S Revenue Requirement** | 744,088 | (I) | 257,997 | (I) | 230,866 | | 1,232,951 | (I) |

(1) The amount includes the authorized distribution base revenue approved in GRC D.17-05-013 and updated for the 2018 uncollectibles factor as determined in Advice 3896-G/5162-E. (T)

(2) Pursuant to D.09-09-020, PG&E will maintain the annual contribution to the Company's retirement plan trust fund at the adopted 2013 amount. The calculation of the 2018 pension RRQ reflects the capitalization and functional labor ratios approved in the 2017 GRC D.17-05-013. (T)

(3) The SGIP revenue requirement was authorized in D.17-04-017.

(4) The 2015 Gas Transmission & Storage Phase 2 Revenue Requirement was adopted in D.16-12-010.

*Some numbers may not add precisely due to rounding.

(Continued)

**GAS PRELIMINARY STATEMENT PART C** Sheet 3
GAS ACCOUNTING TERMS & DEFINITIONS

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

| Description | Amount ($000) Core | Noncore | Unbundled | Core Procurement | Total |
|---|---|---|---|---|---|
| ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5): | | | | | |
| Illustrative Gas Supply Portfolio | | | | 533,673 (R) | 533,673 (R) |
| Interstate and Canadian Capacity | | | | 139,218 (R) | 139,218 (R) |
| RF&U (on items above and Procurement Account Balances Below) | | | | 9,002 (R) | 9,002 (R) |
| Backbone Capacity (incl. RF&U) | (100,754) (R) | | | 100,754 (I) | 0 |
| Backbone Volumetric (incl. RF&U) | (29,616) (R) | | | 29,616 (I) | 0 |
| Storage (incl. RF&U) | (74,593) (R) | | | 74,593 (I) | 0 |
| Carrying Cost on PG&E Working Gas in Storage (incl. RF&U) | (2,275) (R) | | | 2,275 (I) | 0 |
| Core Brokerage Fee (incl. RF&U) | | | | 6,583 | 6,583 |
| Procurement Account Balances | | | | - | - |
| **Illus. Core Procurement Revenue Requirement** | (207,237) (R) | | | 895,713 (R) | 688,476 (R) |
| **TOTAL GAS REVENUE REQUIREMENT (without PPP)** | 2,565,589 (I) | 430,767 (I) | 230,866 | 895,713 (R) | 4,122,934 (R) |
| GT&S LATE IMPLEMENTATION REVENUE REQUIREMENT (7): | | | | | |
| Local Transmission | 121,559 | 54,588 | | | 176,147 |
| Backbone | (1,764) | 7,080 | | | 5,316 |
| Storage | 6,774 | (11,502) | | | (4,728) |
| **Total GT&S Late Implementation Revenue Requirement** | 126,569 | 50,166 | | | 176,735 |
| PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (RF&U exempt) (6): | | | | | |
| Energy Efficiency (EE) | 61,216 (R) | 6,814 | | | 68,030 (R) |
| Energy Savings Assistance (ESA) | 68,121 (I) | 7,583 (I) | | | 75,704 (I) |
| Research, Demonstration and Development (RD&D) | 6,111 (I) | 4,571 | | | 10,682 (R) |
| CARE Administrative Expense | 1,969 (I) | 1,727 (I) | | | 3,696 (I) |
| Statewide Marketing, Education & Outreach | 1,025 (I) | 114 (I) | | | 1,139 (I) |
| BOE and CPUC Administrative Cost | 238 (R) | 178 | | | 416 (R) |
| PPP Balancing Accounts | (19,316) (R) | (9,134) (R) | | | (28,450) (R) |
| CARE Discount Recovered from non-CARE customers | 62,231 (R) | 54,579 (R) | | | 116,810 (R) |
| **Total PPP Funding Requirement in Rates** | 181,595 (R) | 66,432 (R) | | | 248,027 (R) |
| **TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT** | 2,873,753 (I) | 547,365 (I) | 230,866 (I) | 895,713 (R) | 4,547,696 (R) |

(5) The credits shown in the Core column represent the core portion of the GT&S RRQ that is included in the illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly.
(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2018 PPP Surcharge AL 3901-G; and includes ESA program and CARE annual administrative expense funding adopted in D.14-08-030, EE program funding adopted in D.14-10-046 and D.15-10-028, excluding RF&U per D.04-08-010. (T)
(7) See Appendix J, Table 1 of D.16-12-010.

Note: Totals may not foot due to rounding.

(Continued)

**GAS PRELIMINARY STATEMENT PART C**
GAS ACCOUNTING TERMS & DEFINITIONS



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

3. COST ALLOCATION FACTORS:

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

| | Factor | | | |
|---|---|---|---|---|
| Cost Category | Core | Noncore | Unbundled Storage and System Load Balancing | Total |
| Distribution Base Revenue Requirements | 0.965187 (R) | 0.034813 (I) | | 1.000000 |
| Intervenor Compensation | 0.965187 (R) | 0.034813 (I) | | 1.000000 |
| Other – Equal Distribution Based on All Transportation Volumes | 0.394375 | 0.605625 | | 1.000000 |
| Carrying Cost on PG&E Working Gas in Storage | 0.807551 (R) | | 0.192449 (I) | 1.000000 |
| ARB AB32 Cost of Implementation Fee | 0.608811 (I) | 0.391189 (R) | | 1.000000 |

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

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

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

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

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

(Continued)

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

6. REVENUE FEES AND UNCOLLECTIBLE: See Gas Rule 1 for definition

The RF&U factor is equal to ................................................................................................ 1.013411 (I)

7. GAS SUPPLY PORTFOLIO: This portfolio includes the cost of gas procured by PG&E for its Core Portfolio (Core Procurement) customers. The costs and payouts for hedge instruments transacted under the core gas hedging plans, as approved in Decision 05-10-015 (effective October 6, 2005), Decision 06-08-027 (effective August 24, 2006), and Decision 07-06-013 (effective June 7, 2007) are included in the Gas Supply Portfolio, but are tracked separately. Gas Supply Portfolio costs are recovered through the Procurement Revenue Requirement described in Section C.10.d.

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

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

(Continued)

**GAS PRELIMINARY STATEMENT PART O** Sheet 1
CPUC REIMBURSEMENT FEE

O. CPUC REIMBURSEMENT FEE

1. REIMBURSEMENT FEE

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

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

c. The current CPUC Reimbursement Fee Rate is $0.00168 per therm including (T)
Revenue Fees and Uncollectible (RF&U) accounts expense for all applicable gas rate schedules (see Preliminary Statement, Part B), except for gas rate schedule G-EG (Electric Generation)

The current CPUC Reimbursement Fee Rate for gas rate schedule G-EG is
$0.00007 per therm including RF&U as adopted in PG&E's 2010 Biennial Cost (T)
Allocation Proceeding Decision 10-06-035.

2. MASTER-METERED MOBILEHOME PARK SAFETY PROGRAM SURCHARGE

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

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

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

**GAS SCHEDULE G-AA**
AS AVAILABLE TRANSPORTATION ON-SYSTEM



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

1. Usage Charge:

| Path: | Usage Rate (Per Dth) | |
|---|---|---|
| Redwood to On-System | $0.5409 | (I) |
| Baja to On-System | $0.5889 | (I) |
| Silverado to On-System | $0.3395 | (I) |
| Mission to On-System | $0.0000 | |

2. Additional Charges:

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

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

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

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

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

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

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

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

**GAS SCHEDULE G-AAOFF** Sheet 2
AS-AVAILABLE TRANSPORTATION OFF-SYSTEM

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

1. Usage Charge:

| Path: | Usage Rate (Per Dth) | |
|---|---|---|
| Redwood to Off-System | $0.5409 | (I) |
| Baja to Off-System | $0.5889 | (I) |
| Silverado to Off-System | $0.5409 | (I) |
| Mission to Off-System | $0.5409 | (I) |
| Mission to Off-System Storage Withdrawals | $0.0000 | |

2. Additional Charges:

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

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

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

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

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

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

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

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

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

**GAS SCHEDULE G-AFT** Sheet 2
ANNUAL FIRM TRANSPORTATION ON-SYSTEM

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

1. Reservation Charge:

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

| Path: | Reservation Rate (Per Dth per month) | | | |
|---|---|---|---|---|
| | MFV Rates | | SFV Rates | |
| Redwood to On-System | $10.1813 | (I) | $13.6814 | (I) |
| Redwood to On-System (Core Procurement Groups only) | $9.1607 | (I) | $11.8245 | (I) |
| Baja to On-System | $11.0848 | (I) | $14.8954 | (I) |
| Baja to On-System (N) (Core Procurement Groups only) (N) | $10.1008 | (I) | $13.0380 | (I) |
| Silverado to On-System (including Core Procurement Groups) | $6.4307 | (I) | $8.5814 | (I) |
| Mission to On-System (including Core Procurement Groups) | $6.4307 | (I) | $8.5814 | (I) |

2. Usage Charge:

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

| Path: | Usage Rate (Per Dth) | | | |
|---|---|---|---|---|
| | MFV Rates | | SFV Rates | |
| Redwood to On-System | $0.1160 | (I) | $0.0010 | (I) |
| Redwood to On-System (Core Procurement Groups only) | $0.0886 | (I) | $0.0010 | |
| Baja to On-System | $0.1263 | (I) | $0.0010 | |
| Baja to On-System (N) (Core procurement Groups only) (N) | $0.0977 | (I) | $0.0011 | |
| Silverado to On-System (including Core Procurement Groups) | $0.0715 | (I) | $0.0008 | (I) |
| Mission to On-System (including Core Procurement Groups) | $0.0715 | (I) | $0.0008 | (I) |
| Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only) | $0.0000 | | $0.0000 | |

(Continued)

**GAS SCHEDULE G-AFTOFF** Sheet 2
ANNUAL FIRM TRANSPORTATION OFF-SYSTEM

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

1. Reservation Charge:

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

| Path: | Reservation Rate (Per Dth per month) | | | |
|---|---|---|---|---|
| | MFV Rates | | SFV Rates | |
| Redwood to Off-System | $10.1813 | (I) | $13.6814 | (I) |
| Baja to Off-System | $11.0848 | (I) | $14.8954 | (I) |
| Silverado to Off-System | $10.1813 | (I) | $13.6814 | (I) |
| Mission to Off-System | $10.1813 | (I) | $13.6814 | (I) |

2. Usage Charge:

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

| Path: | Usage Rate (Per Dth) | | | |
|---|---|---|---|---|
| | MFV Rates | | SFV Rates | |
| Redwood to Off-System | $0.1160 | (I) | $0.0010 | (I) |
| Baja to Off-System | $0.1263 | (I) | $0.0010 | |
| Silverado to Off-System | $0.1160 | (I) | $0.0010 | (I) |
| Mission to Off-System | $0.1160 | (I) | $0.0010 | (I) |

3. Additional Charges:

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

(Continued)

**GAS SCHEDULE G-BAL** Sheet 4
GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MONTHLY BALANCING OPTIONS: (Cont'd.)

CASHOUT FOR MONTHLY BALANCING:

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

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

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

SELF-BALANCING OPTION:

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

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

SELF-BALANCING CREDIT:

The Self-Balancing option allows a Balancing Agent to receive a credit. The Self-Balancing credit is $0.0200 (I) per Decatherm multiplied by the actual recorded monthly usage. Credits will be provided to the Balancing Agent on a monthly basis, subject to adjustments. (T)

LIMIT ON SELF-BALANCING PARTICIPATION:

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

(Continued)

# GAS SCHEDULE G-CFS
## CORE FIRM STORAGE



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

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

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

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

ALLOCATED STORAGE MONTHLY CHARGE: CTAs and CGS holding an allocation of core firm storage (Allocated Storage), pursuant to the provisions of Schedule G-CT, will be billed each month based upon the amount of Allocated Storage held for all or a portion of the current month. The monthly charge is calculated by multiplying the applicable monthly rate, shown below, by the inventory quantity associated with the CTA's and CGS' Allocated Storage for that month subject to proration in the event of an assignment of Allocated Storage during the current month.

Reservation Charge per Dth per month $0.1913 (I)

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

SERVICE AGREEMENT: A <u>Gas Transmission Service Agreement</u> (GTSA) (Form No. 79-866) and applicable exhibit(s) and an Electronic Commerce System User Agreement (Form No. 79-982) are required for CTAs and CGS taking service under this Rate Schedule.

TERM: Core firm storage is allocated for a one-year term starting on April 1 and ending on March 31 of the following year (Storage Year), and may be assigned by CTA and CGS under the provisions of Assignment Of Allocated Storage, specified below.

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

ANNUAL INVENTORY/ INJECTION/ WITHDRAWAL: This schedule provides the Annual Inventory including the firm injection and withdrawal capacities for CTAs and CGS. It also specifies month-end minimum inventory targets for CTAs and CGS.

<u>Annual Inventory (AI)</u>

PG&E's Total Core Storage Capacity Reservation is:

Annual Inventory 33,477,700 Dth

The CTA Groups Annual Inventory is calculated as follows:

Calculations are in Dth.

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

(Continued)

**GAS SCHEDULE G-EG** Sheet 1
GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

APPLICABILITY: This rate schedule* applies to the transportation of natural gas used in: (a) electric generation plants served directly from PG&E gas facilities that have a maximum operation pressure greater than sixty pounds per square inch (60 psi); (b) all Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 216.6** and other electric generation facilities that meet an overall electric efficiency of at least 45%; (c) solar electric generation plants, defined herein and (d) Advanced Electrical Distributed Generation technology that meets all of the conditions specified in Public Utilities Code Section 379.8, as defined in Rule 1, and are first operational at a site prior to January 1, 2016. This schedule does not apply to gas transported to non-electric generation loads.

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

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

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

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

1. Customer Access Charge:

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

| Average Monthly Use (Therms) | Per Day | |
|---|---|---|
| 0 to 5,000 therms | $1.10893 | (R) |
| 5,001 to 10,000 therms | $3.30279 | (R) |
| 10,001 to 50,000 therms | $6.14729 | (R) |
| 50,001 to 200,000 therms | $8.06762 | (R) |
| 200,001 to 1,000,000 therms | $11.70542 | (R) |
| 1,000,001 and above therms | $99.29227 | (R) |

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

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

(Continued)

**GAS SCHEDULE G-EG** Sheet 2

GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

RATES: (Cont'd.)

2. Transportation Charge:

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

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

      Backbone Level Rate: $0.02533 per therm (I)

   b. All Other Customers: $0.12770 per therm (I)

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

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

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

NEGOTIABLE RATES: Rates under this schedule may be negotiated.

NEGOTIATED RATE GUIDELINES:

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

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

3. PG&E will issue monthly reports to the Commission listing all negotiated contracts, including those negotiated under G-EG. PG&E will make the report available to others upon request. Customer names, including PG&E's affiliates and other departments, will not be provided in the report. However, the report will indicate whether a particular transaction was with an affiliate. The report will show the negotiated rates and dates of service.

METER REQUIREMENT: All electric generation load served under this schedule shall be separately metered using a PG&E-owned and installed gas meter, unless it can be demonstrated that it is not economically feasible. For generation facilities without a separate PG&E installed gas meter, the volume of gas transported under this schedule will be determined under the provisions of the Limitation of Gas Use section below.

(Continued)

**GAS SCHEDULE G-LEND** Sheet 1

MARKET CENTER LENDING SERVICES

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

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

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

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

Minimum Rate (per transaction): .......................................... $57.00

Maximum Rate (per Dth per day): ........................................ $1.1650 (R)

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

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

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

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

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

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

(Continued)

**GAS SCHEDULE G-LNG** Sheet 1

EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE

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

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

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

| | |
|---|---|
| Liquefaction Charge (Per Therm): | $0.26538 (I) |
| LNG Gallon Equivalent:<br>(Conversion factor - One LNG Gallon = 0.82 Therms) | $0.21761 (I) |

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

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

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

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

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

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

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

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

(Continued)

**GAS SCHEDULE G-NAS** Sheet 1

NEGOTIATED AS-AVAILABLE STORAGE SERVICE

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

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

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

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

| | Maximum Rates (Per Dth/Day) | |
|---|---|---|
| Injection | $5.7236 | (R) |
| Withdrawal | $26.1629 | (R) |

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

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

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

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

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

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

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

## GAS SCHEDULE G-NFS
NEGOTIATED FIRM STORAGE SERVICE



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

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

RATES: Rates under this schedule are negotiable and may be structured as one-part rates (Usage or Reservation Charge) or two-part rates (both Reservation and Usage Charges), as negotiated between the Customer and PG&E. Reservation Charges, if applicable, shall be based on the injection, inventory, and/or withdrawal quantities specified in the Exhibit E to the Gas Transmission Service Agreement (GTSA) (Form 79-866-E). Any Usage Charges shall be equal to the applicable effective rate in the GTSA multiplied by the actual injection, inventory, or withdrawal quantities occurring during that billing period, including volumes traded pursuant to Schedule G-BAL. Any injections and withdrawals which occur during a billing period, but which are not recorded in that billing period, will be deferred to a future billing period.

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

| | Maximum Rates (Dth) | |
|---|---|---|
| Injection/Day | $5.7236 | (R) |
| Inventory | $3.5541 | (R) |
| Withdrawal/Day | $26.1629 | (R) |

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

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

(Continued)

**GAS SCHEDULE G-NGV4** Sheet 1
NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

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

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

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

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

The following charges apply to service under this schedule:

1. Customer Access Charge:

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

| Average Monthly Use (Therms) | Per Day | |
|---|---|---|
| 0 to 5,000 | $1.10893 | (R) |
| 5,001 to 10,000 | $3.30279 | (R) |
| 10,001 to 50,000 | $6.14729 | (R) |
| 50,001 to 200,000 | $8.06762 | (R) |
| 200,001 to 1,000,000 | $11.70542 | (R) |
| 1,000,001 and above | $99.29227 | (R) |

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

(Continued)

**GAS SCHEDULE G-NGV4** Sheet 2
NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

RATES: (Cont'd.)

2. Transportation Charge:

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

a. Backbone Level Rate:

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

Backbone Level Rate (per therm) .................................... $0.02563 (I)

b. Transmission-Level Rate:

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

Transmission-Level Rate (per therm)............................... $0.12801 (I)

c. Distribution-Level Rate:

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

| Average Monthly Use (Therms) | Summer (Per Therm) | | Winter (Per Therm) | |
|---|---|---|---|---|
| Tier 1: 0 to 20,833 | $0.34168 | (I) | $0.41939 | (I) |
| Tier 2: 20,834 to 49,999 | $0.26119 | (I) | $0.31073 | (I) |
| Tier 3: 50,000 to 166,666 | $0.24475 | (I) | $0.28853 | (I) |
| Tier 4: 166,667 to 249,999 | $0.23189 | (I) | $0.27118 | (I) |
| Tier 5: 250,000 and above* | $0.12801 | (I) | $0.12801 | (I) |

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES FEES AND TAXES:

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

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

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* Tier 5 Summer and Winter rates are the same.

(Continued)

# GAS SCHEDULE G-NT
Sheet 1

## GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

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

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

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

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

1. Customer Access Charge:

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

| Average Monthly Use (Therms) | Per Day | |
|---|---|---|
| 0 to 5,000 | $1.10893 | (R) |
| 5,001 to 10,000 | $3.30279 | (R) |
| 10,001 to 50,000 | $6.14729 | (R) |
| 50,001 to 200,000 | $8.06762 | (R) |
| 200,001 to 1,000,000 | $11.70542 | (R) |
| 1,000,001 and above | $99.29227 | (R) |

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

(Continued)

**GAS SCHEDULE G-NT** Sheet 2
GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

RATES: (Cont'd.)

2. Transportation Charge:

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

a. Backbone Level Rate:

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

Backbone Level Rate (per therm): $0.02563 (I)

b. Transmission-Level Rate:

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

Transmission-Level Rate (per therm): $0.13735 (I)

c. Distribution-Level Rate:

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

| Average Monthly Use (Therms) | Summer (Per Therm) | | Winter (Per Therm) | |
|---|---|---|---|---|
| Tier 1: 0 to 20,833 | $0.34168 | (I) | $0.41939 | (I) |
| Tier 2: 20,834 to 49,999 | $0.26119 | (I) | $0.31073 | (I) |
| Tier 3: 50,000 to 166,666 | $0.24475 | (I) | $0.28853 | (I) |
| Tier 4: 166,667 to 249,999 | $0.23189 | (I) | $0.27118 | (I) |
| Tier 5: 250,000 and above* | $0.13735 | (I) | $0.13735 | (I) |

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES, FEES AND TAXES:

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

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

* Tier 5 Summer and Winter rates are the same.

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

(Continued)

# GAS SCHEDULE G-PARK
## MARKET CENTER PARKING SERVICES



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

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

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

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

Minimum Rate (per transaction): ........................................ $57.00

Maximum Rate (per Dth per day): ....................................... $1.1650 (R)

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

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

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

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

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

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

(Continued)

## GAS SCHEDULE G-SFS
STANDARD FIRM STORAGE SERVICE



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

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

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

1. Reservation Charges:

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

   Reservation Charge per Dth of Contract Inventory per month.......... $0.2962 (R)

2. Additional Charges:

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

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

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**GAS SCHEDULE G-SFT** Sheet 2
SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY

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

1. Reservation Charge:

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

| Path: | Reservation Rate (Per Dth per month) | | | |
|---|---|---|---|---|
| | MFV Rates | | SFV Rates | |
| Redwood to On-System | $12.2175 | (I) | $16.4176 | (I) |
| Baja to On-System | $13.3017 | (I) | $17.8745 | (I) |
| Baja to On-System (Core Procurement Groups only) | $12.1209 | (I) | $15.6456 | (I) |
| Silverado to On-System | $7.7168 | (I) | $10.2977 | (I) |
| Mission to On-System | $7.7168 | (I) | $10.2977 | (I) |

2. Usage Charge:

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

| Path: | Usage Rate (Per Dth) | | | |
|---|---|---|---|---|
| | MFV Rates | | SFV Rates | |
| Redwood to On-System | $0.1392 | (I) | $0.0012 | (I) |
| Baja to On-System | $0.1516 | (I) | $0.0013 | (I) |
| Baja to On-System (Core Procurement Groups only) | $0.1172 | (I) | $0.0013 | |
| Silverado to On-System | $0.0858 | (I) | $0.0009 | |
| Mission to On-System | $0.0858 | (I) | $0.0009 | |

3. Additional Charges:

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

(Continued)

# GAS SCHEDULE G-WSL



## GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS

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

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

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

1. Customer Access Charge:

| | Per Day | |
|---|---|---|
| Palo Alto | $78.30247 | (R) |
| Coalinga | $23.48416 | (R) |
| West Coast Gas-Mather | $12.46685 | (R) |
| Island Energy | $15.91167 | (R) |
| Alpine Natural Gas | $5.30992 | (R) |
| West Coast Gas-Castle | $13.64186 | (R) |

2. Transportation Charges:

For gas delivered in the current billing month:

| | Per Therm | |
|---|---|---|
| Palo Alto-T | $0.12152 | (I) |
| Coalinga-T | $0.12152 | (I) |
| West Coast Gas-Mather-T | $0.12152 | (I) |
| West Coast-Mather-D | $0.37086 | (I) |
| Island Energy-T | $0.12152 | (I) |
| Alpine Natural Gas-T | $0.12152 | (I) |
| West Coast Gas-Castle-D | $0.30982 | (I) |

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

(Continued)

**GAS SCHEDULE G-XF** Sheet 1

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

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

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

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

1. Reservation Charge:

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

| Reservation Rates: | Per Dth Per Month |
|---|---|
| SFV Rates: | $5.7955 (I) |

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

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

(Continued)

| TITLE OF SHEET | CAL P.U.C. SHEET NO. | |
|---|---|---|
| Title Page | **33958**-G | (T) |
| Rate Schedules | **33959**,**33960**-G | (T) |
| Preliminary Statements | **33961**,33775-G | (T) |
| Preliminary Statements, Rules | 33606-G | |
| Rules, Maps, Contracts and Deviations | 33776-G | |
| Sample Forms | 31943,32986,32987,32886,32887,32888-G | |

(Continued)

**GAS TABLE OF CONTENTS** Sheet 2



(Continued)

## GAS TABLE OF CONTENTS





(Continued)

## GAS TABLE OF CONTENTS





(Continued)

# <u>Attachment 7</u>

## Confidential: PG&E’s 2018 Natural Gas GHG Limit

# <u>Attachment 8</u>

## Confidentiality Declaration

**DECLARATION SUPPORTING**
**CONFIDENTIAL DESIGNATION**
**ON BEHALF OF**
**PACIFIC GAS AND ELECTRIC COMPANY**

1. I, Leslie Almond, am a/the Case Manager, Expert, in the Regulatory Proceedings section at Pacific Gas and Electric Company ("PG&E"), a California corporation. Robert Kenney, the Vice President, Regulatory Affairs, delegated authority to me to sign this declaration. My business office is located at:

   Pacific Gas and Electric Company
   77 Beale Street
   Mailstop B23A
   San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

   Name or Docket No. of CPUC Proceeding: *Rulemaking (R.) 14-03-003, Order Instituting Rulemaking to Address Natural Gas Distribution Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions*

3. Title and description of document(s): *Advice Letter 3919-G, Pacific Gas and Electric Company's Annual Gas True-Up of Gas Transportation Balancing Accounts for Rates Effective January 1, 2018*

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents have been marked as confidential, and the

basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart:

| Check | Basis for Confidential Treatment | Where Confidential Information is located on the documents |
|---|---|---|
| ☐ | Customer-specific data, which may include demand, loads, names, addresses, and billing data<br>(Protected under PUC § 8380; Civ. Code §§ 1798 *et seq.*; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029; and General Order (G.O.) 77-M) | |
| ☐ | Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual<br>(Protected under Civ. Code §§ 1798 *et seq.* and G.O. 66-C) | |
| ☐ | Physical facility or cyber-security sensitive data or critical energy infrastructure information (CEII), as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113<br>(Protected under Govt Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR §29.2) | |
| ☐ | Accident reports<br>(Protected under PUC § 315 and G.O. 66-C, 2.1) | |
| ☒ | Commercial records that, if revealed, would place PG&E at an unfair business disadvantage, including market-sensitive data; business plans and strategies; long-term fuel buying and hedging plans; price, load, or demand forecasts; power purchase agreements within three years of execution; and internal financial information<br>(Protected under Govt Code §§ 6254, 6276.44; Evid Code § 1060; Civ. Code § 3426 *et seq.;* G.O. 66-C, 2.2 (b) and D.15-10-032, Appendix B) | Attachment 7: 2018 Natural Gas GHG Limit in its entirety |
| ☐ | Proprietary and trade secret information or other intellectual property | |

| | | |
|---|---|---|
| | (Protected under Civ. Code § 3426 *et seq.;* Govt Code § 6254.15) | |
| ☐ | Corporate financial records<br>(Protected under Govt Code § 6254.15) | |
| ☐ | Third-Party information subject to non-disclosure or confidentiality agreements<br>(*See, eg.,* D.11-01-036) | |
| ☐ | Other basis: ______ | |

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 21st day of December, 2017 at San Francisco, California.

Leslie E. Almond
Case Manager, Expert
Regulatory Proceedings
Pacific Gas and Electric Company

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

AT&T
Albion Power Company
Alcantar & Kahl LLP
Anderson & Poole
Atlas ReFuel
BART
Barkovich & Yap, Inc.
Braun Blaising Smith Wynne P.C.
CalCom Solar
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 Research
Coast Economic Consulting
Commercial Energy
County of Tehama - Department of Public Works
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Dept of General Services
Division of Ratepayer Advocates
Don Pickett & Associates, Inc.
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
Energy Management Service
Evaluation + Strategy for Social Innovation
G. A. Krause & Assoc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
Green Power Institute
Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Leviton Manufacturing Co., Inc.
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
Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
SCE
SDG&E and SoCalGas
SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Utilities
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.
TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists
Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy