Application of SAN DIEGO GAS & ELECTRIC COMPANY For Authority to Update Marginal Costs, Cost Allocation, And Electric Rate Design (U 902-E))

Application No. 07-01-__
Exhibit No.: (SDGE-05) ________

PREPARED DIRECT TESTIMONY

OF JAMES S. PARSONS

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

JANUARY 31, 2007

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PREPARED DIRECT TESTIMONY

OF

JAMES S. PARSONS

CHAPTER 5

I. OVERVIEW AND PURPOSE

The purpose of my direct testimony is to present San Diego Gas & Electric Company's (SDG&E) proposals for revenue allocation to customer classes using distribution marginal customer costs, marginal distribution demand costs, marginal generating capacity costs, and marginal energy costs. The marginal customer and marginal distribution demand costs comprise marginal distribution costs. The marginal generation and energy costs comprise the marginal commodity costs. The unit marginal cost prices for the commodity function are disaggregated between capacity and energy components. I sponsor the unit marginal distribution costs, the unit marginal generating capacity costs, and the unit marginal energy costs, and explain their derivation in the following sections of this chapter. I am also sponsoring the determinants used in conjunction with the unit marginal generating costs to derive marginal customer cost revenue responsibilities, or marginal cost revenue by customer class.

The marginal distribution costs are used in conjunction with the marginal commodity costs to allocate SDG&E's proposed authorized revenues for those two functions to customer classes by using the Equal Percent of Marginal Cost (EPMC) methodology. The purpose of this EPMC methodology is to reconcile the distribution and commodity marginal cost revenue responsibilities to the authorized revenue requirements of these two functions adopted in Phase 1 of SDG&E's Test Year 2008 (TY 2008) General Rate Case (GRC) proceeding.

I also present the revenue allocation of the other components that make up the total SDG&E revenue requirement as collected in rates. These are shown in the proposed revenue allocation in order to present the complete unbundled proposed rate components. Witness Robert W. Hansen explains revenue allocation principles in Chapter 2 of this application. Chapter 5 will describe mechanics of the revenue allocation and the resulting allocation to customer classes.

The proposals for revenue allocation and marginal costs will be used by the rate design witnesses in their rate design proposals contained in Chapters 6, 7, 8, and 10 of this application. SDG&E proposes these marginal costs and determinants strictly for revenue allocation and rate design purposes. These marginal costs are not proposed for any other purposes at this time. SDG&E proposes these rates be implemented January 1, 2008.

II. SDG&E REVENUE ALLOCATION REGULATORY HISTORY

The California Public Utilities Commission (Commission) has adopted a settlement on revenue allocation in every SDG&E Rate Design Window (RDW) proceeding since 1996. With the exception of the settlement in the 2004 RDW proceeding, as adopted by Decision (D.) 04-04-042, these settlements have been all-party settlements.

In these prior proceedings, SDG&E proposed marginal costs and an EPMC revenue allocation to customer classes based on those marginal costs, capping the revenue changes to classes when necessary. The other parties then proposed their versions of marginal costs and the resulting revenue allocations. A comprise revenue allocation was then settled upon, which resulted in a reasonable allocation acceptable to all the parties, and which was then used in the rate design.

III. OVERVIEW OF REVENUE ALLOCATION

Revenue allocation is the assignment of the proposed or authorized revenue requirement among the various rate classes using the marginal costs of those classes. The various marginal costs by customer classes are multiplied by the applicable determinant to calculate the revenue that would be collected were unit marginal costs used as rates. These values are the customer class marginal cost revenue responsibilities, or marginal cost revenue. A separate marginal cost revenue is calculated for the distribution function (customer costs, feeders and local distribution costs, and substation costs) and the commodity function. This is necessary since the authorized revenue requirements are disaggregated into distribution revenue requirements and commodity revenue requirements. The marginal cost revenues by customer class are then reconciled to the authorized revenue requirement to derive proposed customer class revenue requirements. The proposed customer class revenue allocation for both the distribution and commodity functions are then used in rate design for the various customer classes.

IV. DISTRIBUTION REVENUE ALLOCATION

SDG&E proposes to continue using the Commission adopted EPMC revenue allocation method for allocating the distribution revenue requirement to customer classes.

The EPMC methodology simply scales the customer class distribution revenue responsibilities, or marginal cost revenues, up or down by a single factor such that the sum equals the authorized distribution revenue requirement.

The proposed distribution revenue requirement is the revenue requirement proposed in the Test Year 2008 GRC Phase 1. The revenue at current rates is the rates in effect on January 1, 2007 applied to the forecast TY 2008 sales. The proposed distribution revenue allocation allocates this GRC Phase 1 distribution revenue requirement among the customer classes based on the proposed marginal costs revenue responsibilities by customer class. The customer class revenue responsibilities for distribution demand and customer are summed for use for in the allocation. No capping is proposed for the Distribution revenue allocation.

The resulting proposed distribution revenue allocation is provided in JSP-5-3.

V. COMMODITY REVENUE ALLOCATION

SDG&E proposes to also use the EPMC revenue allocation methodology to allocate the commodity component revenue requirement. This revenue requirement is composed of revenue requirements from the Department of Water Resources (DWR) and Utility Retained Generation (URG). The marginal generation capacity revenue responsibilities and the marginal energy revenue responsibilities are combined by customer class to use as the allocation factor for the DWR and URG revenue requirements. The EPMC methodology is then used to scale the customer class allocations to sum to the DWR and URG revenue requirements. No capping is proposed for the generation and energy revenue allocation. The proposed allocation is provided in JSP-5-2.

VI. TOTAL PROPOSED REVENUE ALLOCATION

The total revenue allocation based on all the revenue requirement components is provided in JSP-5-1. This allocation table provides the class revenue allocations for both current and proposed revenues and the changes between current and proposed both in dollars and percentages for each of the ten components of the total utility Electric revenue requirements.

I am sponsoring the revenue allocation for two of the revenue requirement components: (1) the Distribution revenue allocation and (2) the Commodity revenue allocation. The other revenue requirement allocations are determined in other regulatory proceedings.

There are three changes to revenue requirements and/or revenue allocation that are determined in other regulatory proceedings. The first change involves the Competition Transition Charge (CTC) revenue requirement and allocation. The CTC revenue requirement for commercial industrial rate schedules was previously collected as a demand charge. Effective January 1, 2007, the collection of the CTC revenue requirement switched from a demand charge basis to an energy charge basis. With the increased sales forecast for Test Year 2008, the revenue requirement was thereby reduced, and the revenue allocation changed.

The second change involves the Total Rate Adjustment Component (TRAC) revenue requirement. The TRAC revenue requirement reflects the Rate Design

Settlement (RDS) impacting the residential class for which there was an over-collection at year-end 2006. This over-collection is shown as a residential class revenue requirement reduction in both the current and proposed revenue allocations.

The third change involves the removal of the DWR Bond Charge (DWR-BC) out of the Commodity revenue requirements and revenue allocation. This rate is applied to sales and does not change between current and proposed revenue allocations.

This concludes my prepared direct testimony.

VII. QUALIFICATIONS OF JAMES S. PARSONS

My name is James S. Parsons. My business address is 8315 Century Park Court, San Diego, California, 92123. I am a Principal Regulatory Economics Advisor in the Electric Rate Design Section of the Regulatory Policy and Analysis Group at San Diego Gas & Electric Company (SDG&E). My primary responsibilities include the development of electric cost-of-service studies, revenue allocation studies, and derivation of rate designs.

I received a Bachelor of Science degree in Engineering from The Pennsylvania State University 1966. I received a Master of Science degree in Business Administration from the San Diego State University 1972 I am a Registered Professional Engineer, Mechanical Branch, in the State of California. I have been employed by SDG&E since 1972 in various engineering, regulatory analysis, and rate design capacities.

I have testified before this Commission since 1980 in numerous costs of service, revenue allocation, and rate design proceedings.

ATTACHMENT

JSP-5-1

ATTACHMENT JSP-5-1
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
PROPOSED REVENUE ALLOCATION

Line No.	Customer Class	(A) Distribution Revenues ($)	(B) Transmission Revenues ($)	(C) Public Goods Revenues ($)	(D) Nuc Decom Revenues ($)	(E) FTA Bond Revenues ($)	(F) On-Going CTC Revenues ($)	(G) RS Revenues ($)	(H) TRAC Revenues ($)	(I) DWR-BC Revenues ($)	(J) Total UDC Revenues ($)	(K) Commodity Revenues ($)	(L) Total Revenues ($)	Line No.
	Revenue at Current Rates (01/01/07)													
1	Residential	474,469,044	66,631,702	47,155,923	3,527,110	39,334,941	10,721,709	46,159,131	(7,186,813)	31,194,752	712,007,499	555,429,198	1,267,436,698	1
2	Small Comm.	97,614,061	21,807,508	16,629,788	966,421	10,999,369	3,782,862	13,592,927	0	9,739,953	175,132,888	178,881,266	354,014,155	2
3	Med. & Lg. C&I	276,226,118	75,304,460	63,857,490	4,912,115	0	16,671,371	60,451,878	0	34,664,001	532,087,433	620,325,863	1,152,413,296	3
4	Agriculture	4,169,956	934,968	699,875	41,434	0	136,012	582,779	0	387,661	6,952,685	6,750,597	13,703,282	4
5	Lighting	7,829,884	602,780	478,557	49,954	0	0	583,589	0	512,814	10,057,578	6,748,588	16,806,167	5
6	System Total	860,309,063	165,281,418	128,821,633	9,497,034	50,334,310	31,311,954	121,370,304	(7,186,813)	76,499,181	1,436,238,085	1,368,135,514	2,804,373,598	6
	Proposed Revenue Allocation													
7	Residential	564,962,651	66,631,702	47,155,923	3,527,110	0	10,274,624	46,159,131	(7,186,813)	31,194,752	762,719,080	605,872,601	1,368,591,681	7
8	Small Comm.	128,127,269	21,807,508	16,629,788	966,421	0	3,760,640	13,592,927	0	9,739,953	194,624,506	172,317,866	366,942,372	8
9	Med. & Lg. C&I	290,152,342	75,304,460	63,857,490	4,912,115	0	16,124,550	60,451,878	0	34,664,001	545,466,836	589,154,055	1,134,620,891	9
10	Agriculture	5,070,573	934,968	699,875	41,434	0	133,310	582,779	0	387,661	7,850,600	6,485,784	14,336,384	10
11	Lighting	10,797,292	602,780	478,557	49,954	0	0	583,589	0	512,814	13,024,986	6,096,579	19,121,565	11
12	System Total	999,110,127	165,281,418	128,821,633	9,497,034	0	30,293,124	121,370,304	(7,186,813)	76,499,181	1,523,686,008	1,379,926,885	2,903,612,893	12
	Proposed Revenue Change													
13	Residential	90,493,607	0	0	0	(39,334,941)	(447,085)	0	0	0	50,711,580	50,443,403	101,154,983	13
14	Small Comm.	30,513,208	0	0	0	(10,999,369)	(22,222)	0	0	0	19,491,617	(6,563,400)	12,928,217	14
15	Med. & Lg. C&I	13,926,224	0	0	0	0	(546,821)	0	0	0	13,379,403	(31,171,808)	(17,792,405)	15
16	Agriculture	900,617	0	0	0	0	(2,702)	0	0	0	897,915	(264,813)	633,102	16
17	Lighting	2,967,408	0	0	0	0	0	0	0	0	2,967,408	(652,009)	2,315,399	17
18	System Total	138,801,064	0	0	0	(50,334,310)	(1,018,830)	0	0	0	87,447,924	11,791,371	99,239,295	18
	Proposed Revenue Change Percentages													
19	Residential	19.07%	0.00%	0.00%	0.00%	-100.00%	-4.17%	0.00%	0.00%	0.00%	7.12%	9.08%	7.98%	19
20	Small Comm.	31.26%	0.00%	0.00%	0.00%	-100.00%	-0.59%	0.00%	0.00%	0.00%	11.13%	-3.67%	3.65%	20
21	Med. & Lg. C&I	5.04%	0.00%	0.00%	0.00%	0.00%	-3.28%	0.00%	0.00%	0.00%	2.51%	-5.03%	-1.54%	21
22	Agriculture	21.60%	0.00%	0.00%	0.00%	0.00%	-1.99%	0.00%	0.00%	0.00%	12.91%	-3.92%	4.62%	22
23	Lighting	37.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	29.50%	-9.66%	13.78%	23
24	System Total	16.13%	0.00%	0.00%	0.00%	-100.00%	-3.25%	0.00%	0.00%	0.00%	6.09%	0.86%	3.54%	24

ATTACHMENT

JSP-5-2

ATTACHMENT JSP-5-2
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
COMMODITY REVENUE ALLOCATION

Commodity Revenue Allocation by Customer Classes

Line No	Customer Class	Commodity EPMC Factors (A)	Proposed Allocatrion (Dollars) (B)	Current Allocation (Dollars) (C)	Revenue Change (Dollars) (D)	Percentage Change (E)	Line No
1	Residential	43.86%	605,275,645	555,429,026	49,846,619	8.97%	1
2	Small Comm.	12.52%	172,717,648	178,881,249	(6,163,601)	-3.45%	2
3	Med. & Lg. C&I	42.72%	589,460,974	620,327,071	(30,866,097)	-4.98%	3
4	Agriculture	0.47%	6,488,557	6,750,597	(262,040)	-3.88%	4
5	Lighting	0.43%	5,984,061	6,748,588	(764,527)	-11.33%	5
6	System Total	100.00%	1,379,926,886	1,368,136,532	11,790,354	0.86%	6

ATTACHMENT JSP-5-2
SAN DIEGO GAS ELECTRIC - ELECTRIC DEPARTMENT
2008 GRC PHASE II
COMMODITY REVENUE ALLOCATION

Commodity Revenue Allocation EPMC Factors by Customer Classes

Line No	Customer Class	Marginal Capacity Revenue ($) (A)	Percentage Allocator (B)	Marginal Energy Revenue ($) (C)	Percentage Allocator (D)	Marginal Commodity Revenue ($) (E)	Commodity EPMC Allocator	Line No
1	Residential	116,013,720	41.59%	546,145,499	44.38%	662,159,219	43.86%	1
2	Small Comm.	39,154,229	14.04%	149,795,358	12.17%	188,949,586	12.52%	2
3	Med. & Lg. C&I	122,407,537	43.88%	522,450,754	42.45%	644,858,291	42.72%	3
4	Agriculture	1,340,990	0.48%	5,757,360	0.47%	7,098,349	0.47%	4
5	Lighting	15,732	0.01%	6,530,710	0.53%	6,546,441	0.43%	5
6	System Total	278,932,206	100.00%	1,230,679,681	100.00%	1,509,611,887	100.00%	6

Proposed Commodity Rates for Rate Design

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Capacity (¢/kWhr or $/kW) (B)	Marginal Cost Total (¢/kWhr or $/kW) (C)	Proposed Commodity Rate (¢/kWhr or $/kW) (D)	Adjusted For Rate Desgn (¢/kWhr or $/kW) (E)	Line No
	Residential Class (Schedules DR/DM/DS/DT)						
1	Summer Season - ¢/kWhr	7.18741	3.01946	10.20687	9.33004	9.33004	1
2	Winter Season - ¢/kWhr	7.09444	0.00000	7.09444	6.48498	6.48498	2
3	Annual - ¢/kWhr	7.14102	1.51265	8.65367	7.91026	7.91026	3
	Schedule DR-TOU						
4	Summer On-Peak - ¢/kWhr	9.21458	13.00423	22.21881	20.31008	20.31008	4
5	Summer Off-Peak - ¢/kWhr	6.54857	0.91111	7.45969	6.81885	6.81885	5
6	Winter On-Peak - ¢/kWhr	7.88998	0.00000	7.88998	7.21218	7.21218	6
7	Winter Off-Peak - ¢/kWhr	6.84219	0.00000	6.84219	6.25441	6.25441	7
8	Annual - ¢/kWhr	7.01035	1.50938	8.51973	7.78784	7.78784	8
	Schedule DR-SES						
9	Summer On-Peak - ¢/kWhr	9.14980	10.81100	19.96080	18.24604	18.24604	9
10	Summer Semi-Peak - ¢/kWhr	7.66541	0.89543	8.56084	7.82541	7.82541	10
11	Summer Off-Peak - ¢/kWhr	5.97428	0.75531	6.72959	6.15148	6.15148	11
12	Winter Semi-Peak - ¢/kWhr	7.72040	0.00000	7.72040	7.05717	7.05717	12
13	Winter Off-Peak - ¢/kWhr	6.76320	0.00000	6.76320	6.18220	6.18220	13
14	Annual - ¢/kWhr	7.14114	1.51759	8.65873	8.52836	8.52836	14
	Schedule EV-TOU						
15	Summer On-Peak - ¢/kWhr	8.72135	11.25980	19.98115	18.26465	18.26465	15
16	Summer Off-Peak - ¢/kWhr	6.68795	0.26068	6.94863	6.35170	6.35170	16
17	Summer Super Off-Peak - ¢/kWhr	4.24894	0.00000	4.24894	3.88393	3.88393	17
18	Summer On-Peak - ¢/kWhr	7.87674	0.00000	7.87674	7.20008	7.20008	18
19	Summer Off-Peak - ¢/kWhr	7.15044	0.00000	7.15044	6.53617	6.53617	19
20	Winter Super Off-Peak - ¢/kWhr	4.47313	0.00000	4.47313	4.08886	4.08886	20
21	Annual - ¢/kWhr	6.72414	1.45824	8.18238	7.47947	7.47947	21

Proposed Commodity Rates for Rate Design

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Capacity (¢/kWhr or $/kW) (B)	Marginal Cost Total (¢/kWhr or $/kW) (C)	Proposed Commodity Rate (¢/kWhr or $/kW) (D)	Adjusted For Rate Desgn (¢/kWhr or $/kW) (E)	Line No
	Schedule A						
	Summer						
22	Secondary - ¢/kWhr	7.09757	4.17628	11.27385	10.30536	10.30536	22
23	Primary - ¢/kWhr	6.97525	4.10430	11.07955	10.12775	10.12775	23
	Winter						
24	Secondary - ¢/kWhr	7.31651	0.12182	7.43833	6.79933	6.79933	24
25	Primary - ¢/kWhr	7.18934	0.11970	7.30904	6.68115	6.68115	25
26	Annual - ¢/kWhr	7.22041	0.00000	7.22041	6.60013	6.60013	26
	Schedule ATC						
27	Summer Season - ¢/kWhr	6.94536	3.29488	10.24024	9.36054	9.36054	27
28	Winter Season - ¢/kWhr	7.26210	0.06655	7.32865	6.69908	6.69908	28
29	Annual - ¢/kWhr	7.12316	1.54941	8.67256	7.92754	7.92754	29
	Schedule A-TOU						
	Summer						
30	On-Peak - ¢/kWhr	8.98810	13.26158	22.24969	20.33830	20.33830	30
31	Semi-Peak - ¢/kWhr	7.33171	0.91354	8.24525	7.53693	7.53693	31
32	Off-Peak - ¢/kWhr	5.49246	0.58356	6.07602	5.55405	5.55405	32
	Winter						
33	On-Peak - ¢/kWhr	8.78953	0.15592	8.94545	8.17698	8.17698	33
34	Semi-Peak - ¢/kWhr	8.10149	0.23752	8.33901	7.62264	7.62264	34
35	Off-Peak - ¢/kWhr	6.03990	0.00000	6.03990	5.52104	5.52104	35
36	Annual - ¢/kWhr	7.07119	1.79456	8.86575	8.10413	8.10413	36
	Schedule AD						
	Maximum Demand: Summer						
37	Secondary - $/kW/month		10.11	10.11	9.24	9.24	37
38	Primary - $/kW/month		9.97	9.97	9.11	9.11	38
	Maximum Demand: Summer						
39	Secondary - $/kW/month		0.30	0.30	0.28	0.28	39
40	Primary - $/kW/month		0.30	0.30	0.27	0.27	40
	Summer Energy						
41	Secondary - ¢/kWhr	7.24171		7.24171	6.61960	6.61960	41
42	Primary - ¢/kWhr	7.11691		7.11691	6.50552	6.50552	42
	Winter Energy						
43	Secondary - ¢/kWhr	7.46179		7.46179	6.82078	6.82078	43
44	Primary - ¢/kWhr	7.33210		7.33210	6.70223	6.70223	44
45	Annual - ¢/kWhr	7.36619		7.36619	6.73339	6.73339	45

Proposed Commodity Rates for Rate Design

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Capacity (¢/kWhr or $/kW) (B)	Marginal Cost Total (¢/kWhr or $/kW) (C)	Proposed Commodity Rate (¢/kWhr or $/kW) (D)	Adjusted For Rate Desgn (¢/kWhr or $/kW) (E)	Line No
	Schedule A6-TOU Capacity						
	Maximum On-Peak Demand: Summer						
47	Primary - $/kW/month		17.08	17.08	15.61	15.61	47
48	Primary Substation - $/kW/month		17.08	17.08	15.61	15.61	48
49	Transmission - $/kW/month		16.66	16.66	15.23	15.23	49
	Maximum On-Peak Demand: Winter						
50	Primary - $/kW/month		0.11	0.11	0.10	0.10	50
51	Primary Substation - $/kW/month		0.11	0.11	0.10	0.10	51
52	Transmission - $/kW/month		0.11	0.11	0.10	0.10	52
	Schedule PA-T-1 Capacity						
	Demand: Summer						
	Option C						
53	Secondary - $/kW/month		13.78	13.78	12.60	12.60	53
54	Primary - $/kW/month		13.59	13.59	12.42	12.42	54
55	Transmission - $/kW/month		13.26	13.26	12.12	12.12	55
	Option D						
56	Secondary - $/kW/month		14.37	14.37	13.14	13.14	56
57	Primary - $/kW/month		14.18	14.18	12.96	12.96	57
58	Transmission - $/kW/month		13.83	13.83	12.64	12.64	58
	Option E						
59	Secondary - $/kW/month		14.08	14.08	12.87	12.87	59
60	Primary - $/kW/month		13.88	13.88	12.69	12.69	60
61	Transmission - $/kW/month		13.54	13.54	12.38	12.38	61
	Option F						
62	Secondary - $/kW/month		13.47	13.47	12.31	12.31	62
63	Primary - $/kW/month		13.29	13.29	12.14	12.14	63
64	Transmission - $/kW/month		12.96	12.96	11.85	11.85	64
	Demand: Winter						
	Option C						
65	Secondary - $/kW/month		0.43	0.43	0.39	0.39	65
66	Primary - $/kW/month		0.43	0.43	0.39	0.39	66
67	Transmission - $/kW/month		0.42	0.42	0.38	0.38	67
	Option D						
68	Secondary - $/kW/month		0.46	0.46	0.42	0.42	68
69	Primary - $/kW/month		0.45	0.45	0.42	0.42	69
70	Transmission - $/kW/month		0.44	0.44	0.40	0.40	70
	Option E						
71	Secondary - $/kW/month		0.45	0.45	0.41	0.41	71
72	Primary - $/kW/month		0.44	0.44	0.41	0.41	72
73	Transmission - $/kW/month		0.43	0.43	0.40	0.40	73
	Option F						
74	Secondary - $/kW/month		0.46	0.46	0.42	0.42	74
75	Primary - $/kW/month		0.45	0.45	0.42	0.42	75
76	Transmission - $/kW/month		0.44	0.44	0.40	0.40	76

Proposed Commodity Rates for Rate Design

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Capacity (¢/kWhr or $/kW) (B)	Marginal Cost Total (¢/kWhr or $/kW) (C)	Proposed Commodity Rate (¢/kWhr or $/kW) (D)	Adjusted For Rate Desgn (¢/kWhr or $/kW) (E)	Line No
	Schedules AL-TOU / AY-TOU Capacity						
	Demand: Summer						
77	Secondary - $/kW/month		13.47	13.47	12.31	12.31	77
78	Primary - $/kW/month		13.29	13.29	12.14	12.14	78
79	Secondary Substation - $/kW/month		13.47	13.47	12.31	12.31	79
80	Primary Substation - $/kW/month		13.29	13.29	12.14	12.14	80
81	Transmission - $/kW/month		12.96	12.96	11.85	11.85	81
	Demand: Winter						
82	Secondary - $/kW/month		0.43	0.43	0.39	0.39	82
83	Primary - $/kW/month		0.43	0.43	0.39	0.39	83
84	Secondary Substation - $/kW/month		0.43	0.43	0.39	0.39	84
85	Primary Substation - $/kW/month		0.43	0.43	0.39	0.39	85
86	Transmission - $/kW/month		0.42	0.42	0.38	0.38	86

Proposed Commodity Rates for Rate Design

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Capacity (¢/kWhr or $/kW) (B)	Marginal Cost Total (¢/kWhr or $/kW) (C)	Proposed Commodity Rate (¢/kWhr or $/kW) (D)	Adjusted For Rate Desgn (¢/kWhr or $/kW) (E)	Line No
	Commercial/Industrial TOU Energy (Schedules AL-TOU, AY-TOU, A6-TOU, PA-T-1)						
	Summer On-Peak						
87	Secondary - ¢/kWhr	8.94390		8.94390	8.17556	8.17556	87
88	Primary - ¢/kWhr	8.80663		8.80663	8.05009	8.05009	88
89	Secondary Substation - ¢/kWhr	8.94390		8.94390	8.17556	8.17556	89
90	Primary Substation - ¢/kWhr	8.80663		8.80663	8.05009	8.05009	90
91	Transmission - ¢/kWhr	8.65528		8.65528	7.91174	7.91174	91
	Summer Semi-Peak						
92	Secondary - ¢/kWhr	7.24708		7.24708	6.62451	6.62451	92
93	Primary - ¢/kWhr	7.13237		7.13237	6.51965	6.51965	93
94	Secondary Substation - ¢/kWhr	7.24708		7.24708	6.62451	6.62451	94
95	Primary Substation - ¢/kWhr	7.13237		7.13237	6.51965	6.51965	95
96	Transmission - ¢/kWhr	7.01697		7.01697	6.41417	6.41417	96
	Summer Off-Peak						
97	Secondary - ¢/kWhr	5.45538		5.45538	4.98673	4.98673	97
98	Primary - ¢/kWhr	5.35364		5.35364	4.89373	4.89373	98
99	Secondary Substation - ¢/kWhr	5.45538		5.45538	4.98673	4.98673	99
100	Primary Substation - ¢/kWhr	5.35364		5.35364	4.89373	4.89373	100
101	Transmission - ¢/kWhr	5.28297		5.28297	4.82913	4.82913	101
	Winter On-Peak						
102	Secondary - ¢/kWhr	8.78751		8.78751	8.03261	8.03261	102
103	Primary - ¢/kWhr	8.65534		8.65534	7.91179	7.91179	103
104	Secondary Substation - ¢/kWhr	8.78751		8.78751	8.03261	8.03261	104
105	Primary Substation - ¢/kWhr	8.65534		8.65534	7.91179	7.91179	105
106	Transmission - ¢/kWhr	8.50104		8.50104	7.77075	7.77075	106
	Winter Semi-Peak						
107	Secondary - ¢/kWhr	8.07900		8.07900	7.38497	7.38497	107
108	Primary - ¢/kWhr	7.95003		7.95003	7.26707	7.26707	108
109	Secondary Substation - ¢/kWhr	8.07900		8.07900	7.38497	7.38497	109
110	Primary Substation - ¢/kWhr	7.95003		7.95003	7.26707	7.26707	110
111	Transmission - ¢/kWhr	7.82351		7.82351	7.15142	7.15142	111
	Winter Off-Peak						
112	Secondary - ¢/kWhr	6.02015		6.02015	5.50298	5.50298	112
113	Primary - ¢/kWhr	5.90724		5.90724	5.39977	5.39977	113
114	Secondary Substation - ¢/kWhr	6.02015		6.02015	5.50298	5.50298	114
115	Primary Substation - ¢/kWhr	5.90724		5.90724	5.39977	5.39977	115
116	Transmission - ¢/kWhr	5.82966		5.82966	5.32886	5.32886	116
117	Annual - ¢/kWhr	7.06622		7.06622	6.45919	6.45919	117

Proposed Commodity Rates for Rate Design

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Capacity (¢/kWhr or $/kW) (B)	Marginal Cost Total (¢/kWhr or $/kW) (C)	Proposed Commodity Rate (¢/kWhr or $/kW) (D)	Adjusted For Rate Desgn (¢/kWhr or $/kW) (E)	Line No
	Agriculture						
118	Summer Season - ¢/kWhr	6.77688	3.01111	9.78799	8.94714	8.94714	118
119	Winter Season - ¢/kWhr	7.16931	0.11964	7.28895	6.66278	6.66278	119
120	Annual - ¢/kWhr	6.96536	1.62235	8.58772	7.84998	7.84998	120
	Lighting						
121	Annual - ¢/kWhr	5.97274	0.01439	5.98712	5.47279	5.47279	121

ATTACHMENT

JSP-5-3

ATTACHMENT JSP-5-3
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008GRC PHASE II
DISTRIBUTION REVENUE ALLOCATION

Proposed Allocation of Distribution Revenue Requirement

Line No	Customer Class	Distribution EPMC Factors (%) (A)	Non Marginal Revenue ($ x 1000) (B)	Allocation Marginal Revenue ($ x 1000) (C)	Proposed Allocation ($ x 1000) (D)	TY 2008 Sales (GWhrs) (E)	Proposed Avg Rate (¢/kWhr) (F)	Current Revenue ($ x 1000) (G)	Current Avg Rate (¢/kWhr) (H)	Percentage Change (%) (I)	Line No
1	Residential	57.0%		564,963	564,962.651	7,673.0	7.363	479,922	6.255	17.7%	1
2	Small Commercial	12.9%		128,127	128,127.269	2,100.9	6.099	99,402	4.731	28.9%	2
3	Commercial Industrial	28.8%	4,576	285,577	290,152.342	9,944.9	2.918	269,048	2.705	7.8%	3
4	Agricultural	0.5%		5,071	5,070.573	90.1	5.629	4,248	4.717	19.4%	4
5	Lighting	0.7%	4,115	6,682	10,797.292	109.5	9.861	7,899	7.213	36.7%	5
6	System	100.0%	8,691	990,419	999,110.127	19,918.4	5.016	860,519	4.320	16.1%	6

Distribution Revenue Requirement:	1,000,558
Non Marginal Rev Req Components:	
Lighting Facilities Charges:	4,115
Standby Revenue:	2,301
Distance Adjustment Fees:	2,275

ATTACHMENT JSP-5-3
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
DISTRIBUTION REVENUE ALLOCATION

Distribution EPMC Factors

Line No	Customer Class	Customer LRMC Rev ($ x 1000) (A)	Percentage Allocator (%) (B)	Local Distribution LRMC Rev ($ x 1000) (C)	Substation LRMC Rev ($ x 1000) (D)	Local and Substation Subtotal ($ x 1000) (E)	Percentage Allocator (%) (F)	Total Distribution LRMC Rev ($ x 1000) (G)	Distribution EPMC Factor (%) (H)	Line No
1	Residential	151,495	67.1%	171,391	31,036	202,427	51.3%	353,921	57.0%	1
2	Small Commercial	38,712	17.1%	31,685	9,869	41,553	10.5%	80,265	12.9%	2
3	Commercial Industrial	31,161	13.8%	113,605	34,133	147,738	37.4%	178,900	28.8%	3
4	Agricultural	1,171	0.5%	1,605	401	2,006	0.5%	3,176	0.5%	4
5	Lighting	3,360	1.5%	725	101	826	0.2%	4,186	0.7%	5
6	System	225,899	100.0%	319,011	75,539	394,550	100.0%	620,449	100.0%	6

ATTACHMENT JSP-5-3
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
DISTRIBUTION REVENUE ALLOCATION

Distribution Marginal Cost Revenue

Line No	Customer Class	Secondary (A)	Primary (B)	Secondary Substation (C)	Primary Substation (D)	Total (F)	Line No
	Customer LRMC ($ x 1000):						
1	Residential	151,495				151,495	1
2	Small Commercial	38,712				38,712	2
3	Commercial Industrial	30,780	338	8	36	31,161	3
4	Agricultural	1,171				1,171	4
5	Lighting	3,360				3,360	5
6	System	225,517	338	8	36	225,899	6
	Feeders & Local Distribution Demand LRMC ($ x 1000):						
7	Residential	171,391				171,391	7
8	Small Commercial	31,685				31,685	8
9	Commercial Industrial	89,680	13,220	1,860	8,846	113,605	9
10	Agricultural	1,605				1,605	10
11	Lighting	725				725	11
12	System	295,085	13,220	1,860	8,846	319,011	12
	Substation Demand LRMC ($ x 1000):						
13	Residential	31,036				31,036	13
14	Small Commercial	9,869				9,869	14
15	Commercial Industrial	26,944	3,972	559	2,658	34,133	15
16	Agricultural	401				401	16
17	Lighting	101				101	17
18	System	68,351	3,972	559	2,658	75,539	18

Distribution Marginal Cost Determinants

Line No	Customer Class	Secondary (A)	Primary (B)	Secondary Substation (C)	Primary Substation (D)	Total (F)	Line No
	Customer LRMC (Average Customers per month):						
1	Residential	1,233,646				1,233,646	1
2	Small Commercial	120,401	121			120,521	2
3	Commercial Industrial	21,967	324	7	29	22,327	3
4	Agricultural	3,465				3,465	4
5	Lighting	6,458				6,458	5
6	System	1,385,937	445	7	29	1,386,417	6
	Feeders & Local Distribution Demand LRMC (MW):						
7	Residential	3,891				3,891	7
8	Small Commercial	719				719	8
9	Commercial Industrial	2,036	300	42	201	2,579	9
10	Agricultural	36				36	10
11	Lighting	16				16	11
	Substation Demand LRMC (MW):						
12	Residential	1,679				1,679	12
13	Small Commercial	534				534	13
14	Commercial Industrial	1,458	215	30	144	1,847	14
15	Agricultural	22				22	15
16	Lighting	5				5	16

ATTACHMENT JSP-5-3
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
DISTRIBUTION REVENUE ALLOCATION

Distribution Marginal Cost Summary

Line No	Customer Class	Secondary (A)	Primary (B)	Secondary Substation (C)	Primary Substation (D)	Total (F)	Line No
	Customer LRMC ($/Customer/Yr) :						
1	Residential	122.80				122.80	1
2	Small Commercial	321.53				321.20	2
3	Commercial Industrial	1,401.16	1,041.13	1,222.17	1,233.56	1,395.65	3
4	Agricultural	337.87				337.87	4
5	Lighting	520.28				520.28	5
6	System	157.01	1,041.13	1,222.17	1,233.56	157.32	6
	Feeders & Local Distribution Demand LRMC ($/kW/Yr) :						
7	All Classes	44.05	44.05	44.05	44.05	44.05	7
	Substation Demand LRMC ($/kW/Yr) :						
8	All Classes	18.48	18.48	18.48	18.48	18.48	8