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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

Resolution E-4620
December 19, 2013

R E S O L U T I O N

Resolution E-4620. Pacific Gas and Electric Company (PG&E) consolidated electric revenue and rate changes effective January 1, 2014.

PROPOSED OUTCOME: Authorizes PG&E to revise electric rates effective January 1, 2014 to reflect revenue requirement changes approved by the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC) by December 19, 2013, and amortization of balancing accounts. Rate and revenue changes made pursuant to this Resolution are subject to audit, verification, and adjustment.

SAFETY CONSIDERATIONS: Pursuant to Public Utilities Code Section 451, PG&E must take all actions necessary to promote the safety, health, comfort, and convenience of utility patrons, employees, and the public.

ESTIMATED COST: The estimated net increase in annual electric revenue requirements is approximately $295.3 million for PG&E customers if the CPUC and FERC approve revenue requirements changes by December 19, 2013 in the proceedings identified herein.

By Advice Letters 4278-E/E-A filed on August 30, 2013 and September 16, 2013.

SUMMARY

Pacific Gas and Electric Company (PG&E) proposes to revise electric rates effective January 1, 2014 to reflect revenue requirement changes authorized in various proceedings by the California Public Utilities Commission (CPUC) and the Federal Electric Regulatory Commission (FERC) by December 19, 2013. This Resolution estimates a $295.3 million increase in PG&E's system-wide electric revenues, which is $16.7 million more than PG&E's estimate of $278.6 million. For revenue requirements that are not yet approved by the CPUC and the FERC, PG&E is using an estimated amount. PG&E will file a supplemental advice letter in late December 2013 to reflect amounts actually approved by the CPUC by December 19, 2012. PG&E's proposal is approved with modifications.

- Consistent with previous years' Annual Electric True-Up (AET) processes, PG&E shall submit a supplement to Advice Letter (AL) 4278-E by December 31, 2013 with revised tariffs effective January 1, 2014. The supplemental AL shall reflect only revenue requirement changes approved by the CPUC or the FERC by December 19, 2012, as described in this Resolution. The supplemental AL will also include recorded balancing account data through October 31, 2013, and forecasted account balances on December 31, 2013.
- The estimated increase in revenue requirement is $295.3 million over revenues at present rates, not $278.6 million as originally estimated by PG&E in AL 4278-E. The discrepancy results from a $16. 7 million refund that FERC authorized and PG&E implemented on October 1, 2013. PG&E did not incorporate this amount in AL 4278-E/E-A because the advice letter had been filed prior to the refund implementation date of October 1, 2013.
- PG&E is authorized to recover its full 2014, CPUC-approved revenue requirements in rates effective January 1, 2014 resulting from CPUC orders adopted by December 19, 2013, as described herein.
- PG&E is authorized to amortize its forecasted December 31, 2013 account balances, updated by the December supplement to AL 4278-E, in rates effective January 1, 2014, as described herein.
- Balances in balancing accounts authorized for recovery in rates shall be subject to future audit, verification, and adjustment.
- PG&E's request to establish the 2014 revenue requirement for the Energy Recovery Bonds Balancing Account (ERBBA) through AL 4278-E is

consistent with previous years' AET filings, provides the customer benefits intended in Decision (D.) 04-11-015, and is granted.

- If the December 31, 2013 supplement to AL 4278-E shows that PG&E's authorized January 1, 2014 revenues are lower than at present rates, PG&E requests the discretion to hold total electric revenue at present levels until a final decision is adopted in the 2014 PG&E GRC in order to avoid rate fluctuations. PG&E's request is granted to the extent that the orders authorizing the approved revenues do not require revenue requirement changes to be reflected in rates on January 1, 2014.
- PG&E's request to set January 1, 2014 rates based on the sales forecast in its 2014 Energy Resource Recovery Account (ERRA) Application (A.), A.13-05-015, regardless of whether a final decision is adopted in that proceeding by the December 19, 2013 CPUC meeting, is approved, on the condition that PG&E will adjust rates upon the approval of a final decision in the 2014 PG&E GRC to reflect the sales forecast adopted by the final decision in A.13-05-015, should the final ERRA decision include a different sales forecast than the one presented in the November 2013 update to A.13-05-015.
- The joint protest of Aglet Consumer Alliance, EMF Safety Network, and The Utility Reform Network is denied on the grounds that open proceedings included in AL 4278-E illustrative rates serve only as placeholders, and that PG&E will only consolidate revenue requirements authorized by the December 19, 2013 CPUC meeting in January 1, 2014 rates.

Attachment A to this Resolution includes an alphabetical list of terms and associated acronyms used herein.

PG&E forecasts a consolidated net revenue requirement increase of $278.6 million on January 1, 2014.

PG&E estimates that there will be a net increase in electric revenue requirements of approximately $278.6 million on January 1, 2014 incorporating various increases and decreases, authorized or to be authorized, resulting in a 2.4% increase in its system bundled average electric rates. The consolidated revenue requirement increase results from a combined $243.1 million increase in CPUC-jurisdictional revenues and a $35.5 million increase in FERC-jurisdictional revenues.

BACKGROUND

The AET is the vehicle that PG&E has used for many years to consolidate revenue requirements that have been authorized by the end of a given year by the CPUC or the FERC for recovery, and to amortize balances in regulatory accounts. Rate changes addressed in the AET become effective on January 1 of the following year after the CPUC acts on the AL.

The major electric utilities generally change rates two to three times per year to implement revenue requirements and rate design changes authorized by the CPUC and FERC. For example, in 2013, PG&E changed electric rates on January 1, May 1, and October 1. The January 1, 2013 rate change occurred through the AET process as described below. PG&E's electric rate changes on May 1, 2013 and October 1, 2013 were made pursuant to CPUC and FERC orders that authorized rate changes to be made effective later in the year. Although electric transmission rates are set by the FERC, they are presented in the AET due to their incorporation into PG&E's overall rate design used to calculate system-wide rates.

On August 31, 2012 PG&E filed AL 4096-E, its 2012 AET, in which it proposed to consolidate electric revenue requirements authorized by the CPUC and the FERC, and to recover balances in regulatory accounts, for inclusion in rates effective January 1, 2013. Resolution E-4548 authorized PG&E to consolidate revenue requirements and amortize year-end 2012 account balances upon filing a supplement to AL 4096-E by December 31, 2012. Ordering Paragraph (OP) 10 of Resolution E-4548 also provided that,

> "If PG&E requests amortization of future balances in the accounts authorized for amortization in [Resolution E-4548] by means of the [AET] for rates effective January 1, it shall file the [AL] no later than September 1 of the year prior to when rates become effective. The [AL] shall reflect balances recorded as of July 31 of the year in which the [AL] is filed and the estimated balances for August through December of that year."

On August 30, 2013, PG&E filed AL 4278-E, its tenth annual AET AL, addressing electric revenues and rates to be effective January 1, 2014.

PG&E requests in AL 4278-E to recover revenue requirements authorized by the CPUC and the FERC by December 19, 2013—the date of the last scheduled CPUC meeting in 2013—and to recover year-end 2013 balances in the accounts authorized for recovery in last year's AET Resolution E-4548.

PG&E forecasts a $243.1 million net increase in CPUC-jurisdictional revenue requirements.

In AL 4278-E, PG&E estimates that there will be a net increase in CPUC-jurisdictional electric revenue requirements of approximately $243.1 million on January 1, 2014 relative to revenues in rates that became effective May 1, 2013. This results from increases in some revenue components and decreases in others.

The revenue increases PG&E forecasts total $1.13 billion, and are comprised of:

1. $978.6 million in electricity procurement, ongoing competition transition charge (CTC), and cost allocation mechanism (CAM) revenue requirements, including amortization of balances in the ERRA, the Modified Transaction Cost Balancing Account (MTCBA), and the New System Generation Balancing Account (NSGBA)
2. $153 million for non-fuel related generation revenue requirements including amortization of balances in the Utility Generation Balancing Account (UGBA) (after transfer of the Market Redesign and Technology Upgrade [MRTU] Memorandum Account [MRTUMA] balance to the UGBA).

PG&E forecasts the following revenue decreases totaling $888.5 million, comprising of:

1. $62.1 million in public purpose program (PPP) revenue requirements including amortization of balances recorded in the Public Purpose Revenue Adjustment Mechanism (PPPRAM), the California Alternate Rates for Energy (CARE) Account (CAREA), and the Procurement Energy Efficiency Revenue Adjustment Mechanism (PEERAM).
2. $136.8 million for distribution revenue requirements including amortization of the balance in the Distribution Revenue Adjustment Mechanism (DRAM) and Family Electric Rate Assistance Balancing Account (FERABA).
3. $114.8 million for the Energy Cost Recovery Amount (ECRA), including the ERBBA revenue requirement and amortization of the ERBBA balance.
4. $0.9 million for nuclear decommissioning revenue requirements including amortization of the balance in the Nuclear Decommissioning Adjustment Mechanism (NDAM).
5. $48.6 million in the California Department of Water Resources (DWR) power charge revenue requirements, DWR franchise fees, and

amortization of the balance in the Power Charge Collection Balancing Account (PCCBA).

6. $525.3 million for return of Assembly Bill (AB) 32 allowance revenues.

PG&E forecasts a $35.5 million net increase in FERC-jurisdictional revenue requirements.

In AL 4278-E, PG&E estimates a FERC-jurisdictional net revenue increase of $35.5 million effective January 1, 2014 relative to revenues that became effective in rates on May 1, 2013. This results from an increase in three FERC components and a decrease in another FERC component.

PG&E expects a $52.4 million overall increase to FERC-jurisdictional revenues relative to revenues at present rates, attributed to: a $2.6 million increase in revenues related to the Transmission Revenue Balancing Account Adjustment (TRBAA), a mechanism that ensures revenues received by PG&E from the California Independent System Operator (CAISO) are credited to PG&E's customers; a $21.1 million increase in revenues related to the Reliability Services Balancing Account (RSBA), a FERC-jurisdictional mechanism through which PG&E recovers the reliability services costs it is assessed by the CAISO from customers; and a $28.7 million increase in revenues related to the End-Use Customer Refund Balancing Account (ECRBA), a mechanism that returns FERC-ordered refunds to retail transmission customers.

PG&E also anticipates a decrease in revenues stemming from its TO15 rate filing with FERC, in which PG&E proposed a $16.9 million reduction in base transmission revenue requirements to be effective October 1, 2013. PG&E filed ALs 4282-E and 4282-E-A on September 13, 2013 and September 26, 2013, respectively, to alert the CPUC of its proposal.[1]

PG&E's forecast of January 1, 2014 CPUC-jurisdictional revenues presented in AL 4278-E does not include proposed revenues requested in PG&E's 2014 General Rate Case (GRC).

PG&E filed its 2014 General Rate Case (GRC) Application (A.12-11-009) on November 15, 2012, in which PG&E presents its base distribution and generation

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[1] FERC approved TO15 on September 24, 2013 and authorized a $16.7 million revenue reduction, subject to refund, effective in system-wide rates on October 1, 2013. As such, PG&E's estimated $35.5 million net increase in FERC-jurisdictional revenues effective January 1, 2014 compared to revenues at present rates can be adjusted to a $52.2 million net increase.

revenue requirement requests for Test Year (TY) 2014. Given that PG&E does not anticipate the CPUC to adopt a final decision in A.12-11-009 by the December 19, 2013 CPUC meeting, the illustrative 2014 rates presented in AL 4278-E do not include the proposed distribution and generation revenues in the 2014 GRC request. Instead, base distribution and generation revenue requirements are kept at the same levels as those made effective in AL 4096-E-A, the December 2012 supplement to the 2013 AET, with the exception of PG&E's Pension Contribution, which was separated out of base distribution and generation revenues in AL 4278-E.[2] Upon issuance of the 2014 GRC decision, PG&E would then consolidate all of its then-authorized revenue requirements and implement the resulting rate changes.

PG&E requests to set its 2014 Energy Recovery Bonds Balancing Account (ERBBA) revenue requirement in AL 4278-E.

Consistent with previous AETs, PG&E proposes to establish its 2014 ERBBA revenue requirement in AL 4278-E based on a forecast of 2014 ERBBA activity, as well the amortization of the forecasted December 31, 2013 ERBBA balance. AL 4278-E includes an ERBBA revenue requirement of $27.6 million revenue requirement and a forecasted December 31, 2013 ERBBA balance of ($158.9) million.

The following tables provide a breakdown of various increases and decreases adding up to the net increase of $278.6 million PG&E has estimated in AL 4278-E.

In AL 4278-E, PG&E provides illustrative rates effective January 1, 2014, based on revenue requirement changes in CPUC and FERC proceedings expected to be authorized by December 19, 2013, and on revenue changes resulting from amortization of forecasted December 31, 2013 regulatory account balances. PG&E's forecasted December 31, 2013 account balances are based on recorded balances through July 2013 and forecasted balances from August through December 2013.

A breakdown of the components of the annual revenue requirement increase estimated in AL 4278-E is shown in Tables 1 through 3 below. The illustrative rates that PG&E provides in AL 4278-E are summarized in Table 4 below.

[2] See p. 11, Table 2, line 4 and p. 12, "2014 General Rate Case" in AL 4278-E.

Table 1. CPUC-authorized revenue changes effective January 1, 2014 forecasted by PG&E	Million $
Public Purpose program revenue requirements including amortization of balances in the PPPRAM, CAREA, and PEERAM accounts.	($62.1)
Distribution revenue requirements including amortization of balances in the DRAM and FERABA accounts.	($136.8)
Non-fuel generation revenue requirements including amortization of balances in the UGBA (after transfer of the MRTUMA balance to the UGBA).	$153.0
ECRA revenue requirements including the ERBBA revenue requirement and amortization of the balance in the ERBBA account.	($114.8)
Nuclear Decommissioning revenue requirements including amortization of the balance in the NDAM account.	($0.9)
DWR power charge revenue requirements including DWR franchise fees, and amortization of the balance in the PCCBA account.	($48.6)
Energy procurement, ongoing CTC, CAM, revenue requirements including amortization of the ERRA and MTCBA accounts.	$978.6
Return of AB 32 Allowance Revenues	($525.3)
Total net CPUC-authorized revenue change	**$243.1**

Table 2. FERC-authorized revenue changes effective January 1, 2014 forecasted by PG&E	Million $
Transmission Revenue Balancing Account Adjustment (TRBAA)	$2.6
Reliability Services Balancing Account (RSBA)	$21.1
End-Use Customer Refund Balancing Account (ECRBA)	$28.7
TO15 Rate Filing	($16.9)
Total net FERC-authorized revenue change	**$35.5**

PG&E forecasts that the net increases in CPUC- and FERC-authorized revenues will result in an overall increase of $278.6 million.

Table 3. Change in revenue requirements effective January 1, 2014 forecasted by PG&E	**Million $**
CPUC-authorized	$243.1
FERC-authorized	$35.5
Total AET increase	**$278.6**

Table 4. Summary of Illustrative Average Bundled Customer Rates Shown in AL 4278-E ($/kWh)[3]

Customer Class	**Present Rates**	**Proposed Rates on January 1, 2014**	**Percent Change**
Residential CARE	0.09763	0.08598	(11.9%)
Residential Non-CARE	0.19492	0.19292	(1.0%)
Total Residential	0.17106	0.16669	(2.6%)
Small and Medium Commercial	0.18156	0.19131	5.4%
Large Commercial and Industrial	0.13388	0.14395	7.5%
Agricultural	0.14106	0.14920	5.8%
Streetlighting	0.17833	0.18698	4.9%
System	**0.15964**	**0.16353**	**2.4%**

According to AL 4278-E, this will amount to a 2.4% increase in PG&E's system average bundled customer electric rate.

[3] Derived from data shown in Table 3 of AL 4278-E. Residential CARE rates are based on combined Schedules EL-1, EL-7, and EL-8. Residential Non-CARE rates are based on combined Schedules E-1, E-7, and E-8. Small and Medium Commercial rates are based on the combined small light and power and medium light and power schedules. Large Commercial and Industrial rates are based on combined Schedules E-19, E-20, and Standby.

The revenue requirement changes that PG&E expects to be authorized by the December 19, 2013 CPUC meeting and incorporated into rates effective January 1, 2014 are the result of several factors.

As seen in Table 1, the largest driver of CPUC-authorized revenue increases is energy procurement costs, as requested in PG&E's 2014 ERRA forecast proceeding, A.13-05-015. PG&E expects higher procurement costs primarily resulting from higher electric supply costs due to increased renewable generation, the inclusion of greenhouse gas (GHG) allowance costs in rates, and higher market prices for electricity caused by increased costs for natural gas. A CPUC decision in A.13-05-015 is expected by the end of 2013.

The other significant driver of the CPUC-jurisdictional revenue increase relates to non-fuel generation revenue requirements, nearly half of which is represented by the recovery of costs related to the implementation of the CAISO MRTU initiative. In A.12-01-014 and A.12-04-014, PG&E requested recovery of $64.9 million and $7.9 million, respectively, in costs related to MRTU projects that became operative between 2009 and 2011, while PG&E's 2012 ERRA Compliance filing, A.13-02-023, included a ($0.3) million revenue requirement stemming from MRTU projects that became operative in 2012, resulting in a net revenue requirement of $72.5 million. If these applications are approved by the December 19, 2013 CPUC meeting, the costs would be transferred to the UGBA for amortization in January 1, 2014 rates.

Reductions in forecasted CPUC-jurisdictional revenues vis-à-vis current revenues are due to a number of factors. Primarily, PG&E proposes to return $525.3 million in deferred AB 32 GHG allowance revenues to eligible bundled, Direct Access (DA), and Community Choice Aggregation (CCA) customers through distribution rates, pursuant to the methodologies adopted in D.12-12-033. D.12-12-033 directed PG&E to defer inclusion of GHG costs and revenues in rates until the CPUC declares that the GHG allocation methodology is ready for implementation, which will occur upon issuance of a letter on the service list of R.11-03-012 by the Director of the Energy Division.

Secondary drivers of forecasted 2014 reductions in CPUC-jurisdictional revenues compared to revenues at present rates stem from:

- Distribution-related revenue requirements and amortization of balances in the DRAM and FERABA, totaling to a $136.8 million reduction. This reduction is largely driven by a smaller forecasted DRAM balance than that which is amortized in current rates.

- ECRA revenue requirements, ERBBA revenue requirements, and the amortization of the ERBBA balance, totaling a $114.8 million reduction. The ECRA rate component finances costs associated with PG&E's emergence from bankruptcy in 2004, and amortizes the balance in the ERBBA. The reduction in 2014 ECRA revenues is attributed to a $114.8 million forecasted increase in the overcollected ERBBA balance, which was primarily driven by funds released from PG&E Energy Funding LLC to PG&E in 2013 related to amounts collected in 2013 that exceeded PG&E's bond obligation.[4]
- PPP revenue requirements and amortization of balances in the PPPRAM, CAREA, and PEERAM, totaling a $62.1 million reduction.
- DWR power charge revenue requirements including DWR franchise fees and amortization of the PCCBA balance, totaling a $48.6 reduction. The PCCBA tracks the difference between revenues collected from bundled customers through the PCCBA rate component and the amount remitted to the DWR using the Power Charge Remittance Rate. The forecasted January 1, 2014 reduction is primarily due to a large reduction in the PCCBA.

PG&E proposes to file a supplement to AL 4278-E in late December 2013 to consolidate updated balancing account balances and revenue requirement changes approved by the CPUC and FERC by the December 19, 2013 CPUC meeting.

PG&E proposes to supplement AL 4278-E prior to the end of 2013 to incorporate recorded October 31, 2013 account balances and forecasted balances through the end of 2013 for amortization in January 1, 2014 rates, as well as revenue requirement changes authorized by the CPUC and FERC by December 19, 2013. The December 2013 supplement to AL 4278-E would include the new rates and revised tariffs to become effective on January 1, 2014.

[4] Per PG&E's response to Question 3.f of an Energy Division Data request dated October 15, 2013.

PG&E requests discretion to smooth its customers' rates in 2014 by delaying implementation of certain revenue requirement changes authorized by the CPUC by December 19, 2013 in rates until a decision is adopted in the 2014 PG&E GRC, anticipated in spring 2014.

PG&E notes that, besides the 2014 PG&E GRC discussed above, there are a number of pending proceedings included in the illustrative rates in AL 4278-E for which the CPUC may not adopt a final decision by the end of 2013, such as the 2014 ERRA forecast (A.13-05-015), the 2012 ERRA Compliance proceeding (A.13-02-023), two separate MRTU applications (A.12-01-014 and 12-04-009), and the Default Residential Peak Day Pricing application (A.10-08-005). As such, there is a possibility that the sum of the revenue requirements authorized in CPUC and FERC decisions by the December 19, 2013 CPUC meeting, combined with the forecasted net balance of balancing accounts to be amortized in rates, will be less than combined CPUC- and FERC-jurisdictional revenues at present rates, leading to a rate decrease on January 1, 2014. If PG&E's December 2013 supplement to AL 4278-E shows that its authorized January 1, 2014 system-wide revenue is lower than at present rates due to these circumstances, PG&E requests authority to hold total electric revenue constant, subject to later true-up. The adjustments to hold the revenue constant would be reflected in PG&E's distribution and generation rate components in its December supplement to AL 4278-E. Upon the adoption of the 2014 GRC decision, PG&E would then consolidate all of the revenue requirements authorized up to that point and implement the resulting rate changes. This would prevent customers from experiencing rate shock resulting from a decrease in rates effective January 1, 2014, followed by an increase in rates upon the issuance of 2014 GRC decision.

PG&E requests flexibility in implementing rate design changes resulting from the Default Residential Peak Day Pricing Program (A.10-08-050), the Peak Time Rebate Program (A.10-02-028), and the 2012 Rate Design Window application (A.12-02-020).

The illustrative rates presented in the AET will be updated by the December 2013 supplement to AL 4278-E, which will be used to set January 1, 2014 rates using only the revenue requirements that are approved by the December 19, 2013 CPUC meeting. However, PG&E requests flexibility in implementing rate design changes resulting from the Default Residential Peak Day Pricing Program (A.10-08-050), the Peak Time Rebate Program (A.10-02-028), and the 2012 Rate Design Window application (A.12-02-020). These proceedings are pending the CPUC's approval and have not been incorporated into proposed rates. To the extent that these applications are approved, PG&E requests to implement them, in whole or in part, on January 1, 2014, or during a later rate change depending on the implementation time required.

PG&E requests to use the sales forecast in A.13-05-015 to set January 1, 2014 rates, even if the CPUC does not adopt a final decision in that proceeding by the December 19, 2013 CPUC meeting.

PG&E will set January 1, 2014 rates based on the sales forecast submitted in A.13-05-015, PG&E's 2014 ERRA proceeding. In the event that the CPUC does not approve a final decision in A.13-05-015 by the December 19, 2013 CPUC meeting, PG&E requests that the CPUC still allow it to implement its electric rates effective January 1, 2014 based on the 2014 sales forecast presented in A.13-05-015. If the final approved sales forecast in the adopted decision differs from the sales forecast presented in the November 2013 update to A.13-05-015 and used to calculate January 1, 2014 rates, PG&E states it will then confer with the CPUC on any appropriate rate adjustments going forward.

PG&E's 2014 bundled sales forecast is higher than its 2013 bundled sales forecast.

For balancing accounts with revenues, PG&E forecasted revenues using rates presently in effect, and the sales forecast used in the 2014 ERRA forecast proceeding (A.13-05-015).

PG&E provided illustrative January 1, 2014 electric rates to provide the CPUC with an estimate of the effect of approval of AL 4278-E, as well as a resolution of the pending and/or anticipated decisions and AL dispositions discussed herein. Rates are determined based on the sales forecast submitted by PG&E on May 31, 2013 in A.13-05-015, the rate design and revenue allocation methodology established in D.11-12-053 for rate changes between GRCs, and the residential rate design approved in D.11-05-047.[5] As the 2014 bundled sales forecast is higher than the 2013 forecast, the illustrative rates are lower than what they otherwise would have been without an increase in forecasted sales.

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[5] AL 4278-E, p. 20.

AL 4278-E-A, filed on September 16, 2013, clarifies that the illustrative residential rates in the AET have been updated to reflect the impact of D.12-08-044 on the overall proportion of CARE and Non-CARE residential customers.

D.12-08-044 allows PG&E to remove residential CARE electric customers from the CARE program if, after recording more than 600% of baseline consumption in a single monthly billing period, they do not lower their electricity consumption below 600% of baseline within 90 days and undergo Post Enrollment Verification and apply for the Energy Savings Assistance (ESA) Program within 45 days.[6] Consistent with this decision, PG&E updated the CARE and Non-CARE portions of its residential sales forecast in supplemental AL 4278-E-A to estimate the impacts of removing customers anticipated to be ineligible for the CARE program. While this update does not affect the total system sales forecast provided in A.13-05-015, it does entail a reclassification of sales between residential CARE and Non-CARE customers for rate-setting purposes. These changes will be reflected in PG&E's year-end sales forecast that will be included in its November update to A.13-05-015 and used in its December supplement to AL 4278-E.

NOTICE

Notice of AL 4278-E and AL 4278-E-A was made by publication in the CPUC's Daily Calendar. PG&E states that a copy of each AL was mailed and distributed electronically in accordance with Section 4.3 of General Order 96-B, and served on parties to A.12-01-014, A.12-04-009, A.98-05-007, A.13-05-015, A.12-11-009, A.10-08-005, A.10-02-028, A.11-03-014, A.13-07-001, A.13-08-003, A.13-02-023, A.12-08-007, R.09-06-018, A.10-03-014 and A.12-02-020.

[6] D.12-08-044, OP 101, p. 400.

PROTESTS

Aglet Consumer Alliance (Aglet), EMF Safety Network (Network), and The Utility Reform Network (TURN) submitted a joint protest to AL 4278-E, arguing against the inclusion of the proposed revenue requirements from three open proceedings in the illustrative rates presented in AL 4278-E, based on the probable timing of final decisions in those proceedings.

Aglet, Network, and TURN (Joint Protestants) timely submitted a joint protest to PG&E AL 4278-E. In their protest, the Joint Protestants take issue with PG&E's inclusion of the $4.4 million balance in the SmartMeter™ Opt-Out Memorandum Account–Electric (SOMA-E) in the illustrative rates presented in AL 4278-E, given the low likelihood of a CPUC decision in either of the two phases of A.11-03-014 before the end of 2013.

Similarly, TURN argues against PG&E's inclusion of the $12.8 million revenue requirement request to convert master-metered mobile home park (MHP) utility systems to direct utility service from electric and gas corporations, as well as the $3.4 million revenue requirement request for PG&E's proposed acquisition of the Hercules Municipal Utility (HMU) in the illustrative rates presented in AL 4278-E, on the same grounds that CPUC decisions are unlikely to be adopted in R.11-02-018 and A.13-07-001, respectively, by the end of 2013. Aglet and Network are not parties to R.11-02-018 or A.13-07-001, and thus do not take a position on these two issues raised by TURN.

As such, the Joint Protestants recommend that the CPUC deny PG&E's request to recover the $4.4 million balance in the SOMA-E, while TURN recommends that the CPUC deny PG&E's request to recover $12.8 million in costs related to the conversion of master-metered MHP utility systems to direct utility service, as well as PG&E's request to recover $3.4 million in costs related to PG&E's acquisition of the HMU.

PG&E submitted a reply to the Joint Protestants' protest, noting that the inclusion of open proceedings in AL 4278-E illustrative rates only serve as placeholders.

PG&E's filed a reply to the Joint Protestants' protest on September 26, 2013. In its reply, PG&E points out that while the CPUC has indeed not adopted final decisions in the proceedings cited in the protest, the Joint Protestants ignore the process described in AL 4278-E by which PG&E will only include revenues approved by the December 19, 2013 CPUC meeting in the December supplement to AL 4278-E. As such, PG&E believes the Joint Protestants' concerns are unwarranted and requests that the CPUC rejects their protest of AL 4278-E.

DISCUSSION

PG&E is authorized to incorporate the following revenue requirements that have been authorized for recovery in rates effective January 1, 2014.

PG&E may reflect the following revenue requirements that have been previously authorized for recovery by CPUC decisions in January 1, 2014 rates:

- $12.1 million for administrative costs related to the CARE program, consisting of the 81% electric share of the $14.8 million authorized in D.12-08-044, plus a $0.129 million allowance for Franchise Fees and Uncollectibles (FF&U).
- $85.9 million for the California Solar Initiative (CSI), encompassing an $85 million revenue requirement approved for 2014 in D.11-12-019 along with a $0.917 million allowance for FF&U.
- $64.95 million for Demand Response (DR), consisting of $61.0 million in forecasted DR program expenses authorized by D.12-04-045, $3.3 million for DR-related Integrated Demand Side Management expenses authorized by D.12-11-015, plus a $0.693 million allowance for FF&U.
- $3,377.0 million in base GRC-related distribution revenue requirements, recorded in the DRAM, held at current revenue levels per the rate smoothing discussion above, less the allocation of PG&E's 2013 Pension Contribution approved in D.09-09-020 and AL 4147-E to distribution rates.
- $82.037 million to be recorded in the Electric Program Investment Charge (EPIC) Revenue Adjustment Mechanism Balancing Account (EPICRAM), encompassing $81.162 million for the 2014 EPIC authorized in D.12-05-037 plus a $0.876 million allowance for FF&U.
- $120.7 million for the former electric public goods charge portion of Energy Efficiency (EE) portfolio funding to be collected in the PPPRAM, consisting of $119.4 million approved by D.11-12-038 and AL 3819-E plus a $1.3 million allowance for FF&U.
- $94.89 million for the ESA program, consisting of a 58% electric share of the $161.8 million approved by D.12-08-044 for 2014, plus a $1.01 million allowance for FF&U.
- $44.3 million for nuclear decommissioning activities, recorded in the NDAM, per D.10-07-047.
- $134.0 million for PG&E's Pension Contribution, with an allocation of $85.7 million to distribution rates and $48.4 million to generation rates.

D.09-09-020 allowed the authorized 2013 Pension Contribution revenue requirement to be carried over until changed through the GRC or a separate application. The $162.29 million authorized in D.09-09-020 for 2013 has been reduced due to a reduction in 2014 GRC cycle rate base, and because of a Cost of Capital adjustment provided for in D.12-12-034.

- $219.0 million for the procurement portion of EE revenues to be collected in the PEERAM, consisting of a revised net benefit split of 82% electric and 18% gas (approved in AL 4176-E-A, as discussed below) of total 2014 EE portfolio revenues approved by D.12-11-015 and attributable to the PEERAM, less a $1.61 million reduction for denied San Francisco Bay Area Regional Energy Network (BayREN) funding per the proposed decision (PD) in A.12-07-001, plus a $2.34 million allowance for FF&U.[7]
- $38.85 million for the Photovoltaic (PV) Program, Program Year (PY) 1 sites to be collected through generation rates in the UGBA, per D.10-04-052 and AL 3920-E.
- $29.8 million for the Self-Generation Incentive Program (SGIP), resulting from the $36 million SGIP budget allocated PG&E for 2014 in D.11-12-030 and adjusted by the net benefit split of 82% electric/18% gas in AL 4176-E-A, as discussed below, plus a $0.319 million allowance for FF&U.
- $2.5 million for the 2014 Flex Alert program, approved in D.13-04-021.
- $1,666.5 million in base GRC-related generation revenue requirements, recorded in the UGBA, held at current revenue levels per the rate smoothing discussion above, less the allocation of PG&E's 2013 Pension Contribution approved in D.09-09-020 and AL 4147-E to generation rates.

PG&E may include its proposed revenue requirement placeholders for the Cornerstone Improvement Project and the SmartMeter™ Project in the

[7] As described in its response to Question 4 of an Energy Division Data Request dated October 15, 2013, PG&E intends to update the PEERAM balance in the December supplement to AL 4728-E to reflect D.13-09-004, the final decision approved in A.12-07-001, to credit the return of the electric portion of the two-year, $3.825 million BayREN-denied funds through the PEERAM balance rather than reduce the 2014 PEERAM revenue requirement for the annualized electric portion of the BayREN based on the PD. PG&E also intends to credit the return of 2010-2012 unspent, uncommitted EE funds in the PEERAM balance in the December 2013 supplement to AL 4278-E, as discussed below.

December 2013 supplement to AL 4278-E, as ongoing capital-related revenue requirements associated with these projects are being deliberated in A.12-11-009, the 2014 PG&E GRC.

The CIP was approved by D.10-06-048. PG&E filed AL 3716-E in 2010 to provide its calculation of authorized CIP revenue requirements for 2011-2013, in compliance with D.10-06-048. Energy Division made AL 3716-E effective on September 10, 2010. The 2011-2013 SmartMeter™ Project revenue requirement was authorized in D.11-05-018, the 2011 PG&E GRC Settlement, and implemented through AL 3850-E, which was made effective by Energy Division on May 31, 2011.

PG&E includes revenue requirement placeholders of $54.033 million and $158.8 million for the CIP and SmartMeter™ Project, respectively, in AL 4278-E illustrative rates, which are carried over into 2014 based on the authorized 2013 revenue requirements for both projects. In AL 4278-E, its response to Question 1 of an Energy Division Data Request dated October 15, 2013, and its comments on the Draft Resolution filed December 9, 2013, PG&E notes that the inclusion of these placeholders is due to the fact that the two projects entail ongoing capital-related revenue requirements beyond their original authorizations through 2013 that, until now, have not been handled through the GRC process. These ongoing revenue requirements are currently being deliberated in A.12-11-009, the 2014 PG&E GRC, in which a final decision will not be adopted until after January 1, 2014. PG&E proposes to include these amounts as placeholders in the December 2013 AET supplement that sets January 1, 2014 rates, and will remove them from rates upon the issuance of a final decision in A.12-11-009. We approve PG&E's proposal to carry over the 2013 revenue requirements for the CIP and SmartMeter™ Project into January 1, 2014 rates, as the request is analogous to holding GRC-related distribution and generation revenue constant until a decision is issued in the 2014 GRC.

PG&E's request to establish the 2014 ERBBA revenue requirement is granted. This provides the benefits to customers intended in D.04-11-015 and is consistent with the approach requested in last year's AET AL 4096-E and approved in Resolution E-4548.

The ERBBA records benefits and costs associated with Energy Recovery Bonds. In this AET filing, PG&E proposes that the 2014 ERBBA revenue requirement be established using a forecast of 2014 ERBBA activity, including the amortization of the forecasted December 31, 2013 ERBBA balance. This provides the benefits to customers intended in D.04-11-015 and is consistent with the approach requested in last year's AET AL 4096-E and approved in Resolution E-4548.

PG&E's request to establish the 2014 ERBBA revenue requirement of $27.6 million as proposed in AL 4278-E is granted. This includes establishing the ERBBA revenue requirement using the most recent rate of return adopted by the CPUC.

PG&E is authorized to incorporate revenue requirement changes and/or amortize account balances in rates effective January 1, 2014 resulting from decisions approved by December 19, 2013 in the following pending CPUC proceedings.

If the CPUC adopts final decisions in the formal proceedings listed below by the December 19, 2013 CPUC meeting, PG&E is authorized to consolidate the revenue requirements authorized in those decisions for 2014 in the December supplement to AL 4278-E to be put into rates effective January 1, 2014. As discussed later in this Resolution, the supplement shall be filed by December 31, 2013.

- A.10-08-005, in which PG&E requests recovery of $29.2 million related to implementation of its Default Residential Peak Day Pricing program for its eligible residential customers beginning May 1, 2014. The $29.2 million revenue requirement request encompasses both the $4.4 million request for 2013 and the $24.8 million request for 2014 presented in A.10-08-005, due to the delay in adopting a final decision in the proceeding.
- A.10-02-028, in which PG&E requests to refund $0.412 million to customers related to implementation of its Peak Time Rebates program in 2012 and 2013. PG&E would credit the DRAM through the Dynamic Pricing Memorandum Account.
- A.11-03-014, in which PG&E's requests to recover the $4.4 million balance recorded in the SOMA-E, incurred to cover PG&E's incremental capital and operating expenses needed to implement its SmartMeter™ Opt-Out Program for residential customers, through the DRAM.
- A.13-07-001, in which PG&E requests to recover $3.4 million associated with the acquisition and transfer of the assets of the HMU.
- R.11-02-018, addressing PG&E's estimated 2014 revenue requirement of $12.8 million associated with the conversion of master-metered MHP utility systems to direct utility service from electric and gas corporations.
- A.13-08-003, addressing PG&E's proposed GHG Allowance Revenue Allocation, which would return $525.3 million in cap-and-trade allowance revenue to eligible customers through distribution rates over the course of 2014, pursuant to D.12-12-033.

- A.13-05-015, PG&E's 2014 ERRA and Generation Non-Bypassable Charges Forecast, in which PG&E requests recovery of 2014 electric procurement costs, including forecasted costs and expected revenue requirements of $4,784.3 million for the ERRA, $94.04 million for the CTC, and $235.8 million for the CAM, and also requests amortization of account balances in the ERRA, MTCBA, and NSGBA. PG&E filed an update to A.13-05-015 in early November 2013 providing updated forecasted 2014 sales, 2014 electric procurement revenue requirements, and end-of-2013 ERRA, MTCBA, and NSGBA balances.
- DWR's proposed 2014 power and bond charge revenue requirement determinations of $3.022 million and $397.8 million, respectively, based on the bond charge rate filed by DWR on June 17, 2013 and updated August 1, 2013, and the sales forecast presented in A.13-05-015. The power charge revenue requirement is recorded in the PCCBA. PG&E will update the DWR bond charge revenue requirement in the December 2013 supplement to reflect DWR's October 2013 update to its 2014 electric forward price forecast, as well as PG&E's November 2013 update to its 2014 ERRA forecast.
- DWR Franchise Fees of $3.053 million, calculated from total forecasted DWR revenues (DWR bond and power charge revenue requirements and the amortized forecasted PCCBA balance) multiplied by the 2011 GRC Franchise Fee factor. PG&E will update its DWR Franchise Fee revenue requirement in the December 2013 supplement based on the updates to DWR's revenue requirement determination and PG&E's ERRA forecast, as described above.
- A.13-02-023, PG&E's 2012 ERRA Compliance proceeding, in which PG&E requests recovery of the $25.7 million balance recorded in the Diablo Canyon Seismic Studies Balancing Account (DCSSBA), as well as a ($0.3) million revenue requirement recorded in the MRTUMA associated with MRTU projects that became operative in 2012, through the UGBA.
- A.12-01-014, in which PG&E requests authorization to recover through the UGBA $64.9 million recorded in the MRTUMA, associated with MRTU projects that became operative in 2010; 2009 MRTU projects for which revenue requirements had not been previously approved; and forecasted revenue requirements for 2012 and 2013 MRTU projects.
- A.12-04-009, in which PG&E requests authorization to recover $7.9 million recorded in the MRTUMA associated with MRTU projects that became operative in 2011.

- A.12-08-007, in which PG&E proposes a $12.4 million budget for 2014 Statewide Marketing, Education, and Outreach (SW ME&O) activities related to the Energy Upgrade California (EUC) program, in compliance with D.12-04-045 and D.12-05-015. The $12.4 million req encompasses 2014 budgets of $9.8 million for EUC Marketing and Awareness; $1.3 million for the Flex Alert Program; and $1.2 million for Implementation and Administration. However, D.13-04-021, the Phase I decision, approved $2.5 million for the 2014 Flex Alert Program. As such, should the CPUC adopt a Phase 2 decision in A.12-08-007 by the December 19, 2013 CPUC meeting, PG&E will also include the remaining $11 million in January 1, 2014 rates, allocating $4.45 million for DR, to be collected through the DRAM and $6.55 million for EE, to be collected through the PEERAM.

PG&E is authorized to incorporate revenue requirement changes in rates effective January 1, 2014 from the following advice letters that were pending as of the AL 4278-E filing date but have since been approved.

PG&E may consolidate revenue requirements in rates effective January 1, 2014 presented in the following advice letters that were pending upon the filing date of the AET but have since been approved:

- AL 4176-E/E-A/E-B, approved by the Energy Division on September 17, 2013, in which PG&E requested to: 1) update the PEERAM account balance to reflect the return of an estimated $7 million in residual, unspent, and uncommitted EE funds in 2014 rates; and 2) to adjust the net benefit split from 84% electric/16% gas as authorized in D.12-11-015 to 82% electric/18% gas for procurement EE activities recorded in the PEERAM, and for the SGIP.
- AL 4265-E-A, approved by the Energy Division on October 4, 2013, in which PG&E updated its PV Program revenue requirements to include the PY 3 sites' first annual revenue requirement of $44 million. As discussed below, PG&E also removed the portion of AL 4265-E that notified the CPUC of the revenue requirements associated with the Smart Grid Pilot Deployment Project (SGPDP), stating that PG&E would make a separate advice filing for such notification instead.

PG&E is authorized to incorporate revenue requirement changes in January 1, 2014 rates from the pending advice letters listed below if they are made effective by the December 19, 2013 CPUC meeting.

PG&E may consolidate revenue requirement changes associated with the following advice letters in January 1, 2014 rates should they be approved by the December 19, 2013 CPUC meeting:

- AL 4215-E, filed April 19, 2013, in which PG&E, Southern California Edison Company, and San Diego Gas and Electric Company request approval for the first program period of California Energy Systems for the 21st Century (CES-21) proposed research projects and associated revenue requirements. Pursuant to D.12-12-031, PG&E's $12.5 million revenue requirement request stems from PG&E's 55% share of the overall $30 million dollar budget, allocated between PG&E Electric and Gas in 75%/25% shares, as described in AL 4215-E.
- AL 4228-E, filed May 24, 2013, in which PG&E updated its PV Program revenue requirements for the PY 2 sites' second annual revenue requirement of $38.75 million. Pursuant to D.10-04-052, PV program revenue requirements are recorded to the UGBA for recovery in generation rates.
- AL 4291-E, filed September 30, 2013, requesting electric earnings of $17.7 million in 2011 shareholder incentives (based on a total 2011 earnings request of $21.6 million and the 82% electric/18% gas net benefits spread presented in AL 4217-E) to be recorded in the Customer Energy Efficiency Incentive Account (CEEIA), per D.12-12-032.
- AL 4314-E, filed November 13, 2013, in accordance with Public Utilities Code Sections 739.1 and 739.9 restrictions, seeking approval of a January 1, 2014 increase to residential rates for usage up to 130% of baseline.
- A Tier 1 advice filing by the end of 2013 describing 2014 SGPDP revenue requirements adopted in D.13-03-032, which authorizes $81.6 million for four smart grid pilot projects from 2013 to 2016. PG&E anticipates a 2014 revenue requirement of $1.068 million, consisting of $0.577 for Line Sensors, Volt/Var Optimization, and Detect and Locate Faults pilots, and $0.492 for the Demand Forecasting pilot.
- An advice filing implementing the amortization of the $91.1 million balance in the ERRA GHG Subaccount, created in D.12-12-008 in order for PG&E to defer collection of its 2013 GHG Compliance costs, in rates.

PG&E is authorized to amortize forecasted December 31, 2013 balances in the following balancing accounts previously authorized by the CPUC in January 1, 2014 rates.

This Resolution allows PG&E to amortize the following accounts through this year's AET advice letter, as previously approved for recovery by Resolution E-4548, which addressed PG&E's AET AL 4096-E filed in 2012: the DRAM, PPPRAM, NDAM, UGBA, PEERAM, EPICRAM, PCCBA, Hazardous Substance Mechanism (HSM), CAREA, ERBBA, FERABA, CEEIA, SmartMeter Project Balancing Account (SBA-E), the Non-Tariffed Balancing Account (NTBA), and the Land Conservation Plan Environmental Remediation Memorandum Account (LCPERMA).

Consistent with Resolution E-4548, PG&E is also authorized to amortize balances in the Revised Customer Energy Statement Balancing Account–Electric (RCESBA-E), the Meter Reading Cost Balancing Account–Electric (MRCBA-E), the Smart Grid Memorandum Account (SGMA), and the Cornerstone Improvement Project Balancing Account (CIPBA), subject to the limitations set forth in PG&E's tariffs described below.

PG&E is authorized to amortize the year-end 2013 balance in the Revised Customer Energy Statement Balancing Account–Electric (RCESBA-E) in rates effective January 1, 2014 subject to the limitation on cost recovery set forth in its tariff.

The RCESBA-E was established in 2012 pursuant to D.12-03-015. The account records the actual electric revenue requirements associated with PG&E's costs for implementing its revised customer energy statement. PG&E's combined electric and gas cost for implementing the energy statement is capped at $19.012 million over the period from 2012 through 2016, with 55%, or $10.461 million, of the $19.012 million cap allocated to electric customers. According to the RCESBA-E tariff, Electric Preliminary Statement Part FX, the annual disposition of the balance in the account shall be through the AET. PG&E estimates in AL 4278-E that the RCESBA-E balance to be transferred to the DRAM for recovery in rates effective January 1, 2014 will be approximately $0.124 million.

PG&E is allowed to transfer the balance in the Electric Meter Reading Costs Balancing Account (MRCBA-E) to the DRAM for recovery in rates effective January 1, 2014, subject to the annual cap set forth in its tariffs.

The MRCBA-E records electric meter reading costs pursuant to D.11-05-018, PG&E's 2011 GRC decision. The combined balance of the MRCBA-E and the Gas Meter Reading Costs Balancing Account (MRCBA-G; Gas Preliminary Statement Part CR) is capped annually at $76.2 million. In accordance with PG&E's MRCBA-E tariff, Electric Preliminary Statement Part FQ, disposition of the balance in the account shall be through the AET advice letter process, via the DRAM. PG&E is hereby authorized to transfer its MRCBA-E year-end 2013 balance to the DRAM for recovery in rates effective January 1, 2014, subject to the annual combined electric and gas maximum of $76.2 million authorized by D.11-05-018 and set forth in PG&E's tariffs. PG&E estimates in AL 4278-E that the MRCBA-E balance to be transferred to the DRAM for recovery in rates effective January 1, 2014 to be approximately $42.4 million.

PG&E is authorized to transfer the year-end 2013 balance in the Smart Grid Memorandum Account (SGMA) to the DRAM for recovery in rates effective January 1, 2014, subject to the limits set forth in PG&E's tariff.

The SGMA records PG&E's costs for Smart Grid projects as authorized by the Commission in D.09-09-029. In accordance with the SGMA tariff, Preliminary Statement FD, disposition of the balance recorded for projects approved by the CPUC and the Department of Energy (D.O.E.) is transferred to the DRAM at the end of each year for recovery through the AET process. Accordingly, the forecasted year-end 2013 SGMA balance presented in the December 2013 supplement to AL 4278-E shall be transferred to the DRAM for recovery in rates effective January 1, 2014, subject to the limitation on cost recovery through the AET that is set forth in PG&E's tariff.[8] PG&E estimates in AL 4278-E that the SGMA balance to be transferred to the DRAM for recovery in rates effective January 1, 2014 to be approximately $6.9 million.

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[8] Preliminary Statement Part FD, Smart Grid Memorandum Account, Part 3: Once a project is approved by the CPUC and by the D.O.E., the balance in the subaccount for that project is transferred to the DRAM Account at the end of each year for recovery through the Annual Electric True-up Advice letter until the PG&E portion of the total expenditure amount adopted for that project is reached. Revenue requirements associated with expenditures in excess of the adopted amounts shall continue to accrue in the subaccount, but are not transferred to DRAM for recovery unless and until authorized by the Commission.

PG&E is authorized to transfer the year-end 2013 balance in the Cornerstone Improvement Project (CIP) Balancing Account (CIPBA) to the DRAM for recovery in rates effective January 1, 2014, subject to limits set forth in PG&E's tariff.

The CIPBA records the difference between the CIP revenue requirement authorized by the CPUC in D.10-06-048 and PG&E's costs for implementing the project subject to a limitation on the total capital costs incurred from 2010 through 2013. According to PG&E's CIPBA tariff, Electric Preliminary Statement Part FL, the disposition of the balance in the CIPBA will be determined in the AET by transferring the balance to the DRAM at the end of each year. Accordingly, the year-end 2013 CIPBA balance shall be transferred to the DRAM for recovery in rates effective January 1, 2014 subject to the capital cost limitation set forth in PG&E's tariff ($357.448 million over the 2010 to 2013 time period). PG&E estimates in AL 4278-E that the CIPBA balance to be transferred to the DRAM for recovery in rates effective January 1, 2014 will be ($11.3) million.

PG&E is authorized to recover the balance in the Smart Grid Customer Data Access Balancing Account in January 1, 2014 rates.

PG&E is authorized to amortize the balance in the Smart Grid Customer Data Access (CDA) Balancing Account (CDABA), a one-way balancing account established in D.13-09-025 to record and recover the actual costs of the CDA project from 2013-2016 up to a $19.4 million spending cap. The CDABA tariff, which was filed in AL 4297-E and approved effective October 9, 2013 pursuant to D.13-09-025, establishes that the disposition of the CDABA balance shall be determined in the AET via the DRAM. PG&E will update the CDABA balance in the December 2013 supplement to AL 4728-E to reflect actual CDA expenditures for amortization in January 1, 2014 rates.[9]

[9] As described in PG&E's response to Question 3 of an Energy Division Data Request dated October 15, 2013.

The balances in all accounts authorized for recovery in rates are subject to audit, verification, and adjustment as necessary.

The balances in the accounts authorized for recovery by this Resolution are subject to future audit, verification, and adjustment.

PG&E's request to submit a supplement to AL 4278-E in late December 2013 with recorded account balance data through October 31, 2013 and an updated forecast of December 31, 2013 balances for recovery is granted.

In previous years' AET resolutions (E-4121, E-4217, E-4289, E-4379, E-4432, and E-4548), the CPUC allowed PG&E to submit a supplement to the AET advice letter reflecting recorded account balance data from January through October, and forecasted balances for November and December, of a given year. We allow PG&E to use recorded data from January 1 through October 31, 2013, and forecasted data for November and December 2013 to update account balances in its December supplement to AL 4278-E for amortization in January 1, 2014 rates.

If PG&E's December 2013 supplement to AL 4278-E shows that its authorized January 1, 2014, system-wide revenue will be lower than at present rates, PG&E may delay implementation of certain revenue requirement changes until a 2014 PG&E GRC decision is issued in order to avoid rate fluctuations.

As discussed above, there is a possibility that the sum of 2014 revenue requirements authorized in CPUC and FERC decisions by the December 19, 2013 CPUC meeting, combined with the forecasted net balance of balancing accounts to be amortized in January 1, 2014 rates, will be less than combined CPUC- and FERC-jurisdictional revenues at present rates. If the December supplement to AL 4278-E shows this to be the case, PG&E is authorized to hold total electric revenue constant, subject to later true-up, in order to avoid rate fluctuations. PG&E shall reflect the adjustments to hold the revenue constant in PG&E's distribution and generation rate components in its December supplement to AL 4278-E. Upon the adoption of the 2014 GRC decision, PG&E will then consolidate all of the revenue requirements authorized up to that point and implement the resulting rate changes. This will prevent customers from experiencing rate fluctuations resulting from a decrease in rates effective January 1, 2014, followed by an increase in rates upon the issuance of 2014 GRC decision. We approved the same proposal in AET Resolutions E-4032 and E-4379 for rates effective January 1, 2007 and January 1, 2011, respectively, when PG&E's 2007 and 2011 GRC applications were pending.

PG&E's proposal to design rates based on decisions in Phase 2 of its 2011 GRC, and the sales forecast proposed in its 2014 ERRA forecast proceeding is granted, as the rate design adopted in the 2011 GRC will continue until the CPUC adopts a new rate design in PG&E's TY 2014 GRC.

The illustrative rates submitted by PG&E in AL 4278-E were designed using the revenue allocation and rate design methods approved in D.11-05-047, addressing residential rate design, and D.11-11-053, addressing revenue allocation and non-residential rate design, in PG&E's 2011 Phase 2 GRC, A.10-03-014. The final rates that PG&E submits in its December 2013 supplement to AL 4278-E shall be based on these decisions since they present the most recent methodology adopted by the CPUC for allocating revenues and designing rates.

PG&E proposes to use the 2014 sales forecast served in A.13-05-015, its 2014 ERRA forecast proceeding, to set rates effective January 1, 2014. PG&E requests that it be allowed to implement rates based on its 2014 ERRA sales forecast regardless of whether the CPUC adopts a decision in A.13-05-015 by December 19, 2013. PG&E states that if the sales forecast adopted in the CPUC's final decision in A.13-05-015 differs from the sales forecast in November 2013 update to A.13-05-015 used to set January 1, 2014 electric rates, PG&E will confer with the CPUC on any appropriate rate adjustments going forward. We grant PG&E's request to use the sales forecast provided in its November 2013 update to A.13-05-015 for designing rates effective January 1, 2014. If the sales forecast adopted by the CPUC differs from that in the November 2013 update, PG&E shall adjust rates upon the approval of a final decision in the 2014 PG&E GRC to reflect the sales forecast approved by the final decision in A.13-05-015.

PG&E is granted the flexibility to implement rate design changes associated with the Default Residential Peak Day Pricing Program, the Peak Time Rebate Program, and the 2012 Rate Design Window Application in rates effective January 1, 2014, or during a later rate change depending on the implementation time required.

PG&E notes that the rate design changes stemming from the pending Default Residential Peak Day Pricing (A.10-08-005), Peak Time Rebate (A.10-02-028), and 2012 Rate Design Window (A.12-02-020) proceedings are not reflected in the illustrative rates presented in AL 4278-E, due to the uncertainty surrounding the implementation timeframes entailed by these applications once final decisions are adopted. As such, we grant PG&E the flexibility to implement these rate design changes in rates effective January 1, 2014, or in a future rate change as PG&E sees fit, depending on whether the CPUC adopts final decisions in these proceedings by the end of 2013 and the time it takes PG&E to implement the rate design changes these proceedings entail. Should the CPUC adopt final decisions in any of these three proceedings by the December 19, 2013 CPUC meeting, PG&E shall explain its decision to implement or not implement the rate design changes stemming from such decisions in January 1, 2014 rates in its December 2013 supplement to AL 4278-E. However, PG&E is not authorized to consolidate the revenue requirements associated with the Default Residential Peak Day Pricing or Peak Time Rebate programs in January 1, 2014 rates without implementing the concomitant rate design changes, or vice versa, should decisions in these proceedings be approved. Furthermore, this flexibility is granted on the condition that the final decisions in these proceedings do not require PG&E to make the rate design or revenue requirement changes effective on a certain date.

Pursuant to D.09-12-048 PG&E will file an advice letter to implement residential rate changes allowed by Public Utilities Code Section 739.9 (Senate Bill 695). However, since those changes are revenue neutral, they will not affect revenue requirements.

Senate Bill 695, signed into law in October 2009, added Section 739.9 to the Public Utilities Code. That section allows the CPUC to increase residential rates for usage up to 130% of baseline (Tier 1 and 2 rates) by specific percentages based on specific indices. In developing illustrative rates in AL 4278-E, PG&E assumed a 3% increase to non-CARE Tier 1 and Tier 2 rates (the lower bound of potential increases specifically mentioned in Section 739.9) and no increase to CARE Tier 1 and Tier 2 rates. CARE Tier 3 rates, authorized effective November 1, 2011 in D.11-05-047, were increased by 1.5 cents per kWh in 2013 as approved by D.11-05-047. PG&E then set non-CARE rates for usage in excess of 130% of baseline to ensure the revenue allocated to the residential class is fully collected, while maintaining the fixed differential (4 cents per kWh) between non-CARE Tier 3 and Tier 4 rates approved by D.11-05-047. On November 13, 2013, PG&E filed AL 4314-E seeking approval of a January 1, 2014 increase to residential rates for usage up to 130% of baseline in accordance with the provisions adopted in D.09-12-048, which implemented P.U. Code Section 739.9. If AL 4314-E is approved by December 19, 2013, PG&E shall reflect those rate changes in its December supplement to AL 4278-E.

PG&E shall revise its estimate of revenue requirements and rates filed in AL 4278-E to reflect actual changes authorized by the CPUC by December 19, 2013, along with the changes authorized by the FERC by December 2013.

PG&E shall supplement AL 4278-E by December 31, 2013 to reflect the actual rate and revenue changes authorized by the CPUC by December 19, 2013 in the proceedings and advice letters as specified in this Resolution, along with the actual changes authorized by the FERC by December 19, 2013. The December 2013 supplement to AL 4278-E shall also incorporate updated end-of-2013 account balance forecasts, based on recorded account data through October 31, 2013, to be amortized in rates on January 1, 2014. The rates PG&E files in its supplemental advice letter will be reviewed for compliance after January 1, 2014. If any rates filed in the December 2013 supplement are not in compliance with this order, PG&E shall modify the rates as required and re-bill customers if necessary, or make other appropriate adjustments in a timely manner. This process is consistent with the procedure established in prior resolutions addressing PG&E AET advice letters.[10]

The rates authorized by this Resolution shall be subject to refund to the same extent that they are subject to refund at the FERC.

Under the filed rate doctrine, the CPUC is obligated to allow PG&E to recover FERC-authorized costs for reliability services, transmission access, transmission revenue adjustments, and base transmission rate changes, adjusted for end-use customer refunds required to be paid to customers. It is just and reasonable for PG&E to begin recovering FERC-authorized revenues addressed in AL 4278-E that are authorized by December 19, 2013. The rates authorized by this Resolution shall be subject to refund to the same extent that they are subject to refund at the FERC.

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[10] The following resolutions on prior PG&E AET advice letters authorized this same process; the effective date of the new rates addressed by the resolution is in parentheses: Resolution E-3906 (Jan. 1, 2005); Res. E-3956 (Jan. 1, 2006); Res. E-4032 (Jan. 1, 2007); Res. E-4121 (Jan.1, 2008); Res. E-4217 (Jan. 1, 2009); Res. E-4289 (Jan. 1, 2010); Res. E-4379 (Jan. 1, 2011), Res. E-4432 (January 1, 2012), Res. E-4548 (January 1, 2013).

The joint protest of AL 4278-E filed by Aglet Consumer Alliance, EMF Safety Network, and The Utility Reform Network is denied.

The joint protest filed by the Joint Protestants argues against PG&E's inclusion of three items in the illustrative rates presented in AL 4278-E: 1) the forecasted $4.4 million end-of-year balance in the SOMA-E; 2) the $12.8 million revenue requirement request to convert master-metered MHP utility systems to direct utility service from electric and gas corporations; and 3), the $3.4 million revenue requirement request for PG&E's proposed acquisition of the HMU. The Joint Protestants recommend that the CPUC deny PG&E's requests to recover these amounts due to the likelihood that the CPUC will not issue final decisions in these proceedings by the December 19, 2013 CPUC meeting. As PG&E describes in AL 4278-E and in their reply to the Joint Protestants' protest, PG&E includes open proceedings in AL 4278-E solely for illustrative purposes, and will only include the revenues and balances that are approved by the December 19, 2013 CPUC meeting in January 1, 2014 rates, which will be consolidated in the December 2013 supplement to AL 4278-E. As such, we agree with PG&E that the Joint Protestants' concerns are unwarranted, and deny their protest to AL 4278-E.

COMMENTS

Per statutory requirement, a Draft Resolution was mailed to parties for comment.

Public Utilities Code section 311(g)(1) generally requires resolutions to be served on all parties and subject to at least 30 days public review and comment prior to a vote of the CPUC. Accordingly, the Draft Resolution was served on PG&E and issued for public review and comment no later than 30 days prior to a vote of the CPUC.

PG&E submitted comments to the Draft Resolution on December 9, 2013. PG&E suggested minor changes to the Draft Resolution regarding its treatment of AL 4314-E, the master-metered MHP rulemaking, and the credit of denied BayREN funds to the PEERAM balance, which were incorporated. PG&E also requested that the Draft Resolution be modified to reverse its original denial of placeholder revenue requirements totaling $196.1 million relating to the SmartMeter™ Project ($158.8 million) and Cornerstone Improvement Project ($54.033 million) in January 1, 2014 rates. The Draft Resolution denied these amounts on the grounds that both projects were originally authorized through the end of 2013; that both projects were being considered beyond 2013 in A.12-11-009, the 2014 GRC proceeding; and that D.13-04-023, issued in A.12-11-009, provided that all revenues approved in the 2014 GRC would be made effective January 1, 2014, given the likelihood that a decision in that proceeding would not be adopted until after that date. In its comments on the Draft Resolution, PG&E argued that both projects entail ongoing capital-related revenue requirements beyond their original authorizations through 2013 that have heretofore not been handled through the GRC process, and have instead been included in the stand-alone revenue requirements recovered through the SBA and the CIPBA. We are persuaded by PG&E's argument in its comments that, given that ongoing revenue requirements associated with these two projects are being considered in the 2014 GRC proceeding, the revenue requirements associated with the SmartMeter™ Project and Cornerstone Improvement Project are analogous to GRC-related distribution and generation revenues that the Draft Resolution holds constant until the adoption of a 2014 GRC decision. Therefore, the Draft Resolution has been modified to allow PG&E to include these placeholder revenue requirements in the December 2013 AET supplement.

FINDINGS AND CONCLUSIONS

1. The AET is a process in which PG&E's revenue requirements authorized by the CPUC in various proceedings are consolidated in rates on January 1 of a given year. The AET is also a forum for PG&E to recover costs recorded in memorandum and balancing accounts that have been reviewed and approved for recovery by the CPUC in a separate proceeding or advice letter, or are pending separate review that will be completed prior to end of the year.
2. PG&E filed AL 4278-E on August 30, 2013, proposing to establish 2014 electric rates to recover balances in accounts, establish the 2014 ERBBA revenue requirement, and consolidate CPUC- and FERC-authorized rate changes, effective January 1, 2014.
3. PG&E filed supplemental AL 4278-E-A on September 16, 2013 to clarify that the 2014 sales forecast provided in the November 2013 update to A.13-05-015 entails a reclassification of sales between residential CARE and Non-CARE customers to reflect the removal of customers from the CARE program per D.12-08-044.
4. It is reasonable for PG&E to establish the 2014 ERBBA revenue requirement using a forecast of 2014 ERBBA activity, including the amortization of the forecasted December 31, 2013 ERBBA balance, consistent with what was authorized in Resolution E-4548 addressing AL 4096-E, PG&E's 2013 AET. PG&E requests a 2014 ERBBA revenue requirement of $27.6 million.
5. PG&E should supplement AL 4278-E by December 31, 2013 to reflect the revenue requirement changes authorized by the CPUC and FERC, and to

update balances in accounts specified in this Resolution to be amortized beginning January 1, 2014. The updated balances, revenues, and rates should be subject to future audit, verification, and adjustment pending review of the December supplement to AL 4278-E.

6. PG&E should reflect the following revenue requirements that have been previously authorized for recovery by CPUC decisions in January 1, 2014 rates in its December 2013 supplement to AL 4278-E:

   - $12.1 million for CARE program administrative costs, per D.12-08-044.
   - $85.9 million for the CSI, per D.11-12-019.
   - $64.95 million for DR, per D.12-04-045 and D.12-11-015.
   - $3,377.0 million in base GRC-related distribution revenue requirements, held at current revenue levels per the rate smoothing discussion above, less the distribution rate share of PG&E's 2013 Pension Contribution approved in D.09-09-020 and AL 4147-E.
   - $82.037 million for the EPICRAM, per D.12-05-037.
   - $120.7 million for the former electric public goods charge portion of EE portfolio funding collected in the PPPRAM, per D.11-12-038 and AL 3819-E.
   - $94.89 million for the ESA program, per D.12-08-044.
   - $44.3 million for nuclear decommissioning activities, per D.10-07-047.
   - $134.0 million for PG&E's Pension Contribution, per D.09-09-020, reduced by a reduction in 2014 GRC-cycle rate base and a Cost of Capital adjustment provided for in D.12-12-034.
   - $219.0 million for the procurement portion of EE revenues collected in the PEERAM, per D.12-11-015 and AL 4176-E-A.
   - $38.85 million for the PV Program PY 1 sites, per D.10-04-052 and AL 3920-E.
   - $29.8 million for the SGIP, per D.11-12-030 and AL 4176-E-A.
   - $2.5 million for the 2014 Flex Alert program, approved in D.13-04-021.

- $1,666.5 million in base GRC-related generation revenue requirements, held at current revenue levels per the rate smoothing discussion above, less the generation rate share of PG&E's 2013 Pension Contribution approved in D.09-09-020 and AL 4147-E.

7. PG&E should include the revenue requirement for the Cornerstone Improvement Project ($54.033 million) and the SmartMeter™ Project ($158.8 million) as placeholders in the revenues consolidated in the December 2013 supplement to AL 4278-E.

8. PG&E should consolidate revenue requirements in rates effective January 1, 2014 presented in the following advice letters that were pending when AL 4278-E was filed:

   - AL 4176-E/E-A/E-B, in which PG&E gained authorization to return an estimated $7 million in residual, unspent, and uncommitted EE funds in 2014 rates through the PEERAM, and to adjust the net benefit split for the SGIP and procurement EE activities recorded in the PEERAM to 82% electric/18% gas.
   - AL 4265-E-A, in which PG&E updated its PV Program revenue requirements to include the PY 3 sites' first annual revenue requirement of $44 million.

9. PG&E's December 2013 supplement to AL 4278-E should reflect all CPUC- and FERC-authorized revenue requirement changes and amortization of account balances to the extent approved by December 19, 2013, in the following, pending formal proceedings:

   - A.10-08-005, addressing PG&E's $29.2 million request to implement its Default Residential Peak Day Pricing (PDP) program.
   - A.10-02-028, addressing PG&E's proposed ($0.412) million return associated with implementing its 2012 and 2013 Peak Time Rebates program.
   - A.11-03-014, addressing PG&E's request to recover the $4.4 million balance recorded in the SOMA-E.
   - A.13-07-001, addressing PG&E's $3.4 million request associated with the acquisition and transfer of the assets of the HMU.
   - R.11-02-018, addressing PG&E's $12.8 million request associated with the conversion of master-metered MHP utility systems to direct utility service from electric and gas corporations.

- A.13-08-003, addressing PG&E's proposed ($525.3) million GHG Allowance Revenue Allocation return.
- A.13-05-015, PG&E's 2014 ERRA forecast proceeding, addressing PG&E's 2014 revenue requirement requests of $4,784.3 million, $94.04 million, and $235.8 million for the ERRA, CTC, and CAM, respectively, as well as a request to amortize account balances in the ERRA, MTCBA, and NSGBA.
- DWR's proposed 2014 power and bond charge revenue requirement determinations of $3.022 million and $397.8 million, respectively.
- DWR's $3.053 million proposal for 2014 Franchise Fees.
- A.13-02-023, PG&E's 2012 ERRA Compliance proceeding, in which PG&E requests authority to amortize the $25.7 million balance recorded in the DCSSBA and a ($0.3) million balance recorded in the MRTUMA.
- A.12-01-014, addressing PG&E's request for authority to recover a $64.9 million balance recorded in the MRTUMA.
- A.12-04-009, addressing PG&E's request for authority to recover a $7.9 million balance recorded in the MRTUMA.
- A.12-08-007, addressing PG&E's proposed $12.4 million budget for 2014 SW ME&O activities.

10. PG&E should consolidate revenue requirement changes associated with the following advice letters in January 1, 2014 rates should they be approved by the December 19, 2013 CPUC meeting:

- AL 4215-E, in which PG&E requests approval of proposed research projects and associated revenue requirements for the first program period of CES-21.
- AL 4228-E, in which PG&E requests inclusion of the second annual revenue requirement for PV Program PY 2 sites of $38.75 million.
- 4291-E, in which PG&E requests recovery of $17.7 million in electric earnings in the CEEIA related to 2011 shareholder incentives.
- AL 4314-E, in which PG&E seeks approval of a January 1, 2014 increase to residential rates for usage up to 130% of baseline.
- A Tier 1 advice filing describing PG&E's anticipated 2014 SGPDP revenue requirement of $1.068 million.
- An advice filing requesting the amortization of the $91.1 million balance in the ERRA GHG Subaccount.

11. PG&E should recover balances in the following accounts authorized by Resolution E-4548 in rates effective January 1, 2014: the DRAM, PPPRAM, NDAM, UGBA, PEERAM, EPICRAM, PCCBA, HSM, CAREA, ERBBA, FERABA, CEEIA, SBA-E, NTBA, and the LCPERMA.
12. PG&E should recover the year-end 2013 balance recorded in the RCESBA-E in rates effective January 1, 2014 in accordance with the RCESBA-E tariff, which states that the annual disposition of the RCESBA-E shall be through the AET and sets a cumulative 2012-2016 cap of $10.5 million that can be recovered from PG&E electric customers.
13. PG&E should recover the year-end 2013 balance recorded in the MRCBA-E in rates effective January 1, 2014 in accordance with the MRCBA-E tariff, which states that the annual disposition of the MRCBA-E shall be through the AET and sets an annual cap of $76.2 million that can be recovered from PG&E's electric and gas customers for meter reading activities.
14. PG&E should recover the year-end 2013 balance recorded in the SGMA in rates effective January 1, 2014 in accordance with the SGMA tariff, which states that the annual disposition of the SGMA shall be through the AET and limits the amount that can be recovered for smart grid projects through the AET to the revenue requirements authorized by D.09-09-029.
15. PG&E should recover the year-end 2013 balance recorded in the CIPBA in rates effective January 1, 2014 in accordance with the CIPBA tariff, which states that the annual disposition of the CIPBA shall be through the AET and sets a cumulative 2010-2013 cap of $357.4 million in capital costs that can be recovered from PG&E customers for the CIP.
16. PG&E should recover the year-end 2013 balance recorded in the CDABA in rates effective January 1, 2014 in accordance with the CDABA tariff, which states that the annual disposition of the CDABA shall be through the AET and sets a cumulative 2013-2016 cap of $19.4 million that can be recovered from PG&E customers for the CDA project.
17. PG&E's request to submit the December 2013 supplemental advice letter with forecasted December 31, 2013 account balances, including recorded data through October 31, 2013, is reasonable.
18. PG&E should be allowed to amortize all accounts authorized in the ordering paragraphs of this Resolution in January 1, 2014 rates, subject to future audit, verification, and adjustment.

19. If PG&E's December 2013 supplement to AL 4278-E shows that its authorized January 1, 2014, system-wide revenue will be lower than at present rates, PG&E should be granted discretion to delay implementation of certain revenue requirement changes in rates and hold revenues constant until a 2014 PG&E GRC decision is issued.
20. The rates that PG&E files in its December 2013 supplement to AL 4278-E should be designed based on the revenue allocation and rate design methods approved in D.11-05-047 and D.11-11-053 in A.10-03-014.
21. PG&E should design January 1, 2014 rates in its December 2013 supplement to AL 4278-E using the November 2013 update to the 2014 sales forecast that PG&E proposes in A.13-05-015.
22. If the CPUC adopts a different 2014 sales forecast than what PG&E proposes in A.13-05-015 and uses to design rates in its December 2013 supplement to AL 4278-E, PG&E should adjust rates upon the approval of a final decision in the 2014 PG&E GRC to reflect the sales forecast approved by the final decision in A.13-05-015.
23. PG&E should be granted the flexibility to implement rate design changes associated with the Default Residential Peak Day Pricing Program, the Peak Time Rebate Program, and the 2012 Rate Design Window Application in rates effective January 1, 2014, or during a later rate change depending on the implementation time required, on the conditions that: 1) the rate design changes and revenue requirements must be implemented at the same time; and 2) the final decisions in these proceedings do not require PG&E to implement these changes on a certain date.
24. PG&E's proposal to modify residential rates pursuant to Public Utilities Code Section 739.9 in the December 2013 supplement to AL 4278-E is subject to approval of AL 4314-E, in which PG&E seeks to increase residential rates for usage up to 130% of baseline.
25. In accordance with the filed rate doctrine, the CPUC allows PG&E to recover FERC-authorized costs for reliability services, transmission access, transmission revenue adjustments, and base transmission rate changes, adjusted for end-use customer refunds required to be paid to customers.
26. It is just and reasonable for PG&E to begin recovering in rates FERC-authorized revenues that are authorized by December 19, 2013.
27. The rates authorized by this resolution should be subject to refund to the same extent that they are subject to refund at the FERC.

28. The joint protest of AL 4278-E filed by Aglet Consumer Alliance, EMF Safety Network, and The Utility Reform Network should be denied.

THEREFORE IT IS ORDERED THAT:

1. PG&E's request in Advice Letter 4278-E is approved with modifications and only to the extent described in the ordering paragraphs below.
2. PG&E's request to establish the 2014 ERBBA revenue requirement using a forecast of 2014 ERBBA activity, including the amortization of the forecasted December 31, 2013 ERBBA balance, is approved.
3. PG&E shall file a supplement to AL 4278-E with revised tariffs no later than December 31, 2013. The supplemental filing shall be effective on January 1, 2014, but remain subject to Energy Division determination that PG&E is in compliance with this Resolution. The updated revenues and rates contained in the December supplemental filing shall be subject to audit, verification and adjustment. PG&E shall provide workpapers supporting the rates filed in this supplemental advice letter and the revenue allocation underlying those rates to the Energy Division and any party requesting them. The December supplement shall do the following:
   a. Amortize forecasted December 31, 2013 balances, updated with recorded account balance data as of October 31, 2012 in the December supplement, in the following accounts: the DRAM, PPPRAM, NDAM, UGBA, PEERAM, EPICRAM, PCCBA, HSM, CAREA, ERBBA, FERABA, CEEIA, SBA-E, NTBA, LCPERMA, RCESBA-E, MRCBA-E, SGMA, CIPBA, and the CDABA. The balance in the RCESBA-E is authorized to be transferred to the DRAM for recovery in rates subject to the limitation on cost recovery set forth in PG&E's RCESBA-E tariff (55%of $19.012 million, or $10.461 million, to be recovered from electric customers from 2012 through 2016). The balances in the SGMA and the MRCBA-E are authorized to be transferred to the DRAM for recovery in rates subject to the limitations on cost recovery set forth in PG&E's SGMA and MRCBA tariffs ($76.2 million in combined annual balances between the MRCBA-E and the MRCBA-G). The balance in the CIPBA is authorized to be transferred to the DRAM for recovery in rates subject to the limitation on cost recovery set forth in PG&E's CIPBA tariff ($357.448 million over the 2010 to 2013 time period). The balance in the CDABA is authorized to be transferred to the DRAM for recovery in rates subject to the limitation on cost recovery set forth in PG&E's CDABA tariff ($19.4 million over the 2013-2016 time period).
   b. Reflect the 2014 ERBBA revenue requirement in rates.

c. Reflect all previously-approved CPUC- and FERC-jurisdictional revenue requirement changes in the proceedings and advice letter filings specified in Findings and Conclusions Nos. 6, 7, and 8 in rates.

d. Reflect all CPUC- and FERC-authorized revenue requirement changes and account balance amortizations approved by December 19, 2013 in the proceedings and advice letter filings specified in Findings and Conclusions Nos. 9 and 10 in rates. To the extent CPUC approval is not granted by December 19, 2013, PG&E shall not include items from any of those proceedings or advice letter filings, save for the 2014 sales forecast contained in A.13-05-015, which will be used in the supplement to set January 1, 2014 rates per Ordering Paragraph No. 6.

4. PG&E shall use the rate design and revenue allocation methods approved in D.11-05-047 and D.11-11-053 to design the rates it files in its December 2013 supplement to AL 4278-E.

5. PG&E shall use the November 2013 update to the sales forecast it proposes in A.13-05-015 to design the rates it files in the December 2013 supplement to AL 4278-E. If the CPUC approves a different sales forecast than that which is used to design rates filed in the December 2013 supplement, PG&E shall adjust rates upon the approval of a final decision in the 2014 PG&E GRC to reflect the sales forecast approved by the final decision in A.13-05-015.

6. PG&E is granted the flexibility to implement rate design changes associated with the Default Residential Peak Day Pricing Program, the Peak Time Rebate Program, and the 2012 Rate Design Window Application in rates effective January 1, 2014, or during a later rate change depending on the implementation time required, on the conditions that: 1) the rate design changes and revenue requirements must be implemented at the same time; and 2) the final decisions in these proceedings do not require PG&E to implement these changes on a certain date.

7. PG&E shall include residential rate changes for usage of up to 130% of baseline under P.U. Code Section 739.9 in its December supplemental advice filing, if the CPUC approves AL 4314-E, filed by PG&E on November 13, 2013, in accordance with D.09-12-048 by December 19, 2013. Changes to residential rates developed pursuant to AL 4314-E shall be revenue neutral and shall not affect the total revenue allocated to the residential class.

8. Balances in all accounts authorized for recovery by this resolution are subject to audit, verification and adjustment.

9. The rates authorized by this Resolution shall be subject to refund to the same extent that they are subject to refund at the FERC.
10. The joint protest of AL 4278-E filed by Aglet Consumer Alliance, EMF Safety Network, and The Utility Reform Network is rejected.
11. If any rates filed in the December supplement are not in compliance with this order, PG&E shall modify rates as required and make any necessary billing or other adjustments in a timely manner.
12. If PG&E requests amortization of future balances in the accounts authorized for amortization in this resolution by means of the annual electric true-up advice letter for rates effective January 1, it shall file the advice letter no later than September 1 of the year prior to when rates become effective. The advice letter shall reflect balances recorded as of July 31 of the year in which the advice letter is filed and the estimated balances for August through December of that year.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 19, 2013; the following Commissioners voting favorably thereon:

/s/ PAUL CLANON
Paul Clanon
Executive Director

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA J. PETERMAN
Commissioners

ATTACHMENT A

List of Acronyms in Alphabetical Order:

A.	Application
AB	Assembly Bill
AET	Annual Electric True-up
Aglet	Aglet Consumer Alliance
AL	Advice Letter
BayREN	Bay Area Regional Energy Network
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARE	California Alternate Rates for Energy
CAREA	California Alternate Rates for Energy Account
CCA	Community Choice Aggregation
CDA	Customer Data Access
CDABA	Customer Data Access Balancing Account
CEEIA	Customer Energy Efficiency Incentive Account
CES-21	California Energy Systems for the 21st Century
CIP	Cornerstone Improvement Project
CIPBA	Cornerstone Improvement Project Balancing Account
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CTC	Competition Transition Charge
D.	Decision
DA	Direct Access
DCSSBA	Diablo Canyon Seismic Studies Balancing Account
D.O.E.	Department of Energy
DR	Demand Response
DRAM	Distribution Revenue Adjustment Mechanism
DWR	California Department of Water Resources
ECRA	Energy Cost Recovery Amount
ECRBA	End-Use Customer Refund Balancing Account
EE	Energy Efficiency
EPIC	Electric Program Investment Charge
EPICRAM	Electric Program Investment Charge Revenue Adjustment Mechanism
ERRA	Energy Resource Recovery Account
ERBBA	Energy Recovery Bonds Balancing Account

ESA	Energy Savings Assistance
EUC	Energy Upgrade California
FERABA	Family Electric Rate Assistance Balancing Account
FERC	Federal Energy Regulatory Commission
FF&U	Franchise Fees and Uncollectibles
GHG	Greenhouse Gas
GRC	General Rate Case
HMU	Hercules Municipal Utility
HSM	Hazardous Substance Mechanism
LCPERMA	Land Conservation Plan Environmental Remediation Memorandum Account
MHP	Mobile Home Park
MRCBA-E	Meter Reading Costs Balancing Account–Electric
MRTU	Market Redesign and Technology Upgrade
MRTUMA	Market Redesign and Technology Upgrade Memorandum Account
MTCBA	Modified Transition Cost Balancing Account
NDAM	Nuclear Decommissioning Adjustment Mechanism
Network	EMF Safety Network
NSGBA	New System Generation Balancing Account
NTBA	Non-Tariffed Balancing Account
OP	Ordering Paragraph
PEERAM	Procurement Energy Efficiency Revenue Adjustment Mechanism
PCCBA	Power Charge Collection Balancing Account
PD	Proposed Decision
PG&E	Pacific Gas and Electric Company
PPP	Public Purpose Program
PPPRAM	Public Purpose Programs Revenue Adjustment Mechanism
PV	Photovoltaic
PY	Program Year
R.	Rulemaking
RCESBA-E	Revised Customer Energy Statement Balancing Account-Electric
RSBA	Reliability Services Balancing Account
SBA-E	SmartMeter™ Project Balancing Account
SGIP	Self Generation Incentive Program
SGMA	Smart Grid Memorandum Account
SGPDP	Smart Grid Pilot Deployment Project
SOMA-E	SmartMeter™ Opt-Out Memorandum Account–Electric
SW ME&O	Statewide Marketing, Education, and Outreach
TO15	Transmission Owner 15
TRBAA	Transmission Revenue Balancing Account Adjustment

TURN	The Utility Reform Network
TY	Test Year
UGBA	Utility Generation Balancing Account

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August 30, 2013

Advice 4278-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

__Subject__: **Annual Electric True-Up Filing – Change PG&E Electric Rates on January 1, 2014**

Purpose

Pacific Gas and Electric Company (PG&E) files this Annual Electric True-Up (AET) advice letter to consolidate authorized changes to establish its 2014 electric rates, including the recovery of balances in the balancing accounts previously approved for amortization in 2014, as listed in Table 1. Consistent with previous years, this advice letter also establishes PG&E's 2014 Energy Recovery Bonds (ERBBA) Balancing Account revenue requirement.

California Public Utilities Commission (CPUC or Commission) Resolutions E-3906, E-3956, E-4032, E-4121, E-4217, E-4289, E-4379, E-4432 and E-4548 require PG&E to file an advice letter by September 1 of each year with its preliminary forecast of electric rate changes expected to be effective January 1 of the following year. The illustrative rates provided in this advice letter include: (1) the forecast December 31, 2013 balancing account balances for amortization in 2014; (2) currently authorized test year 2014 revenue requirements; and (3) electric rate and revenue requirement changes being considered in a number of pending proceedings and advice letters, as well as advice letters that have not yet been filed but are expected to be filed and approved by the end of 2013[1]; but exclude (4) rate impacts that are subject to pending legislation that could result in rate changes on January 1, 2014.

PG&E plans to include only those revenue changes that are authorized by the Commission by the end of 2013 in its electric rates effective January 1, 2014. PG&E will submit its supplemental advice letter for its effective rates before the January 1, 2014 rate change.

[1] These preliminary estimates do not include PG&E's 2014 General Rate Case (GRC) Application (A.12-11-009) for which a decision by the end of 2013 is unlikely.

In this preliminary AET filing, PG&E forecasts a $278.6 million increase in its 2013 revenue compared to present rates. This reflects a 2.4 percent increase in its system bundled average electric rate and 2.3 decrease in its system average rate for Direct Access (DA) and Community Choice Aggregation (CCA) customers, whose average rates are exclusive of commodity charges, because they are assessed by third-party service providers. PG&E will file a supplement to this advice letter by December to update its forecast revenue and effective rate changes as of January 1, 2014.

PG&E will also implement increases to residential Tier 1 and Tier 2 rates authorized by the Commission for usage under 130 percent of baseline pursuant to Public Utilities (PU) Code Sections 739.1 and 739.9, and uses illustrative 3 percent increases to those rates.

Additionally, this advice letter provides information on Federal Energy Regulatory Commission (FERC) jurisdictional electric transmission and reliability services rate changes that have been or are expected to be approved before January 1. Rates for electric transmission are prescribed by the FERC, but they are incorporated into PG&E's overall rate design to calculate total rates. Resolution E-4548 found that PG&E could begin recovering FERC-authorized revenues in rates on the date that FERC makes rates effective.[2]

Overview of Rate Proposal to Smooth Rates in 2014

PG&E is requesting a discretionary proposal to smooth its customers' rates in 2014.

There are several pending items for which the Commission may not issue final decisions by year end, as discussed on pages 12 to 18 of this advice letter. These include, among other things, the 2014 Energy Resource Recovery Account (ERRA) Forecast, Market Redesign and Technology Upgrade (MRTU) and Default Residential Peak Day Pricing cost recovery applications (A.13-05-015, A.12-01-014, A.12-04-009 and A.10-08-005). If the Commission does not issue the final decisions on all or some of these pending items by year end, the final decisions result in lower revenue requirements, or its balancing accounts become over-collected, there is a possibility that PG&E's electric revenue and rates would decrease on January 1, 2014.

If PG&E's December 2013 supplemental filing shows that its authorized January 1, 2014 revenue is lower than present rates because of the circumstances mentioned above, it requests authority to hold total electric revenue constant,[3] subject to later true-up. Upon the issuance of the 2014 GRC decision, PG&E would then consolidate all its then-authorized revenue requirements and implement the resulting rate changes.

This proposal would ease the impact to customers whom otherwise would experience a rate decrease in January 1, followed by a subsequent increase.

[2] Resolution E-4548, Finding 25.

[3] The adjustments to hold the revenue constant will be effected in PG&E's distribution and generation rate components in its December supplement advice letter.

Under this proposal, all individual rate components will be changed based upon CPUC-approved methods for rate changes between General Rate Cases. (See D.11-12-053.)

Recovery of Balancing Accounts Already Approved for Amortization in 2013

This advice letter requests rate revisions to fully amortize the forecast December 31, 2013 balances in the balancing accounts listed in Table 1. Ordering Paragraph (OP) 10 of Resolution E-4548, Table 1 shows these accounts and their July 31, 2013 balances, as well as a forecast of their balances through December 31, 2013. The December supplement to this advice letter will update these December 31, 2013 forecast balances based on October 31, 2013 recorded account balances.

The $151.6 million overcollection shown in Table 1 (see line 20) is the 2013 end-of-year account balance forecast for accounts authorized for amortization through the AET, while the $278.6 million in Table 2 (see line 59) reflects the incremental increase over present rate revenues when they are combined with revenue requirements and balancing accounts authorized through their own separate applications and advice letters.

Table 1: PG&E Annual Electric True-Up

Under/(Over) collected balancing accounts authorized for recovery

Line #	Revenue Requirement	7/31/2013 Balance for Recovery	12/31/13 Forecast Under/(Over) collected Balance Requested for Recovery	Rate Component Functional Allocation	Amortization Period
1	DRAM (Distribution Revenue Adjustment Mechanism)	190,932,645	17,509,063	Distribution	12 months
2	PPPRAM (Public Purpose Program Revenue Adjustment Mechanism)	(14,667,212)	(15,852,497)	Public Purpose Programs	12 months
3	EPICRAM (Electric Program Investment Charge Revenue Adjustment Mechanism Balancing Account)	1,813,958	1,553,862	Public Purpose Programs	12 months
4	NDAM (Nuclear Decommissioning Adjustment Mechanism)	153,538	(386,642)	Nuclear Decommissioning	12 months
5	UGBA (Utility Generation Balancing Account)	142,971,849	29,618,383	Generation	12 months
6	PEERAM (Procurement Energy Efficiency Revenue Adjustment Mechanism)	(19,382,249)	(11,735,626)	Public Purpose Programs	12 months
7	PCCBA (Power Charge Cost Balancing Account)	24,230,623	(1,762,060)	Generation	12 months
8	HSM (Hazardous Substance Mechanism)	22,606,671	22,617,035	Distribution	12 months
9	CAREA (California Alternate Rates for Energy Account)	(25,575,275)	(23,396,708)	Public Purpose Programs	12 months
10	ERBBA (Energy Recovery Bonds Balancing Account)	(177,034,638)	(158,913,916)	Energy Cost Recovery Amount	12 months
11	FERABA (Family Electric Rate Assistance Balancing Account)	4,427,232	7,588,552	Distribution	12 months
12	CEEIA (Customer Energy Efficiency Incentive Account)	9,115,147	1,080,600	Distribution	12 months
13	SBA (SmartMeter™ Project Balancing Account)	(30,601,260)	(57,728,808)	Distribution	12 months
14	NTBA (Non-Tariffed Balancing Account)	(192,001)	(192,106)	Distribution	12 months
15	LCPERMA (Land Conservation Plan Environmental Remediation Memorandum Account)	212,055	212,172	Generation	12 months
16	CIPBA (Cornerstone Improvement Project Balancing Account)	(11,251,852)	(11,258,042)	Distribution	12 months
17	SGMA (Smart Grid Memorandum Account) [1]	3,018,696	6,951,181	Distribution	12 months
18	MRCBA (Meter Reading Cost Balancing Account)	19,044,919	42,362,209	Distribution	12 months
19	RCESBA (Revised Customer Energy Statement Balancing Account)	124,296	124,364	Distribution	12 months
20	Total	139,947,143	(151,608,984)		

Note 1 In accordance with D.10-01-025, the 12/31/2013 forecasted balance for SGMA includes a $1 million reduction due to the California Energy Commission's award of $1 million in research funding sought for PG&E's Compressed Air Energy Storage Demonstration Project.

The following paragraphs provide more information on these balancing accounts.

Revenue Adjustment Mechanisms

Effective January 1, 2004, per Resolution E-3862, PG&E implemented Revenue Adjustment Mechanisms (RAM) for recovery of its authorized Distribution, Public Purpose Program (PPP), Nuclear Decommissioning, and Utility Generation revenue requirements. The mechanisms are listed below.

- *Distribution Revenue Adjustment Mechanism (DRAM)* (Electric Preliminary Statement Part CZ);
- *Public Purpose Program Revenue Adjustment Mechanism (PPPRAM)* (Electric Preliminary Statement Part DA);
- *Nuclear Decommissioning Adjustment Mechanism (NDAM)* (Electric Preliminary Statement Part DB); and
- *Utility Generation Balancing Account (UGBA)* (Electric Preliminary Statement Part CG).

All of these accounts true-up revenues to authorized revenue requirements. Advice 2617-E modified PG&E's tariffs to allow disposition of the above accounts through the advice letter process. Consistent with Resolution E-4548, this AET advice letter is the appropriate vehicle to adjust the electric revenue requirements related to the above RAMs for a related rate change effective January 1.

Through subsequent resolutions and authorizations, two new RAMs were created as follows:

- *Procurement Energy Efficiency Revenue Adjustment Mechanism (PEERAM)* (Electric Preliminary Statement EF)

On July 17, 2006, the Energy Division approved PG&E's request in Advice 2838-E to create the PEERAM to track the actual revenues for the authorized procurement portion of energy efficiency activities from the PEERAM rate component against the procurement portion of the authorized revenue requirement for such activities. Electric Preliminary Statement Part EF provided that disposition of the balance in the PEERAM will be through the AET.

- *Electric Program Investment Charge Revenue Adjustment Mechanism Balancing Account (EPICRAM)* (Electric Preliminary Statement FU)

On April 14, 2013, the Energy Division approved PG&E's request in Advice 3976-E and Advice 3976-E-A to create the Electric Program Investment Charge Balancing Account (EPIC) to track, on an interim basis until Phase 2 of the Public Goods Charge OIR, funds collected as authorized in D.11-12-036 through the EPIC revenue component as part of the current PPP rates. On June 15, 2013, PG&E filed Tier 1 Advice 4062-E to modify its Electric Preliminary Statement FU to clarify the expected duration of the EPIC program and to more accurately reflect the purpose of the balancing account. EPIC was renamed the Electric Program Investment Charge

Revenue Adjustment Mechanism Balancing Account (EPICRAM). The Electric Preliminary Statement Part FU included in Advice 4062-E provided that disposition of the balance in the EPICRAM will be through the AET.

Other Balancing Accounts Previously Authorized for Recovery Through the AET

Resolution E-4548 provided that PG&E file an advice letter by September 1 of each year if PG&E wants to use the AET as the vehicle to amortize the balances in the following electric balancing accounts:[4]

- *Power Charge Collection Balancing Account (PCCBA);*
- *Hazardous Substance Mechanism (HSM);*
- *California Alternate Rates for Energy Account (CAREA);*
- *Energy Recovery Bonds Balancing Account (ERBBA);*
- *Family Electric Rate Assistance Balancing Account (FERABA)*;
- *Customer Energy Efficiency Incentive Account (CEEIA);*
- *SmartMeter™ Project Balancing Account (SBA);*
- *Non-Tariffed Products and Services Balancing Account - Electric (NTBA-E);*
- *Land Conservation Plan Environmental Remediation Memorandum Account (LCPERMA);*
- *Cornerstone Improvement Project Balancing Account (CIPBA);*
- *Smart Grid Memorandum Account (SGMA);*
- *Meter Reading Cost Balancing Account (MRCBA-E); and*
- *Revised Customer Energy Statement Balancing Account (RCESBA).*

These balancing accounts are described below:

- *Power Charge Collection Balancing Account (PCCBA)*

The PCCBA (Electric Preliminary Statement Part DG) tracks the difference between (1) the amounts remitted to the California Department of Water Resources (DWR) using the Power Charge Remittance Rate established in the relevant Commission decisions; and (2) the portion of total amounts collected from bundled customers attributable to the PCCBA rate component as adopted by the Commission in the annual DWR power charge revenue requirement cost allocation proceeding.

- *Hazardous Substance Mechanism (HSM)*

The HSM (Electric Preliminary Statement Part S) provides a uniform methodology for allocating costs associated with hazardous substance clean-up and litigation, and related insurance recoveries.

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[4] Resolution E-4548, OP 8.

- *California Alternate Rates for Energy Account (CAREA)*

The CAREA (Electric Preliminary Statement Part M) records the difference between the California Alternate Rates for Energy (CARE) Program revenue shortfall and CARE administrative costs and the revenues collected through the CAREA rate component. D.12-08-044 dated August 23, 2012 authorized the 2012-2014 Investor Owned Utilities (IOUs) CARE administrative programs and budgets which approved an electric/gas allocation for the administrative CARE budget of 81%/19%, respectively for the program cycle.

- *Energy Recovery Bonds Balancing Account (ERBBA)*

The ERBBA (Electric Preliminary Statement Part DT) records the benefits and costs associated with Energy Recovery Bonds (ERB) that are not provided to customers elsewhere and returns those benefits or charges those costs to customers.

In this filing, PG&E proposes that the 2014 ERBBA revenue requirement be established using a forecast of 2013 ERBBA activity, including the amortization of the December 31, 2013 forecast ERBBA balance.[5] This approach provides the benefits to customers intended in D.04-11-015 and is consistent with PG&E's proposal in last year's AET.[6]

- *Family Electric Rate Assistance Balancing Account (FERABA)*

The FERABA (Electric Preliminary Statement Part DX) records the revenue shortfalls and program administrative costs for the large household program (also called the Family Electric Rate Assistance (FERA) program) approved by D.04-02-057. Pursuant to Advice 4035-E, these shortfalls were transferred to DRAM rather than UGBA, effective July 1, 2012.

- *Customer Energy Efficiency Incentive Account (CEEIA)*

The CEEIA records the electric portion of the award or penalty from the EE Risk Reward Incentive Mechanism (RRIM) that is authorized by the Commission to be recovered in rates and the associated billed revenue. The forecast balance is made up of the residual balance from 2013 and the cost of any energy efficiency incentives authorized to be recorded in the account. As approved in Advice 2929-G/3277-E, no interest is applied to the balance in the account.

- *SmartMeter™ Project Balancing Account (SBA)*

The SBA (Electric Preliminary Statement Part EI) records and recovers the incremental operations and maintenance (O&M) and administrative and general

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[5] Potential generator refunds are not included in the December 31, 2013 forecast ERRBA balance. PG&E notes that legislation pending in the California Legislature, SB 96, may affect the timing of entries into ERBBA that relate to CPUC-related energy crisis refund settlements, such as the recent Powerex settlement announced by the CPUC and California Attorney General. See: http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_0051-0100/sb_96_bill_20130826_amended_asm_v98.pdf.

[6] OP 2 of Resolution E-4548 allowed PG&E to amortize the December 31, 2011 forecast balance in the ERBBA. OP 3.b. of Resolution E-4548 allowed PG&E to "reflect in rates the 2013 ERBBA revenue requirement."

(A&G) expenditures, capital-related costs, capital-related revenue requirements, benefits and revenues associated with the SmartMeter™ Project as authorized by the Commission in D.06-07-027, D.09-03-026, and in Advice 3210-G/3850-E. Electric Preliminary Statement Part EI included in approved Advice 2877-E provided that disposition of the balance in the SBA will be through the AET.

- *Non-Tariffed Products and Services Balancing Account – Electric (NTBA-E)*

The NTBA-E (Electric Preliminary Statement Part ET) 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 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 in A.98-05-007 by D.99-04-021. The NTBA-E 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 proposals to offer the Mover Service Program, to recover costs and disburse net revenues through the NTBA-E, to transfer the balance at the end of the year from the NTBA to the DRAM, and to include it in the AET filing, in order to credit customers with revenues pursuant to D.99-04-021.[7]

- *Land Conservation Plan Environmental Remediation Memorandum Account (LCPERMA)*

The LCPERMA (Electric Preliminary Statement Part EZ) is used to record and recover hazardous substance investigation, remediation, or mitigation costs incurred by PG&E related to properties which will be or are encumbered or transferred pursuant to the Land Conservation Commitment (consistent with D.03-12-035). These costs may include, for example: investigation costs, remediation costs, monitoring costs, closure costs, agency oversight fees, permit fees, hazardous waste taxes, and costs to pursue, defend or pay claims relating to hazardous substance remediation or mitigation (provided that recoveries from third parties due to any such PG&E claims shall be recorded as a credit to the LCPERMA). Advice 3387-E approved on February 27, 2009, provided that disposition of the balance in the LCPERMA will be through the AET via the UGBA, its successor, or another proceeding as authorized by the Commission.

- *Cornerstone Improvement Project Balancing Account (CIPBA)*

The CIPBA (Electric Preliminary Statement Part FL) is used to record and recover the incremental O&M and A&G expenditures, capital-related costs, capital-related revenue requirements, benefits, and revenues associated with the Cornerstone Improvement Project as authorized by the Commission in D.10-06-048. As required by D.10-06-048, the capital expenditures used in the monthly computation of the capital-related revenue requirement set forth in Item 5.b. are limited to $357.4 million

[7] If the balance at the end of the year for any product or service category is a debit, no transfer will be made for that product or service and the balance for that product or service category will be reset to zero at the beginning of the year.

over the 2010 to 2013 time period. Advice 3716-E, approved on October 6, 2010, provided that disposition of the balance in the CIPBA will be through the AET, or as otherwise authorized by the Commission.

- *Smart Grid Memorandum Account (SGMA)*

The SGMA (Electric Preliminary Statement Part FD) is used to record and recover the incremental O&M and A&G expenditures and capital-related revenue requirements associated with PG&E's incurred costs for Smart Grid Projects as authorized by the Commission in OP 2 of D.09-09-029 from the effective date of that decision. Advice 3614-E, approved on June 15, 2010, provided that once a project is approved by the Commission and by the Department of Energy (DOE), the balance in the subaccount for that project is transferred to the DRAM at the end of each year for recovery through the AET until the PG&E portion of the total expenditure amount adopted for that project is reached. Revenue requirements associated with expenditures in excess of the adopted amounts shall continue to accrue in the subaccount, but are not transferred to DRAM for recovery unless and until authorized by the Commission.

- *Meter Reading Costs Balancing Account (MRCBA-E)*

The MRCBA-E (Electric Preliminary Statement Part FQ) records and recovers electric meter reading costs, including Energy Data Services (EDS) meter reading costs and severance costs, up to an annual combined electric and gas balancing accounts cap of $76.2 million, pursuant to D.11-05-018 in PG&E's 2011 General Rate Case (GRC). Advice 3850-E filed in compliance with D.11-05-018 provided that the disposition of the balance in the account shall be through the AET, via the DRAM, or its successor, or through another proceeding as authorized by the Commission.

- *Revised Customer Energy Statement Balancing Account (RCESBA-E)*

The RCESBA-E (Electric Preliminary Statement Part FT) tracks and records actual electric revenue requirements associated with authorized cost incurred to implement the Revised Customer Energy Statement Project, pursuant to D.12-03-015. Advice 4016-E filed in compliance with D.12-03-015 provided that the disposition of the balance in the account shall be through the AET via the DRAM, or its successor, or through another proceeding as authorized by the Commission.

Determination of the December 31, 2013 Forecast Balancing Account Balances

As directed by Resolution E-4548, PG&E has presented forecast December 31, 2013 balances in the balancing accounts requested for amortization in Table 1 of this advice letter.[8]

For illustrative purposes, PG&E has also presented forecast December 31, 2013 balances for balancing accounts associated with pending proceedings and advice letters that are expected to be approved by the end of 2013 that would result in rate changes on January 1, 2014. (See Table 2.) The forecasts use recorded balances as of July 31, 2013.

[8] Resolution E-4548, OP 10.

For the balancing accounts that record billed revenues, revenues are forecasted using (1) rates presently in effect in Preliminary Statement Part I; and (2) the sales forecast used in the 2014 Energy Resource Recovery Account (ERRA) Forecast Application (A.13-05-015) filed on May 31, 2013. Revenue requirements or actual costs are then compared to those revenues to determine the forecast balances. For the balancing accounts that record revenue requirements, on a monthly basis, one-twelfth of the adopted annual revenue requirement is applied against revenues. Interest is then calculated on the balance using the interest rate on three-month Commercial Paper.[9]

In the December 2013 supplement to this advice letter, PG&E will update the forecast to reflect October 31, 2013 recorded balances.

Pending and Anticipated CPUC Proceedings and Advice Letters

As discussed above, a number of additional changes to PG&E's electric rates are expected to be approved by the Commission in other proceedings by the end of 2013. Unless otherwise noted, the potential rate changes of the pending and anticipated CPUC proceedings and advice letters are included in the total 2014 illustrative rates. If the Commission issues a final decision in any of these pending proceedings and advice letters by December 19, PG&E will consolidate the results of those decisions and resolutions in the December supplement to this advice letter, except for certain proceedings where PG&E has requested flexibility due to longer implementation time frames needed.[10] Revenue requirements assumptions underlying the illustrative rates are presented in Table 2.

[9] Except for year-end forecast of Customer Energy Efficiency Incentive Account (CEEIA), which does not carry interest.

[10] See footnote 16 for a description of these proceedings.

Table 2: Annual Electric True-Up Projected 2014 Revenue Requirements

Line #		Test Year 2014 RRQ A	12/31/13 Forecast BA Amortization B	Total Projected 2014 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution/DRAM	3,377,029,000	17,509,063	3,394,538,063
4	Pension Contribution (Distribution & Generation) [1]	134,046,000		134,046,000
5	FERABA (Distribution & Generation)		7,588,552	7,588,552
6	Demand Response	64,953,631		64,953,631
7	Statewide ME&O/Demand Response	4,447,476		4,447,476
8	Self Generation Incentive Program	29,838,521		29,838,521
9	CPUC Fee	20,862,925		20,862,925
10	Advanced Metering/SBA	158,800,000	(57,728,808)	101,071,192
11	Meter Reading Cost Balancing Account		42,362,209	42,362,209
12	California Solar Initiative	85,917,150		85,917,150
13	HSM		22,617,035	22,617,035
14	CEEIA	17,902,884	1,080,600	18,983,484
15	NTBA		(192,106)	(192,106)
16	CIPBA (Cornerstone)	54,033,000	(11,258,042)	42,774,958
17	Default Residential Pricing	29,237,000		29,237,000
18	Peak Time Rebates	(412,000)		(412,000)
19	SGPDPBA (Distribution and Generation) [2]	1,068,874		1,068,874
20	SGMA (Compressed Air Energy Storage)		6,951,181	6,951,181
21	RCSEBA		124,364	124,364
22	CES21BA-E		12,500,000	12,500,000
23	Smart Grid - Customer Data Access	898,708		898,708
24	SmartMeter™ Opt-Out Memorandum Account (SOMA)		4,407,953	4,407,953
25	Hercules Municipal Utility Acquisition	3,397,000		3,397,000
26	Mobile Home Park	12,832,158		12,832,158
27	GHG Revenue Balancing Account	(525,253,479)		(525,253,479)
28	**Generation**			
29	Utility Retained Generation Base/UGBA	1,666,510,000	29,618,383	1,696,128,383
30	Photovoltaic Program	121,600,000		121,600,000
31	DCSSBA		25,725,000	25,725,000
32	Electric Procurement/ERRA	4,784,285,989	202,144,848	4,986,430,837
33	ERRA GHG SubAccount (D.12-12-008)		91,050,295	91,050,295
34	DWR--Power Charge/PCCBA	3,022,740	(1,762,060)	1,260,681
35	DWR Franchise Fees	3,053,102		3,053,102
36	MRTUMA (Distribution& Generaion) [3]		72,511,390	72,511,390
37	LCPERMA		212,172	212,172
38	**Ongoing CTC/MTCBA**	94,040,956	62,532,635	156,573,591
39	**Cost Allocation Mechanism/NSGBA**	235,843,268	9,628,193	245,471,461
40	**ERB Balancing Account (ERBBA)**	27,600,000	(158,913,916)	(131,313,916)
41	**Nuclear Decommissioning**	44,270,000	(386,642)	43,883,358
42	**Public Purpose Programs**			
43	(1) Energy Efficiency (Formerly PGC)	120,734,365		120,734,365
44	(2) ESA (formerly known as LIEE)	94,892,989		94,892,989
45	(3) PPPRAM		(15,852,497)	(15,852,497)
46	Electric Program Investment Charge (EPIC)	82,037,738	1,553,862	83,591,600
47	Procurement EE/PEERAM	219,015,515	(11,735,626)	207,279,889
48	Statewide ME&O/PEERAM	6,548,164		6,548,164
49	CAREA	12,089,933	(23,396,708)	(11,306,775)
50	**DWR Bonds**	397,785,393		397,785,393
51	**Total CPUC Jurisdictional**	11,382,929,001	328,891,330	11,711,820,331
52	**CPUC Revenues at Present Rates**			11,468,684,408
53	**Change in CPUC Jurisdictional**			243,135,923
54	**Total FERC Jurisdictional**			1,337,162,156
55	**FERC Revenues at Present Rates**			1,301,626,356
56	**Change in FERC Jurisdictional**			35,535,800
57	**Grand Total Projected Revenues**			**13,048,982,487**
58	**Total Revenues at Present Rates**			**12,770,310,764**
59	**Total Change**			**278,671,723**

Notes to Table 2:

1 Of the Pesion revenue requirement, $85,684,000 is allocated to distribution and $48,362,000 is allocated to generation.

2 Of the SGPDPBA projected revenue, $576,721 is allocated to distribution and $449,803 is allocated to generation.

3 Of the MRTU projected revenue, $8,260,094 is allocated to distribution and $64,251,296 is allocated to generation.

Pending and Anticipated CPUC Proceedings Affecting CPUC Balancing Accounts

- *2014 General Rate Case*

On November 15, 2012, PG&E filed its 2014 GRC Application (A.12-11-009), including a proposed distribution and generation revenue requirement. It is unlikely the Commission will issue a final decision in this case before the end of 2013.[11] As a result, the proposed GRC revenue requirements are not reflected in the illustrative 2014 rates in this 2014 AET Advice Letter. Instead, the distribution and generation revenue requirements are kept at the same level as those effective in the 2013 AET Advice 4096-E-A as a placeholder with one exception. 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 of $327 million. Accordingly, PG&E has substituted the 2014 pension-related revenue requirement of $85.7 million for electric distribution and $48.4 million for generation for the 2013 pension-related revenue requirements. Since the ongoing revenue requirements associated with the SmartMeter™ and Cornerstone projects are included in the 2014 GRC forecast, these 2013 AET-adopted revenue requirements of these projects are included in the 2014 distribution revenue requirements as placeholders.

- *Default Residential Peak Day Pricing*

On August 9, 2010, PG&E filed A.10-08-005, seeking authorization to implement the Default Residential Peak Day Pricing (PDP) program for all its eligible residential customers beginning on May 1, 2014. PG&E requested that the Commission approve up to $141 million of its incremental costs estimated to be incurred from 2013 through the end of 2014 to implement the Default Residential PDP program. D.13-07-040 extended the statutory deadline for this case to October 7, 2013. If the Commission issues a final decision by November 29, 2013, PG&E will consolidate the results in the December supplement. Under PG&E's proposal, actual expenses recorded in DPMA and forecast to be incurred by the end of the year will be recovered in DRAM. If the Commission issues a final decision on December 19, PG&E will incorporate the approved cost as authorized by the Commission in the supplement.

- *Peak Time Rebate*

On October 28, 2011, PG&E filed updated testimony in A.10-02-028, seeking Commission authorization to implement a two-part Peak Time Rebate (PTR) program for all its eligible residential customers beginning May 1, 2013, pursuant to D.09-03-026. PG&E requested that the Commission approve up to $33.7 million in its incremental costs estimated to be incurred from 2013 through the end of 2014 to implement the proposed program. D.13-07-040 extended the statutory deadline for this case to October 7, 2013. If the Commission issues a final decision on December 19, PG&E will incorporate the approved cost as authorized by the Commission in the supplement.

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[11]The Assigned Commissioner has publicly stated that he hopes to issue a decision in this proceeding in the first quarter of 2014.

- *SmartMeter™ Opt-Out*

On August 10, 2012, PG&E filed A.11-03-014 seeking recovery of its incremental capital and operating expenses needed to implement its SmartMeter™ Opt-Out Program for residential customers. PG&E requests that the Commission allow it to recover its recorded balance in the SmartMeter™ Opt-Out Memorandum Account (SMOMA-E), through the DRAM, via the AET. If the Commission issues a final decision by December 19, PG&E will incorporate the final adopted amounts in the supplement.

- *Hercules Municipal Utility Acquisition*

On July 1, 2013, PG&E filed A.13-07-001, seeking authorization to recover costs associated with the acquisition and transfer of the assets of the Hercules Municipal Utility at a cost of $13.7 million, with an associated revenue requirement of approximately $3.4 million in 2014. If the Commission issues a final decision by December 19, PG&E will consolidate the results in the supplement.

- *Mobile Home Park*

On February 24, 2011, the Commission issued an Order Instituting Rulemaking (OIR) to examine what the Commission can and should do to encourage the transfer of master-metered mobile home park (MHP) utility systems to direct utility service from electric and gas corporations. The Assigned Commissioner issued an amended scoping memo on July 17, 2013, reclassifying the proceeding to ratesetting and requiring additional information on an initial 3-year MHP conversion program to be implemented in 2014. PG&E submitted an estimated 2014 MHP conversion program revenue requirement of $12.8 million on August 19, 2013. If the Commission issues a final decision adopting a MHP conversion program by December 19, PG&E will consolidate the results in the supplement.

- *Greenhouse Gas Allowance Revenue*

On August 1, 2013, PG&E filed A.13-08-003, seeking authorization to adopt its proposed Greenhouse Gas (GHG) Allowance Revenue Allocation to its customers. PG&E's cap-and-trade allowance revenue return methodology will distribute allowance revenues to eligible customers over the course of each year as ordered in D.12-12-033. Returns will be provided on either an annual basis (for Emissions-Intensive, Trade-Exposed (EITE) entities), semi-annual basis (for the Climate Dividend for residential households), and/or monthly basis (for eligible-small business and residential customers on a volumetric basis).[12] Pursuant to D.12-12-033, the illustrative 2014 GHG allowance credit included in this advice filing shall be embedded in PG&E's distribution rates for return to its eligible bundled, DA, and CCA customers. If the Commission issues a decision by December 19, PG&E will consolidate the results in the supplement.

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[12] See D.12-12-033 at pp. 205-206 (OP 1).

- *Electric Procurement Revenue Requirements – Energy Resource Recovery Account (ERRA), Ongoing Competition Transition Charge (CTC), Power Charge Indifference Amount (PCIA), and Cost Allocation Mechanism (CAM)*

On May 31, 2013, PG&E filed its "*2014 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast*" Application (A.13-05-015) to recover 2014 electric procurement costs, including forecasted costs and expected revenue requirements for the ERRA, Ongoing Competition Transition Charge (CTC), Power Charge Indifference Amount (PCIA) and Cost Allocation Mechanism (CAM).

The illustrative 2014 ERRA, CTC, PCIA and New System Generation (NSG) rates[13] in this advice filing include the amortized, forecasted December 31, 2013 balances, reflecting July 31, 2013 actual recorded balances for ERRA, the Modified Transition Cost Balancing Account (MTCBA) and the NSG Balancing Account (NSGBA).[14] This methodology is consistent with other balancing account forecasts included in this advice letter.

PG&E will file an updated 2014 electric procurement revenue requirement forecast in early November 2013. If the Commission issues a final decision by December 19, PG&E will consolidate the results in the supplement.

- *2014 DWR Power Charge Revenue Requirement and 2014 DWR Bond Charge Revenue Requirement*

On June 17, 2013, the DWR issued its proposed 2014 revenue requirement determination. PG&E's forecast of its allocation of the 2014 DWR power and bond charge revenue requirements is based on this determination, and it includes the impact of the prior-year adjustments resulting from the permanent allocation decision. PG&E's forecast is reflected in the illustrative 2014 rates submitted with this advice filing. DWR typically would file its determination of the 2014 revenue requirement with the Commission in August. The Commission has 120 days to respond to the determination by issuing a final decision allocating the 2014 revenue requirements among the three California electric IOUs. PG&E's power and bond charge revenue requirements will be finalized when the Commission issues this final allocation decision. DWR intends to update its 2014 forecast in October 2013 to reflect more current gas and electric forward prices at that time. If the Commission issues a final decision by December 19, PG&E will consolidate the results in the supplement.

- *Diablo Canyon Seismic Study Balancing Account (DCSSBA)*

The DCSSBA (Electric Preliminary Statement FM) records and tracks actual costs associated with conducting incremental seismic studies (including project management costs) to implement the California Energy Commission Assembly Bill 1632 Report recommendations approved in D.10-08-003 and D.12-09-008. In

[13] Similar to previous AET advice letters, the NSG rate is used to recover the Cost Allocation Mechanism (CAM) eligible cost, authorized in D.10-12-035.
[14] The New System Generation Balancing Account was established in Advice 3922-E and approved by the Commission on December 19, 2011 to recover the CAM eligible cost.

D.12-09-008, the Commission ordered that disposition of the balance in the DCSSBA shall be through the ERRA compliance review proceeding via the UGBA. In the 2012 ERRA Compliance Application (A.13-02-023) filed on February 28, 2013, PG&E requests recovery of its 2012 recorded cost, amounting to $25.8 million, in the DCSSBA in its 2014 rates. If the Commission issues a final decision by December 19, PG&E will consolidate the results in the supplement.

- *Market Redesign and Technology Upgrade (MRTU)*

On January 31, 2012, PG&E filed a joint application (A.12-01-014) with SCE and SDG&E, seeking authority to recover, in its 2013 rates, a $64.9 million revenue requirement associated with its MRTU projects that became operative in 2010, together with revenue requirements not already approved associated with 2009 projects, and forecasted revenue requirements for 2012 and 2013. On April 16, 2012, PG&E filed A.12-04-009 with the Commission requesting authority to include $7.9 million associated with MRTU projects that became operative in 2011, in PG&E's 2013 rates. Finally, on February 28, 2013, PG&E included as part of its 2012 ERRA Compliance filing a request to include a $(0.3) million revenue requirement in 2014 rates associated with MRTU projects that became operative in 2012. If the Commission issues final decisions in these applications by December 19, PG&E will consolidate their results in the supplement.

- *Energy Efficiency 2013-2014 Portfolio*

On November 15, 2012, the Commission issued D.12-11-015, which approved PG&E's 2013-2014 EE Portfolio with an overall two-year budget of $823.1 million. The 2014 annual EE program funding to be recovered from electric customers is $339.7 million, which represents the electric portion of the annual adopted funding of $341.4 million, reduced by a credit of $1.6 million as authorized in the Energy Efficiency Financing Pilot proposed decision issued on June 25, 2013, and expected to be approved by the end of the year. The credit reduces the annual EE funding recovered in PG&E's electric rates for the Bay Area Regional Energy Network (BayREN). The PEERAM balancing account forecast includes an adjustment to return the BayREN financing pilot funding already collected in PG&E's 2013 electric rates.

PG&E Advice 3356-G-A/4176-E-A, which is expected to be approved by the end of the year, includes PG&E's request to return the residual of pre-2010 unspent, uncommitted energy efficiency funds in 2014 rates. A forecast of the unspent and uncommitted funds to be returned in rates is included in the PEERAM balancing account balance. The PEERAM balancing account balance also includes an adjustment to PG&E's net benefit split of 82 percent electric and 18 percent gas as filed in Advice 3356-G-A/4176-E-A, to be effective January 1, 2013, compared to the net benefit split of 84 percent electric and 16 percent gas approved in D.12-11-015 and used to set 2013 rates.

The total funding to be recovered through the PEERAM includes the electric portion of Statewide Marketing, Education and Outreach funding allocated to energy efficiency as discussed below.

The resulting EE related electric revenue requirement is included in Table 2 of this AL. If the Commission issues a final financing pilot decision and disposition of Advice 3356-G-A/4176-E-A by December 19, PG&E will consolidate the results in the supplement.

- *Self Generation Incentive Program (SGIP) Cost Recovery*

The above-mentioned change to PG&E's net benefit split in Advice 3356-G-A/ 4176-E-A, will also apply to the Self Generation Incentive Program. The proposed adjustment, which represents 82 percent of the 2014 SGIP budget, is included in Table 2.

- *Demand-Side Management – Statewide Marketing Education & Outreach*

On August 2, 2012, PG&E filed its 2013-14 Statewide Marketing Education & Outreach (SW ME&O) Application (A.12-08-007) as directed by D.12-04-045 and D.12-05-015. PG&E's application requested $24.8 million (including Franchise Fees and Uncollectibles (FF&U) to support a statewide umbrella brand and marketing campaign known as "Energy Upgrade California" (EUC) during 2013 and 2014.

On January 18, 2013, the Commission issued a Scoping Memo and Ruling on the SW ME&O Plans for 2013-2014. It divided the case into two phases. The first phase addressed budgets and activities for the Flex Alert program for 2013 and 2014. On April 18, 2013, the Commission issued Phase 1 D.13-04-021 that established an annual budget of $2.5 million (plus FF&U) for PG&E's Flex Alert program in 2013 and 2014.

The second phase of the proceeding will address all other aspects of the SW ME&O plans for 2013-2014. PG&E is reflecting the annual amount requested in A.12-08-007 for SW ME&O of $12.4 million (annual electric revenue requirement is $11 million, including FF&U) in this Advice Filing, which includes the funding for Flex Alert. The amount to be recovered through the AET in 2014 electric rates is $4.4 million through the DRAM and $6.6 million through the PEERAM balancing accounts, as proposed in A.12-08-007. However, should the Phase 2 decision be delayed, PG&E plans to reflect only the approved annual budget of $2.5 million (plus FF&U) for its 2013 and 2014 Flex Alert Program in the supplement.

- *Smart Grid Customer Data Access (CDA) Project*

PG&E filed an application for the Smart Grid Customer Data Access (CDA) Project on March 5, 2012, seeking to develop and implement a platform to provide third-party access to customer usage data via the utility backhaul when authorized by the customer. On July 17, 2013, the Commission issued a Proposed Decision (PD) that approves PG&E's application. The PD authorizes PG&E's costs associated with the CDA Project, which total $19.4 million ($8.91 million capital and $10.45 million expense) over 4 years. If PG&E spends more than the authorized amount, it must obtain Commission approval to recover any additional costs in rates. In addition, the PD authorizes PG&E to establish the Customer Data Access Balancing Account (CDABA), a one-way balancing accounting to record and recover the actual costs of the CDA Project from 2013-2016. PG&E is authorized to recover funds booked to the CDABA by transferring the year-end balance of the CDABA, up to the amount as authorized by the Commission, to DRAM, and to consolidate the transferred amount with other DRAM revenue as part of the AET process. Any costs and revenue requirements associated with this project beyond 2016 shall be considered in PG&E's future GRC proceedings. If the Commission issues a final decision by December 19, PG&E will consolidate the results in the supplement.

Pending and Anticipated CPUC Advice Letters

- *California Energy Systems for the 21st Century (CES-21) Project*

In compliance with OPs 8, 9, 12, and 14 of D.12-12-031, PG&E, SCE, and SDG&E (collectively referred to as the Joint Utilities) submitted a joint Tier 3 advice letter on April 19, 2013, seeking the Commission's approval for the CES-21 proposed research projects for the first program period and the Cooperative Research and Development Agreement (CRADA), as well as a budget of $30 million to be allocated between the Joint Utilities. The amount allocated to PG&E in this advice letter is $12.5 million. If the Commission issues a final resolution by December 19, PG&E will consolidate the results in the supplement.

- *Photovoltaic Program Revenue Requirements*

PG&E filed two Tier 1 advice letters, Advice 4228-E and 4265-E, to update its Photovoltaic Program Revenue Requirements. In Advice 4228-E filed on May 24, 2013, PG&E updated its 2013 electric generation base revenue requirements for the Photovoltaic Program (PV Program) Program Year (PY) 2 PV sites (Cantua, Huron and Giffen) 2nd annual revenue requirements. On August 15, 2013, PG&E filed Advice 4265-E to update its revenue requirements for the 1st annual revenue requirements associated with three additional PV sites (West Gates, Gates and Guernsey) that were placed into operation in 2013. In compliance with D.10-04-052, the PV Program revenue requirements are recorded to the UGBA as part of the electric generation base amount.

- *Smart Grid Pilot Deployment Project*

PG&E's Tier 1 Advice 4265-E described above also includes an update to its electric generation base revenue requirements of $593,736 for the Smart Grid Pilot Deployment Project (SGDPDP) associated with the Short Term Demand Forecasting pilot costs. In compliance with D.13-03-032, PG&E is recording the authorized revenue requirements for this project in the UGBA effective June 21, 2013. There are no 2013 electric distribution revenue requirements for the SGDPDP projects.

PG&E stated that it will file future advice letters to update its electric generation and electric distribution base revenue requirements for years 2014 through 2016 as they become effective. PG&E intends to file a Tier 1 advice letter by end of 2013 to include its 2014 SGDPDP revenue requirements adopted in D.13-03-032, in its UGBA and DRAM, effective January 1, 2014.

- *Greenhouse Gas (GHG) Deferred 2013 Compliance Cost*

Pursuant to OP 4 of D.12-12-008, PG&E deferred the collection of its 2013 GHG Compliance Cost in its ERRA GHG Subaccount. PG&E plans to file a Tier 1 advice letter by the end of 2013 to implement the allocation of this deferral. PG&E will reflect this allocation in the supplement.

- *Residential Tier 1 and Tier 2 Rate Increases*

PG&E will file an advice letter in November 2013 seeking approval of a January 1, 2014 increase to residential rates for usage up to 130 percent of baseline in accordance with PU Code Sections 739.1 and 739.9 restrictions and will incorporate any approved increase in the supplement.

- *Energy Efficiency Risk/Reward Incentive Mechanism (RRIM)*

D.12-12-032 adopted a new incentive mechanism applicable to the 2010-2012 Energy Efficiency Program cycle. Under the 2010-2012 incentive mechanism, PG&E may file an advice letter in the third quarter of 2013 requesting earnings for 2011 to be approved before the end of the year. PG&E estimates the 2011 earning request at a total of $21 million, with the electric portion of $17 million based on PG&E's net benefit split of 82 percent electric and 18 percent gas as filed in Advice 3356-G-A/4176-E-A, to be effective January 1, 2013, compared to the net benefit split of 84 percent electric and 16 percent gas approved in D.12-11-015 and used to set 2013 rates. If the Commission approves PG&E's advice filing by December 19, 2013, PG&E will consolidate the results in the supplement.

Anticipated FERC Filings

There are also pending changes that would affect FERC-jurisdictional electric rates on January 1, 2014. The anticipated changes are updates to amortization of prior balances and 2013 revenue requirement forecasts for the Transmission Revenue Balancing Account Adjustment (TRBAA) and Reliability Service Balancing Account (RSBA). In addition, the End-Use Customer Refund Balancing Account Adjustment (ECRBA) has been established to implement the refunds related to PG&E's Transmission Owner (TO) rate case proceedings.

Transmission Owner Revenue Requirement

PG&E has proposed to FERC in PG&E's fifteenth TO Tariff rate case filing (TO15) of July 24, 2013, a reduction in its base TO revenue requirement and requested an effective date for rates of October 1, 2013. Consistent with that filing, the AET forecast in Table 2 is based on the TO15 filed rates. In the event FERC does not grant PG&E's request to reduce TO rates on October 1, 2013, the rates from PG&E's

September 28, 2012 TO14 rate filing will be in effect on January 1, 2014. PG&E's supplement will reflect FERC's decision.

Transmission Owner Tariff Balancing Account Adjustments

- *Transmission Revenue Balancing Account Adjustment (TRBAA)*

The TRBAA is a FERC-jurisdictional mechanism that ensures that revenues received from the California Independent System Operator (CAISO) by PG&E, as a Participating Transmission Owner (PTO), are credited to transmission rates for both retail and wholesale customers taking service from PG&E. In October 2013, PG&E will file with FERC to update the revenue requirements and rates related to this mechanism for 2014. The illustrative rates reflect an estimate of these amounts. If FERC approves the TRBAA update filing by December 19, PG&E will consolidate the final amounts in the supplement.

- *Reliability Service Balancing Account (RSBA)*

The RSBA is a FERC-jurisdictional mechanism through which the PTO recovers from customers the reliability services costs it is assessed by the CAISO. In October 2013, PG&E will file with FERC to update the revenue requirements and rates related to this mechanism for 2014. The illustrative rates reflect an estimate of these amounts to be included in this separate FERC filing. If FERC approves the RSBA update filing by December 19, PG&E will consolidate the final amounts in the supplement.

- *End-Use Customer Refund Adjustment Balancing Account (ECRBA)*

The ECRBA is an approved FERC-jurisdictional mechanism that returns FERC-ordered refunds to the appropriate retail customers. The ECRBA was approved by FERC for an effective date of January 1, 2011, and replaces the previous End-Use Customer Refund Adjustment (EUCRA) that was approved by FERC on September 22, 2004. The ECRBA mechanism applies to rates in effect on or after the effective date of new or revised retail rates authorized by the CPUC that modify the retail rates charged during the transition period established pursuant to Section 368 of the PU Code.

In October 2013, PG&E will file with FERC to update the revenue requirements and rates related to this mechanism for 2014. The illustrative rates reflect an estimate of these amounts to be included in this separate FERC filing. If FERC approves the ECRBA filing by December 19, PG&E will consolidate the final amounts in the supplement.

- *Transmission Access Charge Balancing Account Adjustment (TACBAA)*

The TACBAA is not changing. The forecast in Table 2 is based on TACBAA rate currently in place as of March 1, 2013 as accepted by FERC under Docket No. ER13-46-000. The TACBAA is a FERC-jurisdictional mechanism designed to provide recovery of differences between utility-specific transmission rates and CAISO grid-wide transmission rates. PG&E generally makes annual filings with the FERC to update its TACBAA revenue requirement and associated rate effective March 1 of each year.

Illustrative 2014 Rate Design and Resulting Rates

To provide the Commission with an estimate of the effect of approval of this advice letter, as well as resolution of the pending and anticipated proceedings and advice letters, PG&E is providing illustrative January 1, 2014 electric rates. Rates are determined based on: (1) the sales forecast in the ERRA Forecast Application (A.13-05-015) filed on May 31, 2013; (2) the rate design and revenue allocation methodology established in D.11-12-053 for rate changes between GRCs;[15] and (3) the residential rate design approved by D.11-05-047.

PG&E requests that the Commission allow it to implement its electric rates effective January 1, 2014 based on its 2014 forecast sales if a final decision on A.13-05-015 is not issued by December 19, 2013. If, once a final decision is issued for A.13-05-015, the final approved sales forecast differs from what is proposed and incorporated in the January 1, 2014 effective rates, then PG&E will confer with the Commission on any appropriate rate adjustments necessary going forward.

The rate changes presented here are relative to present rates, effective May 1, 2013. Actual January 1, 2014 electric rates will be filed in the December supplement, with rate changes relative to present rates in effect at that time. The actual January 1, 2014 rates will include only actual outcomes of the pending proceedings and advice letters authorized by December 19, 2013, as described above.[16]

CPUC-Jurisdictional Rates

- *Distribution*

Distribution rates will be designed according to the guidelines established for rate changes between GRCs set forth in D.11-12-053. The distribution revenue requirement in Table 2 is reduced by the estimated CARE program discounts prior to allocation. The CARE program discount and administrative and marketing costs are then recovered via the CARE portion of the PPP rates.

The distribution allocation begins with distribution revenue at present rates, adjusted to remove non-allocated revenue and the estimated present CARE program discounts. Additionally, a special adjustment is calculated for the change in certain

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[15] D.11-12-053, Appendix A, p. 12.

[16] Except for the flexibility in rate design implementation of the Default Residential Peak Day Pricing (A.10-08-005), Peak Time Rebate Program (A.10-02-028) and the 2012 Rate Design Window Application (A.12-02-020). These proceedings are pending the Commission's approval and have not been incorporated into proposed rates. To the extent that these applications are approved, PG&E may implement them, in whole or in part, on January 1, 2014, or during a later rate change depending on the implementation time required.

program revenues in accordance with the 2011 GRC Phase 2 settlement adopted in D.11-12-053.[17]

PG&E calculates allocation factors based on each schedule's share of the adjusted present distribution revenue. Because the cost responsibility varies for programs included in the adjusted present distribution revenue, PG&E separates the allocation of adjusted revenue into three pieces: (1) the proposed change in revenue for the FERA administration and distribution discount cost[18] (allocated only to residential customers); (2) the special adjustment for the change in specified program revenues per D.11-12-053 (allocated among customer classes and schedules per the 2011 GRC Phase 2 settlement; and (3) the proposed change in revenue for remaining distribution costs (allocated to all customers). The sum of the schedule-level adjusted present distribution revenue, the change in schedule-level cost allocation for FERA (as applicable), the schedule-level cost allocation for the Phase 2 special adjustment and other residual distribution program costs, and any applicable non-allocated revenue and proposed CARE discounts,[19] equals the proposed schedule-level distribution revenues to be allocated.

PG&E anticipates incorporation of an additional adjustment to the distribution allocation and to the PPP allocation described in the PPP section below, for disposition of the Distribution Bypass Deferral Rate Memorandum Account (DBDRMA) balance. On September 16, 2009, PG&E filed Advice 3524-E, requesting the Commission deem reasonable the revenues it received from customers taking service under Schedule E-31 for the period beginning 2004 and extending through 2008. As stated in the advice letter, subject to a determination that the contracts are reasonable, PG&E will make adjustments to its revenue allocation and rate design in the first subsequent AET to ensure that only customers greater than 20 kilowatts (kW) are responsible for amounts associated with these contracts recorded in DBDRMA.[20]

To allocate the DBDRMA balance, PG&E will adjust the projected end-of-year balance for DRAM and projected non-CARE PPP revenue to exclude the associated distribution and PPP shares of the DBDRMA balance, from the allocation of revenue, and will allocate the remaining revenue under the applicable requirements for revenue allocation per D.11-12-053. PG&E will then assign the balance in the DBDRMA to all customers except those customers served under residential schedules and Schedules A-1, A-6 and A-15 based on applicable revenue shares for DRAM and non-CARE PPP revenue.[21]

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[17] D.11-12-053, Appendix A, p. 14.
[18] As noted previously in the discussion of the FERABA, FERA program revenue shortfalls were transferred to DRAM rather than UGBA pursuant to Advice 4035-E, effective July 1, 2012.
[19] Per D.11-12-053, Appendix A, p. 15, CARE program discounts will be determined annually in the AET.
[20] PG&E has filed advice letters for Annual Reasonableness Review of Schedule E-31 contracts every year since 2009 and would seek to make appropriate rate adjustments for any of these advice letters approved by November 29, 2013.
[21] As explained in Advice 3524-E, eligibility for PG&E's rates is not defined at 20 kW. PG&E is, therefore, using this set of schedules to implement the provision of Section 454.1 which excludes customers under 20 kW from the allocation of the DBDRMA balance.

Distribution rates are changed by the percentage change on each rate schedule necessary to collect the distribution revenue allocated to that schedule, except that no adjustment is made to the level of distribution customer charges, meter charges and streetlight facilities charges authorized by D.11-12-053**.** Applicable demand and energy charges generally collect all of the change in distribution revenue allocated to the schedule.

An additional adjustment to agricultural distribution rates is required as adopted in D.11-12-053 in PG&E's 2011 GRC Phase 2 proceeding. PG&E will work with intervenors representing agricultural customers' interests while preparing the supplement to finalize the preliminary estimates incorporated herein to reflect authorized "after-the-fact revenue neutral adjustments" designed to account for revenue shortfalls due to the March 2013 mandatory migration of non-TOU agricultural customers to TOU (time-of-use) rates. All revenue shortfalls will be recovered from agricultural AET Distribution rates, and are to be decremented from the general DRAM balances that would otherwise be recovered from other customer classes.

The December AET supplemental advice letter will modify and update the following preliminary adjustment for the revenue shortfall covering the March 2013 to September 2013 timeframe. PG&E will determine the difference in total revenue collected from migrating customers to TOU rates and total revenue that would have been collected had the customers stayed on flat rates; this is the initial or "nominal" revenue shortfall created by the migration to TOU rates. However, in the calculation, customers are credited back any revenue driven by a change in their TOU load shapes in 2013 compared to 2012. That is, PG&E will not collect revenues lost from customers shifting their usage or demand from peak to off-peak periods.

Revenues are calculated for each migration group on the initial non-TOU and final TOU schedules by multiplying the applicable billing determinants by the applicable rates during that month. The revenues on the two schedules are then compared and the revenue shortfall is retained by the TOU schedule during the revenue allocation calculation process. Initial estimates using preliminary forecasts of the after-the-fact adjustment for March 2013 through September 2013 for the two largest migration groups are $4.8 million for customers transitioning from AG-1A to AG-4A and $1.0 million for customers transitioning from AG-1B to AG-4B. These customers make up over 98% of all migrating customers. The total preliminary after-the-fact adjustment for March to September 2013 is estimated to be $6.4 million. This estimate was based on actual March 2013 to May 2013 usage, and used June 2012 to September 2012 usage as a proxy for 2013 usage not yet available. The December AET supplement will be updated as actual usage data becomes available for the summer of 2013.

- *Generation*

Generation rates will be designed according to the guidelines established for rate changes between GRCs set forth in D.11-12-053 to collect generation revenue presented in Table 2. PG&E adjusts generation revenue at present rates to reflect residual generation revenue that would remain under current rates after any revision to CTC, and to remove non-allocated revenue. PG&E calculates allocation factors based on each schedule's share of the adjusted present generation revenue. The sum of the schedule-level adjusted present generation revenue, the change in schedule-level cost allocation for generation costs, and any applicable non-allocated revenue equals the proposed schedule-level generation allocation. Generation demand and energy charges are revised to collect the revenue allocated to each schedule.

PG&E incorporates additional adjustments to the generation allocation described above for non-Residential PDP and Residential SmartRate™ adjustments. In D.10-02-032, the Commission adopted PG&E's proposals for PDP, including an annual adjustment to rates to account for revenue undercollections or overcollections when the program is operated other than 12 times per year. These structural amounts are to be determined administratively based on the number of PDP participants in each class, the total PDP event charges (on a design basis for each customer class) and the actual number of events. At this point in the season, PG&E anticipates calling the program 12 times by year-end, so PG&E has not included illustrative revenue adjustments in this advice letter. In the event that PG&E calls the program other than 12 times by year-end, adjustments will be included in the supplement based on the method adopted in D.10-02-032. PG&E may also need to include adjustments for PDP bill protection in the supplement.

An adjustment of approximately $1.1 million is directly assigned to the residential class (after removing that amount from the full generation revenue level to be allocated to all classes). This adjustment reflects the estimated costs of bill protection and customer participation incentive credits associated with the SmartRate™ program for residential customers adopted in D.06-07-027. Final adjustments for PDP and SmartRate™ will be included in PG&E's supplement.

- *Ongoing Competition Transition Costs (CTC) and Power Charge Indifference Adjustment (PCIA)*

The total revenue requirement for Ongoing CTC applicable to bundled, departing load (DL), DA and CCA customers is presented in Table 2. CTC rates for bundled, DA, DL and CCA customers are determined based on the peak 100-hour methodology as set forth in PG&E's ERRA application, and vary by class, and by voltage for Schedule E-20.

PG&E's vintaged PCIA rates are based upon the identical rate design methods used to derive rates currently in effect[22] and proposed rates filed in PG&E's ERRA A.13-05-015 with the vintaged PCIA rates designed in proportion to ongoing CTC rates, and including franchise fees for DWR-related components.

[22] PCIA rates currently in effect for non-exempt DA, CCA and most DL customers were filed in Advice 4212-E, and became effective May 1, 2013, pending final disposition.

- *Energy Cost Recovery Amount (ECRA)*

The rates for ECRA recover the revenue requirement for the ERBBA as provided in Table 2. The ECRA rate is set at the same cents per kWh rate for all eligible customers.

- *Nuclear Decommissioning*

The nuclear decommissioning rate is set at the same cents per kWh rate for all eligible customers based on the revenue requirement from Table 2.

- *Public Purpose Programs (PPP)*

Rates for public purpose programs recover the revenue requirements for the public goods charges for EE, ESA Program, and the amortization of the PPPRAM balancing account. The PPPRAM balance is allocated to EE, EPIC and ESA Program in proportion to the associated proposed revenue requirements. In addition, total PPP rates include procurement EE, the amortization of the PEERAM balancing account, the CARE rate which funds the CARE distribution discount, CAREA balancing account under and over collections and CARE administration expenses.

Pursuant to the 2011 GRC Phase 2 Settlement, PPP rates will be developed as the sum of three pieces and will be allocated to each customer group in the manner described below.

1. The cost of the CARE program will be determined and the CARE surcharge will be set once per year in the AET proceeding based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the CSI and the DWR Bond charge. The cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates.
2. The cost of the ESA Program and Procurement EE will be allocated to customers based on an equal percent of the sum of then-current ESA Program and Procurement EE revenue (that is, the same percentage will be applied to the then-current revenue for each customer group to determine the allocated revenue).
3. PG&E will continue its current practice of allocating revenues for the former Public Goods Charge (i.e., former EE PGC and EPIC) based on the rate cap established in PU Code Section 399.8 until these issues are addressed in a future GRC Phase 2 proceeding.

PPP rates vary by customer class, schedule and voltage, and are set on a per kWh basis.

- *DWR Bond*

The DWR Bond rate is set by the Commission in the annual DWR Revenue Requirement allocation proceeding (R.09-06-018). The DWR Bond rate is the same cents per kWh for all eligible customers, statewide.

- *New System Generation Charge*

The total revenue requirement for the NSGC applicable to bundled, eligible DL,[23] DA and CCA customers is presented in Table 2 (see line 36, Cost Allocation Mechanism). NSGC rates for bundled, DA, CCA and eligible DL customers are determined based on the 12 Coincident Peak methodology as set forth in PG&E's ERRA application, and vary by customer class.

- *Conservation Incentive Adjustment (Residential Only)*

Conservation Incentive Adjustment rates are set residually, reflecting decrements from or increments to schedule average rates, to preserve the current four-tiered non-Care residential total rate structure pursuant to the constraints on total rates discussed in the Total Rates section below.

- *Assembly Bill (AB) 32 Greenhouse Gas Allowance Revenue Return*

AB 32 allowance revenue return rates included in Table 4 illustrate that rates were set according to the Joint IOU's proposal in the GHG OIR. If approved for January 1, 2014 implementation, PG&E will include AB 32 allowance revenue return rates conforming to the approved allocation and design methodology in the December supplement to this advice letter.

2. FERC-Jurisdictional Rates

Per Resolution E-3930, PG&E may pass through rate changes for transmission-related costs that have been filed with and become effective at the FERC. Resolution E-3930 established a process for addressing FERC-approved rate changes at the CPUC. Two requirements of that process are to: (1) file an advice letter with the Commission concurrently with the filing at FERC or as soon thereafter as possible which passes through the requested FERC changes in rates (process item 3 of the resolution); and (2) propose an interim means of revenue allocation and rate design should there be an allocation issue on which the Commission has not articulated a policy (process item 5 of the resolution).

PG&E presents changes to TRBAA, RSBA, and ECRBA rates to comply with the requirements of Resolution E-3930.[24] Since PG&E has not yet filed its request at FERC for TRBAA, RSBA, and ECRBA, the estimates provided here are subject to revision based on PG&E's annual update filing in October. Nonetheless, this advice letter addresses both process items required by the CPUC. PG&E requests that the Commission include the FERC-jurisdictional transmission rates, terms and conditions for purposes of inclusion in retail electric rates.

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[23] D.08-09-012, OP 1. The two types of departing load obligated to pay this charge are new Western Area Power Authority DL (NWDL, billed on Schedule E-NWDL) and split-wheeling DL (SDL, billed on Schedule E-SDL). Only incremental NWDL customers are subject to this charge, as existing NWDL (as of 2009) non-bypassable charge obligations were resolved by D.09-08-015.

[24] As discussed in previously, PG&E is not changing the TO and TACBAA rates in January 2014.

- *Transmission Revenue Balancing Account Adjustment (TRBAA)*

The illustrative TRBAA rates are based on PG&E's best estimate of the 2014 revenue requirement and are subject to revision based on the final determination of these rates to be filed at FERC later this year.

- *Reliability Services Balancing Account (RSBA)*

Illustrative RSBA rates are based on PG&E's best estimate of the 2014 revenue requirement and are subject to revision based on the final determination of these rates to be filed at FERC later this year.

- *End-Use Customer Refund Balancing Account (ECRBA)*

Illustrative ECRBA rates are based on PG&E's best estimate of the 2014 revenue requirement and are subject to revision based on the final determination of these rates to be filed at FERC later this year.

3. Total Illustrative Rates

- *CPUC-Jurisdictional Total Illustrative Rates*

PG&E determines total bundled rates by adding together the components determined above. The exception to this general rule is that increases to rates for residential usage up to 130 percent of baseline are constrained under the requirements of PU Code Sections 739.1 and 739.9.[25] In developing the Table 4 illustrative rates, PG&E assumed a 3 percent increase to non-CARE Tier 1 and Tier 2 rates on January 1, 2014 (3 percent is the lower bound of potential increases allowed) and no increase to CARE Tier 1, Tier 2 or Tier 3 rates. PG&E then set non-CARE rates for usage in excess of 130 percent of baseline to ensure the revenue allocated to the residential class is fully collected, while maintaining the fixed differential ($0.04 per kWh) between non-CARE Tier 3 and Tier 4 rates approved by D.11-05-047. As noted previously, PG&E will file a separate advice letter seeking approval of a January 1, 2014 increase to residential rates for usage up to 130 percent of baseline in accordance with the PU Code requirements and will incorporate any approved increase in the supplement.

- *Changes to Total Rates due to FERC-Jurisdictional Rate Changes*

For both CPUC- and FERC-jurisdictional rate components, PG&E determines total bundled rates by adding together the components determined above. The same restrictions on changes to total residential rates described above apply equally whether those changes were due to underlying changes to FERC- or CPUC-jurisdictional rate components.

Table 3 sets forth PG&E's illustrative 2014 revenue and average rate summaries for: (1) bundled customers; and (2) DA and CCA customers consistent with the revenue

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[25] PU Code Sections 739.1 and 739.9 allow, among other things, annual increases to residential rates for usage up to 130% of baseline (Tier 1 and Tier 2 usage) in accordance with specific formulas.

requirements set forth in Table 2. Present rates are based on rates effective May 1, 2013. PG&E will revise the final January 1, 2014 revenue allocation and associated rate calculations in the December supplement if necessary, to reflect present rates in effect at that time.

Similar to bundled rates, DA and CCA rates are determined by simply adding together the applicable illustrative rate components which include transmission (and transmission rate adjustments), distribution, applicable AB 32 allowance revenue return, conservation incentive adjustment, reliability services, nuclear decommissioning, PPP and NSGC. In addition, DA and CCA customers pay the applicable Cost Responsibility Surcharge (CRS), which includes the Energy Cost Recovery Amount, CTC, DWR bond and the applicable PCIA, and the applicable Franchise Fee Surcharge. Finally, while not shown in the illustrative tables, DL charges will decrease by approximately $2.6 million, from $33.3 million to $30.7 million, or 7.8 percent, because of changes in component charges DL customers are responsible for paying.

Illustrative rates are shown in Table 4 consistent with the revenue requirements provided in Table 2. PG&E intends to file a complete set of rates in December to consolidate all electric rate changes to be implemented on January 1, 2014. At that time, PG&E will revise each rate schedule to show the consolidated rates.

<u>Protests</u>

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than **September 19, 2013**, which is 20 days after the date of this filing. Protests must be submitted to:

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

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

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

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

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C

P.O. Box 770000
San Francisco, California 94177

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

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

Effective Date

PG&E requests that this advice filing be approved on **January 1, 2014**, which is greater than 30 days after the date of filing. PG&E requests that the Commission approve this Tier 3 advice letter by resolution no later than at the Commission's December 19, 2013 business meeting.

PG&E requests confirmation in the resolution that it may, via a supplemental advice letter to be filed after the Commission's December 19, 2013 business meeting:

- Recover, in 2014 electric rates, the December 31, 2013 forecast balances in balancing accounts already approved for amortization in 2014, described in Table 1 of this advice letter;
- Consolidate changes to PG&E's January 1, 2014 electric rates resulting from all final decisions issued by the Commission by December 19, 2013, except as noted in this advice letter;
- Exercise discretion in holding total electric revenue constant, subject to later true-up, if its authorized January 1, 2014 revenue is lower than present in the December supplemental filing; and
- Implement PG&E's electric rates effective January 1, 2014, based on its 2014 forecast sales if a final decision on its ERRA Forecast Application (A.13-05-015) is not issued by December 19, 2013. If the final approved sales forecast differs from what is proposed in A.13-05-015 and incorporated in the January 1, 2014 effective rates, then PG&E will confer with the Commission on any appropriate rate adjustments necessary going forward.

Commission action on pending proceedings and advice letters prior to the end of 2013 will affect the rates proposed in this filing. Therefore, PG&E expects that the Resolution addressing the request will require a supplemental advice letter for the purpose of establishing January 1, 2014, electric rates subject to Energy Division review to: (1) update October 31 account balances; and (2) incorporate rate changes from proceedings and advice letters resolved prior to the filing of the supplement to this advice letter, subject to the discretions mentioned in this advice letter.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the service lists for A.12-01-014, A.12-04-009, A.98-05-007, A.13-05-015, A.12-11-009, A.10-08-005, A.10-02-028, A.11-03-014, A.13-07-001, A.13-08-003, A.13-02-023, A.12-08-007, R.09-06-018, A.10-03-014 and A.12-02-020. Address changes to the General Order 96-B service list should be directed to email PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian Cherry /slw

Vice President – Regulatory Relations

Attachments: Tables 3 and 4

cc: Service Lists for A.12-01-014, A.12-04-009, A.98-05-007, A.13-05-015, A.12-11-009, A.10-08-005, A.10-02-028, A.11-03-014, A.13-07-001, A.13-08-003, A.13-02-023, A.12-08-007, R.09-06-018, A.10-03-014 and A.12-02-020.

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 E)**

Utility type:	Contact Person: **Shirley Wong**
☑ ELC ☐ GAS	Phone #: **(415) 972-5505**
☐ PLC ☐ HEAT ☐ WATER	E-mail: **slwb@pge.com and PGETariffs@pge.com**

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

Advice Letter (AL) #: **4278-E** Tier: **3**
Subject of AL: **Annual Electric True-Up Filing - Change PG&E Electric Rates on January 1, 2014**
Keywords (choose from CPUC listing): **Compliance, Balancing Accounts, Increase Rates**

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: **Resolutions E-3906, E-3956, E-4032, E-4121, E-4217, E-4289, E-4379, E-4432 and E-4548**

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

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

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

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

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

Resolution Required? ☑ Yes ☐No

Requested effective date: **January 1, 2014** No. of tariff sheets: **N/A**

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

Estimated system average rate effect (%):

Bundled: 2.4%

DA/CCA: -2.3%

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). **Please see Table 3.**

Tariff schedules affected:

Service affected and changes proposed:

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:

CPUC, Energy Division
ED Tariff Unit
505 Van Ness Ave., 4th Floor
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

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

ADVICE 4278-E

AUGUST 30, 2013

PACIFIC GAS AND ELECTRIC COMPANY

2014 ANNUAL ELECTRIC TRUE-UP

TABLE 3

BDLD RESULTS

Class/Schedule	Total Revenue At Present	Generation Revenue	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	DWR Bond Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	AB32 Credit Revenue	CIA Revenue	Total Proposed Revenue
RESIDENTIAL																	
E-1	$4,308,955,037	$2,046,135,417	$325,014,787	$89,163,349	-$27,656,126	$0	$2,818,737	$1,548,899,695	$303,821,564	$10,849,054	$102,719,021	$45,759,719	-$33,485,230	$74,924,603	-$358,694,382	$126,433,404	$4,256,703,613
EL-1	$729,137,987	$691,035,245	$109,695,257	$30,093,389	-$9,334,178	$0	$952,011	-$51,841,550	$48,276,688	$3,660,592	$0	$15,443,931	-$11,301,284	$25,287,097	-$87,870,671	($122,829,210)	$641,267,317
E-7	$130,121,767	$76,280,050	$10,523,735	$2,887,042	-$895,485	$0	$91,353	$36,221,529	$9,850,900	$351,169	$3,301,976	$1,461,631	-$1,084,201	$2,425,945	-$9,431,319	$65,256	$132,069,583
EL-7	$5,937,652	$7,026,002	$875,237	$240,109	-$74,476	$0	$7,598	-$933,789	$819,279	$29,206	$0	$123,224	-$90,171	$201,761	-$425,436	($2,286,329)	$5,512,215
E-8	$127,422,478	$94,776,839	$8,595,927	$2,358,175	-$731,444	$0	$74,619	$24,021,615	$8,717,627	$286,840	$2,995,994	$1,210,216	-$885,590	$1,981,545	-$8,040,762	($4,540,803)	$130,820,796
EL-8	$8,445,946	$14,159,933	$1,299,718	$356,560	-$110,595	$0	$11,282	-$4,386,816	$675,174	$43,371	$0	$182,987	-$133,903	$299,613	-$440,129	($3,951,377)	$8,005,817
TOTAL RES	$5,310,020,868	$2,929,413,487	$456,004,661	$125,098,624	-$38,802,303	$0	$3,955,600	$1,551,980,683	$372,161,233	$15,220,232	$109,016,991	$64,201,707	-$46,980,379	$105,120,563	-$464,902,698	($7,109,059)	$5,174,379,342
SMALL L&P																	
A-1	$1,351,189,095	$683,927,960	$88,789,749	$28,085,781	-$8,711,471	$0	$770,223	$461,132,923	$102,219,326	$3,416,253	$35,636,032	$12,613,625	-$10,547,346	$19,963,609	-$15,684,978		$1,401,611,687
A-6	$254,831,415	$137,662,608	$17,948,249	$5,674,489	-$1,760,077	$0	$155,617	$82,456,084	$18,376,794	$690,224	$7,189,101	$2,548,474	-$2,131,000	$4,033,474	-$1,283,591		$271,560,446
A-15	$306,696	$55,386	$7,267	$2,299	-$713	$0	$63	$234,343	$8,371	$280	$2,920	$1,032	-$863	$1,634	-$2,217		$309,802
TC-1	$7,025,773	$3,099,106	$487,255	$154,132	-$47,808	$0	$4,227	$3,053,401	$271,885	$18,748	$195,820	$69,222	-$57,883	$109,558	$0		$7,357,664
TOTAL SMALL	$1,613,352,979	$824,745,060	$107,232,520	$33,916,701	-$10,520,068	$0	$930,130	$546,876,752	$120,876,377	$4,125,506	$43,023,873	$15,232,353	-$12,737,092	$24,108,276	-$16,970,786		$1,680,839,599
MEDIUM L&P																	
A-10 T	$310,727	$226,918	$39,997	$10,131	-$3,142	$0	$347	$12,768	$31,200	$1,232	$12,871	$4,920	-$3,805	$6,654	-$699		$339,393
A-10 P	$7,909,018	$4,840,697	$813,724	$205,646	-$63,786	$0	$7,053	$1,594,432	$653,051	$25,014	$259,564	$99,870	-$77,229	$135,062	-$51,487		$8,441,611
A-10 S	$1,182,934,460	$719,696,681	$105,696,290	$28,118,969	-$8,721,764	$0	$916,325	$271,122,189	$91,384,087	$3,420,290	$35,565,080	$13,655,680	-$10,559,810	$18,467,682	-$3,169,775		$1,265,591,926
TOTAL MEDIUM	$1,191,154,205	$724,764,297	$106,550,011	$28,334,746	-$8,788,693	$0	$923,725	$272,729,389	$92,068,338	$3,446,537	$35,837,515	$13,760,470	-$10,640,843	$18,609,398	-$3,221,961		$1,274,372,930
E-19 CLASS																	
E-19 T	$5,574,542	$3,901,585	$650,061	$193,056	-$59,881	$0	$5,613	$420,515	$556,866	$23,483	$245,272	$76,473	-$72,500	$126,793	-$43,401		$6,023,934
E-19 P	$121,445,425	$79,811,100	$10,298,747	$3,512,462	-$1,089,473	$0	$88,975	$21,117,275	$10,150,927	$427,243	$4,458,449	$1,391,351	-$1,319,071	$2,306,878	-$290,593		$130,864,270
E-19 S	$1,667,457,002	$1,059,586,981	$123,931,630	$45,960,155	-$14,255,631	$0	$1,073,782	$341,244,646	$142,357,129	$5,590,428	$58,344,398	$18,205,667	-$17,259,896	$30,185,230	-$4,046,347		$1,790,918,172
TOTAL E-19	$1,794,476,969	$1,143,299,665	$134,880,438	$49,665,673	-$15,404,985	$0	$1,168,370	$362,782,436	$153,064,922	$6,041,154	$63,048,119	$19,673,491	-$18,651,468	$32,618,901	-$4,380,340		$1,927,806,376
STREETLIGHTS	$69,901,669	$32,867,822	$3,276,953	$1,579,680	-$489,975	$0	$28,445	$30,781,075	$2,830,654	$192,147	$2,006,938	$100,875	-$593,234	$711,662	$0		$73,293,041
STANDBY																	
STANDBY T	$47,290,909	$28,081,754	$7,704,174	$1,659,703	-$514,796	$0	$33,233	$5,097,917	$4,808,047	$201,880	$2,108,605	$482,532	-$623,285	$1,706,309	-$1,161,241		$49,584,831
STANDBY P	$9,392,295	$3,288,032	$668,365	$164,516	-$51,028	$0	$3,294	$4,553,697	$674,226	$20,011	$209,012	$47,830	-$61,782	$169,135	-$123,346		$9,561,962
STANDBY S	$698,426	$229,728	$47,125	$11,376	-$3,529	$0	$228	$361,742	$44,113	$1,384	$14,453	$3,307	-$4,272	$11,695	-$7,161		$710,189
TOTAL STANDBY	$57,381,630	$31,599,515	$8,419,663	$1,835,594	-$569,353	$0	$36,755	$10,013,356	$5,526,385	$223,275	$2,332,070	$533,669	-$689,340	$1,887,140	-$1,291,748		$59,856,981
AGRICULTURE																	
AG-1A	$17,958,003	$6,370,522	$607,263	$241,825	-$75,008	$0	$5,270	$9,627,838	$1,205,632	$29,415	$307,232	$108,591	-$90,815	$138,501	-$332,348		$18,143,918
AG-RA	$6,018,547	$2,240,298	$273,584	$108,947	-$33,793	$0	$2,374	$2,965,088	$429,186	$13,252	$138,414	$48,923	-$40,914	$62,398	-$64,159		$6,143,599
AG-VA	$4,465,881	$1,722,565	$202,649	$80,699	-$25,031	$0	$1,759	$2,150,172	$318,581	$9,816	$102,526	$36,238	-$30,306	$46,219	-$49,542		$4,566,345
AG-4A	$72,176,586	$27,358,388	$3,081,743	$1,227,216	-$380,650	$0	$26,744	$40,648,118	$4,820,490	$149,274	$1,559,143	$551,080	-$460,869	$702,867	-$646,833		$78,636,711
AG-5A	$19,159,200	$9,875,763	$1,094,565	$435,879	-$135,198	$0	$9,499	$6,733,394	$1,506,834	$53,019	$553,772	$195,731	-$163,690	$249,642	-$143,101		$20,266,107
AG-1B	$48,776,871	$21,513,325	$2,081,163	$828,763	-$257,061	$0	$18,061	$21,629,897	$3,322,330	$100,808	$1,052,920	$372,155	-$311,234	$474,660	-$193,687		$50,632,101
AG-RB	$6,767,521	$3,171,604	$345,282	$137,499	-$42,648	$0	$2,996	$2,680,257	$506,834	$16,725	$174,688	$61,744	-$51,636	$78,750	-$17,014		$7,065,081
AG-VB	$3,468,139	$1,553,754	$183,587	$73,108	-$22,676	$0	$1,593	$1,413,184	$266,995	$8,893	$92,882	$32,829	-$27,455	$41,872	-$5,958		$3,612,607
AG-4B	$95,950,439	$46,519,347	$5,076,005	$2,021,373	-$626,977	$0	$44,051	$37,308,801	$7,157,847	$245,873	$2,568,097	$907,695	-$759,107	$1,157,708	-$233,544		$101,387,167
AG-4C	$12,047,166	$5,438,335	$663,748	$264,319	-$81,985	$0	$5,760	$4,830,083	$940,496	$32,151	$335,809	$118,692	-$99,262	$151,384	-$28,376		$12,571,154
AG-5B	$526,272,689	$312,114,412	$42,566,322	$16,950,818	-$5,257,698	$0	$369,402	$112,161,813	$48,095,800	$2,061,837	$21,535,531	$7,611,745	-$6,365,718	$9,708,295	-$6,479,412		$555,073,149
AG-5C	$173,827,404	$109,093,809	$14,627,971	$5,825,170	-$1,806,815	$0	$126,946	$30,402,230	$16,183,594	$708,553	$7,400,713	$2,615,786	-$2,187,587	$3,336,268	-$561,941		$185,764,698
Total AG A	$119,778,217	$47,567,537	$5,259,803	$2,094,566	-$649,679	$0	$45,646	$62,124,609	$8,280,723	$254,775	$2,661,086	$940,562	-$786,594	$1,199,627	-$1,235,982		$127,756,680
Total AG B	$867,110,228	$499,404,586	$65,544,079	$26,101,051	-$8,095,860	$0	$568,810	$210,426,265	$76,473,895	$3,174,838	$33,160,641	$11,720,646	-$9,802,000	$14,948,937	-$7,519,931		$916,105,957
TOTAL AG	$986,888,445	$546,972,122	$70,803,882	$28,195,617	-$8,745,539	$0	$614,456	$272,550,874	$84,754,618	$3,429,614	$35,821,727	$12,661,208	-$10,588,594	$16,148,565	-$8,755,913		$1,043,862,637
E-20 CLASS																	
E-20 T	$356,713,091	$283,308,908	$36,005,598	$14,518,233	-$4,503,174	$0	$305,396	-$1,200,306	$35,554,980	$1,765,946	$18,445,001	$4,556,522	-$5,452,184	$7,750,777	-$5,345,371		$385,710,327
E-20 P	$501,463,265	$343,576,107	$39,032,802	$15,939,257	-$4,943,938	$0	$336,672	$72,322,941	$44,818,908	$1,938,794	$20,250,372	$5,647,924	-$5,985,836	$8,509,412	-$1,850,759		$539,592,656
E-20 S	$230,189,439	$147,802,464	$17,936,463	$6,657,327	-$2,064,928	$0	$155,072	$43,642,231	$20,183,278	$809,773	$8,457,944	$2,480,054	-$2,500,096	$3,554,114	-$522,061		$246,591,637
TOTAL E-20	$1,088,365,796	$774,687,478	$92,974,863	$37,114,818	-$11,512,040	$0	$797,140	$114,764,866	$100,557,166	$4,514,513	$47,153,317	$12,684,501	-$13,938,115	$19,814,302	-$7,718,191		$1,171,894,620
SYSTEM	$12,111,542,561	$7,008,349,446	$980,142,993	$305,741,453	-$94,832,957	$0	$8,454,619	$3,162,479,432	$931,839,693	$37,192,976	$338,240,550	$138,848,275	-$114,819,065	$219,018,807	-$507,241,638	-$7,109,059	$12,406,305,524

BDLD RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	Generation Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	DWR Bond Rates	CTC Rates	ECRA Rates	NSGC Rates	AB32 Credit Rates	CIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																			
E-1	22,125,420,719	$0.19475	$0.09248	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.07001	$0.01373	$0.00049	$0.00464	$0.00207	-$0.00151	$0.00339	-$0.01621	$0.00571	$0.19239	-1.2%
EL-1	7,467,342,184	$0.09764	$0.09254	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	-$0.00694	$0.00647	$0.00049	$0.00000	$0.00207	-$0.00151	$0.00339	-$0.01177	-$0.01645	$0.08588	-12.1%
E-7	716,387,702	$0.18164	$0.10648	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.05056	$0.01375	$0.00049	$0.00461	$0.00207	-$0.00151	$0.00339	-$0.01317	$0.00009	$0.18435	1.5%
EL-7	59,580,461	$0.09966	$0.11792	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	-$0.01567	$0.01375	$0.00049	$0.00000	$0.00207	-$0.00151	$0.00339	-$0.00714	-$0.03837	$0.09252	-7.2%
E-8	585,155,032	$0.21776	$0.16197	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.04105	$0.01490	$0.00049	$0.00512	$0.00207	-$0.00151	$0.00339	-$0.01374	-$0.00776	$0.22357	2.7%
EL-8	88,476,368	$0.09546	$0.16004	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	-$0.04958	$0.00763	$0.00049	$0.00000	$0.00207	-$0.00151	$0.00339	-$0.00497	-$0.04466	$0.09049	-5.2%
TOTAL RES	31,042,362,467	$0.17106	$0.09437	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.05000	$0.01199	$0.00049	$0.00351	$0.00207	-$0.00151	$0.00339	-$0.01498	-$0.00023	$0.16669	-2.6%
SMALL L&P																			
A-1	6,969,176,494	$0.19388	$0.09814	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.06617	$0.01467	$0.00049	$0.00511	$0.00181	-$0.00151	$0.00286	-$0.00225		$0.20112	3.7%
A-6	1,408,061,781	$0.18098	$0.09777	$0.01275	$0.00403	-$0.00125	$0.00000	$0.00011	$0.05856	$0.01305	$0.00049	$0.00511	$0.00181	-$0.00151	$0.00286	-$0.00091		$0.19286	6.6%
A-15	570,385	$0.53770	$0.09710	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.41085	$0.01468	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00286	-$0.00389		$0.54314	1.0%
TC-1	38,246,101	$0.18370	$0.08103	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.07984	$0.00711	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00286	$0.00000		$0.19238	4.7%
TOTAL SMALL	8,416,054,761	$0.19170	$0.09800	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.06498	$0.01436	$0.00049	$0.00511	$0.00181	-$0.00151	$0.00286	-$0.00202		$0.19972	4.2%
MEDIUM L&P																			
A-10 T	2,513,896	$0.12360	$0.09027	$0.01591	$0.00403	-$0.00125	$0.00000	$0.00014	$0.00508	$0.01241	$0.00049	$0.00512	$0.00196	-$0.00151	$0.00265	-$0.00028		$0.13501	9.2%
A-10 P	51,028,887	$0.15499	$0.09486	$0.01595	$0.00403	-$0.00125	$0.00000	$0.00014	$0.03125	$0.01280	$0.00049	$0.00509	$0.00196	-$0.00151	$0.00265	-$0.00101		$0.16543	6.7%
A-10 S	6,977,411,580	$0.16954	$0.10315	$0.01515	$0.00403	-$0.00125	$0.00000	$0.00013	$0.03886	$0.01310	$0.00049	$0.00510	$0.00196	-$0.00151	$0.00265	-$0.00045		$0.18138	7.0%
TOTAL MEDIUM	7,030,954,363	$0.16942	$0.10308	$0.01515	$0.00403	-$0.00125	$0.00000	$0.00013	$0.03879	$0.01309	$0.00049	$0.00510	$0.00196	-$0.00151	$0.00265	-$0.00046		$0.18125	7.0%
E-19 CLASS																			
E-19 T	47,904,692	$0.11637	$0.08144	$0.01357	$0.00403	-$0.00125	$0.00000	$0.00012	$0.00878	$0.01162	$0.00049	$0.00512	$0.00160	-$0.00151	$0.00265	-$0.00091		$0.12575	8.1%
E-19 P	871,578,642	$0.13934	$0.09157	$0.01182	$0.00403	-$0.00125	$0.00000	$0.00010	$0.02423	$0.01165	$0.00049	$0.00512	$0.00160	-$0.00151	$0.00265	-$0.00033		$0.15015	7.8%
E-19 S	11,404,504,973	$0.14621	$0.09291	$0.01087	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02992	$0.01248	$0.00049	$0.00512	$0.00160	-$0.00151	$0.00265	-$0.00035		$0.15704	7.4%
TOTAL E-19	12,323,988,307	$0.14561	$0.09277	$0.01094	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02944	$0.01242	$0.00049	$0.00512	$0.00160	-$0.00151	$0.00265	-$0.00036		$0.15643	7.4%
STREETLIGHTS	391,980,055	$0.17833	$0.08385	$0.00836	$0.00403	-$0.00125	$0.00000	$0.00007	$0.07853	$0.00722	$0.00049	$0.00512	$0.00026	-$0.00151	$0.00182	$0.00000		$0.18698	4.9%
STANDBY																			
STANDBY T	411,836,868	$0.11483	$0.06819	$0.01871	$0.00403	-$0.00125	$0.00000	$0.00008	$0.01238	$0.01167	$0.00049	$0.00512	$0.00117	-$0.00151	$0.00414	-$0.00282		$0.12040	4.9%
STANDBY P	40,822,741	$0.23008	$0.08054	$0.01637	$0.00403	-$0.00125	$0.00000	$0.00008	$0.11155	$0.01652	$0.00049	$0.00512	$0.00117	-$0.00151	$0.00414	-$0.00302		$0.23423	1.8%
STANDBY S	2,822,805	$0.24742	$0.08138	$0.01669	$0.00403	-$0.00125	$0.00000	$0.00008	$0.12815	$0.01563	$0.00049	$0.00512	$0.00117	-$0.00151	$0.00414	-$0.00254		$0.25159	1.7%
TOTAL STANDBY	455,482,414	$0.12598	$0.06938	$0.01849	$0.00403	-$0.00125	$0.00000	$0.00008	$0.02198	$0.01213	$0.00049	$0.00512	$0.00117	-$0.00151	$0.00414	-$0.00284		$0.13141	4.3%
AGRICULTURE																			
AG-1A	60,006,194	$0.29927	$0.10616	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.16045	$0.02009	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00554		$0.30237	1.0%
AG-RA	27,034,011	$0.22263	$0.08287	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.10968	$0.01588	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00237		$0.22725	2.1%
AG-VA	20,024,577	$0.22302	$0.08602	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.10738	$0.01591	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00247		$0.22804	2.2%
AG-4A	304,520,075	$0.23702	$0.08984	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.13348	$0.01583	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00212		$0.25823	9.0%
AG-5A	108,158,558	$0.17714	$0.09131	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.06225	$0.01393	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00132		$0.18737	5.8%
AG-1B	205,648,500	$0.23719	$0.10461	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.10518	$0.01616	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00094		$0.24621	3.8%
AG-RB	34,118,795	$0.19835	$0.09296	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.07856	$0.01485	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00050		$0.20707	4.4%
AG-VB	18,141,027	$0.19118	$0.08565	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.07790	$0.01472	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00033		$0.19914	4.2%
AG-4B	501,581,488	$0.19130	$0.09275	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.07438	$0.01427	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00047		$0.20213	5.7%
AG-4C	65,587,768	$0.18368	$0.08292	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.07364	$0.01434	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00043		$0.19167	4.3%
AG-5B	4,206,158,347	$0.12512	$0.07420	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02667	$0.01143	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00154		$0.13197	5.5%
AG-5C	1,445,451,726	$0.12026	$0.07547	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02103	$0.01120	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00039		$0.12852	6.9%
Total AG A	519,743,415	$0.23046	$0.09152	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.11953	$0.01593	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00238		$0.24581	6.7%
Total AG B	6,476,687,651	$0.13388	$0.07711	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.03249	$0.01181	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00116		$0.14145	5.7%
TOTAL AG	6,996,431,066	$0.14106	$0.07818	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.03896	$0.01211	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00125		$0.14920	5.8%
E-20 CLASS																			
E-20 T	3,602,539,322	$0.09902	$0.07864	$0.00999	$0.00403	-$0.00125	$0.00000	$0.00008	-$0.00033	$0.00987	$0.00049	$0.00512	$0.00126	-$0.00151	$0.00215	-$0.00148		$0.10707	8.1%
E-20 P	3,955,150,718	$0.12679	$0.08687	$0.00987	$0.00403	-$0.00125	$0.00000	$0.00009	$0.01829	$0.01133	$0.00049	$0.00512	$0.00143	-$0.00151	$0.00215	-$0.00047		$0.13643	7.6%
E-20 S	1,651,942,240	$0.13934	$0.08947	$0.01086	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02642	$0.01222	$0.00049	$0.00512	$0.00150	-$0.00151	$0.00215	-$0.00032		$0.14927	7.1%
TOTAL E-20	9,209,632,281	$0.11818	$0.08412	$0.01010	$0.00403	-$0.00125	$0.00000	$0.00009	$0.01246	$0.01092	$0.00049	$0.00512	$0.00138	-$0.00151	$0.00215	-$0.00084		$0.12725	7.7%
SYSTEM	75,866,885,714	$0.15964	$0.09238	$0.01292	$0.00403	-$0.00125	$0.00000	$0.00011	$0.04168	$0.01228	$0.00049	$0.00446	$0.00183	-$0.00151	$0.00289	-$0.00669	-$0.00009	$0.16353	2.4%

DA/CCA RESULTS

Class/Schedule	Total Revenue At Present	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	DWR Bond Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	AB32 Credit Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																	
E-1	$80,369,224	$9,235,023	$2,533,502	-$785,826	$0	$80,166	$44,048,820	$8,632,727	$308,166	$3,117,722	$1,300,194	-$951,432	$2,128,870	-$10,863,150	$7,932,242	$6,920,713	$73,637,738
EL-1	$2,004,822	$1,322,251	$362,741	-$112,513	$0	$11,478	-$621,919	$581,924	$44,123	$0	$186,159	-$136,224	$304,807	-$1,360,434	-$1,688,586	$1,039,997	-$66,196
E-7	$2,981,832	$372,130	$102,089	-$31,665	$0	$3,230	$1,220,711	$348,337	$12,418	$117,978	$52,392	-$38,338	$85,784	-$412,933	$720,390	$236,430	$2,788,953
EL-7	$22,858	$26,743	$7,336	-$2,276	$0	$232	-$31,731	$25,033	$892	$0	$3,765	-$2,755	$6,165	-$11,758	-$48,015	$16,136	-$10,233
E-8	$1,688,141	$237,624	$65,189	-$20,220	$0	$2,063	$671,385	$240,988	$7,929	$79,972	$33,455	-$24,481	$54,777	-$254,811	$267,931	$143,505	$1,505,305
EL-8	-$64,622	$31,883	$8,747	-$2,713	$0	$277	-$110,715	$16,562	$1,064	$0	$4,489	-$3,285	$7,350	-$9,592	-$74,903	$16,016	-$114,821
TOTAL RES	$87,002,255	$11,225,653	$3,079,604	-$955,212	$0	$97,447	$45,176,552	$9,845,572	$374,592	$3,315,672	$1,580,453	-$1,156,516	$2,587,752	-$12,912,678	$7,109,059	$8,372,797	$77,740,746
SMALL L&P																	
A-1	$24,428,039	$2,758,979	$872,738	-$270,700	$0	$23,934	$14,883,897	$3,176,466	$106,157	$1,105,214	$391,956	-$327,749	$620,350	-$242,221		$862,648	$23,961,668
A-6	$8,145,702	$1,017,625	$321,902	-$99,845	$0	$8,828	$4,787,089	$1,043,656	$39,155	$399,356	$144,569	-$120,887	$228,810	-$38,466		$430,986	$8,162,777
A-15	$1,120	$46	$14	-$4	$0	$0	$978	$52	$2	$7	$6	-$5	$10	-$33		$1	$1,076
TC-1	$99,910	$10,430	$3,299	-$1,023	$0	$90	$69,179	$5,820	$401	$4,192	$1,482	-$1,239	$2,345	$0		$5,839	$100,815
TOTAL SMALL	$32,674,772	$3,787,079	$1,197,954	-$371,574	$0	$32,853	$19,741,143	$4,225,995	$145,715	$1,508,769	$538,014	-$449,880	$851,515	-$280,720		$1,299,474	$32,226,336
MEDIUM L&P																	
A-10 T	$10,971	$3,064	$915	-$284	$0	$27	$2,830	$2,817	$111	$1,162	$444	-$343	$601	-$3		-$376	$10,964
A-10 P	$320,799	$60,163	$17,959	-$5,570	$0	$522	$133,959	$57,241	$2,184	$22,816	$8,721	-$6,744	$11,795	-$606		$23,271	$325,709
A-10 S	$54,015,369	$9,345,695	$2,826,911	-$876,833	$0	$81,033	$25,386,636	$9,208,207	$343,855	$3,590,297	$1,372,859	-$1,061,619	$1,856,629	-$92,575		$2,351,252	$54,332,346
TOTAL MEDIUM	$54,347,139	$9,408,922	$2,845,784	-$882,687	$0	$81,581	$25,523,424	$9,268,265	$346,151	$3,614,275	$1,382,025	-$1,068,707	$1,869,024	-$93,184		$2,374,147	$54,669,019
E-19 CLASS																	
E-19 T	-$1,443	$0	$0	$0	$0	$0	-$1,443	$0	$0	$0	$0	$0	$0	-$4,959		$0	-$6,402
E-19 P	$10,560,707	$2,041,724	$727,193	-$225,556	$0	$17,703	$4,067,851	$2,102,754	$88,453	$923,878	$288,054	-$273,090	$477,598	-$79,769		$388,606	$10,545,398
E-19 S	$214,170,536	$33,337,296	$14,357,100	-$4,453,195	$0	$289,054	$89,361,021	$44,490,419	$1,746,346	$18,063,703	$5,687,113	-$5,391,672	$9,429,306	-$391,686		$8,428,767	$214,953,573
TOTAL E-19	$224,729,800	$35,379,020	$15,084,293	-$4,678,751	$0	$306,756	$93,427,429	$46,593,173	$1,834,799	$18,987,581	$5,975,167	-$5,664,762	$9,906,904	-$476,415		$8,817,373	$225,492,568
STREETLIGHTS	$889,459	$71,450	$34,443	-$10,683	$0	$620	$655,567	$60,897	$4,190	$43,759	$2,199	-$12,935	$15,517	$0		$9,602	$874,627
STANDBY																	
STANDBY T	$1,707,650	$612,846	$128,164	-$39,753	$0	$2,566	$130,348	$371,282	$15,589	$162,828	$37,262	-$48,131	$131,763	$0		$226,751	$1,731,514
STANDBY P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0
STANDBY S	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$20		$0	-$20
TOTAL STANDBY	$1,707,650	$612,846	$128,164	-$39,753	$0	$2,566	$130,348	$371,282	$15,589	$162,828	$37,262	-$48,131	$131,763	-$20		$226,751	$1,731,495
AGRICULTURE																	
AG-1A	$46,629	$1,979	$788	-$244	$0	$17	$38,036	$3,929	$96	$982	$354	-$296	$451	-$672		-$329	$45,091
AG-RA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0
AG-VA	$2,262	$158	$63	-$19	$0	$1	$1,652	$248	$8	$80	$28	-$24	$36	-$46		-$23	$2,161
AG-4A	$24,255	$1,895	$755	-$234	$0	$16	$19,193	$2,964	$92	$910	$339	-$283	$432	-$403		-$305	$25,371
AG-5A	$44,384	$5,022	$2,000	-$620	$0	$44	$27,660	$6,913	$243	$2,541	$898	-$751	$1,145	-$772		-$867	$43,456
AG-1B	$11,755	$548	$218	-$68	$0	$5	$9,471	$874	$27	$277	$98	-$82	$125	-$253		$83	$11,323
AG-RB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0
AG-VB	$97	$0	$0	$0	$0	$0	$97	$0	$0	$0	$0	$0	$0	$0		$0	$97
AG-4B	$47,180	$4,735	$1,885	-$585	$0	$41	$30,963	$6,676	$229	$2,395	$847	-$708	$1,080	-$40		-$677	$46,841
AG-4C	$1,853	$117	$47	-$14	$0	$1	$1,326	$166	$6	$59	$21	-$18	$27	-$167		$127	$1,698
AG-5B	$2,520,789	$397,190	$158,170	-$49,060	$0	$3,447	$1,105,859	$448,787	$19,239	$200,950	$71,026	-$59,399	$90,589	-$35,600		$148,526	$2,499,724
AG-5C	$127,588	$22,252	$8,861	-$2,748	$0	$193	$52,566	$24,618	$1,078	$11,258	$3,979	-$3,328	$5,075	-$23,152		$3,052	$103,703
Total AG A	$117,530	$9,054	$3,605	-$1,118	$0	$79	$86,541	$14,055	$439	$4,513	$1,619	-$1,354	$2,065	-$1,893		-$1,524	$116,081
Total AG B	$2,709,262	$424,841	$169,181	-$52,475	$0	$3,687	$1,200,282	$481,121	$20,579	$214,939	$75,970	-$63,534	$96,895	-$59,211		$151,111	$2,663,386
TOTAL AG	$2,826,792	$433,895	$172,786	-$53,594	$0	$3,765	$1,286,823	$495,176	$21,017	$219,453	$77,589	-$64,888	$98,960	-$61,104		$149,587	$2,779,466
E-20 CLASS																	
E-20 T	$53,653,607	$16,330,329	$7,723,025	-$2,395,479	$0	$141,528	-$7,198,901	$21,735,931	$1,079,581	$8,530,609	$2,423,858	-$2,900,308	$4,123,053	-$2,071,417		$3,778,949	$51,300,756
E-20 P	$121,562,797	$22,540,986	$9,695,342	-$3,007,240	$0	$195,353	$41,861,930	$27,358,318	$1,183,477	$12,234,699	$3,435,452	-$3,640,993	$5,176,004	-$1,854,580		$3,850,853	$119,029,602
E-20 S	$46,051,492	$7,188,179	$3,169,642	-$983,140	$0	$62,297	$18,263,384	$10,410,104	$417,664	$4,026,940	$1,180,787	-$1,190,329	$1,692,161	-$261,724		$1,536,972	$45,512,937
TOTAL E-20	$221,267,895	$46,059,495	$20,588,009	-$6,385,859	$0	$399,177	$52,926,413	$59,504,353	$2,680,722	$24,792,248	$7,040,097	-$7,731,630	$10,991,218	-$4,187,721		$9,166,774	$215,843,295
SYSTEM	$625,445,764	$106,978,359	$43,131,037	-$13,378,113	$0	$924,765	$238,867,698	$130,364,712	$5,422,774	$52,644,584	$16,632,807	-$16,197,448	$26,452,654	-$18,011,841	$7,109,059	$30,416,505	$611,357,552

DA/CCA RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	DWR Bond Rates	CTC Rates	ECRA Rates	NSGC Rates	AB32 Credit Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																			
E-1	628,660,545	$0.12784	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.07007	$0.01373	$0.00049	$0.00496	$0.00207	-$0.00151	$0.00339	-$0.01728	$0.01262	$0.01101	$0.11713	-8.4%
EL-1	90,010,255	$0.02227	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	-$0.00691	$0.00647	$0.00049	$0.00000	$0.00207	-$0.00151	$0.00339	-$0.01511	-$0.01876	$0.01155	-$0.00074	-103.3%
E-7	25,332,168	$0.11771	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.04819	$0.01375	$0.00049	$0.00466	$0.00207	-$0.00151	$0.00339	-$0.01630	$0.02844	$0.00933	$0.11010	-6.5%
EL-7	1,820,465	$0.01256	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	-$0.01743	$0.01375	$0.00049	$0.00000	$0.00207	-$0.00151	$0.00339	-$0.00646	-$0.02638	$0.00886	-$0.00562	-144.8%
E-8	16,175,869	$0.10436	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.04151	$0.01490	$0.00049	$0.00494	$0.00207	-$0.00151	$0.00339	-$0.01575	$0.01656	$0.00887	$0.09306	-10.8%
EL-8	2,170,382	-$0.02977	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	-$0.05101	$0.00763	$0.00049	$0.00000	$0.00207	-$0.00151	$0.00339	-$0.00442	-$0.03451	$0.00738	-$0.05290	77.7%
TOTAL RES	764,169,685	$0.11385	$0.01469	$0.00403	-$0.00125	$0.00000	$0.00013	$0.05912	$0.01288	$0.00049	$0.00434	$0.00207	-$0.00151	$0.00339	-$0.01690	$0.00930	$0.01096	$0.10173	-10.6%
SMALL L&P																			
A-1	216,560,375	$0.11280	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.06873	$0.01467	$0.00049	$0.00510	$0.00181	-$0.00151	$0.00286	-$0.00112		$0.00398	$0.11065	-1.9%
A-6	79,876,336	$0.10198	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.05993	$0.01307	$0.00049	$0.00500	$0.00181	-$0.00151	$0.00286	-$0.00048		$0.00540	$0.10219	0.2%
A-15	3,574	$0.31347	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.27369	$0.01468	$0.00049	$0.00209	$0.00181	-$0.00151	$0.00286	-$0.00911		$0.00034	$0.30097	-4.0%
TC-1	818,678	$0.12204	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.08450	$0.00711	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00286	$0.00000		$0.00713	$0.12314	0.9%
TOTAL SMALL	297,258,963	$0.10992	$0.01274	$0.00403	-$0.00125	$0.00000	$0.00011	$0.06641	$0.01422	$0.00049	$0.00508	$0.00181	-$0.00151	$0.00286	-$0.00094		$0.00437	$0.10841	-1.4%
MEDIUM L&P																			
A-10 T	226,950	$0.04834	$0.01350	$0.00403	-$0.00125	$0.00000	$0.00012	$0.01247	$0.01241	$0.00049	$0.00512	$0.00196	-$0.00151	$0.00265	-$0.00001		-$0.00165	$0.04831	-0.1%
A-10 P	4,456,246	$0.07199	$0.01350	$0.00403	-$0.00125	$0.00000	$0.00012	$0.03006	$0.01285	$0.00049	$0.00512	$0.00196	-$0.00151	$0.00265	-$0.00014		$0.00522	$0.07309	1.5%
A-10 S	701,466,737	$0.07700	$0.01332	$0.00403	-$0.00125	$0.00000	$0.00012	$0.03619	$0.01313	$0.00049	$0.00512	$0.00196	-$0.00151	$0.00265	-$0.00013		$0.00335	$0.07746	0.6%
TOTAL MEDIUM	706,149,934	$0.07696	$0.01332	$0.00403	-$0.00125	$0.00000	$0.00012	$0.03614	$0.01313	$0.00049	$0.00512	$0.00196	-$0.00151	$0.00265	-$0.00013		$0.00336	$0.07742	0.6%
E-19 CLASS																			
E-19 T	0																		
E-19 P	180,444,834	$0.05853	$0.01131	$0.00403	-$0.00125	$0.00000	$0.00010	$0.02254	$0.01165	$0.00049	$0.00512	$0.00160	-$0.00151	$0.00265	-$0.00044		$0.00215	$0.05844	-0.1%
E-19 S	3,562,555,942	$0.06012	$0.00936	$0.00403	-$0.00125	$0.00000	$0.00008	$0.02508	$0.01249	$0.00049	$0.00507	$0.00160	-$0.00151	$0.00265	-$0.00011		$0.00237	$0.06034	0.4%
TOTAL E-19	3,743,000,776	$0.06004	$0.00945	$0.00403	-$0.00125	$0.00000	$0.00008	$0.02496	$0.01245	$0.00049	$0.00507	$0.00160	-$0.00151	$0.00265	-$0.00013		$0.00236	$0.06024	0.3%
STREETLIGHTS	8,546,670	$0.10407	$0.00836	$0.00403	-$0.00125	$0.00000	$0.00007	$0.07670	$0.00713	$0.00049	$0.00512	$0.00026	-$0.00151	$0.00182	$0.00000		$0.00112	$0.10234	-1.7%
STANDBY																			
STANDBY T	31,802,418	$0.05370	$0.01927	$0.00403	-$0.00125	$0.00000	$0.00008	$0.00410	$0.01167	$0.00049	$0.00512	$0.00117	-$0.00151	$0.00414	$0.00000		$0.00713	$0.05445	1.4%
STANDBY P	0																		
STANDBY S	0																		
TOTAL STANDBY	31,802,418	$0.05370	$0.01927	$0.00403	-$0.00125	$0.00000	$0.00008	$0.00410	$0.01167	$0.00049	$0.00512	$0.00117	-$0.00151	$0.00414	$0.00000		$0.00713	$0.05445	1.4%
AGRICULTURE																			
AG-1A	195,555	$0.23844	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.19450	$0.02009	$0.00049	$0.00502	$0.00181	-$0.00151	$0.00231	-$0.00344		-$0.00168	$0.23058	-3.3%
AG-RA	0																		
AG-VA	15,576	$0.14522	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.10606	$0.01591	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00296		-$0.00145	$0.13876	-4.4%
AG-4A	187,266	$0.12952	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.10249	$0.01583	$0.00049	$0.00486	$0.00181	-$0.00151	$0.00231	-$0.00215		-$0.00163	$0.13548	4.6%
AG-5A	496,239	$0.08944	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.05574	$0.01393	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00155		-$0.00175	$0.08757	-2.1%
AG-1B	54,111	$0.21724	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.17503	$0.01616	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00467		$0.00153	$0.20925	-3.7%
AG-RB	0																		
AG-VB	0																		
AG-4B	467,838	$0.10085	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.06618	$0.01427	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00008		-$0.00145	$0.10012	-0.7%
AG-4C	11,571	$0.16016	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.11462	$0.01434	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.01444		$0.01100	$0.14672	-8.4%
AG-5B	39,248,069	$0.06423	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02818	$0.01143	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00091		$0.00378	$0.06369	-0.8%
AG-5C	2,198,766	$0.05803	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02391	$0.01120	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.01053		$0.00139	$0.04716	-18.7%
Total AG A	894,636	$0.13137	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.09673	$0.01571	$0.00049	$0.00504	$0.00181	-$0.00151	$0.00231	-$0.00212		-$0.00170	$0.12975	-1.2%
Total AG B	41,980,355	$0.06454	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.02859	$0.01146	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00141		$0.00360	$0.06344	-1.7%
TOTAL AG	42,874,991	$0.06593	$0.01012	$0.00403	-$0.00125	$0.00000	$0.00009	$0.03001	$0.01155	$0.00049	$0.00512	$0.00181	-$0.00151	$0.00231	-$0.00143		$0.00349	$0.06483	-1.7%
E-20 CLASS																			
E-20 T	2,202,350,977	$0.02436	$0.00741	$0.00351	-$0.00109	$0.00000	$0.00006	-$0.00327	$0.00987	$0.00049	$0.00387	$0.00110	-$0.00132	$0.00187	-$0.00094		$0.00172	$0.02329	-4.4%
E-20 P	2,414,299,614	$0.05035	$0.00934	$0.00402	-$0.00125	$0.00000	$0.00008	$0.01734	$0.01133	$0.00049	$0.00507	$0.00142	-$0.00151	$0.00214	-$0.00077		$0.00160	$0.04930	-2.1%
E-20 S	852,036,566	$0.05405	$0.00844	$0.00372	-$0.00115	$0.00000	$0.00007	$0.02143	$0.01222	$0.00049	$0.00473	$0.00139	-$0.00140	$0.00199	-$0.00031		$0.00180	$0.05342	-1.2%
TOTAL E-20	5,468,687,158	$0.04046	$0.00842	$0.00376	-$0.00117	$0.00000	$0.00007	$0.00968	$0.01088	$0.00049	$0.00453	$0.00129	-$0.00141	$0.00201	-$0.00077		$0.00168	$0.03947	-2.5%
SYSTEM	11,062,490,595	$0.05654	$0.00967	$0.00390	-$0.00121	$0.00000	$0.00008	$0.02159	$0.01178	$0.00049	$0.00476	$0.00150	-$0.00146	$0.00239	-$0.00163	$0.00064	$0.00275	$0.05526	-2.3%

ADVICE 4278-E

AUGUST 30, 2013

PACIFIC GAS AND ELECTRIC COMPANY

2014 ANNUAL ELECTRIC TRUE-UP

TABLE 4

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-1													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
EM													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
EM TOU													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.15421)	.24122	.29581
Tier 2	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.13557)	.24122	.31445
Tier 3	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.05565	.24122	.48820
Tier 4	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09565	.24122	.52820
Tier 5	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09565	.24122	.52820
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04435)	.11683	.18054
Tier 2	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.02571)	.11683	.19918
Tier 3	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16551	.11683	.37293
Tier 4	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20551	.11683	.41293
Tier 5	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20551	.11683	.41293
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.03700)	.06629	.10376
Tier 2	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.01835)	.06629	.12241
Tier 3	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.17287	.06629	.29616
Tier 4	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.21287	.06629	.33616
Tier 5	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.21287	.06629	.33616
Winter													
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06710)	.08661	.12493
Tier 2	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04846)	.08661	.14357
Tier 3	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14276	.08661	.31732
Tier 4	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18276	.08661	.35732
Tier 5	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18276	.08661	.35732
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04904)	.07323	.10810
Tier 2	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.03040)	.07323	.12674
Tier 3	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16082	.07323	.30049
Tier 4	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20082	.07323	.34049
Tier 5	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20082	.07323	.34049
METER CHARGE ($/meter/day)	-	-	.25298	-	-	-	-	-	-	-		-	.25298
MINIMUM CHARGE													
($/meter/day)	-	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh) - Regular Chg	.00278	-	-	-	-	-	-	-	-	-		-	

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
ES													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
DISCOUNT ($/dwelling unit/day)	-	-	(.02300)	-	-	-	-	-	-	-		-	(.02300)
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
MARL ($/kWh)	-	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000		.03985	.04892
ESR													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
ET													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
DISCOUNT ($/dwelling unit/day)	-	-	.07721	-	-	-	-	-	-	-		-	.07721
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
MARL ($/kWh)	-	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000		.03985	.04892

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-6													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.15421)	.24122	.29581
Tier 2	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.13557)	.24122	.31445
Tier 3	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.05565	.24122	.48820
Tier 4	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09565	.24122	.52820
Tier 5	.01469	.00013	.16791	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09565	.24122	.52820
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04435)	.11683	.18054
Tier 2	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.02571)	.11683	.19918
Tier 3	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16551	.11683	.37293
Tier 4	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20551	.11683	.41293
Tier 5	.01469	.00013	.06717	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20551	.11683	.41293
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.03700)	.06629	.10376
Tier 2	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.01835)	.06629	.12241
Tier 3	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.17287	.06629	.29616
Tier 4	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.21287	.06629	.33616
Tier 5	.01469	.00013	.03358	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.21287	.06629	.33616
Winter													
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06710)	.08661	.12493
Tier 2	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04846)	.08661	.14357
Tier 3	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14276	.08661	.31732
Tier 4	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18276	.08661	.35732
Tier 5	.01469	.00013	.06453	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18276	.08661	.35732
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04904)	.07323	.10810
Tier 2	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.03040)	.07323	.12674
Tier 3	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16082	.07323	.30049
Tier 4	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20082	.07323	.34049
Tier 5	.01469	.00013	.04302	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20082	.07323	.34049
METER CHARGE ($/meter/day)	-	-	.25298	-	-	-	-	-	-	-		-	.25298
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.12371	.00681	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-7													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.12993	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.29876)	.46011	.33219
Tier 2	.01469	.00013	.12993	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.27949)	.46011	.35146
Tier 3	.01469	.00013	.12993	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	(.08715)	.46011	.52633
Tier 4	.01469	.00013	.12993	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	(.04715)	.46011	.56633
Tier 5	.01469	.00013	.12993	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	(.04715)	.46011	.56633
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.05197	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.08929)	.08045	.08404
Tier 2	.01469	.00013	.05197	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.07003)	.08045	.10330
Tier 3	.01469	.00013	.05197	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.12232	.08045	.27818
Tier 4	.01469	.00013	.05197	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16232	.08045	.31818
Tier 5	.01469	.00013	.05197	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16232	.08045	.31818
Winter													
Peak													
Baseline (Tier 1)	.01469	.00013	.05817	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.28043)	.29904	.11769
Tier 2	.01469	.00013	.05817	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.26117)	.29904	.13695
Tier 3	.01469	.00013	.05817	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	(.06882)	.29904	.31183
Tier 4	.01469	.00013	.05817	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	(.02882)	.29904	.35183
Tier 5	.01469	.00013	.05817	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	(.02882)	.29904	.35183
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.03878	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04676)	.05472	.08765
Tier 2	.01469	.00013	.03878	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.02750)	.05472	.10691
Tier 3	.01469	.00013	.03878	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16485	.05472	.28179
Tier 4	.01469	.00013	.03878	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20485	.05472	.32179
Tier 5	.01469	.00013	.03878	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20485	.05472	.32179
METER CHARGE ($/meter/day)													
E-7	-	-	.11532	-	-	-	-	-	-	-		-	.11532
Rate W	-	-	.03843	-	-	-	-	-	-	-		-	.03843
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.13126	.00682	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-8													
ENERGY CHARGE ($/kWh)													
Summer													
Baseline (Tier 1)	.01469	.00013	.03752	.01490	.00049	.00512	.00207	(.00151)	.00339	.00000	(.13412)	.19532	.14078
Tier 2	.01469	.00013	.03752	.01490	.00049	.00512	.00207	(.00151)	.00339	.00000	(.13412)	.19532	.14078
Tier 3	.01469	.00013	.03752	.01490	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.05823	.19532	.31566
Tier 4	.01469	.00013	.03752	.01490	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09823	.19532	.35566
Tier 5	.01469	.00013	.03752	.01490	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09823	.19532	.35566
Winter										.00000			
Baseline (Tier 1)	.01469	.00013	.02502	.01490	.00049	.00512	.00207	(.00151)	.00339	.00000	(.10589)	.12896	.09015
Tier 2	.01469	.00013	.02502	.01490	.00049	.00512	.00207	(.00151)	.00339	.00000	(.10589)	.12896	.09015
Tier 3	.01469	.00013	.02502	.01490	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.08645	.12896	.26502
Tier 4	.01469	.00013	.02502	.01490	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.12645	.12896	.30502
Tier 5	.01469	.00013	.02502	.01490	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.12645	.12896	.30502
CUSTOMER CHARGE ($/meter/day)	-	-	.41160	-	-	-	-	-	-	-		-	.41160
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-9 RATE A													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.05882)	.20167	.32015
Tier 2	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.03954)	.20167	.33943
Tier 3	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18565	.20167	.54715
Tier 4	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.22565	.20167	.58715
Tier 5	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.22565	.20167	.58715
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.11827)	.12757	.10477
Tier 2	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.09900)	.12757	.12404
Tier 3	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.12620	.12757	.33177
Tier 4	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16620	.12757	.37177
Tier 5	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16620	.12757	.37177
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.10253)	.07405	.03971
Tier 2	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.08326)	.07405	.05898
Tier 3	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.05158	.07405	.17635
Tier 4	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09158	.07405	.21635
Tier 5	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09158	.07405	.21635
Winter													
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.09330)	.10585	.10465
Tier 2	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.07405)	.10585	.12390
Tier 3	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.15116	.10585	.33164
Tier 4	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.19116	.10585	.37164
Tier 5	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.19116	.10585	.37164
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.08569)	.06030	.04965
Tier 2	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06643)	.06030	.06891
Tier 3	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.05848	.06030	.17635
Tier 4	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09848	.06030	.21635
Tier 5	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.09848	.06030	.21635
METER CHARGE ($/meter/day)	-	-	.21881	-	-	-	-	-	-	-		-	.21881
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.13126	.00682	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-9 RATE B													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06363)	.20167	.31534
Tier 2	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04435)	.20167	.33462
Tier 3	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18084	.20167	.54234
Tier 4	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.22084	.20167	.58234
Tier 5	.01469	.00013	.13639	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.22084	.20167	.58234
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.12308)	.12757	.09996
Tier 2	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.10381)	.12757	.11923
Tier 3	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.12139	.12757	.32696
Tier 4	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16139	.12757	.36696
Tier 5	.01469	.00013	.05456	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16139	.12757	.36696
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.09473)	.07405	.04751
Tier 2	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.07545)	.07405	.06679
Tier 3	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14974	.07405	.27451
Tier 4	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18974	.07405	.31451
Tier 5	.01469	.00013	.02728	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18974	.07405	.31451
Winter													
Part-Peak													
Baseline (Tier 1)	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.09757)	.10585	.10038
Tier 2	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.07832)	.10585	.11963
Tier 3	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14690	.10585	.32738
Tier 4	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18690	.10585	.36738
Tier 5	.01469	.00013	.05119	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18690	.10585	.36738
Off-Peak													
Baseline (Tier 1)	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.07869)	.06030	.05665
Tier 2	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	.00000	(.05943)	.06030	.07591
Tier 3	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.16578	.06030	.28365
Tier 4	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20578	.06030	.32365
Tier 5	.01469	.00013	.03413	.01375	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.20578	.06030	.32365
METER CHARGE ($/meter/day)	-	-	.21881	-	-	-	-	-	-	-		-	.21881
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.13126	.00682	.00024	-	-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			

FERA CSI EXEMPTION FACTORS

E-1	1.27%
E-7	2.38%
E-A7	0.00%
E-8	5.01%
E-9	2.38%
E-6	1.60%

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
EL-1													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.03103)	.09256	.08316
Tier 2	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.01856)	.09256	.09563
Tier 3	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 4	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 5	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.09429	.00372	.00028		-	-	-	-			.11828
($/kWh)	.01747	-	-	-	-		.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-		-	-	-	-			
EML													
ENERGY CHARGE ($/kWh)													
Baseline (Tier 1)	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.03103)	.09256	.08316
Tier 2	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.01856)	.09256	.09563
Tier 3	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 4	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 5	.01469	.00013	(.00688)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.09429	.00372	.00028		-	-	-	-			.11828
($/kWh)	.01747	-	-	-	-		.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-		-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
EML TOU													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.16417)	.24122	.19655
Tier 2	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.15064)	.24122	.21008
Tier 3	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.05089)	.24122	.30983
Tier 4	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.05089)	.24122	.30983
Tier 5	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.05089)	.24122	.30983
Part-Peak													
Baseline (Tier 1)	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.02107)	.11683	.11451
Tier 2	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.00754)	.11683	.12804
Tier 3	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05119	.11683	.18677
Tier 4	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05119	.11683	.18677
Tier 5	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05119	.11683	.18677
Off-Peak													
Baseline (Tier 1)	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.00841	.06629	.05987
Tier 2	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02194	.06629	.07340
Tier 3	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05335	.06629	.10481
Tier 4	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05335	.06629	.10481
Tier 5	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05335	.06629	.10481
Winter													
Part-Peak													
Baseline (Tier 1)	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.02779)	.08661	.07494
Tier 2	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.01428)	.08661	.08845
Tier 3	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02468	.08661	.12741
Tier 4	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02468	.08661	.12741
Tier 5	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02468	.08661	.12741
Off-Peak													
Baseline (Tier 1)	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.00489)	.07323	.06295
Tier 2	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.00863	.07323	.07647
Tier 3	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.04159	.07323	.10943
Tier 4	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.04159	.07323	.10943
Tier 5	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.04159	.07323	.10943
METER CHARGE ($/meter/day)	-	-	.20238	-	-		-	-	-	-		-	.20238
MINIMUM CHARGE													
($/meter/day)	-	.00000	.09429	.00372	.00028		-	-	-	-			.11828
($/kWh)	.01747	-	-	-	-		.00207	(.00151)	.00339	.00000			
TRA ($/kWh) - Regular Chg	.00278	-	-	-	-		-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

ESL

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
ENERGY CHARGE ($/kWh)													
CARE Baseline (Tier 1)	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	(.03103)	.09256	.08316
Tier 2	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	(.01856)	.09256	.09563
Tier 3	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 4	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 5	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Non-CARE Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979

The master-metered customer's energy consumption will be billed at the CARE rate using the ratio of the number of qualifying CARE apartments/units to the total number of apartments/units.

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.09429	.00372	.00028	-	-	-	-	-			.11828
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
DISCOUNT ($/dwelling unit/day)	-	-	(.02300)	-	-	-	-	-	-	-		-	(.02300)
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
MARL ($/kWh)	-	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			.04892

ESRL

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
ENERGY CHARGE ($/kWh)													
CARE Baseline (Tier 1)	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	(.03103)	.09256	.08316
Tier 2	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	(.01856)	.09256	.09563
Tier 3	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 4	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 5	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Non-CARE Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979

The master-metered customer's energy consumption will be billed at the CARE rate using the ratio of the number of RV park spaces or marina slips/berths occupied by qualifying CARE tenants to the total number of RV park spaces or marina slips/berths.

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.09429	.00372	.00028	-	-	-	-	-			.11828
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
ETL													
ENERGY CHARGE ($/kWh)													
CARE Baseline (Tier 1)	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	(.03103)	.09256	.08316
Tier 2	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	(.01856)	.09256	.09563
Tier 3	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 4	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Tier 5	.01469	.00013	(.00688)	.00647	.00049	-	.00207	(.00151)	.00339	.00000	.02555	.09256	.13974
Non-CARE Baseline (Tier 1)	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.06738)	.09256	.13627
Tier 2	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	.00000	(.04874)	.09256	.15491
Tier 3	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.14361	.09256	.32979
Tier 4	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979
Tier 5	.01469	.00013	.07020	.01373	.00049	.00512	.00207	(.00151)	.00339	(.01747)	.18361	.09256	.36979

The master-metered customer's energy consumption will be billed at the CARE rate using the ratio of the number of mobilehome spaces occupied by qualifying CARE tenants to the total number of mobilehome spaces.

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.09429	.00372	.00028	-	-	-	-	-			.11828
($/kWh)	.01747	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			
DISCOUNT ($/dwelling unit/day)	-	-	.07721	-	-	-	-	-	-	-		-	.07721
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
MARL ($/kWh)	-	-	-	-	-	.00512	.00207	(.00151)	.00339	.00000			.04892

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
EL-6													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.16417)	.24122	.19655
Tier 2	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.15064)	.24122	.21008
Tier 3	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.05089)	.24122	.30983
Tier 4	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.05089)	.24122	.30983
Tier 5	.01469	.00013	.09099	.00647	.00049		.00207	(.00151)	.00339	.00000	(.05089)	.24122	.30983
Part-Peak													
Baseline (Tier 1)	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.02107)	.11683	.11451
Tier 2	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.00754)	.11683	.12804
Tier 3	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05119	.11683	.18677
Tier 4	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05119	.11683	.18677
Tier 5	.01469	.00013	(.00976)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05119	.11683	.18677
Off-Peak													
Baseline (Tier 1)	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.00841	.06629	.05987
Tier 2	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02194	.06629	.07340
Tier 3	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05335	.06629	.10481
Tier 4	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05335	.06629	.10481
Tier 5	.01469	.00013	(.04334)	.00647	.00049		.00207	(.00151)	.00339	.00000	.05335	.06629	.10481
Winter													
Part-Peak													
Baseline (Tier 1)	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.02779)	.08661	.07494
Tier 2	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.01428)	.08661	.08845
Tier 3	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02468	.08661	.12741
Tier 4	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02468	.08661	.12741
Tier 5	.01469	.00013	(.01239)	.00647	.00049		.00207	(.00151)	.00339	.00000	.02468	.08661	.12741
Off-Peak													
Baseline (Tier 1)	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	(.00489)	.07323	.06295
Tier 2	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.00863	.07323	.07647
Tier 3	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.04159	.07323	.10943
Tier 4	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.04159	.07323	.10943
Tier 5	.01469	.00013	(.03390)	.00647	.00049		.00207	(.00151)	.00339	.00000	.04159	.07323	.10943
METER CHARGE ($/meter/day)	-	-	.20238	-	-		-	-	-	-		-	.20238
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.09429	.00372	.00028		-	-	-	-			.11828
($/kWh)	.01747						.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-		-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
EL-7													
ENERGY CHARGE ($/kWh)													
Summer													
Peak													
Baseline (Tier 1)	.01469	.00013	.06148	.01375	.00049		.00207	(.00151)	.00339	.00000	(.28925)	.46011	.26813
Tier 2	.01469	.00013	.06148	.01375	.00049		.00207	(.00151)	.00339	.00000	(.27366)	.46011	.28372
Tier 3	.01469	.00013	.06148	.01375	.00049		.00207	(.00151)	.00339	.00000	(.14018)	.46011	.41720
Tier 4	.01469	.00013	.06148	.01375	.00049		.00207	(.00151)	.00339	.00000	(.14018)	.46011	.41720
Tier 5	.01469	.00013	.06148	.01375	.00049		.00207	(.00151)	.00339	.00000	(.14018)	.46011	.41720
Off-Peak													
Baseline (Tier 1)	.01469	.00013	(.01648)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.03871)	.08045	.06105
Tier 2	.01469	.00013	(.01648)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.02312)	.08045	.07664
Tier 3	.01469	.00013	(.01648)	.01375	.00049		.00207	(.00151)	.00339	.00000	.00682	.08045	.10658
Tier 4	.01469	.00013	(.01648)	.01375	.00049		.00207	(.00151)	.00339	.00000	.00682	.08045	.10658
Tier 5	.01469	.00013	(.01648)	.01375	.00049		.00207	(.00151)	.00339	.00000	.00682	.08045	.10658
Winter													
Peak													
Baseline (Tier 1)	.01469	.00013	(.01028)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.23542)	.29904	.08913
Tier 2	.01469	.00013	(.01028)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.21983)	.29904	.10472
Tier 3	.01469	.00013	(.01028)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.17585)	.29904	.14870
Tier 4	.01469	.00013	(.01028)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.17585)	.29904	.14870
Tier 5	.01469	.00013	(.01028)	.01375	.00049		.00207	(.00151)	.00339	.00000	(.17585)	.29904	.14870
Off-Peak													
Baseline (Tier 1)	.01469	.00013	(.02967)	.01375	.00049		.00207	(.00151)	.00339	.00000	.00323	.05472	.06407
Tier 2	.01469	.00013	(.02967)	.01375	.00049		.00207	(.00151)	.00339	.00000	.01882	.05472	.07966
Tier 3	.01469	.00013	(.02967)	.01375	.00049		.00207	(.00151)	.00339	.00000	.05027	.05472	.11111
Tier 4	.01469	.00013	(.02967)	.01375	.00049		.00207	(.00151)	.00339	.00000	.05027	.05472	.11111
Tier 5	.01469	.00013	(.02967)	.01375	.00049		.00207	(.00151)	.00339	.00000	.05027	.05472	.11111
METER CHARGE EL-7 ($/meter/day)	-	-	-	-	-		-	-	-	-		-	(N/A)
MINIMUM CHARGE													
($/meter/day)	.00000	.00000	.13126	.00682	.00024		-	-	-	-			.14784
($/kWh)	.01747	-	-	-	-		.00207	(.00151)	.00339	.00000			
TRA ($/kWh)	.00278	-	-	-	-		-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
EL-8													
ENERGY CHARGE ($/kWh)													
Summer													
Baseline (Tier 1)	.01469	.00013	(.05147)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.08728)	.19532	.08624
Tier 2	.01469	.00013	(.05147)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.08728)	.19532	.08624
Tier 3	.01469	.00013	(.05147)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.02916)	.19532	.14436
Tier 4	.01469	.00013	(.05147)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.02916)	.19532	.14436
Tier 5	.01469	.00013	(.05147)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.02916)	.19532	.14436
Winter													
Baseline (Tier 1)	.01469	.00013	(.06398)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.04231)	.12896	.05234
Tier 2	.01469	.00013	(.06398)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.04231)	.12896	.05234
Tier 3	.01469	.00013	(.06398)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.00114)	.12896	.09351
Tier 4	.01469	.00013	(.06398)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.00114)	.12896	.09351
Tier 5	.01469	.00013	(.06398)	.00763	.00049		.00207	(.00151)	.00339	.00000	(.00114)	.12896	.09351
CUSTOMER CHARGE ($/meter/day)	-	-	.32927	-	-		-	-	-	-		-	.32927
TRA ($/kWh)	.00278	-	-	-	-		-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
A-1													
ENERGY CHARGE ($/kWh)													
Summer	.01274	.00011	.06914	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.11791	.22613
Winter	.01274	.00011	.04104	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.07629	.15641
CUSTOMER CHARGE ($/meter/day)													
Single-phase	-	-	.32854	-	-	-	-	-	-	-		-	.32854
Polyphase	-	-	.65708	-	-	-	-	-	-	-		-	.65708
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
A-1 TOU													
ENERGY CHARGE ($/kWh)													
Summer													
Peak	.01274	.00011	.06914	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.13810	.24632
Part-Peak	.01274	.00011	.06914	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.12924	.23746
Off-Peak	.01274	.00011	.06914	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.10226	.21048
Winter													
Part-Peak	.01274	.00011	.04104	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.08623	.16635
Off-Peak	.01274	.00011	.04104	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.06692	.14704
CUSTOMER CHARGE ($/meter/day)													
Single-phase	-	-	.32854	-	-	-	-	-	-	-		-	.32854
Polyphase	-	-	.65708	-	-	-	-	-	-	-		-	.65708
TRBAA ($/kWh)	.00278												
A-6													
ENERGY CHARGE ($/kWh)													
Summer													
Peak	.01274	.00011	.19072	.01307	.00049	.00512	.00181	(.00151)	.00286	.00000		.33690	.56509
Part-Peak	.01274	.00011	.08683	.01307	.00049	.00512	.00181	(.00151)	.00286	.00000		.13752	.26182
Off-Peak	.01274	.00011	.04482	.01307	.00049	.00512	.00181	(.00151)	.00286	.00000		.06413	.14642
Winter													
Part-Peak	.01274	.00011	.03353	.01307	.00049	.00512	.00181	(.00151)	.00286	.00000		.09708	.16808
Off-Peak	.01274	.00011	.03632	.01307	.00049	.00512	.00181	(.00151)	.00286	.00000		.06263	.13642
METER CHARGE ($/meter/day)													
Rate A-6	-	-	.20107	-	-	-	-	-	-	-		-	.20107
Rate W	-	-	.05914	-	-	-	-	-	-	-		-	.05914
Rate X	-	-	.20107	-	-	-	-	-	-	-		-	.20107
CUSTOMER CHARGE ($/meter/day)													
Single-phase	-	-	.32854	-	-	-	-	-	-	-		-	.32854
Polyphase	-	-	.65708	-	-	-	-	-	-	-		-	.65708
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
A-10													
DEMAND CHARGE ($/kW)													
Transmission													
Summer	4.48	.04	.41	-	-	-	-	-	-	-		4.40	9.33
Winter	4.48	.04	.41	-	-	-	-	-	-	-		.00	4.93
Primary													
Summer	4.48	.04	4.50	-	-	-	-	-	-	-		3.94	12.96
Winter	4.48	.04	2.05	-	-	-	-	-	-	-		.00	6.57
Secondary													
Summer	4.48	.04	5.04	-	-	-	-	-	-	-		4.17	13.73
Winter	4.48	.04	1.84	-	-	-	-	-	-	-		.00	6.36
ENERGY CHARGE ($/kWh)													
Transmission													
Summer	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.09679	.12285
Winter	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.07215	.09821
Primary													
Summer	-	-	.02293	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.09940	.14667
Winter	-	-	.01031	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.07664	.11129
Secondary													
Summer	-	-	.02563	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.10674	.15699
Winter	-	-	.00932	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.08313	.11707
CUSTOMER CHARGE ($/meter/day)	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
A-10 TOU													
DEMAND CHARGE ($/kW)													
Transmission													
Summer	4.48	.04	.41	-	-	-	-	-	-	-		4.40	9.33
Winter	4.48	.04	.41	-	-	-	-	-	-	-		.00	4.93
Primary													
Summer	4.48	.04	4.50	-	-	-	-	-	-	-		3.94	12.96
Winter	4.48	.04	2.05	-	-	-	-	-	-	-		.00	6.57
Secondary													
Summer	4.48	.04	5.04	-	-	-	-	-	-	-		4.17	13.73
Winter	4.48	.04	1.84	-	-	-	-	-	-	-		.00	6.36
ENERGY CHARGE ($/kWh)													
Transmission													
Summer													
Peak	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.10976	.13582
Part-Peak	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.10471	.13077
Off-Peak	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.08556	.11162
Winter													
Part-Peak	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.07994	.10600
Off-Peak	-	-	.00216	.01241	.00049	.00512	.00196	(.00151)	.00265	.00000		.06475	.09081
Primary													
Summer													
Peak	-	-	.02293	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.11366	.16093
Part-Peak	-	-	.02293	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.10814	.15541
Off-Peak	-	-	.02293	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.08705	.13432
Winter													
Part-Peak	-	-	.01031	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.08509	.11974
Off-Peak	-	-	.01031	.01285	.00049	.00512	.00196	(.00151)	.00265	.00000		.06859	.10324
Secondary													
Summer													
Peak	-	-	.02563	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.12383	.17408
Part-Peak	-	-	.02563	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.11609	.16634
Off-Peak	-	-	.02563	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.09257	.14282
Winter													
Part-Peak	-	-	.00932	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.09349	.12743
Off-Peak	-	-	.00932	.01313	.00049	.00512	.00196	(.00151)	.00265	.00000		.07331	.10725
CUSTOMER CHARGE ($/meter/day)	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
A-15													
ENERGY CHARGE ($/kWh)													
Summer	.01274	.00011	.06914	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.11791	.22613
Winter	.01274	.00011	.04104	.01468	.00049	.00512	.00181	(.00151)	.00286	.00000		.07629	.15641
CUSTOMER CHARGE ($/meter/day)	-	-	.32854	-	-	-	-	-	-	-		-	.32854
FACILITY CHARGE ($/meter/day)	-	-	.82136	-	-	-	-	-	-	-		-	.82136
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
E-19 Secondary													
DEMAND CHARGES ($/kW)													
Summer													
Peak	-	-	4.61	-	-	-	-	-	-	-		13.04	17.65
Part-Peak	-	-	1.24	-	-	-	-	-	-	-		2.82	4.06
Maximum	4.48	.04	7.81	-	-	-	-	-	-	-		.00	12.33
Winter													
Part-Peak	-	-	.20	-	-	-	-	-	-	-		.00	.20
Maximum	4.48	.04	7.81	-	-	-	-	-	-	-		.00	12.33
ENERGY CHARGES ($/kWh)													
Summer													
Peak	-	-	.00000	.01249	.00049	.00512	.00160	(.00151)	.00265	.00000		.13894	.16256
Part-Peak	-	-	.00000	.01249	.00049	.00512	.00160	(.00151)	.00265	.00000		.08757	.11119
Off-Peak	-	-	.00000	.01249	.00049	.00512	.00160	(.00151)	.00265	.00000		.05392	.07754
Winter													
Part-Peak	-	-	.00000	.01249	.00049	.00512	.00160	(.00151)	.00265	.00000		.08075	.10437
Off-Peak	-	-	.00000	.01249	.00049	.00512	.00160	(.00151)	.00265	.00000		.05777	.08139
POWER FACTOR ADJ RATE ($/kWh/%)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
CUSTOMER CHARGE ($/meter/day) - non Smart Meter only													
E-19			19.71253	-	-	-	-	-	-	-		-	19.71253
Rate V			4.77700	-	-	-	-	-	-	-		-	4.77700
Rate W			4.63507	-	-	-	-	-	-	-		-	4.63507
Rate X			4.77700	-	-	-	-	-	-	-		-	4.77700
CUSTOMER CHARGE ($/meter/day) - Smart Meter Interval Billing only													
E-19			19.71253	-	-	-	-	-	-	-		-	19.71253
Rate V	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Rate W	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Rate X	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-19 Primary													
DEMAND CHARGES ($/kW)													
Summer													
Peak	-	-	4.06	-	-	-	-	-	-	-		13.50	17.56
Part-Peak	-	-	1.12	-	-	-	-	-	-	-		2.61	3.73
Maximum	4.48	.04	5.29	-	-	-	-	-	-	-		.00	9.81
Winter													
Part-Peak	-	-	.38	-	-	-	-	-	-	-		.00	.38
Maximum	4.48	.04	5.29	-	-	-	-	-	-	-		.00	9.81
ENERGY CHARGES ($/kWh)													
Summer													
Peak	-	-	.00000	.01165	.00049	.00512	.00160	(.00151)	.00265	.00000		.12640	.14918
Part-Peak	-	-	.00000	.01165	.00049	.00512	.00160	(.00151)	.00265	.00000		.08182	.10460
Off-Peak	-	-	.00000	.01165	.00049	.00512	.00160	(.00151)	.00265	.00000		.05527	.07805
Winter													
Part-Peak	-	-	.00000	.01165	.00049	.00512	.00160	(.00151)	.00265	.00000		.07679	.09957
Off-Peak	-	-	.00000	.01165	.00049	.00512	.00160	(.00151)	.00265	.00000		.05845	.08123
POWER FACTOR ADJ RATE ($/kWh/%)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
CUSTOMER CHARGE ($/meter/day) - non Smart Meter only													
E-19			32.85421	-	-	-	-	-	-	-		-	32.85421
Rate V			4.77700	-	-	-	-	-	-	-		-	4.77700
Rate W			4.63507	-	-	-	-	-	-	-		-	4.63507
Rate X			4.77700	-	-	-	-	-	-	-		-	4.77700
CUSTOMER CHARGE ($/meter/day) - Smart Meter Interval Billing only													
E-19			32.85421	-	-	-	-	-	-	-		-	32.85421
Rate V	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Rate W	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Rate X	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-19 Transmission													
DEMAND CHARGES ($/kW)													
Summer													
Peak	-	-	-	-	-	-	-	-	-	-		16.32	16.32
Part-Peak	-	-	-	-	-	-	-	-	-	-		3.61	3.61
Maximum	4.48	.04	1.51	-	-	-	-	-	-	-		.00	6.03
Winter													
Part-Peak	-	-	-	-	-	-	-	-	-	-		.00	.00
Maximum	4.48	.04	1.51	-	-	-	-	-	-	-		.00	6.03
ENERGY CHARGES ($/kWh)													
Summer													
Peak	-	-	.00000	.01162	.00049	.00512	.00160	(.00151)	.00265	.00000		.07118	.09393
Part-Peak	-	-	.00000	.01162	.00049	.00512	.00160	(.00151)	.00265	.00000		.06673	.08948
Off-Peak	-	-	.00000	.01162	.00049	.00512	.00160	(.00151)	.00265	.00000		.05120	.07395
Winter													
Part-Peak	-	-	.00000	.01162	.00049	.00512	.00160	(.00151)	.00265	.00000		.06516	.08791
Off-Peak	-	-	.00000	.01162	.00049	.00512	.00160	(.00151)	.00265	.00000		.05284	.07559
POWER FACTOR ADJ RATE ($/kWh/%)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
CUSTOMER CHARGE ($/meter/day) - non Smart Meter only													
E-19			59.13758	-	-	-	-	-	-	-		-	59.13758
Rate V			4.77700	-	-	-	-	-	-	-		-	4.77700
Rate W			4.63507	-	-	-	-	-	-	-		-	4.63507
Rate X			4.77700	-	-	-	-	-	-	-		-	4.77700
CUSTOMER CHARGE ($/meter/day) - Smart Meter Interval Billing only													
E-19			59.13758	-	-	-	-	-	-	-		-	59.13758
Rate V	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Rate W	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Rate X	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-20 Secondary													
DEMAND CHARGES ($/kW)													
Summer													
Peak	-	-	4.40	-	-	-	-	-	-	-		12.83	17.23
Part-Peak	-	-	1.13	-	-	-	-	-	-	-		2.60	3.73
Maximum	4.53	.04	7.51	-	-	-	-	-	-	-		.00	12.08
Winter													
Part-Peak	-	-	.22	-	-	-	-	-	-	-		.00	.22
Maximum	4.53	.04	7.51	-	-	-	-	-	-	-		.00	12.08
ENERGY CHARGES ($/kWh)													
Summer													
Peak	-	-	.00000	.01222	.00049	.00512	.00150	(.00151)	.00215	.00000		.12556	.14831
Part-Peak	-	-	.00000	.01222	.00049	.00512	.00150	(.00151)	.00215	.00000		.08232	.10507
Off-Peak	-	-	.00000	.01222	.00049	.00512	.00150	(.00151)	.00215	.00000		.05381	.07656
Winter													
Part-Peak	-	-	.00000	.01222	.00049	.00512	.00150	(.00151)	.00215	.00000		.07618	.09893
Off-Peak	-	-	.00000	.01222	.00049	.00512	.00150	(.00151)	.00215	.00000		.05496	.07771
POWER FACTOR ADJ RATE ($/kWh)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
CUSTOMER CHARGE($/meter/day)	-	-	32.85421	-	-	-	-	-	-	-		-	32.85421
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
E-20 Primary													
DEMAND CHARGES ($/kW)													
Summer													
Peak	-	-	4.40	-	-	-	-	-	-	-		12.46	16.86
Part-Peak	-	-	1.21	-	-	-	-	-	-	-		2.28	3.49
Maximum	4.53	.04	5.24	-	-	-	-	-	-	-		.00	9.81
Winter													
Part-Peak	-	-	.24	-	-	-	-	-	-	-		.00	.24
Maximum	4.53	.04	5.24	-	-	-	-	-	-	-		.00	9.81
ENERGY CHARGES ($/kWh)													
Summer													
Peak	-	-	.00000	.01133	.00049	.00512	.00143	(.00151)	.00215	.00000		.12599	.14778
Part-Peak	-	-	.00000	.01133	.00049	.00512	.00143	(.00151)	.00215	.00000		.08196	.10375
Off-Peak	-	-	.00000	.01133	.00049	.00512	.00143	(.00151)	.00215	.00000		.05621	.07800
Winter													
Part-Peak	-	-	.00000	.01133	.00049	.00512	.00143	(.00151)	.00215	.00000		.07699	.09878
Off-Peak	-	-	.00000	.01133	.00049	.00512	.00143	(.00151)	.00215	.00000		.06021	.08200
POWER FACTOR ADJ RATE ($/kWh)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
CUSTOMER CHARGE ($/meter/day)	-	-	49.28131	-	-	-	-	-	-	-		-	49.28131
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-20 Transmission													
DEMAND CHARGES ($/kW)													
Summer													
Peak	-	-	-	-	-	-	-	-	-	-		16.13	16.13
Part-Peak	-	-	-	-	-	-	-	-	-	-		3.50	3.50
Maximum	4.53	.04	.13	-	-	-	-	-	-	-		.00	4.70
Winter													
Part-Peak	-	-	-	-	-	-	-	-	-	-		.00	.00
Maximum	4.53	.04	.13	-	-	-	-	-	-	-		.00	4.70
ENERGY CHARGES ($/kWh)													
Summer													
Peak	-	-	.00000	.00987	.00049	.00512	.00126	(.00151)	.00215	.00000		.08387	.10403
Part-Peak	-	-	.00000	.00987	.00049	.00512	.00126	(.00151)	.00215	.00000		.06533	.08549
Off-Peak	-	-	.00000	.00987	.00049	.00512	.00126	(.00151)	.00215	.00000		.04981	.06997
Winter													
Part-Peak	-	-	.00000	.00987	.00049	.00512	.00126	(.00151)	.00215	.00000		.06672	.08688
Off-Peak	-	-	.00000	.00987	.00049	.00512	.00126	(.00151)	.00215	.00000		.05385	.07401
POWER FACTOR ADJ RATE ($/kWh)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
CUSTOMER CHARGE ($/meter/day)	-	-	65.70842	-	-	-	-	-	-	-		-	65.70842
OPTIONAL METER DATA ACCESS CHARGE ($/meter/day)	-	-	.98563	-	-	-	-	-	-	-		-	.98563
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
E-37													
DEMAND CHARGE Rates W and X ($/kW)													
Summer													
Peak	-	-	3.17	-	-	-	-	-	-	-		5.54	8.71
Maximum	-	-	8.09	-	-	-	-	-	-	-		4.53	12.62
Winter													
Maximum	-	-	4.49	-	-	-	-	-	-	-		.00	4.49
VOLTAGE DISCOUNT ($/kW of maximum demand)													
Primary													
Summer	-	-	.23	-	-	-	-	-	-	-		1.38	1.61
Winter	-	-	.15	-	-	-	-	-	-	-		.00	.15
Transmission													
Summer	-	-	6.73	-	-	-	-	-	-	-		2.52	9.25
Winter	-	-	3.86	-	-	-	-	-	-	-		.00	3.86
ENERGY CHARGE Rates W and X ($/kWh)													
Summer													
Peak	.01012	.00009	.01643	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.14415	.19322
Off-Peak	.01012	.00009	.00000	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.04764	.08028
Winter													
Part-Peak	.01012	.00009	.00000	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.06775	.10039
Off-Peak	.01012	.00009	.00000	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.03933	.07197
CUSTOMER CHARGE Rates W and X ($/meter/da)	-	-	1.18275	-	-	-	-	-	-	-		-	1.18275
METER CHARGE ($/meter/day)													
Rate W	-	-	.03943	-	-	-	-	-	-	-		-	.03943
Rate X	-	-	.19713	-	-	-	-	-	-	-		-	.19713
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
E-CARE ($/kWh)													
A-1			(.07779)	(.00727)		(.00512)							(.09018)
A-6			(.07438)	(.00727)		(.00512)							(.08677)
A-15			(.07779)	(.00727)		(.00512)							(.09018)
A10 (all voltages)			(.06960)	(.00727)		(.00512)							(.08199)
E19 (all voltages)			(.05936)	(.00727)		(.00512)							(.07175)
E20 (all voltages)			(.04733)	(.00727)		(.00512)							(.05972)

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
LS-1													
ENERGY CHARGE ($/kWh)	.00836	.00007	.03492	.00701	.00049	.00512	.00026	(.00151)	.00182	.00000		.08385	.14317
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
LS-2													
ENERGY CHARGE ($/kWh)	.00836	.00007	.03492	.00701	.00049	.00512	.00026	(.00151)	.00182	.00000		.08385	.14317
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
LS-3													
ENERGY CHARGE ($/kWh)	.00836	.00007	.03492	.00701	.00049	.00512	.00026	(.00151)	.00182	.00000		.08385	.14317
CUSTOMER CHARGE ($/meter/day)	-	-	.19713	-	-	-	-	-	-	-		-	.19713
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
TC-1													
ENERGY CHARGE ($/kWh)													
Summer	.01274	.00011	.04376	.00711	.00049	.00512	.00181	(.00151)	.00286	.00000		.08103	.15630
Winter	.01274	.00011	.04376	.00711	.00049	.00512	.00181	(.00151)	.00286	.00000		.08103	.15630
CUSTOMER CHARGE ($/meter/day)	-	-	.32854	-	-	-	-	-	-	-		-	.32854
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
OL-1													
ENERGY CHARGE ($/kWh)	.00836	.00007	.03492	.01428	.00049	.00512	.00026	(.00151)	.00182	.00000		.08385	.15044
BASE CHARGE, per lamp per month	-	-	6.370	-	-	-	-	-	-	-		-	6.370
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
Standby Secondary													
RESERVATION CHARGE ($/kW)	.53	.00	2.11	-	-	-	-	-	-	-		.48	3.12
(per kW per month applied to 85% of the Reservation Capacity)													
ENERGY CHARGE ($/kWh)													
Summer													
Peak	.00930	.00008	.32075	.01563	.00049	.00512	.00117	(.00151)	.00414	.00000		.09599	.45394
Part-Peak	.00930	.00008	.12830	.01563	.00049	.00512	.00117	(.00151)	.00414	.00000		.08841	.25391
Off-Peak	.00930	.00008	.06415	.01563	.00049	.00512	.00117	(.00151)	.00414	.00000		.06538	.16673
Winter													
Part-Peak	.00930	.00008	.02167	.01563	.00049	.00512	.00117	(.00151)	.00414	.00000		.08735	.14622
Off-Peak	.00930	.00008	.01445	.01563	.00049	.00512	.00117	(.00151)	.00414	.00000		.06760	.11925
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
POWER FACTOR ADJ RATE ($/kWh)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)	-	-	.35	-	-	-	-	-	-	-		-	.35
Standby Primary													
RESERVATION CHARGE ($/kW)	.53	.00	2.16	-	-	-	-	-	-	-		.43	3.12
(per kW per month applied to 85% of the Reservation Capacity)													
ENERGY CHARGE ($/kWh)													
Summer													
Peak	.00930	.00008	.32746	.01652	.00049	.00512	.00117	(.00151)	.00414	.00000		.09382	.45937
Part-Peak	.00930	.00008	.13099	.01652	.00049	.00512	.00117	(.00151)	.00414	.00000		.08797	.25705
Off-Peak	.00930	.00008	.06549	.01652	.00049	.00512	.00117	(.00151)	.00414	.00000		.06566	.16924
Winter													
Part-Peak	.00930	.00008	.02213	.01652	.00049	.00512	.00117	(.00151)	.00414	.00000		.08539	.14561
Off-Peak	.00930	.00008	.01476	.01652	.00049	.00512	.00117	(.00151)	.00414	.00000		.06790	.12075
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
POWER FACTOR ADJ RATE ($/kWh)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)	-	-	.35	-	-	-	-	-	-	-		-	.35
Standby Transmission													
RESERVATION CHARGE ($/kW)	.53	.00	.18	-	-	-	-	-	-	-		.34	1.05
(per kW per month applied to 85% of the Reservation Capacity)													
ENERGY CHARGE ($/kWh)													
Summer													
Peak	.00930	.00008	.00000	.01167	.00049	.00512	.00117	(.00151)	.00414	.00000		.07773	.11097
Part-Peak	.00930	.00008	.00000	.01167	.00049	.00512	.00117	(.00151)	.00414	.00000		.07299	.10623
Off-Peak	.00930	.00008	.00000	.01167	.00049	.00512	.00117	(.00151)	.00414	.00000		.05501	.08825
Winter													
Part-Peak	.00930	.00008	.00000	.01167	.00049	.00512	.00117	(.00151)	.00414	.00000		.07117	.10441
Off-Peak	.00930	.00008	.00000	.01167	.00049	.00512	.00117	(.00151)	.00414	.00000		.05690	.09014
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			
POWER FACTOR ADJ RATE ($/kWh)	-	-	.00005	-	-	-	-	-	-	-		-	.00005
MAXIMUM REACTIVE DEMAND CHRG ($/kVAR)	-	-	.35	-	-	-	-	-	-	-		-	.35

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
Standby													
Customer & Meter Charges													
Residential													
Customer Charge	-	-	.16427	-	-	-	-	-	-	-		-	.16427
Meter Charge	-	-	.12813	-	-	-	-	-	-	-		-	.12813
Agricultural													
Customer Charge	-	-	.52567	-	-	-	-	-	-	-		-	.52567
Meter Charge	-	-	.19713	-	-	-	-	-	-	-		-	.19713
Small Light and Power													
(Reservation Capacity ≤ 50 kW)													
Single Phase Service													
Customer Charge	-	-	.32854	-	-	-	-	-	-	-		-	.32854
Meter Charge	-	-	.20107	-	-	-	-	-	-	-		-	.20107
PolyPhase Service													
Customer Charge	-	-	.65708	-	-	-	-	-	-	-		-	.65708
Meter Charge	-	-	.20107	-	-	-	-	-	-	-		-	.20107
Medium Light and Power													
(Reservation Capacity > 50 kW and < 500 kW)													
Customer Charge	-	-	4.59959	-	-	-	-	-	-	-		-	4.59959
Meter Charge	-	-	.17741	-	-	-	-	-	-	-		-	.17741
Medium Light and Power													
(Reservation Capacity ≥ 500 kW and < 1000 kW)													
Transmission Customer Charge	-	-	59.13758	-	-	-	-	-	-	-		-	59.13758
Primary Customer Charge	-	-	32.85421	-	-	-	-	-	-	-		-	32.85421
Secondary Customer Charge	-	-	19.71253	-	-	-	-	-	-	-		-	19.71253
Large Light and Power													
(Reservation Capacity ≥ 1000 kW)													
Transmission Customer Charge	-	-	65.70842	-	-	-	-	-	-	-		-	65.70842
Primary Customer Charge	-	-	49.28131	-	-	-	-	-	-	-		-	49.28131
Secondary Customer Charge	-	-	32.85421	-	-	-	-	-	-	-		-	32.85421
Supplemental Standby Service													
Meter Charge	-	-	6.11088	-	-	-	-	-	-	-		-	6.11088
Standby													
***Reduced* Customer Charges**													
Small Light and Power													
(Reservation Capacity < 50 kW)	-	-	.47014	-	-	-	-	-	-	-		-	.47014
Medium Light and Power													
(Reservation Capacity > 50 kW and < 500 kW)	-	-	2.45971	-	-	-	-	-	-	-		-	2.45971
Medium Light and Power													
(Reservation Capacity ≥ 500 kW and < 1000 kW)	-	-	39.65122	-	-	-	-	-	-	-		-	39.65122

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-1													
CONNECTED LOAD CHARGE ($/hp)													
Rate A													
Summer	-	-	4.78	-	-	-	-	-	-	-		1.44	6.22
Winter	-	-	1.11	-	-	-	-	-	-	-		.00	1.11
DEMAND CHARGE ($/kW)													
Rate B													
Maximum													
Summer	-	-	7.16	-	-	-	-	-	-	-		2.15	9.31
Winter	-	-	1.79	-	-	-	-	-	-	-		.00	1.79
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)													
Summer	-	-	.35	-	-	-	-	-	-	-		.76	1.11
Winter	-	-	.24	-	-	-	-	-	-	-		.00	.24
ENERGY CHARGE ($/kWh)													
Rate A													
Summer	.01012	.00009	.08973	.02009	.00049	.00512	.00181	(.00151)	.00231	.00000		.10068	.23171
Winter	.01012	.00009	.05982	.02009	.00049	.00512	.00181	(.00151)	.00231	.00000		.08050	.18162
Rate B													
Summer	.01012	.00009	.06537	.01616	.00049	.00512	.00181	(.00151)	.00231	.00000		.10154	.20428
Winter	.01012	.00009	.04360	.01616	.00049	.00512	.00181	(.00151)	.00231	.00000		.07888	.15985
CUSTOMER CHARGE ($/meter/day)													
Rate A	-	-	.56838	-	-	-	-	-	-	-		-	.56838
Rate B	-	-	.75565	-	-	-	-	-	-	-		-	.75565
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-R													
CONNECTED LOAD CHARGE ($/hp)													
Rates A and D													
Summer	-	-	4.21	-	-	-	-	-	-	-		1.37	5.58
Winter	-	-	.86	-	-	-	-	-	-	-		.00	.86
DEMAND CHARGE ($/kW)													
Rates B and E													
Summer													
Peak	-	-	1.13	-	-	-	-	-	-	-		2.17	3.30
Maximum	-	-	5.70	-	-	-	-	-	-	-		2.02	7.72
Winter													
Maximum	-	-	1.48	-	-	-	-	-	-	-		.00	1.48
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)													
Summer	-	-	.24	-	-	-	-	-	-	-		.49	.73
Winter	-	-	.23	-	-	-	-	-	-	-		.00	.23
ENERGY CHARGE ($/kWh)													
Rates A and D													
Summer													
Peak	.01012	.00009	.16014	.01588	.00049	.00512	.00181	(.00151)	.00231	.00000		.25796	.45519
Off-Peak	.01012	.00009	.05338	.01588	.00049	.00512	.00181	(.00151)	.00231	.00000		.06404	.15451
Winter													
Part-Peak	.01012	.00009	.05072	.01588	.00049	.00512	.00181	(.00151)	.00231	.00000		.07095	.15876
Off-Peak	.01012	.00009	.03381	.01588	.00049	.00512	.00181	(.00151)	.00231	.00000		.06021	.13111
Rates B and E													
Summer													
Peak	.01012	.00009	.11193	.01485	.00049	.00512	.00181	(.00151)	.00231	.00000		.27462	.42261
Off-Peak	.01012	.00009	.03730	.01485	.00049	.00512	.00181	(.00151)	.00231	.00000		.07512	.14848
Winter													
Part-Peak	.01012	.00009	.03422	.01485	.00049	.00512	.00181	(.00151)	.00231	.00000		.06881	.13909
Off-Peak	.01012	.00009	.02278	.01485	.00049	.00512	.00181	(.00151)	.00231	.00000		.05842	.11726
CUSTOMER CHARGE ($/meter/day)													
Rates A and D	-	-	.56838	-	-	-	-	-	-	-		-	.56838
Rates B and E	-	-	.75565	-	-	-	-	-	-	-		-	.75565
METER CHARGE ($/meter/day)													
Rate A	-	-	.22341	-	-	-	-	-	-	-		-	.22341
Rate B	-	-	.19713	-	-	-	-	-	-	-		-	.19713
Rate D	-	-	.06571	-	-	-	-	-	-	-		-	.06571
Rate E	-	-	.03943	-	-	-	-	-	-	-		-	.03943
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-V													
CONNECTED LOAD CHARGE ($/hp)													
Rates A and D													
Summer	-	-	4.18	-	-	-	-	-	-	-		1.44	5.62
Winter	-	-	.89	-	-	-	-	-	-	-		.00	.89
DEMAND CHARGE ($/kW)													
Rates B and E													
Summer													
Peak	-	-	1.03	-	-	-	-	-	-	-		2.28	3.31
Maximum	-	-	5.87	-	-	-	-	-	-	-		1.86	7.73
Winter													
Maximum	-	-	1.46	-	-	-	-	-	-	-		.00	1.46
PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)													
Summer	-	-	.27	-	-	-	-	-	-	-		.52	.79
Winter	-	-	.22	-	-	-	-	-	-	-		.00	.22
ENERGY CHARGE ($/kWh)													
Rates A and D													
Summer													
Peak	.01012	.00009	.15200	.01591	.00049	.00512	.00181	(.00151)	.00231	.00000		.23446	.42358
Off-Peak	.01012	.00009	.05065	.01591	.00049	.00512	.00181	(.00151)	.00231	.00000		.06386	.15163
Winter													
Part-Peak	.01012	.00009	.05042	.01591	.00049	.00512	.00181	(.00151)	.00231	.00000		.07225	.15979
Off-Peak	.01012	.00009	.03359	.01591	.00049	.00512	.00181	(.00151)	.00231	.00000		.06131	.13202
Rates B and E													
Summer													
Peak	.01012	.00009	.11140	.01472	.00049	.00512	.00181	(.00151)	.00231	.00000		.23927	.38660
Off-Peak	.01012	.00009	.03714	.01472	.00049	.00512	.00181	(.00151)	.00231	.00000		.07115	.14422
Winter													
Part-Peak	.01012	.00009	.03403	.01472	.00049	.00512	.00181	(.00151)	.00231	.00000		.06728	.13724
Off-Peak	.01012	.00009	.02268	.01472	.00049	.00512	.00181	(.00151)	.00231	.00000		.05710	.11571
CUSTOMER CHARGE ($/meter/day)													
Rates A and D	-	-	.56838	-	-	-	-	-	-	-		-	.56838
Rates B and E	-	-	.75565	-	-	-	-	-	-	-		-	.75565
METER CHARGE ($/meter/day)													
Rate A	-	-	.22341	-	-	-	-	-	-	-		-	.22341
Rate B	-	-	.19713	-	-	-	-	-	-	-		-	.19713
Rate D	-	-	.06571	-	-	-	-	-	-	-		-	.06571
Rate E	-	-	.03943	-	-	-	-	-	-	-		-	.03943
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-4													
CONNECTED LOAD CHARGE ($/hp)													
Rates A and D													
Summer	-	-	4.83	-	-	-	-	-	-	-		1.43	6.26
Winter	-	-	.90	-	-	-	-	-	-	-		.00	.90
DEMAND CHARGE ($/kW)													
Rates B and E													
Summer													
Peak	-	-	1.88	-	-	-	-	-	-	-		2.53	4.41
Maximum	-	-	5.27	-	-	-	-	-	-	-		2.45	7.72
Winter													
Maximum	-	-	1.64	-	-	-	-	-	-	-		.00	1.64
Rates C and F													
Summer													
Peak	-	-	4.50	-	-	-	-	-	-	-		5.84	10.34
Part-Peak	-	-	.94	-	-	-	-	-	-	-		1.00	1.94
Maximum	-	-	3.63	-	-	-	-	-	-	-		.00	3.63
Winter													
Part-Peak	-	-	.40	-	-	-	-	-	-	-		.00	.40
Maximum	-	-	1.76	-	-	-	-	-	-	-		.00	1.76
"B & E" PRIMARY VOLTAGE DISCOUNT ($/kW of maximum demand)													
Summer	-	-	.32	-	-	-	-	-	-	-		.59	.91
Winter	-	-	.25	-	-	-	-	-	-	-		.00	.25
"C & F" PRIMARY VOLTAGE DISCOUNT													
Summer ($/kW of **Peak** Demand)	-	-	.23	-	-	-	-	-	-	-		1.00	1.23
Winter ($/kW of **Max** Demand)	-	-	.22	-	-	-	-	-	-	-		.00	.22
"C & F" TRANSMISSION VOLTAGE DISCOUNT													
Summer ($/kW)													
Peak	-	-	3.21	-	-	-	-	-	-	-		1.90	5.11
Part-Peak	-	-	.94	-	-	-	-	-	-	-		.00	.94
Max	-	-	.17	-	-	-	-	-	-	-		.00	.17
Winter ($/kW)													
Part-Peak	-	-	.40	-	-	-	-	-	-	-		.00	.40
Max	-	-	1.22	-	-	-	-	-	-	-		.00	1.22
ENERGY CHARGE ($/kWh)													
Rates A and D													
Summer													
Peak	.01012	.00009	.16679	.01583	.00049	.00512	.00181	(.00151)	.00231	.00000		.16034	.36417
Off-Peak	.01012	.00009	.05559	.01583	.00049	.00512	.00181	(.00151)	.00231	.00000		.06852	.16115
Winter													
Part-Peak	.01012	.00009	.05746	.01583	.00049	.00512	.00181	(.00151)	.00231	.00000		.07268	.16718
Off-Peak	.01012	.00009	.03830	.01583	.00049	.00512	.00181	(.00151)	.00231	.00000		.06175	.13709
Rates B and E													
Summer													
Peak	.01012	.00009	.08732	.01427	.00049	.00512	.00181	(.00151)	.00231	.00000		.12053	.24333
Off-Peak	.01012	.00009	.02910	.01427	.00049	.00512	.00181	(.00151)	.00231	.00000		.06943	.13401
Winter													
Part-Peak	.01012	.00009	.03059	.01427	.00049	.00512	.00181	(.00151)	.00231	.00000		.06767	.13374
Off-Peak	.01012	.00009	.02041	.01427	.00049	.00512	.00181	(.00151)	.00231	.00000		.05740	.11329

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-4 (continued)													
ENERGY CHARGE ($/kWh) (cont'd)													
Rates C and F													
Summer													
Peak	.01012	.00009	.05593	.01434	.00049	.00512	.00181	(.00151)	.00231	.00000		.13847	.22995
Part-Peak	.01012	.00009	.02236	.01434	.00049	.00512	.00181	(.00151)	.00231	.00000		.07786	.13577
Off-Peak	.01012	.00009	.01120	.01434	.00049	.00512	.00181	(.00151)	.00231	.00000		.05583	.10258
Winter													
Part-Peak	.01012	.00009	.01555	.01434	.00049	.00512	.00181	(.00151)	.00231	.00000		.06208	.11318
Off-Peak	.01012	.00009	.01034	.01434	.00049	.00512	.00181	(.00151)	.00231	.00000		.05261	.09850
CUSTOMER CHARGE ($/meter/day)													
Rates A and D	-	-	.56838	-	-	-	-	-	-	-		-	.56838
Rates B and E	-	-	.75565	-	-	-	-	-	-	-		-	.75565
Rates C and F	-	-	2.12895	-	-	-	-	-	-	-		-	2.12895
METER CHARGE ($/meter/day)													
Rate A	-	-	.22341	-	-	-	-	-	-	-		-	.22341
Rates B and C	-	-	.19713	-	-	-	-	-	-	-		-	.19713
Rate D	-	-	.06571	-	-	-	-	-	-	-		-	.06571
Rates E and F	-	-	.03943	-	-	-	-	-	-	-		-	.03943
TRA ($/kWh)	.00278	-	-	-	-	-	-	-	-	-			

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-5													
CONNECTED LOAD CHARGE ($/hp)													
Rates A and D													
Summer	-	-	5.88	-	-	-	-	-	-	-		3.76	9.64
Winter	-	-	1.62	-	-	-	-	-	-	-		.00	1.62
DEMAND CHARGE ($/kW)													
Rates B and E													
Summer													
Peak	-	-	3.17	-	-	-	-	-	-	-		5.54	8.71
Maximum	-	-	8.09	-	-	-	-	-	-	-		4.53	12.62
Winter													
Maximum	-	-	4.49	-	-	-	-	-	-	-		.00	4.49
Rates C and F													
Summer													
Peak	-	-	4.70	-	-	-	-	-	-	-		10.19	14.89
Part-Peak	-	-	1.12	-	-	-	-	-	-	-		1.92	3.04
Maximum	-	-	4.40	-	-	-	-	-	-	-		.00	4.40
Winter													
Part-Peak	-	-	.66	-	-	-	-	-	-	-		.00	.66
Maximum	-	-	2.75	-	-	-	-	-	-	-		.00	2.75
"B & E" PRIMARY VOLTAGE DISCOUNT													
Summer ($/kW of Max Demand)	-	-	.23	-	-	-	-	-	-	-		1.38	1.61
Winter ($/kW of Max Demand)	-	-	.15	-	-	-	-	-	-	-		.00	.15
"B & E" TRANSMISSION VOLTAGE DISCOUNT													
Summer ($/kW of Max Demand)	-	-	6.73	-	-	-	-	-	-	-		2.52	9.25
Winter ($/kW of Max Demand)	-	-	3.86	-	-	-	-	-	-	-		.00	3.86
"C & F" PRIMARY VOLTAGE DISCOUNT													
Summer ($/kW of **Peak** Demand)	-	-	.27	-	-	-	-	-	-	-		2.08	2.35
Winter ($/kW of **Max** Demand)	-	-	.18	-	-	-	-	-	-	-		.00	.18
"C & F" TRANSMISSION VOLTAGE DISCOUNT													
Summer ($/kW)													
Peak	-	-	4.70	-	-	-	-	-	-	-		3.98	8.68
Part-Peak	-	-	1.12	-	-	-	-	-	-	-		.02	1.14
Max	-	-	2.50	-	-	-	-	-	-	-		.00	2.50
Winter ($/kW)													
Part-Peak	-	-	.66	-	-	-	-	-	-	-		.00	.66
Max	-	-	1.80	-	-	-	-	-	-	-		.00	1.80
ENERGY CHARGE ($/kWh)													
Rates A and D													
Summer													
Peak	.01012	.00009	.08323	.01393	.00049	.00512	.00181	(.00151)	.00231	.00000		.14807	.26644
Off-Peak	.01012	.00009	.02775	.01393	.00049	.00512	.00181	(.00151)	.00231	.00000		.07257	.13546
Winter													
Part-Peak	.01012	.00009	.03133	.01393	.00049	.00512	.00181	(.00151)	.00231	.00000		.07608	.14255
Off-Peak	.01012	.00009	.02088	.01393	.00049	.00512	.00181	(.00151)	.00231	.00000		.06469	.12071
Rates B and E													
Summer													
Peak	.01012	.00009	.01643	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.14415	.19322
Off-Peak	.01012	.00009	.00000	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.04764	.08028
Winter													
Part-Peak	.01012	.00009	.00000	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.06775	.10039
Off-Peak	.01012	.00009	.00000	.01143	.00049	.00512	.00181	(.00151)	.00231	.00000		.03933	.07197

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
AG-5 (continued)													
ENERGY CHARGE ($/kWh) (cont'd)													
Rates C and F													
Summer													
Peak	.01012	.00009	.00000	.01120	.00049	.00512	.00181	(.00151)	.00231	.00000		.11775	.15016
Part-Peak	.01012	.00009	.00000	.01120	.00049	.00512	.00181	(.00151)	.00231	.00000		.06746	.09987
Off-Peak	.01012	.00009	.00000	.01120	.00049	.00512	.00181	(.00151)	.00231	.00000		.04874	.08115
Winter													
Part-Peak	.01012	.00009	.00000	.01120	.00049	.00512	.00181	(.00151)	.00231	.00000		.05435	.08676
Off-Peak	.01012	.00009	.00000	.01120	.00049	.00512	.00181	(.00151)	.00231	.00000		.04583	.07824
CUSTOMER CHARGE ($/meter/day)													
Rates A and D	-	-	.56838	-	-	-	-	-	-	-		-	.56838
Rates B and E	-	-	1.18275	-	-	-	-	-	-	-		-	1.18275
Rates C and F	-	-	5.25667	-	-	-	-	-	-	-		-	5.25667
METER CHARGE ($/meter/day)													
Rate A	-	-	.22341	-	-	-	-	-	-	-		-	.22341
Rates B and C	-	-	.19713	-	-	-	-	-	-	-		-	.19713
Rate D	-	-	.06571	-	-	-	-	-	-	-		-	.06571
Rates E and F	-	-	.03943	-	-	-	-	-	-	-		-	.03943
TRA ($/kWh) Rates A, B, C, D, E and F	.00278	-	-	-	-	-	-	-	-	-			

Vintaged PCIA Rates (with DWR Bond FF)

	Residential	Small L&P	Medium L&P	E19	Streetlights	Standby	Agriculture	E20 T	E20 P	E20 S
Pre-2009	(.00203)	(.00177)	(.00192)	(.00156)	(.00022)	(.00113)	(.00177)	(.00122)	(.00139)	(.00146)
Vin 2009	.01162	.01017	.01101	.00899	.00149	.00659	.01017	.00709	.00804	.00843
Vin 2010	.01259	.01101	.01192	.00974	.00162	.00713	.01101	.00768	.00871	.00913
Vin 2011	.01304	.01140	.01235	.01009	.00167	.00739	.01140	.00795	.00902	.00946
Vin 2012	.01209	.01057	.01145	.00935	.00155	.00685	.01057	.00737	.00836	.00877
Vin 2013	.01209	.01058	.01145	.00935	.00155	.00685	.01058	.00737	.00836	.00877
Vin 2014	.01209	.01058	.01145	.00935	.00155	.00685	.01058	.00737	.00836	.00877

E-FFS Rates ($/kWh)

	Residential	Small L&P	Medium L&P	E19	Streetlights	Standby	Agriculture	E20 T	E20 P	E20S
Pre-2009	.00082	.00085	.00089	.00080	.00071	.00060	.00068	.00068	.00075	.00076
Vin 2009	.00070	.00075	.00078	.00071	.00070	.00054	.00058	.00061	.00067	.00068
Vin 2010	.00070	.00074	.00077	.00070	.00070	.00053	.00057	.00060	.00067	.00067
Vin 2011	.00069	.00074	.00077	.00070	.00070	.00053	.00057	.00060	.00066	.00067
Vin 2012	.00070	.00074	.00078	.00071	.00070	.00053	.00057	.00060	.00067	.00068
Vin 2013	.00070	.00074	.00078	.00071	.00070	.00053	.00057	.00060	.00067	.00068
Vin 2014	.00070	.00074	.00078	.00071	.00070	.00053	.00057	.00060	.00067	.00068

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
Table 4

	Trans	RS	Distr	PPP	ND	DWR Bond	CTC	ECRA	NSGC	AB32 Credit	CIA	Gen	Total
PRELIMINARY STATEMENT PART I RATES							Pre 2009	2009	2010	2011	2012	2013	
							PCIA	PCIA	PCIA	PCIA	PCIA	PCIA	
	Trans	RS	Distr	PPP	Gen	ECRA	DWR FF	DWR FF	DWR FF	DWR FF	DWR FF	DWR FF	
All Customers													
California Public Utilities Commission Fee			.00024										
CEE Incentive Rate			.00022										
Smartmeter Project Balancing Account Electric (SBA-E)			.00116										
Transmission Access Charge	.00403												
Transmission Revenue Balancing Account Adjustme	(.00125)												
Existing Transmission Contract Cost Differentials (E	.00000												
End-Use Customer Refund Adjustment (ECRA):													
Residential	.00000												
Small L&P	.00000												
Medium L&P	.00000												
E-19	.00000												
Streetlights	.00000												
Standby	.00000												
Agriculture	.00000												
E-20	.00000												
CARE Surcharge				.00727									
Procurement Energy Efficiency Revenue Adjustment Mechanism				.00240									
Electric Program Investment Charge				.00094									
Energy Recovery Bond DRC Charge - Series 1						.00000							
Energy Recovery Bond DRC Charge - Series 2						.00000							
Energy Recovery Bond Balancing Account						(.00151)							
Bundled Service Customers													
Power Charge Collection Balancing Account: CORE					(.00050)								
Power Charge Collection Balancing Account: NonCORE					(.00050)								
Energy Resource Recovery Account (ERRA)					.06585								
DWR Franchise Fees					.00003								
Regulatory Asset Tax Balancing Account (RATBA)					.00000								
Headroom Account (HA)					.00000								
Non-Bundled Service Customers													
PCIA - DWR Franchise Fees													
All Customer Classes							.00004	.00004	.00004	.00004	.00004	.00004	

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
	AVERAGE		SCHEDULE LS-2		SCHEDULE LS-1								
LAMP WATTS	kWhr PER MONTH	INITIAL LUMENS	A	C	A	B	C	D	E	F	OL-1	LS-1 & LS-2	OL-1
MERCURY VAPOR LAMPS													
40	18	1,300	$2.783	--	--	--	--	--	--	--	--	$0.117	--
50	22	1,650	$3.356	--	--	--	--	--	--	--	--	$0.143	--
100	40	3,500	$5.933	$8.109	$12.097	--	$10.370	--	--	--	--	$0.260	--
175	68	7,500	$9.942	$12.118	$16.106	$14.308	$14.379	--	$16.591	$17.645	$16.600	$0.443	$0.465
250	97	11,000	$14.093	$16.269	$20.257	$18.459	$18.530	--	--	--	--	$0.631	--
400	152	21,000	$21.968	$24.144	$28.132	$26.334	$26.405	--	--	--	$29.237	$0.989	$1.039
700	266	37,000	$38.289	$40.465	$44.453	$42.655	$42.726	--	--	--	--	$1.731	--
1,000	377	57,000	$54.181	$56.357	--	--	--	--	--	--	--	$2.453	--
INCANDESCENT LAMPS													
58	20	600	$3.069	--	$9.233	--	--	--	--	--	--	$0.130	--
92	31	1,000	$4.644	$6.820	$10.808	--	--	--	--	--	--	$0.202	--
189	65	2,500	$9.512	$11.688	$15.676	$13.878	--	--	--	--	--	$0.423	--
295	101	4,000	$14.666	$16.842	$20.830	$19.032	--	--	--	--	--	$0.657	--
405	139	6,000	$20.107	$22.283	$26.271	--	--	--	--	--	--	$0.905	--
620	212	10,000	$30.558	$32.734	--	--	--	--	--	--	--	$1.380	--
860	294	15,000	$42.298	--	--	--	--	--	--	--	--	$1.913	--
LOW PRESSURE SODIUM VAPOR LAMPS													
35	21	4,800	$3.213	--	--	--	--	--	--	--	--	$0.137	--
55	29	8,000	$4.358	--	--	--	--	--	--	--	--	$0.189	--
90	45	13,500	$6.649	--	--	--	--	--	--	--	--	$0.293	--
135	62	21,500	$9.083	--	--	--	--	--	--	--	--	$0.404	--
180	78	33,000	$11.373	--	--	--	--	--	--	--	--	$0.508	--

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
	AVERAGE		SCHEDULE LS-2		SCHEDULE LS-1							LS-1 &	
LAMP WATTS	kWhr PER MONTH	INITIAL LUMENS	A	C	A	B	C	D	E	F	OL-1	LS-2	OL-1
HIGH PRESSURE SODIUM VAPOR LAMPS AT 120 VOLTS													
35	15	2,150	$2.354	--	--	--	--	--	--	--	--	$0.098	--
50	21	3,800	$3.213	--	--	--	--	--	--	--	--	$0.137	--
70	29	5,800	$4.358	$6.534	$10.522	--	$8.795	$11.395	$11.007	$12.061	$10.733	$0.189	$0.198
100	41	9,500	$6.076	$8.252	$12.240	--	$10.513	$13.113	$12.725	$13.779	$12.538	$0.267	$0.280
150	60	16,000	$8.796	$10.972	$14.960	--	$13.233	$15.833	$15.445	$16.499	--	$0.390	--
200	80	22,000	$11.660	--	$17.824	--	$16.097	$18.697	$18.309	$19.363	--	$0.521	--
250	100	26,000	$14.523		$20.687	--	$18.960	$21.560	$21.172	$22.226		$0.651	
400	154	46,000	$22.254		$28.418	--	$26.691	$29.291	$28.903	$29.957		$1.002	
AT 240 VOLTS													
50	24	3,800	$3.642	--	--	--	--	--	--	--	--	$0.156	--
70	34	5,800	$5.074	$7.250	$11.238	--	--	--	--	--	--	$0.221	--
100	47	9,500	$6.935	$9.111	$13.099	--	$11.372	--	$13.584	$14.638	--	$0.306	--
150	69	16,000	$10.085	$12.261	$16.249	--	$14.522	--	$16.734	$17.788	--	$0.449	--
200	81	22,000	$11.803	$13.979	$17.967	--	$16.240	--	$18.452	$19.506	$18.556	$0.527	$0.554
250	100	25,500	$14.523	$16.699	$20.687	--	$18.960	--	$21.172	$22.226	$21.414	$0.651	$0.684
310	119	37,000	$17.243	--	--	--	--	--	--	--	--	$0.774	--
360	144	45,000	$20.822	--	--	--	--	--	--	--	--	$0.937	--
400	154	46,000	$22.254	$24.430	$28.418	--	$26.691	--	$28.903	$29.957	▶ $29.538	$1.002	$1.053
METAL HALIDE LAMPS													
70	30	5,500	$4.501	--	--	--	--	--	--	--	--	$0.195	--
100	41	8,500	$6.076	--	--	--	--	--	--	--	--	$0.267	--
150	63	13,500	$9.226	--	--	--	--	--	--	--	--	$0.410	--
175	72	14,000	$10.514	--	--	--	--	--	--	--	--	$0.469	--
250	105	20,500	$15.239	--	--	--	--	--	--	--	--	$0.683	--
400	162	30,000	$23.400	--	--	--	--	--	--	--	--	$1.054	--
1,000	387	90,000	$55.613	--	--	--	--	--	--	--	--	$2.519	--
INDUCTION LAMPS													
23	9	1,840	$1.495	--	--	--	--	--	--	--	--	$0.059	--
35	13	2,450	$2.067	--	--	--	--	--	--	--	--	$0.085	--
40	14	2,200	$2.210	--	--	--	--	--	--	--	--	$0.091	--
50	18	3,500	$2.783	--	--	--	--	--	--	--	--	$0.117	--
55	19	3,000	$2.926	--	--	--	--	--	--	--	--	$0.124	--
65	24	5,525	$3.642	--	--	--	--	--	--	--	--	$0.156	--
70	27	6,500	$4.072	--	--	--	--	--	--	--	--	$0.176	--
80	28	4,500	$4.215	--	--	--	--	--	--	--	--	$0.182	--
85	30	4,800	$4.501	--	--	--	--	--	--	--	--	$0.195	--
100	36	8,000	$5.360	--	--	--	--	--	--	--	--	$0.234	--
120	42	8,500	$6.149	--	--	--	--	--	--	--	--	$0.270	--
135	48	9,450	$7.078	--	--	--	--	--	--	--	--	$0.312	--
150	51	10,900	$7.508	--	--	--	--	--	--	--	--	$0.332	--
165	58	12,000	$8.510	--	--	--	--	--	--	--	--	$0.377	--
200	72	19,000	$10.514	--	--	--	--	--	--	--	--	$0.469	--

All LEDs now on separate tab.

Energy Rate @ $0.14317 per kwh LS-1 & LS-2
$0.15044 per kwh OL-1

Pole Painting Charge @ Per Pole Per Month

29-Aug-13

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
LIGHT EMITTING DIODE (LED) LAMPS
TOTAL RATES (FACILITY + ENERGY CHGS)

NOMINAL LAMP RATINGS		ALL NIGHT RATES PER LAMP PER MONTH	HALF-HOUR ADJUSTMENT	ALL NIGHT RATES PER LAMP PER MONTH			
Lamp Watts	Average kWh Per Month	LS-2A	LS-1A, C, E, F & LS-2A	LS-1A	LS-1C	LS-1E	LS-1F
0.0-5.0	0.9	$0.335	$0.006	$6.499	$4.772	$6.984	$8.038
5.1-10.0	2.6	$0.578	$0.017	$6.742	$5.015	$7.227	$8.281
10.1-15.0	4.3	$0.822	$0.028	$6.986	$5.259	$7.471	$8.525
15.1-20.0	6.0	$1.065	$0.039	$7.229	$5.502	$7.714	$8.768
20.1-25.0	7.7	$1.308	$0.050	$7.472	$5.745	$7.957	$9.011
25.1-30.0	9.4	$1.552	$0.061	$7.716	$5.989	$8.201	$9.255
30.1-35.0	11.1	$1.795	$0.072	$7.959	$6.232	$8.444	$9.498
35.1-.40.0	12.8	$2.039	$0.083	$8.203	$6.476	$8.688	$9.742
40.1-45.0	14.5	$2.282	$0.094	$8.446	$6.719	$8.931	$9.985
45.1-50.0	16.2	$2.525	$0.105	$8.689	$6.962	$9.174	$10.228
50.1-55.0	17.9	$2.769	$0.117	$8.933	$7.206	$9.418	$10.472
55.1-60.0	19.6	$3.012	$0.128	$9.176	$7.449	$9.661	$10.715
60.1-65.0	21.4	$3.270	$0.139	$9.434	$7.707	$9.919	$10.973
65.1-70.0	23.1	$3.513	$0.150	$9.677	$7.950	$10.162	$11.216
70.1-75.0	24.8	$3.757	$0.161	$9.921	$8.194	$10.406	$11.460
75.1-80.0	26.5	$4.000	$0.172	$10.164	$8.437	$10.649	$11.703
80.1-85.0	28.2	$4.243	$0.184	$10.407	$8.680	$10.892	$11.946
85.1-90.0	29.9	$4.487	$0.195	$10.651	$8.924	$11.136	$12.190
90.1-95.0	31.6	$4.730	$0.206	$10.894	$9.167	$11.379	$12.433
95.1-100.0	33.3	$4.974	$0.217	$11.138	$9.411	$11.623	$12.677
100.1-105.1	35.0	$5.217	$0.228	$11.381	$9.654	$11.866	$12.920
105.1-110.0	36.7	$5.460	$0.239	$11.624	$9.897	$12.109	$13.163
110.1-115.0	38.4	$5.704	$0.250	$11.868	$10.141	$12.353	$13.407
115.1-120.0	40.1	$5.947	$0.261	$12.111	$10.384	$12.596	$13.650
120.1-125.0	41.9	$6.205	$0.273	$12.369	$10.642	$12.854	$13.908
125.1-130.0	43.6	$6.448	$0.284	$12.612	$10.885	$13.097	$14.151
130.1-135.0	45.3	$6.692	$0.295	$12.856	$11.129	$13.341	$14.395

Pacific Gas and Electric Company
2014 Annual Electric True-Up
August Filing
LIGHT EMITTING DIODE (LED) LAMPS
TOTAL RATES (FACILITY + ENERGY CHGS)

NOMINAL LAMP RATINGS		ALL NIGHT RATES PER LAMP PER MONTH	HALF-HOUR ADJUSTMENT	ALL NIGHT RATES PER LAMP PER MONTH			
Lamp Watts	Average kWh Per Month	LS-2A	LS-1A, C, E, F & LS-2A	LS-1A	LS-1C	LS-1E	LS-1F
135.1-140.0	47.0	$6.935	$0.306	$13.099	$11.372	$13.584	$14.638
140.1-145.0	48.7	$7.178	$0.317	$13.342	$11.615	$13.827	$14.881
145.1-150.0	50.4	$7.422	$0.328	$13.586	$11.859	$14.071	$15.125
150.1-155.0	52.1	$7.665	$0.339	$13.829	$12.102	$14.314	$15.368
155.1-160.0	53.8	$7.909	$0.350	$14.073	$12.346	$14.558	$15.612
160.1-165.0	55.5	$8.152	$0.361	$14.316	$12.589	$14.801	$15.855
165.1-170.0	57.2	$8.395	$0.372	$14.559	$12.832	$15.044	$16.098
170.1-175.0	58.9	$8.639	$0.383	$14.803	$13.076	$15.288	$16.342
175.1-180.0	60.6	$8.882	$0.394	$15.046	$13.319	$15.531	$16.585
180.1-185.0	62.4	$9.140	$0.406	$15.304	$13.577	$15.789	$16.843
185.1-190.0	64.1	$9.383	$0.417	$15.547	$13.820	$16.032	$17.086
190.1-195.0	65.8	$9.627	$0.428	$15.791	$14.064	$16.276	$17.330
195.1-200.0	67.5	$9.870	$0.439	$16.034	$14.307	$16.519	$17.573
200.1-205.0	69.2	$10.113	$0.450	$16.277	$14.550	$16.762	$17.816
205.1-210.0	70.9	$10.357	$0.461	$16.521	$14.794	$17.006	$18.060
210.1-215.0	72.6	$10.600	$0.472	$16.764	$15.037	$17.249	$18.303
215.1-220.0	74.3	$10.844	$0.484	$17.008	$15.281	$17.493	$18.547
220.1-225.0	76.0	$11.087	$0.495	$17.251	$15.524	$17.736	$18.790
225.1-230.0	77.7	$11.330	$0.506	$17.494	$15.767	$17.979	$19.033
230.1-235.0	79.4	$11.574	$0.517	$17.738	$16.011	$18.223	$19.277
235.1-240.0	81.1	$11.817	$0.528	$17.981	$16.254	$18.466	$19.520
240.1-245.0	82.9	$12.075	$0.540	$18.239	$16.512	$18.724	$19.778
245.1-250.0	84.6	$12.318	$0.551	$18.482	$16.755	$18.967	$20.021
250.1-255.0	86.3	$12.562	$0.562	$18.726	$16.999	$19.211	$20.265
255.1-260.0	88.0	$12.805	$0.573	$18.969	$17.242	$19.454	$20.508
260.1-265.0	89.7	$13.048	$0.584	$19.212	$17.485	$19.697	$20.751
265.1-270.0	91.4	$13.292	$0.595	$19.456	$17.729	$19.941	$20.995

Pacific Gas and Electric Company
2014 Annual Electric True-Up
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LIGHT EMITTING DIODE (LED) LAMPS
TOTAL RATES (FACILITY + ENERGY CHGS)

NOMINAL LAMP RATINGS		ALL NIGHT RATES PER LAMP PER MONTH	HALF-HOUR ADJUSTMENT	ALL NIGHT RATES PER LAMP PER MONTH			
Lamp Watts	Average kWh Per Month	LS-2A	LS-1A, C, E, F & LS-2A	LS-1A	LS-1C	LS-1E	LS-1F
270.1-275.0	93.1	$13.535	$0.606	$19.699	$17.972	$20.184	$21.238
275.1-280.0	94.8	$13.779	$0.617	$19.943	$18.216	$20.428	$21.482
280.1-285.0	96.5	$14.022	$0.628	$20.186	$18.459	$20.671	$21.725
285.1-290.0	98.2	$14.265	$0.639	$20.429	$18.702	$20.914	$21.968
290.1-295.0	99.9	$14.509	$0.650	$20.673	$18.946	$21.158	$22.212
295.1-300.0	101.6	$14.752	$0.661	$20.916	$19.189	$21.401	$22.455
300.1-305.0	103.4	$15.010	$0.673	$21.174	$19.447	$21.659	$22.713
305.1-310.0	105.1	$15.253	$0.684	$21.417	$19.690	$21.902	$22.956
310.1-315.0	106.8	$15.497	$0.695	$21.661	$19.934	$22.146	$23.200
315.1-320.0	108.5	$15.740	$0.706	$21.904	$20.177	$22.389	$23.443
320.1-325.0	110.2	$15.983	$0.717	$22.147	$20.420	$22.632	$23.686
325.1-330.0	111.9	$16.227	$0.728	$22.391	$20.664	$22.876	$23.930
330.1-335.0	113.6	$16.470	$0.739	$22.634	$20.907	$23.119	$24.173
335.1-340.0	115.3	$16.714	$0.750	$22.878	$21.151	$23.363	$24.417
340.1-345.0	117.0	$16.957	$0.761	$23.121	$21.394	$23.606	$24.660
345.1-350.0	118.7	$17.200	$0.772	$23.364	$21.637	$23.849	$24.903
350.1-355.0	120.4	$17.444	$0.784	$23.608	$21.881	$24.093	$25.147
355.1-360.0	122.1	$17.687	$0.795	$23.851	$22.124	$24.336	$25.390
360.1-365.0	123.9	$17.945	$0.806	$24.109	$22.382	$24.594	$25.648
365.1-370.0	125.6	$18.188	$0.817	$24.352	$22.625	$24.837	$25.891
370.1-375.0	127.3	$18.432	$0.828	$24.596	$22.869	$25.081	$26.135
375.1-380.0	129.0	$18.675	$0.840	$24.839	$23.112	$25.324	$26.378
380.1-385.0	130.7	$18.918	$0.851	$25.082	$23.355	$25.567	$26.621
385.1-390.0	132.4	$19.162	$0.862	$25.326	$23.599	$25.811	$26.865
390.1-395.0	134.1	$19.405	$0.873	$25.569	$23.842	$26.054	$27.108
395.1-400.0	135.8	$19.648	$0.884	$25.812	$24.085	$26.297	$27.351

LED lights are only applicable to LS-1A, 1C, 1E and 1F

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

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