Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

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

Fax: 415.973.7226

January 31, 2013

Advice 3362-G/4187-E
(Pacific Gas and Electric Company ID U 39M)

Public Utilities Commission of the State of California

Subject: **Tax Act Memorandum Account (TAMA-E) and (TAMA-G): Conforming Changes to Reflect One-Year Extension of 50% Bonus Depreciation and to Incorporate the Commission's Test Year 2013 Cost Of Capital Decision**

Pacific Gas and Electric Company (PG&E) hereby submits this Tier 2 advice letter to make the following conforming changes to Electric Preliminary Statement Part FR, Tax Act Memorandum Account - Electric (TAMA-E) and Gas Preliminary Statement Part CS, Tax Act Memorandum Account - Gas (TAMA-G):

1. To reflect the one-year extension of bonus depreciation provided by the "American Taxpayer Relief Act of 2012" ("Extended Tax Relief Act") (see Attachment 1).
2. To incorporate the Commission's Test Year 2013 Cost of Capital (COC) Decision 12-12-034 (see Attachment 2).

Unless otherwise defined, all capitalized terms have the same meaning as used in the approved PG&E Advice 3216-G-A/3859-E-A (see Attachment 3) on December 1, 2011.

Purpose

Under Resolution L-411A and the approved Advice 3216-G-A/3859-E-A, PG&E established TAMA-E and TAMA-G to reflect, over the Memo Account Period, the revenue requirement impacts of bonus depreciation expanded and extended by the Tax Relief Act, offset by capital revenue requirements on additional infrastructure enabled by the Tax Relief Act. The Extended Tax Relief Act continues 50% bonus depreciation for an additional year, enabling PG&E, to claim bonus depreciation for all eligible capital additions in 2013, the last year of the General Rate Case (GRC) Memo Account Period. The purpose of this filing, consistent with Resolution L-411A and the terms of the approved Advice 3216-G-A/3859-E-A is to conform the TAMA-E and TAMA-G to reflect this additional year of bonus depreciation provided by the Extended Tax Relief Act, using the same principles and guidelines as were originally adopted to reflect the Tax Relief Act. As mentioned in the approved Advice 3216-G-A/3859-E-A, p. 11, PG&E is also proposing to reflect the modified weighted average cost of capital in 2013 to comply with the Commission's recent COC Decision[1].

Background

The TAMA-E and TAMA-G allow PG&E to track and record on a CPUC-jurisdictional, revenue requirement basis, the impacts of the Tax Relief Act as follows:

Section A – Estimates the annual revenue requirement impact of the Tax Relief Act incremental tax depreciation on deferred tax liabilities associated with adopted electric distribution, electric generation, gas distribution and gas transmission capital additions for the period from September 2010 through December 2012. The rate base adjustment in this section represents the increase in deferred tax liabilities net of the estimated tax net operating loss (NOL) resulting from the Tax Relief Act.

Section B – Estimates the annual revenue requirements on additional utility infrastructure investment (i.e., incremental capital additions above adopted levels referred to in Section A, above) enabled by tax savings from the Tax Relief Act.

Section C – Estimates the annual revenue requirements associated with other impacts of the Tax Relief Act including the loss of the Section 199 manufacturer's tax deductions (MTD), working cash adjustments and reduced Income Tax Component on Contribution (ITCC) revenue.

Annual revenue requirements associated with Sections A, B and C are calculated over the appropriate Memo Account Period for both the GRC and Gas Transmission & Storage (GT&S) lines of business.

On December 20, 2012, the Commission adopted the Phase I Cost of Capital Decision, adopting a 10.4% return on equity (ROE) for PG&E, and an overall return on rate base (ROR) of 8.06%. The decision also adopts PG&E's proposed capital structure, cost of long-term debt, and cost of preferred equity.

On January 2, 2013, President Obama signed the Extended Tax Relief Act. Among other provisions, the Extended Tax Relief Act continues the 50% bonus depreciation provisions for an additional year so that it applies to qualified property placed in service before 2014 (before Jan. 1, 2015 for certain long-production-period property).

As stated in approved Advice 3216-G-A/3859-E-A (see Attachment 3), the Memo Account Period will end for the electric distribution, generation, and gas distribution as of December 31, 2013 and for gas transmission as of December 31, 2014. Consistent with the Commission's intent in adopting Resolution L-411A and approving PG&E's

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[1] See COC Decision 12-12-034, p. 53.

Advice 3216-G-A/3859-E-A, the computations for 2013 should be modified only to reflect the following:

Section A[2], is hereby extended to also reflect the revenue requirement impact of the Extended Tax Relief Act incremental tax depreciation on deferred tax liabilities associated with adopted electric distribution, electric generation, gas distribution and gas transmission capital additions through December 2013. The Pre-Tax Cost of Capital (see Attachment 4), based on the Commission's 2013 COC Decision, will be used on these incremental deferred taxes to calculate the revenue requirement impact.

Section B[3], is hereby extended to also reflect the impact of annual revenue requirements on additional infrastructure investment through December 31, 2013 enabled by the Extended Tax Relief Act, using the same principles as was applied to determine revenue requirements and additional infrastructure investment in the Tax Relief Act. By way of example, for purpose of determining 2013 incremental additions over the base line, PG&E will use the same base line levels in 2013 as it used in 2012 (2012 base line amounts were, in turn, based on adopted 2011 levels) for the GRC lines of business. For gas transmission, PG&E will use the 2013 capital additions adopted as part of the GT&S settlement decision. Also, the annual revenue requirements associated with the additional infrastructure investment in 2013 will be developed by multiplying the CPUC-jurisdictional incremental capital additions at the line of business (LOB) level by appropriate annual composite revenue requirement factors which fully reflect the benefits of bonus depreciation taken under the Extended Tax Relief Act. Consistent with regulatory convention, these annual revenue requirement factors for 2013 include the cost of capital[4], book depreciation and income taxes.

Section C, is hereby extended to also reflect other revenue requirement changes resulting from the Extended Tax Relief Act, including amounts reflecting the impacts of any decrease in MTD, changes in working cash and any decrease in the ITCC received due to changes in the tariffed tax component of contributions-in-aid-of-construction (CIAC)[5].

As stated above, the Memo Account Period will end for the electric distribution, generation, and gas distribution as of December 31, 2013 and for gas transmission as of December 31, 2014.

Protests

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

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[2] See Advice 3216-G-A/3859-E-A p. 3.
[3] See Advice 3216-G-A/3859-E-A p. 3.
[4] Per Commission's 2013 COC Decision.
[5] Per Pending PG&E Advice 3346-G-A/4148-E-A (See Attachment 5)

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

Effective Date

PG&E requests this **Tier 2** advice filing be effective, subject to Energy Division approval, **January 1, 2013**.

Notice

In accordance with General Order 96-B, Rule 4, a copy of this advice letter is being sent electronically and/or via U.S. mail to parties shown on the attached list and Service Lists A.09-12-020 and A.09-09-013. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian Cherry /IG

Vice President, Regulatory Relations

Attachments:

Attachment 1:	Sec. 331 of the American Taxpayer Relief Act of 2012
Attachment 2:	Commission's Test Year 2013 Cost of Capital (COC) Decision 12-12-034
Attachment 3:	Approved Advice 3216-G-A/3859-E-A
Attachment 4:	PG&E's 2013 Adopted Cost of Capital
Attachment 5:	Pending Advice 3346-G-A/4148-E-A

cc: Service Lists for A.09-12-020 (PG&E's 2011 GRC) and A.09-09-013 (PG&E's 2011 GT&S).

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 M)**

Utility type:

☑ ELC ☑ GAS

☐ PLC ☐ HEAT ☐ WATER

Contact Person: Igor Grinberg

Phone #: (415) 973-8580

E-mail: ixg8@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **3362-G/4157-E** **Tier: 2**

Subject of AL: **Tax Act Memorandum Account (TAMA-E) and (TAMA-G): Conforming Changes to Reflect One-Year Extension of 50% Bonus Depreciation and to Incorporate the Commission's Test Year 2013 Cost Of Capital Decision**

Keywords (choose from CPUC listing): Memorandum Account, Taxes

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

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, 2013** No. of tariff sheets: N/A

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

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

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

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

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

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

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

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

Advice 3362-G/4187-E

Attachment 1

Sec. 331 of the American Taxpayer Relief Act of 2012

SEC. 329. EXTENSION OF TEMPORARY INCREASE IN LIMIT ON COVER OVER OF RUM EXCISE TAXES TO PUERTO RICO AND THE VIRGIN ISLANDS.

(a) IN GENERAL.—Paragraph (1) of section 7652(f) is amended by striking "January 1, 2012" and inserting "January 1, 2014".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to distilled spirits brought into the United States after December 31, 2011.

SEC. 330. MODIFICATION AND EXTENSION OF AMERICAN SAMOA ECONOMIC DEVELOPMENT CREDIT.

(a) MODIFICATION.—

(1) IN GENERAL.—Subsection (a) of section 119 of division A of the Tax Relief and Health Care Act of 2006 is amended by striking "if such corporation" and all that follows and inserting "if—

"(1) in the case of a taxable year beginning before January 1, 2012, such corporation—

"(A) is an existing credit claimant with respect to American Samoa, and

"(B) elected the application of section 936 of the Internal Revenue Code of 1986 for its last taxable year beginning before January 1, 2006, and

"(2) in the case of a taxable year beginning after December 31, 2011, such corporation meets the requirements of subsection (e).".

(2) REQUIREMENTS.—Section 119 of division A of such Act is amended by adding at the end the following new subsection:

"(e) QUALIFIED PRODUCTION ACTIVITIES INCOME REQUIREMENT.—A corporation meets the requirement of this subsection if such corporation has qualified production activities income, as defined in subsection (c) of section 199 of the Internal Revenue Code of 1986, determined by substituting 'American Samoa' for 'the United States' each place it appears in paragraphs (3), (4), and (6) of such subsection (c), for the taxable year.".

(b) EXTENSION.—Subsection (d) of section 119 of division A of the Tax Relief and Health Care Act of 2006 is amended by striking "shall apply" and all that follows and inserting "shall apply—

"(1) in the case of a corporation that meets the requirements of subparagraphs (A) and (B) of subsection (a)(1), to the first 8 taxable years of such corporation which begin after December 31, 2006, and before January 1, 2014, and

"(2) in the case of a corporation that does not meet the requirements of subparagraphs (A) and (B) of subsection (a)(1), to the first 2 taxable years of such corporation which begin after December 31, 2011, and before January 1, 2014.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2011.

SEC. 331. EXTENSION AND MODIFICATION OF BONUS DEPRECIATION.

(a) IN GENERAL.—Paragraph (2) of section 168(k) is amended—

(1) by striking "January 1, 2014" in subparagraph (A)(iv) and inserting "January 1, 2015", and

(2) by striking "January 1, 2013" each place it appears and inserting "January 1, 2014".

(b) SPECIAL RULE FOR FEDERAL LONG-TERM CONTRACTS.—Clause (ii) of section 460(c)(6)(B) is amended by inserting ", or after December 31, 2012, and before January 1, 2014 (January 1, 2015, in the case of property described in section 168(k)(2)(B))" before the period.

(c) EXTENSION OF ELECTION TO ACCELERATE THE AMT CREDIT IN LIEU OF BONUS DEPRECIATION.—

(1) IN GENERAL.—Subclause (II) of section 168(k)(4)(D)(iii) is amended by striking "2013" and inserting "2014".

(2) ROUND 3 EXTENSION PROPERTY.—Paragraph (4) of section 168(k) is amended by adding at the end the following new subparagraph:

"(J) SPECIAL RULES FOR ROUND 3 EXTENSION PROPERTY.—

"(i) IN GENERAL.—In the case of round 3 extension property, this paragraph shall be applied without regard to—

"(I) the limitation described in subparagraph (B)(i) thereof, and

"(II) the business credit increase amount under subparagraph (E)(iii) thereof.

"(ii) TAXPAYERS PREVIOUSLY ELECTING ACCELERATION.—In the case of a taxpayer who made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, a taxpayer who made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008, or a taxpayer who made the election under subparagraph (I)(iii) for its first taxable year ending after December 31, 2010—

"(I) the taxpayer may elect not to have this paragraph apply to round 3 extension property, but

"(II) if the taxpayer does not make the election under subclause (I), in applying this paragraph to the taxpayer the bonus depreciation amount, maximum amount, and maximum increase amount shall be computed and applied to eligible qualified property which is round 3 extension property.

The amounts described in subclause (II) shall be computed separately from any amounts computed with respect to eligible qualified property which is not round 3 extension property.

"(iii) TAXPAYERS NOT PREVIOUSLY ELECTING ACCELERATION.—In the case of a taxpayer who neither made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, nor made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008, nor made the election under subparagraph (I)(iii) for any taxable year ending after December 31, 2010—

"(I) the taxpayer may elect to have this paragraph apply to its first taxable year ending after December 31, 2012, and each subsequent taxable year, and

"(II) if the taxpayer makes the election under subclause (I), this paragraph shall only apply to eligible qualified property which is round 3 extension property.

"(iv) ROUND 3 EXTENSION PROPERTY.—For purposes of this subparagraph, the term 'round 3 extension property' means property which is eligible qualified property solely by reason of the extension of the application of the special allowance under paragraph (1) pursuant to the amendments made by section 331(a) of the American Taxpayer Relief Act of 2012 (and the application of such extension to this paragraph pursuant to the amendment made by section 331(c)(1) of such Act).".

(d) NORMALIZATION RULES AMENDMENT.—Clause (ii) of section 168(i)(9)(A) is amended by inserting "(respecting all elections made by the taxpayer under this section)" after "such property".

(e) CONFORMING AMENDMENTS.—

(1) The heading for subsection (k) of section 168 is amended by striking "JANUARY 1, 2013" and inserting "JANUARY 1, 2014".

(2) The heading for clause (ii) of section 168(k)(2)(B) is amended by striking "PRE-JANUARY 1, 2013" and inserting "PRE-JANUARY 1, 2014".

(3) Subparagraph (C) of section 168(n)(2) is amended by striking "January 1, 2013" and inserting "January 1, 2014".

(4) Subparagraph (D) of section 1400L(b)(2) is amended by striking "January 1, 2013" and inserting "January 1, 2014".

(5) Subparagraph (B) of section 1400N(d)(3) is amended by striking "January 1, 2013" and inserting "January 1, 2014".

(f) EFFECTIVE DATE.—The amendments made by this section shall apply to property placed in service after December 31, 2012, in taxable years ending after such date.

TITLE IV—ENERGY TAX EXTENDERS

SEC. 401. EXTENSION OF CREDIT FOR ENERGY-EFFICIENT EXISTING HOMES.

(a) IN GENERAL.—Paragraph (2) of section 25C(g) is amended by striking "December 31, 2011" and inserting "December 31, 2013".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to property placed in service after December 31, 2011.

SEC. 402. EXTENSION OF CREDIT FOR ALTERNATIVE FUEL VEHICLE REFUELING PROPERTY.

(a) IN GENERAL.—Paragraph (2) of section 30C(g) is amended by striking "December 31, 2011." and inserting "December 31, 2013".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to property placed in service after December 31, 2011.

SEC. 403. EXTENSION OF CREDIT FOR 2- OR 3-WHEELED PLUG-IN ELECTRIC VEHICLES.

(a) IN GENERAL.—Section 30D is amended by adding at the end the following new subsection:

"(g) CREDIT ALLOWED FOR 2- AND 3-WHEELED PLUG-IN ELECTRIC VEHICLES.—

"(1) IN GENERAL.—In the case of a qualified 2- or 3-wheeled plug-in electric vehicle—

"(A) there shall be allowed as a credit against the tax imposed by this chapter for the taxable year an amount equal to the sum of the applicable amount with respect

Advice 3362-G/4187-E

Attachment 2

Commission's Test Year 2013 Cost of Capital (COC) Decision 12-12-034

ALJ/MFG/rs6 **Date of Issuance 12/26/2012**

Decision 12-12-034 December 20, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism.	Application 12-04-015 (Filed April 20, 2012)
And Related Matters.	Application 12-04-016 Application 12-04-017 Application 12-04-018

Angelica M. Morales, Attorney at Law, for Southern California Edison Company, applicant.
Laura M. Earl, Attorney at Law, for San Diego Gas & Electric Company, applicant.
Kim F. Hassan, Attorney at Law, for Southern California Gas Company, applicant.
Peter Van Mieghem, Attorney at Law, for Pacific Gas and Electric Company, applicant.
Marcel Hawiger, Attorney at Law, for The Utility Reform Network, interested party.
John Cummins, Attorney at Law, for Federal Executive Agencies;
Evelyn Kahl, Alcantar & Kahl, Attorney at Law, for Energy Producers and Users Coalition, interest party.
L. Jan Reid, for self, interested party.
Norman A. Pedersen, Attorney at Law, Hanna and Morton, LLP, for Southern California Generation Coalition, interested party.
Jonathan Bromson, Attorney at Law, for the Division of Ratepayer Advocates.

DECISION ON TEST YEAR 2013 COST OF CAPITAL FOR THE MAJOR ENERGY UTILITIES

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DECISION ON TEST YEAR 2013 COST OF CAPITAL FOR THE MAJOR ENERGY UTILITIES

1. Summary

This decision establishes the 2013 ratemaking return on common equity (ROE) and return on rate base (ROR) for Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E). The test year 2013 authorized ROE, ROR and resulting revenue requirement reduction is as follows.

UTILITY	Return on Common Equity	Return on Rate Base	Reduction in Revenue Requirement
SCE[1]	10.45%	7.90%	$217 Million
SDG&E[2]	10.30%	7.79%	$ 34 Million
SoCalGas[3]	10.10%	8.02%	$ 22 Million
PG&E[4]	10.40%	8.06%	$237 Million

This reduction in revenue requirement is estimated to reduce the utility's average residential customer's monthly bill as follows.

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[1] Late-filed Hearing Exhibit 150 shows that a 10 basis point change (a one basis point change equals 0.01%) in SCE's authorized ROE equates to a $16.8 million revenue requirement change and a $0.20 change in an average residential customer monthly bill using 600 kilowatt-hours of electricity. The overall revenue requirement reduction is revised upward and average residential bill change downward to $0.16 per 10 basis point change pursuant to its opening comments on the proposed decision.

[2] Late-filed Hearing Exhibit 151 shows that a 10 basis point change in SDG&E's authorized ROE equates to a $3.4 million ($2.8 million electric and $.6 million gas) revenue requirement change and, a $0.04 change in an average residential customer monthly bill using 500 kilowatt-hours of non-core inland electricity and $0.02 change in an average residential customer monthly bill using 33 therms of gas. The overall revenue requirement reduction is revised upward pursuant to its opening comments on the proposed decision.

[3] Late-filed Hearing Exhibit 152 shows that a 10 basis point change in SoCalGas' authorized ROE equates to a $2.6 million revenue requirement change and a $0.03 change in an average residential customer monthly bill using 38 therms of gas. The overall revenue requirement reduction is revised upward pursuant to its opening comments on the proposed decision.

[4] Late-filed Exhibit 153 shows that a 10 basis point change in PG&E's authorized ROE equates to a $17 million ($13 million electric and $4 million gas) revenue requirement change and, a $0.08 change in an average electric residential customer monthly bill using 550 kilowatt-hours of electricity and $0.04 change in an average gas residential customer monthly bill using 37 therms of gas. The overall revenue requirement reduction is revised upward pursuant to its opening comments on the proposed decision.

UTILITY/SERVICE	AVERAGE MONTHLY USAGE	AVERAGE MONTHLY SAVINGS
SCE/Electric[5]	600 kilowatt-hours	$1.52
SDG&E/Electric	500 kilowatt-hours/noncore	$ .32
SDG&E/Gas	33 therms	$ .16
SoCalGas/Gas	38 therms	$ .22
PG&E/Electric	550 kilowatt-hours	$ .76
PG&E/Gas	37 therms	$ .38

This proceeding remains open to address modifications to the multi-year cost of capital mechanism adopted by Decision 08-05-035 for use in the two years between the energy utilities' triennial cost of capital applications.

2. Jurisdiction and Background

Applicants are public utilities subject to the jurisdiction of this Commission as defined in Section 218 of the Public Utilities Code.[6] Southern California Edison (SCE), a California corporation and wholly owned subsidiary of Edison International, provides electric service principally in southern California. San Diego Gas &Electric (SDG&E), a California corporation wholly owned by Sempra Energy, provides electric service in a portion of Orange County and electric and gas services in San Diego County. Southern California Gas Company (SoCalGas), a California corporation wholly owned by Sempra Energy, provides gas services throughout Central and Southern California from

[5] The differences between SCE's monthly bill change and those of the other utilities result from differences in rate base per customer served and the percentage of the total revenue requirement that is allocated to residential customers.

[6] All statutory references are to the Public Utilities Code unless otherwise stated.

Visalia to the Mexican border. Pacific Gas and Electric Company (PG&E), a California corporation, provides electric and gas services in northern and central California.

Three of the four utilities filed applications on April 20, 2012 for authority to reduce their Returns on Equity (ROEs). SCE seeks to reduce its ROE to 11.10% from 11.50%, SDG&E to 11.00% from 11.10% and PG&E to 11.00% from 11.35%. On the same day, SoCal Gas filed an application for authority to increase its ROE to 10.90% from 10.82%. SDG&E, SoCalGas and PG&E also propose to change their respective capital structures while SCE proposes to maintain its currently authorized capital structure.

3. Capital Structure

Capital structure consists of long-term debt, preferred stock, and common equity.[7] Because the level of financial risk that the utilities face is determined in part by the proportion of their debt to permanent capital, or leverage, we must ensure that the utilities' adopted equity ratios are sufficient to maintain reasonable credit ratings and to attract capital.

3.1. SCE

SCE seeks a test year 2013 ratemaking capital structure of 43.00% long-term debt, 9.00% preferred stock, and 48.00% common equity. This is the same capital structure that it is currently authorized.

Except for the Federal Executive Agencies (FEA), all parties[8] concur with SCE's proposed capital structure. FEA recommends that SCE's capital structure should be set more in line with the average capital structure that SCE has

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[7] Debt due within one year, short-term debt, is excluded.

[8] Parties consist of all appearances of record.

actually used over the most recent five quarters (from March of 2011 through March of 2012), a capital structure consisting of 48.00% common equity, 7% preferred stock and 45% long-term debt.

FEA's capital structure adjustment of a 2% reduction in SCE's preferred stock ratio with a corresponding increase in long-term debt is based on recorded long-term debt found in SCE's quarterly reports filed with the Securities and Exchange Commission (SEC).[9] However, FEA's capital structure analysis is flawed because recorded long-term debt is not the same long-term debt used for SCE's ratemaking capital structure.

Two adjustments must be made to the recorded long-term debt reported to the SEC to arrive at SCE's California ratemaking capital structure. These ratemaking adjustments are: (1) to exclude recorded long-term debt balances supporting nuclear fuel inventories, which is recoverable in the energy resource recovery account proceedings and excluded from ratemaking rate base; and, (2) to amortize recorded long-term debt financing issuance costs over the life of each security issued.[10] After these adjustments are made, SCE's debt ratio is in line with SCE's average and requested capital structure. We find SCE's requested capital structure reasonable and we will adopt it.

3.2. SDG&E

SDG&E seeks a test year 2013 ratemaking capital structure consisting of 45.25% long-term debt, 2.75% preferred stock, and 52.00% common equity. This is a 3.00% increase in its common equity ratio and a corresponding decrease in its

[9] Hearing Exhibit 30 at 86 and Schedule 10 at 6.

[10] Hearing Exhibit 19 at 19.

preferred stock ratio from its currently authorized capital structure. SDG&E's requested capital structure is intended to preserve its strong "A" investment grade credit rating of long-term debt, to attract long-term debt at low costs, and to maintain financial strength for the long-term management of its capital investment program, expected to average over $1.1 billion per year during the 2013-2015 years.[11] This capital structure is also intended to support SDG&E's current credit rating while mitigating the need for SDG&E to take on more debt for its pending Application (A.) 11-05-023, which seeks authority to enter into Purchase Power Tolling Agreements with the Pio Pico Energy Center and Quail Brush Power peaker plant facilities.[12]

Except for FEA, all parties concur with SDG&E's proposed capital structure. FEA opposes SDG&E's requested 3% increase in common equity because: (1) it is not in line with the average common equity ratio of 48.60% that SDG&E has actually used over the most recent five quarters (from March of 2011 through March of 2012); (2) SDG&E's requested capital structure shifts more costs to ratepayers; (3) SDG&E can issue first mortgage debt that has an "AA" rating; and, (4) SDG&E's parent company, Sempra Energy, raised its dividend earlier this year by 25%, which represented a transfer of significant capital.[13]

FEA recommends that SDG&E's proposed 3% increase in its common equity ratio be split evenly between long-term debt and common equity, resulting in a capital structure of 46.75% long-term debt, 2.75% preferred stock and 50.5% common equity.

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[11] Hearing Exhibit 4 at 4-8.

[12] Hearing Exhibit 4 at 8.

[13] Hearing Exhibit 30 at 82 and 86-88.

Similar to its flawed capital structure analysis for SCE, FEA failed to adjust recorded long-term debt to compare SDG&E's average ratemaking capital structure to its requested capital structure. SDG&E's actual common equity ratio would have been in line with its requested common equity ratio if FEA had made the appropriate ratemaking adjustments to SDG&E's recorded long-term debt, as highlighted in the following tabulation.[14]

	FEA Recorded Debt	SDG&E Adjusted Debt	SDG&E Requested Structure
Long-term Debt	50.37%	47.16%	45.25%
Preferred Stock	1.04%	1.13%	2.75%
Common Equity	**48.60%**	**51.71%**	**52.00%**
Total	100.00%[15]	100.00%	100.00%

We find SDG&E's requested 3.00% increase in its common equity ratio and a corresponding decrease in its preferred stock ratio from its currently authorized capital structure would shift more costs to ratepayers. This is because common equity financing is more costly than long-term debt and preferred stock financing. Ratepayers receive the most benefit from the use of long-term debt financing because debt is less costly and it is tax-deductible. Preferred stock has qualities of both debt and equity financing and is treated by credit rating agencies as a hybrid of debt and equity.[16] However, as long-term debt ratios are increased, credit ratings tend to be downgraded which results in increased

14 Hearing Exhibit 8 at Attachment A.

15 Difference between the 100.00% total and the adding of individual percentages (100.01%) is due to rounding the percentages.

16 Hearing Exhibit 4 at 16.

financial risks for common equity holders, thereby requiring greater returns on common equity.

SDG&E has strong investment grade credit ratings.[17] However, the dividend policy of SDG&E's parent company is not relevant in this proceeding. What is relevant is SDG&E's actual experience of paying dividends to Sempra Energy. Due to SDG&E's large capital program, its dividend plans have been suspended for several recent years. In fact, SDG&E has received more common equity inflows from its parent than it has provided in dividends since 2008. While SDG&E paid $150 million of common stock dividends in 2009, SDG&E received $200 million of common equity from Sempra Energy in 2011. SDG&E did not pay any common stock dividends in 2008, 2010, 2011, and 2012.[18]

SDG&E's current credit ratings of "A" from Standard & Poor (S&P) and A2 from Moody's are one step stronger than Division of Ratepayer Advocates' (DRA) proxy group average S&P credit rating of A-/BBB+ and average Moody's credit rating of A3/Baa1.[19]

Although S&P has imputed $182 million of debt equivalence[20] into SDG&E's long-term debt in June 2011, SDG&E expects S&P to increase imputed debt equivalence into its long-term debt ten-fold, in excess of $1.6 billion. Approximately $772 million, or almost half of the expected debt equivalence, is expected to occur as a result of future contracts pending Commission approval.[21]

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[17] Hearing Exhibit 5 at 11.

[18] Hearing Exhibit 8 at 5-6.

[19] Hearing Exhibit 5 at 11 and Exhibit 24, Attachment JRW-4 at 1.

[21] Hearing Exhibit 4 at 10.

This expected debt equivalence increase is due to including financial statement consolidation of SDG&E's pending purchase power tolling agreements pursuant to Accounting Standards Codification 810 (ASC 810), formerly referred to as Financial Accounting Standards Board Interpretation No. 46 R.[22]

Credit agencies do not use a standard method to calculate long-term debt equivalence. S&P's uses a risk factor of 50% as a generic guideline for utilities with PPAs included as an operating expense in base tariffs and lowers that risk factor to 25%, as appropriate, when purchased power costs may be recovered via a fuel-adjustment clause.[23] Moody's employs a different methodology in assessing utility PPAs. In certain cases, Moody's would not impute any debt and in other cases consider PPAs as a positive risk mitigation factor.[24] Moody's recognizes that PPAs have been used by utilities as a risk management tool. Thus, it will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Moody's look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are considered by Moody's to be similar to long-term supply contracts used by other industries and their

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[22] ASC 810 is a generally accepted accounting principal that requires an entity such as SDG&E having a controlling financial interest in another entity, such as its proposed purchase power tolling agreements, to consolidate those other entities into the financial statements of the controlling financial entity.

[23] Hearing Exhibit 24 at 3-21.

[24] Reporter's Transcript, Volume 1 at 79 lines 23-26, and 81 lines 2-7.

treatment should not therefore be fundamentally different from that other contracts of a similar nature.[25]

The Commission has previously reasoned that the utilities should be given some discretion to manage their capitalization with a view towards a balance between shareholders' interest, regulatory requirements, and ratepayers' interest.[26] In this case, SDG&E seeks a common equity ratio for its revenue requirement which is the same as its actual common equity ratio. We concur with SDG&E and find a 46.25% long-term debt, 2.75% preferred stock and 52.00% common equity capital structure reasonable and we adopt it.

3.3. SoCalGas

SoCalGas seeks a test year 2013 ratemaking capital structure of 45.60% long-term debt, 2.40% preferred stock, and 52.00% common equity. This is a 4.00% increase in its common equity ratio and a corresponding decrease in its preferred stock ratio from its currently authorized capital structure.

Except for FEA, all parties concur with SoCalGas proposed capital structure. FEA recommends that SoCalGas' requested 4% increase in common equity be split evenly between equity and debt for the same reasons it recommends an even split in SDG&E's requested common equity increase.

However, FEA's analysis of SoCalGas' capital structure contains the same flaws addressed in our prior SCE and SDG&E capital structure discussions and

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[25] Reporter's Transcript, Volume 1 at 80 at lines 2 through 81 at line 1. *See* also Exhibit 38.

[26] 33 CPUC2d (1989) 495 at 541 through 545.

will not be repeated here. It is important to note that SoCalGas' authorized capital structure with a 48% common equity ratio has not changed since 1997.[27]

The Utility Reform Network (TURN) supports SoCalGas' requested equity ratio because the requested 52% common equity ratio is well below TURN's natural gas company proxy group equity ratio.[28] SoCalGas' current "A" credit rating by S&P and "A2" credit rating by Moody's is in the same range as TURN's natural gas company proxy group, which averages an "A" credit rating by both S&P and Moody's.[29] Approval of SoCalGas' requested 52% common equity ratio will bring its capital structure closer to the gas industry average. At the same time, a lower preferred stock ratio will reduce SoCalGas' perceived financial risk because credit rating agencies treat preferred stock as a hybrid of debt and equity.[30] We find SoCalGas' requested capital structure reasonable and we adopt it.

3.4. PG&E

PG&E seeks a test year 2013 ratemaking capital structure of 47.00% long-term debt, 1.00% preferred stock, and 52.00% common equity. This is a 1.00% increase in its long-term debt ratio and a corresponding decrease in its preferred stock ratio from its currently authorized capital structure. There is no opposition to PG&E's proposed capital structure and we adopt it.

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[27] 69 CPUC2d (1996) 327 at 350.

[28] Hearing Exhibit 26 at 82 and Exhibit 27, Schedule DJL-18.

[29] Hearing Exhibit 13 at 10 and Exhibit 27, Schedule DJL-18.

[30] Hearing Exhibit 4 at 16, and Reporter's Transcript, Volume 1 at 89, lines 10-23.

3.5. Summary

The capital structures requested by SCE, SoCalGas and PG&E and SDG&E's capital structure recommended by FEA are balanced, attainable and are intended to maintain an investment grade rating and to attract capital. For these reasons, we find that the capital structures shown below are fair, consistent with law, in the public interest and should be adopted. The adopted capital structures are detailed in the following tabulation:

CAPITAL RATIO	SCE	SDG&E	SoCalGas	PG&E
Long-term Debt	43.00%	46.75%	45.60%	47.00%
Preferred Stock	9.00%	2.75%	2.40%	1.00%
Common Equity	48.00%	50.50%	52.00%	52.00%
Total	100.00%	100.00%	100.00%	100.00%

The next step in determining a fair ROE is to establish reasonable long-term debt and preferred stock costs.

4. Long-term Debt and Preferred Stock Costs

Long-term debt and preferred stock costs are based on actual, or embedded, costs. Future interest rates must be anticipated to reflect projected changes in a utility's cost caused by the issuance and retirement of long-term debt and preferred stock during the year. This is because the ROE is established on a forecast basis.

We recognize that actual interest rates do vary and that our task is to determine "reasonable" debt cost rather than actual cost based on an arbitrary selection of a past figure.[31] In this regard, we conclude that the latest available

[31] 38 CPUC2d (1990) 233 at 242 and 243.

interest rate forecast should be used to determine embedded debt cost in cost of capital proceedings. Consistent with this conclusion, the assigned Commissioner's Scoping Memo and Ruling allowed the utilities to update their long-term debt and preferred stock costs based on Global Insight's September 2012 forecasted interest rates for 2013. That update was submitted on October 9, 2012 as late-filed Exhibits 150, 151, 152 and 153 by SCE, SDG&E, SoCalGas and PG&E, respectively.

4.1. SCE

SCE projected its test year 2013 long-term debt cost to be 5.53%. SCE started with its recorded embedded costs as of the end of February 2012 and then incorporated its current projection of long-term debt to be issued through the end of 2013, consisting of $850 million of new long-term debt issuance in 2012 and $625 million of new long-term debt issuance in 2013. Embedded costs for 2013 are estimated as the average of projected embedded cost at the beginning of 2013 and the end of 2013.

Based on its late-filed exhibit that updated the impact of the most recently forecasted interest rates, SCE increased its new long-term debt issuance in 2013 to $725 million from $625 million and decreased its forecasted long-term debt cost to 5.49% from 5.53%.[32] This revised rate is 73 basis points lower than the 6.22% long-term debt cost authorized in its test year 2008 cost of capital proceeding.

SCE used that same method to calculate a preferred stock cost of 5.86%. Its forecast provided for the issuance of $400 million new preferred stock in 2012

[32] Late-filed Hearing Exhibit 150.

and $150 million of new preferred stock in 2013. Based on its late-filed exhibit that updated the impact of the most recent forecasted interest rates, SCE increased its new preferred stock issuance to $175 million from $150 million and decreased its forecasted preferred stock cost to 5.79% from 5.86%. This revised rate is 22 basis points lower than the 6.01% preferred stock cost SCE was authorized in its test year 2008 cost of capital proceeding.

4.2. SDG&E

SDG&E projected its test year 2013 long-term debt cost to be 5.09%. That 2013 forecast provides for the issuance of $250 million in new long-term debt. Based on its late-filed exhibit that updated the impact of the most recently forecasted interest rates, SDG&E decreased its forecasted long-term debt to 5.00% from 5.09%. This revised rate is 62 basis points lower than the 5.62% long-term debt cost authorized in its test year 2008 cost of capital proceeding.

SDG&E used that same method to calculate a preferred stock cost of 6.35%. Its forecast provided for an $80 million issuance of preferred stock in test year 2013. Based on its late-filed exhibit that updated the impact of the most recently forecasted interest rates, SDG&E decreased its forecast to 6.22% from 6.35%.[33] This revised rate is 103 basis points lower than the 7.25% preferred stock costs authorized in its test year 2008 cost of capital proceeding.

4.3. SoCalGas

SoCalGas projected its test year 2013 long-term debt cost to be 5.72%. This forecast takes into account $500 million of new long-term debt in 2012 and $350 million in 2013. Based on its late-filed exhibit that updated the impact of the

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[33] Late-filed Hearing Exhibit 151.

most recently forecasted interest rates, SoCalGas increased its forecast to 5.77% from 5.72%.[34] This revised rate is 119 basis points lower than the 6.96% currently authorized long-term debt rate.

SoCalGas projected a preferred stock cost of 6.00%, a 117 basis points increase from its currently authorized 4.83% rate. In the absence of any projected issuances or retirements of preferred stock, the forecasted embedded cost of preferred stock is equivalent to the current actual embedded cost. Its late-filed exhibit that updated the impact of the most recently forecasted interest rates has no impact on the cost of preferred stock because its rate is based on the embedded cost of preferred stock and SoCalGas is not planning on retiring or issuing any such stock during the test year.

4.4. PG&E

PG&E projected its test year 2013 long-term debt cost to be 5.69%. PG&E started with its recorded cost of debt as of March 31, 2012, and incorporated projected changes in the amounts or costs of debt outstanding through the remainder of 2012 and 2013. Those changes included $925 million of new long-term debt in 2012 and $1.875 billion of new long-term debt in 2013.

Based on its late-filed exhibit that updated the impact of the most recently forecasted interest rates, PG&E decreased its forecast to 5.52%.[35] This revised rate is 53 basis points lower than the 6.05% long-term debt cost authorized in its test year 2008 cost of capital proceeding.

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[34] Late-filed Hearing Exhibit 152.

[35] Late-filed Hearing Exhibit 153.

PG&E projected its 2013 test year preferred stock cost in the same way it projected its embedded cost of debt. PG&E started with its recorded cost of preferred stock as of March 31, 2012 and incorporated changes for the remainder of 2012 and all of 2013. The only change impacting PG&E's cost of preferred stock is amortization of costs associated with preferred stock previously redeemed. This change results in a preferred stock cost of 5.60%, an 8 basis point decrease from its currently authorized rate of 5.68%. Therefore, the updated forecast of interest rates did not impact its test year preferred stock cost.

4.5. Summary

There is no opposition to the utilities' proposed long-term debt and preferred stock costs for the test year 2013. We have reviewed these undisputed costs which have been updated to reflect the most recent forecasted interest rates and find that the following long-term debt and preferred stock costs for the utilities are consistent with the law, in the public interest and should be adopted.

	SCE	SDG&E	SoCal Gas	PG&E
Long-term Debt	5.49%	5.00%	5.77%	5.52%
Preferred Stock	5.79%	6.22%	6.00%	5.60%

Having determined the appropriate long-term debt and preferred stock costs, we address the appropriate ROE.

5. Return on Common Equity

The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the Bluefield and Hope cases.[36] The

[36] The Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of the State of Virginia, 262 U.S. 679 (1923).

Bluefield decision states that a public utility is entitled to earn a return upon the value of its property employed for the convenience of the public and sets forth parameters to assess a reasonable return.[37] Such return should be equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. That return should also be reasonably sufficient to ensure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties.

The Hope decision reinforces the Bluefield decision and emphasizes that such returns should be sufficient to cover operating expenses and capital costs of the business. The capital cost of business includes debt service and stock dividends. The return should also be commensurate with returns available on alternative investments of comparable risks. However, in applying these parameters, we must not lose sight of our duty to utility ratepayers to protect them from unreasonable risks including risks of imprudent management.

We attempt to set the ROE at a level of return commensurate with market returns on investments having corresponding risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility service obligation. To accomplish this objective, we have consistently evaluated analytical financial models as a starting point to arrive at a fair ROE.

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[37] Hope held that the value of a utility's property could be calculated based on the amount of prudent investment minus depreciation.

5.1. Proxy Groups

To enhance comparability of the financial modeling results among the parties in energy utilities ROE proceedings, the Commission adopted the Value Line Investment Survey (Value Line) electric industry classifications (includes combination electric and gas companies) for use in energy utilities' ROE proceedings where the financial models require the use of a proxy group.[38] Three basic screens were also adopted in selecting a comparable proxy group. Those screens are: (1) to exclude companies that do not have investment grade credit ratings; (2) exclude companies that do not have a history of paying dividends; and, (3) exclude companies undergoing a restructure or merger. Additional screens are acceptable to the extent that justification is provided.

SCE, SDG&E, SoCalGas, and PG&E started with the Value Line gas and electric utility industry group lists to establish proxy groups of companies for their financial models. PG&E used Value Line's non-utility companies' list for its second proxy group. The utilities then screened those companies to ensure that they were compatible to their respective utility.

The intervenors[39] also used Value Line's gas and electric utility industry group list to establish their respective proxy groups. L. Jan Reid used a total of seven different proxy groups including: all Value Line utilities including water utilities; all Value Line energy utilities; all Value Line western electric and

[38] Ordering Paragraph 4 of Decision (D.) 07-12-049.

[39] Named intervenors are: the DRA, Energy Producers and Users Coalition (EPUC), FEA, Reid, and TURN.

combination utilities; and the comparable groups used by SCE, SDG&E, SoCalGas and PG&E.[40]

The following tabulation compares the number of entities included in each party's proxy group.

	SCE	SDG&E	SoCalGas	PG&E
Utility	26 Electric	31 Electric 14 Utilities[41]	31 Electric 7 Gas	14 Electric 12 Non-Utility[42]
DRA	34 Electric 8 Gas	34 Electric 8 Gas	34 Electric 8 Gas	34 Electric 8 Gas
EPUC	Same as Utility	not applicable	not applicable	Same as Utility
FEA	16 Electric 7 Gas	16 Electric 7 Gas	16 Electric 7 Gas	16 Electric 7 Gas
Reid	not applicable	not applicable	not applicable	64 Electric, Gas, Water
TURN	Same as Utility	Same as Utility	Same as Utility	Same as Utility

A proxy, by common definition, is a substitute. Hence, companies selected as a proxy group of a utility should have characteristics similar to that utility. In order to ensure comparability and reasonableness of financial modeling results, the utilities and companies selected in the proxy group should be exposed to similar risks.

However, the parties (excluding TURN and EPUC) used different companies for their proxy groups making it difficult to determine which intervenor financial modeling results are comparable to SCE, SDG&E, SoCalGas,

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[40] Hearing Exhibit 33 at 14 and 15.

[41] SDG&E's 14 combined electric and gas company proxy group consists of Value Line's Western utility group.

[42] PG&E used its non-utility proxy group results to demonstrate that the end result of its electric proxy group was consistent with competitive non-utility markets. (Reporter's Transcript, Volume 2 at 197.)

and PG&E financial modeling results. It is further difficult due to the individual parties utilizing numerous variations of the individual financial models which tend to skew a party's individual financial modeling result. For example, SDG&E utilized nine variations while TURN utilized 14.[43] Four of SDG&E's modeling variations were related to the Discounted Cash Flow (DCF) Model, two of the variations were related to including a different number of companies in gas and electric utilities proxy groups. The remaining variations were due to different sources of forecasts, and different projected earnings per share growth forecast.[44] Eight of TURN's modeling variations for SDG&E were applicable to the DCF Model. SoCalGas used the identical number of companies, sources of forecasts, projected earnings per share growth forecasts, and modeling results as SDG&E.[45]

5.1.1. Non-Utility Proxy Group

PG&E utilized a non-utility proxy group to corroborate the results of its energy utility proxy group. In doing so it reasoned that relative risk, not a particular business activity or degree of regulation, should be the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return.[46]

However, a 250 basis point DCF modeling result differential between its average utility and average non-utility proxy groups leads us to question whether the non-utility proxy group is actually comparable to its utility proxy

[43] Hearing Exhibit 1 at 65 and Exhibit 26 at 70.

[44] Hearing Exhibit 1 at RAM-2 and RAM-3.

[45] Compare Exhibit 1 at RAM-2 to Exhibit 12 at RAM-4 and Exhibit 1 at RAM 4 to Exhibit 12 at RAM-5.

[46] Hearing Exhibit 21 at 2-15.

group and to PG&E.[47] This is especially true given that non-utility earnings are dependent on the extent of competition and ability to price products or services at rates a buyer is willing to pay while maintaining a competitive edge in comparison to utility earnings being dependent on a fair return on investments with reasonable pricing of utility services, irrespective of what a buyer is willing to pay for a product or service for which they may have no alternative. Therefore, we decline to consider the financial modeling results from PG&E's non-utility proxy group.

We next review the financial models used by the parties to assess the comparability and reasonableness of their results.

5.2. Financial Models

The financial models commonly used in ROE proceedings are the Capital Asset Pricing Model (CAPM), Risk Premium Model (RPM), and DCF Model.[48] Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method.[49] Detailed descriptions of these financial models are contained in the record and are not repeated here.

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47 Hearing Exhibit 21 at 2-28 and 2-29 simple average of PG&E's four utility proxy group average DCF modeling results compared to the simple average of its four non-utility proxy group average DCF modeling results.

48 Evidence was presented on the use of an additional financial model, *Fama French*, which was considered and rejected by the Commission in D.07-12-049 and D.05-12-043. (Hearing Exhibit 33 at 13-15).

49 Hearing Exhibit 12 at 15.

The application of these financial models is applied to a proxy group of companies comparable to the respective utility. A contributing factor resulting in a wide range of financial modeling results is the parties' difference in the time period and the availability of subjective inputs. While financial modeling results from the utilities were due on April 20, 2012, as part of their applications, intervenors had access to more recent data to use for their subjective inputs because their financial modeling results were not due until three and a half months later on August 6, 2012. It is the result of differences in subjective inputs used in models that result in a wide range of ROEs being recommended by the parties.

5.2.1. Flotation Costs

SDG&E and SoCalGas were the only parties that included flotation costs[50] as a subjective input into their respective financial models, resulting in an upward adjustment in its financial models of approximately 25 basis points.[51] While PG&E did not make an explicit flotation cost adjustment in its financial models, it recommended that such an adjustment be considered in evaluating a ROE for PG&E from within the results of its financial models.[52] The inclusion of flotation costs in the various financial models is not a new issue.

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[50] Flotation costs commonly includes underwriter costs for marketing, consulting, printing and distribution, legal costs and discounts that must be provided to place a new common stock in the open market.

[51] Reporter's Transcript, Volume 1 at 166.

[52] Hearing Exhibit 21 at 2-24. One method identified by PG&E in which a flotation adjustment can be calculated is to make a 5% to 10% upward adjustment to the ROE. This method is based on Roger Morin's "New Regulatory Finance" finance literature, the same person who recommended an approximate 25 basis point adjustment for SDG&E and SoCalGas in this proceeding.

We concluded in D.92-11-047 that any merit to a flotation adjustment would apply only to existing common stock at the time of actual new issuances. We also concluded in that decision that a flotation adjustment is not applicable to sales in the secondary market, and that such an adjustment is inappropriate as long as utility stocks are trading significantly above their book value. We further concluded in that decision that any reconsideration of a flotation adjustment in a future proceeding would require a showing of theoretical, practical, utility and market specific data, and a showing that a flotation cost adjustment does not shift the burden of the transaction costs from investors to ratepayers.[53]

The utilities proposing a flotation adjustment have: (1) not identified any of their actual flotation costs; (2) not identified any new common stock issuances in the test year; and, (3) not demonstrated that their utility stocks are trading at, or below, their book value. Consistent with the reasons set forth in D.92-11-047, we reject consideration of a flotation adjustment in this proceeding. The following financial modeling results and discussions of SDG&E and SoCalGas exclude their flotation adjustments.

5.2.2. CAPM

The CAPM is a risk premium approach that gauges an entity's cost of equity based on the sum of an interest rate on a risk-free bond and a risk premium. Two primary variations to the CAPM were used by the parties, traditional and empirical CAPMs. The empirical CAPM (ECAPM) is designed to include the relationship between *beta*[54] and security returns, which the traditional

[53] 46 CPUC2d (1992) 319 at 362 and 406.

[54] The term "beta" refers to - a company specific multiplier of general market risk.

CAPM does not. However, the ECAPM tends to produce higher overall cost of capital estimates because adjusting electric utilities' *betas*, which tend to have low *betas*, upward guarantees a higher ROE.[55]

Each party utilized different subjective inputs into their CAPM. For example, the average risk free rate utilized by parties ranged from 2.48% to 4.20% and market risk premium ranged from 5.01% to 9.70%.[56] The following tabulation summarizes the simple average result of the CAPM variations calculated by the individual parties using subjective inputs.[57]

	SCE	**SDG&E**	**SoCalGas**	**PG&E**
Utility	10.70%[58]	10.50 %[59]	10.20%[60]	11.10%
DRA	7.60%	7.60%	7.60%	7.60%
EPUC	8.40%	not applicable	not applicable	8.40%
FEA	7.80%	7.80%	7.80%	7.80%
REID	not applicable	not applicable	not applicable	7.10%
TURN	9.20%	9.20%	9.10%	9.10%

55 1 CPUC3d (1999) 146 at 168-169.

56 Hearing Exhibit 35-A.

57 All financial modeling results are rounded to a tenth (.001) of a percent.

58 Excludes SCE's after-tax weighted average cost of capital (ATWACC) adjustments identified in Exhibit 17 at 68-71. Although SCE is not proposing that its ATWACC adjustments be used to directly determine its cost of capital and acknowledges that the Commission rejected ATWACC adjustments (D.04-12-047, mimeo, 40-42 and D.99-06-057 (1 CPUC3d 146 at 169-170)), it nevertheless calculated ATWACC adjustments.

59 SDG&E's 25 basis point flotation adjustment is excluded. (Reporter's Transcript, Volume 1 at 165-166.)

60 SoCal Gas' 25 basis point flotation adjustment is excluded. (Reporter's Transcript, Volume 1 at 165-166.)

5.2.3. RPM

Similar to the CAPM, the RPM measures a company's cost of equity capital by adding a risk premium to a risk-free long-term treasury or utility bond yield. A risk premium is derived by an assessment of historic utility stock and bond returns, a historical RPM. A variation to the historical RPM is an allowed RPM which estimates the common equity allowed by regulatory commissions over a period of time in relationship to the level of long-term Treasury bond yield.

Each party utilized different subjective inputs into their RPMs. For example, the average risk premium used by parties ranged from 3.31% to 5.95%, and return on low risk asset from 2.48% to 5.88%.[61] The following tabulation summarizes the simple average result of the RPM variations calculated by the individual parties using subjective inputs.[62]

	SCE	SDG&E	SoCalGas	PG&E
Utility	8.80%[63]	10.20%[64]	10.00%[65]	11.10%
DRA	8.10%	8.10%	8.10%	8.10%
EPUC	9.10%	not applicable	not applicable	9.10%
FEA	7.80%	7.80%	7.80%	7.80%
REID	not applicable	not applicable	not applicable	6.70%
TURN	9.60%	9.60%	9.60%	9.60%

5.2.4. DCF

The DCF model is used to estimate an equity return from a proxy group by adding estimated dividend yields to investors' expected long-term dividend

61 Hearing Exhibit 35-A.

62 All financial modeling results are rounded to a tenth (.001) of a percent.

63 SCE's result excludes its ATWACC identified in Exhibit 17 at 68-71.

64 SDG&E's 30 basis point flotation adjustment is excluded. (Exhibit 1 at 52.)

65 SoCal Gas' 30 basis point flotation adjustment is excluded. (Exhibit 12 at 46-47.)

growth rate. Several DCF variations were used by the parties. These variations included analysts' growth,[66] constant growth,[67] sustainable growth,[68] and multi-stage growth.[69]

Each party utilized different subjective inputs into their various DCF models. For example, the average dividend yield ranged from 3.88% to 4.65% and average growth rate ranged from 4.62% to 5.23%.[70] The following tabulation summarizes the simple average result of different versions of the DCF model calculated by the individual parties using subjective inputs.[71]

	SCE	SDG&E	SoCalGas	PG&E
Utility	9.70%[72]	10.10%[73]	9.10%[74]	9.60%
DRA	8.50%	8.50%	8.50%	8.50%
EPUC	9.10%	not applicable	not applicable	9.30%
FEA	8.90%	8.90%	8.80%	8.90%
REID	not applicable	not applicable	not applicable	8.40%
TURN	9.20%	9.40%	9.20%	9.30%

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66 This is a consensus of analysts 'projections of the annual rate of increase in earnings per share.

67 The growth rate investors expect over the long term.

68 Based on percentage of a utility's earnings that is retained and reinvested in utility plant and equipment.

69 Multi-stage growth reflects the possibility of non-constant growth for a company over time.

70 Hearing Exhibit 35-A.

71 All financial modeling results are rounded to a tenth (.001) of a percent.

72 SCE's ATWACC adjustments identified in Exhibit 17 at 68-71 is excluded.

73 SDG&E's 21 to 23 basis point flotation adjustment is excluded. (Exhibit 1 at 30–32.)

74 SoCal Gas' 20 basis point flotation adjustment is excluded. (Exhibit 12 at 25-28.)

5.2.5. Summary

From the results of these broad financial models which are dependent on subjective inputs, the parties advance arguments in support of their respective analyses and in criticism of the input assumptions used by other parties. These arguments will not be addressed extensively in this opinion, since they do not materially alter the modeling results. However, it should be noted that none of the parties agreed with the financial modeling results of the others.

In the final analysis, it is the application of informed judgment, not the precision of financial models, which is the key to selecting a specific ROE estimate. We affirmed this view in D.89-10-031, noting that it is apparent that all these models have flaws and, as we have routinely stated in past decisions, the models should not be used rigidly or as definitive proxies for the determination of the investor-required ROE. Consistent with that skepticism, we found no reason to adopt the financial modeling of any one party. The models are only helpful as rough gauges of the realm of reasonableness.

5.3. Additional Risk Factors

We also consider additional risk factors not specifically included in the financial models. Those additional risk factors fall into three categories: financial, business and regulatory. Of the four utilities, only SDG&E and SoCalGas have requested that a premium be added to their financial modeling results to compensate them for increased financial, business and regulatory risks. SDG&E seeks a 10 basis point premium for changing business and capital investments, to maintain a strong credit rating and continued supportive regulatory environment. SoCalGas seeks a 90 basis point premium to compensate it for a higher risk profile, and increased financial, business and regulatory risks. Both SCE and PG&E reflect the impact of any perceived increased financial, business and regulatory risk in their selection of specific ROEs within the range of their financial modeling results.

5.3.1. Financial Risk

Financial risk is tied to the utility's capital structure. The proportion of its debt to permanent capital determines the level of financial risk that a utility faces. As a utility's debt ratio increases, a higher return on equity may be needed to compensate for that increased risk. However, in this proceeding, there is minimal change in financial risk because the debt ratios being adopted in this proceeding are not materially changed from the utilities' last authorized debt ratios.[75]

Debt equivalence, raised as a financial risk by the utilities, does have an impact on the financial risk of SCE, SDG&E, SoCalGas, and PG&E.[76] As recognized in D.04-12-047, debt equivalence has been reflected in the utilities' credit ratings since at least 1990. In D.05-12-043, we affirmed that debt equivalence would be assessed on a case-by-case basis along with other financial, regulatory and operational risks in setting a balanced capital structure and fair ROE. Our goal in so doing was, and continues to be, to provide reasonable confidence in the utilities' financial soundness, to maintain and support investment-grade credit ratings, and provide utilities the ability to raise money necessary for the proper discharge of their public duty. We have no reason to change that goal. Debt equivalence is considered in arriving at an overall ROE.

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[75] SDG&E's long-term debt ratio is being increased 1.5% and PG&E's 1.0%.

[76] A discussion of the credit agencies different methods of calculating debt equivalence is addressed in our prior Section 3.2 discussion of SDG&E's capital structure discussion.

5.3.2. Business Risk

Business risk pertains to *new* uncertainties resulting from competition and the economy. An increase in business risk can be caused by a variety of events that include capital investments, electric procurement, and catastrophic events. Each of these business risks overlap into financial and regulatory risk. Capital investment risk is addressed in our subsequent authorized ROE risk discussion (Section 5.3.3.1.) and Electric procurement risk in our cost recovery risk discussion (Section 5.3.3.2.).

SCE and SDG&E identified the 2007 Southern California wildfire as an example of a catastrophic event resulting in a need to further compensate investors through a higher ROE because of heightened perceived business risk.[77] However, none of the credit agencies reporting on the creditworthiness of either SCE or SDG&E mentioned any risks associated with wildfires.[78]

While the anticipation of catastrophic events may expose investors to added risks, such events are not limited to California. These business risks are already captured in the parties' financial modeling results. Any upward adjustment to the financial modeling results being adopted due to business risks would be redundant and possibly excessive. For example, S&P has given SCE a business risk profile of excellent which reflects its utility operations that are subject to limited competition in the provision of essential public service.[79] While its generation portfolio lacks diversity, S&P acknowledges that SCE's purchased

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[77] Hearing Exhibit 17 at 32 and Hearing Exhibit 3 at 13, respectively.

[78] Hearing Exhibit 28 at 35.

[79] Hearing Exhibit 136 at 4.

power supplies offers some diversification benefits and that comprehensive regulation of its business activities provides substantial financial support.

5.3.3. Regulatory Risk

Regulatory risk pertains to *new* risks that investors may face from future regulatory actions that we, and other regulatory agencies, might take. Regulatory risk assessment is also used by rating agencies to set utility bond ratings.[80] Each of the utilities maintains an investment grade bond rating. For example, SCE has an S&P bond rating of BBB, SDG&E an A, SoCalGas an A, and PG&E a BBB.[81] The A ratings are considered by S&P to be upper medium investment grade level and BBB to be medium investment grade level.[82] These investment grade ratings are a good indication that California regulatory risks are low. SDG&E and SoCalGas' financial modeling witness also acknowledged the existence of a favorable regulatory climate in California.[83] Nevertheless, we will address the parties' regulatory risk testimony, which fall into three categories: (1) authorized ROE; (2) cost recovery; and, (3) regulatory lag.

5.3.3.1. Authorized ROE Risk

An authorized ROE has risk when it does not adequately compensate a utility for the risk that investors must assume.[84] California is generally perceived as having a constructive regulatory environment. However, the utilities are

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80 Hearing Exhibit 74.

81 Hearing Exhibits 18, 5, 13, and 25, respectively.

82 S&P has four investment grade levels, the lowest level is medium grade (BBB-, BBB, and BBB+ ratings), upper grade (A-, A, and A+), high grade (AA-, AA, and AA+), and highest grade of AAA.

83 Reporter's Transcript, Volume 1 at 163.

84 Hearing Exhibit 3 at 15, and Exhibit 11 at 18.

concerned that a lower ROE could potentially harm their credit profile and increase their cost of capital during a time when they need to spend substantial amounts on capital investment projects, above their historic norm.

California utilities are not the only utilities experiencing an increase of capital investment projects.[85] Therefore, the parties' financial modeling results derived from various proxy groups already include the impact of increasing capital investment by utilities outside of California. Further, the utilities authorized ROE risk concern is without merit because we consistently set the rate of return at a level that meets the test of reasonableness as set forth in the Bluefield and Hope cases and we will continue to do so.

5.3.3.2. Cost Recovery Risk

Cost recovery risk occurs when a utility is precluded from having the ability to fairly and consistently recover its cost in a timely manner. Identified cost recovery issues included: (1) power procurement commitments; (2) balancing and memorandum accounts; and, (3) revenue decoupling. There are opposing sides to this risk argument. The intervenors assert that these cost recovery mechanisms should be reflected as risk reductions in establishing the utilities' ROEs, while the utilities assert that these mechanisms do not make them any less risky than the utilities in their comparable proxy groups.[86]

Since the late 1990s, California energy utilities have transitioned from owning and operating most of their electric generation needs to purchasing generation from other parties under PPAs, the Renewable Auction Mechanism

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[85] Hearing Exhibit 30 at 78-80.

[86] Hearing Exhibits 3 at 70-71, and 23 at 2-2, respectively.

Program, Solar Photovoltaic Program and, the California Renewable Energy Small Tariff. Today's procurement risk is lower than under the regulatory structure during the California energy crisis, when retail rates to customers were fixed and wholesale energy rates were allowed to vary significantly without those cost being passed onto customers.[87]

Current regulation requires the energy utilities to purchase at least 33% of their generation needs from renewable sources by 2020, thereby reducing their ability to earn a return on their generation investments. Instead, they recover costs on a pass-through basis.[88] While the utilities have pre-approval authority to enter into long-term transactions, they continue to face cost recovery risk associated with procurement. This is due to a substantial increase in the number of procurement transactions the utilities are entering into. For example, SCE signed 110 PPAs with renewable generators in the first seven months of 2012.[89] It is also due to being required to regularly justify contract administration, compliance with upfront standards, increasing complexity of procurement contracts, and litigation. Although procurement risk is lower than that existed during the energy crisis such risk does continue to exist today in California and other states and is reflected in the parties' financial modeling results.

In regards to balancing and memorandum accounts, the evidence shows that the potential for disallowance of operating expenses and rate base additions are low given the utilities' ability to recover a substantial portion of their revenue

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[87] Hearing Exhibit 19 at 48.

[88] Other states are looking at a 20% renewable standard in the 2015 through the 2020 period.

[89] Hearing Exhibit 19 at 48.

requirements through balancing and memorandum accounts. For example, SCE recovers 45.24% of its revenue requirements through these mechanisms, SDG&E 44.09%, SoCalGas 54.45%, and PG&E 40.00%.[90] Disallowances from these balancing and memorandum accounts have not been material.

The utilities acknowledge that these cost recovery mechanisms are a benefit. However, they point out that the remainder of their costs is still subject to variability.[91] Moreover, they face uncertainty related to their decisions prior to receiving clear cost-recovery from the Commission.[92] However, rating agencies do recognize the benefit of California balancing and memorandum accounts. For example, S&P stated in its December 15, 2011 Global Portal that a strength of PG&E is the supportive regulatory mechanisms approved by the Commission that allow PG&E timely and certain recovery of costs.[93]

While types of balancing and memorandum account comparisons were made between those used in California and other states, there was no evidence on what percentage of revenues out-of-state utilities recover through those mechanisms.[94] Clearly, the impact of balancing and memorandum accounts is captured in the various financial modeling results. Any adjustment to the financial modeling results being adopted due to cost recovery mechanisms would be redundant or uncertain.

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[90] Hearing Exhibits 18, 5, 13, and 22, respectively.

[91] Hearing Exhibit 3 at 7.

[92] Hearing Exhibit 7 at 13.

[93] Hearing Exhibit 102 at 2.

[94] *See* for example, Hearing Exhibit 23A at Attachment 1.

The third regulatory risk category is revenue decoupling. Decoupling is the regulatory practice of separating authorized base rate revenue from the actual revenues of the utility. It holds base revenue constant and assures that the adopted base revenue requirement will be collected. However, it does not guarantee that the adopted revenue requirement will be sufficient to cover costs. Irrespective, SDG&E concurs with TURN that risk mitigating mechanisms such as decoupling reduce SDG&E's risk.[95]

Revenue decoupling is not unique to California. PG&E has identified 13 utilities in its proxy group that have various stages (partial and full) of revenue decoupling.[96] While the risk associated with revenue decoupling varies between utilities, the financial modeling results already reflect degrees of revenue decoupling risks.

5.3.3.3. Regulatory Lag Risk

Regulatory Lag is commonly defined to be a delay in a utility's ability to recover costs in a timely manner. The utilities contend that they need to be compensated for increased regulatory lag because of extended periods of uncertain outcomes from Commission proceedings which extend beyond the statutory 18 month period.

SCE testified that it takes longer to process general rate cases (GRCs) in California than it does in other states and that time delays in California have

95 Reporter's Transcript, Volume 1 at 67.

96 Hearing Exhibit 23 at 2-2.

increased from 367 days in the 1983-1999 period to 589 days since 1998.[97] SCE identified its current GRC as a particularly egregious example of regulatory lag.

SCE filed its test year 2012 GRC in November of 2010. However, SCE failed to acknowledge that its November 2010 filing was for rates to become effective approximately 420 days later, beginning January 1, 2012. Regulatory lag does not exist prior to the requested effective date. While a final decision has yet to be issued, SCE was authorized to maintain a GRC Revenue Requirement Memorandum Account (GRC RRMA) to track the change in revenue requirement ultimately adopted in its GRC during the period between January 1, 2012 and the date a final decision is adopted.[98] We acknowledge that this delay in recovering test year revenue requirements adversely impacts its cash flow. However, the interest being accrued to the RC RRMA compensates SCE for its loss of cash flow.

No party presented any evidence to substantiate that regulatory lag does not exist in other states or that GRC delays are a new risk. Therefore, we conclude, as SCE and PG&E did, that impacts from regulatory lag are reflected in the financial modeling results. Investors' perceived California regulatory risks do not warrant any upward adjustment to the base ROE range being adopted in this proceeding.

5.3.3.4. Other Regulatory Risks

Other regulatory risks identified by the parties include changes in government laws and regulations and municipalization of regulated utilities.

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[97] Hearing Exhibit 19 at 39.

[98] A.10-11-015 Scoping Memo and Ruling of Assigned Commissioner, dated March 1, 2011. *See* also SCE Advice Letter 2596-E.

These changes have occurred and are expected to continue. To the extent that investors expect government laws and regulations to change and municipalization of regulated utilities to occur, such expectations should already be captured in the financial modeling results.

5.4. Summary

The utilities are being increasingly driven by financial, business and regulatory factors that include energy availability, ability to attract capital to raise money for the proper discharge of their public utility duties and to maintain investment-grade creditworthiness, all of which are important components of the Hope and Bluefield decisions. Based on the above financial, business and regulatory risks discussion we conclude that the ROE ranges being adopted in this proceeding from the various financial models adequately compensates the utilities for these risks.

Having addressed the generic factors used in setting an ROE we now address a fair and reasonable return for the individual utilities. We also consider the utilities credit ratios and how debt equivalency impacts those credit ratios. The attached Appendix A is used as a guide to compare the anticipated range of credit ratio impact between the ROEs requested by the utilities and the lowest recommended ROE by intervenors.

5.5. SCE's Return on Equity

The following tabulation summarizes the average results of different versions of the individual financial models used by the parties including the simple weighted average[99] of the financial modeling results and proposed test year ROE for SCE:

	CAPM	RPM	DCF	Weighted Average[100]	Proposed ROE
SCE	10.70%	8.80%	9.70%	9.70%	11.10%
DRA	7.60%	8.10%	8.50%	8.20%	8.75%
EPUC	8.40%	9.10%	9.10%	8.90%	10.05%[101]
FEA	7.80%	7.80%	8.80%	8.30%	9.00%
TURN	9.20%	9.60%	9.20%	9.30%	9.40%

SCE's requested 11.10% ROE is based on the upper end of the 9.73% to 11.71% range of its CAPM financial modeling results, a level that would compensate it for increased financial, business and regulatory risks.[102] SCE placed no reliance on its RPM and DCF financial modeling results on the basis that the historical risk premium model assumes that relative risk is unchanged between electric utility stocks and "Aa" public utility bonds. It also contends that constant stable market-to book and price/earnings ratios required by the DCF model are not present during this highly volatile market.[103]

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99 Simple weighted average consists of ¼ CAPM, ¼ RPM, and ½ DCF. The CAPM and RPM financial models are risk premium related and given no more than equal weight. The DCF financial model is investor related and assesses the equity returns based on dividend yields and growth.

100 Weighted average is defined in Section 5.5, SCE's Return on Equity. Each party's proposed ROE is higher than the weighted average of their financial model results.

101 EPUC, in light of all of the record evidence, revised its recommended 9.10% ROE for SCE to 10.50%, as set forth in Exhibit 31 at 3 and in its opening and reply briefs, respectively.

102 Hearing Transcript 17 at 7 and 54.

103 Hearing Exhibit 17 at 54.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors, and interest coverage presented by the parties and applying our informed judgment, we arrive at a base ROE range of 9.8%% to 10.6%. From that range we conclude that the adopted ROE should be set at the upper end of the adopted ROE range found just and reasonable. We find that SCE's authorized test year 2013 ROE should be 10.45%. This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility and to maintain investment grade credit ratings while balancing the interests between shareholders and ratepayers. As a reality check, we observe that the 10.45% authorized ROE is comparable to the 10.36% average ROEs granted United States electric utilities during the first six months of 2012.[104]

5.6. SDG&E's Return on Equity

The following tabulation summarizes the average results of different versions of the individual financial models used by the parties including the simple weighted average of the financial modeling results and proposed test year ROE for SDG&E:

	CAPM	RPM	DCF	Weighted Average[105]	Proposed ROE
SDG&E[106]	10.50%	10.20%	10.10%	10.20%	11.00%

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[104] Hearing Exhibit 53.

[105] Weighted average is defined in Section 5.5, SCE's Return on Equity. Except for TURN, each party's proposed ROE is higher than the weighted average of their financial model results.

[106] Financial modeling results exclude flotation adjustments while the proposed ROE includes the impact of flotation adjustments.

DRA	7.60%	8.10%	8.50%	8.20%	8.50%
FEA	7.80%	7.80%	8.80%	8.30%	8.75%
TURN	9.20%	9.60%	9.40%	9.40%	9.40%

SDG&E's requested 11.00% ROE is based on the 10.40% midpoint of its 9.60% to 11.30% combined CAPM, RPM and DCF financial modeling results, which includes flotation adjustments.[107] Added to that 10.40% are 50 basis points (.5%) for perceived risks resulting from differences in the betas between the average electric utility company and SDG&E, and 10 basis points (.1%) for increased business risk.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors, and interest coverage presented by the parties and applying our informed judgment, we arrive at a base ROE range of 9.60% to 10.40%. This includes the impact of excluding flotation costs, recognition of a 3% increased equity ratio, and an investment grade credit rating of "A". From that range we conclude that the adopted ROE should be set at the upper end of the adopted ROE range found just and reasonable. We find that SDG&E's authorized test year 2013 ROE should be 10.30%. This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility and ability to maintain investment grade credit ratings while balancing the interests between shareholders and ratepayers. We observe that the 10.30% ROE is slightly below the 10.36% average ROEs granted United States electric utilities during the first six months of 2012.

[107] Exhibit 1 at 65.

5.7. SoCalGas' Return on Equity

The following tabulation summarizes the average results of different versions of the individual financial models used by the parties including the simple weighted average of the financial modeling results and proposed test year ROE for SoCalGas:

	CAPM	RPM	DCF	Weighted Average[108]	Proposed ROE
SoCalGas[109]	10.20%	10.00%	9.10%	9.60%	10.90%
DRA	7.60%	8.10%	8.50%	8.20%	8.50%
FEA	7.80%	7.80%	8.80%	8.30%	8.75%
TURN	9.10%	9.60%	9.20%	9.30%	9.25%

SoCalGas' requested 10.90% ROE is based on the average, median and truncated[110] averages of its 9.10% to 10.70% financial modeling results (which includes its flotation adjustments of 20 to 25 basis points) with a midpoint of 9.90% after removing the low 8.40% DCF Natural Gas Utilities Value Line Growth financial modeling result .[111] To the 10.10% SoCalGas concluded reasonable, it added 40 basis points (.4%) for a higher risk profile based on four risk indicators,[112] and an additional 40 basis points (.4%) for prospective business and regulatory risk pressures.

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108 Weighted average is defined in Section 5.5, SCE's Return on Equity. Except for TURN, each party's proposed ROE is higher than the weighted average of their financial model results.

109 Financial modeling results exclude flotation adjustments while the proposed ROE includes the impact of flotation adjustments.

110 The truncated mean is obtained by removing the low and high results and averaging the remaining results.

111 Hearing Exhibit 12 at 59.

112 The four risk indicators are: 1) market value ratios, 2) the Commission has allowed SoCalGas a higher return compared to the national average, 3) differences in risk

Footnote continued on next page

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, average results of the financial models, quantitative financial models, additional risk factors, and interest coverage presented by the parties and applying our informed judgment, we arrive at a base ROE range of 9.40% to 10.30%. This includes the impact of excluding flotation costs, an "A" investment grade credit rating, recognition of a 4% increased equity ratio that brings SoCalGas more in line with comparable gas utilities, and recognition that gas utilities are less risky than electric utilities as acknowledged in Reporter's Transcript, Volume 1 at 42. From that range we conclude that the adopted ROE should be set near the middle of the adopted ROE range found just and reasonable. We find that SoCalGas' authorized test year 2013 ROE should be 10.10%, upper middle range of the 9.50% to 10.40% ROE approved for United States gas utilities in the second quarter of 2012 and above the 9.75% average ROE approved during the first six months of 2012.[113] This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility and ability to maintain investment grade credit ratings while balancing the interests between shareholders and ratepayers.

5.8. PG&E's Return on Equity

The following tabulation summarizes the average results of different versions of the individual financial models used by the parties including the simple weighted average of the financial modeling results and proposed test year ROE for PG&E:

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between Western utilities and Eastern/Central utilities, and 4) *beta* difference between SoCalGas and its parent company.

[113] Hearing Exhibit 53.

	CAPM	RPM	DCF	Weighted Average[114]	Proposed ROE
PG&E	11.10%	11.10%	9.60%	10.40%	11.00%
DRA	7.60%	8.10%	8.50%	8.20%	8.75%
EPUC	8.40%	9.10%	9.30%	9.00%	9.90%[115]
FEA	7.80%	7.80%	8.80%	8.30%	9.00%
REID	7.10%	6.70%	8.40%	7.70%	9.00%
TURN	9.10%	9.60%	9.30%	9.30%	9.40%

PG&E requested a 11.00% ROE, which is at the upper end of the 10.20% to 11.40% range it finds fair and reasonable.[116] This range is based on its 10.80% to 11.40% CAPM, 10.80% to 11.50% RPM, and 9.10% to 11.0% DCF financial modeling results. PG&E selected the upper end of its ROE range to compensate it for increased financial, business and regulatory risks.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors, and interest coverage presented by the parties and applying our informed judgment, we arrive at a base ROE range of 9.80% to 10.60%. From that range we conclude that the adopted ROE should be set at the upper end of the adopted ROE range found just and reasonable. We find that PG&E's authorized test year 2013 ROE should be 10.40%. This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility and to maintain investment grade credit ratings while balancing the interests between shareholders and

114 Weighted average is defined in Section 5.5, SCE's Return on Equity. Each party's proposed ROE is higher than the weighted average of their financial model results.

115 EPUC, in light of all of the record evidence, revised its recommended 9.2% ROE for PG&E to 9.9%, as set forth in Exhibit 32 at 3 and its opening and reply briefs, respectively.

116 Hearing Exhibit 21 at 1-3.

ratepayers. As a reality check, we observe that the 10.40% authorized ROE is also comparable to the 10.36% average ROEs granted United States electric utilities during the first six months of 2012.

6. Implementation

SCE shall consolidate the revenue requirement change being authorized in this decision with revenue changes from other SCE applications through a Tier 1 advice letter filing to become effective January 1, 2013.

SDG&E shall consolidate the revenue requirement changes being authorized in this decision with other electric and gas rate changes which are filed at the end of December 2012 to become effective January 1, 2013.

SoCalGas shall consolidate the revenue requirement changes being authorized in this decision with other gas rate changes which are filed at the end of December 2012 to become effective January 1, 2013.

Consistent with PG&E's implementation proposal, the change in total electric and gas rates will be implemented on January 1, 2013. Changes applicable to Direct Access rates for electric service would be made at the same time as changes in bundled electric customer rates. As authorized under current tariffs, PG&E will record the gas distribution, gas transmission and storage, electric distribution, and electric generation revenue requirements reflecting the 2013 cost of capital in the appropriate balancing and memorandum accounts as of January 1, 2013. Rates for each of these revenue requirements will be set based on the then-current approved revenue allocation and rate design method separately approved for each revenue requirement.

7. Procedural Matters

The utilities requested that their respective ROE application be categorized as a ratesetting proceeding within the meaning of Rule 1.3(e). By Resolution

ALJ 176-3293, dated May 10, 2012, the Commission preliminarily determined that the applications of SCE, SDG&E, SoCalGas and PG&E were ratesetting proceedings and that hearings were expected

The applications were consolidated, pursuant to Rule 7.4 of the Commission's Rules of Practice and Procedure. The consolidation of these applications does not necessarily mean that a uniform ROE should be applied to each of the utilities. This is because each of these utilities has unique factors and differences that need to be considered in arriving at a reasonable return. These unique factors and differences encompass three distinct areas: capital structure, long-term debt and preferred stock costs, and return on common equity.

A Prehearing Conference (PHC) was held on June 4, 2012 to identify issues and a hearing schedule. Following the PHC, Commissioner Ferron issued a Scoping Memo and Ruling setting a schedule that included evidentiary hearings. The Scoping Memo also bifurcated the proceeding with the first phase to address the utilities' test year 2013 cost of capital and the second phase to address the cost of capital mechanism.

That Scoping Memo and Ruling, among other matters, designated Administrative Law Judge (ALJ) Galvin as the presiding officer, established a bifurcated evidentiary hearing schedule and determined the issues of this proceeding. The issues to be addressed in the first series of evidentiary hearings encompassed all matters impacting the utilities' test year 2013 cost of capital including capital structure, costs of long-term debt and preferred stock, return on common equity and related revenue requirement recovery. The second set of evidentiary hearings will address the appropriateness of continuing with or modifying the uniform multi-year Cost of Capital Mechanism and the appropriateness of SoCalGas continuing with, modifying or replacing its Market-Indexed Capital Adjustment Mechanism.

The first series of evidentiary hearings were held on September 14, 21, 24 and 28, 2012. Additional hearings were held on October 2 and 3, 2012. Each of the utilities, DRA, EPUC, FEA, Reid, and TURN submitted testimony, evidence, and opening and reply briefs. A total of 153 exhibits were received into evidence and 22 witnesses testified. Public Participation Hearings (PPH) were held in San Bernardino, San Diego, and Fresno on October 4, 5, and 9, 2012, respectively. Sixty-six of the 171 customers who attended the PPHs provided statements on the utilities. Cost of capital applications. Almost uniformly, the speakers supported a 9.40% ROE (TURN'S recommended ROE) for the utilities. However, three speakers supported the utilities request and seven speakers expressed other ideas such as a moratorium on shut-offs for low income customers below 200% of the federal poverty line during the summer months.

The utilities' test year 2013 cost of capital issues were submitted on October 22, 2012 upon the filing of reply briefs and receipt of late-filed exhibits that updating the utilities' test year costs of long-term debt and preferred stock based on Global Insight's September 2012 forecast. This proceeding remains open to address the appropriateness of continuing with and modifying the energy utilities' uniform multi-year Cost of Capital Mechanism and the appropriateness of Southern California Gas Company continuing with, modifying or replacing its Market-Indexed Capital Adjustment Mechanism.

8. Comments on Proposed Decision

The proposed decision of ALJ Galvin in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and

Procedure. Comments were filed on December 10, 2012 by SCE, SDG&E, SoCalGas, PG&E, EPUC, FEA, Reid and TURN. Reply comments were filed on December 17, 2012. These comments resulted in two substantive changes to the proposed decision.

The first substantive change is the adoption of SDG&E's proposed 3% increase in its common equity ratio from the proposed decision's 1½% common equity ratio increase. This change is made to bring its ratemaking common equity ratio in line with its actual common equity ratio. This results in a SDG&E capital structure of 45.25% long-term debt, 2.75% preferred stock and 52.00% common equity and a 7.79% return on rate base for the test year 2013.

The second substantive change is an increase in SCE's ROE to 10.45% from 10.40%, resulting in a 7.90% return on rate base for the test year 2013. This change in SCE's ROE is made to adequately compensate it for its risks.

To the extent such comments required discussion or changes to the proposed decision the discussion or changes have been incorporated into the body of this decision.

9. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and Michael J. Galvin is the assigned ALJ in this proceeding.

Findings of Fact

1. Applicants are public utilities subject to the jurisdiction of this Commission.
2. SCE seeks to reduce its test year 2013 ROE to 11.10% from 11.50%.
3. SDG&E seeks to reduce its test year 2013 ROE to 11.00% from 11.10%.
4. SoCalGas seeks to increase its test year 2013 ROE to 10.90% from 10.82%.
5. PG&E seeks to reduce its test year 2013 ROE to 11.00% from 11.35%.

6. SCE, SDG&E, SoCalGas and PG&E's applications were consolidated pursuant to Rule 7.4.

7. SCE does not propose any change to its authorized capital structure.

8. SDG&E, SoCalGas and PG&E propose minor changes to their currently authorized capital structures.

9. SDG&E expects approximately $772 million of debt equivalency to occur as a result of future contracts pending Commission approval.

10. S&P and Moody's use different methods to determine a utility's debt equivalency.

11. SCE, SDG&E, SoCalGas and PG&E submitted late-filed hearing exhibits to update their cost of long-term debt and preferred stock.

12. There is no opposition to SCE, SDG&E, SoCalGas or PG&E's long-term debt or preferred stock costs.

13. An ROE is set at a level of return commensurate with market returns on investments having corresponding risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligation.

14. The parties used variations of the CAPM, DCF and RPM financial models to support their respective ROE recommendations.

15. SCE, SDG&E, SoCalGas and PG&E used electric utility industry group lists from Value Line to establish proxy groups to be used in their financial models.

16. SCE, SDG&E and PG&E screened the companies in their proxy groups to exclude companies that are not investment grade, do not have a history of paying dividends, and are undergoing a restructure or merger.

17. DRA and FEA used proxy groups that were different than the proxy groups used by the utilities. Reid used a total of seven different proxy groups.

18. PG&E utilized two proxy groups in its financial models, one consisting of utility companies and the other consisting of non-utility companies.

19. The parties used different companies for their proxy groups and, at times, excluded companies from their proxy group when using the CAPM, RPM, and DCF financial models.

20. Each party used different subjective inputs and variations of the CAPM, RPM and DCF financial models as a basis for their recommended ROEs.

21. A flotation cost adjustment to the financial models was rejected by the Commission in D.07-12-049 and D.05-12-043.

22. Financial risk is tied to the utility's capital structure.

23. Debt equivalence has been reflected in the utilities' credit ratings since at least 1990.

24. Business risk pertains to new uncertainties resulting from competition and the economy.

25. Regulatory risk pertains to new risks that investors may face from future regulatory actions.

26. SCE has an investment grade rating of BBB from S&P.

27. SDG&E has an investment grade rating of A from S&P.

28. SoCalGas has an investment grade rating of A from S&P.

29. PG&E has an investment grade rating of BBB from S&P.

30. Quantitative financial models are commonly used as a starting point to estimate a fair ROE.

31. The average ROE authorized for electric and gas utilities in the United States for the first six months of 2012 were 10.36% and 9.75%, respectively.

32. Two important components of the Hope and Bluefield decisions are that the utilities have the ability to attract capital to raise money for the proper discharge of their public utility duties and to maintain creditworthiness.

Conclusions of Law

1. The consolidation of these applications does not mean that a uniform ROE should be applied to each of the utilities.
2. The legal standard for setting the fair ROE has been established by the United States Supreme Court in the Bluefield and Hope cases.
3. The capital structures proposed by SCE, SDG&E, SoCalGas and PG&E should be adopted because they are balanced, attainable, and intended to maintain an investment grade rating and attract capital.
4. The utilities' costs of long-term debt and preferred stock as updated by late-filed hearing exhibits are reasonable and should be adopted.
5. Companies selected for a proxy group should have basic characteristics similar to the utility that the companies are selected to proxy.
6. Companies within a proxy group should not deviate from financial model to financial model.
7. PG&E has not substantiated that investment risks of its proxy group of non-utility companies is comparable to its proxy group of utility companies or to PG&E.
8. The financial modeling results from PG&E's proxy group of non-utility companies should not be considered in this proceeding.
9. Value Line electric industry classifications should continue to be used in ROE proceedings where financial models require the use of a proxy group.

10. Companies within a proxy group should continue to be screened to ensure that the included companies have investment grade credit ratings, a history of paying dividends and are not undergoing a restructure or merger.

11. The financial modeling results should exclude flotation adjustments for the reasons set forth in D.92-11-047.

12. Although the quantitative financial models are objective, the results are dependent on subjective inputs.

13. It is the application of informed judgment, not the precision of quantitative financial models, which is the key to selecting a specific ROE.

14. Company-wide factors such as risks, capital structures, debt costs and credit ratings are considered in arriving at a fair ROE.

15. Debt equivalence should be considered along with other risks in arriving at a fair and reasonable ROE.

16. There should be no adjustment to the financial modeling results for other financial, business or regulatory risks because the financial modeling results already include those risks.

17. A test year 2013 ROE range from 9.80% to 10.60% is just and reasonable for SCE.

18. A test year 2013 ROE range from 9.70% to 10.40% is just and reasonable for SDG&E.

19. A test year 2013 ROE range from 9.40% to 10.30% is just and reasonable for SoCalGas.

20. A test year 2013 ROE range from 9.80% to 10.60% is just and reasonable for PG&E.

21. A test year 2013 ROE of 10.45% and ROR of 7.90% is just and reasonable for SCE.

22. A test year 2013 ROE of 10.30% and ROR of 7.79% is just and reasonable for SDG&E.

23. A test year 2013 ROE of 10.10% and ROR of 8.02% is just and reasonable for SoCalGas.

24. A test year 2013 ROE of 10.40% and ROR of 8.06% is just and reasonable for PG&E.

25. The utilities' ROE applications should be granted to the extent provided for in the following order.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company's cost of capital for its test year 2013 operations is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-term Debt	43.00%	5.49%	2.36%
Preferred Stock	9.00%	5.79%	.52%
Common Equity	48.00%	10.45	5.02%
Return on Rate Base			7.90%

2. San Diego Gas and Electric Company's cost of capital for test year 2013 electric and gas operations is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-term Debt	45.25%	5.00%	2.26%
Preferred Stock	2.75%	6.22%	.17%
Common Equity	52.00%	10.30%	5.36%
Return on Rate Base			7.79%

3. Southern California Gas Company's cost of capital for its test year 2013 gas operations is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-term Debt	45.60%	5.77%	2.63%
Preferred Stock	2.40%	6.00%	.14%
Common Equity	52.00%	10.10%	5.25%
Return on Rate Base			8.02%

4. Pacific Gas and Electric Company's cost of capital for its test year 2013 electric and gas operations is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-term Debt	47.00%	5.52%	2.59%
Preferred Stock	1.00%	5.60%	.06%
Common Equity	52.00%	10.40%	5.41%
Return on Rate Base			8.06%

5. Value Line Investment Survey electric industry classification shall continue to be used in return on equity proceedings where financial models require the use of a proxy group. Three basic screens shall be used in selecting a comparable proxy group. Those screens are to exclude companies that do not have investment grade credit ratings, exclude companies that do not have a history of paying dividends and exclude companies undergoing a restructure or merger. Additional screens may be used to the extent that justification is provided.

6. Southern California Edison Company, San Diego Gas & Electric Company, Southern California Gas Company and Pacific Gas and Electric Company shall implement the revenue requirement changes authorized by this decision as set forth in Section 6 of this decision. Tariffs in those filings shall be subject to review by the Energy Division in accordance with General Order 96-B.

7. Applications 12-04-015, 12-04-016, 12-04-017 and 12-04-018 remain open to consider the appropriateness of continuing with or modifying the uniform multi-year Cost of Capital Mechanism and the appropriateness of Southern California Gas Company continuing with, modifying or replacing its Market-Indexed Capital Adjustment Mechanism.

This order is effective today.

Dated December 20, 2012, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

APPENDIX A
TEST YEAR 2013 CREDIT RATIOS INCLUDING DEBT EQUIVALENCE

	CASH FLOW TIMES (x) INTEREST COVERAGE	DEBT/ CAPITAL	CASH FLOW/ DEBT
S&P Utility Group Financial Targets			
Indicative Ratings			
A	6.0x – 4.0x	40%- 25%	60% - 40%
A -	4.5x - 3.0x	50% - 35%	45% - 25%
BBB -	3.5x – 2.0x	60% - 45%	30% - 10%
SCE (current S&P rating of BBB)			
@ Requested 11.10% ROE	5.0x	57.8%	22.3%
@ Lowest Recommended ROE - 8.75%	4.9x	58.6%	21.1%
SDG&E[1] (current S&P rating of A)			
@ Requested 11.00% ROE[2]	4.0x	58.7%	15.6%
@ Lowest Recommended ROE – 8.50%	3.8x	58.9%	14.8%
SoCalGas[3] (current S&P rating of A**)**			
@ Requested 10.90%	5.1x	51.2%	25.1%
@ Lowest Recommended ROE – 8.50%	4.8x	51.8%	23.4%
PG&E (current S&P rating of BBB)			
@ Requested 11.00% ROE	4.0x	58.2%	17.2%
@ Lowest Recommended ROE – 8.75%	3.8x	58.2%	15.8%

(END OF APPENDIX A)

1 Ratios are based on SDG&E's requested capital structure.

2 Existing, approved and pending PPA debt equivalency is included.

3 Ratios are based on SoCal Gas' requested capital structure.

Advice 3362-G/4187-E

Attachment 3

Approved Advice 3216-G-A/3859-E-A

STATE OF CALIFORNIA

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

Edmund G. Brown Jr., *Governor*

December 1, 2011

Advice Letter 3216-G-A/3859-E-A

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

Subject: Establish Tax Act Memorandum Account (TAMA-E and TAMA-G) per CPUC Resolution No. L-411A and Supplemental Filing

Dear Mr. Cherry:

Advice Letter 3216-G-A/3859-E-A is effective April 14, 2011.

Sincerely,

Edward Randolph

Edward F. Randolph, Director
Energy Division

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulation and Rates

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

Fax: 415.973.6520

October 21, 2011

Advice 3216-G-A/3859-E-A
(Pacific Gas and Electric Company ID U 39 M)

Public Utilities Commission of the State of California

Subject: **Establish Tax Act Memorandum Account (TAMA-E and TAMA-G) Per CPUC Resolution No. L-411A**

Pacific Gas and Electric Company (PG&E) hereby submits this supplemental advice letter to modify Advice 3216-G/3859-E as a result of the issuance of Resolution No. L-411A (Revised Resolution) on June 23, 2011. In this supplement PG&E makes the following revisions to the advice letter submitted on June 13, 2011:

1. Memorandum Account Period (Memo Account Period) to begin on April 14, 2011 instead of January 1, 2011, as proposed in Advice 3216-G/3859-E;
2. Replace references to Resolution L-411 issued on April 23, 20111 with references to resolution L-411A issued on June 23, 2011.

This supplemental filing replaces Advice 3216-G/3859-E filed on June 13, 2011 in its entirety.

Purpose

In accordance with the Revised Resolution, Pacific Gas and Electric Company (PG&E) hereby submits this Tier 2 advice letter to establish Electric Preliminary Statement Part FR, Tax Act Memorandum Account - Electric (TAMA-E), and Gas Preliminary Statement Part CS, Tax Act Memorandum Account - Gas (TAMA-G), as included in Attachment 1. These memorandum accounts allow PG&E to track and record on a CPUC-jurisdictional, revenue requirement basis, the impacts of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 ("Tax Relief Act") including: (a) decreases in its revenue requirement resulting from increases in its deferred tax reserve; (b) offsets to reflect any additional costs or expenses, not otherwise recovered in rates, incurred as a result of certain additional, needed utility infrastructure investment enabled by the bonus depreciation provisions of the Tax Relief Act (see Attachment 2); and (c) other revenue requirement changes resulting from the Tax Relief Act, including amounts reflecting the impacts of any decrease in Section 199 manufacturer's tax deductions (MTD), changes in working cash and any decrease in the

Income Tax Component on Contribution (ITCC) received due to changes in the tariffed tax component of contributions-in-aid-of-construction (CIAC).

Background

On December 17, 2010, President Obama signed the Tax Relief Act. Among other provisions, the Tax Relief Act provides for 100% bonus depreciation on certain business property put into service after September 8, 2010 and before January 1, 2012. The Tax Relief Act also provides for 50% bonus depreciation for property placed into service on or after January 1, 2012 and before January 1, 2013 and for certain property placed into service in 2013 where construction begins prior to January 1, 2013.

PG&E filed its 2011 General Rate Case (GRC) application in December 2009, covering the 2011 through 2013 period. Subsequently, on October 15, 2010 PG&E executed a settlement agreement (Settlement Agreement) with 16 other parties establishing revenue requirements for the years 2011-2013. The Tax Relief Act, referenced above, was enacted two months later. The purpose of the memorandum account is to track on a revenue requirement basis the incremental tax depreciation benefits from the Tax Relief Act, less applicable offsets, not otherwise reflected in rates. Tax benefits from the Small Business Act, signed on September 27, 2010, are specifically excluded from the memorandum account. (See Resolution No. L-411A, p. 3.)

On April 14, 2011, CPUC Resolution L-411 (Original Resolution) directed PG&E and other cost of service utilities to establish, by advice letter, a memorandum account within 60 days of the date of the Original Resolution.[1] PG&E duly submitted Advice 3216-G/3859-E on June 13, 2011 in compliance with the Original Resolution.

On June 23, 2011, a revised version of Resolution L-411, or Resolution L-411A, was issued to remove the inconsistencies, correct the errors, and clarify the Ordering Paragraphs of the original resolution. Both Resolution No. L-411 and Resolution No. L-411A provide that the Memo Account Period begin on the effective date of the resolution, April 14, 2011[2] and that entries are to be made on a revenue requirement basis. They also provide the staff with the flexibility to implement simplifying assumptions and workable solutions.[3]

For simplicity and consistency with the 2011 GRC and GT&S rate case revenue requirements, in Advice 3216-G/3859-E PG&E had originally proposed that the Memo Account track revenue requirement impacts of the Tax Relief Act starting on January 1, 2011. In this advice letter, PG&E is now proposing to calculate revenue requirement changes starting April 14, 2011, consistent with the effective date of the resolution. To

[1] See Resolution No. L-411, Ordering Paragraphs 1 and 6.

[2] See Resolution No. L-411, Findings and Conclusions 23 and Resolution No. L-411A, Ordering Paragraph 1.

[3] See Resolution No. L-411, Findings and Conclusions 19 and Resolution No. L-411A, Findings and Conclusions 18.

develop memo account entries for the period from April 14, 2011 to December 31, 2011, PG&E proposes to prorate the total annual revenue requirement changes based on the number of days between April 14, 2011 and December 31, 2011 divided by the total number of days in the year (i.e., 262 days / 365 days) for all impacted revenue requirement components.

Resolution No. L-411A also provides that the Memo Account Period will end on the date of the PG&E's next rate case cycle[4]. Given that the test years for PG&E's next GRC and Gas Transmission and Storage (GT&S) cases are 2014 and 2015, respectively, the Memo Account Period will end for electric distribution, electric generation and gas distribution as of December 31, 2013 and for gas transmission as of December 31, 2014.

An illustrative summary outlining the annual revenue requirements for each line of business, before the impact of incremental capital additions, is shown in Attachment 4.

Consistent with the Commission's intent in Resolution No. L-411A[5], PG&E has developed an estimate of annual revenue requirements using a simplified model (see Attachment 5)[6] based on standard regulatory conventions similar to other models which have been presented to and accepted by the Commission in other incremental filings. The simplified model also uses inputs from both the 2011 GRC RO model and the 2011 GT&S RO model, collectively referred to as 2011 ROs, which are based on the respective adopted settlement decisions.[7]

There are three primary sections of the simplified model:

Section A – Estimates the annual revenue requirement impact of the Tax Relief Act incremental tax depreciation on deferred tax liabilities associated with adopted electric distribution, electric generation, gas distribution and gas transmission capital additions for the period from September 2010 through December 2012. The rate base adjustment in this section represents the increase in deferred tax liabilities net of a deferred tax asset related to the estimated tax net operating loss (NOL) resulting from the Tax Relief Act.

Section B – Estimates the annual revenue requirements on additional utility infrastructure investment (i.e., incremental capital additions above adopted levels referred to in Section A, above) enabled by tax savings from the Tax Relief Act.

Section C – Estimates the annual revenue requirements associated with other impacts of the Tax Relief Act including the loss of MTD, working cash adjustments and reduced ITCC revenue.

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[4] See Resolution No. L-411A, Ordering Paragraph 3.
[5] See Resolution No. L-411A, Findings and Conclusions 18.
[6] The Simplified TAMA Model was provided electronically with Advice 3216-G/3859-E.
[7] 2011 GRC Decision 11-05-018; GT&S Settlement Decision 11-04-031.

Annual revenue requirements associated with Sections A, B and C will be calculated over the appropriate Memo Account Period for both the GRC and GT&S lines of business. Each of these sections is described in greater detail below.

The simplified model separately calculates the impact for each line of business[8] (electric distribution and generation, gas distribution and gas transmission) with an exception for the impact of the NOL adjustment. Since PG&E can offset taxable income in one line of business with tax losses in another, the NOL deferred tax adjustment is to be calculated in total. The revenue requirement impact of the NOL is then allocated across those lines of business with tax losses.

The line of business amounts are then combined into gas and electric accounts. Attachment 3 illustrates how balances in the gas and electric accounts are to be disposed of at the end of 2013. If both accounts are over-collected, the balances will be allocated for refund to distribution, generation and gas transmission customers in proportion to the net revenue requirement reduction generated by each line of business, calculated separately for gas and electric. If both accounts are under-collected, the balances are simply written off. If the gas account is over-collected and electric under-collected, or vice versa, consistent with the Revised Resolution, an adjustment will be made to transfer all or a portion of the over-collected account balance into the under-collected account. This transfer amount will be limited to 10% of the incremental revenue requirements from part B of the under-collected account.[9] The size of this transfer may not exceed either the net over-collected balance in the over-collected account or the net under-collected balance in the under-collected account. Entries to reflect post 2013 revenue requirement impacts will continue in the gas account through the end of 2014 but only for the gas transmission line of business.

Separately funded revenue requirements with incremental deferred tax reserve amounts related to the Tax Relief Act which are already reflected in rates are excluded from the memorandum account. This includes PG&E's SmartMeter, Cornerstone, and Solar Photovoltaic projects. These projects have separate ratemaking under which forecast revenue requirements are automatically trued-up to actual revenue requirements through balancing accounts.

A. Impact of Tax Relief Act on Adopted Additions

For the purpose of calculating the annual incremental deferred tax revenue requirement impact of the Tax Relief Act on qualifying additions, PG&E has used

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[8] Resolution No. L-411A refers to the term "service function" (Electric and Gas) in its guidelines. (See Resolution No. L-411A, p. 7). The RO Model will use "line of business" as a roll-up to service function.

[9] Per the Revised Resolution, Ordering Paragraph 5, at least 90% of the incremental investment amount must be attributable to the tax benefits associated with that particular service function. This transfer effectively allows up to 10% of the incremental investment amount in the under-collected account to be funded by tax benefits associated with the other service function.

an estimate of the qualified adopted capital additions for each line of business, from the RO Models supporting its 2011 GRC and GT&S Settlement Decisions (see Attachment 6). Capital addition amounts include both a pro-ration of the 2010 RO forecast amounts (for the period September to December) and the entire capital addition forecast for the 2011 calendar year. For gas transmission, PG&E will also use the 2012 capital additions adopted as part of the GT&S settlement decision.

For the GRC lines of business, PG&E proposes to assume the same level of capital additions in 2012 as adopted for 2011. PG&E's 2011 GRC settlement decision did not specifically adopt capital additions for 2012. The adopted attrition increase for 2012 was settled at $180 million (roughly 3% overall) and does not have a specific expense and capital cost basis. This small percentage increase barely covers the additional revenue requirement associated with the fact that qualified additions for 2011 will exceed depreciation in 2011 (this has the effect of increasing starting rate base in 2012 over the 2011 rate base level). If an RO were then run for 2012, incorporating reasonable inflation for expense items, the higher starting rate base, and the authorized rate of return, the result would indicate that capital additions would actually have to decrease in 2012 as compared to 2011. Nonetheless, PG&E proposes for the purpose of this memorandum account to assume capital additions are the same in 2012 as they are in 2011.

The incremental federal tax depreciation is computed by comparing the depreciation that would have been available on qualifying additions in the absence of the Tax Relief Act with the depreciation that is available on qualifying additions under the Tax Relief Act. The Pre-Tax Cost of Capital (see Attachment 8) is used on these incremental deferred taxes to calculate the revenue requirement impact.

For purposes of the memorandum account, qualifying additions are estimated based on the provisions of the Tax Relief Act as well as PG&E's Internal Revenue Service (IRS) audit experience.

In order to qualify for bonus depreciation under the Tax Relief Act, capital additions must be new property and must be:

(1) Depreciable tangible property with a tax recovery period of 20 years or less.
   - This includes all electric and gas transmission and distribution (T&D) property, except structures and land.
   - Office buildings, including improvements, affixed to the structure, do not qualify.
   - However, some structures, such as those at a generation plant, are granted bonus under a provision for special purpose structures.

(2) Computer software. (Other Intangible property does not qualify.)

(3) Qualified leasehold improvements.

As a general matter, virtually all asset classes qualify for bonus depreciation, except Land, Land Rights, Intangibles (other than software), and most Structures.

In addition, 100% bonus depreciation only applies to a portion of certain plant costs incurred after 9/8/2010.[10] Thus, an asset completed in late 2010 after two years of construction would qualify for 100% bonus depreciation only to the extent qualifying costs were incurred after 9/8/2010.

Finally, the IRS audits PG&E's bonus depreciation deduction and has disallowed some amounts. This audit experience[11] supports the qualifying ratios provided in the GRC. For example, based upon previous IRS audits, 96% of qualifying capital additions for most plant function groups will be accepted upon audit by the IRS. In the case of vehicles, the IRS has allowed only 72% of the deduction. The audit experience factor is applied to all bonus-eligible federal tax lives (3, 5, 7, 10, 15 and 20 years).

The amount of 100% bonus depreciation that PG&E will be able to deduct on its tax returns is determined by the kind of plant built or acquired, the dates when capital expenditures were incurred, and the amounts allowed by the IRS.

Resolution No. L-411A refers to the need to be consistent with normalization provisions of the Internal Revenue Code.[12] Thus the following proposed deferred tax asset adjustment is mandatory. When depreciation deductions result in an NOL carryover, the normalization provisions require that a deferred tax asset be recorded to offset the deferred tax liabilities arising from depreciation deductions. To the extent that the Tax Relief Act's bonus depreciation results in a taxable loss (NOL), there is no current year benefit from bonus depreciation. As such, when this situation occurs PG&E will create a deferred tax asset as an offset to incremental deferred taxes calculated on adopted additions. As previously mentioned, the calculation of taxable income is being made on a total CPUC-jurisdictional basis, including generation, electric and gas distribution and gas transmission (i.e., as reflected in the 2011 ROs) to ensure that losses are offset against income before determining the resulting NOL.

[10] See Revenue Procedure 2011-26, issued by the Internal Revenue Service on March 29, 2011.
[11] Variations of Bonus Depreciation have been in place since 2001 except for 2006 to 2007.
[12] Resolution No. L-411A, p. 2; *see also* Findings and Conclusions 4.

B. Additional Utility Infrastructure Investment Offsets in 2011 and 2012

Resolution No. L-411A allows Utilities to use the tax savings realized under the Tax Relief Act to fund additional, needed utility infrastructure investment not otherwise funded in rates. PG&E is currently undertaking a process of identifying incremental capital projects it can fund using the bonus depreciation benefits consistent with the Resolution.

For the purpose of quantifying PG&E's additional infrastructure investment (i.e., incremental capital additions above adopted levels, referred to in Section A) in the memorandum account, PG&E will compare the recorded annual capital additions in certain Major Work Categories (MWCs) with adopted capital additions for those same MWCs as described in Attachment 7.[13]

The annual revenue requirements associated with this additional infrastructure investment are developed by multiplying the CPUC-jurisdictional incremental capital additions at the LOB level by appropriate annual composite revenue requirement factors which fully reflect the benefits of bonus depreciation taken under the Tax Relief Act. Consistent with regulatory convention, these annual revenue requirement factors include the cost of capital, book depreciation and income taxes.

The Commission guidelines describe the kinds of investments that can be recorded in the memorandum account as follows:

> *"Allowable types of infrastructure projects would include typical types of projects included in general rate case type applications. For example, for the electric utilities, projects would include [certain examples]…The spending must not provide generation capacity at a new plant. For gas utilities, projects would include [certain examples]….*
>
> *The property that the investment is made in must be Commission-jurisdictional. For all utilities that provide more than one kind of service, e.g., both gas and electric, at least 90% of the incremental investment amount must be attributable to the tax benefits associated with that particular service function. The property that the investment is made in must itself be eligible for bonus depreciation. At least 90% of the investment must have a tax depreciable life of at least*

[13] This is consistent with Commission guidelines included in the Revised Resolution.

> *15 years, and any remaining investments must be ancillary to such investments."*[14]

Accordingly, under these guidelines, PG&E cannot include projects that would not typically be included in a GRC-type application and cannot include projects that provide generation capacity at a new plant, even though such investments may qualify for bonus depreciation. For the most part, PG&E cannot include projects that have a tax life shorter than 15 years, such as software or vehicles. In addition, PG&E must ensure that its additional gas and electric projects are in proportion to the tax benefits associated with those functions.

PG&E's fixed asset system uses work orders to accrue the costs of building or acquiring plant. Those work orders are categorized by MWC. When the asset is complete, the work order costs settle to plant assets within certain Asset Classes. Asset Classes are then used to determine bonus depreciation eligibility and the proper tax depreciable life. PG&E is using MWCs as a basis for measuring incremental investments because MWCs indicate jurisdiction and service function and correlate with how eligibility for bonus depreciation is ultimately determined in PG&E's fixed asset system.

The table in Attachment 7, i.e., in column (a), used 2010 recorded plant addition activity to determine, for each MWC, how much of the capital work settled to asset classes that (1) qualified for bonus depreciation; and (2) had a tax life of 15 years or more.

Eligible MWCs are those where plant additions typically qualify for bonus depreciation with a tax life of 15 years or more. Ancillary MWCs are those that qualify for bonus depreciation, but with a tax life of less than 15 years. Finally, ineligible MWCs are those that do not qualify for bonus depreciation. To calculate incremental capital additions, PG&E will compare recorded and adopted additions for eligible MWCs only. In addition, up to 10% of PG&E's incremental additions can come from the ancillary MWCs provided that such additions are in fact ancillary to other additions funded by the Tax Relief Act.

C. Other Impacts Resulting From Taking Bonus Depreciation

Taking bonus depreciation reduces PG&E's taxable income and may create a tax loss. As a result, the Manufacturer's Tax Deduction (MTD) may be decreased, or eliminated. The decrease in taxable income also impacts working cash, and the availability of bonus depreciation reduces revenues credited to ratepayers associated with CIAC. Each of these items is described in greater detail below:

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[14] Resolution No. L-411A, p. 6 and p. 7.

(1) Manufacturer's Tax Deduction: Internal Revenue Code (IRC) Section 199 allows a tax deduction for qualifying manufacturing activity. The MTD is computed as 9 percent of the net taxable income of PG&E that is derived from the manufacture of goods produced in the United States. Generation of electricity qualifies for the deduction; the T&D of electricity and gas does not qualify.

The 2011 GRC settlement decision (D.11-05-018) adopted revenue requirements incorporated a $20.6 million credit to reflect the forecasted MTD prior to the enactment of the bonus depreciation provision included in the Tax Relief Act. The bonus depreciation included in the Tax Relief Act will reduce PG&E's taxable income and may cause an overall net taxable loss. For instance, the actual MTD for 2011 is estimated to be zero, increasing PG&E's cost of service by $20.6 million in comparison to the adopted generation revenue requirement. The details of this calculation, and its revenue requirement effects, are shown in Attachment 9.

(2) Working Cash: As part of the working cash calculation in PG&E's GRC rate case, an expense lag study is performed based on several dozen expense items, including current Federal Income Tax (FIT) expense and deferred FIT. The current FIT and deferred FIT expense amounts are significantly altered by the Tax Relief Act. The current FIT, taxes we are forecasting to pay in the test year, is reduced by hundreds of millions of dollars while the deferred FIT is increased by hundreds of millions of dollars. The expense lags associated with these items are 111 days and zero, respectively.

Since the FIT lag is significantly greater than the lag for revenue collection (41 days), the effect of reducing current FIT expense to zero (or near zero) significantly increases working cash. In other words, when the FIT amount was substantial, it resulted in a cash lag benefit to PG&E that was returned to the customer. With the Tax Relief Act, this working cash benefit is greatly reduced. In effect, customers are already benefitted from *some* deferral of current tax expense payments through the working cash adjustments, and this deferral must be reversed when it is being separately recognized through an increase in deferred taxes.

There is also a separate working cash-related revenue requirement increase that results from the growth in deferred taxes. All deferred FIT is included in the working cash calculation with a lag of zero days in accordance with the CPUC Standard Practice U-16. On a ratemaking basis, this reflects a net collection lag for this item equal to the lag for revenue collection, 41 days. As such, any increase in deferred FIT results in a separate increase to working cash.

To model the working cash effects, factors were developed that allow the RO model to approximate the rate base changes. The respective factors are percentages that are multiplied by the FIT and deferred FIT as adjusted for any NOL. The result is a change to rate base. For FIT the percentage is 19% and for deferred FIT it is 11%. These percentages were derived from working cash results developed in a 2011 GRC RO model that included bonus depreciation. The details of the percentage calculation are as shown in Attachment 10.

(3) ITCC: CIAC consists of money or property contributed to PG&E by a customer or potential customer to the extent that the purpose of the contribution is to provide for the expansion, improvement, or replacement of PG&E's facilities. CIACs are required to be included in gross income under IRC Section 118(b).

Under D.87-09-026, the CPUC concluded that to the extent reasonable the entity causing the taxable event should bear the tax. Under this Decision, PG&E was permitted to adopt "Method 5" to recover the tax liability associated with the CIAC.

One element of Method 5 is that the contributor of a CIAC is required to make a payment to PG&E to cover a portion of the tax liability attributable to the CIAC (gross-up or ITCC). This gross-up is credited to deferred revenues and amortized over the tax life of the facilities by crediting Miscellaneous Revenues.

Under Method 5, the revenue requirement increases attributable to ratebasing the tax on CIAC is offset by increasing charges to the customer making the CIAC. These charges to the contributor are referred to as the ITCC. Contributors making taxable CIAC payments to PG&E pay an additional ITCC amount at the time of the contribution that is credited to deferred revenues net of income taxes, which has the result of reducing rate base. The deferred revenues are amortized over the tax life of the facilities by crediting Miscellaneous Revenues which also reduces revenue requirements. In effect, the general ratepayers assume the cost of the tax on CIAC (by creating a deferred tax asset), but their cost is offset to some extent by CIAC contributor's payment of the ITCC, which is an approximation of the net present value of the general ratepayers' costs for including the cost of the deferred tax asset in rate base.

The gross-up is directly impacted by changes to the tax depreciation on the underlying contribution, because the timing of accelerated depreciation determines when the tax on CIAC income is offset. An acceleration of the tax depreciation results in a reduction to the ITCC or gross-up rate charged to the contributor because it reduces the deferred tax asset, that otherwise increases rate base to the general ratepayer.

On December 30, 2010, PG&E filed Advice 3176-G/3784-E requesting that the CPUC further reduce the temporarily lower ITCC tax factor from 0.20 (20 percent) for gas and 0.22 (22 percent) for electric, to 0.08 (8 percent) for gas and 0.08 (8 percent) for electric as a result of 100% bonus depreciation. (See Attachment 11.) (This 0.08 (8 percent) ITCC rate, which is effective until December 31, 2011, reflects only California income taxes on CIAC, since the Federal taxable income from CIAC is fully offset by associated bonus depreciation.) The CPUC approved the reduced ITCC rate on February 28, 2011.

A reduction in the ITCC rate will reduce the deferred revenues that serve to reduce rate base and are amortized to Miscellaneous Revenues. This reduction in the ITCC rate, therefore, has the effect of increasing revenue requirements (e.g., for the 2011 test year a 34% ITCC rate had been assumed). (See Attachment 12.)

As stated above, the Memo Account Period will end for the electric distribution, generation, and gas distribution as of December 31, 2013 and for gas transmission as of December 31, 2014.

PG&E plans on forecasting the memorandum account balance as part of its 2014 GRC Application and having the memorandum account balance disposed of in its test year 2014 decision. As part of PG&E's 2014 GRC and 2015 GT&S applications, PG&E will estimate the forecast memorandum account balances for each line of business.

Consistent with the Commission's intent, this advice letter and the corresponding attachments represent PG&E's best effort to identify and capture all revenue requirement impacts of the Tax Relief Act in a simplified and transparent manner that serves the interest of both PG&E's customers and the Commission. If the methods and assumptions underlying PG&E's proposal are found to be inaccurate, incomplete or outdated, future modifications to the memorandum account structure may be necessary. This includes but is not limited to: changes in forecast additions qualifying for bonus or super bonus depreciation, modifications to PG&E's weighted average cost of capital, and other impacts of the Tax Relief Act on current and deferred federal income taxes that are not already captured in the model. As the need for such changes arises, PG&E will update this advice filing as appropriate.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than **November 10, 2011** which is 20 days after the date of this filing. Protests should be mailed to:

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch

505 Van Ness Avenue
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: jnj@cpuc.ca.gov and mas@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 also should be sent via U.S. mail (and by facsimile and electronically, if possible) to PG&E at the address shown below on the same date it is mailed or delivered to the Commission:

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

Facsimile: (415) 973-6520
E-mail: PGETariffs@pge.com

Effective Date

PG&E requests this Tier 2 advice filing become effective, subject to Energy Division approval, on April 14, 2011, as stated in Resolution No. L-411A, Ordering Paragraph 1.

Notice

In accordance with General Order (GO) 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for Application (A.) 09-12-020 (PG&E's 2011 GRC) and A.09-09-013 (PG&E's 2011 GT&S). Address changes to the GO 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at ProcessOffice@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 /sab

Vice President, Regulation and Rates

<u>Attachments:</u>

Attachment 1:	Gas Preliminary Statement Part CS, Tax Act Memorandum Account - Gas (TAMA-G) and Electric Preliminary Statement Part FR, Tax Act Memorandum Account - Electric (TAMA-E)
Attachment 2:	Sec. 401 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010
Attachment 3:	Summary of Electric and Gas Department Revenue Requirement Changes Due to the Tax Relief Act
Attachment 4:	Summary of Electric and Gas Line of Business Revenue Requirement Changes Due to the Tax Relief Act
Attachment 5:	Simplified TAMA Model
Attachment 6:	Forecasted/Adopted Capital Additions (2011 GRC and 2011 GT&S)
Attachment 7:	Capital Additions by Line of Business (LOB) and Major Work Category (MWC)
Attachment 8:	Adopted Cost of Capital
Attachment 9:	Section 199 Manufacturer's Tax Deduction (MTD) Benefit on Electric Generation
Attachment 10:	Working Cash
Attachment 11:	Approved Advice 3176-G/3784-E
Attachment 12:	ITCC Amortization to Miscellaneous Revenue Forecast

cc: Service Lists: A.09-12-020 and A.09-09-013

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 M)**

Utility type:

☑ ELC ☑ GAS

☐ PLC ☐ HEAT ☐ WATER

Contact Person: Greg Backens

Phone #: (415) 973-4390

E-mail: gab4@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas ☐
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **3216-G-A/3859-E-A** **Tier: 2**

Subject of AL: **Establish Tax Act Memorandum Account (TAMA-E and TAMA-G) per CPUC Resolution No. L-411A**

Keywords (choose from CPUC listing): **Memorandum Account, Taxes,**

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: **L-411A**

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: N/A

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

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

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

Resolution Required? ☐ Yes ☑No

Requested effective date: **April 14, 2011** No. of tariff sheets: **8**

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

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

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

Tariff schedules affected: **New Gas Preliminary Statement Part CS and New Electric Preliminary Statement Part FR**

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
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave., San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

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

ATTACHMENT 1
Advice 3216-G-A

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
29291-G	GAS PRELIMINARY STATEMENT PART CS TAX ACT MEMORANDUM ACCOUNT - GAS Sheet 1	
29292-G	GAS PRELIMINARY STATEMENT PART CS TAX ACT MEMORANDUM ACCOUNT - GAS Sheet 2	
29293-G	GAS TABLE OF CONTENTS Sheet 1	29260-G
29294-G	GAS TABLE OF CONTENTS Sheet 5	28779-G

GAS PRELIMINARY STATEMENT PART CS — Sheet 1 (N)
TAX ACT MEMORANDUM ACCOUNT - GAS (N)

CS. TAX ACT MEMORANDUM ACCOUNT - GAS (TAMA-G) (N)

1. PURPOSE: The purpose of the Tax Act Memorandum Account – Gas ("TAMA-G") is to record and track the gas portion of the revenue requirement impacts of the New Tax Relief Act signed on December 17, 2010 (Tax Relief Act), not addressed in PG&E's 2011 General Rate Case (GRC) Decision 11-05-018 and Gas Transmission & Storage (GT&S) Settlement Decision 11-04-031. It tracks and records on a CPUC-jurisdictional, revenue requirement basis: (a) decreases in revenue requirement resulting from increases in its deferred tax reserve; and (b) other direct changes in revenue requirement resulting from taking advantage of the Tax Relief Act. This is a one way memorandum account that allows the Commission to determine at a future date whether rates should be changed, without having to be concerned with issues of retroactive ratemaking. (N)

2. APPLICABILITY: The TAMA-G applies to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATE: Disposition of the account balance will be initiated in PG&E's next GRC and GT&S rate cases. PG&E will transfer any account balance to the appropriate mechanism for refund, as may be approved by the Commission at that time.

4. RATES: The current TAMA-G does not have a rate component.

5. ACCOUNTING PROCEDURE: The PG&E shall maintain the TAMA-G by making entries a. – c. to this account after the close of each year, entries d and e at the end of 2013, entry f. as authorized and entry g. monthly, as follows:

   a. A credit entry equal to the decreases in the gas distribution, transmission and storage revenue requirements resulting from increases in the net deferred tax reserve (deferred tax liabilities net of deferred tax assets)

   b. A debit entry equal to the increases in the gas distribution, transmission and storage revenue requirements resulting from taking advantage of the Tax Relief Act to reflect any additional costs or expenses, not otherwise recovered in rates, incurred as a result of additional utility infrastructure investment enabled by the bonus depreciation provisions of the Tax Relief Act

   c. A debit entry equal to any increases in the gas distribution, transmission and storage revenue requirements due to Section 199 manufacturer's tax deductions resulting from bonus depreciation taken, changes in working cash resulting from the Tax Relief Act, and, any decrease in the tax component of contributions-in-aid-of-construction (CIAC) received due to changes in the tariffed tax component of CIAC to reflect the Tax Relief Act.

   d. A debit entry to transfer a portion of any net over-collected balance in the TAMA-G into the TAMA-E, if the TAMA-E is under-collected. This entry shall not exceed 10% of the increase in electric distribution and generation revenue requirements resulting from additional utility infrastructure investment as recorded in entry 5.b. of the TAMA-E, and may not exceed the net over-collected balance in the TAMA-G or under-collected balance in the TAMA-E.

   e. A credit entry to transfer a portion of any net over-collected balance in the TAMA-E into the TAMA-G, if the TAMA-G is under-collected. This entry shall not exceed 10% of the increase in gas distribution and gas transmission revenue requirements resulting from additional utility infrastructure investment as recorded in entry 5.b. above, and may not exceed the net over- collected balance in the TAMA-E or under-collected balance in the TAMA-G. (N)

(Continued)

GAS PRELIMINARY STATEMENT PART CS Sheet 2 (N)
TAX ACT MEMORANDUM ACCOUNT - GAS (N)

5. ACCOUNTING PROCEDURE (Cnt'd): (N)

g. A debit entry to transfer all or a portion of the balance in this TAMA-G to any other accounts for future rate adjustment, as may be approved by the CPUC. If, at the end of the memorandum account period, this memorandum account reflects a net revenue requirement increase, the memorandum account shall be terminated without any impact on rates. (N)

h. A debit entry equal to the interest on the average balance at the beginning of the month and the balance after the above entry at a rate equal to the average interest rate on three month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor. (N)

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GAS TABLE OF CONTENTS

Sheet 5

(Continued)

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
30686-E	ELECTRIC PRELIMINARY STATEMENT PART FR TAX ACT MEMORANDUM ACCOUNT - ELECTRIC Sheet 1	
30687-E	ELECTRIC PRELIMINARY STATEMENT PART FR TAX ACT MEMORANDUM ACCOUNT - ELECTRIC Sheet 2	
30688-E	ELECTRIC TABLE OF CONTENTS Sheet 1	30532-E
30689-E	ELECTRIC TABLE OF CONTENTS PRELIMINARY STATEMENT Sheet 17	30383-E*

ELECTRIC PRELIMINARY STATEMENT PART FR Sheet 1 (N)
TAX ACT MEMORANDUM ACCOUNT - ELECTRIC (N)

FR. TAX ACT MEMORANDUM ACCOUNT - ELECTRIC (TAMA-E)

1. PURPOSE: The purpose of the Tax Act Memorandum Account – Electric ("TAMA-E") is to record and track the electric portion of the revenue requirement impacts of the New Tax Relief Act signed on December 17, 2010 (Tax Relief Act), not addressed in PG&E's 2011 General Rate Case (GRC) Decision 11-05-018 and Gas Transmission & Storage (GT&S) Settlement Decision 11-04-031. It tracks and records on a CPUC-jurisdictional, revenue requirement basis: (a) decreases in revenue requirement resulting from increases in its deferred tax reserve; and (b) other direct changes in revenue requirement resulting from taking advantage of the Tax Relief Act. This is a one way memorandum account that allows the Commission to determine at a future date whether rates should be changed, without having to be concerned with issues of retroactive ratemaking. (N)

2. APPLICABILITY: The TAMA-E applies to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATE: Disposition of the account balance will be initiated in PG&E's next GRC. PG&E will transfer the account balance to the appropriate mechanism for refund, as may be approved by the Commission at that time.

4. RATES: The current TAMA-E does not have a rate component.

5. ACCOUNTING PROCEDURE: PG&E shall maintain the TAMA-E by making entries a. – c. to this account after the close of each year, entries d and e at the end of 2013, entry f. as authorized and entry g. monthly, as follows:

   a. A credit entry equal to the decreases in the electric distribution and generation revenue requirements resulting from increases in the net deferred tax reserve (deferred tax liabilities net of deferred tax assets).

   b. A debit entry equal to the increases in the electric distribution and generation revenue requirements resulting from taking advantage of the Tax Relief Act to reflect any additional costs or expenses, not otherwise recovered in rates, incurred as a result of additional utility infrastructure investment enabled by the bonus depreciation provisions of the Tax Relief Act.

   c. A debit entry equal to any increases in the electric distribution and generation revenue requirements due to Section 199 manufacturer's tax deductions resulting from bonus depreciation taken, changes in working cash resulting from the Tax Relief Act, and, any decrease in the tax component of contributions-in-aid-of-construction (CIAC) received due to changes in the tariffed tax component of CIAC to reflect the Tax Relief Act.

   d. A debit entry to transfer a portion of any net over-collected balance in the TAMA-E into the TAMA-G, if the TAMA-G is under-collected. This entry shall not exceed 10% of the increase in gas distribution and gas transmission revenue requirements resulting from additional utility infrastructure investment as recorded in entry 5.b. of the TAMA-G, and may not exceed the net over-collected balance in the TAMA-E or under-collected balance in the TAMA-G.

   e. A credit entry to transfer a portion of any net over-collected balance in the TAMA-G into the TAMA-E, if the TAMA-E is under-collected. This entry shall not exceed 10% of the increase in electric distribution and electric generation revenue requirements resulting from additional utility infrastructure investment as recorded in entry 5.b. above, and may not exceed the net over-collected balance in the TAMA-G or under-collected balance in the TAMA-E. (N)

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART FR Sheet 2 (N)
TAX ACT MEMORANDUM ACCOUNT - ELECTRIC (N)

5. ACCOUNTING PROCEDURE (Cnt'd): (N)

   f. A debit entry to transfer all or a portion of the balance in this TAMA-E to any other accounts for future rate adjustment, as may be approved by the CPUC. If, at the end of the memorandum account period, this memorandum account reflects a net revenue requirement increase, the memorandum account shall be terminated without any impact on rates. (N)

   g. A debit entry equal to the interest on the average balance in the account at the beginning of the month and the balance after the above entry at a rate equal to the average interest rate on three month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor. (N)

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Sheet 1

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ELECTRIC TABLE OF CONTENTS
PRELIMINARY STATEMENT

Sheet 17

(Continued)

Advice 3216-G-A/3859-E-A

Attachment 2

Sec. 401 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010

Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010
[P.L. 111-312 12/17/2010]

TITLE IV. TEMPORARY EXTENSION OF INVESTMENT INCENTIVES [§§401—402]

Law Sec. 401. EXTENSION OF BONUS DEPRECIATION; TEMPORARY 100 PERCENT EXPENSING FOR CERTAIN BUSINESS ASSETS.

(a) In General. Paragraph (2) of section 168(k) is amended—

(1) by striking "January 1, 2012" in subparagraph (A)(iv) and inserting "January 1, 2014", and

(2) by striking "January 1, 2011" each place it appears and inserting "January 1, 2013".

(b) Temporary 100 Percent Expensing. Subsection (k) of section 168 is amended by adding at the end the following new paragraph:

"(5) SPECIAL RULE FOR PROPERTY ACQUIRED DURING CERTAIN PRE-2012 PERIODS.-In the case of qualified property acquired by the taxpayer (under rules similar to the rules of clauses (ii) and (iii) of paragraph (2)(A)) after September 8, 2010, and before January 1, 2012, and which is placed in service by the taxpayer before January 1, 2012 (January 1, 2013, in the case of property described in subparagraph (2)(B) or (2)(C)), paragraph (1)(A) shall be applied by substituting '100 percent' for '50 percent'.".

(c) Extension of Election to Accelerate the AMT Credit in Lieu of Bonus Depreciation.

(1) Extension. Clause (iii) of section 168(k)(4)(D) is amended by striking "or production" and all that follows and inserting "or production—

"(I) after March 31, 2008, and before January 1, 2010, and

"(II) after December 31, 2010, and before January 1, 2013,

shall be taken into account under subparagraph (B)(ii) thereof,".

(2) Rules for Round 2 Extension Property. Paragraph (4) of section 168(k) is amended by adding at the end the following new subparagraph:

"(I) SPECIAL RULES FOR ROUND 2 EXTENSION PROPERTY.-

"(i) IN GENERAL.-In the case of round 2 extension property, this paragraph shall be applied without regard to—

"(I) the limitation described in subparagraph (B)(i) thereof, and

"(II) the business credit increase amount under subparagraph (E)(iii) thereof.

"(ii) TAXPAYERS PREVIOUSLY ELECTING ACCELERATION.-In the case of a taxpayer who made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, or a taxpayer who made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008—

“(I) the taxpayer may elect not to have this paragraph apply to round 2 extension property, but

“(II) if the taxpayer does not make the election under subclause (I), in applying this paragraph to the taxpayer the bonus depreciation amount, maximum amount, and maximum increase amount shall be computed and applied to eligible qualified property which is round 2 extension property.

The amounts described in subclause (II) shall be computed separately from any amounts computed with respect to eligible qualified property which is not round 2 extension property.

“(iii) TAXPAYERS NOT PREVIOUSLY ELECTING ACCELERATION.-In the case of a taxpayer who neither made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, nor made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008—

“(I) the taxpayer may elect to have this paragraph apply to its first taxable year ending after December 31, 2010, and each subsequent taxable year, and

“(II) if the taxpayer makes the election under subclause (I), this paragraph shall only apply to eligible qualified property which is round 2 extension property.

“(iv) ROUND 2 EXTENSION PROPERTY.-For purposes of this subparagraph, the term 'round 2 extension property' means property which is eligible qualified property solely by reason of the extension of the application of the special allowance under paragraph (1) pursuant to the amendments made by section 401(a) of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (and the application of such extension to this paragraph pursuant to the amendment made by section 401(c)(1) of such Act).”.

(d) Conforming Amendments.

(1) The heading for subsection (k) of section 168 is amended by striking “JANUARY 1, 2011” and inserting “JANUARY 1, 2013”.

(2) The heading for clause (ii) of section 168(k)(2)(B) is amended by striking “PRE-JANUARY 1, 2011” and inserting “PRE-JANUARY 1, 2013”.

(3) Subparagraph (D) of section 168(k)(4) is amended—

(A) by striking clauses (iv) and (v),

(B) by inserting “and” at the end of clause (ii), and

(C) by striking the comma at the end of clause (iii) and inserting a period.

(4) Paragraph (5) of section 168(l) is amended—

(A) by inserting “and” at the end of subparagraph (A),

(B) by striking subparagraph (B), and

(C) by redesignating subparagraph (C) as subparagraph (B).

(5) Subparagraph (C) of section 168(n)(2) is amended by striking “January 1, 2011” and inserting “January 1, 2013”.

Advice 3216-G-A/3859-E-A

Attachment 3

Summary of Electric and Gas Department Revenue Requirement Changes Due to the Tax Relief Act

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Summary of Electric and Gas Department Revenue Requirement Changes Due to the Tax Relief Act
($ in millions)

Line No.			Electric		Gas
1	Impact of Adopted Capital Additions (Section A)		(221)		(70)
2	Impact of Additional Infrastructure Investment (Section B)		0		0
3	Impact of Other Items Resulting From Tax Relief Act (Section C)		69		13
4	Change in Revenue Requirements (A + B + C)		(151)		(57)
5	Service Function Adjustment (See Below)		0		0
6	**Total Change in Revenue Requirements at The End of Rate Case Cycle**		(151)		(57)
7		ED*	(132)	GD*	(35)
8		EG*	(19)	GT*	(21)

Service Function Adjustment:

			Electric	Gas
a.	Are TAMA-G and TAMA-E both under-collected?	NO		
b.	Are TAMA-G and TAMA-E both over-collected?	YES		
c.	Is the TAMA-G account over-collected and TAMA-E under-collected?	NO	0	0
d.	Is the TAMA-E over-collected and TAMA-G under-collected?	NO	0	0

* Allocations to LOBs are based on proportion to the Change in Revenue Requirements (L4) above.
Please note that negative amounts indicate an over-collection.

Advice 3216-G-A/3859-E-A

Attachment 4

Summary of Electric and Gas Line of Business Revenue Requirement Changes Due to the Tax Relief Act

Consistent with both Resolution No. L-411 and Resolution No. L-411A, the 2011 Revenue requirements will reflect the period from April 14, 2011 to December 31, 2011.

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Illustration of 2010 Tax Relief Act Impact
Summary of Electric Line of Business Revenue Requirement Changes Due to the Tax Relief Act
($ in millions)

		2011		2012		2013		2011 thru 2013 Total		
		Distribution	Generation	Distribution	Generation	Distribution	Generation	Distribution	Generation	Total Electric
Section A - Impact of Adopted Capital Additions										
1	Adopted Qualifying Capital Additions	1,241	290	1,241	290	N/A	N/A			
2	Incremental Tax Depreciation	1,175	264	485	99	(150)	(49)			
3	x Federal Income Tax Rate	35%	35%	35%	35%	35%	35%			
4	= Incremental Deferred Taxes	411	92	170	35	(52)	(17)			
5	Accumulated Weighted Average Deferred Taxes*	(240)	(80)	(550)	(149)	(627)	(162)			
6	+ Net Operating Loss Adjustment	29	13	40	19	0	0			
7	= Net Incremental Change in Rate Base	(211)	(67)	(510)	(130)	(627)	(162)			
8	x Pre-Tax Return on Rate Base	12.92%	12.92%	12.92%	12.92%	12.92%	12.92%			
9	**= Revenue Requirement - Adopted Additions**	**(27)**	**(9)**	**(66)**	**(17)**	**(81)**	**(21)**	**(174)**	**(46)**	**(221)**
Section B - Impact of Additional Infrastructure Investment										
10	Recorded Qualifying Capital Additions	1,241	290	1,241	290	N/A	N/A			
11	Less: Adopted Qualifying Capital Additions	1,241	290	1,241	290	N/A	N/A			
12	= Incremental Capital Additions	0	0	0	0	N/A	N/A			
13	Accumulated Weighted Average Incremental Additions*	0	0	0	0	0	0			
14	x Imputed Composite Revenue Requirement Factors*	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
15	**= Revenue Requirement - Additional Investment**	0	0	0	0	0	0	**0**	**0**	**0**
Section C - Impact of Other Items Resulting from TRA										
16	Loss of Manufacturer's Tax Deduction	N/A	21	N/A	0	N/A	0			
17	Reduction in ITCC Revenues	7	N/A	9	N/A	11	N/A			
18	Change in Working Cash	11	5	5	2	(2)	(1)			
19	**= Revenue Requirement - Other Items**	**18**	**26**	**15**	**2**	**10**	**(1)**	**42**	**27**	**69**
20	**Total Change in Revenue Requirement** (A + B + C)	**(9)**	**17**	**(51)**	**(14)**	**(72)**	**(22)**	**(132)**	**(19)**	**(151)**

* Amounts are calculated in the Simplified Model. The Revenue Requirement (L15) has been calculated using the simplified model.

Consistent with both Resolution No. L-411 and Resolution No. L-411A, the 2011 Revenue requirements will reflect the period from April 14, 2011 to December 31, 2011.

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Illustration of 2010 Tax Relief Act Impact
Summary of Gas Line of Business Revenue Requirement Changes Due to the Tax Relief Act
($ in millions)

		2011		2012		2013		2011 thru 2013 Total			2014
		Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Total Gas	Transmission
	Section A - Impact of Adopted Capital Additions										
1	Adopted Qualifying Capital Additions	341	144	341	115	N/A	N/A				N/A
2	Incremental Tax Depreciation	320	130	127	34	(48)	(24)				(27)
3	x Federal Income Tax Rate	35%	35%	35%	35%	35%	35%				35%
4	= Incremental Deferred Taxes	112	45	44	12	(17)	(8)				(9)
5	Accumulated Weighted Average Deferred Taxes*	(63)	(43)	(147)	(74)	(166)	(78)				(69)
6	+ Net Operating Loss Adjustment	8	5	11	7	0	0				N/A
7	= Net Incremental Change in Rate Base	(56)	(38)	(136)	(68)	(166)	(78)				(69)
8	x Pre-Tax Return on Rate Base	12.92%	12.92%	12.92%	12.92%	12.92%	12.92%				12.92%
9	**= Revenue Requirement - Adopted Additions**	**(7)**	**(5)**	**(18)**	**(9)**	**(21)**	**(10)**	**(46)**	**(24)**	**(70)**	**(9)**
	Section B - Impact of Additional Infrastructure Investment										
10	Recorded Qualifying Capital Additions	341	144	341	115	N/A	N/A				N/A
11	Less: Adopted Qualifying Capital Additions	341	144	341	115	N/A	N/A				N/A
12	= Incremental Capital Additions	0	0	0	0	N/A	N/A				N/A
13	Accumulated Weighted Average Incremental Additions*	0	0	0	0	0	0				-
14	x Imputed Composite Revenue Requirement Factors*	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				-
15	**= Revenue Requirement - Additional Investment**	0	0	0	0	0	0	**0**	**0**	**0**	*0*
	Section C - Impact of Other Items Resulting from TRA										
16	Reduction in ITCC Revenues	2	N/A	2	N/A	3	N/A				N/A
17	Change in Working Cash	3	2	1	1	(1)	(0)				N/A
18	**= Revenue Requirement - Other Items**	**5**	**2**	**4**	**1**	**2**	**(0)**	**11**	**2**	**13**	**0**
19	**Total Change in Revenue Requirement** (A + B + C)	**(2)**	**(3)**	**(14)**	**(8)**	**(19)**	**(10)**	**(35)**	**(21)**	**(57)**	**(9)**

* Amounts are calculated in the Simplified Model. The Revenue Requirement (L15) has been calculated using the simplified model.

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Attachment 5

Simplified TAMA Model

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
All LOBs Summary Revenue Requirements (RRQ) Estimation Model
(In Millions of Dollars)

Line No.	Description	2010	2011	2012	2013	Source
1	**A. Impact of Tax Relief Act on Adopted Additions**					
2	Sep thru Dec 2010 Additions					
3	**TRA Qualified Capital Additions**	903				SUM of LOBs
4	TRA Bonus Depreciation Factor	100%	0%	0%	0%	L5/L3
5	TRA Bonus Depreciation Amount	903	0	0	0	SUM of LOBs
6	Pre-TRA Depreciation Factor	52.30%	4.38%	3.98%	3.61%	L7/L3
7	Pre-TRA Depreciation	473	40	36	33	SUM of LOBs
8	TRA Incremental Bonus Depreciation	431	(40)	(36)	(33)	L5-L7
9	2011 Additions					
10	TRA Qualified Capital Additions		2,017			SUM of LOBs
11	TRA Bonus Depreciation Factor		100%	0%	0%	L12/L10
12	TRA Bonus Depreciation Amount		2,017	0	0	SUM of LOBs
13	Standard Depreciation Factor		4.41%	8.42%	7.67%	L14/L10
14	Standard Depreciation		89	170	155	SUM of LOBs
15	TRA Incremental Bonus Depreciation		1,928	(170)	(155)	L12-L14
16	2012 Additions					
17	TRA Qualified Capital Additions			1,987		SUM of LOBs
18	TRA Bonus Depreciation Factor			52.20%	4.20%	L19/L17
19	TRA Bonus Depreciation Amount			1,037	83	SUM of LOBs
20	Standard Depreciation Factor			4.40%	8.40%	L21/L17
21	Standard Depreciation			87	167	SUM of LOBs
22	TRA Incremental Bonus Depreciation			950	(83)	L19-L21
23	Total TRA Incremental Depreciation	431	1,889	744	(271)	L8+L15+L22
24						
25	Incremental Deferred Tax					
26	Tax Rate	35%	35%	35%	35%	Attachment 8, L5
27	Current Year Deferred Tax	151	661	260	(95)	L24*L26
28	Accumulated Deferred Tax	151	812	1,072	978	ACC(L27)
29	Rate Base Adjustment - Average Year					
30	Deferred Taxes		(426)	(920)	(1,033)	Previous Year L28 Plus 41.66% of Current Year L27 (Negative)
31						
32	Net Operating Loss (NOL)					
33	Adopted Taxable Income		1,515	1,515	1,515	SUM of LOBs
34	Less: Additional Investment Tax Deductible Loss		0	0	0	SUM of LOBs
35	Less: TRA Bonus Depreciation on Adopted Additions		(1,889)	(744)	271	SUM of LOBs
36	Less: TRA Bonus Depreciation on Additional Investment		0	0		L50*L11 and L54*L18
37	Carry-Forward		(374)	771	1,786	sum(L33:L36)
38	Accumulated Carry-Forward		(374)	0	0	ACC(L37)
39	Tax Rate		35%	35%	35%	Attachment 8, L5
40	Deferred Tax Adjustment		131	0	0	L38*L39 (Negative)
41	NOL Deferred Tax Asset		54	76	0	Previous Year L40 Plus 41.66% of Year over Year Change L40
42						
43	Total Rate Base Adjustment		(372)	(844)	(1,033)	L30+L41
44	Pre-Tax Cost of Capital (%)		12.92%	12.92%	12.92%	Attachment 8
45	**Change in Annual RRQ on Adopted Capital Additions**		(48)	(109)	(133)	L43*L44
46	Accumulated Revenue Requirements on Adopted Additions		(48)	(157)	(291)	ACC(L45)
47						
48	**B. Additional Utility Infrastructure Investment**					
49	2011 Additions					
50	TRA Qualified Capital Additions		0			SUM of LOBs
51	Annual Revenue Requirements Factor		0.00%	0.00%	0.00%	L52/L50
52	Revenue Requirements		0	0	0	SUM of LOBs
53	2012 Additions					
54	TRA Qualified Capital Additions			0		SUM of LOBs
55	Annual Revenue Requirements Factor			0.00%	0.00%	L56/L54
56	Revenue Requirements			0	0	SUM of LOBs
57						
58	**Annual RRQ on Additional Investment**		0	0	0	L52+L56
59						
60	**C. Other RRQ Impacts Resulting from Taking Bonus Depreciation**					
61	Manufacturer's Tax Deduction Adjustment		21	0	0	Elec Gen L61
62	Working Cash Adjustment		21	10	(4)	Working Cash*Pre-tax Cost of Captial (Attachment 8)
63	ITCC Adjustment		9	12	14	Elec Dist L63 + Gas Dist L63
64	**Change in Annual RRQ on Other Impacts**		51	22	10	sum(L61:L63)
65						
66	**Total Change in Annual Revenue Requirements**		**2**	**(87)**	**(123)**	L45+L58+L64
67	Accumulated Revenue Requirements		2	(85)	(208)	ACC(L66)

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Electric Generation Revenue Requirements (RRQ) Estimation Model
(In Millions of Dollars)

Line No.	Description	2010	2011	2012	2013	Source
1	**A. Impact of Tax Relief Act on Adopted Additions**					
2	Sep thru Dec 2010 Additions					
3	**TRA Qualified Capital Additions**	253				Attachment 6, L1
4	TRA Bonus Depreciation Factor	100%	0%	0%	0%	EG ROs
5	TRA Bonus Depreciation Amount	253	0	0	0	L3*L4
6	Pre-TRA Depreciation Factor	52.52%	4.79%	4.30%	3.87%	EG ROs
7	Pre-TRA Depreciation	133	12	11	10	L3*L6
8	TRA Incremental Bonus Depreciation	120	(12)	(11)	(10)	L5-L7
9	2011 Additions					
10	TRA Qualified Capital Additions		290			Attachment 6, L1
11	TRA Bonus Depreciation Factor		100%	0%	0%	EG ROs
12	TRA Bonus Depreciation Amount		290	0	0	L10*L11
13	Standard Depreciation Factor		5.04%	9.57%	8.61%	EG ROs
14	Standard Depreciation		15	28	25	L10*L13
15	TRA Incremental Bonus Depreciation		276	(28)	(25)	L12-L14
16	2012 Additions					
17	TRA Qualified Capital Additions			290		Attachment 6, L1
18	TRA Bonus Depreciation Factor			52.52%	4.79%	EG ROs
19	TRA Bonus Depreciation Amount			153	14	L17*L18
20	Standard Depreciation Factor			5.04%	9.57%	EG ROs
21	Standard Depreciation			15	28	L17*L20
22	TRA Incremental Bonus Depreciation			138	(14)	L19-L21
23	Total TRA Incremental Depreciation	120	264	99	(49)	L8+L15+L22
24						
25	Incremental Deferred Tax					
26	Tax Rate	35%	35%	35%	35%	Attachment 8, L5
27	Current Year Deferred Tax	42	92	35	(17)	L24*L26
28	Accumulated Deferred Tax	42	134	169	152	ACC(L27)
29	Rate Base Adjustment - Average Year					
30	Deferred Taxes		(80)	(149)	(162)	Previous Year L28 Plus 41.66% of Current Year L27 (Negative)
31						
32	Net Operating Loss (NOL)					
33	Adopted Taxable Income		368	368	368	Inputs L4
34	Less: Additional Investment Tax Deductible Loss		0	0	0	RO Taxable Income as % times Incremental Plant
35	Less: TRA Bonus Depreciation on Adopted Additions		(264)	(99)	49	L23
36	Less: TRA Bonus Depreciation on Additional Investment		0	0		L50*L11 and L54*L18
37	Carry-Forward		104	268	416	sum(L33:L36)
38	Accumulated Carry-Forward					
39	Tax Rate					
40	Deferred Tax Adjustment					
41	NOL Deferred Tax Asset		13	19	0	Proportion from Summary L41
42						
43	Total Rate Base Adjustment		(67)	(130)	(162)	L30+L41
44	Pre-Tax Cost of Capital (%)		12.92%	12.92%	12.92%	Attachment 8
45	**Change in Annual RRQ on Adopted Capital Additions**		(9)	(17)	(21)	L43*L44
46	Accumulated Revenue Requirements on Adopted Additions		(9)	(26)	(46)	ACC(L45)
47						
48	**B. Additional Utility Infrastructure Investment**					
49	2011 Additions					
50	TRA Qualified Capital Additions		0			Inputs L11
51	Annual Revenue Requirements Factor		5.98%	11.79%	11.48%	EG ROs
52	Revenue Requirements		0	0	0	L50*L51
53	2012 Additions					
54	TRA Qualified Capital Additions			0		Inputs L11
55	Annual Revenue Requirements Factor			7.05%	13.83%	EG ROs
56	Revenue Requirements			0	0	L54*L55
57						
58	**Annual RRQ on Additional Investment**		0	0	0	L52+L56
59						
60	**C. Other RRQ Impacts Resulting from Taking Bonus Depreciation**					
61	Manufacturer's Tax Deduction Adjustment		21	0	0	Based on Change in Taxable Income for Electric Generation
62	Working Cash Adjustment		5	2	(1)	Proportion from Summary L62
63	ITCC Adjustment		N/A	N/A	N/A	
64	**Change in Annual RRQ on Other Impacts**		26	2	(1)	sum(L61:L63)
65						
66	**Total Change in Annual Revenue Requirements**		**17**	**(14)**	**(22)**	L45+L58+L64
67	Accumulated Revenue Requirements		17	3	(19)	ACC(L66)

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Electric Distribution Revenue Requirements (RRQ) Estimation Model
(In Millions of Dollars)

Line No.	Description	2010	2011	2012	2013	Source
1	**A. Impact of Tax Relief Act on Adopted Additions**					
2	Sep thru Dec 2010 Additions					
3	**TRA Qualified Capital Additions**	406				Attachment 6, L2
4	TRA Bonus Depreciation Factor	100%	0%	0%	0%	ED ROs
5	TRA Bonus Depreciation Amount	406	0	0	0	L3*L4
6	Pre-TRA Depreciation Factor	52.02%	3.88%	3.56%	3.28%	ED ROs
7	Pre-TRA Depreciation	211	16	14	13	L3*L6
8	TRA Incremental Bonus Depreciation	195	(16)	(14)	(13)	L5-L7
9	2011 Additions					
10	TRA Qualified Capital Additions		1,241			Attachment 6, L2
11	TRA Bonus Depreciation Factor		100%	0%	0%	ED ROs
12	TRA Bonus Depreciation Amount		1,241	0	0	L10*L11
13	Standard Depreciation Factor		4.04%	7.76%	7.13%	ED ROs
14	Standard Depreciation		50	96	88	L10*L13
15	TRA Incremental Bonus Depreciation		1,191	(96)	(88)	L12-L14
16	2012 Additions					
17	TRA Qualified Capital Additions			1,241		Attachment 6, L2
18	TRA Bonus Depreciation Factor			52.02%	3.88%	ED ROs
19	TRA Bonus Depreciation Amount			646	48	L17*L18
20	Standard Depreciation Factor			4.04%	7.76%	ED ROs
21	Standard Depreciation			50	96	L17*L20
22	TRA Incremental Bonus Depreciation			596	(48)	L19-L21
23	Total TRA Incremental Depreciation	195	1,175	485	(150)	L8+L15+L22
24						
25	Incremental Deferred Tax					
26	Tax Rate	35%	35%	35%	35%	Attachment 8, L5
27	Current Year Deferred Tax	68	411	170	(52)	L24*L26
28	Accumulated Deferred Tax	68	480	649	597	ACC(L27)
29	Rate Base Adjustment - Average Year					
30	Deferred Taxes		(240)	(550)	(627)	Previous Year L28 Plus 41.66% of Current Year L27 (Negative)
31						
32	Net Operating Loss (NOL)					
33	Adopted Taxable Income		803	803	803	Inputs L5
34	Less: Additional Investment Tax Deductible Loss		0	0	0	RO Taxable Income as % times Incremental Plant
35	Less: TRA Bonus Depreciation on Adopted Additions		(1,175)	(485)	150	L23
36	Less: TRA Bonus Depreciation on Additional Investment		0	0		L50*L11 and L54*L18
37	Carry-Forward		(372)	319	953	sum(L33:L36)
38	Accumulated Carry-Forward					
39	Tax Rate					
40	Deferred Tax Adjustment					
41	NOL Deferred Tax Asset		29	40	0	Proportion from Summary L41
42						
43	Total Rate Base Adjustment		(211)	(510)	(627)	L30+L41
44	Pre-Tax Cost of Capital (%)		12.92%	12.92%	12.92%	Attachment 8
45	**Change in Annual RRQ on Adopted Capital Additions**		(27)	(66)	(81)	L43*L44
46	Accumulated Revenue Requirements on Adopted Additions		(27)	(93)	(174)	ACC(L45)
47						
48	**B. Additional Utility Infrastructure Investment**					
49	2011 Additions					
50	TRA Qualified Capital Additions		0			Inputs L12
51	Annual Revenue Requirements Factor		5.86%	11.59%	11.30%	ED ROs
52	Revenue Requirements		0	0	0	L50*L51
53	2012 Additions					
54	TRA Qualified Capital Additions			0		Inputs L12
55	Annual Revenue Requirements Factor			6.95%	13.67%	ED ROs
56	Revenue Requirements			0	0	L54*L55
57						
58	**Annual RRQ on Additional Investment**		0	0	0	L52+L56
59						
60	**C. Other RRQ Impacts Resulting from Taking Bonus Depreciation**					
61	Manufacturer's Tax Deduction Adjustment		N/A	N/A	N/A	
62	Working Cash Adjustment		11	5	(2)	Proportion from Summary L62
63	ITCC Adjustment		7	9	11	Inputs L27
64	**Change in Annual RRQ on Other Impacts**		18	15	10	sum(L61:L63)
65						
66	**Total Change in Annual Revenue Requirements**		**(9)**	**(51)**	**(72)**	L45+L58+L64
67	Accumulated Revenue Requirements		(9)	(60)	(132)	ACC(L66)

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Attachment 5

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Gas Distribution Revenue Requirements (RRQ) Estimation Model
(In Millions of Dollars)

Line No.	Description	2010	2011	2012	2013	Source
1	**A. Impact of Tax Relief Act on Adopted Additions**					
2	Sep thru Dec 2010 Additions					
3	**TRA Qualified Capital Additions**	99				Attachment 6, L3
4	TRA Bonus Depreciation Factor	100%	0%	0%	0%	GD ROs
5	TRA Bonus Depreciation Amount	99	0	0	0	L3*L4
6	Pre-TRA Depreciation Factor	52.43%	4.63%	4.18%	3.77%	GD ROs
7	Pre-TRA Depreciation	52	5	4	4	L3*L6
8	TRA Incremental Bonus Depreciation	47	(5)	(4)	(4)	L5-L7
9	2011 Additions					
10	TRA Qualified Capital Additions		341			Attachment 6, L3
11	TRA Bonus Depreciation Factor		100%	0%	0%	GD ROs
12	TRA Bonus Depreciation Amount		341	0	0	L10*L11
13	Standard Depreciation Factor		4.86%	9.25%	8.35%	GD ROs
14	Standard Depreciation		17	32	28	L10*L13
15	TRA Incremental Bonus Depreciation		324	(32)	(28)	L12-L14
16	2012 Additions					
17	TRA Qualified Capital Additions			341		Attachment 6, L3
18	TRA Bonus Depreciation Factor			52.43%	4.63%	GD ROs
19	TRA Bonus Depreciation Amount			179	16	L17*L18
20	Standard Depreciation Factor			4.86%	9.25%	GD ROs
21	Standard Depreciation			17	32	L17*L20
22	TRA Incremental Bonus Depreciation			162	(16)	L19-L21
23	Total TRA Incremental Depreciation	47	320	127	(48)	L8+L15+L22
24						
25	Incremental Deferred Tax					
26	Tax Rate	35%	35%	35%	35%	Attachment 8, L5
27	Current Year Deferred Tax	17	112	44	(17)	L24*L26
28	Accumulated Deferred Tax	17	128	173	156	ACC(L27)
29	Rate Base Adjustment - Average Year					
30	Deferred Taxes		(63)	(147)	(166)	Previous Year L28 Plus 41.66% of Current Year L27 (Negative)
31						
32	Net Operating Loss (NOL)					
33	Adopted Taxable Income		212	212	212	Inputs L6
34	Less: Additional Investment Tax Deductible Loss		0	0	0	RO Taxable Income as % times Incremental Plant
35	Less: TRA Bonus Depreciation on Adopted Additions		(320)	(127)	48	L23
36	Less: TRA Bonus Depreciation on Additional Investment		0	0		L50*L11 and L54*L18
37	Carry-Forward		(108)	86	260	sum(L33:L36)
38	Accumulated Carry-Forward					
39	Tax Rate					
40	Deferred Tax Adjustment					
41	NOL Deferred Tax Asset		8	11	0	Proportion from Summary L41
42						
43	Total Rate Base Adjustment		(56)	(136)	(166)	L30+L41
44	Pre-Tax Cost of Capital (%)		12.92%	12.92%	12.92%	Attachment 8
45	**Change in Annual RRQ on Adopted Capital Additions**		(7)	(18)	(21)	L43*L44
46	Accumulated Revenue Requirements on Adopted Additions		(7)	(25)	(46)	ACC(L45)
47						
48	**B. Additional Utility Infrastructure Investment**					
49	2011 Additions					
50	TRA Qualified Capital Additions		0			Inputs L13
51	Annual Revenue Requirements Factor		6.03%	11.91%	11.60%	GD ROs
52	Revenue Requirements		0	0	0	L50*L51
53	2012 Additions					
54	TRA Qualified Capital Additions			0		Inputs L13
55	Annual Revenue Requirements Factor			7.11%	13.96%	GD ROs
56	Revenue Requirements			0	0	L54*L55
57						
58	**Annual RRQ on Additional Investment**		0	0	0	L52+L56
59						
60	**C. Other RRQ Impacts Resulting from Taking Bonus Depreciation**					
61	Manufacturer's Tax Deduction Adjustment		N/A	N/A	N/A	
62	Working Cash Adjustment		3	1	(1)	Proportion from Summary L62
63	ITCC Adjustment		2	2	3	Inputs L28
64	**Change in Annual RRQ on Other Impacts**		5	4	2	sum(L61:L63)
65						
66	**Total Change in Annual Revenue Requirements**		**(2)**	**(14)**	**(19)**	L45+L58+L64
67	Accumulated Revenue Requirements		(2)	(16)	(35)	ACC(L66)

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Gas Transmission & Storage Revenue Requirements (RRQ) Estimation Model
(In Millions of Dollars)

Line No.	Description	2010	2011	2012	2013	2014	Source
1	A. **Impact of Tax Relief Act on Adopted Additions**						
2	Sep thru Dec 2010 Additions						
3	**TRA Qualified Capital Additions**	146					Attachment 6, L5
4	TRA Bonus Depreciation Factor	100%	0%	0%	0%	0%	GT ROs
5	TRA Bonus Depreciation Amount	146	0	0	0	0	L3*L4
6	Pre-TRA Depreciation Factor	52.60%	4.93%	4.42%	3.96%	3.55%	GT ROs
7	Pre-TRA Depreciation	77	7	6	6	5	L3*L6
8	TRA Incremental Bonus Depreciation	69	(7)	(6)	(6)	(5)	L5-L7
9	2011 Additions						
10	TRA Qualified Capital Additions		144				Attachment 6, L5
11	TRA Bonus Depreciation Factor		100%	0%	0%	0%	GT ROs
12	TRA Bonus Depreciation Amount		144	0	0	0	L10*L11
13	Standard Depreciation Factor		5.20%	9.86%	8.83%	7.91%	GT ROs
14	Standard Depreciation		8	14	13	11	L10*L13
15	TRA Incremental Bonus Depreciation		137	(14)	(13)	(11)	L12-L14
16	2012 Additions						
17	TRA Qualified Capital Additions			115			Attachment 6, L5
18	TRA Bonus Depreciation Factor			52.60%	4.93%	4.42%	GT ROs
19	TRA Bonus Depreciation Amount			60	6	0	L17*L18
20	Standard Depreciation Factor			5.20%	9.86%	8.83%	GT ROs
21	Standard Depreciation			6	11	10	L17*L20
22	TRA Incremental Bonus Depreciation			54	(6)	(10)	L19-L21
23	Total TRA Incremental Depreciation	69	130	34	(24)	(27)	L8+L15+L22
24							
25	Incremental Deferred Tax						
26	Tax Rate	35%	35%	35%	35%	35%	Attachment 8, L5
27	Current Year Deferred Tax	24	45	12	(8)	(9)	L24*L26
28	Accumulated Deferred Tax	24	70	81	73	64	ACC(L27)
29	Rate Base Adjustment - Average Year						
30	Deferred Taxes		(43)	(74)	(78)	(69)	Previous Year L28 Plus 41.66% of Current Year L27 (Negative)
31							
32	Net Operating Loss (NOL)						
33	Adopted Taxable Income		132	132	132	132	Inputs L7
34	Less: Additional Investment Tax Deductible Loss		0	0	0	0	RO Taxable Income as % times Incremental Plant
35	Less: TRA Bonus Depreciation on Adopted Additions		(130)	(34)	24	27	L23
36	Less: TRA Bonus Depreciation on Additional Investment		0	0			L50*L11 and L54*L18
37	Carry-Forward		2	98	156	159	sum(L33:L36)
38	Accumulated Carry-Forward						
39	Tax Rate						
40	Deferred Tax Adjustment						
41	NOL Deferred Tax Asset		5	7	0	N/A	Proportion from Summary L41
42							
43	Total Rate Base Adjustment		(38)	(68)	(78)	(69)	L30+L41
44	Pre-Tax Cost of Capital (%)		12.92%	12.92%	12.92%	12.92%	Attachment 8
45	**Change in Annual RRQ on Adopted Capital Additions**		(5)	(9)	(10)	(9)	L43*L44
46	Accumulated Revenue Requirements on Adopted Additions		(5)	(14)	(24)	(33)	ACC(L45)
47							
48	B. **Additional Utility Infrastructure Investment**						
49	2011 Additions						
50	TRA Qualified Capital Additions		0				Inputs L14
51	Annual Revenue Requirements Factor		5.22%	10.36%	10.19%	9.99%	GT ROs
52	Revenue Requirements		0	0	0	0	L50*L51
53	2012 Additions						
54	TRA Qualified Capital Additions			0			Inputs L14
55	Annual Revenue Requirements Factor			6.29%	12.39%	12.01%	GT ROs
56	Revenue Requirements			0	0	0	L54*L55
57							
58	**Annual RRQ on Additional Investment**		0	0	0	0	L52+L56
59							
60	C. **Other RRQ Impacts Resulting from Taking Bonus Depreciation**						
61	Manufacturer's Tax Deduction Adjustment		N/A	N/A	N/A	N/A	
62	Working Cash Adjustment		2	1	(0)	N/A	Proportion from Summary L62
63	ITCC Adjustment		N/A	N/A	N/A	N/A	
64	**Change in Annual RRQ on Other Impacts**		2	1	(0)	0	sum(L61:L63)
65							
66	**Total Change in Annual Revenue Requirements**		**(3)**	**(8)**	**(10)**	**(9)**	L45+L58+L64
67	Accumulated Revenue Requirements		(3)	(11)	(21)	(30)	ACC(L66)

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Revenue Requirements Estimation Model
Model Assumptions and Inputs
(In Millions of Dollars)

Line No.				2010	2011	2012	2013	Source
1	**A.**	**Impact of Tax Relief Act on Adopted Additions**						
2								
3		**Adopted Taxable Income**						
4		Electric Generation		198	368			2011 GRC RO Model; Decision 11-05-018, Attachment 2, Table 3-3, Col (B), L42
5		Electric Distribution		621	803			2011 GRC RO Model; Decision 11-05-018, Attachment 4, Table 1-3 (ADOPTED), Col (B), L42
6		Gas Distribution		166	212			2011 GRC RO Model; Decision 11-05-018, Attachment 2, Table 2-3, Col (B), L42
7		Gas Transmission		132	132			2011 GT&S RO Model (Decision 11-04-031)
8			Total	1,118	1,515			
9								
10	**B.**	**Incremental Additional Infrastructure Investment**						
11		Electric Generation						Electric Generation Input for Section B Incremental Infrastructure Investment
12		Electric Distribution						Electric Distribution Input for Section B Incremental Infrastructure Investment
13		Gas Distribution						Gas Distribution Input for Section B Incremental Infrastructure Investment
14		Gas Transmission						Gas Transmission and Storage Input for Section B Incremental Infrastructure Investment
15			**Total**		-	-		
16								
17	**C.**	**Other RRQ Impacts Resulting from Taking Bonus Depreciation**						
18								
19	**i**	**Manufacturer's Tax Deduction (%)**						
20		Electric Generation			9%	9%	9%	
21								
22	**ii**	**Working Cash - Ratebase Impact (%)**						
23		Federal Income Tax			19%			Attachment 10
24		Deferred Federal Income Taxes			11%			Attachment 10
25								
26	**iii**	**ITCC**						
27		Electric Distribution			7	9	11	Attachment 12
28		Gas Distribution			2	2	3	Attachment 12
29			Total		9	12	14	

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Attachment 6

Forecasted/Adopted Capital Additions (2011 GRC and 2011 GT&S)

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Forecasted/Adopted Capital Additions (2011 GRC and 2011 GT&S)
($ in millions)

Line No.		Forecasted/Adopted Capital Additions 2010 Sep-Dec	2011	2012	Audit Experience Factor (%)	TRA** Qualified Capital Additions 2010 Sep-Dec	2011	2012
		(a)	(b)	(c)	(d)	(a x d)	(b x d)	(c x d)
	2011 General Rate Case							
1	Electric Generation*	292	336	336	86.35%	253	290	290
2	Electric Distribution	426	1,301	1,301	95.40%	406	1,241	1,241
3	Gas Distribution	105	360	360	94.75%	99	341	341
4	Sub-total	823	1,997	1,997		758	1,873	1,873
	2011 Gas Transmission & Storage Rate Case							
5	Gas Transmission & Storage	152	151	120	95.60%	146	144	115
6	**Total**	**975**	**2,149**	**2,117**		**903**	**2,017**	**1,987**

***** Colusa Generating Plant was excluded from 2010 Capital Additions since it was constructed over the 2008 thru 2010 period. More than 90% of the project cost was incurred prior to September 8, 2010.

** TRA is the same as the Tax Relief Act.

Advice 3216-G-A/3859-E-A

Attachment 7

Capital Additions by Line of Business (LOB) and Major Work Category (MWC)

New MWCs may replace current MWCs listed below so as to provide greater reporting granularity. (See PG&E's Budget Report filed with the CPUC on August 3, 2011)

Pacific Gas & Electric Company
Tax Act Memorandum Account (TAMA)
Capital Additions by Line of Business (LOB) and Major Work Category (MWC)
($ in thousands)

Line No.		Major Work Category	Section B: Incremental Investment Eligibility	Adopted Capital Additions 2011 Direct Including General	Common Allocation	Total	2012 Direct Including General	Common Allocation	Total
			(a)	(b)	(c)	(d = b+c)	(e)	(f)	(g = e+f)
		2011 General Rate Case (GRC)							
		Electric Distribution							
1	03	Office Furniture & Equipment	Ancillary	-	36	36	-	36	36
2	04	Fleet / Auto Equip	Ancillary	-	44,326	44,326	-	44,326	44,326
3	05	Tools & Equipment	Ancillary	1,296	1,442	2,738	1,296	1,442	2,738
4	06	E Distr New Capacity - Line	Eligible	86,363	-	86,363	86,363	-	86,363
5	07	E Dist Replace/Reinforce Poles	Eligible	54,121	-	54,121	54,121	-	54,121
6	08	E Dist Mitigate Recur Outages	Eligible	12,000	-	12,000	12,000	-	12,000
7	09	E Dist Automation & Protection	Ancillary	30,991	-	30,991	30,991	-	30,991
8	10	E Dist Work Requested by Other[3]	Eligible	58,388	-	58,388	58,388	-	58,388
9	12	Implement Environment Projects	Eligible	-	1,206	1,206	-	1,206	1,206
10	16	E Dist Customer Connects[3]	Eligible	288,706	-	288,706	288,706	-	288,706
11	17	E Dist Emergency Response	Eligible	112,061	-	112,061	112,061	-	112,061
12	19	Special Programs	Ineligible	(3,453)	-	(3,453)	(3,453)	-	(3,453)
13	21	Purchase/Install-Other Capital	Ancillary	114	-	114	114	-	114
14	25	Install New Electric Meters[3]	Eligible	19,044	-	19,044	19,044	-	19,044
15	28	EV - Station Infrastructure	Ineligible	996	-	996	996	-	996
16	30	E Dist WRO - Rule 20A	Eligible	72,107	-	72,107	72,107	-	72,107
17	46	E Distr New Capacity - Substat	Eligible	111,373	-	111,373	111,373	-	111,373
18	48	E Dist Replace Subst Equipment	Eligible	15,852	-	15,852	15,852	-	15,852
19	49	E T&D Mainline Prot & Rebuild	Eligible	27,137	-	27,137	27,137	-	27,137
20	53	IT - Applications	Ancillary	5,605	5,020	10,624	5,605	5,020	10,624
21	54	E Dist Replace Subst Transform	Eligible	67,151	-	67,151	67,151	-	67,151
22	56	E Dist Replace Underground Cbl	Eligible	46,576	-	46,576	46,576	-	46,576
23	57	E Dist Prev Maintenance-Facts	Eligible	117,467	-	117,467	117,467	-	117,467
24	58	E Dist Repl Substation Safety	Eligible	5,757	-	5,757	5,757	-	5,757
25	59	E Dist Repl Subst-Emergency	Eligible	28,900	-	28,900	28,900	-	28,900
26	78	Manage Buildings	Ancillary	-	9,482	9,482	-	9,482	9,482
27	79	Land Management	Ineligible	-	2,375	2,375	-	2,375	2,375
28	85	IT - Infrastructure	Ancillary	2,873	37,935	40,808	2,873	37,935	40,808
29	87	Office Equipment	Ancillary	4,396	85	4,481	4,396	85	4,481
30	88	Office Furniture	Ancillary	-	1,769	1,769	-	1,769	1,769
31	95	ED Major Emergency[3]	Eligible	31,616	-	31,616	31,616	-	31,616
32		**Sub-total Electric Distribution**		1,197,437	103,675	1,301,112	1,197,437	103,675	1,301,112
		Gas Distribution							
33	03	Office Furniture & Equipment	Ancillary	-	18	18	-	18	18
34	04	Fleet / Auto Equip	Ancillary	-	21,728	21,728	-	21,728	21,728
35	05	Tools & Equipment	Ancillary	1,060	707	1,767	1,060	707	1,767
36	12	Implement Environment Projects	Eligible	-	591	591	-	591	591
37	14	Gas Pipeline Replacement Pgm	Eligible	118,432	-	118,432	118,432	-	118,432
38	19	Special Programs	Ineligible	(2,825)	-	(2,825)	(2,825)	-	(2,825)
39	21	Purchase/Install-Other Capital	Ancillary	94	-	94	94	-	94
40	27	Gas Meter Protection-Capital	Eligible	570	-	570	570	-	570
41	29	G Dist Customer Connects[3]	Eligible	61,579	-	61,579	61,579	-	61,579
42	31	NGV - Station Infrastructure	Eligible	3,534	-	3,534	3,534	-	3,534
43	47	G Dist New Capacity - Gas	Eligible	12,266	-	12,266	12,266	-	12,266
44	50	G Dist Reliability	Eligible	19,849	-	19,849	19,849	-	19,849
45	51	G Dist Work Requested by Other[3]	Eligible	20,511	-	20,511	20,511	-	20,511
46	52	G Dist Emergency Response	Eligible	253	-	253	253	-	253
47	53	IT - Applications	Ancillary	4,586	2,461	7,046	4,586	2,461	7,046
48	74	Install New Gas Meters[3]	Eligible	65,614	-	65,614	65,614	-	65,614
49	78	Manage Buildings	Ancillary	-	4,648	4,648	-	4,648	4,648
50	79	Land Management	Ineligible	-	1,164	1,164	-	1,164	1,164
51	85	IT - Infrastructure	Ancillary	-	18,595	18,595	-	18,595	18,595
52	87	Office Equipment	Ancillary	3,597	42	3,638	3,597	42	3,638
53	88	Office Furniture	Ancillary	-	867	867	-	867	867
54		**Sub-total Gas Distribution**		309,121	50,819	359,940	309,121	50,819	359,940

New MWCs may replace current MWCs listed below so as to provide greater reporting granularity. (See PG&E's Budget Report filed with the CPUC on August 3, 2011)

Pacific Gas & Electric Company
Tax Act Memorandum Account (TAMA)
Capital Additions by Line of Business (LOB) and Major Work Category (MWC)
($ in thousands)

				Adopted Capital Additions					
				2011			2012		
Line No.		Major Work Category	Section B: Incremental Investment Eligibility	Direct Including General	Common Allocation	Total	Direct Including General	Common Allocation	Total
			(a)	(b)	(c)	(d = b+c)	(e)	(f)	(g = e+f)
		2011 General Rate Case (GRC)							
		Electric Generation							
55	03	Office Furniture & Equipment	Ancillary	200	18	218	200	18	218
56	04	Fleet / Auto Equip	Ancillary	2,192	22,304	24,496	2,192	22,304	24,496
57	05	Tools & Equipment	Ancillary	2,831	726	3,557	2,831	726	3,557
58	11	Power Gen Licenses & Permits	Eligible	14,883	-	14,883	14,883	-	14,883
59	12	Implement Environment Projects	Eligible	8,874	607	9,481	8,874	607	9,481
60	13	Power Gen Safety & Regulatory	Eligible	97,096	-	97,096	97,096	-	97,096
61	20	DCPP Capital	Eligible	40,648	-	40,648	40,648	-	40,648
62	53	IT - Applications	Ancillary	-	2,526	2,526	-	2,526	2,526
63	78	Manage Buildings	Ancillary	10,077	4,771	14,848	10,077	4,771	14,848
64	79	Land Management	Ineligible	-	1,195	1,195	-	1,195	1,195
65	81	Power Gen Maint Relabil/Avail	Eligible	96,197	-	96,197	96,197	-	96,197
66	85	IT - Infrastructure	Ancillary	9,623	19,088	28,712	9,623	19,088	28,712
67	87	Office Equipment	Ancillary	-	43	43	-	43	43
68	88	Office Furniture	Ancillary	1,546	890	2,436	1,546	890	2,436
69		**Sub-total Electric Generation**		284,168	52,167	336,335	284,168	52,167	336,335
70		**Chargebacks**	Ineligible	(4,664)	-	(4,664)	(4,664)	-	(4,664)
71		**Total 2011 General Rate Case**		1,786,061	206,662	1,992,723	1,786,061	206,662	1,992,723
		2011 Gas Transmission & Storage (GT&S) Rate Case							
72	03	Office Furniture & Equipment	Ancillary		3	3		1	1
73	04	Fleet / Auto Equip	Ancillary		4,293	4,293		1,741	1,741
74	05	Tools & Equipment	Ancillary	294	140	433	314	356	670
75	12	Implement Environment Projects	Eligible	4,345	117	4,462	7,405	46	7,451
76	53	IT - Applications	Ancillary		486	486		373	373
77	26	G Trans - New Business[3]	Eligible	29,184		29,184 [1]	3,235		3,235
78	73	G Trans New Capacity - Gas	Eligible	16,065		16,065	4,718		4,718
79	75	G Trans Reliability - Pipeline	Eligible	13,368		13,368	28,688		28,688
80	76	G Trans Reliability - Station	Eligible	42,031	683	42,715 [2]	33,518	1,299	34,817
81	78	Manage Buildings	Ancillary	300	918	1,218	103	2,595	2,698
82	79	Land Management	Ineligible		230	230			0
83	83	G Trans Work Requested by Othr[3]	Eligible	8,961		8,961	8,593		8,593
84	84	G Trans Gathering System	Eligible	2,248		2,248	2,159		2,159
85	85	IT - Infrastructure	Ancillary		3,674	3,674		1,137	1,137
86	87	Office Equipment	Ancillary		8	8		2	2
87	88	Office Furniture	Ancillary		171	171		67	67
88	91	Pwr Gen Metering:PG&E Rev Mtrs	Eligible	2,280		2,280	921		921
89	98	Pipeline Integrity Pgm Mgmt	Eligible	21,183		21,183	22,362		22,362
90	96	Separately Funded Capital	Ineligible	165		165	175		175
91		**Total 2011 Gas Trans. & Storage Rate Case**		140,423	10,724	151,147	112,190	7,617	119,807
92		**GRAND TOTAL 2011 GRC & 2011 GT&S Cases**		**1,926,484**	**217,386**	**2,143,870**	**1,898,252**	**214,279**	**2,112,530**

Notes:

1 Exclude GT&S adder projects (See GT&S Settlement Decision 11-04-031, Appendix A, p.8 - p.10).

2 Exclude Delevan K2 project

3 These MWC's include capital expenditures that are generally eligible for bonus depreciation but will be ineligible for incremental capital additions in Section B of the memorandum account because spending in these areas is almost entirely driven by exogenous events (new customer connections, major storm activity, etc.) and not influenced by savings available under the Tax Relief Act. Deferred tax benefits related to adopted plant additions in these MWCs will still be captured in Section A of the account.

Advice 3216-G-A/3859-E-A

Attachment 8

Adopted Cost of Capital

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Adopted Cost of Capital (Decision 09-10-016)

Line No.	Description	Capitalization	Cost	Weighted Cost	Tax Gross-up Factor	Pre-Tax Cost
		(a)	(b)	(c = a x b)	(d)	(e = c x d)
1	Debt	46.00%	6.05%	2.78%	1.00	2.78%
2	Preferred	2.00%	5.68%	0.11%	1.69	0.19%
3	Common Equity	52.00%	11.35%	5.90%	1.69	9.96%
4	Total	100.00%		8.79%		**12.92%**
						(To Attachment 5)
	Tax Gross-up Factor					
5	Federal Income Tax Rate	35.00%				
6	State Income Tax Rate	8.84%				
7	Composite Rate	40.75%				
8	Factor*	1.69				
9	Factor Excluding State Dedn for FIT*	1.78	(Used for Sec. 199 Manufacturer's Tax Deduction Calculation)			

* Note: Excludes Franchise Fees and Uncollectibles

Advice 3216-G-A/3859-E-A

Attachment 9

Section 199 Manufacturer's Tax Deduction (MTD) Benefit on Electric Generation

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Section 199 Manufacturer's Tax Deduction (MTD) Benefit on Electric Generation
(In Millions of Dollars)

Line No.	**Description**	**Year 2011**	**Source**
1	Adopted Federal Taxable Income	367.7	2011 GRC Settlement Decision RO
2	x Mfg. Dedn. %	0.1	Manufacturer's Tax Deduction (%)
3	Mfg. Dedn.	33.1	L1*L2
4	x Federal Income Tax Rate	0.4	
5	Tax Benefit	11.6	L3*L4
6	x Tax Gross-up factor	1.8	
7	**MTD Benefit**	**(20.6)**	L5*L6

Advice 3216-G-A/3859-E-A

Attachment 10

Working Cash

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Working Cash
2011 GRC Settlement Bonus Depreciation Update

Pacific Gas and Electric Company
2011 CPUC General Rate Case (SETTLEMENT)
Year 2011 Lead Lag Study at Proposed Rates
Total Company GRC
(Thousands of Dollars)

FIT Percentage = Ratebase change divided by FIT change:
19% = 93,401 / 486,778

Deferred FIT Percentage = Ratebase change divided by deferred income tax change:
11% = 66,676 / 596,310

Line No.		Amount (A)	Average Daily Amount (B)	Avg No of Days Lag in Paying Expenses (C)	Weighted Average (D)	Rate Base Impact (E)	Line No.
1	Natural Gas Purchased	0	0	41.17	0	0	1
2	Fuel Oil	0	0	15.45	0	0	2
3	Geothermal Steam	0	0	45.54	0	0	3
4	Nuclear Fuel	0	0	30.00	0	0	4
5	Purchased Power	0	0	40.48	0	0	5
6	Depreciation	0	0	0.00	0	0	6
7	Decommissioning	0	0	30.59	0	0	7
8	Federal Income Tax, Current @ Proposed	(486,778)	(1,334)	110.85	(147,830)	93,401	8
9	State Corp. Franchise Tax @ Proposed	259	1	104.82	74	(45)	9
10	Income Taxes, Deferred	596,310	1,634	0.00	0	66,676	10
11	Ad Valorem Tax	0	0	44.24	0	0	11
12	S.F. Payroll Expense Tax	0	0	88.62	0	0	12
13	FICA Tax (net of	0	0	12.62	0	0	13
14	Federal Unempl	0	0	75.08	0	0	14
15	State Unemploy	0	0	76.08	0	0	15
16	Settlements and	0	0	27.91	0	0	16
17	Pensions	0	0	61.01	0	0	17
18	Savings Fund Plan	0	0	11.62	0	0	18
19	Group Life Insurance	0	0	0.00	0	0	19
20	Health, Vision & Dental Plans	0	0	(0.38)	0	0	20
21	Post-Retirement Medical	0	0	174.50	0	0	21
22	Franchise Requirements	(1)	0	246.36	(1)	1	22
23	Payroll (net of STIP)	0	0	12.16	0	0	23
24	Goods and Services	0	0	39.64	0	0	24
25	Materials from Storeroom	0	0	0.00	0	0	25
26	FICA Tax (STIP)	0	0	167.50	0	0	26
27	Short-Term Incentive Plan (STIP)	0	0	166.80	0	0	27
28	Research and Development	0	0	0.00	0	0	28
29	Project Amortization	0	0	0.00	0	0	29
30	Total	109,790	301	(491.22)	(147,756)	160,032	30
31	Avg No of Days Lag in the Collection of Revenue			40.81			31
32	Less Avg No of Days Lag in the Payment of Exps			(491.22)			32
33	Excess No. of Days Lag in the Collection of Revenues over the Payment of Expenses			532.03			33
34	Average Daily Operating Expenses		301				34
35	Working Cash Capital Requirement Resulting from the Lag in the Collection of Revenues Being Greater than the Lag in the Payment of Expenses					160,032	35

Advice 3216-G-A/3859-E-A

Attachment 11

Approved Advice 3176-G3784-E

STATE OF CALIFORNIA

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

Edmund G. Brown Jr., *Governor*

February 28, 2011

Advice Letter 3176-G/3784-E

Jane K. Yura
Vice President, Regulation and Rates
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10B
P.O. Box 770000
San Francisco, CA 94177

Subject: Revision of PG&E's Tariffs to Reflect the Extension of Lower ITCC Rates Due to Tax Law Changes

Dear Ms. Yura:

Advice Letter 3176-G/3784-E is effective September 9, 2010.

Sincerely,

Julie A. Fitch, Director
Energy Division

Pacific Gas and Electric Company™

Jane K. Yura
Vice President
Regulation and Rates

Mailing Address
Mail Code B10B
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177

Fax: 415.973.6520

December 30, 2010

Advice 3176-G/3784-E
Pacific Gas and Electric Company (U 39-M)

Public Utilities Commission of the State of California

Subject: **Revision of PG&E's Tariffs to Reflect the Extension of Lower ITCC Rates Due to Tax Law Changes**

Pacific Gas and Electric Company (PG&E) hereby submits for filing revisions to Gas and Electric Preliminary Statement Parts P and J. The affected tariff sheets are listed in Attachment 1.

Purpose

This filing is necessary in order to revise PG&E's Gas and Electric Preliminary Statements Parts P and J, *Income Tax Component of Contributions Provision*, to reflect recent changes in federal tax law. These changes temporarily extend and further reduce the tax factor used to compute the "Income Tax Component of Contribution (ITCC)" associated with Contributions in Aid of Construction.

In this advice letter, PG&E requests that the California Public Utilities Commission (Commission) further reduce the temporarily lower ITCC tax factor from 0.20 (20 percent) for gas and 0.22 (22 percent) for electric in effect on December 31, 2009 to 0.08 (8 percent) for gas and 0.08 (8 percent) for electric as a result of temporary 100% expensing provided by the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312). This temporary 100% expensing lasts until December 31, 2011. PG&E would apply the reduced ITCC tax factor retroactive to September 9, 2010, and continue it at that level through December 31, 2011.

The Act further extends 50% bonus depreciation beginning on January 1, 2012 through December 31, 2012. As a result of this extension, the ITCC factor for both electric and gas will be 0.22 (22 percent) beginning January 1, 2012 and through December 31, 2012. Previously, the gas and electric tax factors differed because gas assets had a temporary federal tax depreciable life of 15 years, whereas electric distribution property has a life of 20 years. The temporary 15 year depreciable life for gas property expires on December 31, 2010 and was not extended. As such, on January 1, 2012 both gas and electric distribution property will have a depreciable life of 20 years, resulting in an ITCC tax factor of 0.22 (22 percent) for both gas and electric. The ITCC tax factor of 0.22 (22 percent) for gas was included in Advice Filing 2466-G/2386-E approved May 5, 2004. The reduced

ITCC tax factor has been calculated, as set forth in Attachment 2, by using Method 5 as described in Decision (D.) 87-09-026 and D.87-12-028 in OII 86-11-109.

Background

Since the beginning of 2008, the ITCC Rate has been modified as a result of changes in federal tax law.

- February 13, 2008 – President Bush signed into law the Economic Stimulus Act of 2008 which provided for a temporarily lower ITCC tax factor used to compute the "Income Tax Component of Contribution associated with Contributions in Aid of Construction. This legislation modified a depreciation provision, Section 168(k) to the Internal Revenue Code, entitled, "Special allowance for certain property acquired after September 10, 2001, and before January 1, 2005."

  February 22, 2008 – PG&E filed Advice 2906-G/3212-E to implement the temporarily lower ITCC tax factor of 0.20 (20 percent) for gas and 0.22 (22 percent) on property contributed to PG&E after March 1, 2008.

  March 19, 2008 – Advice 2906-G/3212-E was approved with an effective date of March 1, 2008.

- December 2, 2008 – PG&E filed Advice 2975-G/3372-E to notify the Commission that the lower ITCC tax factors under the Economic Stimulus Act of 2008 would expire on December 31, 2008 unless Congress extended the depreciation provision. With no extension under way at that time, PG&E requested that the ITCC tax factors be returned to the statutory levels of 0.31 (31 percent) for gas and 0.34 (34 percent) for electric, calculated using the current income tax rates of 8.84 percent (California) and 35 percent (federal).

  January 15, 2009 -- Advice 2975-G/3372-E was approved on January 15, 2009 with an effective date of January 1, 2009 and in effect restoring the higher tax factors.

- February 17, 2009 – President Obama signed into law the American Recovery and Reinvestment Act of 2009 (the "Recovery Act"; H.R. 1). Section 1201 of the Recovery Act extended the modified depreciation provisions of the Economic Stimulus Act of 2008, which in turn extended the reduction of the ITCC tax factors.

  February 20, 2009 – PG&E filed Advice 2998-G/3424-E to implement the extension of the temporarily lower ITCC tax factor of 0.20 (20 percent) for gas and 0.22 (22 percent) for electric in effect as of December 31, 2008.

March 19, 2009 – Advice 2998-G/3424-E was approved and the reduced ITCC tax factors were extended with an effective date of January 1, 2009.

- December 11, 2009 – PG&E filed Advice 3070-G/3572-E, which notified the Commission that the lower ITCC tax factors under the Recovery Act would expire on December 31, 2009 unless Congress extended the depreciation provision. With no extension under way at that time, PG&E requested that the ITCC tax factors be returned to the statutory levels of 0.31 (31 percent) for gas and 0.34 (34 percent) for electric, calculated using the current income tax rates of 8.84 percent (California) and 35 percent (federal).

  The tax factor for gas in Advice 3070-G also reflected the temporary federal depreciable tax life for gas distribution property of 15 years as adopted by the Energy Tax Incentives Act of 2005. This temporary federal depreciable tax life for gas distribution property is set to sunset on December 31, 2010.

  January 7, 2010 – Advice 3070-G/3572-E was approved with an effective date of January 1, 2010 and in effect restoring the higher tax factors.

- September 27, 2010 – President Obama signed the Small Business Jobs Act of 2010 (Act) (H.R. 5297) into law. Section 2022 of the Act extends the depreciation provision (Section 168(k) of the Internal Revenue Code, entitled, “Special allowance for certain property acquired after September 10, 2001, and before January 1, 2005.”) which had resulted in the temporarily lower ITCC tax factors.

- October 27, 2010 – PG&E filed Advice 3160-G/3750-E to extend the temporarily lower ITCC tax factor of 0.20 (20 percent) for gas and 0.22 (22 percent) for electric in effect as of December 31, 2009 through December 31, 2010.

  November 29, 2010 – Advice 3160-G/3750-E was approved and the reduced ITCC tax factors were extended with an effective date of January 1, 2010.

- December 17, 2010 – President Obama signed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) into law. Section 401 of the Act extends the depreciation provision (Section 168(k) of the Internal Revenue Code, entitled, “Special allowance for certain property acquired after September 10, 2001, and before January 1, 2005.”) which had resulted in the temporarily lower ITCC tax factors. A copy of Section 401 of the Tax Relief Act of 2010 amending Section 168(k) of the Internal Revenue Code is enclosed in Attachment 3.

In addition, the Tax Relief Act of 2010 provides for a temporary 100% expensing of property placed in service after September 8, 2010 and before January 1, 2012.

The Tax Relief Act of 2010 provides for a further reduced ITCC rate for the period September 9, 2010 through December 31, 2011, at which time the ITCC rate will revert to the temporarily reduced rate under the depreciation provisions of the American Recovery and Reinvestment Act of 2009, the Economic Stimulus Act of 2008 and the Small Business Jobs Act of 2010 to December 31, 2012.

Tariff Revisions

Gas Preliminary Statement Part P*, Section 5. a,* has been revised to reflect a further reduction in the ITCC tax factor to 0.08 (8 percent) on property contributed to PG&E after September 8, 2010 and before January 1, 2012. Property contributed to PG&E on or after January 1, 2012, will be subject to the previously authorized ITCC tax factor of 22 percent.

In a similar fashion, Electric Preliminary Statement Part J*, Section 5. a,* has been revised to reflect a further reduction in the ITCC tax factor to 0.08 (8 percent) on property contributed to PG&E after September 8, 2010 and before January 1, 2012. Property contributed to PG&E on or after January 1, 2012, will be subject to the previously authorized ITCC tax factor of 22 percent.

Protests

Anyone wishing to protest this filing may do so by sending a letter by **January 19, 2011**, which is 20 days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

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

Facsimile: (415) 703-2200
E-mail: mas@cpuc.ca.gov and jnj@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4005 and Honesto Gatchalian, Energy Division, at the address shown above.

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

Pacific Gas and Electric Company
Attention: Jane K. Yura
Vice President, Regulation and Rates
77 Beale Street, Mail Code B10B
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-6520
E-Mail: PGETariffs@pge.com

Effective Date

PG&E requests that this Tier 1 advice filing become effective on **September 9, 2010**.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes to the General Order 96-B service list should be directed to 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.

Jane Yura /HAB

Vice President – Regulation and Rates

Attachments:

Attachment 1:	Tariff Revisions
Attachment 2:	The Extended ITCC Tax Factor
Attachment 3:	Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010

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 M)**

Utility type:	Contact Person: Greg Backens
☑ ELC ☑ GAS	Phone #: 415-973-4390
☐ PLC ☐ HEAT ☐ WATER	E-mail: GAB4@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) #: **3176-G/3784-E** **Tier: 1**

Subject of AL: **Revision of PG&E's Tariffs to Reflect the Extension of Lower ITCC Rates Due to Tax Law Changes**

Keywords (choose from CPUC listing): **Taxes**

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.87-09-026, D.87-12-028

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: **September 9, 2010** No. of tariff sheets: **6**

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

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

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

Tariff schedules affected: **Gas Preliminary Statement Part P – Income Tax Component of Contributions Provision, Electric Preliminary Statement Part J – Income Tax Component of Contributions Provision**

Service affected and changes proposed: N/A

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

CPUC, Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave., San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Jane Yura, Vice President, Regulation and Rates
77 Beale Street, Mail Code B10B
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

ATTACHMENT 1
Advice 3176-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
28729-G	GAS PRELIMINARY STATEMENT PART P INCOME TAX COMPONENT OF CONTRIBUTIONS PROVISION Sheet 1	28552-G
28730-G	GAS TABLE OF CONTENTS Sheet 1	28660-G
28731-G	GAS TABLE OF CONTENTS Sheet 4	28640-G

GAS PRELIMINARY STATEMENT PART P
INCOME TAX COMPONENT OF CONTRIBUTIONS PROVISION

P. INCOME TAX COMPONENT OF CONTRIBUTIONS PROVISION

1. GENERAL: All Contributions in Aid of Construction (Contributions, or CIAC) made to PG&E shall include a charge to cover PG&E's resulting estimated liability for Federal and State Income Tax. PG&E shall collect the Federal Income Tax on Contributions made on or after February 11, 1987, for the unit costs under Rule 15 and January 1, 1987, for all other Contributions. California Corporate Franchise Tax shall be collected beginning January 1, 1992.

2. DEFINITIONS:

   a. Contributions: Contributions shall include, but are not limited to, cash, services, facilities, labor, property, and related income taxes provided by a person or agency to PG&E. The value of all contributions shall be based on PG&E's estimates or a contract value acceptable to PG&E. Contributions shall consist of two components, as follows:

      1) Income Tax Component of Contribution (ITCC); and
      2) The balance of the contribution, excluding income taxes (Balance of Contribution).

   b. Government Agency: For purposes of administering this part of the preliminary statement, a government agency shall include the Federal Government, a California state, county, or local government agency.

3. APPLICABILITY: The ITCC shall apply to Contributions including but not limited to charges under the applicable Rate Schedule and Rules, except as provided in Section 4 below.

4. GOVERNMENT AGENCY EXEMPTIONS:

   a. Public Benefit: A contribution for a project will be considered a public benefit if, in the opinion of PG&E, the government agency making the contribution can clearly show that the contribution will benefit the public as a whole. Internal Revenue Service (IRS) Notice 87-82 dated December 3, 1987, excludes from the Public Benefit Exemption any government agency contribution associated with projects causing new or increased usage of utility service.

   b. Condemnation: Contributions resulting from condemnation of company facilities, or the threat or imminence thereof may be excluded from the ITCC requirement when supported by evidence acceptable to PG&E provided by the government agency.

5. DETERMINATION OF ITCC:

   a. The ITCC shall be calculated by multiplying the Balance of Contribution by the tax factor of 0.08 (8 percent). The 8 percent tax factor shall be applicable to contributions received by PG&E on or after September 9, 2010, and before January 1, 2012. As of January 1, 2012, the ITCC shall be calculated by multiplying the Balance of Contribution by the tax factor of 0.22 (22 percent). The 22 percent tax factor shall be applicable to contributions received by PG&E on or after January 1, 2012. PG&E will file an advice letter to reflect any changes in the tax factor which would cause an increase or decrease of five percentage points or more. (T) I I I (T)

   b. The tax factor is established by using Method 5 as set forth in Decisions 87-09-026 and 87-12-028 in OII 86-11-019.

(Continued)

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Sheet 4

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ATTACHMENT 1
Advice 3784-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
29937-E	ELECTRIC PRELIMINARY STATEMENT PART J INCOME TAX COMPONENT OF CONTRIBUTIONS PROVISION Sheet 1	29667-E
29938-E	ELECTRIC TABLE OF CONTENTS Sheet 1	29678-E
29939-E	ELECTRIC TABLE OF CONTENTS PRELIMINARY STATEMENT Sheet 6	29669-E

ELECTRIC PRELIMINARY STATEMENT PART J
INCOME TAX COMPONENT OF CONTRIBUTIONS PROVISION

J. INCOME TAX COMPONENT OF CONTRIBUTIONS PROVISION

1. GENERAL: All Contributions in Aid of Construction (Contributions, or CIAC) made to PG&E shall include a charge to cover PG&E's resulting estimated liability for Federal and State Income Tax. PG&E shall collect the Federal Income Tax on Contributions made on or after February 11, 1987, for the unit costs under Rule 15 and January 1, 1987, for all other Contributions. California Corporate Franchise Tax (CCFT) shall be collected beginning January 1, 1992.

2. DEFINITIONS:

   a. Contributions: Contributions shall include, but are not limited to, cash, services, facilities, labor, property, and related income taxes provided by a person or agency to PG&E. The value of all contributions shall be based on PG&E's estimates or a contract value acceptable to PG&E. Contributions shall consist of two components, as follows:

      1) Income Tax Component of Contribution (ITCC); and
      2) The balance of the contribution, excluding income taxes (Balance of Contribution).

   b. Government Agency: For purposes of administering this part of the preliminary statement, a government agency shall include the Federal Government, a California state, county, or local government agency.

3. APPLICABILITY: The ITCC shall apply to Contributions including but not limited to charges under the applicable Rate Schedule and Rules, except as provided in Section 4 below.

4. GOVERNMENT AGENCY EXEMPTIONS:

   a. Public Benefit: A contribution for a project will be considered a public benefit if, in the opinion of PG&E, the government agency making the contribution can clearly show that the contribution will benefit the public as a whole. Internal Revenue Service (IRS) Notice 87-82 dated December 3, 1987, excludes from the Public Benefit Exemption any government agency contribution associated with projects causing new or increased usage of utility service.

   b. Condemnation: Contributions resulting from condemnation of company facilities, or the threat or imminence thereof may be excluded from the ITCC requirement when supported by evidence acceptable to PG&E provided by the government agency.

5. DETERMINATION OF ITCC:

   a. The ITCC shall be calculated by multiplying the Balance of Contribution by the tax factor of
      0.08 (8 percent). The 8 percent tax factor shall be applicable to contributions received by (T)
      PG&E on or after September 9, 2010, and before January 1, 2012. As of January 1, 2012, I
      the ITCC shall be calculated by multiplying the Balance of Contributions by the tax factor of I
      0.22 (22 percent). The 22 percent tax factor shall be applicable to contributions received by I
      PG&E on or after January 1, 2012. PG&E will file an advice letter to reflect any changes in (T)
      the tax factor which would cause an increase or decrease of five percentage points or more.

   b. The tax factor is established by using Method 5 as set forth in Decisions 87-09-026 and 87-12-028 in OII 86-11-019.

(Continued)

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PRELIMINARY STATEMENT

Sheet 6

(Continued)

Advice 3176-G/3784-E

Attachment 2

CIAC Gross-up Computation Including California Taxes

CIAC GROSS-UP COMPUTATION INCLUDING CALIFORNIA TAXES (Electric)

(A) YEAR	(B) TAX PMT/(BEN) REFLECTING CIAC OF $1,000	(C) TAX BASIS	(D) CALIFORNIA DEPRECIATION RATES	(E) CALIFORNIA RATES	(F) STATE TAX BENEFIT	(G) MODIFIED MACRS RATES	(H) FEDERAL TAX RATE	(I) FEDERAL TAX BENEFIT	(J) REMAINING CIAC PAYABLE	(K) WTD. AVG. UNRECOVERED TAX PMT.	(L) RATE OF RETURN	(M) REVENUE REQUIREMENT ON REMAINING INVESTMENT	(N) DISCOUNT FACTOR 0.12	(O) DISCOUNTED REVENUE REQUIREMENT ON REMAINING INVESTMENT
1	88.4	1,000	3.334%	8.840%	2.9473	100.000%	0.00%	0.0000	85.4527	86.9264	17.000%	14.7775	0.8929	13.1948
2	0		6.445%		5.6974	0.000%		0.0000	79.7554	82.6041	17.000%	14.0427	0.7972	11.1948
3			6.016%		5.3181	0.000%		0.0000	74.4372	77.0963	17.000%	13.1064	0.7118	9.3289
4			5.615%		4.9637	0.000%		0.0000	69.4736	71.9554	17.000%	12.2324	0.6355	7.7739
5			5.241%		4.6330	0.000%		0.0000	64.8405	67.1570	17.000%	11.4167	0.5674	6.4781
6			4.892%		4.3245	0.000%		0.0000	60.5160	62.6783	17.000%	10.6553	0.5066	5.3983
7			4.566%		4.0363	0.000%		0.0000	56.4796	58.4978	17.000%	9.9446	0.4523	4.4984
8			4.261%		3.7667	0.000%		0.0000	52.7129	54.5963	17.000%	9.2814	0.4039	3.7486
9			3.977%		3.5157	0.000%		0.0000	49.1973	50.9551	17.000%	8.6624	0.3606	3.1237
10			3.712%		3.2814	0.000%		0.0000	45.9158	47.5565	17.000%	8.0846	0.3220	2.6030
11			3.465%		3.0631	0.000%		0.0000	42.8528	44.3843	17.000%	7.5453	0.2875	2.1691
12			3.234%		2.8589	0.000%		0.0000	39.9939	41.4234	17.000%	7.0420	0.2567	1.8075
13			3.018%		2.6679	0.000%		0.0000	37.3260	38.6600	17.000%	6.5722	0.2292	1.5062
14			2.817%		2.4902	0.000%		0.0000	34.8358	36.0809	17.000%	6.1338	0.2046	1.2551
15			2.630%		2.3249	0.000%		0.0000	32.5109	33.6733	17.000%	5.7245	0.1827	1.0458
16			2.455%		2.1702	0.000%		0.0000	30.3406	31.4258	17.000%	5.3424	0.1631	0.8715
17			2.367%		2.0924	0.000%		0.0000	28.2482	29.2944	17.000%	4.9801	0.1456	0.7253
18			2.367%		2.0924	0.000%		0.0000	26.1558	27.2020	17.000%	4.6243	0.1300	0.6013
19			2.367%		2.0924	0.000%		0.0000	24.0634	25.1096	17.000%	4.2686	0.1161	0.4956
20			2.367%		2.0924	0.000%		0.0000	21.9709	23.0172	17.000%	3.9129	0.1037	0.4056
21			2.367%		2.0924	0.000%		0.0000	19.8785	20.9247	17.000%	3.5572	0.0926	0.3293
22			2.367%		2.0924			0.0000	17.7861	18.8323	17.000%	3.2015	0.0826	0.2646
23			2.367%		2.0924			0.0000	15.6937	16.7399	17.000%	2.8458	0.0738	0.2100
24			2.367%		2.0924			0.0000	13.6012	14.6474	17.000%	2.4901	0.0659	0.1641
25			2.367%		2.0924			0.0000	11.5088	12.5550	17.000%	2.1344	0.0588	0.1256
26			2.367%		2.0924			0.0000	9.4164	10.4626	17.000%	1.7786	0.0525	0.0934
27			2.367%		2.0924			0.0000	7.3239	8.3702	17.000%	1.4229	0.0469	0.0667
28			2.367%		2.0924			0.0000	5.2315	6.2777	17.000%	1.0672	0.0419	0.0447
29			2.367%		2.0924			0.0000	3.1391	4.1853	17.000%	0.7115	0.0374	0.0266
30			2.367%		2.0924			0.0000	1.0467	2.0929	17.000%	0.3558	0.0334	0.0119
31			1.184%		1.0467			0.0000	(0.0000)	0.5233	17.000%	0.0890	0.0298	0.0027
32					0.0000			0.0000	(0.0000)	(0.0000)	17.000%	0.0000	0.0266	0.0000
			100.000%		88.4000	100.000%		0.0000				188.0041		79.5651
												79.5651	/ 1000	7.9600%
	88.4							88.4000						
														8.0000%

CIAC GROSS-UP COMPUTATION INCLUDING CALIFORNIA TAXES (Gas)

(A) YEAR	(B) TAX PMT/(BEN) REFLECTING CIAC OF $1,000	(C) TAX BASIS	(D) CALIFORNIA DEPRECIATION RATES	(E) CALIFORNIA RATES	(F) STATE TAX BENEFIT	(G) MODIFIED MACRS RATES	(H) FEDERAL TAX RATE	(I) FEDERAL TAX BENEFIT	(J) REMAINING CIAC PAYABLE	(K) WTD. AVG. UNRECOVERED TAX PMT.	(L) RATE OF RETURN	(M) REVENUE REQUIREMENT ON REMAINING INVESTMENT	(N) DISCOUNT FACTOR 0.12	(O) DISCOUNTED REVENUE REQUIREMENT ON REMAINING INVESTMENT
1	88.4	1,000	2.857%	8.840%	2.5256	100.000%	0.00%	0.0000	85.8744	87.1372	17.000%	14.8133	0.8929	13.2268
2	0		5.551%		4.9071	0.000%		0.0000	80.9673	83.4209	17.000%	14.1815	0.7972	11.3054
3			5.234%		4.6269	0.000%		0.0000	76.3405	78.6539	17.000%	13.3712	0.7118	9.5174
4			4.935%		4.3625	0.000%		0.0000	71.9779	74.1592	17.000%	12.6071	0.6355	8.0120
5			4.653%		4.1133	0.000%		0.0000	67.8647	69.9213	17.000%	11.8866	0.5674	6.7448
6			4.387%		3.8781	0.000%		0.0000	63.9866	65.9256	17.000%	11.2074	0.5066	5.6780
7			4.137%		3.6571	0.000%		0.0000	60.3295	62.1580	17.000%	10.5669	0.4523	4.7799
8			3.901%		3.4485	0.000%		0.0000	56.8810	58.6052	17.000%	9.9629	0.4039	4.0238
9			3.678%		3.2514	0.000%		0.0000	53.6296	55.2553	17.000%	9.3934	0.3606	3.3874
10			3.468%		3.0657	0.000%		0.0000	50.5639	52.0968	17.000%	8.8565	0.3220	2.8516
11			3.270%		2.8907	0.000%		0.0000	47.6732	49.1186	17.000%	8.3502	0.2875	2.4005
12			3.084%		2.7263	0.000%		0.0000	44.9470	46.3101	17.000%	7.8727	0.2567	2.0207
13			2.908%		2.5707	0.000%		0.0000	42.3763	43.6616	17.000%	7.4225	0.2292	1.7010
14			2.742%		2.4239	0.000%		0.0000	39.9524	41.1643	17.000%	6.9979	0.2046	1.4319
15			2.585%		2.2851	0.000%		0.0000	37.6672	38.8098	17.000%	6.5977	0.1827	1.2054
16			2.438%		2.1552	0.000%		0.0000	35.5120	36.5896	17.000%	6.2202	0.1631	1.0146
17			2.299%		2.0323	0.000%		0.0000	33.4797	34.4959	17.000%	5.8643	0.1456	0.8541
18			2.168%		1.9165	0.000%		0.0000	31.5632	32.5215	17.000%	5.5287	0.1300	0.7189
19			2.040%		1.8034	0.000%		0.0000	29.7599	30.6615	17.000%	5.2125	0.1161	0.6052
20			2.040%		1.8034	0.000%		0.0000	27.9565	28.8582	17.000%	4.9059	0.1037	0.5086
21			2.040%		1.8034	0.000%		0.0000	26.1531	27.0548	17.000%	4.5993	0.0926	0.4257
22			2.040%		1.8034			0.0000	24.3498	25.2515	17.000%	4.2927	0.0826	0.3548
23			2.040%		1.8034			0.0000	22.5464	23.4481	17.000%	3.9862	0.0738	0.2941
24			2.040%		1.8034			0.0000	20.7431	21.6447	17.000%	3.6796	0.0659	0.2424
25			2.040%		1.8034			0.0000	18.9397	19.8414	17.000%	3.3730	0.0588	0.1984
26			2.040%		1.8034			0.0000	17.1363	18.0380	17.000%	3.0665	0.0525	0.1611
27			2.040%		1.8034			0.0000	15.3330	16.2347	17.000%	2.7599	0.0469	0.1294
28			2.040%		1.8034			0.0000	13.5296	14.4313	17.000%	2.4533	0.0419	0.1027
29			2.040%		1.8034			0.0000	11.7263	12.6279	17.000%	2.1467	0.0374	0.0803
30			2.040%		1.8034			0.0000	9.9229	10.8246	17.000%	1.8402	0.0334	0.0614
31			2.040%		1.8034			0.0000	8.1195	9.0212	17.000%	1.5336	0.0298	0.0457
32			2.040%		1.8034			0.0000	6.3162	7.2179	17.000%	1.2270	0.0266	0.0326
33			2.040%		1.8034			0.0000	4.5128	5.4145	17.000%	0.9205	0.0238	0.0219
34			2.040%		1.8034			0.0000	2.7095	3.6111	17.000%	0.6139	0.0212	0.0130
35			2.040%		1.8034			0.0000	0.9061	1.8078	17.000%	0.3073	0.0189	0.0058
36			1.025%		0.9061			0.0000	(0.0000)	0.4530	17.000%	0.0770	0.0169	0.0013
								0.0000	(0.0000)	0.4530	17.000%	0.0770	0.0169	0.0013
			100.000%		88.4000	100.000%		0.0000				218.7731		84.1601
												84.1601	/ 1000	8.4200%
	88.4							88.4000						
														8.0000%

Advice 3176-G/3784-E

Attachment 3

Section 401 – Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010

Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010
[P.L. 111-312 12/17/2010]

TITLE IV. TEMPORARY EXTENSION OF INVESTMENT INCENTIVES [§§401—402]

Law Sec. 401. EXTENSION OF BONUS DEPRECIATION; TEMPORARY 100 PERCENT EXPENSING FOR CERTAIN BUSINESS ASSETS.

(a) In General. Paragraph (2) of section 168(k) is amended—

(1) by striking “January 1, 2012” in subparagraph (A)(iv) and inserting “January 1, 2014”, and

(2) by striking “January 1, 2011” each place it appears and inserting “January 1, 2013”.

(b) Temporary 100 Percent Expensing. Subsection (k) of section 168 is amended by adding at the end the following new paragraph:

“(5) SPECIAL RULE FOR PROPERTY ACQUIRED DURING CERTAIN PRE-2012 PERIODS.-In the case of qualified property acquired by the taxpayer (under rules similar to the rules of clauses (ii) and (iii) of paragraph (2)(A)) after September 8, 2010, and before January 1, 2012, and which is placed in service by the taxpayer before January 1, 2012 (January 1, 2013, in the case of property described in subparagraph (2)(B) or (2)(C)), paragraph (1)(A) shall be applied by substituting '100 percent' for '50 percent'.”.

(c) Extension of Election to Accelerate the AMT Credit in Lieu of Bonus Depreciation.

(1) Extension. Clause (iii) of section 168(k)(4)(D) is amended by striking “or production” and all that follows and inserting “or production—

“(I) after March 31, 2008, and before January 1, 2010, and

“(II) after December 31, 2010, and before January 1, 2013,

shall be taken into account under subparagraph (B)(ii) thereof,”.

(2) Rules for Round 2 Extension Property. Paragraph (4) of section 168(k) is amended by adding at the end the following new subparagraph:

“(I) SPECIAL RULES FOR ROUND 2 EXTENSION PROPERTY.-

“(i) IN GENERAL.-In the case of round 2 extension property, this paragraph shall be applied without regard to—

“(I) the limitation described in subparagraph (B)(i) thereof, and

“(II) the business credit increase amount under subparagraph (E)(iii) thereof.

“(ii) TAXPAYERS PREVIOUSLY ELECTING ACCELERATION.-In the case of a taxpayer who made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, or a taxpayer who made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008—

“(I) the taxpayer may elect not to have this paragraph apply to round 2 extension property, but

“(II) if the taxpayer does not make the election under subclause (I), in applying this paragraph to the taxpayer the bonus depreciation amount, maximum amount, and maximum increase amount shall be computed and applied to eligible qualified property which is round 2 extension property.

The amounts described in subclause (II) shall be computed separately from any amounts computed with respect to eligible qualified property which is not round 2 extension property.

“(iii) TAXPAYERS NOT PREVIOUSLY ELECTING ACCELERATION.-In the case of a taxpayer who neither made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, nor made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008—

“(I) the taxpayer may elect to have this paragraph apply to its first taxable year ending after December 31, 2010, and each subsequent taxable year, and

“(II) if the taxpayer makes the election under subclause (I), this paragraph shall only apply to eligible qualified property which is round 2 extension property.

“(iv) ROUND 2 EXTENSION PROPERTY.-For purposes of this subparagraph, the term 'round 2 extension property' means property which is eligible qualified property solely by reason of the extension of the application of the special allowance under paragraph (1) pursuant to the amendments made by section 401(a) of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (and the application of such extension to this paragraph pursuant to the amendment made by section 401(c)(1) of such Act).”.

(d) Conforming Amendments.

(1) The heading for subsection (k) of section 168 is amended by striking “JANUARY 1, 2011” and inserting “JANUARY 1, 2013”.

(2) The heading for clause (ii) of section 168(k)(2)(B) is amended by striking “PRE-JANUARY 1, 2011” and inserting “PRE-JANUARY 1, 2013”.

(3) Subparagraph (D) of section 168(k)(4) is amended—

(A) by striking clauses (iv) and (v),

(B) by inserting “and” at the end of clause (ii), and

(C) by striking the comma at the end of clause (iii) and inserting a period.

(4) Paragraph (5) of section 168(l) is amended—

(A) by inserting “and” at the end of subparagraph (A),

(B) by striking subparagraph (B), and

(C) by redesignating subparagraph (C) as subparagraph (B).

(5) Subparagraph (C) of section 168(n)(2) is amended by striking “January 1, 2011” and inserting “January 1, 2013”.

(6) Subparagraph (D) of section 1400L(b)(2) is amended by striking “January 1, 2011” and inserting “January 1, 2013”.

(7) Subparagraph (B) of section 1400N(d)(3) is amended by striking “January 1, 2011” and inserting “January 1, 2013”.

(e) Effective Dates.

(1) In General. Except as provided in paragraph (2), the amendments made by this section shall apply to property placed in service after December 31, 2010, in taxable years ending after such date.

(2) Temporary 100 Percent Expensing. The amendment made by subsection (b) shall apply to property placed in service after September 8, 2010, in taxable years ending after such date.

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

Alcantar & Kahl LLP
Ameresco
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Barkovich & Yap, Inc.
Bartle Wells Associates
Bloomberg
Bloomberg New Energy Finance
Boston Properties
Braun Blaising McLaughlin, P.C.
Brookfield Renewable Power
CA Bldg Industry Association
CLECA Law Office
CSC Energy Services
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Casner, Steve
Chris, King
City of Palo Alto
City of Palo Alto Utilities
Clean Energy Fuels
Coast Economic Consulting
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of Water Resources
Dept of General Services
Division of Business Advisory Services
Douglass & Liddell
Downey & Brand
Duke Energy
Dutcher, John
Economic Sciences Corporation
Ellison Schneider & Harris LLP
Foster Farms
G. A. Krause & Assoc.
GLJ Publications
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Hitachi
In House Energy
International Power Technology
Intestate Gas Services, Inc.
Lawrence Berkeley National Lab
Los Angeles Dept of Water & Power
Luce, Forward, Hamilton & Scripps LLP
MAC Lighting Consulting
MBMC, Inc.
MRW & Associates
Manatt Phelps Phillips
McKenzie & Associates
Merced Irrigation District
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
NLine Energy, Inc.
NRG West
Navigant Consulting
Norris & Wong Associates
North America Power Partners
North Coast SolarResources
Occidental Energy Marketing, Inc.
OnGrid Solar
Praxair
R. W. Beck & Associates
RCS, Inc.
Recurrent Energy
SCD Energy Solutions
SCE
SMUD
SPURR
San Francisco Public Utilities Commission
Santa Fe Jets
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Silo Energy LLC
Southern California Edison Company
Spark Energy, L.P.
Sunshine Design
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Turlock Irrigation District
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation

Advice 3216-G-A/3859-E-A

Attachment 12

ITCC Amortization to Miscellaneous Revenue Forecast

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
ITCC Amortization to Miscellaneous Revenue Forecast
Based on 2011 GRC Settlement Agreement
($ in thousands)

LOB	2011 RRQ	2012 Attrition	2012% Increase	2012 RRQ	2012 Attrition	2013% Increase	2013 RRQ
Electric Distribution	3,189,524	123,000	3.86%	3,312,524	123,000	3.71%	3,435,524
Gas Distribution	1,131,429	35,000	3.09%	1,166,429	35,000	3.00%	1,201,429

Baseline ITCC Amortization	2011 RRQ	2012 Attrition	2012 % Increase	2012 RRQ	2012 Attrition	2013 % Increase	2013 RRQ
Non Refundable Electric	39,295		3.86%	40,810		3.71%	42,326
Refundable Electric	2,987		3.86%	3,102		3.71%	3,217
Subtotal Electric	42,282			43,913			45,543
Non Refundable Gas	6,789		3.09%	6,999		3.00%	7,209
Refundable Gas	1,248		3.09%	1,287		3.00%	1,325
Subtotal Gas	8,037			8,286			8,534
Total ITCC Amortization	**50,319**			**52,198**			**54,077**

ITCC Amortization Impacted by Tax Law**	2011 RRQ	2012 RRQ	2013 RRQ
Non Refundable Electric	35,255	34,672	34,055
Refundable Electric***	-	-	-
Subtotal Electric	35,255	34,672	34,055
Non Refundable Gas	5,964	5,964	5,978
Refundable Gas***	-	-	-
Subtotal Gas	5,964	5,964	5,978
Total ITCC Amortization	**41,219**	**40,636**	**40,033**

(Reduction) Increase in Misc. Rev.:			
Electric Distribution	(7,027)	(9,241)	(11,488)
Gas Distribution	(2,073)	(2,322)	(2,556)
Total (Reduction) Increase in Misc. Rev.	(9,100)	(11,562)	(14,044)

** Note: Includes bonus depreciation related to the Tax Relief Act signed December 17, 2010
*** Note: Includes no assumption for refundable CAC

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

AT&T
Alcantar & Kahl LLP
Ameresco
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Arizona Public Service Company
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Barkovich & Yap, Inc.
Bartle Wells Associates
Bloomberg
Bloomberg New Energy Finance
Boston Properties
Braun Blaising McLaughlin, P.C.
Brookfield Renewable Power
CA Bldg Industry Association
CLECA Law Office
CSC Energy Services
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Casner, Steve
Chris, King
City of Palo Alto
City of Palo Alto Utilities
City of San Jose
Clean Energy Fuels
Coast Economic Consulting
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of Water Resources
Dept of General Services
Douglass & Liddell
Downey & Brand
Duke Energy
Economic Sciences Corporation
Ellison Schneider & Harris LLP
Foster Farms
G. A. Krause & Assoc.
GLJ Publications
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Hitachi
In House Energy
International Power Technology
Intestate Gas Services, Inc.
Lawrence Berkeley National Lab
Los Angeles Dept of Water & Power
Luce, Forward, Hamilton & Scripps LLP
MAC Lighting Consulting
MBMC, Inc.
MRW & Associates
Manatt Phelps Phillips
McKenzie & Associates
Merced Irrigation District
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
NLine Energy, Inc.
NRG West
NaturEner
Navigant Consulting
Norris & Wong Associates
North America Power Partners
North Coast SolarResources
Occidental Energy Marketing, Inc.
OnGrid Solar
Praxair
R. W. Beck & Associates
RCS, Inc.
Recurrent Energy
SCD Energy Solutions
SCE
SMUD
SPURR
San Francisco Public Utilities Commission
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Silo Energy LLC
Southern California Edison Company
Spark Energy, L.P.
Sun Light & Power
Sunshine Design
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Turlock Irrigation District
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation

Advice 3362-G/4187-E

Attachment 4

PG&E’s Adopted 2013 Cost of Capital

Pacific Gas and Electric Company
Tax Act Memorandum Account (TAMA)
Adopted Cost of Capital (Decision 12-12-034)

Line No.	Description	Capitalization	Cost	Weighted Cost	Tax Gross-up Factor	Pre-Tax Cost
		(a)	(b)	(c = a x b)	(d)	(e = c x d)
1	Debt	47.00%	5.52%	2.59%	1.00	2.59%
2	Preferred	1.00%	5.60%	0.06%	1.69	0.10%
3	Common Equity	52.00%	10.40%	5.41%	1.69	9.13%
4	Total	100.00%		8.06%		**11.82%**
	Tax Gross-up Factor					
5	Federal Income Tax Rate	35.00%				
6	State Income Tax Rate	8.84%				
7	Composite Rate	40.75%				
8	Factor*	1.69				

* Note: Excludes Franchise Fees and Uncollectibles

Advice 3362-G/4187-E

Attachment 5

Pending Advice 3346-G-A/4148-E-A

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulatory Relations

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

Fax: 415.973.7226

January 4, 2013

Advice 3346-G-A/4148-E-A
(Pacific Gas and Electric Company ID U 39 M)

Public Utilities Commission of the State of California

<u>Subject:</u> **Supplemental Revision of PG&E's Tariffs to Reflect Changes in the Income Tax Component of Contribution Tax Factors**

Pacific Gas and Electric Company (PG&E) hereby submits for filing a continuation of temporarily reduced Income Tax Component of Contribution (ITCC). This Supplemental Advice Letter replaces Advice 3346-G/4148-E in its entirety, and withdraws the revised tariff sheets submitted therein.

Purpose

On November 29, 2012, PG&E filed Advice 3346-G/4148-E in anticipation of the expiration on December 31, 2012 of temporary changes in certain Federal Income Tax provisions. On January 1, 2013, Congress passed the American Taxpayer Relief Act of 2012 (ATRA), which was signed into law by President Obama. The ATRA once again temporarily extended the Federal Depreciation Provisions of the Internal Revenue Code (IRC) which impacts the factors used to compute the ITCC associated with Contributions in Aid of Construction, this time through the end of 2013.

This filing is necessary to extend the reduced ITCC rates in place in 2012, and to withdraw the tariff sheets filed with Advice 3346-G/4148-E (PG&E's Gas Preliminary Statement Part P and Electric Preliminary Statement Part J, *Income Tax Component of Contributions Provision*).

Background

Since February of 2008, the Federal Government has enacted, each time on a temporary basis, a series of income tax revisions intended to promote investment in capital projects. These revisions provide for accelerated Federal tax depreciation which has the impact of reducing the ITCC rate. On November 29, 2012, PG&E filed Advice 3346-G/4148-E in anticipation of the expiration of those temporary revisions, which would have caused a return of the ITCC to pre-2008 levels effective January 1, 2013.

Congress did not act before the expiration of the temporarily reduced tax rate, but did pass ATRA on January 1, 2013. President Obama signed the bill into law on January 3,

2013. Section 331 of the ATRA contains the extension of the accelerated Federal tax depreciation provisions and is attached. (Attachment 1)

In this Advice Letter, PG&E requests that the California Public Utilities Commission (Commission) authorize PG&E to implement the ATRA and its effect on the ITCC rates. The new ITCC tax factor for Gas contributions is .22 (22 percent), and the new ITCC tax factor for Electric Contributions is also .22 (22 percent). *Because these new tax factors are identical to those in effect through 2012, PG&E requests authorization to withdraw the tariff sheets filed with Advice 3346-G/4148-E, and to leave the previous tariff sheets in place.*

To support the requested ITCC Tax Factors, PG&E has attached the calculation set forth in Method 5, as described in Decision (D.) 87-09-026 and D.87-12-028 in OII 86-11-109. (Attachment 2)

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than **January 24, 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, Rule 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Rule 3.11).

Effective Date

PG&E requests that this Tier 1 Supplemental Advice Letter be approved effective **January 1, 2013**.

Notice

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

Brian Cherry

Vice President, Regulatory Relations

Attachment 1: Section 331 of the ATRA
Attachment 2: ITCC Tax Factors

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 M)**

Utility type:	Contact Person: Kimberly Chang
☑ ELC ☑ GAS	Phone #: (415) 972-5472
☐ PLC ☐ HEAT ☐ WATER	E-mail: kwcc@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **3346-G-A/4148-E-A** **Tier: 1**

Subject of AL: **Supplemental Revision of PG&E's Tariffs to Reflect Changes in the Income Tax Component of Contribution Tax Factors**

Keywords (choose from CPUC listing): Compliance, Taxes

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: N/A

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:

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

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

Resolution Required? ☐Yes ☑No

Requested effective date: **January 1, 2013** No. of tariff sheets: 0

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

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

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

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

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

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

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

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

Attachment 1:
Section 331 of the ATRA

SEC. 329. EXTENSION OF TEMPORARY INCREASE IN LIMIT ON COVER OVER OF RUM EXCISE TAXES TO PUERTO RICO AND THE VIRGIN ISLANDS.

(a) IN GENERAL.—Paragraph (1) of section 7652(f) is amended by striking "January 1, 2012" and inserting "January 1, 2014".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to distilled spirits brought into the United States after December 31, 2011.

SEC. 330. MODIFICATION AND EXTENSION OF AMERICAN SAMOA ECONOMIC DEVELOPMENT CREDIT.

(a) MODIFICATION.—

(1) IN GENERAL.—Subsection (a) of section 119 of division A of the Tax Relief and Health Care Act of 2006 is amended by striking "if such corporation" and all that follows and inserting "if—

"(1) in the case of a taxable year beginning before January 1, 2012, such corporation—

"(A) is an existing credit claimant with respect to American Samoa, and

"(B) elected the application of section 936 of the Internal Revenue Code of 1986 for its last taxable year beginning before January 1, 2006, and

"(2) in the case of a taxable year beginning after December 31, 2011, such corporation meets the requirements of subsection (e).".

(2) REQUIREMENTS.—Section 119 of division A of such Act is amended by adding at the end the following new subsection:

"(e) QUALIFIED PRODUCTION ACTIVITIES INCOME REQUIREMENT.—A corporation meets the requirement of this subsection if such corporation has qualified production activities income, as defined in subsection (c) of section 199 of the Internal Revenue Code of 1986, determined by substituting 'American Samoa' for 'the United States' each place it appears in paragraphs (3), (4), and (6) of such subsection (c), for the taxable year.".

(b) EXTENSION.—Subsection (d) of section 119 of division A of the Tax Relief and Health Care Act of 2006 is amended by striking "shall apply" and all that follows and inserting "shall apply—

"(1) in the case of a corporation that meets the requirements of subparagraphs (A) and (B) of subsection (a)(1), to the first 8 taxable years of such corporation which begin after December 31, 2006, and before January 1, 2014, and

"(2) in the case of a corporation that does not meet the requirements of subparagraphs (A) and (B) of subsection (a)(1), to the first 2 taxable years of such corporation which begin after December 31, 2011, and before January 1, 2014.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2011.

SEC. 331. EXTENSION AND MODIFICATION OF BONUS DEPRECIATION.

(a) IN GENERAL.—Paragraph (2) of section 168(k) is amended—

(1) by striking "January 1, 2014" in subparagraph (A)(iv) and inserting "January 1, 2015", and

(2) by striking "January 1, 2013" each place it appears and inserting "January 1, 2014".

(b) SPECIAL RULE FOR FEDERAL LONG-TERM CONTRACTS.—Clause (ii) of section 460(c)(6)(B) is amended by inserting ", or after December 31, 2012, and before January 1, 2014 (January 1, 2015, in the case of property described in section 168(k)(2)(B))" before the period.

(c) EXTENSION OF ELECTION TO ACCELERATE THE AMT CREDIT IN LIEU OF BONUS DEPRECIATION.—

(1) IN GENERAL.—Subclause (II) of section 168(k)(4)(D)(iii) is amended by striking "2013" and inserting "2014".

(2) ROUND 3 EXTENSION PROPERTY.—Paragraph (4) of section 168(k) is amended by adding at the end the following new subparagraph:

"(J) SPECIAL RULES FOR ROUND 3 EXTENSION PROPERTY.—

"(i) IN GENERAL.—In the case of round 3 extension property, this paragraph shall be applied without regard to—

"(I) the limitation described in subparagraph (B)(i) thereof, and

"(II) the business credit increase amount under subparagraph (E)(iii) thereof.

"(ii) TAXPAYERS PREVIOUSLY ELECTING ACCELERATION.—In the case of a taxpayer who made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, a taxpayer who made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008, or a taxpayer who made the election under subparagraph (I)(iii) for its first taxable year ending after December 31, 2010—

"(I) the taxpayer may elect not to have this paragraph apply to round 3 extension property, but

"(II) if the taxpayer does not make the election under subclause (I), in applying this paragraph to the taxpayer the bonus depreciation amount, maximum amount, and maximum increase amount shall be computed and applied to eligible qualified property which is round 3 extension property.

The amounts described in subclause (II) shall be computed separately from any amounts computed with respect to eligible qualified property which is not round 3 extension property.

"(iii) TAXPAYERS NOT PREVIOUSLY ELECTING ACCELERATION.—In the case of a taxpayer who neither made the election under subparagraph (A) for its first taxable year ending after March 31, 2008, nor made the election under subparagraph (H)(ii) for its first taxable year ending after December 31, 2008, nor made the election under subparagraph (I)(iii) for any taxable year ending after December 31, 2010—

"(I) the taxpayer may elect to have this paragraph apply to its first taxable year ending after December 31, 2012, and each subsequent taxable year, and

"(II) if the taxpayer makes the election under subclause (I), this paragraph shall only apply to eligible qualified property which is round 3 extension property.

"(iv) ROUND 3 EXTENSION PROPERTY.—For purposes of this subparagraph, the term 'round 3 extension property' means property which is eligible qualified property solely by reason of the extension of the application of the special allowance under paragraph (1) pursuant to the amendments made by section 331(a) of the American Taxpayer Relief Act of 2012 (and the application of such extension to this paragraph pursuant to the amendment made by section 331(c)(1) of such Act).".

(d) NORMALIZATION RULES AMENDMENT.—Clause (ii) of section 168(i)(9)(A) is amended by inserting "(respecting all elections made by the taxpayer under this section)" after "such property".

(e) CONFORMING AMENDMENTS.—

(1) The heading for subsection (k) of section 168 is amended by striking "JANUARY 1, 2013" and inserting "JANUARY 1, 2014".

(2) The heading for clause (ii) of section 168(k)(2)(B) is amended by striking "PRE-JANUARY 1, 2013" and inserting "PRE-JANUARY 1, 2014".

(3) Subparagraph (C) of section 168(n)(2) is amended by striking "January 1, 2013" and inserting "January 1, 2014".

(4) Subparagraph (D) of section 1400L(b)(2) is amended by striking "January 1, 2013" and inserting "January 1, 2014".

(5) Subparagraph (B) of section 1400N(d)(3) is amended by striking "January 1, 2013" and inserting "January 1, 2014".

(f) EFFECTIVE DATE.—The amendments made by this section shall apply to property placed in service after December 31, 2012, in taxable years ending after such date.

TITLE IV—ENERGY TAX EXTENDERS

SEC. 401. EXTENSION OF CREDIT FOR ENERGY-EFFICIENT EXISTING HOMES.

(a) IN GENERAL.—Paragraph (2) of section 25C(g) is amended by striking "December 31, 2011" and inserting "December 31, 2013".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to property placed in service after December 31, 2011.

SEC. 402. EXTENSION OF CREDIT FOR ALTERNATIVE FUEL VEHICLE REFUELING PROPERTY.

(a) IN GENERAL.—Paragraph (2) of section 30C(g) is amended by striking "December 31, 2011." and inserting "December 31, 2013".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to property placed in service after December 31, 2011.

SEC. 403. EXTENSION OF CREDIT FOR 2- OR 3-WHEELED PLUG-IN ELECTRIC VEHICLES.

(a) IN GENERAL.—Section 30D is amended by adding at the end the following new subsection:

"(g) CREDIT ALLOWED FOR 2- AND 3-WHEELED PLUG-IN ELECTRIC VEHICLES.—

"(1) IN GENERAL.—In the case of a qualified 2- or 3-wheeled plug-in electric vehicle—

"(A) there shall be allowed as a credit against the tax imposed by this chapter for the taxable year an amount equal to the sum of the applicable amount with respect

Attachment 2:
ITCC Tax Factors

CIAC GROSS-UP COMPUTATION INCLUDING CALIFORNIA TAXES
Effective January 1, 2013 (REVISED as a result of The American Taxpayer Relief Act of 2012)
Depreciation on 20 Year Property (Electric)

(A) YEAR	(B) TAX PMT/(BEN) REFLECTING CIAC OF $1,000	(C) TAX BASIS	(D) CALIFORNIA DEPRECIATION RATES	(E) CALIFORNIA RATES	(F) STATE TAX BENEFIT	(G) MODIFIED MACRS RATES	(H) FEDERAL TAX RATE	(I) FEDERAL TAX BENEFIT	(J) REMAINING CIAC PAYABLE	(K) WTD. AVG. UNRECOVERED TAX PMT.	(L) RATE OF RETURN	(M) REVENUE REQUIREMENT ON REMAINING INVESTMENT	(N) DISCOUNT FACTOR 0.12	(O) DISCOUNTED REVENUE REQUIREMENT ON REMAINING INVESTMENT
1	438.4	1,000	3.334%	8.840%	2.9473	51.875%	35.00%	181.5625	253.8902	346.1451	17.000%	58.8447	0.8929	52.5424
2	-30.94		6.445%		5.6974	3.610%		11.6035	205.6494	229.7698	17.000%	39.0609	0.7972	31.1391
3			6.016%		5.3181	3.339%		9.6924	190.6388	198.1441	17.000%	33.6845	0.7118	23.9760
4			5.615%		4.9637	3.089%		8.9501	176.7251	183.6819	17.000%	31.2259	0.6355	19.8446
5			5.241%		4.6330	2.857%		8.2622	163.8298	170.2774	17.000%	28.9472	0.5674	16.4254
6			4.892%		4.3245	2.643%		7.6289	151.8764	157.8531	17.000%	26.8350	0.5066	13.5954
7			4.566%		4.0363	2.444%		7.0404	140.7996	146.3380	17.000%	24.8775	0.4523	11.2533
8			4.261%		3.7667	2.261%		6.5008	130.5321	135.6659	17.000%	23.0632	0.4039	9.3148
9			3.977%		3.5157	2.231%		6.4901	120.5264	125.5292	17.000%	21.3400	0.3606	7.6954
10			3.712%		3.2814	2.231%		6.5780	110.6669	115.5966	17.000%	19.6514	0.3220	6.3272
11			3.465%		3.0631	2.231%		6.6600	100.9439	105.8054	17.000%	17.9869	0.2875	5.1708
12			3.234%		2.8589	2.231%		6.7364	91.3486	96.1463	17.000%	16.3449	0.2567	4.1953
13			3.018%		2.6679	2.231%		6.8079	81.8728	86.6107	17.000%	14.7238	0.2292	3.3743
14			2.817%		2.4902	2.231%		6.8747	72.5079	77.1904	17.000%	13.1224	0.2046	2.6851
15			2.630%		2.3249	2.231%		6.9369	63.2461	67.8770	17.000%	11.5391	0.1827	2.1082
16			2.455%		2.1702	2.231%		6.9948	54.0810	58.6636	17.000%	9.9728	0.1631	1.6268
17			2.367%		2.0924	2.231%		7.0489	44.9397	49.5104	17.000%	8.4168	0.1456	1.2259
18			2.367%		2.0924	2.231%		7.0762	35.7711	40.3554	17.000%	6.8604	0.1300	0.8921
19			2.367%		2.0924	2.231%		7.0762	26.6025	31.1868	17.000%	5.3018	0.1161	0.6156
20			2.367%		2.0924	2.231%		7.0762	17.4338	22.0181	17.000%	3.7431	0.1037	0.3880
21			2.367%		2.0924	1.110%		3.1527	12.1887	14.8113	17.000%	2.5179	0.0926	0.2331
22			2.367%		2.0924			(0.7323)	10.8286	11.5086	17.000%	1.9565	0.0826	0.1617
23			2.367%		2.0924			(0.7323)	9.4685	10.1485	17.000%	1.7252	0.0738	0.1273
24			2.367%		2.0924			(0.7323)	8.1083	8.7884	17.000%	1.4940	0.0659	0.0984
25			2.367%		2.0924			(0.7323)	6.7482	7.4283	17.000%	1.2628	0.0588	0.0743
26			2.367%		2.0924			(0.7323)	5.3881	6.0681	17.000%	1.0316	0.0525	0.0542
27			2.367%		2.0924			(0.7323)	4.0279	4.7080	17.000%	0.8004	0.0469	0.0375
28			2.367%		2.0924			(0.7323)	2.6678	3.3479	17.000%	0.5691	0.0419	0.0238
29			2.367%		2.0924			(0.7323)	1.3077	1.9877	17.000%	0.3379	0.0374	0.0126
30			2.367%		2.0924			(0.7323)	(0.0524)	0.6276	17.000%	0.1067	0.0334	0.0036
31			1.184%		1.0467			(0.7323)	(0.3668)	(0.2096)	17.000%	(0.0356)	0.0298	-0.0011
32					0.0000			(0.3663)	(0.0005)	(0.1837)	17.000%	(0.0312)	0.0266	-0.0008
			100.000%		88.4000	100.000%		319.0605				427.2776		215.2204
												215.2204	/ 1000	21.5200%
	407.46							407.4605						
														22.0000%

CIAC GROSS-UP COMPUTATION INCLUDING CALIFORNIA TAXES
Effective January 1, 2013 (REVISED as a result of The American Taxpayer Relief Act of 2012)
Depreciation on 20 Year Property (Gas)

(A) YEAR	(B) TAX PMT/(BEN) REFLECTING CIAC OF $1,000	(C) TAX BASIS	(D) CALIFORNIA DEPRECIATION RATES	(E) CALIFORNIA RATES	(F) STATE TAX BENEFIT	(G) MODIFIED MACRS RATES	(H) FEDERAL TAX RATE	(I) FEDERAL TAX BENEFIT	(J) REMAINING CIAC PAYABLE	(K) WTD. AVG. UNRECOVERED TAX PMT.	(L) RATE OF RETURN	(M) REVENUE REQUIREMENT ON REMAINING INVESTMENT	(N) DISCOUNT FACTOR 0.12	(O) DISCOUNTED REVENUE REQUIREMENT ON REMAINING INVESTMENT
1	438.4	1,000	2.857%	8.840%	2.5256	51.875%	35.00%	181.5625	254.3119	346.3560	17.000%	58.8805	0.8929	52.5744
2	-30.94		5.551%		4.9071	3.610%		11.7510	206.7138	230.5129	17.000%	39.1872	0.7972	31.2398
3			5.234%		4.6269	3.339%		9.9690	192.1180	199.4159	17.000%	33.9007	0.7118	24.1298
4			4.935%		4.3625	3.089%		9.1921	178.5633	185.3407	17.000%	31.5079	0.6355	20.0238
5			4.653%		4.1133	2.857%		8.4726	165.9775	172.2704	17.000%	29.2860	0.5674	16.6177
6			4.387%		3.8781	2.643%		7.8109	154.2885	160.1330	17.000%	27.2226	0.5066	13.7918
7			4.137%		3.6571	2.444%		7.1967	143.4347	148.8616	17.000%	25.3065	0.4523	11.4474
8			3.901%		3.4485	2.261%		6.6335	133.3527	138.3937	17.000%	23.5269	0.4039	9.5021
9			3.678%		3.2514	2.231%		6.6015	123.4998	128.4263	17.000%	21.8325	0.3606	7.8730
10			3.468%		3.0657	2.231%		6.6705	113.7636	118.6317	17.000%	20.1674	0.3220	6.4934
11			3.270%		2.8907	2.231%		6.7355	104.1374	108.9505	17.000%	18.5216	0.2875	5.3245
12			3.084%		2.7263	2.231%		6.7968	94.6144	99.3759	17.000%	16.8939	0.2567	4.3362
13			2.908%		2.5707	2.231%		6.8543	85.1894	89.9019	17.000%	15.2833	0.2292	3.5025
14			2.742%		2.4239	2.231%		6.9088	75.8567	80.5230	17.000%	13.6889	0.2046	2.8010
15			2.585%		2.2851	2.231%		6.9601	66.6114	71.2341	17.000%	12.1098	0.1827	2.2124
16			2.438%		2.1552	2.231%		7.0087	57.4475	62.0295	17.000%	10.5450	0.1631	1.7201
17			2.299%		2.0323	2.231%		7.0542	48.3610	52.9043	17.000%	8.9937	0.1456	1.3099
18			2.168%		1.9165	2.231%		7.0972	39.3473	43.8542	17.000%	7.4552	0.1300	0.9695
19			2.040%		1.8034	2.231%		7.1377	30.4063	34.8768	17.000%	5.9291	0.1161	0.6884
20			2.040%		1.8034	2.231%		7.1773	21.4256	25.9159	17.000%	4.4057	0.1037	0.4567
21			2.040%		1.8034	1.110%		3.2538	16.3684	18.8970	17.000%	3.2125	0.0926	0.2973
22			2.040%		1.8034			(0.6312)	15.1963	15.7824	17.000%	2.6830	0.0826	0.2217
23			2.040%		1.8034			(0.6312)	14.0241	14.6102	17.000%	2.4837	0.0738	0.1833
24			2.040%		1.8034			(0.6312)	12.8520	13.4380	17.000%	2.2845	0.0659	0.1505
25			2.040%		1.8034			(0.6312)	11.6798	12.2659	17.000%	2.0852	0.0588	0.1227
26			2.040%		1.8034			(0.6312)	10.5076	11.0937	17.000%	1.8859	0.0525	0.0990
27			2.040%		1.8034			(0.6312)	9.3355	9.9216	17.000%	1.6867	0.0469	0.0791
28			2.040%		1.8034			(0.6312)	8.1633	8.7494	17.000%	1.4874	0.0419	0.0623
29			2.040%		1.8034			(0.6312)	6.9912	7.5772	17.000%	1.2881	0.0374	0.0482
30			2.040%		1.8034			(0.6312)	5.8190	6.4051	17.000%	1.0889	0.0334	0.0363
31			2.040%		1.8034			(0.6312)	4.6468	5.2329	17.000%	0.8896	0.0298	0.0265
32			2.040%		1.8034			(0.6312)	3.4747	4.0608	17.000%	0.6903	0.0266	0.0184
33			2.040%		1.8034			(0.6312)	2.3025	2.8886	17.000%	0.4911	0.0238	0.0117
34			2.040%		1.8034			(0.6312)	1.1304	1.7164	17.000%	0.2918	0.0212	0.0062
35			2.040%		1.8034			(0.6312)	(0.0418)	0.5443	17.000%	0.0925	0.0189	0.0018
36			1.025%		0.9061			(0.6312)	(0.3167)	(0.1793)	17.000%	(0.0305)	0.0169	-0.0005
					0.0000			(0.6312)	0.3145	0.1363	17.000%	0.0232	0.0169	0.0004
			100.000%		88.4000	100.000%		318.7455				447.2783		218.3794
												218.3794	/ 1000	21.8400%
	407.46							407.1455						
														22.0000%

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

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PG&E Gas and Electric
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SPURR
Salazar, Julie
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Seattle City Light
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