Docket	:	A.09-05-026
Exhibit Number	:	DRA-1
Commissioner	:	Simon
Admin. Law Judge	:	Wong
Witness	:	
	:	

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

REPORT

ON

PACIFIC GAS AND ELECTRIC COMPANY'S

2009

BIENNIAL COST ALLOCATION PROCEEDING

A.09-05-026

San Francisco, California
November 4, 2009

404322

TABLE OF CONTENTS

CHAPTER 1 - SUMMARY OF DRA RECOMMENDATIONS

Witness: Jacqueline Greig

1.1 INTRODUCTION AND SUMMARY

On May 29, 2009, Pacific Gas and Electric Company (PG&E) filed its Biennial Cost Allocation Proceeding (BCAP) Application (A.) 09-05-026. PG&E's application requests that the Commission address the allocation of PG&E's distribution costs of providing natural gas service to its customers, and requests Commission approval of various rate design proposals. PG&E requests that the new rates go into effect on July 10, 2010 for a 24-month period. This DRA report addresses PG&E's BCAP request and recommendations as contained within its Application and Testimony.

In a BCAP proceeding, the Commission allocates gas costs to the various customer classes in California and establishes transportation rates for the utilities. For PG&E, the BCAP addresses distribution costs, as gas transmission and storage costs are addressed in PG&E Gas Transmission and Storage rate case proceedings, also referred to as Gas Accord proceedings. The procurement rates for gas commodity costs are set monthly through advice letter filings. PG&E has recently filed its 2011 Gas Transmission and Storage (GT&S) Rate Case A.09-09-013 case for new rates covering the period January 1, 2011 through December 31, 2014. Therefore, this BCAP only addresses transportation rates associated with distribution-level base revenue and customer class charges.

PG&E's most recently adopted distribution revenue requirement presented in this BCAP is $1.09 billion.[1] The proposed rates also reflect adopted customer class charges, public purpose program costs, throughput forecasts, and marginal cost updates. PG&E's and DRA's recommended rates are shown in detail in Tables 5-1, 5-2, and 5-3 of Chapter 5. DRA's recommendations result in unbundled core transportation rates that are 4.4% higher than present rates, while PG&E's[2] proposed core transportation rates would be

[1] Adopted in D.07-03-044 and adjusted annually.

4.7% higher. DRA recommends a 0% change in noncore transportation rates as compared to PG&E's recommendation of a 1% decrease.

1.2 DRA'S RECOMMENDATIONS

DRA's report contains five chapters, and each chapter's recommendations for PG&E's BCAP proposals are summarized as follows:

Chapter 2 presents the throughput forecast recommendations for the core and noncore customer classes, excluding the electric generation customer class which is addressed in Chapter 3. DRA finds that PG&E's core throughput forecasts are reasonable. However, DRA recommends different throughput forecasts for the noncore industrial customer classes. DRA's total noncore throughput forecast recommendation is 2.41% higher than PG&E's noncore forecast. Table 2-1 details the specific customer class forecast recommendations.

Chapter 3 presents the non-econometric forecasts for cogeneration and non-cogeneration electric generation (EG). DRA recommends an EG (including cogeneration) average year throughput forecast of 276,555 MDth per year, as compared to PG&E's proposed forecast of 263,262 MDth per year. DRA's EG recommendation is 5% higher than PG&E's.

Chapter 4 presents DRA's recommendations on marginal costs for distribution and customer access functions. DRA recommends the following:

- That the Commission reject PG&E's proposed updated customer and distribution Long Run Marginal Cost (LRMC) of providing gas distribution service for PG&E's customers and instead adopt the following DRA recommendations which are more reasonable:
    1. A two-year average marginal distribution unit cost of $233.45/MDM (marginal demand measure);
    2. Adjustments in service line length for both new business SRM (service line, regulator, meter) and replacement SRM to derive the weighted average SRM cost for each customer class; and

3. The exclusion of trenching costs in the SRM estimates for replacement of service calculations per customer class.

- That the Commission adopt the proposed distribution investment plan
- That the Commission adopt the proposed marginal cost “loaders” (e.g. growth-related for administrative and general (A&G), Operation and Maintenance (O&M) expenses and economic factors (e.g. discount rate and real economic carrying charge)
- That the Commission reject the following PG&E’s proposed marginal cost revenues and instead adopt those recommended by DRA:

1. the absence of distribution RCA for the replacement cost of existing distribution facilities;
2. the inaccurate calculation of its weighted SRMs with the appropriate service line lengths;
3. the slightly lower throughputs used by PG&E for purposes of the cost allocations; and
4. the flawed inclusion of trenching costs for replacement services.

Chapter 5 presents DRA’s recommendations on rates and rate proposals. Chapter 5 is significant because it contains the illustrative rate tables for the BCAP. DRA’s recommendations are the following:

- Core deaveraging should continue at a more moderate 5% annual rate over the current BCAP period from July 1, 2010 through June 30, 2012, in contrast to PG&E’s proposed 15% annual rate. The remaining non-deaveraged portion should be considered in the next BCAP.
- PG&E should continue to be at risk for 25% of the noncore distribution revenue balancing account as determined by the Commission in the last BCAP decision.
- The Commission should adopt the rates and revenues derived by DRA as shown in Tables 5-1, 5-2, and 5.3.

DRA's recommendations in this report are only for the purposes of the instant PG&E BCAP and should not be construed as DRA's positions in different or future proceedings, including but not limited to, issues within the any Gas Accord reports and negotiations. Further, DRA notes that it did not conduct an audit of PG&E's balancing accounts in this proceeding.

CHAPTER 2 - DEMAND FORECASTS

Witness: Thomas M. Renaghan

2.1 INTRODUCTION

This chapter presents DRA's forecasts of gas throughput for PG&E's BCAP test period July 2010 through June 2012. Specifically, this chapter analyzes the PG&E core throughput forecasts for the residential, small commercial, large commercial, interdepartmental, and core natural gas vehicles (NGV) classes of service. The results reported in this chapter also include an analysis of the non-core industrial distribution demand, non-core transmission demand, non-core NGV and wholesale demand.

DRA's recommendations and PG&E's proposals are summarized in Section II. Section III discusses the econometric methodology, input assumptions, and specific econometric results obtained by DRA and PG&E.

2.2 SUMMARY OF RECOMMENDATIONS

The following summarizes DRA's recommendations.

- DRA concludes that PG&E's residential average temperature and cold-year forecasts are reasonable.[3] Under average temperature conditions forecasts PG&E forecasts residential throughput of 201,320 (Mdth).[4] For the cold-year PG&E forecasts residential throughput of 226,265 (Mdth).[5]
- For the BCAP period PG&E forecasts average temperature small commercial throughput of 79,077 (Mdth).[6] Under cold-year conditions,

[3] The rationale for DRA's conclusions are discussed in greater detail in Section II of this report.

[4] Pacific Gas and Electric Company, 2009 Biennial Cost Allocation Proceeding, Prepared Testimony, May 29, 2009 p. 2-2.

[5] Pacific Gas and Electric Company, 2009 Biennial Cost Allocation Proceeding, Prepared Testimony, May 29, 2009, p. 2-9.

[6] Pacific Gas and Electric, 2009 Biennial Cost Allocation Proceeding, Prepared Testimony, May 29, 2009, p. 2-2.

PG&E's small commercial throughput equals 85,197 (Mdth). DRA concludes these forecasts are reasonable. [7]

- DRA concludes that for the BCAP period PG&E's core interdepartmental and natural gas vehicle (NGV) forecasts of 159 (Mdth) and 2,022 (Mdth), respectively, are reasonable.
- For the industrial distribution non-core class of service DRA recommends a forecast of 27,561 (Mdth) for the BCAP forecast period. PG&E, on the other hand, recommends a forecast of 24,626 (Mdth). Under cold-year conditions, PG&E recommends a forecast of 28,301 (Mdth) while PG&E recommends a forecast of 26,001 (Mdth).
- For the industrial transmission non-core class of service DRA recommends a forecast of 145,331 (Mdth) while PG&E recommends a forecast of 144,150 (Mdth). This class of service is not weather sensitive. As a result, the cold-year forecast is the same as the average-year forecast.
- DRA concludes that PG&E's non-core NGV forecast is reasonable.
- DRA concludes that PG&E's wholesale forecast is reasonable.

DRA's and PG&E's recommended throughput volumes for the BCAP period under average weather conditions are reported in Table 2 - 1. An analogous summary of DRA's and PG&E's recommended throughput volumes under cold-year conditions is summarized in Table 2 – 2.

[7] Pacific Gas and Electric, 2009 Biennial Cost Allocation Proceeding, Prepared Testimony, May 29, p. 2-9.

Table 2 - 1

DRA and PG&E

Average Year BCAP Demand Summary

2010-2012

(Mdth)

Class of Service	DRA	PG&E	Difference
Core			
Residential	201,320	201,320	--
Commercial	86,531	86,531	--
Small Commercial	79,077	79,077	--
Large Commercial	7,454	7,454	--
Interdepartmental	159	159	--
Core NGV	2,022	2,022	--
Total Core	**290,032**	**290,032**	**--**
Non-Core			
Industrial	172,892	168,776	2.43 %
Industrial Distribution	27,561	24,626	11.92 %
Industrial Transmission	145,331	144,150	0.82 %
Non-Core NGV	523	523	--
Wholesale	3,726	3,726	--
Total Non-Core[8]	**350,039**	**341,801**	**2.41 %**

[8] Excluding Cogeneration and Electric Generation.

Table 2 - 2

DRA and PG&E

Cold Year BCAP Demand Summary

2010-2012

(Mdth)

Class of Service	**DRA**	**PG&E**	**Difference**
Core			
Residential	226,265	226,265	--
Commercial	93,064	93,064	--
Small Commercial	85,197	85,197	--
Large Commercial	7,867	7,867	--
Interdepartmental	159	159	--
Core NGV	2,022	2,022	--
Total Core	**321,510**	**321,510**	**--**
Industrial	173,632	170,151	2.04 %
Industrial Distribution	28,301	26,001	8.85 %
Industrial Transmission	145,331	144,150	0.82 %
Non-Core NGV	523	523	--
Wholesale	3,749	3,749	--
Total Non-Core[9]	**351,266**	**344,574**	**1.94 %**

[9] Excluding Cogeneration and Electric Generation.

2.3 DISCUSSION / ANALYSIS OF THROUGHPUT

2.3.1 Overview of PG&E's and DRA's Forecast Methodology

DRA and PG&E developed econometric models to forecast residential, small commercial, large commercial, industrial distribution, and industrial transmission throughput. These models forecast gas throughput as a function of weather, gas prices faced by consumers, seasonal effects, and economic conditions in PG&E's service area. For the residential and small commercial sector PG&E relied upon monthly observations and for industrial distribution and industrial transmission sectors PG&E relied upon quarterly observations. DRA, on the other hand, estimated its models with quarterly observations. [10] Forecasts are developed for average as well as cold-year conditions.

2.3.2 DRA Discussion/Analysis

2.3.2.1 Residential

PG&E models residential gas demand as a function of average constant dollar gas rates, heating degree days, the percentage of households added after 1978, monthly seasonal dummy variables, and dummy variables for the energy crises and the 1020 Plus gas program.[11] PG&E's model is estimated with monthly observations over the period January 1994 to November 2008. PG&E relies upon a log-linear specification.[12]

DRA's model is similar, regressing quarterly historical residential gas demand upon lagged values of historic gas demand, real average residential gas rates, the

[10] PG&E explained that in relied upon monthly observations for the residential and small commercial models and quarterly observations for the industrial distribution and industrial transmission sectors because: "Seasonal variation in demand is far more important in determining throughput for the residential and small commercial classes than it is for large customers (distribution and transmission), where temperature sensitivity is small or non-existent." (PG&E Response to DRA Data Request, DRA_002_Q13, June 29, 2009).

[11] A dummy or binary variable takes on the value of one at a particular observation or set of observations and zero elsewhere.

[12] In a log linear model the natural log of the dependent variable, in this case use per customer, is regressed upon the natural log of the explanatory variables. The advantage of this type of specification is that the estimated coefficients yield the estimated elasticities. PG&E's residential econometric model results are shown on page 2A-2 of Pacific Gas and Electric Company, Biennial Cost Allocation Proceeding, Prepared Testimony, May 29, 2009, p. 2A-2.

percentage of households added after 1987, heating degree days, quarterly seasonal variables, and a binary variable capturing the impact of the energy crises.[13] Similar, to PG&E, DRA relied upon a log-linear functional form. DRA's residential econometric model results are reported in the appendix to this chapter.

The DRA and PG&E residential econometric models yield reasonable results. The signs on the coefficients in the model are of the correct sign and generally statistically significant. DRA's model yields a short-term price elasticity of demand of -0.104 and a long-run price elasticity of demand of -0.130.[14] PG&E's residential model yields a short-run price elasticity of -0.0919. This is very close to DRA's short-run price elasticity of -0.104.

2.3.2.2 Commercial Core

PG&E's small commercial econometric equation, models gas demand as a function of heating degree days, real (constant dollar) commercial gas rates, lagged one month, commercial employment lagged one month, monthly seasonal binary variables, and dummy variables capturing the impact of the energy crises and the 1020 Gas plus program. Commercial employment is included in the model to capture the impact of economic activity in PG&E's service area on gas demand. PG&E's commercial employment forecast is taken from Economy.com's December 2008 forecast of the U. S. economy.[15] PG&E explains that: "The projection is for the

[13] Unlike PG&E, DRA relied upon quarterly rather than monthly observations. PG&E's residential econometric model generated a very low Durbin-Watson statistic, (0.819260). This low Durbin-Watson statistic suggests PG&E's model may be subject to first-order auto-correlation. When DRA re-estimated PG&E's PG&E residential model after correcting for first-order auto-correlation, the sign on the price term in the model changed signs from negative to positive. Normally, one would expect a negative sign on price, reflecting the inverse relationship between quantity demanded and price.

[14] In a linear log model with a lagged dependent variable such as $\log(Y_t) = \alpha + \beta \log(Y_{t-1}) + \gamma \log(X_t)$, the short-run elasticity is equal to γ and the long-run elasticity is equal to $\gamma / (1-\beta)$.

[15] PG&E's small commercial employment variable covers the following North American Industrial Classification System (NAICS) sectors.

Employment: Electrical Equipment, Appliance and Component Manufacturing.

Employment: Merchant Wholesalers, Non-Durable Goods.

Employment: Wholesale Electronic Markets and Agents and Brokers.

recession to continue to deepen through the first half of 2009, and then start showing some signs of recovery by the third quarter of 2009. Lagging measures of economic recovery, such as employment growth, may not show a turnaround until mid-2010."[16]

DRA's small commercial econometric model is similar to PG&E's. DRA regressed small commercial gas demand on small commercial gas demand lagged one quarter, real average small commercial gas rates, commercial employment, heating

---

Employment: Motor Vehicle and Parts Dealers.

Employment: Furniture and Home Furnishings Stores.

Employment: Electronics and Appliance Stores.

Employment: Building Materials, Garden Equipment, and Supplies Dealers.

Employment: Food and Beverage Stores.

Employment: Health and Personal Care Stores.

Employment: Gas Stations.

Employment: Clothing and Clothing Accessories Stores.

Employment: Sporting Goods, Hobby, Book and Music Stores.

Employment: General Merchandise Stores.

Employment: Miscellaneous Store Retailers.

Employment: Non-Store Retailers.

Employment: Monetary Authorities-Central Ban.

Employment: Credit Intermediation and Related Activities.

Employment: Securities, Commodity Contracts, and Other Financial Investments.

Employment: Insurance Carriers and Related Activities.

Employment: Funds, Trusts, and Other Financial Vehicles.

Employment: Real Estate.

Employment: Rental and Leasing Services.

Employment: Lessors of Nonfinancial Intangible Assets.

Employment: Professional, Scientific, and Professional Services.

Employment: Management of Companies and Enterprises.

Employment: Administrative and Support Services.

Employment: Elementary and Secondary Schools.

Employment: Junior Colleges.

(Pacific Gas & Electric Company, Response to DRA Data Request, DRA_004_Q4, July 23, 2009).

[16] Pacific Gas and Electric Company, 2009 Biennial Cost Allocation Proceeding, Prepared Testimony, May 29, 2009, p. 2-4.

degree days, seasonal quarterly dummy variables, along with binary variables capturing the impact on gas demand of the energy crises and the 1020 Gas Plus program. In its forecast analysis of the small commercial sector, DRA utilized PG&E forecast of commercial employment. IHS Global Insight's (Global Insight) forecast of employment growth is similar to Economy.Com's projections. Global Insight's most recent forecast of the U.S. Economy (August, 2009) notes that: "The bottom of the recession appears to be here, at least for output, though not for employment…The economy contracts 2.7 % during 2009, before growing 1.8 % in 2010. The unemployment rate reaches 10.1 %."[17]

As in the case of the residential class of service, the DRA and PG&E small commercial econometric equations yield reasonable results. The signs on the coefficients in the models have the expected signs and are, for the most part, statistically significant. PG&E's model yields a short-run employment elasticity of 0.539 and short-run price elasticity of -0.046. Both variables are statistically significant. DRA's equation yields a short-run price elasticity of -0.040 and long-run price elasticity of -0.046. DRA's estimated short-run employment elasticity equals 0.501 while the long-run employment elasticity equals 0.572.

2.3.2.3 Large Commercial – Distribution

PG&E's large commercial distribution econometric equation models historic quarterly large commercial usage as a function of historic usage lagged one quarter, real average gas rates lagged one quarter, and a measure of manufacturing output lagged one quarter, heating degree days, and quarterly seasonal binary variables.[18] A

[17] IHS, Global Insight, U.S. Executive Summary, August 2009, p. 1.

[18] For the large commercial distribution sector PG&E's output variable covers the following NAICS sectors:

Gross Product: Food Manufacturing.

Gross Product: Pulp, Paper, and Paperboard Mills.

Gross Product: Chemical Manufacturing.

Gross Product: Audio and Vehicle Equipment.

Gross Product: Other Support Services.

log-linear functional form is used with the model estimated from the second quarter of 1994 through the third quarter of 2008.

DRA's model is similar. DRA regressed historic large commercial distribution level demand on historic usage lagged one quarter, real average gas rates, a measure of manufacturing output, heating degree days, and quarterly seasonal binary variables. As in the case of the small commercial model, DRA's forecast is based on PG&E's forecast of manufacturing output in its service area. A log-linear functional form was used with the model estimated over the period from the first quarter of 1995 through the third quarter of 2008.[19]

Both models yield reasonable results. The explanatory variables in the DRA and PG&E models have the correct sign and are generally statistically significant. PG&E's model yields a short-run price elasticity of -0.0329 and a short-run output elasticity of 0.0895. DRA's model yields short- and long-run price elasticities of -0.0587 and -0.171, respectively. DRA's model yields a short-run output elasticity of 0.108 and a long-run output elasticity of 0.316.

2.3.2.4 Large Commercial – Transmission

PG&E's large commercial transmission econometric equation models historic gas demand as a function of gas demand lagged one quarter, real industrial gas prices lagged one quarter, a measure of manufacturing output, and series of quarterly binary variables.[20] A log-linear functional form is used with the model estimated over the period from the second quarter of 2004 through the fourth quarter of 2008.

Gross Product: Waste Management and Remediation Services.

Gross Product: Electronic and Precision Equipment Repair and Maintenance.

(Source: PG&E Response to DRA Data Request, DRA_004_Q02, July 23, 2009)

[19] PG&E deflated nominal gas rates for this class of service by the Consumer Price Index-All Urban Consumers (CPI-U) while DRA deflated nominal gas rates by the Wholesale Price Index (WPI). DRA's forecast of the WPI was taken from IHS Global Insight's Review of the U.S. Economy, June, 2009.

[20] For the large commercial transmission sector, PG&E's manufacturing output variable covers the following NAICS sectors:

Gross Product: Food Manufacturing.

Gross Product: Petroleum and Coal Products.

DRA's econometric model for this sector is similar to PG&E's. DRA models demand to this sector as a function of gas demand lagged one quarter, real average gas rates, a measure of manufacturing output, and a series of quarterly dummy variables. Similar to PG&E, a log-linear functional form is used with the model estimated over the period from the second quarter of 1994 through the fourth quarter of 2008.[21]

Both models yield reasonable results with the correct signs on the explanatory variables. PG&E's econometric equation yields a short-run price elasticity of -0.0187. DRA's model yields a short-term price elasticity of -0.0343 and a long-run price elasticity of -0.0845. PG&E's short-run output elasticity equals 0.173 and the long-run output elasticity is 0.589. DRA's model yields short- and long-run output elasticities of 0.116 and 0.286, respectively.

2.3.2.5 Wholesale

For the wholesale class of service, PG&E's forecast under average and cold-year conditions, is based on information provided by each wholesale customer. As PG&E explains: "The forecasts for these customers' loads are based on customer specific information collected from the customers themselves."[22]

2.4 CONCLUSION

DRA and PG&E developed econometric models to forecast gas throughput to the residential, small commercial, large commercial – distribution, and large commercial – transmission classes of service. The econometric equations model gas demand as a function of real average gas prices, economic conditions in PG&E's service area, heating degree days, and seasonal factors. Forecasts are developed under normal and cold year conditions. DRA and PG&E relied upon a log-linear functional form for each sector.

Gross Product: Building Materials Products.

(Source: PG&E Response to DRA Data Request, DRA_004_Q3, July 23, 2009).

[21] As in the case of the large commercial distribution model, DRA deflated nominal average gas rates by the WPI rather than the CPI. DRA's forecast of the WPI was taken from IHS Global Insight's Review of the U.S. Economy, June, 2009.

[22] Pacific Gas and Electric Company, 2009 Biennial Allocation Proceeding, Prepared Testimony, May 29, 2009, p. 2-7.

DRA concludes that PG&E’s forecasts for the residential, small commercial, interdepartmental, and natural gas vehicles are reasonable. For the non-core industrial distribution and transmission classes of service DRA recommends higher throughput forecasts than does PG&E.

APPENDIX

Econometric Results

DRA Mnemonics List

AVGUSE	Residential Use Per Household
COMDEMAND	Large Commercial Distribution Throughput
COMEMP	Large Commercial Distribution Employment
CPI	Consumer Price Index
DUMEC	Energy Crises Dummy
DUM00	Third Quarter 2000 Dummy
DUM01	First Quarter 2001 Dummy
DUM02	First Quarter 2002 Dummy
DUM04	Second Quarter 2004 Dummy
DUM99	First Quarter 1999 Dummy
DUM06	Second Quarter 2006 Dummy
DUM1012	2006,2007,2008 First Quarter Dummy
GNTT	Employment – Large Commercial Transport
GPRICER	Constant Dollar Gas Price – Large Commercial Transport and Large Commercial Distribution
HDD	Heating Degree Days
HDDC	Cold Year Heating Degree Days
HHPGE	Households PG&E Service Area
INDTRANG	Large Commercial Transportation Demand
L	Natural log operator
P87HHPGE	Percentage of Households Added After 1987
RESDEMAND	Residential Gas Throughput

RESPRICE	Residential Real Average Gas Price
SMCOM	Small Commercial Throughput
SMEMP	Small Commercial Employment
SMPRICE	Small Commercial Real Average Gas Price
SQ1	First Quarter Dummy Variable
SQ2	Second Quarter Dummy Variable
SQ3	Third Quarter Dummy Variable
SQ4	Fourth Quarter Dummy Variable
WPI	Wholesale Price Index

TABLE A-1

DRA RESIDENTIAL ECONOMETRIC MODEL

Variable	Coefficient	Standard Error	t-Statistic	P-Value
CONSTANT	0.4911	0.1909	2.573	0.013
LAVGUSE(-1)	0.1988	0.0913	2.178	0.034
HDD	0.0008	0.0001	7.900	0.000
LP87HHPGE	-0.3754	0.1100	-3.413	0.001
LRESPRICE	-0.1041	0.0458	-2.274	0.027
SQ2	-0.3758	0.0644	-5.837	0.000
SQ3	-0.4292	0.0850	-5.053	0.000
SQ4	0.1380	0.0845	1.633	0.109
DUMEC	-0.0290	0.0227	-1.274	0.209

Adjusted R2 = 0.9844

Durbin-Watson = 1.781

Durbin's h = 1.114

TABLE A-2

DRA SMALL COMMERCIAL ECONOMETRIC MODEL

Variable	Coefficient	Standard Error	t-Statistic	P-Value
CONSTANT	3.9230	0.6377	6.152	0.000
LSMLCOM(-1)	0.1231	0.0834	1.477	0.145
HDD	0.0006	0.00004	9.503	0.000
LSMEMP	0.5015	0.0789	6.353	0.000
LSMPRICE	-0.0408	0.0285	-1.432	0.158
SQ2	-0.2036	0.0419	-4.859	0.000
SQ3	-0.2076	0.0518	-4.009	0.000
SQ4	0.0395	0.0484	0.8154	0.418
DUM02	-0.0604	0.0428	-1.410	0.164
DUM1012	-0.0445	0.0275	-1.621	0.111
DUMEC	-0.0073	0.0143	-0.5158	0.608

Adjusted R2 = 0.9845

Durbin-Watson = 1.734

Durbin's h = 1.363

TABLE A-3

DRA LARGE COMMERCIAL DISTRIBUTION ECONOMETRIC MODEL

Variable	Coefficient	Standard Error	t-Statistic	P-Value
CONSTANT	2.323	1.019	2.278	0.027
LCOM(-1)	0.657	0.084	7.808	0.000
HDD	0.0001	0.00006	1.924	0.060
LGPRICER	-0.058	0.0154	-3.808	0.000
LEMP	0.108	0.073	1.477	0.146
SQ2	-0.084	0.039	-2.151	0.037
SQ3	0.044	0.049	0.903	0.371
SQ4	0.088	0.021	4.071	0.000
DUM00	0.089	0.036	2.468	0.0171

Adjusted R2 = 0.8779

Durbin-Watson = 2.0511

Durbin's h = -1.148

TABLE A-4

DRA LARGE COMMERCIAL TRANSPORT ECONOMETRIC MODEL

Variable	Coefficient	Standard Error	t-Statistic	P-Value
Constant	3.254	0.966	3.367	0.002
LINDTRANG(-1)	0.594	0.0696	8.532	0.000
LGPRICER	-0.0343	0.0170	-2.008	0.050
LGNTT	0.116	0.0888	1.305	0.198
SQ2	0.0466	0.0215	2.167	0.035
SQ3	0.4482	0.0221	20.225	0.000
SQ4	-0.0405	0.0261	-1.547	0.128
DUM99	-0.1081	0.0524	-2.062	0.045
DUM01	-0.1398	0.0581	-2.406	0.020
DUM04	-0.1758	0.0522	-3.366	0.002
DUM06	-0.3870	0.0518	-7.460	0.000

Adjusted R2 = 0.9316

Durbin-Watson = 1.6365

Durbin’s h = 1.3896

CHAPTER 3 – ELECTRIC GENERATION THROUGHPUT FORECAST

Witness: Maricela P. Sierra

3.1 INTRODUCTION

This chapter presents the DRA's analyses and recommendations regarding PG&E's proposal for the electric generation (EG) throughput forecast for the BCAP forecast period of July 1, 2010 through June 30, 2012.

3.2 SUMMARY OF RECOMMENDATIONS

The following summarizes DRA's recommendations:

- DRA recommends that the Commission adopt an updated EG throughput forecast of 276,555 MDth per year, in contrast to PG&E's forecast of 263,262 MDth per year. DRA's recommendation relies on more current gas price forecast assumptions.
- Table 2-1 presents PG&E's and DRA's proposed EG Gas demand forecast for the BCAP period.

TABLE 3-1
EG THROUGHPUT FORECAST
JULY 1, 2010 THROUGH JUNE 30, 2012
MDth/yr

Customer Class	PG&E	DRA	Difference	% Change
Electric Generation	263,262	276,555	13,293	5.05%

3.3 DISCUSSION / ANALYSIS OF ELECTRIC GENERATION GAS DEMAND FORECAST

3.3.1 Overview of PG&E's Proposal

PG&E's EG gas throughput forecast for this BCAP is 263, 262 MDth per year. PG&E divides electric generators into two categories (1) non market-responsive cogenerators (non market-responsive COGEN) and (2) market responsive generators and cogenerators (market-responsive EG and COGEN). The operation of non market-responsive cogeneration plants is not strongly affected by conditions in the electricity market because the plants are co-producing electricity and some other energy product, usually steam, and because they have Qualifying Facility power-sales agreements with PG&E. The operation of market responsive plants is affected by changes in the electricity market.

PG&E's market-responsive EG forecast is based on results from the Market Builder model. Market Builder is a proprietary economic-equilibrium model that has been applied to various markets with spatially distributed supplies and demands, such as the North American natural gas market. Since northern California is part of a much larger western electricity market, PG&E used Market Builder to simulate the entire Western Energy Coordinating Council (WECC) area. Many assumptions including regional electric demands, hydroelectric conditions, and fuel prices are incorporated into the model.

3.3.2 Electric Generation Gas Demand Forecast

DRA noted that PG&E used out-dated natural gas prices provided by Sempra for the 2008 California Gas Report to run the Market Builder model to forecast the EG Gas Demand for the BCAP period 2010-2012. DRA requested that PG&E rerun the Market Builder model using a current gas price forecast. PG&E reran the Market Builder model using the current gas prices forecasts as of August 20, 2009 provided by HIS Cambridge Energy Research Associates, Inc".[23] As a result, PG&E's market responsive EG forecast increased to 203,315 MDth/year compared to 190,022 MDth/year that PG&E filed in its testimony for the BCAP period 2010-2012.

TABLE 3-2
EG THROUGHPUT FORECAST
BY CLASS
JULY 1, 2010 THROUGH JUNE 30, 2012
MDth/yr

Customer Class	PG&E	DRA	Difference	% Change
Market Responsive EG and COGEN	190,022	203,315	13,293	7.00%
Non Market Responsive COGEN	73,240	73,240	0	0.00%
Electric Generation	263,262	276,555	13,293	5.05%

3.4 CONCLUSION

DRA recommends that the Commission adopt an updated EG throughput forecast of 276,555 MDth per year in contrast to PG&E's forecast of 263,262 MDth per year. DRA's recommendation relies on using an updated gas prices forecast in the Market Builder model, which is more consistent with current market conditions.

[23] Based on PG&E DR Response to Question 1 in DRA-MPS 1 dated August 14, 2009.

CHAPTER 4 - COST ALLOCATION ISSUES

Witness: Pearlie Z. Sabino

4.1 INTRODUCTION

Pursuant to Commissioner Simon and ALJ Wong's Ruling dated August 11, 2009 in A.09-05-026, this chapter presents DRA analyses and recommendations regarding the PG&E's proposals on "whether the cost allocation application of PG&E's gas distribution costs should be granted with rates effective July 1, 2010… and should PG&E's proposals regarding marginal cost proposals be granted."[24] These two issues are significant as stated in the Scoping Memo.

Regarding marginal costs, PG&E states that "marginal cost updates in this proceeding result in a slight increase in the distribution revenue requirement allocation to core customers, from 96.7 percent to 96.9 percent and a slight decrease to noncore customers, 3.3 percent to 3.1 percent."[25] Accordingly and with respect to its marginal cost updates, PG&E requests that the Commission:[26]

- Adopt PG&E's updated customer and distribution LRMC of providing gas distribution service;
- Adopt PG&E's proposed distribution investment plan;
- Adopt PG&E's proposed marginal cost "loaders" (e.g. growth-related for administrative and general (A&G), Operation and Maintenance (O&M) expenses and economic factors (e.g. discount rate and real economic carrying charge); and
- Adopt PG&E's proposed marginal cost revenues.

PG&E states that its marginal cost proposals are based on the methodologies adopted in D.05-06-029 for PG&E's 2005 BCAP.

---

[24] See Scoping Memo and Ruling, p.2.

[25] PG&E Prepared Testimony in A.09-05-026, p.1-1.

[26] Ibid, p.1-5 and p.3-1.

The Commission first adopted the Long Run Marginal Cost (LRMC) methodology for California gas utilities in D.92-12-058. Through the years, in both gas and electric utility proceedings, the Commission affirmed its preference for the LRMC cost allocation methodology.[27] In D.05-06-029, the Commission adopted the current BCAP cost allocation methodology for PG&E, which is the new customer only (NCO) marginal cost method. DRA supports both the Commission's preference for LRMC (NCO) and the Commission's general guiding principles on cost allocation. These Commission guidelines focus on cost incurrence, economic efficiency, and equity. The Commission considers these as an important basis to determine whether allocation factors are both just and reasonable.[28]

Further, as established in the past LRMC decisions, the results of the cost allocation are ultimately scaled and reconciled with the total revenue requirement pursuant to the utility's adopted final numbers in the General Rate Case (GRC).[29] The Commission scales these costs to ensure that utilities meet their authorized total revenue requirement goals and concurrently meet the customer's needs at the lowest total cost.[30]

In this application, PG&E uses the equal percent of marginal costs (EPMC) method to allocate the scaled distribution and customer marginal cost revenues to the distribution-level base revenue requirements.[31] Also, as later explained in Section III.B., the Commission in D.05-06-029, agreed with PG&E that the replacement cost adder (RCA) is already recognized in marginal distribution costs through the real economic carrying charge (RECC). The Commission also recognized that the calculation of marginal customer costs for gas service should not continue to include the replacement

[27] See Decisions (D.) 93-05-066, D.95-12-053, D.96-04-050, D.97-08-055, D.97-04-082, D.97-08-062, D.98-06-073, D.00-04-060, D.01-11-001, and D.05-06-029.

[28] See D.86-12-009, D.90-07-055, and D.92-12-058.

[29] The currently adopted distribution level base revenue requirement was approved in PG&E's 2007 GRC decision in D.07-03-044.

[30] See D.92-12-058.

[31] PG&E Prepared Testimony in A.09-05-026, pp.3-2 and 4-1.

costs of gas facilities.[32] Notwithstanding those findings and conclusions in D.05-06-029, PG&E admits that it has kept the RCA in the marginal customer cost calculation and only removed the RCA from the marginal distribution cost calculation.[33] In that regard, PG&E's practice appears contrary to stated Commission policy. In this testimony, DRA will properly analyze and define the Commission's position with respect to the RCA. And, DRA will demonstrate that per Commission policy, the RCA should be included in both the calculation of the marginal customer cost and the marginal distribution cost.

4.2 SUMMARY OF RECOMMENDATIONS

In summary, DRA recommends:

- That the Commission reject the PG&E proposed updated customer and distribution LRMC of providing gas distribution service for PG&E's customers and instead adopt those recommended by DRA as follows:
    - (i) A two-year average marginal distribution unit cost of $233.45/MDM (marginal demand measure);
    - (ii) Adjustments in service line length for both new business SRM (service line, regulator, meter) and replacement SRM to derive the weighted average SRM cost for each customer class; and
    - (iii) The exclusion of trenching costs in the SRM estimates for replacement of service calculations per customer class.
- That the Commission adopt the proposed distribution investment plan;
- That the Commission adopt the proposed marginal cost "loaders" (e.g. growth-related for administrative and general (A&G), Operation and

[32] See Finding of Fact #s 14 & 15 and Conclusion of Law #6 in D.05-06-029. Also, see discussion on page 20 of D.05-06-029 regarding replacement cost adder.

[33] Refer to PG&E's Response to DRA Data Request in A.09-05-026 DRA-PZS2-2.

Maintenance (O&M) expenses and economic factors (e.g. discount rate and real economic carrying charge); and

- That the Commission reject the PG&E proposed marginal cost revenues and instead adopt those recommended by DRA because PG&E's proposal is deficient in several respects:
    - (i.) the absence of distribution RCA for the replacement cost of existing distribution facilities;
    - (ii.) the inaccurate calculation of its weighted SRMs with the appropriate service line lengths;
    - (iii.) the slightly lower throughputs used by PG&E for purposes of the cost allocations; and
    - (iv.) the flawed inclusion of trenching costs for replacement services.

DRA's review of PG&E's proposed allocation of its distribution level revenue requirements to the different customer classes yield the following Core/Non-Core allocations summarized below in Table 4-1.

TABLE 4-1

SUMMARY RESULTS OF PG&E'S GAS

DISTRIBUTION MARGINAL COST REVENUE

AVERAGE OF 2 YEAR BCAP PERIOD (JULY 2010 – JUNE 2012)

[in $000 and Percent Share By Customer Class]

Customer Class	DRA Recommended[34].	DRA as % of Total System	PG&E Proposed	PG&E as % of Total System	Amt PG&E > DRA	Percent PG&E > DRA
(a)	(b)	(c)	(d)	(e)	(h)	(i)
Residential	$ 830,867	79.18%	$792,386	80.21%	$(38,480.68)	0.87%
Small Commercial	$ 174,235	16.60%	$158,736	16.07%	$(15,498.96)	-0.42%
Large Commercial	$ 6,045	0.58%	$5,264	0.53%	$(780.90)	-0.04%
NGV Core	$ 1,001	0.10%	$724	0.07%	$(277.44)	-0.02%
Total Core	$ 1,012,148	96.45%	$957,110	96.88%	$(55,037.98)	0.39%
Industrial Distribution	$ 25,141	2.40%	$20,235	2.05%	$ (4,905.90)	-0.32%
Industrial Transmission	$ 7,379	0.70%	$6,384	0.65%	$ (994.25)	-0.05%
EG (Cogen Dist)	$ 4,542	0.43%	$4,048	0.41%	$ (493.98)	-0.02%
Total NonCore	$ 37,241.94	3.55%	$30,824	3.12%	$ (6,417.92)	-0.39%
Total System	$ 1,049,390	100.00%	$987,934	100.00%	$(61,455.90)	0.00%

Source: PG&E Workpapers Supporting Prepared Testimony in A.09-05-026.

4.3 OVERVIEW OF PG&E'S PROPOSAL

The current cost allocation methodology for the PG&E gas distribution level revenue requirement is the LRMC methodology. LRMC methodology applies to the utility's distribution level revenue requirement which is the basic gas distribution service

[34] From DRA's Workpapers on Cost Allocation. This Recommendation is based on using DRA'S Throughput forecast, adding Distribution RCA, changing the service line length to calculate the weighted SRMs, and removing the trenching cost for replacement service.

revenues that include distribution costs (without any storage and transmission costs which are determined as part of the Gas Accord) and customer costs (including service lines, meters, and regulators). The gas commodity cost is not considered part of the PG&E distribution level revenue requirement.

In the instant application, PG&E proposes to use the LRMC NCO method for the cost allocation of its marginal customer cost.[35] The LRMC NCO methodology is also sometimes referred to as "one-time hookup" approach which includes the access costs for new customers. In this application, PG&E uses the regression method for the marginal capacity cost of its distribution. For other marginal cost components, PG&E uses different loaders and provides a summary of those methodologies in Table 3-1 of its Prepared Testimony, as amended.[36]

According to PG&E in its application, "marginal cost updates in this proceeding result in a slight increase in the distribution revenue requirement allocation to core customers, from 96.7 percent to 96.9 percent and a slight decrease to noncore customers, 3.3 percent to 3.1 percent."[37]

However, the Commission needs to first determine, as the scoping memo states, "whether the cost allocation application of PG&E's gas distribution costs should be granted with rates effective July 1, 2010… and should PG&E's proposals regarding marginal cost proposals be granted."[38]

[35] The embedded cost method is used for PG&E's transmission and gas storage functions. The latter was adopted pursuant to the original PG&E Gas Accord in 1997, and subsequent extensions, as approved by the Commission. See original Gas Accord approved in D.97-08-055.

[36] Based on PG&E's revised Response to DRA Data Request in A.09-05-026 DRA-PZS3-3.

[37] PG&E Prepared Testimony in A.09-05-026, p.1-1.

[38] See Scoping Memo and Ruling, p.2.

4.4 DRA DISCUSSION/ANALYSIS

DRA's review is based on PG&E's Prepared Testimony presented in Chapter 3, including errata as well as, all workpapers and discovery responses received by DRA via mail, email, and telephone conversations.

The Commission's purpose in the instant proceeding is to allocate the distribution level revenue requirement to the cost causers according to how each customer class imposes costs on the system. To achieve this under the LRMC methodology, the calculated marginal unit costs will be multiplied by the marginal demand measures (MDM).[39] For purposes of PG&E's gas distribution BCAP, the MDM is expressed in terms of the cold winter day demand.[40] In this BCAP, PG&E proposes an MDM of 2,027 MDthd (thousands of decatherms per day).[41] DRA recommends an MDM of 2,036 MDthd.[42]

The calculation of PG&E's gas distribution marginal costs has two major components: distribution and customer marginal unit costs. DRA's discussion in this section is divided into the following four parts:

(i) the derivation of PG&E's distribution marginal unit costs;
(ii) customer marginal unit costs;
(iii) the loaders associated with both distribution and customer marginal costs; and
(iv) the resulting marginal cost revenues.

The distribution marginal unit costs consist of the utility's gas distribution marginal cost of investment capital, the different marginal O&M-related costs associated

[39] The Commission adopted the cold winter day for distribution MDMs for calculating gas marginal distribution costs and allocating distribution revenues in D.95-12-053. See also PG&E's Prepared Testimony in A.09-05-026, p.2-10.

[40] See D.92-12-058 where the term Marginal Demand Measure (MDM) was first adopted to refer to the criterion that causes a utility to need more capacity.

[41] Refer to Line 5 of Table 3-6 in PG&E's Prepared Testimony in A.09-05-026, p.3-18.

[42] Based on recommendations by DRA BCAP Witnesses Tom Renaghan and Maricela Sierra who sponsored the throughput forecasts for DRA (econometric and non-econometric).

with such investment capital, the replacement costs adders (RCA), and Administrative and General (A&G) costs that are incurred for each unit of the MDM.

The customer marginal unit costs consist of the new customers' one-time hook-up costs (fixed cost component), the customers' variable costs (both customer accounts and O&M, A&G-related, General Plant-related loaders), and the replacement cost adder for all customers.

The marginal unit costs of distribution per customer class are multiplied by the MDMs per customer class to generate the marginal distribution cost revenues. The customer marginal unit costs per customer class are multiplied by the forecast number of customers to generate the marginal customer cost revenues. The combined total of these marginal cost revenues determines what the cost allocation should be to each customer class within PG&E's distribution system.

4.4.1. Distribution Marginal Costs

The annualized marginal capital investment cost is the single largest element of the distribution marginal cost. Thus, it is very important for the utility to generate a reasonable forecast of its distribution investment plan.

In calculating the components of its distribution marginal costs, PG&E derives its annualized marginal capital investment by multiplying its Real Economic Carrying Charge (RECC) of 9.55 percent and its marginal investment cost of $1,587 (expressed in 2010$).[43] The latter amount of $1,587 is the result of PG&E's 15-year regression analysis. The analysis regresses the combined PG&E 10-year historical streams of gas distribution plant additions and 5-year forecast gas distribution investment plan against PG&E's combined 10-years historical gas distribution demand and 5-years of forecast demand. To forecast the five years (2009 through 2013) of load-growth-related plant additions, PG&E uses all available historical data from 1988 through 2008. According to PG&E, its 5-year projected load growth-related gas distribution investments are not based

[43] Refer to lines 2 & 3 of Table 3-6 of PG&E's Prepared Testimony in A.09-05-026.

on the investment cost of specific projects to be constructed but instead bases it on occurrence "in the form of many small investments undertaken in relatively short periods of time throughout PG&E's service territory as the result of many local decisions."[44] DRA reviewed the historical investment data shown in PG&E's workpapers and could not reconcile the early part of the historical data. PG&E explains that they left the prior historical data from previous BCAPs unchanged and only updated recent historical data. PG&E states that the distinction between current year dollars and real dollars may be the reason why it is difficult to reconcile the information provided.[45] Compared to the prior 5-year period shown, PG&E's forecasted load-growth-related distribution investments from 2009-2013 are lower with approximately $36 million per year for total distribution demand of 24 mdthd on the average. This investment level is estimated to be 20 percent lower relative to prior 5-year distribution investments of approximately $46 million per year for total distribution demand of 25 mdthd on the average. PG&E explains the minimizing of the error terms squared analysis that establishes a historic relationship between two variables, as provided by the regression analysis, is a better indication of the forecast's appropriateness rather than comparing the period averages.[46] DRA does not oppose PG&E's explanation.

DRA notes that there is no provision for an RCA for existing facilities in PG&E's proposed distribution marginal cost.[47] PG&E states that their calculation of the marginal distribution cost calculation is consistent with D.05-06-029, the latter decision that accepted PG&E's proposal to remove the replacement cost adder.[48] PG&E states that this relates to the replacement costs of future facilities installed to meet load growth.[49]

[44] PG&E's Prepared Testimony, p.3-5.

[45] Based on PG&E's Response to DRA Data Request in A.09-05-026 DRA-PZS6.

[46] Based on PG&E's Response to DRA Data Request in A.09-05-026 DRA-PZS8.

[47] Based on PG&E's Response to DRA Data Request in A.09-05-026 DRA-PZS3-1 (Revised).

[48] Based on PG&E's Responses in A.09-05-026 DRA-PZS3 Question 2 and DRA-PZS2 Question 2.

[49] Ibid.

PG&E explains that "D.05-06-029 did not alter PG&E's long-standing method of calculating the replacement of future facilities installed to meet load growth using the real economic carrying charge."[50] DRA disagrees with PG&E. DRA's calculation provides for an RCA with respect to existing distribution facilities. DRA uses the depreciation proxy for the RCA. DRA explains below why an RCA for existing facilities should be part of the long run marginal cost calculations.

Prior to PG&E's 2005 BCAP, the Commission had supported the inclusion of replacement cost provisions for both existing and future facilities. When the Commission first started developing the LRMC methodology in 1987 decision, the Commission clearly recognized the need to include provisions for replacements of existing system facilities. The Commission states in D.87-03-044.[51]

> The resource plan studies should describe and justify all capital additions to the utilities' intrastate rate base expected during the next 15 years. Therefore, we are interested in <u>both resource additions that are required to meet increased capital needs and replacements of existing system components due to physical depreciation.</u>

In the 1995 BCAP for PG&E, the Commission states in D.95-12-053.[52]

> DRA and TURN's recommendation <u>to include in PG&E's resource plan all future capital investment needed to maintain reliable service is a necessary refinement to our adopted methodology in order to meet our objectives of promoting economic efficiency, market-based pricing, equitable rates, and fostering competition</u>. This refinement <u>is consistent with marginal cost economic theory and with our definition in D.92-12-058 of the resource planning process</u>."

Moreover, in D.97-04-082, the Commission further states:[53]

---

[50] Ibid.

[51] See D.87-03-044, 24 CPUC 2d., p.54, emphasis added.

[52] See D.95-12-053, mimeo, p.22, emphasis added.

[53] See D.97-04-082, p.48, emphasis added.

> Turning to the issue of the definition of marginal costs, we find that including the future replacement costs is not an embedded costing methodology. In the long run, new capital additions are planned to serve the projected system load in an efficient manner, not simply duplicate the existing system. It is a well accepted principle of economics that the "long run" is defined as a period of time in which all inputs to a firm are considered variable for decision making purposes. In other words, <u>in the true definition of long run, all costs are variable and there is an opportunity cost to not replacing the existing system</u>. <u>If replacement costs are not incurred, additional capacity costs will be required to maintain efficiency</u>."

DRA too has previously supported the Commission's inclusion of replacement cost adders for existing facilities in PG&E's BCAPs including the last BCAP of 2005. DRA has always taken the position that if the replacement cost adder is rejected for the demand-related function, then for the sake of consistency, the adder should also be removed from marginal customer costs.[54] More importantly as noted above, with the exception in D.05-06-029, the Commission has previously consistently supported the inclusion of the replacement cost adder for existing and future load-growth-related facilities.

In D.05-06-029 for the 2005 PG&E BCAP, the Commission states in Findings Of Fact #14 and #15:

> Economic literature does not resolve whether replacement costs are appropriately included in long run marginal cost calculations.
>
> PG&E argues convincingly that replacement cost for distribution facilities are already recognized in marginal distribution costs.

Notwithstanding Finding of Fact #14 in D.05-06-029, DRA notes that the last 2005 PG&E BCAP proceeding did not show any explicit review of economic literature

---

[54] See reference to DRA in D.00-04-060, p.36.

regarding either replacement costs and/or long run marginal cost calculations. The Commission finding simply states that economic literature does not resolve the issue of whether replacement costs belong in long run marginal cost calculation. In this BCAP, as part of its testimony, DRA provides below some insights into the thinking of economists who worked in the area of utility regulation regarding the inclusion of depreciation as part of long run marginal cost calculations. Long run marginal cost calculations are those originally adopted by the Commission in D.92-12-058. The depreciation estimate is considered an acceptable proxy for replacement cost.[55]

DRA quotes below from the writings of Alfred E. Kahn, one of the most well-respected economists in the field of utility rate regulation. Kahn's writings support the notion that the cost of replacing worn out facilities is appropriately a part of the marginal cost calculation:[56]

> Variable costs include any sacrifice of future value or any future realization of higher costs that are causally attributable to present production. Short-run marginal cost is simply the change in total variable cost caused by producing an additional unit; <u>to the extent wear and tear of equipment varies with use – and it certainly does – depreciation is a variable cost</u>, although it is typically most convenient for accounting purposes to lump physical wear-and-tear together with provision for obsolescence, label the package "depreciation," and charge it off per unit of time instead of output. If price does not cover such variable costs, it is not doing its job, which is to reflect the marginal opportunity costs to society of providing the service.

Another equally prominent and well-respected economist in the same field is James C. Bonbright. DRA quotes below from Dr. Bonbright, et al, as the authors discuss the characteristics of short-run marginal costs :[57]

---

[55] D.95-12-053, p.22.

[56] Affred E. Kahn, The Economics of Regulation, Vol.1, pp.71-72, 1970 John Wiley & Sons Inc. Emphasis added.

[57] James C. Bonbright, Albert L.Danielsen, and David R. Kamerschen, Principles of Public Utility Rates,

> In short-run analysis the capital costs of plant and equipment are treated as unalterable or fixed (and perhaps sunk if they are irreversible and assets illiquid) and hence are excluded for the purpose of the estimate. Indeed, even a large share of the costs which accountants call operating expenses is treated in the same way, on the ground that many of these costs do not vary, at least not materially, with changes in the rate of plant utilization. <u>This exclusion of a good part even of the operating costs applies notably to a portion, usually the major portion, of the operating-expense deduction for annual depreciation (in reality a capital cost), since only a minor part of this depreciation is deemed to be affected by the degree of use made of the equipment</u>.

The same authors explain however that under long run marginal costs, all costs are treated as variable, including all costs that are treated as fixed under short-run cost analysis:[58]

> As already noted, what distinguishes long-run from short-run marginal cost is that the former cost is measured under the assumption of a *sustained* increment in the rate of output – sustained for a period sufficiently long to require, or at least to justify, a change in the capacity and design of the plant and equipment. <u>This means that those capital and operating costs which are treated as unalterable or fixed, and hence are excluded in short-run cost analysis, are here treated as variable</u>.

With respect to the other issue in Finding of Fact #15 that replacement costs are already being provided for in marginal distribution costs (through the RECC), it should be pointed out that PG&E's methodology applies the RECC only on the load-growth-related marginal investment cost for distribution.[59] Therefore, the calculation does not capture the replacement cost related to the existing distribution facilities because the RECC applies only to the future load-growth-related investments. PG&E confirmed the

---

2nd edition 1988, p.418, Public Utilities Reports, Inc., Emphasis added.

[58] Ibid., p.422, Emphasis added.

[59] PG&E Prepared Testimony, p.3-5.

exclusion of any capital investments necessary to replace the worn-out facilities of the existing distribution system to maintain output from going down, including those originating from the Gas Pipeline Replacement Program.[60] Based on the foregoing, the RECC in PG&E's methodology provides for the replacement cost of only future distribution investments. The RECC represents a level annual Revenue Requirement for depreciation, insurance, property taxes, state and federal taxes and return in constant dollars over the service life of an investment, adjusted for inflation and discounted at PG&E's current cost of capital.[61] In this BCAP, PG&E's RECC is 9.55% for gas distribution. When applied to PG&E's marginal investment cost of $1,587 (in $2010), the resulting amount of $151.5986/Dthd is the annualized marginal capital investment in distribution.[62] PG&E's annualized marginal capital investment represents future investments in distribution facilities to meet load-growth and does not provide for the replacement of existing distribution facilities. The resulting two-year average of PG&E's proposed distribution marginal cost is $197.94/MDM.[63] DRA recommends the inclusion of a distribution RCA based on a depreciation proxy in PG&E's marginal distribution unit costs.[64] DRA's recommendation will result in a two-year average marginal distribution unit cost of $233.45/MDM.

4.4.2 Customer Marginal Costs

In D.05-06-029, Conclusion of Law #6, the Commission states:

> The calculation of marginal customer costs for gas service should not continue to include a value recognizing replacement costs of gas facilities.

---

[60] Based on PG&E's Response in A.09-05-026 DRA-PZS3-1 (Revised) and PZS3-3(c) (Revised).

[61] Based on the RECC calculation in PG&E's Response to DRA Data Request in A.09-05-026 in DRA-PZS1-2.

[62] See Table 3-6 on page 3-18 of PG&E's Prepared Testimony.

[63] Ibid., as shown on Line 13.

[64] The replacement cost is shown in cell E14 in Tab DISTMC of the excel spreadsheet workpaper in the filename Switch2010_2009Update.

PG&E explains that "the language quoted from Conclusion of Law #6 was taken directly from the discussion of the replacement cost adder as it related to the distribution marginal costs. Unfortunately, the Commission used the term marginal customer costs when it concluded its discussion."[65] Further, PG&E argues "the inclusion of replacement costs in the customer marginal costs was not raised as an issue in the proceeding and that the Commission has consistently adopted replacement costs as a component of customer marginal costs in PG&E's BCAPs as well as the BCAPs of the other utilities. There is no reason for the Commission to have denied its inclusion in PG&E's last BCAP."[66] Notwithstanding Conclusion of Law #6, DRA agrees with PG&E on the provision of an RCA in the customer marginal cost calculation. Further, there is no reason for the Commission to contradict what it said earlier in FoF #16 in D.95-12-053 (emphasis added) where the Commission clearly states its position regarding the inclusion of customer replacement costs:

> utilities incur investment-related customer costs based on hooking up new customers and <u>periodic replacement of the service, regulator, and meter for all customers</u>; this is the change in total costs that should be measured.

The NCO method measures the cost imposed by the addition of a new customer. Under the NCO method, the cost of new service lines, regulator, and meter (SRM) are multiplied by the projected number of new customers for each customer class to calculate the total new customer costs. This cost is a total investment for new customers only in a given year, rather than an annualized cost for the investment. Since NCO does not use an annualized cost, the real economic carrying cost (RECC) factors are not part of the calculation.[67]

---

[65] Based on PG&E's Responses to DRA Data Request in A.09-05-026 DRA-PZS2-2.

[66] Ibid.

[67] Under a rental method, the RECC is used to develop an annualized cost for the investment. This annualized cost is charged to all customers. This is the fundamental difference in methodology between the LRMC (NCO) and the rental method.

In developing its SRM costs, PG&E explains that except for its meter set costs, it updated SRM costs in 2009 by pulling the materials costs from its SAP system.[68] For the meter sets, PG&E explains that the costs are based on material costs from the SAP system in 2006 and then escalated to 2010$.[69] PG&E also explains that it updated labor costs to account for PG&E's labor contract increases in 2009.[70] With these 2009 material and labor costs as basis, PG&E then escalated them to 2010$. Also, in this BCAP, PG&E explains that it calculated the design cost for individual customers as $68 based on labor rates in 2009 escalated to 2010$ and multiplied by the estimated time spent performing the design work.[71] Overall, the updated SRM costs for new business do not appear to be significantly different from those used in the 2005 BCAP.[72] Instead, what is notably different is the SRM for replacement of service.

In a clarification response provided to DRA by PG&E, the Applicant stated that it is correct to state that it would cost more to replace SRMs than to hook up a new customer.[73] PG&E attributes this to the additional labor and material costs of installation and additional labor dollars involved in determining the type of meter to be replaced.[74] On top of these, PG&E states that "there is additional trenching, backfilling, restoring and paving work as specified in column F (Trench, Backfill, Restore & Pave)…"[75] Although

---

[68] Based on PG&E's Response in A.09-05-026 DRA-PZS2-1. Also, the SAP acronym refers to PG&E's business and accounting system (Systems Applications and Products) which has been in use since May 1996. See reference to SAP in D.00-02-046.

[69] Ibid.

[70] Ibid.

[71] Based on PG&E's Response in A.09-05-026 DRA-PZS3-6. In the 2005 BCAP, PG&E had proposed $101, but the one adopted by the Commission was the design cost of $43 that was proposed by TURN.

[72] At the lower range of demand from 275 to 3500 cubic ft/hr, the difference between the SRM costs in the two BCAP years range from 5% to 19% at most, without even accounting for the difference in their price level. In 2005 BCAP, the SRMs were expressed in 2000$ while in this BCAP, the SRMs were expressed in 2010$.

[73] Based on PG&E's Response in A.09-05-026 DRA-PZS7-1.

[74] Ibid.

[75] Ibid.

some of the additional costs cited by PG&E may be applicable for replacement of service, DRA disagrees with the inclusion of additional trenching costs that were in the SRM estimates for replacement of service calculated by PG&E. DRA's calculation excludes these trenching costs on the basis of Finding of Fact 19 in D.95-12-053, wherein the Commission excluded trenching costs:

> PG&E and DRA recommend that with today's technology there is no longer an additional trenching cost for replacement of service compared to new service; therefore the RECC for marginal customer cost and marginal distribution cost should be modified to reflect this.

Further, DRA's review indicates that in deriving the weighted average SRM cost for each customer class, PG&E uses the average service line lengths historic data for the period 1989-2008. In the last 2005 PG&E BCAP, PG&E indicated to DRA in a data response that two things happened during the early part of this period which may affect the average service length. First, PG&E's past practice was to locate the service riser for the gas meter wherever the customer requested. In contrast, PG&E's current practice is to locate the riser and meter at the nearest acceptable location nearest the gas main. DRA understands that this tends to shorten the needed service length. This also tended to minimize the length needed to connect to a new service. Therefore, in the last PG&E BCAP, the Commission adopted DRA's recommendation to adjust PG&E's calculation of the service length for purposes of the SRM cost computations by using the historic data from July 1998 to better reflect these changes. Consequently, in this BCAP, DRA asked PG&E to make the modifications to include only data from July 1998 period.[76] The DRA recommendation for both new business SRM and replacement SRM includes this change in the service line length.

In terms of the Return, Taxes, and Insurance (RTI) factor that is used for purposes of determining the total one-time hook-up cost per customer, DRA found no issue. The

---

[76] Based on PG&E responses to Data Request A.09-05-026 DRA-PZS2-4 and PZS2-5.

apparent difference in the RTI compared to that used in the 2005 BCAP stems from a new cost of capital rate of return. PG&E explains that the current BCAP employed a new cost of capital rate of return based on a more recent Cost of Capital decision that occurred after the 2005 BCAP proceeding.[77]

The forecast of customer numbers for this BCAP were prepared by PG&E in January 2009 and is the same forecast that was used in PG&E's 2011 GRC NOI application.[78] The 2010 forecast number represents approximately a 1 percent increase over the 2007 recorded number of PG&E customers. Further slight increases in customer count of less than 1 percent are shown in the forecast for years 2011 and 2012.

4.4.3 Marginal Cost Loaders

DRA's review of the marginal O&M cost shows that PG&E's estimate based on the 2004 recorded adjusted distribution expense and updated by the O&M price indices appears reasonable. PG&E's gas distribution O&M expenses each year for the period 2000 through 2008 showed a rising trend.[79]

DRA reviewed PG&E's proposed General Plant (GPLF) and A&G loaders used in the LRMC calculations and does not oppose them.

4.4.4 Marginal Cost Revenues

Overall, DRA's review indicates that under the PG&E proposal, approximately 96.9% of total marginal cost revenues are allocated to its core customers while 3.1% are allocated to its noncore customers. In comparison, the current cost allocation to PG&E's customers from those adopted in D.05-06-029 allocates approximately 96.7% to core customers and 3.3% to noncore customers. Therefore, if adopted in this 2009 BCAP,

---

[77] Ibid., PZS2-6.

[78] Based on PG&E email dated 9-16-2009 confirming that workpapers prepared by PG&E's Kate Tiedman are for Matt Master's Chapter 2 Testimony in this proceeding.

[79] Based on PG&E's responses to DRA Data Request in A.09-05-026 DRA-PZS3-4.

PG&E's proposal will increase the cost allocation to core customers and decrease those to noncore customers.

On the other hand, based on DRA's review and analysis discussed in the foregoing sections, PG&E's proposal is deficient in several respects: (1) the absence of distribution RCA for the replacement cost of existing distribution facilities; (2) the inaccurate calculation of its weighted SRMs with the appropriate service line lengths; (3) the slightly lower throughputs used by PG&E for purposes of the cost allocations; and (4) the flawed inclusion of trenching costs for replacement services.

Based on DRA's calculations, DRA recommends the adoption of the marginal cost revenues shown in Table IV-1. DRA's recommendation will result in approximately 96.45 percent allocation to core customers and 3.55 percent to noncore customers.

4.4 CONCLUSION

Based on the foregoing, DRA respectfully requests the Commission adopt the above recommendations.

A T T A C H M E N T S

PG&E Data Request No.:	DRA_005-02		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_005-Q02		
Request Date:	July 27, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 1
Date Sent:	August 10, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 2

At line 3, Table 3-6, page 3-18, PG&E shows the use of an RECC of 9.55% for the calculation of the annualized marginal capital investment. Please provide the calculation for the RECC used by PG&E to enable DRA to replicate the RECC of 9.55% since the values in the workpaper excel spreadsheet appear to be hard-wired. This is in cell AG12 of Tab DISTMC, which refers to TIMRECC, and that in turn, refers to cell C7 in at Tab Compliance of Gas Loaders, Support files.

ANSWER 2

The calculation for the RECC used by PG&E to enable DRA to replicate the RECC of 9.55% is shown in Column N on the 'Gas Distribution' tab in the excel file, 'GRECC.xls'. The results are then copied and pasted to column T by clicking the 'Update' macro button.

PG&E Data Request No.:	DRA_006-01		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_006-Q01		
Request Date:	July 28, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 2
Date Sent:	August 10, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 1

At lines 11-15, page 3-10, of the above subject, PG&E states:

> "Service, regulator, and meter costs are developed using the methodology adopted in the BCAP decision 05-06-029. These service, regulator and meter costs are identified as customer costs since they are completely dedicated to providing gas service to a single customer."

The weighted average SRM costs are shown in Table 3-3 on page 3-13. Please identify the basic data that were used to develop the service, regulator, and meter (SRM) costs in Table 3-3. If PG&E developed the SRM costs by updating costs from a previous PG&E study of SRMs, please identify the study, state the year the study was prepared and the price level of the basic data, and explain the method you used in updating the SRM data in the study.

ANSWER 1

Except for 'meter sets.xls', PG&E updated costs in 2009 by pulling the material costs from its SAP system. The costs for 'meter sets.xls' are based on material costs from the SAP system in 2006 and then escalated to 2010 $. PG&E also updated labor costs to account for PG&E's labor contract increases in 2009. The 2009 material and labor costs were then escalated to 2010 $.

PG&E Data Request No.:	DRA_006-02		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_006-Q02		
Request Date:	July 28, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 2
Date Sent:	August 10, 2009	Requesting Party:	DRA
PG&E Witness:	Ronald R. Helgens	Requester:	Pearlie Sabino

QUESTION 2

At lines 29-34, page 3-10 through page 3-11 of the above, PG&E states:

> "In addition to new hookup and ongoing O&M costs, PG&E incurs an annual replacement cost for service lines, regulators and meters that are reaching the end of their useful lives. Customer marginal costs include a replacement assumption for this equipment. The replacement cost is an ongoing expense that is allocated to existing customers. Customer equipment replacement costs are marginal costs because they vary with the number of customers PG&E serves (more customers imply that there will be more replacements needed)."

However, in the last PG&E BCAP decision in D.05-06-029, the Commission states in Conclusion of Law #6:

> "The calculation of marginal customer costs for gas service should not continue to include a value recognizing replacement costs of gas facilities."

Please state whether PG&E gave any consideration to the foregoing Conclusion of Law, and if so, please state how it was considered and state whether PG&E is seeking a change to the said conclusion of law as it applies to the current PG&E BCAP application. Also, please indicate how PG&E's proposal statement that "customer replacement costs are marginal costs" conforms with the above Conclusion of Law. Please state and discuss whether D.05-06-029 allows for or does not allow for "customer replacement costs" to be considered marginal costs.

ANSWER 2

It is clear from the context of the issues contained in D.05-06-029 that the Commission intended that the replacement cost adder should not be included in distribution marginal costs. The Commission decision stated:

> "Economic literature apparently does not explicitly address the issue of replacement costs as an element of long run marginal costs. However, the record before us demonstrates that PG&E does include the cost of replacing existing facilities in its marginal distribution costs through the real economic carrying charge, which recognizes the costs of new facilities and the costs of replacing them in the future. Thus, including the replacement cost in marginal distribution costs double counts these costs. Moreover, although the economic literature may not explicitly address this point, including replacement costs as an element of marginal costs is conceptually inconsistent with economic theory. Once a utility makes an investment in new facilities to serve increasing customer demand, the utility will repair or replace those facilities without regard for incremental increases in demand. For these reasons, we eliminate the replacement cost adder from the equation used to calculate marginal customer costs."

The language quoted from the Conclusion of Law #6 was taken directly from the discussion of the replacement cost adder as it related to the distribution marginal costs. Unfortunately, the Commission used the term marginal customer costs when it concluded its discussion.

In addition, the inclusion of replacement costs in the customer marginal costs was not raised as an issue in the proceeding. The Commission has consistently adopted replacement costs as a component of customer marginal costs in PG&E's BCAPs as well as the BCAPs of the other utilities. In addition, it has adopted replacement costs as part of the electric customer marginal costs. There is no reason for the Commission to have denied its inclusion in PG&E's last BCAP.

Also, the data files that were employed by the Energy Division to implement the rates authorized in D.05-06-029 included replacement costs as a component of customer marginal costs but did not include the replacement cost adder in the distribution marginal costs consistent with the Commission's intent in D.05-06-029.

PG&E Data Request No.:	DRA_006-04		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_006-Q04		
Request Date:	July 28, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 2
Date Sent:	August 10, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 4

Table 3-3, page 3-13 of the prepared testimony shows the weighted average SRM cost for each customer class. The calculations for these are shown in the workpaper WP-3-8 and also in spreadsheet SRM-New Business.xls. In deriving the unit costs, PG&E uses average service line lengths historic data for the period 1989-2008. In the last 2005 PG&E BCAP, PG&E indicated to DRA in a data response that two things happened during the early part of this period which may affect the average service length.[1] First, PG&E's past practice was to locate the service riser for the gas meter wherever the customer requested. In contrast, PG&E's current practice is to locate the riser and meter at the nearest acceptable location nearest the gas main. DRA understands that this tends to shorten the needed service length. Second, PG&E also stated in the DR response that in July 1998, one of the gas rules was changed so the service allowance could be no longer than 100 feet. This also tended to minimize the length needed to connect to a new service. Therefore, in the last PG&E BCAP, the Commission adopted DRA's recommendation to adjust PG&E's calculation of the service length for purposes of the SRM cost computations by using the historic data from July 1998 to better reflect these changes.

(a) In this application, please provide DRA with a revised calculation of SRM for new business using service line length historic data from July 1998-2008.

(b) Please provide revised calculations of weighted SRMs for new business.

ANSWER 4

(a) The following 1998 data has been modified to include only new services between 7/1/2008 and 12/31/2008.

Assumed Service Diameter	# of	Miles

	Svcs	
	1998	
1/4" & 1/2"	15,486	91.514
3/4" & 1"	1,407	45.822
1"		
1"		
1"		
1-1/4"	143	4.827
1-1/4"		
1-1/4"		
1-1/2"		
2"	134	6.662
3"	7	0.195
3"		
4"	3	0.344
6"	1	0.152
6"		
8"		

Please use the above data to replace columns T and U on the ‘New Services’ tab in the ‘New Service Length.xls’.

(b) Please replace the numbers as described in (a) above and replace the formula in columns AP and AQ with the years from 1998 to 2008 on the ‘New Services’ tab in the ‘New Service Length.xls’ to re-calculate the weighted SRMs for new business.

PG&E Data Request No.:	DRA_006-05		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_006-Q05		
Request Date:	July 28, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 2
Date Sent:	August 10, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 5

Continuing with the subject matter above in question 4, please provide revised calculations of weighted average SRM for reconstruction to the extent service line length historic data were used.

ANSWER 5

The following 1998 data has been modified to include only replaced services between 7/1/2008 and 12/31/2008.

Assumed Service Diameter	# of Svcs	Miles
	1998	
1/4" & 1/2"	5,138	51.148
3/4" & 1"	537	6.515
1"		
1"		
1"		
1-1/4"	88	1.322
1-1/4"		
1-1/4"		
1-1/2"	1	0.007
2"	34	0.492
3"	4	0.127
3"		
4"	0	0
6"	0	0

6"
8"

Please replace the numbers as described in (a) above and replace the formula in columns AP and AQ with the years from 1998 to 2008 on the ‘Replaced Services’ tab in the ‘New Service Length.xls’ to re-calculate the weighted SRMs for reconstruction.

PG&E Data Request No.:	DRA_006-06		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_006-Q06		
Request Date:	July 28, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 2
Date Sent:	August 10, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 6

At lines 7-12, page 3-9,PG&E states that a Return, Taxes and Insurance factor of 1.4991 is multiplied by the direct cost of service lines, house regulators and meters for purposes of determining the total one-time hook up cost per customer.

(a) Please provide each of the values of the return, taxes, and insurance that were used by PG&E to arrive at the factor of 1.4991.

(b) Please explain whether these were the same values for Return, Taxes, and Insurance used in the 2005 BCAP. If different, please explain why.

ANSWER 6

(a) The return is at 7.66%, state tax rate is at 8.84%, federal tax rate is at 35% and ad valorem taxes & insurance is at 1%.

(b) In the 2005 BCAP, the return is at 9.24%, state tax rate is at 8.84%, federal tax rate is at 35% and ad valorem taxes & insurance is at 1%. The 2010 BCAP employed a new cost of capital rate of return based on a more recent Cost of Capital decision that occurred after the 2005 BCAP proceeding.

PG&E Data Request No.:	DRA_007-01Rev1		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_007-Q01Rev1		
Request Date:	August 7, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 3
Date Sent:	August 27, 2009	Requesting Party:	DRA
PG&E Witness:	Karen Lang	Requester:	Pearlie Sabino

QUESTION 1

Table 3-1 on page 3-3, which is the summary of marginal cost methodologies, indicates that PG&E's marginal cost component for replacement costs of existing distribution facilities are included in the O&M adder, whether growth-related or not (Only growth-related replacement is included in investment plans) while replacement costs of future facilities installed to meet load growth are included implicitly, through the real economic carrying cost (RECC).

(a) Please confirm whether the above statement means that replacement costs of existing distribution facilities are included in the O&M adder shown in Table 3-6 (on page 3-18) in the amount of $19.2364/Dthd. If so, then please identify the portion of $19.2364 that is for the replacement cost of existing distribution facilities and explain the basis why you believe this is a reasonable estimate to use in this BCAP. If not, then please explain what the above statement means and identify the amount provided for the replacement cost of existing distribution facilities and explain how it was derived.

(b) Please confirm whether the above statement means that replacement costs of future facilities installed to meet load growth are included in the RECC of 9.55% shown in Table 3-6. If so, then please identify the components of 9.55% that provides for the replacement of future facilities to meet load growth and explain why you believe this is a reasonable estimate to use in this BCAP. If not, then please explain what you mean in the statement.

(c) Please explain whether it is PG&E's testimony that the replacement costs of existing distribution facilities (as shown in Table 3-6) are marginal costs, and if so, discuss the why. If PG&E's testimony is otherwise, then please explain why that is the case.

ANSWER 1 REVISED

(a) Replacement costs of existing distribution facilities are not included in the O&M adder shown in Table 3-6 (on page 3-18) in the amount of $19.2364/Dthd

(b) PG&E accounts for both the costs of new distribution facilities installed to meet load growth and the costs of replacing them in the future in the RECC of 9.55%.shown in Table 3-6. The RECC is applied to the marginal investment cost (Line 3 of Table 3-6) relating to load growth, resulting in an resulting annualized marginal capital investment (Line 4, Table 3-6) for load growth. This methodology was found reasonable in D.05-06-029 (See the response to DRA_007-02).

(c) See the response to (a) above.

PG&E Data Request No.:	DRA_007-02		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_007-Q02		
Request Date:	August 7, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 3
Date Sent:	August 17, 2009	Requesting Party:	DRA
PG&E Witness:	Karen Lang	Requester:	Pearlie Sabino

QUESTION 2

In D.05-06-029 Finding of Fact #14, the Commission states that "Economic literature does not resolve whether replacement costs are appropriately included in long run marginal cost calculations." In addition, Finding of Fact #15 in the same decision, states that "PG&E argues convincingly that replacement cost for distribution facilities are already recognized in marginal distribution costs."

(a) Please state and discuss whether D.05-06-029 allows for, or does not allow for, the replacement costs of existing distribution facilities and replacement costs of future facilities installed to meet load growth. In your response, please clearly indicate whether D.05-06-029 allows for or does not allow for both types of replacement costs for distribution facilities or not.

ANSWER 2

Regarding the replacement costs of existing facilities, see the response to DRA_007-01 (a). Regarding the replacement costs of future facilities installed to meet load growth, D.05-06-029 accepted PG&E's proposal to remove the replacement cost adder.

> PG&E argues convincingly that replacement cost for distribution facilities are already recognized in marginal distribution costs. [D.05-06-029, Finding of Fact #15]

Other than the elimination of the replacement cost adder adjustment, D.05-06-029 did not alter PG&E's long-standing method of calculating the replacement of future facilities installed to meet load growth using the real economic carrying charge.

> This decision modifies PG&E's throughput, makes minor changes to cost allocation and rate design, and approves minor changes to accounting and ratemaking for PG&E's natural gas distribution rates. This decision generally follows past Commission decisions in these areas except where a party or parities have made very compelling showings in favor of changing existing policies or analytical methods.

We see no reason to depart from past policy in this implementation proceeding unless circumstances have changed substantially, new information is available, or a party can demonstrate a past order misstates or misapplies facts, policy or analysis. [D.05-06-029, pp4-5]

PG&E Data Request No.:	DRA_007-03Rev1		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_007-Q03Rev1		
Request Date:	August 7, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 3
Date Sent:	August 27, 2009	Requesting Party:	DRA
PG&E Witness:	Karen Lang, Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 3

In the past, PG&E had a Gas Pipeline Replacement Program (GPRP) which contains a list of projects representing segments of pipeline where those with the highest risk or in worst physical condition are targeted to be replaced first.

(a) Please confirm whether PG&E still implements the above program and describe the period for which PG&E is continuing to implement the program.

(b) If the response in (a) is affirmative, please provide DRA with a copy of the current GPRP.

(c) Further to your responses above, please confirm whether the projects and costs in the GPRP represent the replacement costs of existing distribution facilities that are included in the O&M adder (as shown in Table 3-1 and Table 3-6). In your response, please clearly indicate how the GPRP was used in developing cost estimates in this BCAP. If not, please explain what the GPRP represents in terms of existing distribution facilities in this BCAP.

ANSWER 3 REVISED

(a) PG&E's GPRP is still ongoing. PG&E currently expects the end-date of the program to be in 2013.

(b) Attachment DRA_007-03 contains the 2008 GPRP Annual Progress Report.

(c) The replacement costs of existing facilities, including those originating from the GPRP, are not included in the O&M adder.

PG&E Data Request No.:	DRA_007-04		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_007-Q04		
Request Date:	August 7, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 3
Date Sent:	August 26, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 4

In this BCAP, PG&E proposes to use an A&G loading factor of 42.06 percent of total O&M expense (on page 3-8). In the last BCAP for PG&E, the A&G loading factor was 28.56 percent of total O&M expense (based on PG&E's year 2002 adjusted recorded data) and was adopted in the last BCAP decision.

(a) Please provide the following: (i) PG&E's Gas Distribution O&M expenses each year for the period 2000 through 2008 and (ii) PG&E's Gas Distribution Labor-related A&G + Payroll tax expenses each year for the period 2000 through 2008 that are consistent with 42.06 percent and 28.56 percent A&G loading factors.

(b) The A&G loading factor appears to show a rising trend. Please state whether this observation is correct and explain the reason for such rising trend.

ANSWER 4

(a) PG&E's gas distribution O&M expenses (in 000s) each year for the period 2000 through 2008 are as follows:

	O&M	Customer Accounts	Total Gas Distribution – Pipes & Services
2000	115,396	138,787	254,183
2001	108,077	155,847	263,924
2002	116,019	165,803	281,823
2003	116,552	182,437	298,990
2004	111,434	168,808	280,242
2005	122,756	171,364	294,120
2006	130,551	169,426	299,977
2007	138,681	174,415	313,096
2008	166,201	150,370	316,570

PG&E’s gas distribution estimated labor related A&G and payroll tax expenses (jn 000s) each for the period 2000 through 2008 are as follows:

2000 77,295
2001 34,013
2002 98,464
2003 103,758
2004 95,422
2005 90,080
2006 125,425
2007 106,001
2008 114,500

In 2005 BCAP, the A&G loading factor is calculated based on 2002 recorded adjusted gas distribution expenses (in 2000 $) and 2003 forecast A&G and payroll taxes (in 2000 $). In 2009 BCAP, the A&G loading factor is calculated based on 2007 forecast gas distribution expenses (in 2004 $) and 2007 forecast A&G and payroll taxes (in 2004 $).

(b) The A&G loading factor appears to show a rising trend because both A&G and payroll taxes have increased over the years.

PG&E Data Request No.:	DRA_007-06		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_007-Q06		
Request Date:	August 7, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 3
Date Sent:	August 17, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 6

As stated in the last BCAP decision, TURN and PG&E agreed that the design cost for individual customers should be $43 rather than $101 originally proposed by PG&E. This modification was adopted for PG&E's estimate of design costs for individual customers. In this BCAP, please describe PG&E's proposed design cost for individual customers relative to the $43 and explain the basis for any increase in the proposal over the $43. Please cite the support for this in PG&E's workpapers.

ANSWER 6

In this BCAP (A.09-05-026), PG&E calculated the design cost for individual customers as $68 based on labor rates in 2009 escalated to 2010 $ multiplied by the estimated time spent performing the design work. In PG&E's last BCAP (A.04-07-044), the $43 design cost had no analytical basis. The design cost was proposed by TURN and PG&E did not rebut the proposal.

PG&E Data Request No.:	DRA_014-01		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_014-Q01		
Request Date:	August 31, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 6
Date Sent:	September 16, 2009	Requesting Party:	DRA
PG&E Witness:	Karen Lang, Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 1

In Tab DISTMC of the Switch2010_2009 Update file, the Investment Plans for input shown in Column U are based on data from the excel file "BCAP 2008 distinvs dft1.xls" at Tab Regression 15-year shown in Column L. To verify the investment plans for input, DRA is trying to reconcile the information PG&E provided as investment plans for input from the data on distribution investments from 1987 to 1996 shown in Tab Dist Invest 87-96 and capital expenditures for each year in Tabs CAP96, CAP95, and so forth until CAP90, and those from 1997 through 2008. So far, DRA has managed to match only the investment plans for the years 2004 through 2008 with the data from the excel file "2003-2008 Capital Additions Summary.xls." The investment amounts shown at Tab Regression 15-year in Column L and in Column D (for the earlier years) could not be verified as they do not appear to match any of the data so far reviewed from those excel files. Please provide DRA with the appropriate reference to verify the investment plan inputs from the PG&E workpapers.

ANSWER 1

The investment plan inputs from 1987 to 2003 were used as inputs in the previous BCAP. PG&E does not currently have the cost references for these inputs.
The distribution investments from 1987 to 1996 shown in the Tab Dist Invest 87-96 and capital expenditures for each year in Tabs CAP96, CAP95, and so forth until CAP90 are in current year dollars. The historical data shown in the regression run represents real dollars (e.g. using the Handy Whitman Index to convert current year dollars to real dollars). PG&E only updated recent historical data for each successive BCAP; leaving the prior historical data from previous BCAPs unchanged. This distinction between current year dollars and real dollars may be the reason why it is difficult to reconcile the information provided.

PG&E Data Request No.:	DRA_019-01		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_019-Q01		
Request Date:	September 18, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 7
Date Sent:	September 25, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 1

Looking at the Errata for chapter 3, I'm now confused by what PG&E says about marginal customer cost - SRM replacement cost calculation. In the Errata, PG&E states "The cost of a replacement installation is no more than the cost of a new one. As a proxy, it is assumed that the cost of a replacement installation, excluding trenching and other costs, is the same as the cost of a new installation." If you recall, I asked in my DR PZS2 Question 3(f) [or, in PG&E's File name: BCAP-PGE-2009_DR_DRA_006-Q03 (f)] about why it appears that it would cost more to replace SRMs than to hook up a new customer. PG&E responded "It is correct to state that it would cost more to replace SRMs than to hook up a new customer..." It does not appear to me that you had provided a revised response to that DR question. However, assuming that you did revise or plan to revise that response, please address the original question which asks PG&E for an explanation on why the weighted average cost for SRM replacement appears to be higher for each category of maximum demand compared to the weighted average cost for new hook ups. That is, if you believe that they should instead be the same, please confirm and provide me with the necessary correction in the spreadsheets and calculations to address Question 3(f). Your expedited clarification on this will be highly appreciated.

ANSWER 1

A clarification of the response provided for DR PZS2 Question 3(f) is as follows:
It is correct to state that it would cost more to replace SRMs than to hook up a new customer. When SRM is replaced, the gas service representative and estimator are involved in determining what type of meter should be used to replace the existing SRM in the same location. In addition to the labor and material costs of installation, there is the additional labor dollars involved in determining the type of meter to be replaced. *Also, there is additional trenching, backfilling, restoring and paving work as specified in column F (Trench, Backfill, Restore & Pave), 'SRM – Reconstruction.xls', 'Service' tab.*

PG&E Data Request No.:	DRA_020-01		
PG&E File Name:	BCAP-PGE-2009_DR_DRA_020-Q01		
Request Date:	September 21, 2009	Requester DR No.:	PG&E BCAP A.09-05-026 -DRA- PZS 8
Date Sent:	September 25, 2009	Requesting Party:	DRA
PG&E Witness:	Mona F. Neal	Requester:	Pearlie Sabino

QUESTION 1

At pages 1-4 to 1-5 of PG&E’s Prepared Testimony, PG&E requests the adoption of the following with respect to the above subject chapter:

- A proposed distribution investment plan.

Based on the data shown on page WP-3-59 of PG&E’s workpapers for distribution marginal cost, the 5-year forecast of distribution investment plans (in years 11 to 15) amounts to approximately $36 million per year while in the prior 5-year period (in years 6 to 10) these investments amount to approximately $46 million per year. The prior 5-year period distribution investments were approximately 20 percent higher relative to those in the forecast period. With respect to demand, the total distribution DMD on CWD for the 5-year forecast period average 24 Mdth/d, while those in the prior 5-year period the DMD on CWD averaged 25 Mdth/d. The prior 5-year period demand was approximately only 6 percent higher relative to those in the forecast period. Please provide an explanation on why PG&E’s forecast is 20 percent lower for distribution investments compared to the most recent historical period, given that there is only a 6 percent difference in demand level in that period.

ANSWER 1

PG&E's forecast of investment expenditures is based on a regression analysis that models investment expenditures as a function of marginal demand measures (MDM's).

A regression analysis constructs this historical relationship by establishing a linear relationship between the two variables that minimizes the sum of the error terms squared. It does not base it on an average of one variable compared to the average of another since such a method would allow data point outliers to skew the results. While the MDMs for year 2003 are extremely low (i.e. 15, which brings down the average substantially), PG&E believes it would be inappropriate to base a conclusion on a comparison of average values of one historic variable to the average of another.

CHAPTER 5 – RATE DESIGN ISSUES AND RATE TABLES

Witness: Kelly C. Lee

5.1 INTRODUCTION

This chapter presents the DRA analyses and recommendations regarding Pacific Gas & Electric Company's (PG&E) rate proposals on distribution base revenue and customer class charge allocation. The chapter also presents illustrative rates resulting from DRA's recommended changes to PG&E's throughput forecast, marginal cost allocation, and rate proposals on distribution base revenue and customer class charge allocation.

PG&E sets forth several proposals on cost allocation and rate changes. These proposals relate to core deaveraging, West Coast gas rates, the core brokerage fee, master-meter discounts and the diversity benefit adjustment, Natural Gas Vehicle (NGV) compression cost study, and noncore distribution revenue balancing account treatment. In this chapter, DRA focuses only on PG&E's proposals relating to core deaveraging, noncore distribution revenue balancing account treatment, and the NGV compression cost study.

5.2 SUMMARY OF RECOMMENDATIONS

The following summarizes DRA's recommendations:

- Core deaveraging should continue at a 5% annual rate over the current BCAP period from July 1, 2010 through June 30, 2012, in contrast to PG&E's proposed 15% annual rate. The remaining non-deaveraged portion should be considered in the next BCAP.
- PG&E should continue to be at risk for 25% of the noncore distribution revenue balancing account as determined by the Commission in the last BCAP decision.
- DRA does not oppose PG&E's NGV cost study.

- The Commission should adopt the rates and revenues derived by DRA as shown in Tables 5-2.

Table 5-3 compares DRA's recommendations with PG&E's proposals.

5.3 DISCUSSION / ANALYSIS OF CORE DEAVERAGING

5.3.1 Overview of PG&E's Proposal

PG&E proposes to fully deaverage the core residential and small commercial customer rates over the 2-year BCAP period. These rates are currently deaveraged at the 70 percent level as of January 1, 2009. With PG&E's proposal, the rates will be deaveraged by 15 percent to the 85 percent level in the first year of the BCAP, and then by another 15 percent to the 100 percent level in the second year. With core deaveraging reaching the 100 percent level within a two year period, the average residential customer's bundled gas bill will face a 1.64 percent increase from their current bill, and the average small commercial customer's bundled gas bill will decrease about 5.51 percent.[80] On an unbundled basis over the two year period, the average residential customer's bill would increase by 3.83 percent from their current unbundled bill, and the average small commercial customer's bill would decrease by 14.39 percent.[81]

5.3.2 DRA DISCUSSION/ANALYSIS

PG&E's proposal to accelerate the pace of core deaveraging from the current 10 percent per year to 15 percent per year over this BCAP period will put an added burden on core customers in the current difficult economic cost environment. A moderate deaveraging pace of 5 percent a year is more appropriate. The 5 percent a year approach will provide rate stability and less volatility. This pace is also consistent with the 5 percent a year reached in the settlement of the San Diego Gas and Electric and Southern

[80] Lines 1 to 5, Page 4-6, Pacific Gas and Electric Company 2009 Biennial Cost Allocation Proceeding Prepared Testimony, May 29, 2009.

[81] PG&E's response to Question 1 of DRA's Data Request, PG&E Data Request No: DRA_016-01, September 18, 2009.

California Gas Company BCAP.[82] DRA recommends that the PG&E core deaveraging proposal of an annual 15 percent be rejected and instead that the Commission adopt DRA's more moderate and reasonable approach of 5 percent annual core deaveraging over the two year BCAP period. DRA also recommends that the remaining deaveraging be addressed in the next BCAP. The adoption of the 5 percent annual core deaverage along with DRA's recommendations on marginal cost allocation and throughput forecast will lighten the strain on the residential customers. At the end of the 2-year BCAP period, the average residential customer's monthly bill would increase by 0.5 percent on bundled basis and 1.9 percent on unbundled basis, as compared to 1.64 percent and 3.83 percent proposed by PG&E, respectively. The average small commercial customer's bill would have a smaller decrease based on DRA's recommendations as compared to PG&E's proposals: 1.71 percent decrease for DRA versus 5.51 percent decrease for PG&E on bundled basis, and 4.6 percent decrease for DRA versus 14.39 percent decrease for PG&E on unbundled basis.

5.4 DISCUSSION / ANALYSIS OF NONCORE DISTRIBUTION REVENUE BALANCING ACCOUNT TREATMENT

5.4.1 Overview of PG&E's Proposal

PG&E proposes full balancing account protection of PG&E's noncore distribution revenue requirement. PG&E unsuccessfully proposed the same unfair request in the last BCAP. In the last BCAP, Decision (D.)05-06-029 adopted a settlement which set PG&E's noncore distribution revenue risk at 25 percent. DRA was a party to the settlement. In its current testimony, PG&E states that the annual noncore distribution rate component was relatively small, 9 percent of the bundled cost of natural gas transportation and illustrated commodity rate for noncore distribution customers, and was less than 1 percent of the rate for industrial transmission and electric generation

[82] The Settlement in A.08-02-001 is currently before the Commission.

customers.[83] PG&E uses this argument to state that the share of the noncore distribution transportation rate component will not have any significant impact on the noncore distribution gas sales volumes and revenues. PG&E claims that full balancing account protection will not affect the amount it will recover of the authorized revenue requirement.[84]

5.4.2 DRA Discussion/Analysis

Regardless of PG&E's assertions, PG&E shareholders should bear some risk on noncore distribution revenue to ensure that an incentive exists to influence PG&E to act more responsibly to the ratepayers. A minimal risk is required to ensure proper ratepayer protection. PG&E's shareholders should bear a portion of the risk that ratepayers must share. The Commission recognized this fact in the last BCAP decision by imposing 25 percent of risk for noncore throughput on PG&E. DRA continues to believe that a minimal level of risk for shareholders is appropriate to ensure that PG&E does not ignore the ratepayers in developing its rates.

PG&E points out in its testimony that "the noncore distribution rate component has consistently been too small relative to other natural gas unit costs to significantly impact noncore distribution gas sales."[85] However, DRA strongly believes that a modest level of throughput risk assures the Utility will act responsibly to achieve an equitable balance for ratepayer and shareholder interests**.**

DRA recommends that the Commission reject PG&E's proposal for full balancing account protection of its noncore distribution revenue requirement. Instead, the Commission should continue the equitable order from the last BCAP decision, ordering

---

[83] Lines 13 to 18, Page 4-38, Pacific Gas and Electric Company 2009 Biennial Cost Allocation Proceeding Prepared Testimony, May 29, 2009.

[84] Lines 22 to 28, Page 4-37, Pacific Gas and Electric Company 2009 Biennial Cost Allocation Proceeding Prepared Testimony, May 29, 2009.

[85] Lines 22 5o 24, Page 4-37, Pacific Gas and Electric Company 2009 Biennial Cost Allocation Proceeding Prepared Testimony, May 29, 2009.

PG&E to share the risk between its shareholders and its customers by imposing 25 percent risk for noncore distribution throughput.

5.5 DISCUSSION OF NATURAL GAS VEHICLE COMPRESSION COST STUDY

The last BCAP, D.05-06-029, adopted a settlement between PG&E and Clean Energy which required PG&E to perform a cost study to update the compression cost component of the G-NGV2 rate. PG&E conducted a cost study using cost information from five of its NGV stations in various service locations with relatively high public usage. Based on its own cost study, PG&E determined that a rate increase of about $0.20 per therm is reasonable. Therefore, PG&E proposes to increase the compression component of the G-NGV2 rate from the current $0.546 to $0.744 per therm excluding the electric compression cost. In response to a DRA data request[86], PG&E indicated that the proposed NGV rate increase of $0.20/therm would result in a decrease to the cost allocation to other customer classes, including residential classes. The impact would be about a 0.8 cent decrease on the average residential customer's monthly bill. DRA reviewed the cost study and the data response and does not oppose PG&E's NGV study.

5.6 RATE TABLES

DRA studied and analyzed PG&E's proposals on throughput, cost allocation, and other distribution revenue proposals. DRA recommends several changes in throughput forecast as described in Chapters 2 and 3, marginal cost allocation as described in Chapter 4, and cost allocation and rate proposals as described in this chapter. DRA's recommended changes are incorporated into the rate design model. The resulting gas rates are presented in the following summary Tables 5-1 and 5-2. A comparison of DRA's recommended rates and PG&E's proposed rates are shown in Table 5-3.

---

[86] PG&E's response to DRA Data Request, PG&E Data Request No: DRA_022-01 and DRA_022-02, October 6, 2009.

Table 5-1. Summary of July 2010 Rates

EXECUTIVE SUMMARY
DIVISION OF RATEPAYER ADVOCATES
2010 PG&E BCAP: July 1, 2010
USING CURRENTLY ADOPTED (JANUARY 2009 AGT) GAS REVENUE REQUIREMENT

Line No.	Customer Class	Present (1/2009)	Proposed**** (7/2010)	$ Change	% Change
1	**BUNDLED—RETAIL CORE***				
2	Residential Non-CARE**/***	$1.393	$1.416	$0.023	1.6%
3	Small Commercial Non-CARE**	$1.210	$1.227	$0.017	1.4%
4	Large Commercial	$0.979	$0.997	$0.017	1.8%
5	Uncompressed Core NGV	$0.896	$0.929	$0.033	3.7%
6	Compressed Core NGV	$1.807	$2.106	$0.298	16.5%
7	**TRANSPORT ONLY—RETAIL NONCORE**				
8	Industrial – Distribution	$0.149	$0.151	$0.002	1.2%
9	Industrial – Transmission	$0.058	$0.058	$0.000	0.4%
10	Industrial – Backbone	$0.038	$0.038	($0.000)	-0.2%
11	Uncompressed Noncore NGV – Distribution	$0.137	$0.139	$0.002	1.3%
12	Uncompressed Noncore NGV – Transmission	$0.051	$0.046	($0.005)	-10.1%
13	Electric Generation – Distribution/Transmission	$0.020	$0.020	$0.000	0.0%
14	Electric Generation – Backbone	$0.005	$0.005	($0.000)	-0.1%
15	**TRANSPORT ONLY—WHOLESALE**				
16	Alpine Natural Gas (T)	$0.025	$0.025	($0.000)	-0.3%
17	Coalinga (T)	$0.024	$0.024	($0.000)	-0.3%
18	Island Energy (T)	$0.045	$0.045	($0.000)	-0.1%
19	Palo Alto (T)	$0.017	$0.017	($0.000)	-0.4%
20	West Coast Gas – Castle (D)	$0.084	$0.169	$0.085	101.3%
21	West Coast Gas – Mather (D)	$0.078	$0.191	$0.114	146.0%
22	West Coast Gas – Mather (T)	$0.025	$0.025	($0.000)	-0.3%

* Illustrative Bundled Rate incorporates illustrative 2009 WACOG $0.703 per therm and Procurement Revenue Requirements as filed in PG&E's 2009 AGT.

** CARE customers receive a 20% discount on transportation and procurement and are exempt from CARE surcharges.

*** July 1, 2010 impact on monthly average non-CARE residential gas bill is $0.84 (as shown on Table 5-D)

**** Changes to Public Purpose Program Surcharge rates (G-PPPS) occur on January 1, 2011 and are not shown on this table. Proposed core deaveraging and phase-in of distribution costs for West Coast Gas also occur on January 1, 2011 and January 1, 2012 and are not shown on this table. See Table 5-N for January 2011 and January 2012 class average rate changes including the impact of PG&E's proposed throughput forecast on G-PPPS rates. The proposed changes to G-PPPS rates are shown on Table 5-M.

TABLE 5-2

**ILLUSTRATIVE IMPACT OF DRA MODIFICATIONS TO PG&E'S BCAP PROPOSALS ON GAS RATES DURING BCAP TEST PERIOD
USING CURRENTLY ADOPTED (JANUARY 2009 AGT) GAS REVENUE REQUIREMENT**

Line No.	Customer Class	Present (1/2009)	**Proposed (7/2010)**	$ Change	% Change	**Proposed (1/2011)**	$ Change	% Change	**Proposed (1/2012)**	$ Change	% Change
	BUNDLED—RETAIL CORE*										
1	Residential Non-CARE**	$1.393	**$1.416**	$0.023	1.6%	**$1.419**	$0.003	0.2%	**$1.423**	$0.004	0.3%
2	Small Commercial Non-CARE**	$1.210	**$1.227**	$0.017	1.4%	**$1.217**	($0.010)	-0.8%	**$1.208**	($0.009)	-0.8%
3	Large Commercial	$0.979	**$0.997**	$0.017	1.8%	**$0.996**	($0.000)	0.0%	**$0.996**	$0.000	0.0%
4	Uncompressed Core NGV	$0.896	**$0.929**	$0.033	3.7%	**$0.929**	($0.000)	0.0%	**$0.929**	$0.000	0.0%
5	Compressed Core NGV	$1.807	**$2.106**	$0.298	16.5%	**$2.105**	($0.000)	0.0%	**$2.105**	$0.000	0.0%
	TRANSPORT ONLY—RETAIL CORE										
6	Residential Non-CARE**	$0.545	**$0.568**	$0.023	4.2%	**$0.575**	$0.007	1.3%	**$0.579**	$0.004	0.7%
7	Small Commercial Non-CARE**	$0.376	**$0.392**	$0.017	4.5%	**$0.384**	($0.008)	-2.1%	**$0.374**	($0.010)	-2.6%
8	Large Commercial	$0.182	**$0.199**	$0.017	9.4%	**$0.206**	$0.007	3.6%	**$0.206**	$0.000	0.0%
9	Uncompressed Core NGV	$0.094	**$0.127**	$0.033	34.8%	**$0.128**	$0.001	0.6%	**$0.128**	$0.000	0.0%
10	Compressed Core NGV	$1.006	**$1.304**	$0.298	29.7%	**$1.305**	$0.001	0.1%	**$1.305**	$0.000	0.0%
	TRANSPORT ONLY—RETAIL NONCORE										
11	Industrial – Distribution	$0.149	**$0.151**	$0.002	1.2%	**$0.150**	($0.001)	-0.5%	**$0.150**	$0.000	0.0%
12	Industrial – Transmission	$0.058	**$0.058**	$0.000	0.4%	**$0.056**	($0.001)	-2.3%	**$0.056**	$0.000	0.0%
13	Industrial – Backbone	$0.038	**$0.038**	($0.000)	-0.2%	**$0.036**	($0.001)	-3.5%	**$0.036**	$0.000	0.0%
14	Uncompressed Noncore NGV – Distribution	$0.137	**$0.139**	$0.002	1.3%	**$0.139**	($0.000)	-0.3%	**$0.139**	$0.000	0.0%
15	Uncompressed Noncore NGV – Transmission	$0.051	**$0.046**	($0.005)	-10.1%	**$0.045**	($0.000)	-0.8%	**$0.045**	$0.000	0.0%
16	Electric Generation – Distribution/Transmission	$0.020	**$0.020**	$0.000	0.0%	**$0.020**	($0.000)	-0.1%	**$0.020**	$0.000	0.0%
17	Electric Generation – Backbone	$0.005	**$0.005**	($0.000)	-0.1%	**$0.005**	($0.000)	0.0%	**$0.005**	$0.000	0.0%
	TRANSPORT ONLY—WHOLESALE										
18	Alpine Natural Gas (T)	$0.025	**$0.025**	($0.000)	-0.3%	**$0.025**	($0.000)	0.0%	**$0.025**	$0.000	0.0%
19	Coalinga (T)	$0.024	**$0.024**	($0.000)	-0.3%	**$0.024**	($0.000)	0.0%	**$0.024**	$0.000	0.0%
20	Island Energy (T)	$0.045	**$0.045**	($0.000)	-0.1%	**$0.045**	($0.000)	0.0%	**$0.045**	$0.000	0.0%
21	Palo Alto (T)	$0.017	**$0.017**	($0.000)	-0.4%	**$0.017**	($0.000)	0.0%	**$0.017**	$0.000	0.0%
22	West Coast Gas – Castle (D)	$0.084	**$0.169**	$0.085	101.3%	**$0.169**	($0.000)	0.0%	**$0.169**	$0.000	0.0%
23	West Coast Gas – Mather (D)	$0.078	**$0.191**	$0.114	146.0%	**$0.191**	($0.000)	0.0%	**$0.191**	$0.000	0.0%
24	West Coast Gas – Mather (T)	$0.025	**$0.025**	($0.000)	-0.3%	**$0.025**	($0.000)	0.0%	**$0.025**	$0.000	0.0%

* Illustrative Bundled Rate incorporates illustrative 2009 WACOG $0.703 per therm and Procurement Revenue Requirements as filed in PG&E's 2009 AGT.

** CARE customers receive a 20% discount on transportation and procurement rates and are exempt from paying CARE-related costs included in PG&E's G-PPPS rate.

*** Changes to G-PPPS rates due to forecast BCAP volumes occur on January 1, 2011. Proposed core deaveraging and phase-in of distribution costs for West Coast Gas occur on January 1, 2011 and January 1, 2012.

TABLE 5-3
PACIFIC GAS AND ELECTRIC COMPANY
2009 BIENNIAL COST ALLOCATION PROCEEDING
ILLUSTRATIVE CLASS AVERAGE GAS RATES ($/th)

Line No.	Customer Class	Present Rates (JULY 2009)	PG&E's Recommended Rates Rate	PG&E's Recommended Rates % Change	DRA's Recommended Rates Rate	DRA's Recommended Rates % Change
		(A)	(B)	(C)	(D)	(E)
	BUNDLED - Retail Core					
1	Residential Non-CARE	$1.393	$1.421	2.0%	$1.416	1.6%
2	Small Commercial Non-CARE	$1.210	$1.222	1.0%	$1.227	1.3%
3	Large Commercial	$.979	$.990	1.0%	$.997	1.8%
	TRANSPORTATION ONLY - Retail Core					
4	Residential Non-CARE	$.545	$.573	5.1%	$.568	4.2%
5	Small Commercial None-CARE	$.376	$.387	3.1%	$.392	4.5%
6	Large Commercial	$.182	$.192	5.6%	$.199	9.5%
	TRANSPORTATION ONLY - Retail Noncore					
7	Industrial Distribution	$.150	$.146	-2.4%	$.151	1.2%
8	Industrial Transmission	$.058	$.057	-0.3%	$.058	0.4%
9	Electric Generation	$.020	$.020	-0.1%	$.020	0.4%
	TRANSPORTATION ONLY - Wholesale Core and Noncore					
10	Alpine Natural Gas (T)	$.025	$.025	-0.4%	$.025	-0.3%
11	Coalinga (T)	$.024	$.024	-0.4%	$.024	-0.3%
12	Island Energy (T)	$.045	$.045	-0.2%	$.045	-0.2%
13	Palo Alto (T)	$.017	$.017	-0.5%	$.017	-0.5%
14	West Coast Gas - Castle (D)	$.084	$.092	9.0%	$.169	101.3%
15	West Coast Gas - Mather (D)	$.078	$.085	8.8%	$.191	145.9%

Notes:

Illustrative Bundled Rate incorporates illustrative 2009 WACOG $0.703 per therm and Procurement Revenue Requirement as filed in PG&E's 2009 AGT.

CARE customers receive a 20% discount on transportation and procurement rates and are exempt from paying CARE-related costs included in PG&E's G-PPPS rate.

APPENDIX A

QUALIFICATIONS OF DRA WITNESSES

QUALIFICATIONS AND PREPARED TESTIMONY
OF
JACQUELINE GREIG

Q.1. Please state your name and address.

A.1. My name is Jacqueline Greig. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Cost of Service and Natural Gas Branch of the Office of Ratepayer Advocates (DRA).

Q.3. Please provide a brief description of your educational background and professional experience.

A.3. I graduated from San Francisco State University in December 1987, with a Bachelor of Science degree in International Business. I have completed Graduate Economics courses at San Francisco State University. I was employed by the Commission in 1988 in DRA for seven years. After a departure from 1995-1999, I re-joined the Commission in 1999 in DRA.

I have worked on electric, telecommunications, and primarily gas industry issues. My responsibilities have included sponsoring reports/testimony in proceedings, such as, reasonableness reviews, capacity brokering, infrastructure expansions, incentive ratemaking, BCAPs, gas industry OIRs and OIIs, and greenhouse gas/climate applications. I have served as project manager and witness for many natural gas proceedings and I have previously testified before the Commission.

Q.4 What is the area of your responsibility in this proceeding?

A.4 I am sponsoring Chapter 1 of DRA's Testimony in this proceeding.

Q.5 Does this conclude your prepared direct testimony?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
THOMAS M. RENAGHAN

Q.1. Please state your name and address.

A.1. My name is Thomas M. Renaghan My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Division of Ratepayer Advocates (DRA), Energy Cost of Service and Natural Gas Branch.

Q.3. Please briefly describe your educational background and work experience.

A.3. I have a Bachelor of Arts in Economics from California State University, Hayward and a Ph.D in Economics from the University of California, Davis.

I have been employed with the Commission since January 1984. I have worked in the areas of escalation, gas sales forecasting, gas rate design, and the development of company-specific and industry measures of total factor productivity for energy and telecommunications.

Q.4. What is your area of responsibility in this proceeding?

A.4 I am responsible for Chapter 2 Demand Forecasts.

A.5 Does that complete your prepared testimony?

Q.5. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
MARICELA P. SIERRA

Q.1 Please state your name, business address, and position with the California Public Utilities Commission (Commission).

A.1 My name is Maricela P. Sierra and my business address is 505 Van Ness Avenue, San Francisco, CA. I am a Public Utilities Regulatory Analyst in the Division of Ratepayer Advocates of the Energy Cost of Service Division.

Q.2 Please summarize your educational background.

A.2 I received a Bachelor of Arts degree in Economics from California State University, Sacramento. I attended a four days seminar on General Rate Case Training conducted by NRRI in conjunction with the Commission.

Q.3 Please summarize your business experience.

A.3 After graduation from Sacramento State, I joined the Commission and have worked on the following areas: Cost-Benefit Analysis, Depreciation, Econometric and Non-Econometric forecast, Operating Revenues, Rate Design, Depreciation (ROR), Conservation, Insurance and Pension & Benefits (P&B) on various energy, natural gas and water utilities' General Rate Case proceedings.

Q.4 What is your responsibility in this proceeding?

A.4 I am responsible for the Electric Generation Throughput Forecast for Pacific Gas & Electric Company's Biennial Cost Allocation Proceeding 2009.

Q.5 Does this conclude your prepared direct testimony?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
PEARLIE Z. SABINO

Q.1. Please state your name and business address.

A.1. My name is Pearlie Sabino. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the State of California at the California Public Utilities Commission (CPUC) as a Regulatory Analyst in the Division of Ratepayer Advocates (DRA).

Q.3. Please describe your educational background and professional experience.

A.3. I have an M.A. in Economics from Ateneo de Manila University and a B.S. in Business Economics from the University of the Philippines. I graduated from the Executive Training Program in Energy Planning and Policy of the University of Pennsylvania. I have worked for 19 years with the largest electric utility in the Philippines in various professional capacities in the areas of economic research, marginal cost studies, project evaluation, corporate budgeting and monitoring, and project financing.

I joined the Commission staff in 1997. In the last 12 years, I have worked on a number of electric and natural gas matters including but not limited to the following: the review of utilities' gas supply plans in the procurement proceeding; SoCalGas' Gas Cost Incentive Mechanism; the review of BCAP applications for PG&E, SoCalGas and SDG&E; various gas transportation contracts (such as Guardian, Ruby, US Gypsum), various applications pertaining to the grant of CPCN for gas storage contracts, including amendments; SoCalGas/SDG&E system integration and firm access rights proceedings, the Joint SCE/SoCalGas/SDG&E Omnibus proceeding, and the Joint Application for Public Purpose Program Cost Reallocation proceeding.

Q.4 What is your area of responsibility in this proceeding?

A.4 I am sponsoring DRA Chapter 4, which is DRA's Direct Testimony in A.09-05-026 on cost allocation issues for PG&E.

Q.5 Does this complete your testimony?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
KELLY C. LEE

Q.1. Please state your name and address.

A.1. My name is Kelly C. Lee. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission (CPUC) as a Senior Utilities Engineer in the Energy Cost of Service and Natural Gas Branch of the Division of Ratepayer Advocates (DRA).

Q.3. Please describe your educational and professional experience.

A.3. I have a Bachelor of Science Degree in Mechanical Engineering from San Jose State University, a Master of Science Degree and a Master of Engineering Degree from the University of California in Berkeley, and a Master of Business Administration (MBA) from the University of San Francisco.

I am a registered Professional Mechanical Engineer in the State of California.

I joined the DRA/CPUC in 1999. During my time in DRA, I have worked as an analyst and project coordinator on various gas, electric, and telecommunication cases. Before joining the CPUC, I worked in the private industry performing engineering research and analysis, managing programs, and supervising engineers in the aerospace and alternate energy fields.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am responsible for Chapter 5, Rates and Rate Design Policy, of the DRA testimony.

Q.5. Does this conclude your testimony at this time?

A.5. Yes, it does.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of "**REPORT ON THE PACIFIC GAS AND ELECTRIC COMPANY'S 2009 BIENNIAL COST ALLOCATION PROCEEDING"** in **A.09-05-026** by using the following service:

[**X**] **E-Mail Service:** sending the entire document as an attachment to all known parties of record who provided electronic mail addresses.

[ ] **U.S. Mail Service:** mailing by first-class mail with postage prepaid to all known parties of record who did not provide electronic mail addresses.

Executed on November 4, 2009 at San Francisco, California.

/s/ ANGELITA MARINDA

Angelita Marinda

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address and/or e-mail address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

SERVICE LIST
A.09-05-026

liddell@energyattorney.com
dk@utilitycostmanagement.com
ek@a-klaw.com
rhd@cpuc.ca.gov
mflorio@turn.org
nsuetake@turn.org
epoole@adplaw.com
bcragg@goodinmacbride.com
jmrb@pge.com
ken@in-houseenergy.com
service@spurr.org
JerryL@abag.ca.gov
bmcc@mccarthylaw.com
rob@clfp.com
ralphdennis@insightbb.com
francesca.ciliberti@elpaso.com
jlsalazar@semprautilities.com
npedersen@hanmor.com
douglass@energyattorney.com
pk@utilitycostmanagement.com
marcel@turn.org
cpuccases@pge.com
KEL3@pge.com
filings@a-klaw.com
ray.welch@navigantconsulting.com
sls@a-klaw.com
WMLb@pge.com
RegRelCPUCCases@pge.com
cassandra.sweet@dowjones.com
cem@newsdata.com
karla.dailey@cityofpaloalto.org
mrw@mrwassoc.com
tomb@crossborderenergy.com
bill@jbsenergy.com
rmccann@umich.edu
sas@a-klaw.com
cpe@cpuc.ca.gov
jnm@cpuc.ca.gov
jsw@cpuc.ca.gov
psp@cpuc.ca.gov
pzs@cpuc.ca.gov
ram@cpuc.ca.gov