Docket:	:	A.06-03-005
Exhibit Number	:	
Commissioner	:	Rachelle B. Chong
Admin. Law Judge	:	David K. Fukutome
DRA Project Mgrs.	:	Dexter Khoury, Cherie Chan
DRA Witnesses	:	Cherie Chan, Steve Linsey, Louis Irwin, Dexter Khoury

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY ON PHASE 2 OF THE PACIFIC GAS AND ELECTRIC CO. 2007 GENERAL RATE CASE

MARGINAL COST, REVENUE ALLOCATION, AND RATE DESIGN

Dana Appling, Director

San Francisco, California
September 13, 2006

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MEMORANDUM

This report was prepared by the DIVISION OF RATEPAYER ADVOCATES (ORA) of the California Public Utilities Commission (Commission) in A.06-03-005 proceeding. In this report DRA presents its analysis and recommendations associated with the applicant's request.

Dexter Khoury and Cherie Chan served as DRA's project coordinators in this review, and are responsible for the overall coordination in the preparation of this report. DRA's witnesses' prepared qualifications and testimony are contained in Appendix A of this report.

1. EXECUTIVE SUMMARY

A. INTRODUCTION

This report presents The Division of Ratepayer Advocates' ("DRA") analysis and recommendations on the proposed changes to marginal cost, revenue allocation, and rate design made by Pacific Gas and Electric Company ("PG&E") in its 2007 General Rate Case Phase II, A.06-03-005. In this proceeding, PG&E has proposed major changes to the marginal customer cost methodology that would shift significantly more of the revenue requirement to the residential class, and has proposed changing the long standing method for the allocation of CARE costs, which also shifts more revenue responsibilities to the residential class.

In PG&E's last GRC Phase II, there was substantial movement towards marginal cost based rates. DRA proposes to go the remaining short distance to finish this process as long as no new obstacles are introduced. DRA thus opposes PG&E's proposal to introduce major changes to the marginal customer cost methodology and DRA proposes to maintain the current equal cents per kWh allocation method of CARE costs. DRA further recommends that programs such as the Self Generation Incentive Program and the California Solar Initiative, which both create environmental benefits for all customers, also be allocated more equally to all customer classes. If the Commission holds the line on making major changes to marginal cost methodology, and adopts an equal cents per kWh allocation of social and environmental programs, then the residential class can go the remaining relatively short distance to the marginal cost finish line in this proceeding.

B. KEY RECOMMENDATIONS

1. DRA finds PG&E's marginal generation and capacity costs to be reasonable: PG&E's generation costs are in line with current energy futures prices, and PG&E's capacity costs are consistent with values adopted by the Commission in other proceedings such as the recent QF and AMI proceedings.
2. DRA recommends that marginal distribution capacity costs be calculated using the Regression method instead of PG&E's proposed DTIM method.
3. DRA recommends that PG&E reassign primary line costs to distribution costs from customer costs, where these costs are currently assigned.
4. DRA proposes to maintain the existing marginal cost methodology for customer hook up costs. DRA thus proposes rejection of PG&E's proposal to assign primary line extension costs to customer costs. DRA recommends that the current boundaries between customer costs and distribution costs be maintained.
5. DRA recommends that the Commission reject PG&E's proposal to assign Lifetime primary O&M costs and Lifetime Secondary O&M costs to marginal customer costs.
6. DRA recommends that the Commission adopt an NCO adjustment for meter reading costs that are a component of the revenue cycle services of marginal customer costs.
7. DRA recommends that Department of Water Resources ("DWR") power charge revenues be allocated to bundled customers equal cents per kilowatt hour ("kWh").
8. DRA recommends that the Commission maintain the current allocation method of equal cents per kWh for California Alternate Rates for Energy ("CARE) costs.
9. DRA recommends that Base Interruptible Program (E-BIP) costs be allocated equal cents per kWh.
10. DRA recommends that the costs of programs that create environmental benefits such as the Self-Generation Incentive Program ("SGIP") and the California Solar Initiative ("CSI") be allocated equal cents per kWh.
11. DRA recommends that the Commission adopt a revenue allocation cap that limits increases to customer classes to a maximum of average system change plus 2 percent.
12. Any rate increases to the residential class need to be limited to increases to tier 3, tier 4 and tier 5 rates to conform with AB 1X.

13. DRA agrees with PG&E that CARE rates should not be increased.

14. DRA recommends that CARE commercial customers receive the same average discount as residential CARE customers.

C. ORGANIZATION OF REPORT

Chapters 2-4 of this report address marginal cost issues. Chapter 5 discusses the revenue allocation, and chapter 6 discusses residential and small commercial rate design. DRA limits its attention to rate design issues to those affecting residential and small commercial customers pursuant to Public Utilities Code 309.5.

List of DRA Witnesses and Respective Chapters

Chapter	Description	Witness
1	Executive Summary	Dexter Khoury
2	Marginal Generation and Distribution Cost	Cherie Chan
3	Marginal Customer Hookup Cost	Steve Linsey
4	Marginal Customer Service Cost	Louis Irwin
5	Revenue Allocation	Dexter Khoury
6	Residential Rate Design	Dexter Khoury

2. MARGINAL GENERATION AND DISTRIBUTION COSTS

Witness: Cherie Chan

A. SUMMARY

In this proceeding, PG&E proposes updates to its electricity generation costs from as proposed in its 2003 GRC Application, A.04-06-024, and settled by the parties. In general, DRA finds:

- PG&E's marginal generation costs appear to be reasonable and are in-line with current energy futures prices
- PG&E's capacity values appear to be reasonable and similar to values adopted by the Commission and implemented by PG&E in other proceedings relating to Qualifying Facilities and Advanced Metering Infrastructure.
- DRA recommends that regression analysis be used to calculate its marginal distribution costs
- DRA proposes to maintain the existing marginal cost methodology for customer hook up costs. DRA thus proposes rejection of PG&E's proposal to assign primary line extension costs to customer costs and recommends that the current boundaries between customer costs and distribution costs be maintained.

B. PROCEDURAL HISTORY

In PG&E's 2003 Phase 2 GRC proceeding, the settling parties, including DRA, agreed "to the revenue allocation set forth in this Settlement without agreeing on particular marginal costs or costs of service."[1] Because that case was settled, the Commission did not render an opinion on DRA's marginal cost proposals in that proceeding.

C. MARGINAL GENERATION ENERGY COSTS

In this proceeding, PG&E utilizes power market futures prices to provide relevant starting points for estimating its future marginal costs.[2] A comparison of

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[1] CPUC, Proposed Decision of ALJ Mattson, Appendix B., May 13, 2003 Settlement in Application. page 5. Mailed September 30, 2005.

[2] 2007 GRC Phase 2, Exhibit PG&E-1, (Marginal Generation Costs), March 2, 2006, p.2-3, lines

(continued on next page)

PG&E's marginal cost proposals between its last GRC Phase 2 in 2005 and 2007 testimony show projected average marginal energy price increases of 66.4%. Market electricity prices have increased 132% and gas prices have increased 63% during this same period.[3] In light of the increases in energy prices over the same period, PG&E's energy price increases appear reasonable.

Marginal Energy Costs ($/MWH) by TOU Period and Voltage Level for 2005 AND 2007

	Transmission		Primary Distribution		Secondary Distribution	
TOU	2005	2007	2005	2007	2005	2007
Summer On-Peak	62.65	109	64.72	113	67.83	118
Summer Partial-Peak	54.27	88	56	90	57.63	93
Summer Off-Peak	41.64	75	42.64	76	43.49	78
Winter-Partial	53.47	80	54.91	82	57.6	86
Winter-Off	42.9	71	43.89	72	44.77	74
Average	47.48	79	48.73	81	50.23	83
Average MC Increase		66.4%		65.9%		65.5%

1. Gas Price Input

In studying the reasonableness of PG&E's Marginal Cost proposals, DRA finds that PG&E's use of the October, 2005 New York Mercantile Exchange (NYMEX) Henry Hub Gas Futures contract prices to be reasonable. In principle, DRA advocates the use of the most recent representative data available. In practice however, the average NYMEX futures gas prices as found in the October 20, 2005 edition Platt's Daily of $9.75/MMBtu[4] and used by PG&E are reasonably similar to the prices PG&E would have encountered when serving

(continued from previous page)
23-37.

[3] As listed in Platts Energy Markets and Platts Gas Daily, Published Oct. 20th, 2005 and April 2, 2004.

[4] DRA calculated the weighted average of 2007 NYMEX Henry Hub gas futures contracts prices in $/MMBtu as listed in Platt's Gas Daily on October 20th, 2005. This is the same date PG&E used to set its gas futures prices.

testimony $9.83/MMBtu[5], and are similar to current gas futures contract prices of ($9.50/MMBtu).[6]

As PG&E states:

> When the Update was being prepared in later April, early May 2006, the natural gas and electricity prices hadn't changed by more than 5% from the October 20, 2005 prices that PG&E had used in the original testimony; therefore, the impact on marginal costs would have been insignificant even if the gas and electric prices had been updated."[7]

DRA acknowledges that the differences in the projected gas futures prices are relatively minor in this instance, in spite of assumptions that "the gas prices embedded in the MEC's was from one day in October 2005 during a peak in the gas market:[8]"

In the past, DRA has recommended that utilities "use an updated natural gas price to reflect the current reality when calculating marginal generation costs.[9]" However, in that case, the gas futures prices had jumped dramatically from $6.84//MMBtu to $10.15 /MMBtu between the date used by the utility an the time that DRA filed its testimony. DRA confirms that although the price of gas futures at Henry Hub had risen slightly between the October 2005 filing and PG&E's March 2006 update, futures prices have since settled to approximately the same October, 2005 futures levels as originally used by PG&E. Therefore, DRA

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[5] DRA calculated the weighted average of 2007 NYMEX Henry Hub gas futures contracts prices in $/MMBtu as listed in Platt's Gas Daily, NYMEX Henry Hub Gas Futures Contract, March 2. Published March 3rd, 2006. PG&E served testimony on March 2nd, 2006.

[6] DRA calculated the weighted average of 2007 NYMEX Henry Hub gas futures contracts prices in $/MMBtu as listed in Platts Gas Daily, NYMEX Henry Hub Gas Futures Contract, August 31, 2006. Published September 1, 2006.

[7] PG&E Data Response CLECA_004-01, July 7, 2006

[8] CLECA Data Request 004-01, June 26, 2006.

[9] A.05-05-023, Testimony on Phase 2 of the Southern California Edison Co. 2006 General Rate Case, Marginal Cost, Revenue, Allocation, and Rate Design, Testimony of the Office of Ratepayer Advocates, Served December 16th, 2005.

finds PG&E's use of an October 2005 gas futures price to be reasonable for this proceeding, but would not oppose a future update to the pricing inputs if prices change significantly during the course of this proceeding.

2. Electricity Price Input

"In preparing its marginal generation costs, PG&E used the NP-15 firm on-peak energy forward market prices for calendar year 2007, as reported in the October 20, 2005 issue of Platts' Megawatt Daily.[10] DRA has also found the use of this older electricity futures price to be sufficient for accurate marginal costing purposes in this proceeding. On average, DRA found that Forward Market Prices used by PG&E were approximately 15% higher than the market when PG&E filed its testimony in March 2006; however, these prices have currently[11] dropped down to the levels used by PG&E by September 1, 2006.

In practice, DRA recommends the use of the updated long term forward markets prices to more accurately reflect the marginal costs PG&E faces. However, this case, DRA acknowledges that current market prices are relatively similar to those used by PG&E to arrive at its marginal generation energy costs and does not recommend any major changes.

D. MARGINAL GENERATION CAPACITY COSTS

PG&E notes that the predicted load and resource outlook in PG&E's service territory will not require new generation resources until at least 2008 at earliest, at which point PG&E assumes that that a new CT will be the marginal capacity resource utilized.

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[10] 2007 GRC Phase 2, Exhibit PG&E-1, (Marginal Generation Costs), March 2, 2006, p.2-5, lines 11-13.

[11] Platts Megawatt Daily, September 1, 2006.

PG&E proposes levelized 2008-2013 marginal capacity costs of:

Long-Term MCC, Table 2-2, Nominal $/kW-yr			
	Voltage Level		
	Transmission	Primary	Secondary
Levelized Economic Carrying Charge for 2008-2013	$51.54	$53.24	$55.80
2003 GRC Capacity Costs for 2005	24.40	25.15	26.19

In this proceeding, DRA finds PG&E's Marginal Generation Capacity cost estimates to be reasonable and consistent with values proposed by PG&E, unopposed by DRA, and adopted by the Commission in other proceedings.[12]

1. After Tax Cost of Capital

PG&E recommends an after tax cost of capital of 8.16%,[13] citing D.05-12-042, the Interim Opinion Adopting Methodology for the 2005 Market Price Referent proceeding. While DRA has in the past recommended an after-tax cost of capital of 8.79% consistent to PG&E's cost of capital adopted in D.05-12-043[14] in other PG&E proceedings,[15] DRA does not necessarily find these two values to be inconsistent.

For example, when DRA was advocating for an appropriate PG&E discount rate of 8.79% in the recent Advanced Metering Infrastructure proceeding, it was for different reasons: DRA argued that 8.79% "more reasonably reflects the actual costs borne by ratepayers for the use of capital over time, and more accurately reflects the risks of this investment." Because a combustion turbine is not necessarily an asset owned by the utility, the use of an 8.16% discount rate

[12] D.06-07-027. Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure, Mailed July 24th, 2006.

[13] 2007 GRC Phase 2, Exhibit PG&E-1 (Marginal Generation Costs), March 2, 2006, Chapter 2, p. 2-4 line 27.

[14] D.05-12-043, Opinion on Test year 2006 Return on Equity for the Major Energy Utilities, Mailed December 16, 2005.

[15] A.05-06-028, Testimony of the Division of Ratepayer Advocates, January 18, 2006, Chapter 14 (Discount Rate), page 1.

appears to be a reasonable reflection the combined after-tax weighted cost of capital of PG&E and third-party generators.

2. Commission Precedent

PG&E advocates a $52/kW-year Fixed Levelized marginal cost of capacity in this proceeding from 2008-2013. DRA did not dispute PG&E's calculation of a Levelized Net Capacity Cost of $52/kW-year in AMI the AMI proceeding[16], and does not dispute it in this case. For the above reasons, DRA finds PG&E's marginal capacity costs to be reasonable in this case.

E. DISTRIBUTION DEMAND MARGINAL COSTS

1. PG&E's Proposal

In this proceeding, PG&E continues to recommend a forward-based Discounted Total Investment Method ("DTIM") marginal cost methodology that is "generally similar to those described in PG&E's previous General Rate cases beginning with the 1993 GRC."[17] PG&E calculates the DTIM by "dividing the present value of forecasted investments to meet load growth by the present value of forecasted load growth[18]" to capture planned investments and cost differences by geographic divisions.

2. Summary of DRA Recommendations

DRA recommends two significant modifications to PG&E's Distribution Marginal Costs:

a) Reallocate new business marginal primary costs from customer costs to Distribution Marginal Costs.

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[16] A.05-06-028, Testimony of the Division of Ratepayer Advocates, January 18, 2006, Chapter 15 (Cost of Capacity) , page 1,

[17] 2007 GRC Phase 2, Exhibit PG&E-1 (Distribution Expansion Process and Projected Costs), March 2, 2006, Chapter 4A, page 4A-1, lines 21-22.

[18] 2007 GRC Phase 2, Exhibit PG&E-1 (Distribution Expansion Process and Projected Costs), March 2, 2006, Chapter 2, p. 2-4 line 27. (emphasis added by DRA)

b) Use Regression Analysis to calculate the demand-related distribution marginal costs.

The net result of DRA's recommendations (in bold) are summarized in the table below.

Summary of PG&E and DRA Distribution Marginal Costs

		PG&E Proposes	DRA Proposes	
	Primary Distribution $/PCAF-KW-YR	13% New Bus. On Primary $/FLT-KW-YR	100% New Bus On Primary $/FLT-KW-YR	Secondary Distribution $/FLT-KW-YR
Using DTIM	$24.67	$1.56	$11.60	$0.75
Using RA	$31.31	$0.26	$14.12	$0.70
% Change	26.89%	-83.40%	21.74%	-6.54%
Total % Change to 100% New Bus. Using RA =			804.44%	

3. Reassignment of New business Primary to Distribution Costs

DRA recommends a reallocation of new Business marginal primary distribution costs from Customer Costs to Distribution Marginal Costs, the details of which are covered in Chapter 3. Based on this recommendation to reallocate 100% of New Business Primary costs to Distribution costs, DRA proposes modifications to PG&E's Marginal Demand-Related Primary and Secondary Distribution Capacity Costs by Division and System Average as shown in the table below. Note that the recommendations outlined in the table do not reflect the DRA's Distribution Marginal Cost recommendations discussed in section 4 below.

MARGINAL COSTS BY DIVISION, a Comparison of PG&E and DRA Proposals
with Modifications to the Percentage assigned to New Business Primary

Line No.	DIVISION	PRIMARY DISTRIBUTION PROJECTS > $1 MILLION $/PCAF-KW-YR	PROJECTS < $1 MILLION $/PCAF-KW-YR	PROJECTS TOTAL $/PCAF-KW-YR	PG&E Proposes 13% NEW BUS. ON PRIMARY $/FLT-KW-YR	DRA Proposes 100% NEW BUS. ON PRIMARY $/FLT-KW-YR	SECONDARY DISTRIBUTION $/FLT-KW-YR
1	CENTRAL COAST	$ 21.65	$ 14.89	$ 36.55	$ 1.20	$ 8.88	$ 0.97
2	DE ANZA	3.19	8.02	11.21	1.06	7.84	0.96
3	DIABLO	32.12	12.74	44.86	2.05	15.20	1.14
4	EAST BAY	3.05	9.61	12.66	1.37	10.21	0.62
5	FRESNO	12.69	8.31	21.00	1.18	8.74	0.39
6	KERN	1.67	6.95	8.61	1.71	12.68	0.38
7	LOS PADRES	24.19	32.62	56.81	2.61	19.39	1.88
8	MISSION	9.82	8.97	18.79	1.88	13.98	0.76
9	NORTH BAY	12.69	17.43	30.12	1.32	9.80	1.01
10	NORTH COAST	17.91	14.39	32.30	1.50	11.17	0.85
11	NORTH VALLEY	26.81	19.56	46.36	1.87	13.87	1.19
12	PENINSULA	14.28	11.82	26.10	1.39	10.35	1.06
13	SACRAMENTO	3.82	16.22	20.04	1.57	11.63	0.91
14	SAN FRANCISCO	19.10	12.08	31.18	0.61	4.55	0.70
15	SAN JOSE	11.14	7.12	18.27	1.42	10.54	0.88
16	SIERRA	14.46	8.32	22.78	1.73	12.88	0.56
17	STOCKTON	11.73	11.03	22.76	2.13	15.86	0.60
18	YOSEMITE	4.62	9.83	14.45	1.93	14.30	0.52
19	SYSTEM	$ 13.24	$ 11.43	$ 24.67	$ 1.56	$ 11.60	$ 0.75

4. DRA recommends the use of Regression Analysis to calculate the overall demand-related distribution marginal costs.

PG&E proposes forward-looking marginal distribution capacity costs based on growth-related distribution investments only[19] on future costs and investments, not past investments.[20] DRA recommends using a regression method to calculate the total demand-related distribution marginal costs, and the regression includes 10 years of historic data. DRA scaled these results against PG&E's regional marginal costs (which are calculated using PG&E's Discounted Total Investment Method, DTIM) to produce geographically differentiated marginal costs.

a) PG&E's Load Growth and Distribution Capital Projections show different trends.

DRA's analysis of PG&E's load growth and capital additions assumptions show that PG&E's load increases are forecasted to continue to grow while capital additions are projected to decline. Though there may be reasons for these differing trends, PG&E does not explain them in its testimony.

When divergent trends exist in the data, as they do here, DRA recommends that the Commission err on the side of caution. "Forward-looking statements . . . are based on current expectations and assumptions which management believes are reasonable and on information currently available to management but are necessarily subject to various risks and uncertainties."[21] No projection is perfect; for this reason, DRA recommends that a regression including past historic data be adopted to calculate distribution marginal costs.

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[19] 2007 GRC Phase 2, Exhibit PG&E-1 (PG&E's Marginal Cost Proposals), March 2, 2006, Chapter 1, page 1-11, lines 16-17.

[20] 2007 GRC Phase 2, Exhibit PG&E-1 (PG&E's Marginal Cost Proposals), March 2, 2006, Chapter 1, page 1-4, lines 31-34.

[21] "Delivering Value," Presentation by Robert Glynn Jr., Chairman, CEO & President, PG&E Corporation, 39th Edison Electric Institute Financial Conference, Sheraton San Diego Hotel & Marina, San Diego, CA, October 26, 2004.

PG&E Load Growth vs. Capital Additions by Year					
		Load	CAPITAL ADDITIONS (2007$)		
	YEAR	Growth	Primary Distribution	Secondary Distribution	NB Primary Distribution
Recorded	1995	406	19,118,563	2,501,709	80,958,988
	1996	1,000	13,476,023	975,633	108,081,747
	1997	226	171,306,745	4,078,046	126,332,393
	1998	959	168,007,963	5,786,663	95,388,032
	1999	373	153,629,756	5,763,089	96,561,945
	2000	689	125,567,283	3,880,525	81,151,529
	2001	(1,679)	98,764,557	3,635,345	76,892,947
	2002	886	49,894,986	3,046,390	61,922,897
	2003	369	37,878,638	3,472,040	77,598,045
	2004	(102)	38,203,945	2,368,491	69,130,743
Forecast	2005	991	75,765,696	4,172,674	68,343,068
	2006	381	89,326,081	4,329,954	66,523,062
	2007	355	84,218,851	4,251,314	67,433,065
	2008	334	87,447,294	4,251,314	67,433,065
	2009	316	51,938,455	4,251,314	67,433,065
AverageRecorded		312	87,584,846	3,550,793	87,401,927
AverageForecast		476	77,739,275	4,251,314	67,433,065
%difference		52%	-11%	20%	-23%

b) The Commission and DRA Recommend the use of RA to calculate PG&E's Total System Marginal Costs

The Commission has stated that "it is better to apply trended costs to transmission and distribution calculations than to place an emphasis on specific future project. This is yet another reason that the regression method as proposed by ORA is more consistent with our marginal cost goals."

The Commission further elaborates that "regression will be the appropriate estimation method for calculating area-specific marginal costs as well, once the accuracy and completeness of the data collection has been improved."[22] Because no area-specific costs were included in PG&E's regression, DRA modified the regression to arrive at division-specific marginal costs. First, DRA used regression method to arrive at total system marginal costs. It then scaled this new value according to geographic division marginal costs calculated by PG&E using DTIM to arrive at the complete set of values recommended by DRA in this proceeding and detailed in the table on the next page.

F. CONCLUSION

DRA supports PG&E's proposed marginal distribution costs and proposed capacity values, but DRA proposes major changes to marginal distribution costs. DRA finds PG&E's proposed marginal generation costs to be reasonable, and DRA recommends adoption of PG&E's proposed capacity values.

DRA recommends that the Commission adopt the regression method for calculating demand-related marginal distribution costs. DRA also proposes the rejection of PG&E's proposal to assign primary line extension costs to marginal customer costs, and DRA assigns these costs to marginal distribution costs.

DRA thus recommends adoption of its proposed marginal distribution costs including primary line extension costs. DRA is not convinced that the DTIM method is more accurate, and DRA finds potential problems with this method, thus DRA recommends adoption of the more widely accepted regression method.

[22] 71 CPUC 2d, D.97-03-017, 217.

PG&E and DRA's MARGINAL COSTS BY DIVISION

Line No.	DIVISION	PRIMARY DISTRIBUTION											
		PROJECTS > $1 MILLION $/PCAF-KW-YR		PROJECTS < $1 MILLION $/PCAF-KW-YR		PROJECTS TOTAL $/PCAF-KW-YR		13% NEW BUS. ON PRIMARY $/FLT-KW-YR		100% NEW BUS. ON PRIMARY $/FLT-KW-YR		SECONDARY DISTRIBUTION $/FLT-KW-YR	
		PG&E	DRA	PG&E	DRA	PG&E	DRA	PG&E	DRA	PG&E	DRA	PG&E	DRA
1	CENTRALCOAST	21.65	27.47	14.89	18.90	36.55	46.37	1.20	0.20	8.88	10.81	0.97	0.90
2	DEANZA	3.19	4.05	8.02	10.18	11.21	14.23	1.06	0.18	7.84	9.55	0.96	0.90
3	DIABLO	32.12	40.76	12.74	16.16	44.86	56.91	2.05	0.34	15.20	18.51	1.14	1.07
4	EASTBAY	3.05	3.87	9.61	12.19	12.66	16.06	1.37	0.23	10.21	12.43	0.62	0.58
5	FRESNO	12.69	16.10	8.31	10.55	21.00	26.65	1.18	0.20	8.74	10.64	0.39	0.36
6	KERN	1.67	2.11	6.95	8.81	8.61	10.93	1.71	0.28	12.68	15.44	0.38	0.36
7	LOSPADRES	24.19	30.69	32.62	41.39	56.81	72.08	2.61	0.43	19.39	23.61	1.88	1.76
8	MISSION	9.82	12.46	8.97	11.38	18.79	23.84	1.88	0.31	13.98	17.02	0.76	0.71
9	NORTHBAY	12.69	16.11	17.43	22.11	30.12	38.22	1.32	0.22	9.80	11.93	1.01	0.94
10	NORTHCOAST	17.91	22.72	14.39	18.26	32.30	40.98	1.50	0.25	11.17	13.59	0.85	0.79
11	NORTHVALLEY	26.81	34.01	19.56	24.81	46.36	58.83	1.87	0.31	13.87	16.89	1.19	1.11
12	PENINSULA	14.28	18.12	11.82	14.99	26.10	33.11	1.39	0.23	10.35	12.60	1.06	0.99
13	SACRAMENTO	3.82	4.84	16.22	20.58	20.04	25.43	1.57	0.26	11.63	14.16	0.91	0.85
14	SANFRANCISCO	19.10	24.24	12.08	15.32	31.18	39.56	0.61	0.10	4.55	5.54	0.70	0.65
15	SANJOSE	11.14	14.14	7.12	9.04	18.27	23.18	1.42	0.24	10.54	12.83	0.88	0.82
16	SIERRA	14.46	18.35	8.32	10.56	22.78	28.91	1.73	0.29	12.88	15.68	0.56	0.52
17	STOCKTON	11.73	14.89	11.03	14.00	22.76	28.89	2.13	0.35	15.86	19.30	0.60	0.56
18	YOSEMITE	4.62	5.86	9.83	12.47	14.45	18.33	1.93	0.32	14.30	17.41	0.52	0.49
19	SYSTEM	3.24	16.80	11.43	14.50	24.67	31.31	1.56	0.26	11.60	14.12	0.75	0.70

3. MARGINAL CUSTOMER ACCESS COSTS

WITNESS: STEVE LINSEY

A. SUMMARY AND RECOMMENDATIONS

This chapter addresses marginal customer access costs: the costs to hookup new customers, and the costs of maintaining access for existing customers. DRA's conclusions and those of PG&E are diametrically opposed. For new hookup costs, PG&E quite explicitly proposes to redraw the "boundaries" between customer specific costs and primary distribution, and proposes to recategorize some $69 million of primary costs as customer costs. DRA recommends that the Commission decision clearly reject this sharp departure from long-standing marginal cost practices, and extensively critiques PG&E's numerous arguments. In a nutshell, only equipment that is dedicated to a single premise or provides one unit of equipment to a few customers has or should be included in marginal customer cost. When equipment provides service to many customers at many premises, that should be included in distribution marginal cost. Additionally, DRA has determined that many new connections do not incur the level of cost as computed by PG&E.

There are three customer cost components that have been included for operations, maintenance and replacement. PG&E proposes to omit operations and replacement for distribution marginal cost.[23] In order to mitigate an enormous disparity between customer and distribution costs, DRA recommends that costs omitted from distribution also be omitted from customer costs.

[23] Section F at page 4A-15 of PG&E's testimony is entitled Non-marginality of Distribution Operations and Maintenance and Replacement Costs.

Table 3-1: DRA recommended total access costs vs. PG&E			
Class	DRA total	PG&E Total	DRA stated as % of PG&E
Residential	$17.72	$56.01	32%
Ag-A	54.29	216.18	25%
Ag-B	163.64	615.24	27%
Small L&P	71.52	208.14	34%
Medium Primary	248.99	312.37	80%
Medium Secondary	268.31	677.34	40%
E19 P	728.35	3,027.37	24%
E 19 S	646.03	1,836.06	35%
E19 T	5,329.37	10,926.34	49%
E 20 P	728.35	3,027.37	24%
E 20 S	658.81	1,885.91	35%
E 20 T	5,329.37	10,926.34	49%
Streetlight	1.13	20.28	6%

Specifically, DRA finds and recommends each of the following:

1. The Commission should maintain and strengthen its existing one-time hookup methodology by adopting a definition of "customer access" that is consistent with PG&E design practices and tariffs.

2. "Customer access" should be defined as the "provision of service to a single customer" because it provides a clear functional relationship to the number of customers, and is consistent with the definition of a customer service in Tariff Rule 16, and with PG&E design.

3. Customer hookup cost should be defined as the cost of equipment for only an individual customer and which is incapable of becoming shared over time; or the cost of equipment which substitutes for equipment that would serve an individual customer.

4. The Commission's stated policy of placing customer costs at the bottom of the marginal cost hierarchy remains unchanged, but the relative share of customer costs has grown and would predominate were PG&E's proposals to be adopted.

5. The Commission should apply a rigorous and consistent framework to determine when O&M and replacement costs are marginal, and should correspondingly reject PG&E's selective inclusion in customer costs and exclusion from distribution costs.

6. The Commission should adopt the marginal customer costs shown in Table 3-1 above.

B. INTRODUCTION AND BACKGROUND

1. ORGANIZATION

DRA's testimony is organized as follows. First, DRA provides some brief background to set the stage for this multi-year disagreement. Section C provides DRA recommended quantitative outcomes. Section D reviews regulatory history and the lessons of that history. Section E leads with a critique of PG&E's argument, while Section F recaps the manner in which the Commission should reconfirm its existing marginal cost policies.

2. THE STORY SO FAR

PG&E first made its recategorization proposal in Phase 2 of its last general rate case. DRA filed extensive testimony supporting the "transformer, service drop, meter" (TSM) method of customer equipment identification, and in opposition to the expansion of customer costs.[24] Neither PG&E nor DRA testimony was ultimately subject to cross-examination. Parties reached a settlement on revenue allocation and rate design issues, while marginal costs were left unsettled.

PG&E has maintained much of its testimony from the 2003 case. In several cases, DRA also points to evidence from the 2003 case. One of the primary interrelated issues for determining customer access costs is that of line extension allowances. For PG&E's chosen methodology to calculate marginal customer costs is directly based on actual, historical line extension credits allowed to developers. Line extension allowances are credits granted to new development that can be used to offset the costs of customer premises equipment, as well as costs of demand-related extensions between the existing PG&E distribution system and customer sites.

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[24] In this case, DRA uses the TSSM method, which adds secondary distribution to the list of customer equipment. It is DRA's understanding that PG&E's current design for new hookups may use secondary distribution as a substitute for service when secondary design is cheaper.

Both The Utility Reform Network (TURN) and DRA have expressed concern about the large and unwarranted increased in line extension allowances. After expressing these concerns in protests of San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) advice letters, the Commission directed the utilities to make further filings regarding these allowances. PG&E filed A. 05-10-016 in response to this directive. PG&E asked for an increase in its residential line extension allowances similar to that received by the other two utilities, proposes to remedy relatively minor problems with the allowance, and chose not to address fundamental problems with the line extension calculation itself.

In the previous rate case, DRA and TURN took exception to one particular feature of PG&E's line extension allowances, the "50% discount option." This option allowed some residential developers to receive a credit that exceeds the maximum allowed credit. In its line extension testimony, PG&E proposes to eliminate the 50% option, and estimates an expenditure reduction of $6.6 million.[25] No party filed any testimony opposing PG&E's elimination proposal. In rate cases, PG&E has proposed both then and now to include that excess credit in customer marginal cost, and thus in residential rates. Given DRA's recommendations in this case, DRA estimates a reduction of $4.4 million,[26] as set forth in workpapers.

DRA's testimony in A.05-10-016 sets forth the precise way in which current allowances violate the Commission's "no subsidy" policy.[27] PG&E

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[25] See page 8-5 of PG&E A.05-10-016 testimony. The current maximum allowance is $1,313 per unit, while the average cost to PG&E has been $1,401.

[26] The dollar amount that corresponds to PG&E's $6.6 million is $2.9 million. In developing marginal costs, a revenue requirement factor is used which increases the $2.9 million to $4.4 million.

[27] See D.94-12-026; page 12 states "We agree with the utilities that no group should be cross-subsidized by the majority of utility ratepayers." The divisor for Net Revenue "determine[s] the Utility's break-even investment in distribution facilities (Appendix B, which is the gas appendix at page 13 to D.94-12-026, mimeo)."

joined in a Motion to Strike both TURN and DRA testimony, arguing that any adjustment to the current line extension formula went beyond the scope of the proceeding. As of September 13, 2006, that Motion is pending.

C. QUANTITATIVE ISSUES

1. SUMMARY OF DRA AND PG&E POSITIONS

PG&E proposes a large increase in customer marginal costs and an even larger decrease in distribution costs:

TABLE 3-2: PG&E PROPOSED VS. HISTORICAL MARGINAL COST			
	1996 adopted	PG&E proposed	% change
Marginal unit	(2007$)		
Primary distribution	$129.26	$ 24.67	-81%
Customer: residential	59.96	103.13	72%
Customer agriculture A	271.71	354.17	30%

The proposed real increase in customer costs actually understates magnitude, since changes to line extensions since 1996 require the developer to bear some cost, where formerly the developer bore very little cost. Based on PG&E revenue requirements, the decrease in primary distribution cost is not attributable to reduced cost incurrence by PG&E. Rather it evidences ever more selective counting of the actual distribution costs that have and will be incurred. Meanwhile, PG&E proposes to count not only actual expenditures for investment, but also the associated revenue requirement estimated out to 2047.

Were PG&E's proposals to be adopted, 57% of the cost of distribution would be allocated based on customer marginal cost, and 43% based on distribution marginal cost. This portrait of the electric delivery system may be as creative as one of Picasso's cubist images, with perhaps an even more skewed perspective. The selectivity of the costs to be included as marginal does not reflect a rigorous and consistent framework. Rather, the ad hoc series of rationales even goes so far as to treat investments in the same type of equipment made at the same time in completely opposite ways.

This overwhelming inequity does not mirror cost causation or contribute to the Commission's fairness goal for marginal cost ratemaking. Nor does it mirror what we can all see from our window. PG&E would have the Commission, the ALJ and the public believe that the tiny fraction of the vast distribution system extending dedicated to serving individual customers create greater costs than the extensive network beyond. To provide some additional perspective on the selectivity employed, consider the aggregate marginal costs that PG&E recommends be used in revenue allocation. PG&E's EPMC multiplier is 2.8, meaning that marginal costs are barely 1/3 of embedded costs.

TABLE 3-3: SUMMARY OF PG&E AND DRA POSITIONS ON CUSTOMER COST ISSUES			
	PG&E	DRA	Magnitude
TOTAL	$434 million	$143 million	
One time hookup cost and related			
New hookup investment capital	$222 million Dramatically expanded--Proposes to substantially expand to include primary distribution	$143 million Eliminates excess line extension costs PG&E wrongly assumes that every new customer incurs MLX costs Maintains Commission definition that a customer cost is strongly tied to a unique or highly limited set of customers.	+$69 million -$4 million -$6 million
Lifetime primary O&M (zero, since derivative of primary generally)	$50 million New cost category, based on PG&E theory that distribution demand should be reclassified as customer access	$0 Since primary distribution is not a customer marginal cost, neither is primary associated O&M	+$50 million
Lifetime secondary O&M	$5 million New cost category	$0 Unreasonable to include costs extending out to 2047 when the same secondary equipment in distribution is counted as $0 for 2007	+$5 million
One time subtotal	Subtotal reflects positive numbers only		+$124 million (+80%)
Currently included in marginal cost			
Transformer and service maintenance and replacement)	$157.4 million Existing	$0 Suspend for this rate case to make methodology consistent with that for distribution marginal costs	$157.4 million

As shown in Table 3-3, PG&E proposes $124 million for two new cost categories, and the expansion of customer investment to include distribution. DRA recommends zero increase—the boundary for customer access is sound, and PG&E's redefinition of primary distribution as customer access is not. DRA also recommends that maintenance and replacement not be included adopted or recognized as cost elements of customer marginal cost. Maintenance and replacement are sensible elements of marginal costs when consistently applied. There is not good cause to apply maintenance and replacement only to customer costs and not to distribution, as will be demonstrated below.

2. The Data on Hookup Costs - and Beyond

Like PG&E, DRA also relies upon PG&E's "massive download of customer connection cost (MLX) data." Unlike PG&E, DRA does so with considerable reluctance. According to PG&E, the passage of time has strengthened the quality of that data:

> "...PG&E's 2003 GRC models and data were subject to thorough scrutiny over a 10-month time period by a number of parties to that proceeding, and PG&E made a number of corrections to its models as a result of that scrutiny. In particular, both DRA and TURN thoroughly examined PG&E's RCS models, and PG&E has incorporated many of their recommendations (PG&E-1, page 5-15)."

and

> "PG&E is confident, based on a thorough examination of its 2003 GRC Phase 2 marginal cost data by the parties cited above [DRA and TURN] that these data provide a solid foundation for the analysis contained therein (id.)."

In the 2003 GRC, DRA brought up a number of troublesome issues:

- PG&E failed to include the data that would allow empirical testing of its contention that costs are a function of customers rather than demand;
- PG&E's proposed inclusion of primary costs is not from actual jobs, but from PG&E's derivations;

- The number of lots can exceed the number of meters that have been set, thus overstating costs.
- Even a limited review of source data indicated that source data is not reliably reflected in PG&E's data.

Based on the quotes above, DRA asked PG&E what changes to the MLX database were made as a result of DRA (and other parties') scrutiny. PG&E's response: "Other than the removal of ITCC tax, no corrections were made to the extract of MLX data.[28]" The remainder of this section of testimony covers the basic elements of how the data is gathered, and details the significance of the faults identified above.

a) MLX Data – Basic Background

MLX refers to main line extensions. PG&E's residential database works roughly as follows. For each new business request, PG&E gathers and analyzes characteristics of the proposed new business in one of its local offices. A local office planner will perform a job estimate, which becomes the basis of the agreement between the developer and PG&E. Some of the costs from that agreement become part of PG&E's database. Each total project is then divided into an individual record for each lot. So, a 120 unit subdivision that costs $250,000 will divide that $250,000 cost into 120 line items.

PG&E performs a job estimate that is divided into Rule 16 and Rule 15 costs. Rule 16 costs are the costs of the service drop and meters, while Rule 15 costs are everything else. The line allowance of $1,313 per lot is first applied to Rule 16 costs, with any remainder available for Rule 15 costs. Unfortunately, while PG&E enters total Rule 15 costs, PG&E decided not to include the Rule 16 total. PG&E instead enters the cost per lot within the allowance. The cost for jobs in excess of the $1,313 allowance is reflected inaccurately. So the data was inadequate for relating service and meter costs to gross job costs.

[28] PG&E response dated July 27, 2006 to DRA004, Q.17. ITCC refers to Income Tax Component of Contribution.

PG&E uses a few total cost numbers to derive the cost of the meter, service, and primary and secondary costs. These total cost numbers are fixed inputs. Therefore, the reliability of this database is only at the total cost level, rather than for the cost of any specific cost category within PG&E's proposed customer cost methodology.[29]

b) PG&E's data extract did not include demand data, and thus does not allow empirical verification of the relationship to demand and customers

The database PG&E created from its MLX records only picks up the number of customers from the more detailed inputs. Importantly, it omits the quantity of kW of demand. According to PG&E, the demand data resides only in the local office, is not routinely entered into PG&E's systems, and could not be retrieved without undue burden. The association between costs versus kW of demand rather than costs versus customers continues to be unilluminated. While PG&E has chosen to address this problem using hypothetical examples (see pp. 5-9 and 5-10 of PG&E's testimony), a more rigorous approach, such as a multi-class cross-sectional analysis using the MLX database would be necessary to conclude that demand has only a minor cost impact.

c) PG&E has not directly measured primary costs, but rather has indirectly imputed those costs

PG&E's database uses the Rule 15 number to allocate costs for primary, secondary, and to some extent, transformers. In other words, PG&E's proposed inclusion of primary costs is not from actual jobs, but from PG&E's derivations. Furthermore, PG&E's derivation is not from its massive database, but from a small, and not particularly reliable sample.

PG&E's derivation is from data provided in response to a TURN data request in the 1999 general rate case. PG&E totaled the secondary and primary

[29] For example, PG&E's proposed O&M adders would be affected by PG&E's imputed allocation between secondary and primary.

costs, and estimated a ratio of 30% for secondary, and 70% for primary. Unfortunately, the quality and variability of data leads to low confidence that the ratio is actually 30%-70%. This data request reflects 113 jobs. PG&E totaled all jobs into a single cost, calculated the proportion of primary at 72.7%, and then rounded down to 70%. For those jobs, 45 had zero primary costs, 79 had zero secondary cost, and 39 had zero cost for both secondary and primary. The five biggest jobs account for 39% of the total cost. In statistical terms, the data is both highly asymmetric and widely distributed. Thus, little confidence can be placed in it. The secondary cost percentage is less than one standard deviation from a value of zero, and there would be roughly a one in four chance that secondary costs are zero.

d) The validity of PG&E's denominator is questionable

Another feature of PG&E's jobs database is the number of lots can exceed the number of meters that have been set. PG&E uses meter sets as the divisor to calculate the per-unit cost. By one measure, meters sets are about 20% below the number of lots.[30] By using meter sets as the divisor, PG&E's estimation of unit cost will prove too high. Some of PG&E's calculations used more than one transformer per customer, leading to anomalies.[31]

The number of meters or lots is a critical input. The number of meters would seemingly simply be extracted from the relevant electronic data, and copied into PG&E's jobs database. However, even with the small amount of source data, there was one significant error. PG&E's database shows 33 meters, while the source data reflects 52.[32] This increases the unit cost by $51 or about 16%.

[30] See MLX_DATA_R5_DISC.xls, based on computation of relative sums for columns N and O. This is the second largest source of residential data, comprising roughly 25% of residential jobs. Other residential spreadsheets may have a different result.

[31] Exemplary MLX jobs include 119295, 126147, 126712 and 134193. This does not represent a comprehensive listing.

[32] PG&E response to ORA_004_01 in the 2003 GRC, MLX job id of 133808.

DRA asked PG&E for any studies that attempted to validate the data. PG&E did not provide any attempt to determine the validity of actual data entries. PG&E did provide studies showing that PG&E's estimated costs were often at odds with actual incurred costs by substantial margins.[33] In short, both the analytic and input quality of the MLX data are questionable. While DRA makes no recommendation that would specifically address this questionable data, DRA does recommend that the Commission take a cautious approach to relying on it.

e) MLX data cannot be relied upon to determine the costs for all new customers

PG&E has assumed that the cost of every customer served by a new hookup is equal to the costs resulting from the MLX database. DRA noticed a probable discrepancy between the number of MLX units and the number of new customers. DRA asked PG&E to reconcile that discrepancy. PG&E's response:[34]

> Possible reasons for this discrepancy include:
>
> 1. The different time periods covered. The MLX data included 2002 which may have been a slow-growth year as compared to 2003.
>
> 2. Some residential new connects do not require MLX accounts.
>
> 3. Some MLX data was discarded from the analysis because it did not appear to be internally consistent or was inconsistent with information in other PG&E databases.

This response is a series of hypotheses, not reconciliation. However, what it does point to is that PG&E does not need an extension of the distribution system for every new customer. This makes eminent sense. Even in mature, virtually

[33] .For example, Attachment DRA004-26-1 states: "Our target is for the actual costs to be within 10% of the estimated costs, but given the number of jobs exceeding the target, we have established some expanded percentage variances for this audit." Overall 19% of jobs fell within the 10% tolerance band.

[34] PG&E response to DRA004, Q.33.

fully built out areas (such as much of the Bay Area), there are individual lots that are undeveloped. This infill development can make use of existing infrastructure. Some still unknown percentage can be served from the existing system. The cost to hookup such customers would be clearly overstated by MLX costs.

In order to estimate the costs for such customers, it is necessary to make certain assumptions. Because every new customer requires their own meter, DRA includes the MLX meter cost. Most customers would require their own service, so DRA includes service costs. For service-only residential jobs, DRA follows the PG&E convention of excluding transformers.[35] DRA has not made any adjustment to secondary distribution costs, although there is a good possibility that service only jobs have low or no secondary cost. Reduced secondary cost would affect classes other than residential. In order to estimate the percentage of customers who would not have required an MLX extension, DRA compared the number of MLX units to the quantity of customer growth. Surprisingly, the quality of data for the number of customers is surprisingly lacking:

> QUESTION 29
>
> Please provide the historical, recorded number of new connects for each class (residential, small agricultural, etc.) by year for the period 2000 through 2005.
>
> ANSWER 29
>
> The requested data is not available prior to 2003. (DR DRA004)

The MLX data compiled by PG&E extends from January 2002 through August 2003. PG&E further indicated in response to DRA004-32 that "PG&E undertook a major overhaul of its billing/accounting system during December 2002, which created certain anomalies in billing data during the December 2002

[35] PG&E workpaper spreadsheet from 2003 GRC, MLX_Data_R5_Disc, Results worksheet, column AX.

January 2003 period…" DRA's followup requested customer count data that was not subject to such anomalies. PG&E did provide a list with more aggregated classes than are used in marginal cost. Based strictly on that data, the actual number of MLX units was 51% below the number of additional residential customers.[36] DRA considered other data as well. In response to a direct inquiry, PG&E estimated less than 10% of new residential connections completed in 2005 were installed without MLX.[37] PG&E also provided the number of circuit feet associated with particular types of installations. Analysis of that data indicates that the percentage of non-MLX jobs would be at least 20%, and likely much more.[38]

Given this conflicting data, DRA judges the most probable measure of non-MLX jobs as somewhere between 20% and 50%. Taking the simple midpoint of those two figures would result in 35% non-MLX jobs. Although there seems to be little support for PG&E's estimate of less than 10%, DRA is reflecting a conservative 30% figure for non-MLX jobs.

3. PG&E HAS NOT JUSTIFIED THE SEPARATE AND UNEQUAL COUNTING OF EQUAL EXPENDITURES

For this case, DRA recommends that the only customer cost to be included in revenue allocation be the direct investment cost of new hookups. DRA would not oppose the reasonable inclusion of ongoing O&M costs of customer premises equipment. However, the disparity between the determination of distribution

[36] The number of small business customers was also well below the number of MLX units.

[37] Data request DRA007-01. Note that the number of 75,227 recorded new connections is not equal to other results provided by PG&E in DRA006-01 of 73,016.

[38] The simple quantification is based on data provided in response to DRA006-02, and is provided in DRA's electronic workpapers. The 20% figure represents a situation where the average number of circuit feet is equal between MLX and non-MLX jobs. However, since there is no extension for the non-MLX jobs, and since the MLX jobs are inclusive of the number of primary and secondary feet, the MLX jobs would involve more circuit feet per job. For example, if 1/3 of the MLX jobs were service feet, and 2/3 were primary and secondary, and if MLX and non-MLX circuit feet are equal, then 43% of jobs would be non-MLX.

marginal cost and customer marginal cost is both so vast and so vastly unjustified that DRA must recommend methodological steps that reduce that disparity. As discussed below, for every dollar that PG&E invests in precisely the same types of equipment, PG&E proposes to count as high as $1.88 (customer costs) or as low as zero (distribution costs).

Since DRA recommends that the inclusion of primary costs be rejected, DRA correspondingly recommends that the primary cost adder be rejected as well. The scope of the following portion of DRA's testimony applies both to PG&E's proposed two new cost categories (lifetime primary and secondary O&M adders for new connections), as well as the maintenance and replacement of existing facilities.

a) PG&E has not justified the separate and unequal treatment of equal expenditures

Table 5-27a of PG&E's workpapers shows a proposed secondary O&M adder which includes costs out until 2047. PG&E's proposal for distribution marginal O&M costs does not even include 2007 costs. As further shown in Table 4B-1 of PG&E's testimony, PG&E proposes to treat the same type of investment in distribution in three different ways. Neither the investment nor O&M for replacement would be counted at all. For distribution labeled as connectivity, PG&E would move that to customer marginal cost. Only reinforcements for new growth would be included in distribution marginal cost.

Not only does PG&E propose to treat the same investment as three different types of costs, PG&E proposes to count three very different levels of costs for each of those cost types (which is not explicitly shown in Table 4B-1). One dollar of replacement cost would be counted as zero. One dollar of new growth cost would be counted as one distribution dollar. One dollar of new customer growth costs would be counted as $1.88![39]

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[39] $1 of direct investment, 61 cents as a primary adder (PG&E workpapers Table 5-25, page 5-

(continued on next page)

Similarly, PG&E proposes to count replacement and maintenance of existing customer facilities. This is in accordance with standing marginal cost practice. PG&E proposes not to count any replacement and maintenance of existing distribution facilities. DRA believes this is not in accordance with adopted marginal costs, although it is not entirely clear from the Commission's decision.[40] Even if such disparate treatment were fully justified in isolation, this separate and unequal treatment creates a strong perception of the lack of fairness and equity. While PG&E's recommendations are consistent with a policy of favoring slower-growing classes as stated in Chapter 5, the pick and choose element of cost development appears to represent an approach more indicative of marginal cost as an art form than as a consistent reflection of reality. Selective attribution of cost causation is particularly difficult to reconcile with equity, and unlikely to be particularly compatible with economic efficiency either.

b) …nor has PG&E justified treating new equipment as only the equal of old equipment

Aside from the broad marginal cost problems with PG&E's selective adders, PG&E's computational methods significantly overstate what those adders would be. The basic problem is that PG&E treats brand new equipment as if it is just as likely to require the same O&M expenses as average used equipment.

PG&E draws its percentage factors from recorded cost data.[41] That recorded cost data will reflect PG&E's overall cost experience for average equipment. On average, such equipment should be in the vicinity of halfway through its economic life. Since PG&E includes costs out to 2047, that equipment should average about 20 years old. Just as an aging home or vehicle

(continued from previous page)
48, line 14) and 27 cents as a secondary adder (Table 5-27).

[40] The decision states the adopted level, but does not provide a table showing how this number was arrived at.

[41] See for example, pages 5-49 and 50 of PG&E's workpapers.

requires more upkeep than new ones, so too will equipment. PG&E's computations assume that brand new equipment has the same maintenance needs as older equipment. A more accurate representation would have a cost percentage that is low in the early years, rises to the average at 20 years, and then rises further until the replacement year.

c) …and PG&E's rationale to exclude O&M and replacement from distribution applies equally to customer equipment

In the 2003 rate case, PG&E's explanation for excluding distribution replacements from marginal cost is that (page 4B-2):

> Transmission and shared distribution facility replacement costs are generally not marginal because most replacements are caused by age and exposure to the environment, and not by usage, wear, or the amount of power they carry. Deterioration related replacement costs cannot be avoided by reducing demand, and hence do not fit the definition of marginal costs.

In this case, PG&E provides an altered explanation:

> The timing and cost of [distribution pole] replacement may be affected by environmental factors in its specific location, but are largely unaffected by changes in consumer demand for electricity. The same is true for most other distribution equipment, as long as it is operated within normal operating limits (page 4A-15).

Replacements of transformers, service drops and meters are also mostly attributable to age and exposure, rather than the amount of power or the amount of customers that they serve. In evaluating PG&E's argument, the Commission should pay special attention to the reference to "operated within normal operating limits." During the recent heat storm, a number of facilities, in particular transformers failed, due to the demands imposed—demands, not the number of customers. PG&E's second sentence could be restated as "Once we've installed equipment sized to meet peak demand, it is likely to be operated within normal operating limits. So even though demand was the basis for our decision making, that basis no longer matters."

PG&E distinguishes replacement of customer equipment from distribution line extensions and secondary equipment, as extensions tend to become shared. PG&E claims that replacement costs for distribution lines are generally insensitive to the changes in customers unless "**all** of the customers using the facilities take service."

In the prior case, PG&E's sharply differentiated between the avoidability of unshared customer costs and the unavoidability of shared distribution costs.[42] In this case, PG&E appears to have abandoned its justification based on avoidability. DRA replicates its testimony from the prior case, as it provides a further case study of the inconsistent application of attributes of what is marginal and what is not.

While PG&E has characterized the requirements for avoidability, PG&E presents no empirical data or other support.[43] Among other problems, PG&E's contention is overstated. Transformers are shared costs for residential and small commercial customers. On average, one transformer serves over seven residential customers.[44]

The assertion that hookup replacement costs are "avoidable" clearly means something much less than avoidability applied to other marginal cost categories. The Commission hierarchy placed energy at the top of marginal cost categories, and that category is 100% avoidable. Any long-lived capital investment is much less avoidable than a variable cost such as energy. One easy way to assess

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[42] PG&E may have rethought this position, having responded to an ORA data request that: It is relatively uncommon in PG&E's service territory for hookup equipment (e.g., service extensions) to be abandoned, although it can happen in unusual circumstances (DR 18).

[43] DR 18 in the 2003 GRC

[44] See PG&E worksheet fltdfnew.xls, sheet fltdf, cell O13. Since transformers come in standard, non-continuous sizes, the loss of one customer would not necessarily result in a reduced transformer size.

avoidability uses on expected life, which PG&E did in its assessment of replacement frequency. As shown by PG&E, overhead service extensions have an expected service life of 41 years; so the frequency of replacement in any given year is 2.6%. In other words, the probability of not avoiding overhead service extensions is 97.4%.

However, even a probability of 2.6% is too high. To avoid replacing unshared equipment, two events must occur together. First, the equipment must need to be replaced. Then there must be an opportunity to avoid replacing it if there is no customer then taking service at that residence. Given a conservative 10% vacancy rate, the probability of avoidance drops to 0.26%, or 1 out of every 384 customers. Customer equipment replacement is far closer to "totally unavoidable" than "totally avoidable."

Even without assessing shared distribution equipment, PG&E's sharp conceptual distinction between distribution and customer equipment clearly does not exist. Additionally, distribution replacement appears to be significantly more avoidable than PG&E contends. Distribution planning uses aggregate, or collective observed and forecast demand. There is at least some association between economic growth and decline and local electric loads. The dot-com boom and bust, the decline of the North Coast forest products and fisheries industry, adverse environmental changes (such as that which occurred in Hinckley from toxic pollutants), and the like change communities. Avoidability is more associated with decline than growth; the chance of collective economic decline in a local planning area appears to be on par with unshared hookup facilities.

D. REGULATORY HISTORY

The most significant marginal access cost is the investment in equipment to provide access to a customer. The only investment cost that figures into access cost determination is for new customers, not existing customers. Line extension rules and allowances impose this cost upon PG&E (and ultimately, the general body of ratepayers). Commission policy, determined both in previous rate cases, as well as in the line extension proceeding, is to transmit the price signal for customers coming on the system through line extension charges, and not rates.

1. While stated Commission policy putting customer costs at the bottom of the marginal cost barrel has never changed, changed methods elevated customer cost to the top of the heap

The CPUC now has 20 years of regulatory history on the use of marginal customer costs in ratemaking. PG&E's 1986 decision refers back to D.85-12-108, a decision for SDG&E. The Commission remarked that the customer marginal cost issue lacked consensus, and involved several methods with broadly differing results. The Utility Consumer Action Network ("UCAN") showed that the cost to add a customer is much greater than the savings of a departing customer, and that showing was a major reason for broad differences. UCAN's evidence has since been incorporated into marginal customer cost methodology.

The SDG&E decision is notable in several regards. The decision discusses marginal costs as a whole, and sets forth a hierarchy of importance (20 CPUC 2d, page 178)[45] with marginal customer costs at the bottom of all categories.

The SDG&E decision clearly stated the Commission's purpose:

> The Commission is interested to have customer charges included in marginal costs for revenue allocation purposes…This is consistent with our desire to as much as possible provide accurate and appropriate price signals to each customer and customer class (20 CPUC 2d, page 179)

The Commission also addressed the relationship of marginal customer costs and line extension allowances:

> The economic signal that should be sent is to those customers that are on the system and that signal is the

[45] Where not otherwise stated, DRA's references to CPUC decisions are from the second edition of the published volumes.

> cost savings of a customer leaving the system. *The signal to customers coming on to the system is properly transmitted through line extension charges, not rates* (op. cit., page 173, emphasis added).

The Commission ultimately decided not to use marginal customer cost for SDG&E at all, citing the inadequacies of the approaches then available.

PG&E's 1986 rate case took up where D.85-12-108 left off. The Commission first declared that:

> Marginal customer costs are the costs of providing access to the system and the costs of maintaining existing customers on the system (21 CPUC 2d, page 632).

In that rate case, the Public Staff Division proposed the "DAC," or "direct assignment of cost" method. The investment methodology used those distribution components that "…are dedicated and uniquely assignable to individual customers (id at 634)." The Commission adopted the DAC with some adjustments. The discussion portion noted a key premise, that "customer costs are a function of the number of customers, not demand or energy… (id at 636)."

The 1989 general rate case ("GRC") decision kept the overall structure of the 1986 decision. One significant development is that "PG&E initially proposed to use the cost of new business to estimate customer costs."[46] In the 1993 GRC, PG&E was the initial proponent of a new-customer only/one-time hookup methodology. As PG&E's testimony summarized:

> …only new customers cause PG&E to incur forward-looking hook-up costs; and (2) that access equipment has no opportunity value once it has been installed.[47]

PG&E's testimony used the term "opportunity value" to describe equipment that was not cost-effective to reinstall or sell, and so was left in place.[48] In other words, a customer leaving the system creates virtually zero cost savings.

[46] 34 CPUC 2d, page 320

[47] Response to ORA DR 1, Q.8, Exhibit PG&E-2, page 2-34, lines 8-11

PG&E also contrasted the opportunity value of hookup costs with that for capacity, "which is usable by any kW of demand over its entire useful life," and that one customer's reduced demand makes capacity available to serve another customer.[49]

PG&E further argued that its proposal replicated a competitive market, stating:

> If the home were sold, the selling price would reflect ownership of the equipment, or it would reflect the portion of the equipment that is owned…[50]

Transferring ownership requires that title could set forth both the property and property rights that are conveyed. The service drop and meter are identifiable property for which ownership could be transferred. Beyond the service drop and meter, overall distribution system equipment is shared. It is not clear how an ownership transfer would either identify or specify property and property rights for shared equipment.

The Commission's 1993 decision adopted the new customer only/one-time hookup methodology, which stands to this day.[51] Both the 1993 and 1997 decisions also had a separate cost element for secondary distribution marginal cost, and did not apparently include secondary costs in customer cost.[52]

(continued from previous page)
[48] id., Page 2-28

[49] id., Page 2-29, line 1-7

[50] id., Page 2-31, lines 1-3

[51] D.92-12-057 does not actually discuss the one-time hookup method. Instead, the discussion focuses on the use of region specific costs (47 CPUC 2d, page 288). The decision further states "We acknowledge that our discussion of these issues may frustrate some parties, particularly those that lose issues, given the brevity with which we will discuss them…we will focus on the new changes that we are adopting. The criticisms have been analyzed and considered carefully, even if not described in great length here."

[52] 47 CPUC 2d, page 286 et seq, "PG&E proposes adoption of estimates of ongoing and new business secondary distribution marginal capacity costs calculated by division using the present worth method." PG&E's method was adopted. 71 CPUC 2d, page 242: There is no discussion of secondary distribution cost in the text of the decision.

2. Honoring past principles leads to future progress

This case provides a good opportunity to consolidate the lessons from this history, and to reach clearly established policies as a result. DRA's overall recommendation is to determine marginal customer costs to conform to the Commission's original policy goals, and to take no action that further departs from Commission goals. The issue of recovering one-time hookup costs through line extension charges is not within the scope of this proceeding. DRA further recommends that marginal customer cost exclude any cost that is not clearly a function of the number of customers. In that regard, DRA finds much to recommend in the Commission's (and DRA's predecessor organization) concept that customer investment consists of investments should be dedicated to a customer. DRA develops a working definition below. The wisdom of ORA's predecessor's principles continues. Marginal customer costs should have two attributes: costs bear a clear functional relationship to the number of customers, and these costs of connection are "uniquely dedicated" to a customer.

E. CRITIQUE OF THE PG&E PROPOSAL

PG&E states (at 5-8):

> PG&E is proposing a broader characterization of customer access costs—one that focuses on the <u>investments</u> required to connect new customers, rather than one that attempts to distinguish which distribution equipment is customer related and which is demand related. (emphasis in original)

PG&E thus proposes to elevate *when* an investment occurs over *what* function that investment actually achieves. PG&E makes six separate claims to support this theory, which DRA deals with in turn. However, PG&E's proposal has problems at the broadest level of theory.

1. The PG&E theory does not conform to basic principles of logic or economics

PG&E proposes to treat one thing—primary distribution equipment--as two different things. Currently, all primary distribution is treated as primary distribution for marginal cost purposes. Under the PG&E theory, some primary distribution would still be primary distribution, while some would now be customer connection distribution. In three years from now, the infrastructure for new neighborhood retail development in Stockton for example, would be regarded as providing a customer connection, while newly replaced infrastructure in a comparable shopping district of the Bay Area would be ignored altogether.

As PG&E states in its overall policy, marginal cost-based ratemaking promotes fairness (1-4). Treating equal costs unequally departs from fairness; at a minimum, every party on the short end would perceive that as unfair treatment. If marginal cost ratemaking is to continue to promote fairness, the Commission—and the proponent—ought to be able to articulate a rationale that: provides some common sense explanation that a de facto departure from equality is justified, that the rationale is likely to be persuasive to an observer who is neither harmed nor helped, and that the rationale is unlikely to be mocked by a party that is harmed. PG&E has neither recognized nor addressed this issue.

Secondly, PG&E simply hypothesizes away its own citation on the very same page that "the distribution system performs both a capacity or demand related function and a customer access function." In economic terms, this is a classic joint cost problem. PG&E continuously refuses to recognize that not only customers, but also the demand of those customers is being added to the system. While the right answer to a joint cost problem is rarely easy, it is certainly the wrong answer to pretend that a joint cost problem doesn't exist. Nor does PG&E show that the evidence supporting the boundary of customer costs at the final line transformer is faulty. While PG&E does provide evidence on line extension demand and cost (critiqued below), PG&E has not provided any evidence that line extensions do anything other than support the demand imposed by customers.

2. Critique of PG&E's justification to expand the customer access cost boundary

Section C. of Chapter 5 (at pages 5-8 through 5-14) puts forward six arguments to expand the boundary between where customer access ends and distribution begins:

1. current marginal costs are misaligned with cost causation…
2. as well as misaligned with line extension tariffs;
3. extension costs are largely unrelated to demand;
4. line extensions are not fungible;
5. expansion proposal fosters economic efficiency;
6. expansion ameliorate potentially significant cost shifting

PG&E arguments 1, 2 and 5 above all relate to efficiency and cost causation. Arguments 3, 4 and 6 are also related, albeit less strongly, to the descriptive attributes of line extension investments. Argument 3 and 6 are more strongly related to each other than to argument 4. PG&E's efficiency arguments are partially reliant upon line extension attributes. Based on these interrelationships, DRA addresses these arguments as two collective groups, and addresses the attribute arguments first.

a) PG&E has elasticized the concept of "fungibility"

DRA will spend a fair amount of space deconstructing PG&E's argument that distribution line extensions are not fungible. To provide foundation, the definition of "fungibility" is interchangeable. In other words, fungible is a fancy term that means "anyone can use it." The absence of fungibility then means that it is useless to anyone else. A classic example of completely fungibility is a unit of currency. Every person's dollar has precisely the same purchasing power as any other person's dollar.

i. PG&E relies upon non-existent support from prior TURN testimony

Prior TURN testimony contradicts, rather than supports, PG&E's line extension argument	
PG&E	TURN
Cite at 5-11. starting at line 16	Cite at 5-11, footnote 17
The **non-fungibility** of line extensions **contrasts sharply** with distribution capacity investments, such as substation expansions, which occur upstream of the point of interconnection of new customers. In the case of upstream distribution substation, demand reduction by **nearby agricultural** customers served from the substation would free up capacity by nearby agricultural customers (emphasis added by DRA)	Marginal customer investment costs are dissimilar to other utility marginal costs of service…a customer facility is **dedicated** to its location. By contrast, energy, generation capacity, and **to a lesser extent** transmission and distribution capacity, **are more common** or fungible costs. If one customer reduces energy use by a kilowatt-hour or reduces his or her call on the generation supply by one kilowatt**, other customers** have the ability to use that kilowatt-hour or kilowatt.(emphasis added by DRA)
Fungibility is all or nothing	Fungibility is a range, from an extreme of a complete absence for customer premises equipment to a high degree for generation
For an investment to exhibit fungibility it must serve pre-existing customers	An investment exhibits fungibility if it can serve other customers.
Example based on agriculture and a new development	Example contrasts with generation

TURN's rationale is consistent with regulatory history; as mentioned earlier customer cost should include distribution components that "…are dedicated and uniquely assignable to individual customers." PG&E's argument is far more elastic, based not on an individual customer, but a variable and unknown group size of "specific customers for whom they were installed (at 5-11)."

Even if PG&E's argument had conceptual validity, PG&E errs in characterizing line extensions:

> Primary distribution line extensions have the attributes of 'customer facilities': they cannot be used except to

> serve the specific customers for whom there were installed to provide connectivity (page 5-11).

PG&E's testimony in the last GRC is a direct contradiction:

> Primary line extension and secondary wiring, while installed to connect new customers, tend to become shared by multiple customers over time (2003 GRC, PG&E-2, page 5A-5).

PG&E asserts that one part of the system is fungible, while another is not. Within the electric system, there is a range of fungibility from extensive to none at all. In the context of demand reduction, true fungibility means that reduced demand by any customer frees capacity up for any other customer. Generation is the most fungible. Generally, if less demand is placed on the system by a customer, that reduced generation demand will be available to serve other customers.[53]

ii. The imprecise term "nearby" is of no conceptual value in distinguishing customer from demand

PG&E introduces a new conceptual distinction, that of being "nearby," and uses that distinction in both examples in subsection C.4. All primary distribution is far less fungible than generation or transmission. Indeed, primary distribution by its very nature is "local." Reduced use by a customer within that local area frees up capacity to other customers within that local area. This term is imprecise, and DRA asked PG&E to provide greater definition; PG&E responded[54] that "nearby" is intended to mean "within the same Distribution Planning Area (DPA)". Yet, there is virtually no distribution investment that would be available to all customers within the same DPA; nor would there be

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[53] However, even for generation, fungibility is somewhat limited. Local reliability constraints for example mean that reduction within an unconstrained area is not available to a constrained area.

[54] PG&E response to DRA006-05.

virtually any distribution investment that would not be available to some customers within the DPA.

PG&E argues that the demand reduction by nearby agricultural customers would not reduce the cost to extend to a new subdivision. It is by no means clear that PG&E has actually considered the full range of such examples. In PG&E's Figure 1, there is a one-to-one relationship between new extension and new customer. Consider an alternative: a large existing agricultural customer lies at the very south end of a one-mile primary line, which has no excess capacity. The new subdivision is a couple hundred feet north and east from the agricultural customer, and has demand that is equivalent to the agricultural customer's demand. . Thus, a short line extension is necessary to the east. There is no excess capacity on the existing line. To provide service to the subdivision, PG&E would need to upgrade the existing primary line. Were that agricultural customer to reduce their demand, no upgrade is necessary. Nearby demand, and specifically demand reduction, does reduce cost.

Nor does the idea of "nearby" accord with basic math. Consider a new 500 unit subdivision. By PG&E's own reasoning, one customer's demand reduction is available to 499 other customers. Yet, that fungibility is less important than being available to even a few agricultural customers.

In contrast, the current typology of facilities uses more straightforward criteria. If I can use a facility, and my neighbor cannot, it is customer equipment. Ergo, a service drop and meter are customer equipment. If only I and my immediately adjacent neighbors can use it, it is also customer equipment. Ergo, a shared transformer is customer equipment. The final line transformer is actually dedicated to a single customer for many customer classes, but not to residential.[55] If my whole neighborhood can use it, it is distribution equipment. If it is

[55] The final line transformer is actually dedicated to a single customer for many customer classes, but not to residential.

equipment that serves multiple classes of customers, it is distribution equipment. If it is equipment that can serve multiple classes of customers, or be used to serve customers that result from future development, it is distribution equipment.

b) PG&E's evidence on cost shifting is either too limited or hypothetical

PG&E further argues that line extension costs and demand have no substantial relationship. PG&E cites two types of evidence: its engineering study, and testimony in the SCE case.

i. PG&E's engineering study cannot be relied upon to justify reclassification of demand cost

PG&E provides the results of an engineering study in Appendix B that appears to be the primary cost evidence to justify the proposed cost shift of line extensions from demand to customer. According to that study, costs and length have virtually a perfect relationship. Even if this study were perfectly reliable, all the study demonstrates is that length is a cost driver for line extensions.

In order to provide some model validation, DRA requested all the line extensions that met the specifications of PG&E's engineering study (demand up to 500 kW; length of 300 to 2400 feet). PG&E selected and provided a sample of 55 cases; only 13 of those actually met the length criterion. Furthermore, for this sample, the number of customers per job ranged between one and three. This very narrow range means that no conclusions can reasonably be drawn about any relationship between line extension and the number of customers.

PG&E correctly represents that there is a relationship between length and cost, as would be expected. For the wires business, the quantity of wire will clearly affect costs. Were the Commission to accept this relationship as the key descriptive variable in cost causation, the logical outcome would be to consider distance-based pricing. Of course, using distance in retail ratemaking would pose substantial implementation difficulties. Yet, even where distance could be priced, demand is used instead. Consider California's hundreds of miles of transmission lines, where there are a more limited number of lines and of wholesale customers. Generally, there have been “postage stamp” rates that roll the costs of multiple lines together, and are distant invariate.

The Federal Energy Regulatory Commission has jurisdiction over transmission pricing, and there has long been debate over optimal rates. Nonetheless, parallels between transmission and distribution do support a healthy dose of caution in interpreting the meaning between any relationship between length and cost means. Like transmission, there are relatively standardized distribution voltages and equipment. Such standards evolve out of the quantity of demand that needs to be served. Without demand, there is no cost. However, the reliance on standard sizes and equipment tend to reduce the level of cost variation related to demand increments. A long 230 kv transmission line will cost more than a short 500 kv line. A 230 and 500 kv line of equal distance over the same terrain will vary somewhat in cost, certainly not in proportion to demand. PG&E’s testimony would seem to result in concluding that distance is more important than demand.

ii. Cites to the SCE case can be accorded no probative value in this case

While DRA will probably not move to strike the references to the SCE testimony, that testimony can be given no probative value in this case. Unless PG&E’s witness intends to answer all relevant questions about the basis for the cited conclusions, those conclusions have to be regarded as unfounded. PG&E has not even provided workpapers with that testimony as part of its record.

iii. PG&E’s cost shifting example is misleading

The only customer classes PG&E seems to mention are agriculture and residential. While PG&E’s example in section 6 is not inaccurate, Table 3-4 shows that the portrait of differentiation in growth is skewed.

Table 3-4: PG&E forecast of class growth[56]		
Rank	Class	Growth
1	A10 MEDIUM L & P PRIMARY	5.75%
2	E19 PRIMARY	3.17%
3	E20 PRIMARY	3.17%
4	E19 TRANSMISSION	2.47%
5	E20 TRANSMISSION	2.47%
6	E20 SECONDARY	2.37%
7	E19 SECONDARY	2.32%
8	A10 MEDIUM L & P SECONDARY	2.14%
9	A1 SMALL L & P	1.63%
10	RESIDENTIAL TOTAL	1.50%
11	AGRICULTURAL B	0.90%
12	AGRICULTURAL A	0.58%
13	STREETLIGHTS	0.22%

PG&E has contrasted the tenth slowest growing class with the eleventh and twelfth. The rapidly growing classes are commercial and industrial. Class identity is germane to the economic consequences of increasing the costs imposed on growth, as discussed further below.

iv. PG&E has failed to provide the evidence that could sustain its allegation of "significant cost shifting"

PG&E alleges the potential for a significant and inappropriate cost shift in current rates. The hypothetical example alleges that new customers in some classes incur higher costs because of higher demands for line extensions of equal length. More specifically, PG&E apparently alleges that faster growing classes impose lower peak demands for given line extension lengths.

As stated, PG&E's allegation could have been supported by at least some empirical data. PG&E provides none. First of all, PG&E could have shown that peak demand differs substantially between new connection customers in different customer classes. As mentioned, PG&E failed to include that in its database,

56 See workpapers of PG&E, page 5-42, Table 5-23.

despite DRA flagging this as a major deficiency in the last rate case. PG&E could have provided data on the extent to which new connections in some classes are longer than for other customers. PG&E's testimony makes no effort to do so.

3. A policy to burden faster growing classes with greater costs is of questionable wisdom

The Commission faces a situation where there is at least some uncertainty of how to allocate costs that bear no necessary functional relationship to customers or demand.[57] PG&E clearly states a preference for reallocation of marginal costs to faster growing classes.[58]

The Commission certainly could make a policy decision to burden California growth. It is axiomatic that rapidly growing commercial and industrial classes are creating more economic and job growth than slower growing or declining classes. Overall California economic policy appears to be to create a friendlier and healthier business climate. Burdening growth with costs that may not be attributable to that growth is difficult to reconcile with creation of a healthier business climate.

a) Allocating the costs of 2% to that 2% is economically efficient, yet PG&E claims that efficiency requires allocating those costs to the other 98%

The key sentence in Argument 5 is:[59]

> "As TURN observed in its 2003 GRC Phase 2 testimony, it would be most economically efficient for new customers to bear the entire cost of their connections."

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[57] This issue is distinctly different from the Commission's philosophy that faster growing classes bear those costs that are clearly attributable to new customers of that class.

[58] Page 5-2 "These proposals…will make rates more equitable by removing unwarranted cost-shifting from fast-growing customer classes to slower-growing customer classes." PG&E also cites, apparently in concurring with agricultural complaints (page 5-14), of incorrectly determined marginal costs, even as PG&E marginal cost proposals continue to show that agriculture is not paying its share of marginal costs. DRA tempers its conclusion in that Chapter 1, the policy chapter, does not appear to actually address an issue that goes far beyond customer cost.

[59] The percentage of new customers is around 1.7%, which DRA has rounded to 2%.

PG&E's testimony then immediately dismisses all the implications of that sentence:

> "However, given that there are longstanding policy reasons precluding that approach, as a second best approach, the marginal cost revenue responsibility for customer connections should be assigned to the customer class served."

PG&E never does state what "longstanding policy reasons" preclude that approach; nor could DRA locate any such reason. PG&E does not connect those unstated reasons to the "major and highly significant changes to line extension tariffs"; those tariff changes allegedly require changing marginal cost policy to conform with line extension ratemaking.

The most obvious implication of TURN's statement is that line extension ratemaking is the primary obstacle to economic efficiency. PG&E utterly fails to explain why building a new philosophy of marginal costs around the weak, troubled core of line extensions represents a responsible or prudent course in marginal cost implementation.

PG&E's so-called "second best" and very indirect approach is that of assignment to the class with new connections. Indirect solutions do not necessarily have the same consequences as direct solutions. A necessary analytic step is to consider potential differences in actors, actions and consequences. While PG&E's testimony equates new connections with the decisions of new customers (at 5-8), PG&E's more recent testimony proceeds more carefully:

> The key distinction between the two types of customers is that developers—the targets of the POUs' more recent efforts—are not typically the ultimate customers and therefore do not pay end-user rates. Rather, the developer's financial interest is tied to its share of the cost of extending service to the development (A.06-07-027).

In this case, PG&E equates new customers with developers, and fails to show equivalent interests and consequences between new customers and their clearly imperfect developer agents.[60] PG&E's testimony concludes that its proposal would "foster economic efficiency (at 5-12), although there is no evaluation of demonstrably better outcomes of societal allocation of scarce resources.

F. THE COMMISSION SHOULD MAINTAIN AND FURTHER BOUND IDENTIFICATION OF CUSTOMER MARGINAL COST

This section develops a fairly precise designation of what is a marginal customer cost, and what is not. The Commission has not made a persistent designation of what is a customer marginal cost and what is a demand marginal cost. As the Commission itself noted in D.89-12-057, "The distribution system performs both a capacity or demand-related function and a customer access function (35 CPUC 2d, page 423, ff 196)."

In order to make a reasoned designation, DRA relies on several sources. First, DRA also examines PG&E's design practices, as well as how PG&E's tariffs separate equipment. Then DRA looks to the attributes of marginal customer cost established by commission policy. In particular, DRA examines whether a cost type bears a functional relationship to the number of customers or to the quantity of demand, and the extent to which a cost can be considered dedicated.

1. PG&E designs distribution as a function of demand and hookup equipment as a function of customers

PG&E's October 2001 *Electric Design Manual* states its actual, documented design practices.[61] The portions most relevant to marginal cost show that PG&E uses the quantity of demand to design primary and secondary

[60] This distinction is not a new one. DRA's 2003 testimony directly stated that customers often do not make the decision to connect to the grid.

[61] DRA obtained that document in the 2003 GRC.

distribution, while service equipment design relies more on the number of customers.

Chapter 5 of the *Electric Design Manual* addresses residential design. Section 5.3.1 explains the design criteria for primary local line extensions, which PG&E seeks to add to customer marginal costs. Most of that section discusses taps. Demand kva are the main determinant of tap size. Local taps for single families are limited to 100 customers, while taps for large buildings are not limited based on the number of customers.

Section 5.3.1.1 addresses residential distribution. This section uses an entire development to determine design. The manual states that the first step is to calculate total demand. Multiple radial taps are used when a "…development exceeds 46 amps or about 100 customers."

The secondary system includes costs of "transformers, enclosures, splices, 600 V cable and connectors" and design is affected by lot locations and customer load. Finally residential service is: "An underground residential service is a 600 volt cable that originates from a secondary box or pedestal" and "directly feeds a residence."

2. PG&E's tariffs bound the distribution system and customer service facilities

The Commission has thus far determined that "customer marginal cost" is the cost of providing access to a customer. DRA's assessment of access costs uses these attributes: (1) The costs can be causally attributed to a specific customer, are directly associated with a customer, and are for premises equipment, (2) or the equipment and is costs provides an economic substitute for equipment having the attributes above, and (3) the costs bear little relationship to demand. DRA recommends defining "access" as facilities used to deliver service to a single customer from PG&E's distribution system.

To develop a clear and workable definition, DRA has reviewed PG&E's tariff rules. Rule 16 provides useful guidance on Service Extensions:

> APPLICABILITY: This rule is applicable to …PG&E Service Facilities* that extend from PG&E's Distribution Line facilities to the Service Delivery Point

PG&E goes on to describe the number of service extensions in a way that generally bears the one-to-one attribute of dedication:

> NUMBER OF SERVICE EXTENSIONS. PG&E will not normally provide more than one Service Extension, including associated facilities, either overhead or underground for any one building or group of buildings, for a single enterprise on a single Premises…

3. Associating customers with access is also consistent with the discussion in PG&E's testimony

Using service to define access is not only consistent with PG&E tariff rules, but is consistent with the terminology that PG&E has used. PG&E stated in the 2003 GRC, but has omitted here:[62]

> Since the earliest use of CPUC-approved marginal costs for ratemaking, the commission has distinguished customer-access-related marginal costs from demand-related marginal costs. The former are generally driven by customers' connectivity requirements, the latter, by customer demands (citation omitted, emphasis added, 1A-12).

Later PG&E discusses connecting a new customer (at 5A-1 and 2):[63]

> Briefly stated, to connect a new customer (often a residential or commercial development), the utility must (in most cases):
>
> 1. map, design, and estimate the cost of the new connection, and sign a contract with the customer or developer;

[62] To prevent any misunderstanding, it is clear that PG&E's testimony does not recommend equating service and access. ORA here refers to descriptive statements in PG&E's testimony.

[63] This description is substantially similar to page 5-4 and 5-5.

2. extend a primary distribution line from the existing distribution grid to the customer's site;[64]

3. install one or more line transformers;

4. install additional secondary distribution lines;

5. install a service extension to <u>connect</u> each individual customer; and

6. install a meter for each customer (emphasis added)

.

Thus, the only two places that PG&E's testimony directly associates connectivity with a customer is at the engineering phase, and for the service extension.

i. Chang*e*s to the distribution grid are part of an evolutionary process that continues after the grid gets to new customers

Not only does PG&E substitute a developer for a residential customer, PG&E's testimony further concedes that its preferred moniker of "one-time hookup" only represents a snapshot in time, while time changes the nature of that one-time event:

> Primary line extension and secondary wiring, while installed to connect new customers, tend to become shared by multiple customers over time…O&M costs are no longer avoidable once distribution facilities are installed and become shared (PG&E-2, page 5A-5).

In other words a "one-time hookup" tends to cause other hookups to occur later. A new housing development (or new commercial development) changes the community that was there before. Jobs follow housing, and housing follows jobs. As new housing establishes the character of an area, similar housing is likely to follow in its wake. PG&E's methodology does not account for any scale, more efficient use, or facility sharing between customer classes that an expanded, shared system may create.

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[64] PG&E actually incurred primary distribution costs in only 68 out of 113 jobs, or 60%. See 1999 TURN GRC data request.

G. DRA ANALYTIC PROCESS

DRA reviewed several Commission decisions relating both to marginal customer costs and the associated issue of line extension allowances. For line extension issues, DRA reviewed D.87-09-026, D.94-12-026 and D.97-12-098, as well as Part J of PG&E's Preliminary Statement. As mentioned earlier, DRA researched the line of GRC decisions going back to 1986. These decisions included: D.86-08-083, D.89-12-057, D.92-12-057 and D.97-03-017.

4. MARGINAL CUSTOMER SERVICE COSTS

WITNESS: LOUIS IRWIN

A. SUMMARY AND RECOMMENDATIONS

Marginal customer service costs account for about half of PG&E's residential marginal customer costs. Customer service costs correspond to FERC accounts 902 and 903 and generally consist of the costs associated with meter reading and servicing, and billing and collections services. These costs are also commonly called Revenue Cycle Services ("RCS"). DRA is only contesting one area of PG&E's marginal customer service costs – that of meter reading services.

DRA recommends that:

- The Commission adopt the New Customer Only (NCO) methodology for calculating meter reading service marginal costs.

B. INTRODUCTION AND BACKGROUND

PG&E has been relying on Revenue Cycle Services (RCS) data to estimate its marginal customer service costs. In the previous PG&E GRC (2003), DRA found that PG&E's marginal customer service costs were much higher than the other major California utilities (see Table 4-1 below). DRA believes that RCS derived marginal costs were quite high because it is very inclusive in the costs that it considers. These costs are expanded by using long-run marginal costs with a relaxed, far reaching horizon. In the very long run, costs that would ordinarily be regarded as fixed become marginal.

TABLE 4-1

RECENT METER READING, BILLING & COLLECTIONS AND OTHER FERC ACCOUNT 903 COSTS

($ / customer -- month)[1]

	PG&E 1999 (a)	PG&E 2003 GRC (b)	PG&E 2003 post errata (c)	SCE 2003 (d)	SDG&E 2002 (e)	DRA 2005 Proposal (f)
Total Mo. Customer Service Cost	$2.62	$4.08	$3.13	$2.64	$2.43	$2.17
% Difference from PG&E (post draft errata)	-16.3%	30.4%	0.0%	-15.4%	-22.4%	-30.7%

The 2003 GRC PG&E post draft errata cost ($3.13, column c) runs 44% higher than the 2005 DRA proposal of $2.17 per customer month (column f). Therefore, DRA proposed at that time that PG&E further investigate the RCS costs to determine what percentage of the billing and collections were truly marginal. DRA's testimony questioned the methodology PG&E used in its RCS cost study, stating:

> In general, it appears that the objective was to allocate total costs and personnel hours to all the activities, which inherently is a process more like an embedded cost study than a marginal cost study. After this accounting exercise, some activities were classified as fixed and excluded from the marginal cost calculation. These exclusions, however, affected only a low percentage of activities and associated expenses.[2]

DRA also proposed that PG&E adopt the New Customer Only methodology for the marginal costs of meter reading services. This idea is based on the fact that the meter reading costs saved by an existing customer leaving the system (decremental marginal costs) are negligible because, once a meter reading route is established, almost all the costs associated with it are fixed.

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[1] DRA Testimony, PG&E GRC 2003, p. 5-3, January 14, 2005.

[2] Ibid., p. 5-5.

Whereas, new customers impose the most significant incremental marginal cost that of establishing the meter reading route to begin with.

The 2003 GRC ended up being settled before hearings. Therefore, the marginal costs of customer service were settled without specifically presenting the DRA proposals to the Commission.

C. PG&E'S CURRENTLY PROPOSED MARGINAL COSTS OF CUSTOMER SERVICE

For the current GRC, PG&E has made some changes regarding the use of the RCS data. The costs that PG&E is excluding as fixed is now a higher percentage than in the prior GRC. PG&E now has identified 72% of RCS meter reading, billing and collection costs as being marginal, while the rest are presumed fixed and are, therefore, excluded. For the meter maintenance costs, the figure is 65.1% marginal, 34.9% fixed and excluded.[3] PG&E, however, still has not adopted a New Customer Only methodology to arrive at a marginal cost for all customers.

D. DRA PROPOSAL AND RESULTS

PG&E's improvement for this GRC is to better identify the appropriate cost classifications that should be considered in a customer service marginal cost calculation. But, PG&E erroneously applies these costs equally to both new and existing customers without distinction. However, the marginal costs of site-specific activities such as meter reading are much more associated with new rather than existing customers. That is because it is the new customers that catalyze route development and increased staffing costs. Finally, note that the marginal costs of establishing a meter reading route become fixed once the new customers become existing customers.

[3] PG&E 2007 General Rate Case Phase 2, Workpapers Exhibit (PG&E-2) Marginal Cost Chapter 5, Tables 5-6 & 5-7, pp. 5-8 & 5-10, respectively.

This marginal cost schism between new and existing customers is less evident for costs that are not site-specific, such as those associated with the billing function. This is because the billing capacity freed up by departing customers can easily be utilized for new customers anywhere else in the service territory.

To address this issue DRA is proposing the use of the New Customer Only method for meter reading services. DRA employs the New Customer Only method because it believes that much ongoing O&M for meter reading is a sunk cost, much like a traditional fixed cost. This is because, once the meter reading route is established and staffed it is not easily disbanded.

In the case of meter reading, the costs saved for decrements are far less than the costs incurred for increments. This difference can occur because decremental costs are not merely the inverse phenomena of increases – they represent a different population and behavior pattern altogether. The difference is that decrements happen to be spread out through a territory in location and time, while increases are associated with housing developments that create location and time-specific increases in demand. Furthermore, the cost decreases may often be temporary in nature (short term vacancies), and thus are negligible, while the same cannot be said for the duration of increases (which are effectively permanent). The decreases do not result in substantial cost reductions because routes need to be serviced in nearly identical fashion regardless of the decreases. Only the walk up to the meter and actual read is eliminated – the drive to the neighborhood, staffing and planning is not. New housing developments, on the other hand, require the development and staffing for a whole new meter reading route.

For the reasons described above, DRA again proposes applying the New Customer Only (NCO) method as a fair reflection of marginal customer service costs for meter reading services. The NCO would be applied to the incremental costs generated by new customers in a way that is consistent with other applications of NCO. Since PG&E’s marginal cost for meter reading is an annual cost, and the NCO method is normally applied to a multi-year cost, DRA converted annual meter reading costs to a multi-year basis by using an infinite geometric series.[4]

The marginal cost results are substantially less for most customer classes. For instance, for the residential class, the marginal costs of meter reading would be, at $2.91 per customer year, approximately one third of the PG&E proposed value of $8.87 per customer year.[5] For one class only (Schedule A-10 Primary -- Medium Light and Power), its higher growth rate (5.75%) actually leads to a 26% higher marginal cost for meter reading services when using the NCO method. When viewed as a percentage change over all customer service costs (e.g., billing and collections), however, the proposed DRA change is far less dramatic. The largest decrease is for street lighting which experiences a 17.99% decrease (see Table 4-2 below, and specifically the last column for DRA proposed percentage changes in overall customer service marginal costs). The DRA proposed change for residential marginal costs of customer service is a decrease of 12.41%.

DRA's proposal is based on the geographical pattern of meter reading and, therefore, does not apply to other customer services, such as billing and collections. Those services are entirely centralized.

[4] The initial investment costs are divided by (1-((1+inflation rate)/(1+discount rate))). DRA used PG&E's inflation rate of 2.72% (O&M escalation) per year and discount rate of 7.64% per year.

[5] The formula from footnote 5 is applied to SDG&E file 07_GRC2_RCS_COSTS.XLS, Worksheet Tab 5-2 & 5-3. See also DRA Workpapers, Chapter X.

TABLE 4-2
2007 PG&E GRC CUSTOMER SERVICE COSTS
COMPARISON OF PG&E AND DRA MARGINAL COST ESTIMATES
($/Customer – year)[70]

Customer Class	Growth Rate	PG&E Meter Reading	DRA Meter Reading	% Change	PG&E -- Other Cust. Serv. Costs	PG&E Total	DRA Total	% Change
Residential	1.50%	$8.87	$2.91	-67.17%	$39.14	$48.01	$42.05	-12.41%
Agricultural A	0.58%	$25.64	$3.25	-87.34%	$112.66	$138.30	$115.91	-16.19%
Agricultural B	0.90%	$29.65	$5.84	-80.30%	$171.54	$201.19	$177.38	-11.83%
A1 Small L & P	1.63%	$11.72	$4.18	-64.33%	$53.47	$65.19	$57.65	-11.57%
A10 Medium L & P Primary	5.75%	$58.30	$73.39	25.88%	$251.71	$310.01	$325.10	4.87%
A10 Medium L & P Secondary	2.14%	$58.28	$27.24	-53.26%	$251.63	$309.91	$278.87	-10.02%
E19 Primary	3.17%	$866.51	$601.11	-30.63%	$3733.41	$4599.93	$4334.53	-5.77%
E19 Secondary	2.32%	$865.90	$440.26	-49.16%	$3730.82	$4596.72	$4171.08	-9.26%
E19 Trans.	2.47%	$866.57	$468.86	-45.90%	$3733.68	$4600.25	$4202.53	-8.65%
E20 Primary	3.17%	$866.09	$600.82	-30.63%	$3731.64	$4597.73	$4332.46	-5.77%
E20 Secondary	2.37%	$865.76	$448.90	-48.15%	$3730.24	$4596.00	$4179.14	-9.07%
E20 Trans.	2.47%	$866.57	$468.85	-45.90%	$3733.68	$4600.25	$4202.53	-8.65%
Streetlights	0.22%	$7.77	$0.37	-95.28%	$33.37	$41.14	$33.74	-17.99%

[70] DRA Workpapers, Chapter 4.

E. CONCLUSION

PG&E's Marginal Cost of Customer Service methodology is still in transition. PG&E identifies meter reading and meter service costs that can be excluded from its marginal cost calculation. The cuts are approximately 28% and 35%, respectively. While these changes can be viewed as improvements, they also point to the fact that no final resolution or equilibrium solution has been found – on the contrary, the accepted path is in flux. Added to this mix DRA has proposed a further improvement – the use of the NCO methodology for specifically the meter reading portion of customer service costs. DRA established that it was the new customers that were causing the bulk of these costs and, therefore, that these costs should be limited to those generated by the new customers only.

5. REVENUE ALLOCATION

WITNESS: DEXTER KHOURY

A. SUMMARY AND RECOMMENDATIONS

This chapter presents the Division of Ratepayer Advocates' ("DRA") revenue allocation recommendations for Pacific Gas and Electric's ("PG&E") General Rate Case ("GRC"), Phase II (A.06-03-005). DRA's recommendations are based on its marginal cost recommendations that are explained in Chapters 2 through 4.

DRA recommends:

1. DWR power charge revenues should be allocated to bundled customers equal cents per kilowatt hour ("kWh").
2. California Alternative Rates for Energy ("CARE") costs should be allocated equal cents per kWh.
3. Base Interruptible Program (Schedule E-BIP) costs should be allocated equal cents per kWh.
4. Self Generation Incentive Program ("SGIP") costs should be allocated equal cents per kWh.
5. California Solar Initiative ("CSI") costs should be allocated equal cents per kWh.
6. A revenue allocation cap should be adopted that limits customer class increases to a maximum of average system change plus 2 per cent.

Table 5-1 shows DRA's proposed revenue allocation.

B. BACKGROUND

The Commission most recently examined PG&E's marginal costs, revenue allocation, and rates in PG&E's last GRC Phase II. Rates that made substantial progress towards cost based rates were implemented for that proceeding on January 1, 2006. In PG&E's current GRC Phase II proceeding, rather than being content with covering the remaining distance to the marginal cost finish line, (or towards marginal cost based rates) PG&E **moved the finish line.** PG&E

proposes to shift still more costs onto the residential class that has experienced an average increase of 17.6% in the past year. Most increases to the residential class would result from PG&E's proposed changes to the marginal customer cost calculation methodology and from its proposed changes to the allocation method for social and environmental programs.

PG&E filed this proceeding on March 2, 2006, two months after implementation of its last GRC Phase II. PG&E has made new marginal cost proposals, has updated its marginal costs, has proposed changing the allocation of social and environmental programs, and has incorporated these changes into a new proposed revenue allocation. It is unusual to examine and re-allocate marginal costs so frequently, as General Rate Cases are scheduled to occur every three years. Marginal costs and the associated revenue allocation are usually left in place for a number of years and are not replaced every year or two.

In this proceeding, PG&E proposes to move rates significantly closer to an equal percent of marginal cost ("EPMC") allocation based on its definition of marginal costs. They propose moving 75% of the way to a full marginal cost allocation: "PG&E recommends that the Commission adopt the proposed mitigation proposal and a 75 percent movement towards full cost levels."(PG&E-3, p.2-11). DRA recommends that the Commission exercise special caution regarding movement towards a full marginal cost based revenue allocation in this proceeding[71] because residential customers have endured large rate increases in the last year, because there will likely be further increases to PG&E's revenue requirements in March 2007 and May 2007, and because PG&E's last GRC Phase II was implemented so recently. The fact that this decision was issued only ten months ago is relevant when the Commission considers additional movement towards marginal costs that will result in further increases to the residential class.

[71] If all of DRA's marginal cost and revenue allocation recommendations are adopted, there will be no need for a cap for the residential class, but other customer classes such as the agricultural and standby class would still benefit from a revenue allocation cap.

DRA recommends a more gradual cap of 2 percent that would still make progress towards EPMC levels.

It is also important to remember the recent history of the electric industry in California when considering revenue allocation policy in this proceeding. Following the partial deregulation of the electric industry, electric generation markets were manipulated, which in turn led to extremely high electric prices and the energy crisis. During the energy crisis, the Department of Water Resources ("DWR") took over the purchasing of electricity from the utilities, and the Legislature adopted measures designed to protect vulnerable residential customers. AB 1X protected residential customers by prohibiting increases in residential rates for usage up to 130% of baseline usage. The Commission further protected the California Alternate Rates for Energy ("CARE") customers and medical baseline customers from rate increases by exempting them from the 3 cent per kWh surcharge for PG&E and SCE that was implemented in D.01-05-064. The Commission introduced three new tiers of rates that collected the energy surcharges for non-CARE residential customers for usage above 130% of baseline usage.

In this post- energy crisis and continuing high cost environment, it makes sense to make cautious movement towards marginal cost and not abandon the protections put in place during the energy crisis to protect residential customers, and especially CARE (low income) and medical baseline customers. PG&E's revenue allocation proposals move too far because they result in residential Tier 3, Tier 4, and Tier 5 rates significantly higher than they were at the height of the energy crisis.[72] DRA's proposal for a lower cap on the revenue allocation better protects residential customers.

[72] PG&E's residential rates are already higher than they were during the energy crisis in 2001. PG&E's proposal would result in even higher residential rates.

DRA's proposal is also consistent with considerable Commission precedent to limit or cap revenue allocation increases in this range. By moving moderately and deliberately towards EPMC over a period of years, the Commission can reach the goal of EPMC rates while causing fewer bill increases for customers.

C. DISCUSSION

1. Allocation of DWR Costs

PG&E proposes to allocate DWR costs the same way they allocate other generation costs--by the EPMC generation allocator. DRA disagrees with this approach and believes these costs arise from extraordinary events and thus should be treated differently. DRA proposes that DWR costs be allocated by equal cents per kWh.

The DWR costs are for the contracts entered into at the height of the energy crisis. The Department of Water Resources was forced to purchase power for bundled electric customers when PG&E and SCE were no longer able to because of their financial situation during the energy crisis. At first the DWR bought energy on the spot market which was extremely expensive. In an attempt to avoid the exorbitant spot market prices, the DWR entered into long term contracts. These were also expensive although not as expensive as the spot market prices it had been facing. These contracts were entered into for all bundled customers including customers who had been Direct Access customers before the energy crisis and who were forced back to bundled customer status during the energy crisis. Although these contracts were expensive, their costs need to be recovered and should thus be collected as uniformly as possible. All bundled customers benefited from the DWR's actions that kept the lights on in California. As the DWR contract costs stem in essence from an emergency –the energy crisis--which was not the fault of any class of ratepayers, it is appropriate to spread the costs of these contracts as broadly as possible. DRA thus recommends that DWR power costs be allocated equal cents per kWh to bundled customer usage. The equal cents per kWh allocator would most evenly spread the DWR costs between customer classes.

The Commission considered the time period when the DWR contracts were entered into in its Decision on the permanent allocation of DWR costs:

> "…the DWR contracts at issue were signed at a time of crisis, confusion, and uncertainty, rendering our traditional notions of cost causation inappropriate. In large part we are "spreading the pain" of a unique occurrence, for which our standard methods are ill-suited. Accordingly, we must find another way to reach a fair allocation." (D.05-06-060, mimeo, p. 14)

These contracts were entered into on behalf of all bundled customers, and thus bundled customers, who benefited from the DWR's activities during the energy crisis, should all make an equal contribution to pay back these costs. The DWR contract costs stem from a unique occurrence and thus these costs differ from typical generation costs. DRA thus recommends a different allocation of DWR costs that better reflects the cause of these costs. As these costs stem from a solution to a special emergency and bundled customers benefited from this solution, it is fair for all bundled customers to share equally in paying these costs. An equal cents per kWh allocation of these costs would result in bundled customers paying for these costs more equally.

2. Allocation of CARE Costs

PG&E recommends modifying the Commission's long standing practice of allocating CARE costs on an equal cents per kWh basis. PG&E recommends allocating CARE costs by distribution and transmission revenue factors: "Under PG&E's proposal each customer group will pay for the cost of the CARE discount (currently expressed as distribution and generation reductions) in proportion to their responsibility for transmission and distribution revenue, except that streetlighting customers and CARE customers will not pay this surcharge consistent with current practice."(PG&E-3, p.1-8).

PG&E apparently believes its proposals which would result in industrial customers paying a surcharge roughly one third of what residential customers would pay is fair because "...large customers receive little, if any, of the direct benefit of the CARE program." (PG&E-3, p.1-8) PG&E has not provided convincing justification to change the allocation of this important program, and DRA recommends that the current allocation method be retained.

CARE Program

The CARE program is designed to ensure more affordable electricity and gas for low income customers. The Commission established the Low Income Ratepayer Assistance ("LIRA") program in 1989, and this program was later renamed the California Alternate Rate for Energy program or CARE which is described in P.U.Code 739.1(a): "The Commission shall establish a program of assistance to low-income electric and gas customers, the cost of which shall not be borne solely by any single class of customer. The program shall be referred to as the California Alternative Rates for Energy or CARE program. The commission shall ensure that the level of discount for low-income electric and gas customers correctly reflects the level of need."

This important social program took on even greater importance during the California energy crisis. As energy prices increased, this program protected low income energy consumers and helped ensure that these customers continued to be able to afford energy, which is a necessity and is vital to ensuring life, health, and social welfare.[73] In 2001, the Legislature gave further guidance concerning the CARE program by adding P.U. Code Section 739.1(f): "It is the intent of the Legislature that the commission ensure CARE program participants are afforded the lowest possible electric and gas rates and to the extent possible, are exempt from additional surcharges attributable to the current energy crisis".

[73] P.U. Code 739(c)(2) states "...while observing the principle that electricity and gas services are necessities, for which a low affordable rate is desireable..."

Discussion

In this section, DRA discusses the importance of a healthy CARE program, the issue of which customers receive direct benefits from the CARE program, the validity of using distribution and transmission revenues to allocate CARE costs, and other issues PG&E has raised in its testimony.

PG&E's CARE allocation proposal in this proceeding and PG&E's proposals in its Economic Development Rate Proceeding[74] potentially threaten the health and vitality of this important social program. PG&E's proposal would result in industrial customers paying a CARE surcharge far lower than that paid by other classes. Non-CARE residential and many agricultural, standby and small commercial (schedule A-1) customers would conversely pay extremely high CARE surcharges. If industrial customers obtain a lower CARE surcharge, other customer classes will also likely try to obtain a lower CARE surcharge. This would further lead to pressure to reduce the CARE program as CARE surcharges would rise for the other customer classes. The higher CARE surcharges increase, the more other classes would attempt to avoid paying these surcharges.

This situation could develop into a classic death spiral. As some classes pay lower surcharges, either the remaining classes surcharges will increase or there will be insufficient revenue to finance the program. DRA believes that the CARE program is an important program that should continue. Maintaining the current equal cents per kWh allocation will help maintain an adequate amount of funding for the program that will maintain the health of this program.

PG&E states that industrial customers receive no or little of the direct benefit of the CARE program. No customers except CARE customers receiving the CARE discount directly benefits from the CARE program. The Commission

[74] In its Economic Development Rate ("EDR") Proceeding, (A.04-04-008 and A.04-06-018), PG&E proposes allowing EDR customers to be able to pay lower Public Purpose Program ("PPP") charges including discounted CARE surcharges. Such a practice would lead to cost shifting and could also result in a reduction of revenue to fund the CARE program.

recently reviewed a similar claim in PG&E's most recent BCAP. In that proceeding the Commission concluded: "We are not convinced by PG&E's claim that CARE program benefits inure entirely to residential customers. We believe that all businesses and individuals benefit from the economic welfare of the greater community. Moreover, we would not assume that all residential customers are potentially CARE customers any more than we would assume that all business customers may potentially fail in the near term." (D.05-06-029, mimeo, p.16) Clearly CARE residential customers are different from non-CARE residential customers. There is no way to allocate CARE costs to customers based on cost causation. CARE costs ultimately stem from a customer being poor.[75] It is doubtful that the Commission wants to investigate the philosophical or political cause of poverty. No customer class causes CARE costs and no customers except for CARE customers directly benefit from the CARE program.

PG&E proposes to allocate CARE costs based on distribution and transmission revenues. This would greatly reduce the industrial customer's contribution to CARE costs. Part of PG&E's premise for the need for this change is because it is moving "generation discounts" into distribution rates. PG&E implies that it did not include generation factors in its proposed CARE allocation factors because it would need to impute generation costs for Direct Access ("DA") customers. It is possible to impute these costs, but even if PG&E did not do this and only included the generation costs from bundled customers, this would increase the allocation of CARE costs to the industrial class above what PG&E is proposing. In any case there is a mis-match in PG&E's proposal as it would allocate what are distribution and generation costs according to distribution and transmission allocation factors. Thus, DRA recommends that PG&E's

[75] The State of California recently raised the State's minimum wage. Hopefully fewer customers will need the assistance of the CARE program.

proposed allocation of CARE costs by distribution and transmission revenues not be adopted.

The following chart compares class allocations using equal cents per kWh and PG&E's proposed method. Note that PG&E's proposed method would result in the residential class paying 15.26% more than it does under the current allocation of CARE costs.

Comparison of DRA's and PG&E's Proposed CARE Allocations

Customer Class or Schedule	Equal Cents kWh Allocation (%)	Proposed PG&E Allocation (%)	PG&E Greater than Equal Cents kWh (%)
Residential	32.09%	47.35%	15.26%
Small Commercial	10.72%	14.99%	4.27%
A-10	17.51%	15.12%	-2.39%
E-19	14.00%	8.53%	-5.47%
Standby	0.32%	0.41%	0.09%
Agricultural	5.92%	6.43%	0.51%
E-20	18.96%	7.13%	-11.83%

PG&E's proposed method also results in different classes and rate schedules paying widely diverging CARE surcharges. For example, A-1 small commercial customers would pay a surcharge twice that of A-6 small commercial customers, and A-15 customers would pay a surcharge ten times that paid by A-6 customers. PG&E's proposal would result in large differences in CARE surcharges that would be paid by different customer classes and rate schedules, and this is another reason to reject PG&E's proposal. The following chart shows PG&E's proposed CARE surcharges for different rate schedules.

PG&E's Proposed Care Surcharges			
Schedule	Proposed Care Surcharge	Schedule	Proposed Care Surcharge
E-1	$0.00617	Stby E-19 V S	$0.00363
EL-1		Stby E-19 T	0.00697
E-7	0.00482	Stby E-19 P	0.01215
E-8	0.00428	Stby E-19 S	0.00360
EL-8		Stby E-20 T	0.00404
A-1	0.00675	Stby E-20 P	0.02383
A-6	0.00335	Stby E-20 S	
A-15	0.03430	AG-1A	0.01825
TC-1		AG-RA	0.01116
A-10 T	0.00109	AG-VA	0.01110
A-10 Td		AG-4A	0.01073
A-10 P	0.00264	AG-1B	0.00993
A-10 Pd	0.00441	AG-RB	0.00873
A-10 S	0.00349	AG-VB	0.00890
A-10 Sd	0.00449	AG-4B P	0.00404
E-19 Firm T	0.00189	AG-4B S	0.00731
E-19 V T	0.00110	AG-4C	0.01042
E-19 V Td		AG-5A	0.00631
E-19 Nonfirm T		AG-5B P	0.00197
E-19 Firm P	0.00218	AG-5B S	0.00335
E-19 V P	0.00193	AG-5B T	0.00087
E-19 V Pd	0.00292	AG-5C	0.00278
E-19 Nonfirm P	0.00187	E-20 Firm T	0.00077
E-19 Firm S	0.00273	E-20 Nonfirm T	0.00075
E-19 V S	0.00233	E-20 Firm P	0.00176
E-19 V Sd	0.00317	E-20 Nonfirm P	0.00205
E-19 Nonfirm S	0.00301	E-20 Firm S	0.00246
Streetlights	0.00305	E-20 Nonfirm S	0.00258
Stby A-6 S	0.01804	FPP T	(0.00000)
Stby E-19 V T	0.00210	FPP P	0.00078
Stby E-19 V P	0.02336	FPP S	0.00124
		Total	.00410

Moving CARE generation benefits to distribution rates modifies some of what has been done since the energy crisis to protect CARE customers. The CARE generation benefits largely stem from CARE customers being spared both the 1 cent and 3 cent surcharges in 2001 during the energy crisis. (See D.01-05-064) The Legislature also endorsed the policy that CARE customers should be spared the fall out of the energy crisis and this sentiment was enacted in P.U. Code

739.1 (f): "It is the intent of the Legislature that the Commission ensure CARE program participants are afforded the lowest possible electric and gas rates and to the extent possible, are exempt from additional surcharges attributable to the current energy crisis." The "generation CARE benefits" are not new CARE benefits as generation benefits have existed since the energy crisis in 2001 when CARE customers were exempted from paying the DWR or generation surcharges. This may be the first time PG&E has separately quantified CARE generation benefits, but they have existed since 2001. It is thus hard to know if CARE costs have increased or how much CARE costs have increased recently.

<u>CARE Allocation History</u>

The costs of low income discount programs have been allocated on an equal cents per kWh basis since their inception in 1989 (D. 89-09-044). At that time the Commission rejected a proposal to allocate LIRA expenses using a cost of service allocator. The Commission noted that LIRA expenses were different from other utility expenses: "The (Equal Percent of Marginal Cost) methodology is not appropriate because it assumes that every cost has a functionality that allows its incurrence to be attributed to a class of ratepayers." (32CPUC 2d at 417) The Commission thus allocated the costs of the LIRA program by equal cents per kWh for electric usage and equal cents per therm for gas usage. This method allocates these costs most evenly by charging each customer and customer class the same for each kWh of usage, and thus helps ensure that costs of this program are born as broadly as possible.

In the 1996 Southern California Edison ("SCE") GRC the Commission reexamined the issue of CARE allocation. The SCE GRC decision summarizes Commission policy on CARE allocation:

> "In D.89-09-044, we rejected an EPMC allocation of CARE program costs for two reasons. First, we found that the function of the program does not lend itself to an allocation on the basis of a customer group's responsibility for current marginal costs. Second, we found that the equal cents per kWh surcharge was more

consistent with the goal of minimizing the burden on any one class of ratepayers. (See D.89-09-044, 32 CPUC 2d 406, 417.)" (D.96-04-050, mimeo p.80)

"There is no sound theoretical argument for assigning CARE costs on either an equal cents per kWh or an equal percentage of total bill basis. From the perspective of customers that do not receive the CARE discount (but must pay the costs), CARE related expenditures are no more related to energy consumption than they are to the total usage of utility resources. The issue is really one of equity. Under an equal percentage of total bill or (EPMC) allocation, residential and small commercial customers would bear proportionately more of the CARE costs than under an equal cents per kWh allocation method." (D.96-04-050, mimeo, pp. 80-81)

The Commission has reaffirmed that CARE costs be allocated on an equal cents per kWh basis in its Post-Transition Ratemaking Decision: "CARE costs should continue to be allocated on a cents-per-kilowatt-hour basis." (D.00-06-034, mimeo, p. 65)

The Commission has also examined various attempts to change this policy in the gas industry. There have been a number of attempts to allocate a lower amount of CARE costs to industrial customers, but the Commission has maintained the equal cents per therm allocation method. In PG&E's last Biennial Cost Allocation Proceeding ("BCAP") PG&E proposed an allocation of CARE costs similar to what they proposed in this proceeding. They proposed to allocate CARE costs according to equal percent of transportation revenue (distribution and transmission revenue in the electric industry is the equivalent of transportation revenue in the gas industry), and the Commission rejected this proposal.

"As a threshold matter, we are sympathetic to concerns over the costs incurred by California businesses especially during this difficult economic period. On the other hand, we are equally concerned with the plight of families and individuals, many of whom have seen their salaries fall while the cost of living increases." (D.05-06-029, p.16, mimeo)

"We believe that all businesses and individuals benefit from the economic welfare of the greater community. Moreover, we would not assume that all residential customers are potentially

> CARE customers any more than we would assume that all business customers may potentially fail in the near term." (D.05-06-029, p.16)

The Commission maintained the equal cents per therm CARE allocation as it did in previous BCAPS for SoCalGas. In SoCalGas' last BCAP, the intervenor, Ultramar, Inc. proposed placing an annual cap per customer on the annual usage that would be subject to the CARE surcharges. The Commission rejected Ultramar's proposal and maintained the equal cents per therm allocation: "Ultramar has not convinced us that the eight largest users on SoCalGas' system should pay proportionately less than everyone else to meet the costs of a social program. Its request is denied. We adopt ORA's recommendation." (D.00-04-060, mimeo, p.101) In SoCalGas' 1997 BCAP, the Commission rejected a similar CARE capping proposal. "We should not adopt SoCalGas' proposal to cap the CARE surcharge". (D.97-04-082, (1997) 72 CPUC 2d 151, 248)

CARE costs (and earlier LIRA costs) have been allocated equal cents per kWh for electric service and equal cents per therm for gas usage since the creation of the low income programs in 1989. The Commission has examined the issue of the allocation of CARE costs a number of times in both the electric and gas industries and has maintained the policy of allocating these costs by equal cents per kWh or therm because this was the method that spread these costs as broadly as possible.

The Commission should continue to allocate CARE costs on an equal cents per kWh basis as it is the fairest method to allocate these costs to the customers who do not directly benefit from the program. Under this method, the customers not receiving CARE benefits all pay the same amount for every unit of usage of electricity (for every kWh of usage). More than likely none of these customers want to pay for these programs or would voluntarily pay for these programs. To avoid disagreements as to who should pay for the costs of this program, the Commission has wisely decided to have all customers pay the same per kWh of usage. The Commission has endorsed the equal cents per kWh method for social programs such as the CARE program and in other instances where there is no clear connection between the costs of a program and customer usage. The Commission should continue to support the equal cents per kWh method to pay for CARE program costs

DRA notes that average residential rates have increased 17.6% in the last year. PG&E forecasts a further increase for the residential class by May 2007 of 4.8% if its proposals are adopted. All together, this would be a 23.3% increase to the residential class from October 2005 to May 2007.[76] . DRA recommends that the Commission do its best to hold the line and not allow any further increases to the residential class. Maintaining the equal cents per kWh allocation of CARE costs would help reduce further rate increases to the residential class.

3. Allocation of Base Interruptible Program Costs

PG&E proposes to replace the non-firm interruptible program with the Base Interruptible Program (Schedule E-BIP), and to allocate these costs by distribution EPMC.

DRA proposes to allocate these interruptible program costs by equal cents per kWh. In D.02-11-022, the Commission adopted a TURN recommendation to collect these costs in distribution rates so that they could be collected from all customers including DA customers. The E-BIP program is designed to increase system reliability that benefits all customers including DA customers. DRA agrees with TURN and D.02-11-022 that it is proper to collect these costs from all customers. Ideally E-BIP costs should be allocated by generation allocation factors (that include DA customers) because system reliability benefits result in generation cost savings. Currently there are no generation allocation factors that include DA customers and to create one would require imputing DA customer

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[76] This was calculated from information provided by PG&E in response to DRA Data Request DRA-03, question #10, and from information provided by PG&E in response to AECA DR AECA-001, question #6.

generation costs. As a proxy for the ideal generation allocator, DRA recommends allocating E-BIP costs by equal cents per kWh.

4. Allocation of Self Generation Incentive Program Costs and California Solar Initiative Costs

PG&E proposes to allocate Self Generation Incentive Program ("SGIP") costs and California Solar Initiative ("CSI") costs by distribution EPMC allocators. (See PG&E responses to TURN Data request TURN_004, questions 1 and 2). Both the SGIP and the SCI provide environmental benefits that benefit all rate payers. In approving the SGIP that provides incentives for the development of self-generation facilities the Commission stated: "The self-generation programs adopted today will produce significant public (e.g. environmental) benefits for all ratepayers, including gas ratepayers."(D.01-03-073, Finding of Fact 3, p.40) Regarding the CSI the Commission stated: "The development of solar energy projects is consistent with state policies generally that support environmentally sound energy resources and an energy infrastructure that is diverse and disbursed." (D.06-01-024, mimeo, p.12). Because both these programs have environmental benefits, DRA recommends that the Commission allocate the costs of these programs by equal cents per kWh as the Commission has for other programs that have environmental benefits.

The Commission has consistently allocated environmental costs that benefit all customers on an equal cents per kWh or therm basis. For example in 1991 the Commission allocated costs of the Natural Gas Vehicle ("NGV") Program by equal cents per therm as the program promoted air quality benefits for all Californians. The Commission determined that there would be environmental benefits from the NGV program that would benefit all customers, thus, customers should all contribute to paying for this program. "The Legislature has declared that the pursuit of cleaner air and relief from global warming is in the public interest. There is nothing in the hearing record which suggests that these benefits, as well as the strategic advantage of lowering our dependence upon foreign oil, will not be realized by the successful implementation of this program. To the extent that they are, they will be enjoyed by all Californians in their capacity as ratepayers.” (D.91-07-018, 40 CPUC 2d at 738-739) The Commission further stated: “The fixed infrastructure costs associated with the NGV program result in air quality benefits enjoyed by all Californians in their capacity as ratepayers and, as such, should be recovered on an equal cents per therm basis over all volumes sold by PG&E to all customer classes consistent with the intent of Public Utilities Code 740.3(c).” (40 CPUC 2d at 744, Finding of Fact #13)

In 1995, the Commission examined how Hazardous Waste Program costs should be allocated. The Hazardous Waste costs were for cleaning up old gas utility sites. This cleanup created a better environment which benefited all customers, and thus the Commission allocated the costs of the Hazardous Waste Program by equal cents per therm. The Commission stated “No one class is responsible for hazardous waste cleanup costs. As all ratepayers benefit from their incurrence though a cleaner environment, the costs should be spread equitably among all customer classes, including wholesale customers, on a cents per therm basis.” (D.95-05-044, 60 CPUC 2d at 17, Finding of Fact #2)

The Commission has already examined the allocation of SGIP costs for gas customers in PG&E’s last BCAP. The Commission stated that “Consistent with our view that all customers should pay for programs that provide environmental benefits, we include wholesale customers in the allocation of SGIP costs as well as EG customers and adopt PG&E’s proposal to allocate the costs on an equal cents per therm basis.” (D.05-06-029, p.18, mimeo).

For programs that benefit all ratepayers by improving the environment the Commission has consistently allocated the costs of such programs on an equal cents per kWh or therm basis. DRA recommends that the Commission continue this policy by allocating the costs of the SGIP and CSI programs to all customer classes on an equal cents per kWh basis. These programs benefit ratepayers by improving the environment, and thus non-exempt rate payers should pay for these programs equally.

DRA notes that the Commission has exempted CARE customers from paying for the CSI program. The Commission stated: “We do, however, exempt CARE customers from the costs of this program as a matter of equity, especially since CARE customers are the least likely to be beneficiaries of the incentives.” (D.06-01-024, mimeo, pp.19 – 20)

DRA thus recommends that SGIP costs and CSI costs be allocated equal cents per kWh and that CARE customers should not be allocated CSI costs.

5. A Revenue Allocation Cap of No More Than 2% is Justified in This Proceeding

In this proceeding, PG&E reexamines the underlying marginal costs on its system and proposes a new allocation of these costs. Most parties agree that the Commission should consider marginal costs when performing the revenue allocation. However, parties have not yet reached consensus regarding the proper method for calculating these marginal costs. There will likely be a number of marginal cost proposals for distribution, customer, and generation costs in this proceeding. These marginal cost recommendations will be incorporated into each party’s revenue allocation recommendations where the revenue requirement is allocated to customer classes.

If PG&E were to flow all of its calculated marginal costs to the revenue allocation without any capping, the residential class would receive an increase of 5.7%, the agricultural class would receive an increase of 18.5%, and standby customers would receive an increase of 12.4%. PG&E proposes to moderate its revenue allocation somewhat by moving 75% of the way to a full marginal cost basis, and this would result in a 3.9% increase to residential customers, a 14.5% increase to agricultural customers, and a 9.8% increase to standby customers.

Assuming PG&E’s revenue requirement forecasts, but using DRA’s marginal cost calculations and revenue allocation proposals without any mitigation or cap, would result in a 0.4% increase in rates for residential customers.[77] To avoid the large rate increases that could result from the proposals of PG&E and other parties, DRA recommends that the Commission adopt a revenue allocation cap of the average system change plus 2%. This would help moderate bill impacts while also making movement towards cost based rates.

DRA makes this recommendation because (1) the residential class has already experienced large rate increases in the last year, (2) other rate increases will be implemented in March 2007 and May 2007, (3) unnecessarily high residential rates that would result from PG&E's proposed revenue allocation, and (4) capping conforms with Commission policy to cap revenue allocations and moderate rate increases. It is especially important to limit increases to the residential class in a regulatory era characterized by multiple proceedings each year where rate increases are possible.

6. PG&E Customers Have Recently Received Large Rate Increases and Will Receive Further Rate Increases in the Coming Months

DRA recommends limiting the increase to any class in this proceeding to a maximum increase of 2% above average system change. This recommendation takes into account the fact that residential rates increased 17.6% between October 2005 and September 2006, largely because of implementation of PG&E's 2003 GRC Phase II, and ERRA, increases[78]. There will also be further rate increases in March 2007 and in May 2007. PG&E forecasts that average residential rates will increase by a further 4.8% by May 2007.[79] If PG&E's proposals are adopted

[77] If all of DRA's marginal cost and revenue allocation proposals are adopted, there will be no need for a cap for the residential class, but other customer classes such as the agricultural and standby classes would still benefit from a revenue allocation cap. PG&E's revenue allocation model will need to be modified to allow for capping of these classes.

[78] This was calculated from PG&E's response to DRA Date Request DRA-03, q.10.

[79] This was calculated from PG&E's response to DRA Date Request DRA-03, q.10, and to AECA DR AECA-001, q.6.

and its forecasts are accurate, average residential rates will have increased in total by 23.3% between October 2005 and May 2007. This is an extraordinary large increase for a 20 month period. DRA recommends that the Commission use caution and moderate further residential rate increases. Given these other rate increases for the residential class, it is especially important to cap or limit the increase that will result from updating and re-allocating PG&E's marginal costs.

7. High Residential Rates

PG&E's proposed allocation would result in a 3.9 % increase to the residential class, a 14.5% increase to the agricultural class, and a 9.8% increase to standby customers. PG&E's proposals would result in significant increases in Tier 3, Tier 4, and Tier 5 residential rates. For Schedule E-1, PG&E's proposals would result in a 7.8% increase to residential Tier 3 rates, a 10.8% increase to Tier 4 rates, and a 11.9% increase to Tier 5 rates. Their rates would be far higher even than the historic high rates implemented with the 2001 surcharges during the energy crisis (See D.01-05-064).

Under PG&E's proposal, rates for Tier 3, Tier 4, and Tier 5 usage will far exceed the rates resulting from the imposition of surcharges during the energy crisis. Tier 3 rates would be 4.36 cents per kWh higher (18.4% higher); Tier 4 rates (between 200% and 300% of Baseline usage) would be 9.95 cents per kWh higher (42.13% higher), and Tier 5 rates (over 300% of baseline usage) would be 12.95 cents per kWh higher (50.13% higher) than the rates adopted during the energy crisis.

COMPARISON OF PG&E'S TOTAL RATES

Tiers	PG&E Proposed Rates	Adopted in D.01-05-064
Tier 3 – 130%-200% Of Baseline	23.693 cents	19.333 cents
Tier 4 – 200%-300% of Baseline	33.587 cents	23.630 cents
Tier 5 – Over 300% Of Baseline	38.773 cents	25.826 cents

DRA notes that both PG&E's proposed Tier 3, Tier 4, and Tier 5 residential rates, and those adopted during the energy crisis are of an unprecedented level, and Tier 5 rates would be nearly three times the level of residential rates before the energy crisis. There is no compelling emergency to raise residential rates so much above what they were at the height of the energy crisis.

DRA does support PG&E's proposal to maintain CARE rates at the current rate level. The Commission protected low-income customer's rate increases during the energy crisis. DRA agrees that this policy should be maintained.

8. Past Precedents for Capping the Revenue Allocation

The Commission has consistently adopted caps on the revenue allocation to moderate the movement towards full marginal cost rates. Continuing this policy is especially important at the present time. DRA's recommendation to cap any class increase at a maximum of 2% is consistent with past Commission decisions.

In PG&E's 1993 GRC, the Commission was faced with the same considerations of moderating bill impacts, and moving towards EPMC target allocations. The Commission adopted a cap of plus or minus 3%:

> "No party disagrees with our continued and dedicated movement towards EPMC target allocations. However, all parties are in favor of some sort of combination of caps and floors to mitigate the rate impacts. In the last GRC, this took the form of a capped EPMC allocation. Almost all the parties to this GRC

support continuation of this approach, with the exception of TURN". (D.92-12-057, 47 CPUC 2d, p.294)

Parties debated the size of a cap on increases over and above the 3.42% revenue requirement increase that the Commission granted to PG&E in its GRC. Considering this 3.42% increase, the Commission adopted a cap of an additional 3%:

> "Given the size of the rate increase that we are authorizing today, we believe PG&E's recommendation of SAPC plus or minus 3% is appropriate and will not result in onerous rate changes". (D.92-12-057, 47 CPUC 2d, p.294)

In SCE's 1995 GRC Decision, D.96-04-050, the Commission provided an extensive discussion of the policy of capping including a number of proceedings where capping was adopted:

> "In the past, we have capped full movement to 100% EPMC in order to mitigate harsh bill impacts. In Edison's last GRC, we determined that average rate increases of approximately 20% to the agricultural and pumping class should be mitigated by imposing a cap of SAPC plus 3.5%. In Edison's test year 1988 GRC, we capped full EPMC revenue allocation by SAPC plus 5% to mitigate increases to the domestic class of a similar magnitude. (D.87-12-066 26 CPUC 2d 392, 528-529; D.92-06-020, 44 CPUC 2d 471, 496-497.) In these cases, the SAPC was positive, that is, Edison's system average rate was increasing.
>
> We have also capped a full EPMC allocation when system average rates were decreasing. In D.86-08-083, we initiated a cap to ensure that the residential and agricultural groups would share in the significant (12.43%) decrease in PG&E's average rates. Without a cap, these customer groups would have experienced a 3-4% average rate increase. (D.86-08-083, 21 CPUC 2d 613, 643-645.) However, we have generally not initiated a cap when each rate group experiences a decrease in average rates. (See, for example, D.88-12-085 30 CPUC 2d 299, 324.)" (D.96-04-050, mimeo, p.87)

Caps have continued to be used by the Commission to moderate revenue allocation increases to specific classes. In the last few years, the Commission has adopted caps in most rate cases. In San Diego Gas and Electric's ("SDG&E") 2000 Rate Design Window ("RDW") the revenue allocation was caped at SAPC plus or minus 3%. (D.00-12-058, mimeo, Appendix C, p.2) In Pacific Corp's 2003 GRC, the Commission granted an overall system average increase of 4.7% plus a cap of 2.5%. (D.03-11-019, mimeo, p.5) In Sierra Pacific's 2003 GRC, the Commission granted an increase of 6.2% plus a cap of 2.6%. The Commission adopted ORA's proposed cap and in a discussion of this policy stated:

> "Under the circumstances of this proceeding, when allocating an overall system increase, it would be imprudent to increase rates substantially for one class of customers while substantially decreasing rates for others." (D.04-01-027, mimeo, p.16)

In SDG&E's 2003 RDW, the Commission adopted a cap of 3%, unless the system average percent change ("SAPC") exceeded 9%, after which the cap gradually declined until it reached 0% (this would be a straight SAPC allocation) if the SAPC was 12% or greater. The Commission's policy on caps remained the same:

> "ORA states the purpose of caps and floors: "The Joint Settlement on caps allows some movement towards marginal cost, but would also provide for rate stability and would minimize bill impacts to residential and streetlight customers". SDG&E's stated purpose is similarly straightforward: "Electric rates have been subject to highly volatile changes in recent years. SDG&E's proposal for allocation caps and floors correctly moves rates in a cost-based direction, while providing rate stability and moderating adverse bill impacts".(D.04-04-042, mimeo, p.9)

In the 2003 RDW, there was a settlement on the revenue allocation and capping signed by all active parties except for the Federal Executive Agencies ("FEA"). FEA argued that the Commission had abandoned its policy preference for capping when it implemented the energy surcharges during the energy crisis in D.01-05-047 for PG&E and SCE, and in D.01-09-059 for SDG&E. The Commission rejected this argument and adopted caps:

> "Both sides cite past Commission decisions approving various cap and floor levels as precedents for their positions. FEA points in particular to two decisions we issued in 2001 at the height of the energy crisis in which we imposed increases on some customer classes that were far above what the proposed 3% cap and 9% floor in today's settlement would have allowed. Those decisions, FEA argues, show that "The Commission has long since abandoned caps in the range of SAPC plus 3.5% to 5% on total revenues (or 8.75% to 12.5% on distribution revenues) in favor of 'letting the chips fall where they may.'" Those, however, were extraordinary orders issued in response to extraordinary circumstances, and we give them no weight as precedent for FEA's position. Our view today aligns closely with that SDG&E expresses:
>
> From SDG&E's perspective, an almost 10% increase to the residential class (exclusive of any additional increase from the COS proceeding) is inappropriate at this time. Rather, SDG&E supports a gradual movement toward cost-based distribution rates in this proceeding. The derived marginal cost basis used in the revenue allocation process can itself be volatile. The Commission should avoid imposing radical rate swings each time a cost study is produced with potentially differing results from the last adopted marginal cost study."(D.04-04-042, mimeo, pp.10-11)

The Commission reaffirmed a policy of moderating bill increases by adopting caps on the revenue allocation. The unfortunate actions required during the height of the energy crisis did not change the Commission's policy preference for adopting caps on the revenue allocation in more normal circumstances.

In Southern California Edison's ("SCE") 2003 GRC, a cap of 4% was part of a settlement that was adopted by the Commission. In SDG&E's 2005 RDW, an all party settlement was reached that included a 2% cap on the revenue allocation. This settlement was adopted by the Commission in D.05-12-003 on December 2, 2005. The decisions discussed above show the preference of the Commission to limit extraordinary bill increases by adopting caps on the revenue allocation. Because of the current environment where electric prices have increased dramatically in the last year, DRA is recommending a cap that is lower than many of the caps adopted by the Commission. DRA's recommendation of a cap of 2% reflects the realities of the large average system increases that have been implemented in the last year (including the recent implementation of PG&E's last GRC Phase II in January, 2006) and which are forecasted to continue next year. DRA's recommendation is for a cap or limit of a 2% increase above the average system increase that will result from the PG&E's GRC Phase I, and other proceedings.

D. CONCLUSION

The Commission's continuing policy to cap revenue allocations is sound and practical since it allows movement towards marginal cost, but also maintains rate stability and moderates high bill impacts.

DRA recommends that revenue allocation adjustments in this proceeding be limited to a maximum of average system change plus 2%. DRA's recommendation is close to the level of caps adopted by the Commission in past decisions. PG&E's residential customers have recently received increases of 17.6% and potentially face total increases of up to 23.3% for the period October 2005 to May 2007. Thus it is important that the Commission limit further increases. Since it appears that the residential class will experience "rate shock" with rate increases of up to 23.3% in a twenty month period; it is important for the Commission to limit additional increases to the residential class in this proceeding. DRA's proposed cap will reduce bill impacts to the residential and agricultural classes, while allowing for some movement towards marginal cost based rates. The adoption of DRA's proposed cap will limit the increase of PG&E's Tier 3, Tier 4, and Tier 5 residential rates.

DRA also recommends that the Commission continue to allocate CARE costs by equal cents per kWh. DRA further recommends that programs that produce environmental benefits such as the Self-Generation Incentive Program and the California Solar Initiative be allocated equal cents per kWh. DWR costs should also be allocated equal cents per kWh to broadly spread these stemming from the energy crisis to all customers.

Table 5-1 shows DRA's proposed revenue allocation using DRA's proposed marginal cost recommendations, and PG&E's proposed allocation, using its proposed 75% movement towards its proposed marginal costs, and its marginal cost recommendations.

Table 5-1
DRA'S PROPOSED REVENUE ALLOCATIONS
and Comparison with PG&E

	PG&E's Proposed Total Revenue	PERCENT CHANGE	DRA'S PROPOSED TOTAL REVENUE	PERCENT CHANGE	DRA Lower than PG&E
Residential	4,760,409,065	3.9%	4,598,550,504	0.4%	3.40%
Small	1,385,616,332	5.7%	1,316,551,109	0.4%	4.98%
Medium	1,790,750,697	-6.6%	1,827,650,082	-4.7%	-2.06%
E-19	1,212,889,700	-9.8%	1,260,269,329	-6.3%	-3.91%
Streetlights	61,266,910	-8.5%	59,507,310	-11.1%	2.87%
Standby	35,005,355	9.7%	35,546,510	11.4%	-1.55%
Agriculture	627,041,462	14.4%	666,803,622	21.6%	-6.34%
E-20 T	376,674,574	-1.7%	412,771,242	7.7%	-9.58%
E-20 P	541,989,054	-4.9%	595,315,007	4.5%	-9.84%
E-20 S	338,803,366	-9.5%	357,481,799	-4.5%	-5.51%
System	11,130,446,515	0.0%	11,130,446,515	0.0%	0.00%

Note: DRA's proposed revenue allocation does not include DRA's recommendation to include caps.

6. RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN

WITNESS: DEXTER KHOURY

A. SUMMARY AND RECOMMENDATIONS

This chapter presents DRA's rate design recommendations for residential and small commercial customers in PG&E's 2007 General Rate Case ("GRC") Phase II (A.06-03-005). DRA's rate design recommendations are based on DRA's revenue allocation recommendations. These are explained in Chapter 5.

DRA recommends:

1. Any rate increases to the residential class need to be limited to increases to tier 3, tier 4, and tier 5 rates to conform with AB 1X.
2. There should be no increase to CARE rates.
3. There should be no increase in the customer charge for Schedules A-1 and A-6, and no increase in the Schedule A-15 special facilities charge.
4. CARE commercial customers should receive the same average discount as residential CARE customers.

Table 6-1 shows DRA's proposed rates for residential schedule E-1, residential schedule EL-1 CARE customers, and for bundled small commercial customers.

B. DISCUSSION OF ISSUES

1. The Influence of AB 1X on Residential Rate Design

PG&E notes that AB 1X prohibits increases in rates for usage up to 130% of the baseline usage. Thus PG&E maintains the current tier 1 and tier 2 rates to ensure that they comply with AB 1X. PG&E proposes to increase tier 3, tier 4, and tier 5 rates dramatically to implement its proposed residential revenue increase.

DRA agrees that AB 1X prohibits increases in tier 1 and tier 2 rates. AB 1X was passed in early 2001 and contained important provisions that protect residential customers from bill increases. Section 80110 adds the following protections for residential customers using up to 130% of the baseline allowance:

> "In **no case** shall the commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, until such time as the department has recovered the costs of power it has procured for the electrical corporation's retail end use customers as provided in this division."(Emphasis added)

In the baseline proceeding the Commission examined this statute and concluded:

> "We find this statement to be unequivocal: the Legislature, for the life of the legislation, does not want residential customers to pay more money than they were paying on February 1, 2001 for the baseline quantity of electricity they were receiving on that date. Likewise, residential customers should not pay more than they were paying on February 1, 2001 for their usage of electricity of up to 130% of the baseline quantity they were receiving on that date."(D.02-04-026, p.14)[1]

Thus, DRA agrees that any additional revenue allocated to residential customers can only be collected in tier 3, tier 4, and tier 5 rates.

2. Schedule E-1 Rates

DRA and PG&E agree that any increases to the residential class need to be implemented in tier 3, tier 4, and tier 5 rates. DRA's proposed rates for schedule E-1 are also based on DRA's revenue allocation recommendation that increases average residential rates by .4%.

PG&E's proposed residential class increase of 3.9% would lead to much higher tier 3, tier4, and tier 5 rates. Rates for residential usage above 130% of baseline usage would be much higher than they were during the energy crisis if PG&E's proposals are adopted. For Schedule E-1, PG&E's proposals would

[1] D.04-02-057, The Final Opinion on Phase 2 Baseline Issues, contains an extensive discussion

(continued on next page)

result in a 7.8% increase to residential Tier 3 rates, a 10.8% increase to Tier 4 rates, and a 11.9% increase to Tier 5 rates. These rates would be far higher even than the historic high rates implemented with the 2001 surcharges during the energy crisis (See D.01-05-064). There is no compelling emergency to raise residential rates so far above the energy crisis level.

3. CARE Rates

PG&E proposes no increase in rates for California Alternate Rates for Energy ("CARE") (low income) customers. DRA strongly agrees that rates should not increase for CARE customers. The Commission and the Legislature has protected these customers from the impacts of the energy crisis. AB 1X, which prohibits any rate increases for up to 130% of baseline, helped to protect a large portion of CARE usage from rate increases[2]. The CARE class was spared the first 1 cent/kWh surcharge from the beginning of 2001, and both the 3 cent/kWh surcharge, and the five tier residential rate design implemented in D.01-05-064. The Commission fully exempted both CARE and medical baseline customers from the surcharges that were instituted in D.01-05-064:

> "In addition, we exempt all customers who qualify for the California Alternative Rates for Energy (CARE) program from paying the surcharge, as we stated in our March 27, 2001 order, and we also exempt from paying the surcharge all usage of customers on medical baseline rates"(D.01-05-064, p.4).

DRA supports the protection given to CARE customers, and recommends that it be continued. The Commission protected the rates of low income customers during the energy crisis. There is no compelling reason to raise rates

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(continued from previous page)
of AB 1X on pages 92 to 96.

[2] AB 1X prohibits any increases for up to 130% of baseline usage. "In no case shall the Commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers up to 130 percent of existing baseline quantities, until such time as the department has recovered the costs of power it has procured for the electrical corporation's retail end use customers as provided in this division." (Section 80110 of the Water Code).

to these customers now. Low income customers are the most vulnerable customers, and have the least means to pay higher rates. DRA thus recommends that CARE rates be maintained at the current level.

4. Schedules E-6, and E-7 Rate Design

PG&E proposes some changes to the new residential Time of Use ("TOU") schedule E-6 and updates rates to schedule E-7 based on its marginal cost and revenue allocation proposals. DRA anticipates that other parties have a number of ideas relating to these TOU schedules and plan to file testimony on these rate schedules. DRA thus looks forward to reviewing this testimony.

5. Commercial Rate Design

Small Commercial customers are served by PG&E on Schedules A-1, A-6, and A-15. PG&E proposes to maintain the current boundary for small light and power ("SL&P") at 500 kW, and proposes a number of rate design changes.

PG&E proposes to increase the Schedule A-1 and A-6 customer charges from $8.10 to $12.00 per month for single-phase service and from $12.00 to $18.00 per month for polyphase service. For Schedule A-15, PG&E proposes increasing the special facility charge from $15.00 per month to $20 per month. DRA's recommendations for these proposed commercial rates are discussed below.

6. Schedule A-1

DRA recommends that customer charges for small commercial customers should be maintained at the current level. DRA's revenue allocation recommendation results in a 3.4% decrease for A-1 customers, and thus DRA sees less need for increases to customer charges. Also, DRA's proposed marginal customer costs are considerably lower that PG&E's marginal customer costs. DRA further notes that PG&E's proposals result in unnecessarily large bill increases. PG&E is recommending a 2.7% average increase for Schedule A-1 customers. 10% of A-1 customers would receive bill increases of 32% or more, 14% would receive bill increases of 22% or more, 25% would receive a bill increase of 10% or more, and 7.8% of A-1 customers would receive bill increases of 45.6%.[3]

These bill increases are a result of PG&E's proposals to increase customer charges. To prevent these unnecessary bill increases, DRA recommends that the A-1 customer charge be maintained at its current level. With DRA's proposed revenue allocation, Schedule A-1 would experience a small decrease, that DRA recommends be implemented in lower volumetric rates.

7. Schedule A-6

PG&E's revenue allocation proposals would result in a 14.3% increase for Schedule A-6 customers. 92.5% of A-6 customers would receive a bill increase of 10% or more.[4]

DRA's proposed revenue allocation would result in a smaller increase for A-6 customers, and DRA recommends that this increase be collected in volumetric rates (energy charges).

8. Schedule A-15

PG&E's proposals would have an even stronger bill impact on A-15 customers. 48.4% of A-15 customers would receive 32.3% or higher increases if PG&E's proposals were adopted. 79% of these customers would receive a 20% or higher bill increases, and 96% would receive 10% or higher bill increases.[5] These bill increases would result from PG&E's proposal to increase the special facilities charge, and their proposal to increase the customer charge. The special facilities charge was raised on January 1, 2006 from $7.80 a month to $15 a

[3] This information was obtained in PG&E's response to DRA data request DRA-003 question #6.

[4] This information was obtained in PG&E's response to DRA data request DRA-003, question #7.

[5] This information was obtained in PG&E's response to DRA data request DRA-003, question #8.

month. To avoid further bill increases for A-15 customers, DRA recommends that A-15 special facilities charges be maintained at $15 per month .

9. Schedule E-CARE Rate Design

Schedule E-CARE is a commercial low income schedule for non-profit group living facilities. PG&E proposes to change the E-CARE discount from the current percentage discount to a rate per kWh discount.

DRA is concerned about bill impacts for these customers that could result from PG&E's proposals. PG&E's proposal seems to be based on easing administrative concerns. DRA is sympathetic with easing administrative burdens, but is not convinced that PG&E's proposal would protect E-CARE customers as well as residential CARE customers are protected. Because of these concerns, DRA recommends that E-CARE customers continue to receive CARE discounts on a percentage basis, and further that these customers receive the same percentage discount as residential CARE customers. SCE, for example, does set the commercial CARE discount at the same percentage level that residential CARE customers receive. Such treatment is fair and thus DRA recommends the same treatment for Commercial CARE customers of PG&E.

C. CONCLUSION

DRA recommends that the Commission adopt DRA's proposed revenue allocation or a cap of 2% on the revenue allocation in this proceeding. DRA also recommends a more conservative approach to rate design, with no increases in customer charges. DRA's revenue allocation proposal also impacts the level of residential rates and thus helps moderate bill impacts. DRA's rate design recommendations would prevent larger increases to higher usage residential customers, and would moderate large and unnecessary bill increases to small commercial customers.

DRA recommends that increases for the residential class be implemented in tier 3, tier 4, and tier 5 rates, except for CARE customers. DRA agrees with

PG&E that CARE residential rates should be maintained at the current level. DRA recommends that Commercial CARE customers receive the same average percent discount that residential CARE customers receive. DRA proposes no increase to Schedule A-1 and A-6 customer charges and also no increase to the Schedule A-15 Special facilities charge.

TABLE 6-1
DRA'S RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN RECOMMENDATIONS

	PRESENT RATES					PROPOSED RATES				
		Gen	PPP	Other	Total	Distr	Gen	PPP	Other	Total
E-1 - Residential Services										
ENERGY CHARGE ($/kWh)										
Baseline Usage	0.0408	0.0361	0.0070	0.0303	0.11430	0.0325	0.0420	0.0094	0.0303	0.11430
101% - 130% of Baseline	0.0494	0.0432	0.0070	0.0303	0.12989	0.0393	0.0508	0.0094	0.0303	0.12989
131% - 200% of Baseline	0.0755	0.1070	0.0070	0.0303	0.21981	0.0801	0.1035	0.0094	0.0303	0.22330
201% - 300% of Baseline	0.0996	0.1660	0.0070	0.0303	0.30292	0.1178	0.1522	0.0094	0.0303	0.30964
Over 300% of Baseline	0.1122	0.1970	0.0070	0.0303	0.34648	0.1375	0.1777	0.0094	0.0303	0.35489
MINIMUM CHARGE										
($/meter/day)	0.1048	*	0.0031	0.0153	0.14784	0.1018	*	0.0042	0.0153	0.14784
EL-1 - Residential CARE Program Service										
ENERGY CHARGE ($/kWh)										
Baseline Usage	0.0271	0.0253	0.0053	0.0255	0.08316	-0.0043	0.0565	0.0055	0.0255	0.08316
101% - 130% of Baseline	0.0305	0.0344	0.0053	0.0255	0.09563	-0.0043	0.0690	0.0055	0.0255	0.09563
131% - 200% of Baseline	0.0305	0.0344	0.0053	0.0255	0.09563	-0.0043	0.0690	0.0055	0.0255	0.09563
201% - 300% of Baseline	0.0305	0.0344	0.0053	0.0255	0.09563	-0.0043	0.0690	0.0055	0.0255	0.09563
Over 300% of Baseline	0.0305	0.0344	0.0053	0.0255	0.09563	-0.0043	0.0690	0.0055	0.0255	0.09563
MINIMUM CHARGE										
($/meter/day)	0.0841	*	0.0023	0.0146	0.11828	0.0723	*	0.0023	0.0146	0.11828
($/kWh)				0.0134					0.0134	
A-1 - Small General Service										
ENERGY CHARGE ($/kWh)										
Summer	0.0593	0.0814	0.0078	0.0307	0.17917	0.0467	0.0838	0.0102	0.0307	0.17140
Winter	0.0395	0.0529	0.0078	0.0307	0.13088	0.0312	0.0556	0.0102	0.0307	0.12760
CUSTOMER CHARGE ($/meter/day)										
Single-phase	0.2661				0.26612	0.2661				0.26612
Polyphase	0.3943				0.39425	0.3943				0.39425
A-6 - Small General Time-of-Use Service										
ENERGY CHARGE ($/kWh)										
Summer										
Peak	0.0824	0.1920	0.0062	0.0307	0.31125	0.1176	0.1668	0.0086	0.0307	0.32363
Part-Peak	0.0330	0.0842	0.0062	0.0307	0.15397	0.0470	0.0830	0.0086	0.0307	0.16929
Off-Peak	0.0165	0.0389	0.0062	0.0307	0.09221	0.0235	0.0558	0.0086	0.0307	0.11861
Winter										
Part-Peak	0.0272	0.0719	0.0062	0.0307	0.13592	0.0386	0.0615	0.0086	0.0307	0.13932
Off-Peak	0.0181	0.0459	0.0062	0.0307	0.10081	0.0257	0.0529	0.0086	0.0307	0.11789
METER CHARGE ($/meter/day)										
Rate A-6	0.2011				0.20107	0.0000				0.00000
Rate W	0.0591				0.05914	0.0000				0.00000
Rate X	0.2011				0.20107	0.0000				0.00000
CUSTOMER CHARGE ($/meter/day)										
Single-phase	0.2661				0.26612	0.2661				0.26612
Polyphase	0.3943				0.39425	0.3943				0.39425

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document "Testimony on Phase 2 of the Pacific Gas and Electric Co., 2007 General Rate Case, Marginal Cost, Revenue Allocation, and Rate Design" in A.06-03-005.

A copy was served as follows:

[X] **BY E-MAIL**: I sent a true copy via e-mail to all known parties of record who have provided e-mail addresses.

[ ] **BY MAIL**: I sent a true copy via first-class mail to all known parties of record.

Executed in San Francisco, California, on the **13th** day of September, 2006.

Dexter Khoury and Cherie Chan

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