ALJ/BDP/f.s *

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APR 23 1992

Decision 92-04-061 April 22, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company: (1) for Authority to Decrease its Electric Rates Effective May 1, 1992; and (2) for a Commission Order Finding the Company's Gas and Electric Operations and Expenses Reasonable for Applicable Record Periods. (U 902-E)	Application 91-09-059 (Filed September 30, 1991)

(See Appendix B for appearances.)

INTERIM OPINION

Summary

The Commission adopts the joint recommendation of the active parties in San Diego Gas & Electric Company's (SDG&E) 1992 Energy Cost Adjustment Clause (ECAC) proceeding. The joint recommendation results in a $66.3 million rate decrease effective May 1, 1992 instead of the $15.9 million rate decrease originally requested by SDG&E.

Background

On September 30, 1991, SDG&E filed its application in this proceeding requesting a $15.9 million rate decrease effective May 1, 1992, a 1.2% decrease from the presently effective rates. Specifically, SDG&E requested to: (1) decrease electric rates under the ECAC by approximately $61.5 million; (2) increase electric rates under the Electric Revenue Adjustment Mechanism (ERAM) by approximately $55.2 million; (3) decrease base rates by approximately $3.5 million to account for increased sales; (4) decrease electric rates by $13.0 million to terminate the Major Additions Adjustment Clause (MAAC) Post-Commercial Operating Date (Post-COD) balancing rate of 0.089 cents/kWh; (5) increase electric rates by approximately $10.2 million for expanded demand-side management (DSM) programs as a result of amortizing the projected undercollection in the DSM Collaborative Balancing Account; (6) decrease electric rates by approximately $5.6 million under the Low Income Ratepayer Assistance (LIRA) Program; (7) increase electric rates by $2.3 million under the 1990 and 1991 DSM Reward Mechanisms; (8) revise the incremental energy rate (IER) used to determine energy payments to as-available qualifying facilities (QFs) during the forecast period from the current yearly average IER of 9,600 Btu/kWh to 8,451 Btu/kWh; (9) revise the avoided operation & maintenance adder (O&M adder) used to determine energy payments to QFs during the forecast period from 2.5 mills/kWh to 0.72 mills/kWh; (10) utilize an energy reliability index (ERI) of 1.0; (11) revise the avoided capacity costs used to determine capacity payments to QFs during the forecast period from $70.94 to $73.82/kW-yr; and (12) transfer consideration of SDG&E's request for review and approval of changes associated with DSM from this ECAC proceeding to SDG&E's Test Year 1993 General Rate Case (GRC) Application (A.) 91-11-024, filed on November 15, 1991. Thus, SDG&E requested a net rate decrease of $15.9 million.

By Commission order dated August 8, 1990, the Annual Energy Rate (AER) mechanism was suspended (I.90-08-006). Accordingly, SDG&E proposed no AER rate and assumed that 100% of the forecast cost of all energy and fuel-related expenses for the 12 months beginning May 1, 1992 would be recovered through ECAC rates.

A duly noticed public workshop was held in this proceeding on October 21, 1991. A prehearing conference was held on December 13, 1991, in San Diego. Evidentiary hearings were held on January 13, 14, and 22, 1992, in San Diego.

The parties active in the forecast phase proceedings include SDG&E, the Division of Ratepayer Advocates (DRA), the City of San Diego (the City), Utility Consumers' Action Network (UCAN), California Cogeneration Council (CCC), Kelco Division of Merck & Co., Inc. (Kelco), and the United States Department of the Navy and other Federal Executive Agencies (FEA).

Discussion

On January 22, 1992, the active parties to this proceeding reached agreement on the contested forecast phase issues. The parties executed a joint agreement which was received into evidence as Exhibit 8.

The positions of the parties and the events leading to the execution of the joint agreement are discussed below.

SDG&E

At the workshop held on October 21, 1991, SDG&E presented revised values for its fuel and purchased power expense forecast ($464.7 million) and IER (8,203 Btu/kWh).

On December 31, 1991, SDG&E distributed an updated fuel and purchased power expense forecast and an updated revenue requirement reflecting the Commission's findings in the Southern California Gas Company/SDG&E Biennial Cost Allocation Proceeding (BCAP)[1] and the SDG&E 1992 modified attrition proceeding.[2]

Specifically, as a result of this update, SDG&E adjusted its original ECAC application to request an $18.1 million electric rate decrease as follows: (1) a $23.6 million decrease to recover fuel-related expenses and amortize the ECAC and ERAM balancing accounts; (2) a $10.4 million increase to amortize the projected undercollection in the DSM Collaborative Balancing Account; (3) an $11.2 million increase to adjust for sales; and (4) a $5.4 million decrease to recover revenue for LIRA. Additionally, SDG&E revised its fuel and purchased power energy expenses from $464.7 million to

1 Decision (D.) 91-12-075 (December 20, 1991).

2 D.91-12-074 (December 20, 1991).

$474.8 million, its IER from 8,203 Btu/kWh to 8,044 Btu/kWh, and its O&M adder from 0.72 mills/kWh to 0.8 mills/kWh. On January 6, 1992, SDG&E distributed the updated revenue allocation and rate design associated with the December 31, 1991 update.

On January 15, 1992, SDG&E formally moved to transfer consideration of the rate changes associated with DSM from this ECAC proceeding to SDG&E's Test Year 1993 GRC. SDG&E's motion to transfer is unopposed.

On January 17, 1992, SDG&E distributed revised testimony addressing its electric revenue requirement and rate calculations as agreed to by the active parties during off-the-record discussions held at the January 14, 1992 hearing (Exhibit 7). Specifically, Exhibit 7 proposes an electric rate decrease of $66.3 million effective May 1, 1992 which reflects the joint recommendation of the active parties. Exhibit 7 does not include revenue changes associated with the DSM Collaborative Balancing Account on the assumption that SDG&E's motion to transfer consideration of DSM-related rate changes to SDG&E's Test Year 1993 GRC will be granted and those rate increases will not be considered in this proceeding.

<u>DRA</u>

On December 6, 1991, DRA distributed its Report on the Forecast Phase of this proceeding. DRA recommended an electric rate decrease of $69.5 million, or 5.1%, reflecting: (1) a fuel and purchased power expense forecast of $449.9 million; (2) an IER of 8,229 Btu/kWh; and (3) and O&M adder of 1.0 mills/kWh as determined using the SDG&E methodology. On January 10, 1992, DRA updated its fuel and purchased power expense forecast to $461.8 million and proposed an IER of 8,322 Btu/kWh.

<u>CCC/Kelco</u>

On December 20, 1991, CCC/Kelco distributed their prepared testimony requesting an IER of 9,262 Btu/kWh and an O&M adder of 4.8 mills/kWh. Subsequently, on January 7, 1992, CCC/Kelco distributed updated testimony reflecting the BCAP decision and proposed an IER of 9,118 Btu/kWh. The O&M adder remained unchanged. On January 13, 1992, CCC/Kelco updated their testimony to correct an error in their January 7, 1992 testimony. As a result, CCC/Kelco's final proposed IER was 9,228 Btu/kWh.

City of San Diego

The City was an active participant in the workshop, hearing, and negotiating process that lead to the joint recommendation, but did not file any testimony in this proceeding.

UCAN

On January 6, 1992, UCAN distributed its testimony in this proceeding proposing four changes to the costing determinants used to calculate marginal cost revenue responsibility. UCAN proposed to: (1) reduce residential coincident demand costs by using the higher load factor contained in the load research information filed in SDG&E's Test Year 1993 GRC; (2) reduce the noncoincident part of transmission and distribution demand costs to residential customers by using new load forecasts to demonstrate that the substation peak demand between transmission and primary distribution is nearly 14% below SDG&E's value; (3) correct an apparent error in the Rate A noncoincident demand determination; and (4) use four years of data to calculate demand determinants for the sum of Rates AD and AL-TOU, rather than using data from only a single year.

FEA

On December 23, 1991, FEA distributed testimony in which it addressed the determination of marginal costs, revenue allocation, and rate design for Rate Schedules AL-TOU and A6-TOU. Specifically, FEA: (1) claimed that SDG&E selectively adjusted demand data for the agricultural class by using six years of load data, rather than using the four-year average for the agriculture class; (2) corrected an SDG&E typographical error in the winter off-peak marginal energy cost to correctly read 2.48 cents/kWh and applied this value to the revenue allocation schedules; (3) disagreed with SDG&E's proposal to cap the residential class to prevent that class from receiving a small rate increase since the increase would not produce a disruptive increase to the class; (4) recommended that SDG&E implement the rate decrease assigned to the large TOU class by a uniform percentage reduction in all energy charges; and (5) correctly pointed out that SDG&E had overstated the revenue impact of the average rate limiter on proposed rates.

Summary of Joint Recommendation

On January 22, 1992, all the active parties executed a Joint Recommendation.[3] This joint recommendation represents a compromise of all the issues outstanding among all parties in the forecast phase and results in a $66.3 million decrease in electric rates.

Specifically, the joint recommendation sets forth the parties' agreement to: (1) transfer review and consideration of approximately $12.6 million of DSM-related changes to SDG&E's Test Year 1993 GRC; (2) accept a $6.3 million decrease to amortize the projected overcollection in the MAAC Post-COD balancing account as of April 30, 1992; (3) accept a $19.0 million decrease to amortize proceeds from the Heber Binary Project sale; (4) accept a $7.2 million decrease to reflect the interdepartmental component of refunds received from Southern California Gas Company and El Paso Natural Gas Company; (5) accept a $5.8 million decrease in forecast phase rates reflecting a reversal of the July 1991 debit entry to the ECAC balancing account associated with the Century Power settlement proceeds (the parties agreed that this issue would be addressed in the reasonableness phase of this proceeding); (6) accept an $11.2 million increase to adjust for sales;

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3 Exhibit 8. The joint recommendation was executed by SDG&E, DRA, UCAN, the City, CCC, Kelco, and FEA.

(7) accept a fuel and purchased power energy forecast of $464.3 million; (8) accept an average IER of 8,730 Btu/kWh; (9) accept an O&M adder of 2.5 mills/kWh; (10) accept an ERI of 1.0; (11) accept an as-available capacity payment of $73.82/kW-yr; (12) adopt the unit marginal energy, demand, and customer costs specified in Appendix C of the joint recommendation for revenue allocation purposes; (13) adopt the revenue allocation determinants, and transmission and distribution weighting factors specified in Appendix D of the joint recommendation; (14) accept the revenue allocation specified in Appendix E of the joint recommendation; and (15) accept the rates set forth in Appendix F to the joint recommendation. Balancing account forecasts include recorded data through December 31, 1991.

In summary, the joint recommendation represents a compromise among all the active parties that was arrived at during a series of meetings and workshops that involved extensive negotiations. The joint recommendation results in a $66.3 million rate decrease effective May 1, 1992, instead of the $15.9 million rate decrease originally requested by SDG&E. Accordingly, the parties believe the joint recommendation is reasonable and in the public interest.

We agree. The settlement agreement should be adopted because the recommended results are within a reasonable range for revenue requirements, IER, O&M adder, and ERI calculations.

Comments on ALJ's Proposed Decision

The ALJ's proposed decision was filed and mailed to the parties on March 20, 1992. DRA filed comments on the proposed decision in which DRA points out certain typographical and clerical errors. After reviewing DRA's comments, we have made the appropriate corrections to the decision.

Other Corrections

The proposed decision adopts a joint agreement between active parties in this proceeding which requires SDG&E to reduce its rates by $66.3 million. However, the Commission has since discovered a $4.146 million error in SDG&E's Authorized Base Rate Revenues (ABRR) adopted in D.91-12-074. The Commission has modified D.91-12-074 by D.92-04-016. D.92-04-016, among other things, requires SDG&E to reflect the correction to its ABRR in the rates being adopted in this proceeding. Specifically, Ordering Paragraph 6 of D.92-04-016 states that "SDG&E shall reflect a reduction of $4,146,000 in ABRR for its electric department when it files rates to implement the Commission's final decision in Application 91-09-059. Such reduction shall be effective May 1, 1992."

Accordingly, we will modify SDG&E's rates to reflect a reduction of $4,146,000 in ABRR. The correct ABRR being adopted are $888,350,000.

In addition, the Commission has discovered that the DSM offset revenues adopted in the joint agreement were understated by approximately $7,000. This $7,000 adjustment is needed to account for the change in Average Rate Limiter from $0.35 to $5.00 (Joint Agreement, Sec. VIII B). The correct DSM offset revenues being adopted are $21,376,000.

Based on the above-mentioned corrections, the total reduction SDG&E's rates will be $70.4 million.

<u>Arroyo's Petition for Intervention</u>

On April 10, 1992, Arroyo Management Company (Arroyo) filed a petition to intervene and file comments on the ALJ's proposed decision.

Arroyo is the general partner of Arroyo Energy which has a Power Purchase Agreement (PPA) with SDG&E. The PPA was approved by the Commission in D.91-09-079. Arroyo contends that neither it nor Arroyo Energy received SDG&E's notice of filing of this application and that it learned about the ALJ proposed order in casual conversation on or about March 23, 1992.

Arroyo's specific concern with the ALJ's proposed decision is regarding the reduction of SDG&E's IER from 9,600 Btu/kWh to 8,730/kWh. Arroyo is opposed to this reduction in IER and contends that it is unfair.

We will deny Arroyo's petition. Notice of filing of A.91-09-059 was published in various newspapers in SDG&E's service territory as well as the Commission's Daily Calendar. SDG&E's notice of filing complied with the Commission's Rules of Practice and Procedure.

In addition, the PPA which was approved by D.91-09-079 is for a facility which is not expected to come on line until May 1994. Arroyo will have an opportunity to raise the issue of SDG&E's IER before 1994 in a subsequent ECAC proceeding.

While we deny Arroyo's petition to intervene, we will require SDG&E to serve a copy of its future ECAC applications on entities with which it has PPAs or other contracts which could be affected by the outcome of the ECAC proceeding.

Finding of Fact

The joint recommendation is the result of extensive negotiations held in public, and it results in a $66.3 million decrease instead of the $15.9 million decrease originally requested by SDG&E.

Conclusions of Law

1. The joint agreement received into evidence as Exhibit 8 is a satisfactory resolution of the issues in the forecast phase of this proceeding.

2. The joint agreement is reasonable, in the public interest, and it should be adopted.

INTERIM ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company's (SDG&E) rates as a result of this Energy Cost Adjustment Clause (ECAC) proceeding shall be reduced by $70.4 million to reflect the joint settlement agreement, Exhibit 8, which is adopted with the modifications specified in the body of this order.

2. SDG&E's motion to transfer review and consideration of approximately $12.6 million of Demand-Side Management-related rate changes from the ECAC proceeding to SDG&E's Test Year 1993 General Rate Case is granted.

3. SDG&E is authorized to file the rates appended to this order as Appendix A.

4. The rate filing shall comply with General Order 96-A.

5. The new rates shall become effective on May 1, 1992, in concert with the rate design changes scheduled in SDG&E's 1992 rate design window proceeding (Application 87-12-003).

6. This proceeding remains open for hearings on the reasonableness phase of this proceeding.

This order is effective today.

Dated April 22, 1992, at San Francisco, California.

DANIEL Wm. FESSLER
President
JOHN B. OHANIAN
PATRICIA M. ECKERT
NORMAN D. SHUMWAY
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

PB

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT

REVENUE REQUIREMENT, ALLOCATION AND RATE DESIGN

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED ENERGY COSTS
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE	ITEM		COST M$
1	Purchased Energy		329,340.0
2	Nuclear Generation		27,632.0
3	Natural Gas		105,050.0
4	Oil		2,298.0
5			
6			
			===========
7	Subtotal Lines 1-6		464,320.0
8			
9	Fuel Oil Inventory Carrying Costs		931.5
10	Wheeling Expenses		8,872.7
11			
12	Net Losses on Sale of Fuel Oil		0.0
			===========
13	Subtotal Lines 7-12		474,124.2
14			
15	Plus EEDA expences		(924.0)
			===========
16	Total		473,200.2
17	Allocated Amount for ECAC Recovery: Line 16 x Allocation Expense Ratio of	0.957236	452,964.3
17a	ECAC BALANCE AS OF 4/30/92		(41,661.9)
			===========
17b	SUBTOTAL		411,302.4
18	Adopted ECAC Rate (Line 17b / 14,495.7 MM KWHR)		2.837 cents/kwhr
19	Adopted ECAC Rate Adjusted for FF&U (Line 18 x 1.0130)		2.874 cents/kwhr
20	Current ECAC Rate		3.441 cents/kwhr
21	Change to ECAC Rate		-0.567 cents/kwhr

SAN DIEGO GAS & ELECTRIC COMPANY
Electric Department
Summary of Changes in Revenue Requirements
Forecast Period: May 1, 1992 Through April 30, 1993

Line No.	REVENUE ELEMENT:	PRESENT RATE REVENUES	REVENUE CHANGES	ADOPTED REVENUE	Line No.
		|--------- 000'S OF $		----------------|	
1		(A)	(B)	(C)	1
2	BASE RATE REVENUES:				2
3	- (1/1/92) Margin	$892,496	$0	$892,496	3
4	- D.92-04-016 modification		($4,146)	($4,146)	4
5					5
6	- Sales Adjustment	($11,181)	$11,181	$0	6
7					7
8	Total Base Rate Revenues	$881,315	$7,035	$888,350	8
9					9
10	MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC):				10
11	- SONGS 2&3 pre-COO amortization	$0	$0	$0	11
12	- SONGS 2&3 post-COO amortization	$13,026	($13,026)	$0	12
13					13
14	Total MAAC	$13,026	($13,026)	$0	14
15					15
16	ECAC,ERAM,AER:				16
17	- Energy Cost Adjustement Clause (ECAC) Balancing	$0	($42,609)	($42,609)	17
18	- Energy Cost Adjustment Clause (ECAC) Offset	$503,676	($40,247)	$463,429	18
19	- Annual Energy Rate (AER)	$0	$0	$0	19
20	- Electric Rev. Adj. Mechanism (ERAM) Balancing	($4,538)	$23,717	$19,179	20
21					21
22	Total ECAC,ERAM,AER	$499,138	($59,139)	$439,999	22
23					23
24	MISCELLANEOUS OFFSETS:				24
25	- Low-Income Rate Assistance (LIRA)	$1,847	($5,313)	($3,466)	25
26	- Demand Side Management (DSM) Offset	$21,369	$7	$21,376 (1)	26
27					27
28					28
29	Total Miscellaneous Offsets	$23,216	($5,306)	$17,910	29
30					30
31	SUBTOTAL - Revenue from retail sales	$1,416,695	($70,436)	$1,346,259	31
32					32
33					33
34					34
35	Miscellaneous Revenues	$17,005	$0	$17,005	35
36	Non-Jurisdictional Revenues	$1,445	$0	$1,445	36
37					37
38	TOTALS FOR ELECTRIC DEPARTMENT	$1,435,145	($70,436)	$1,364,709	38

Notes:
1. The change in the Demand Side Management Revenue is due to the change in the Average Rate Limiter.

APPENDIX A
TABLE 3
SHEET 1 OF 1
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED UNIT MARGINAL COST
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993
UNIT MARGINAL ENERGY COSTS

	SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	SUMMER SUPER-OFF PEAK	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	WINTER SUPER-OFF PEAK	ANNUAL (G)
Hours	760	978	1151	760	456	1977	1612	1066	8760
Avoided Cost Developed from ELFIN ($/KWH) - Includes 0.0025 O&M Adder									
	0.0312	0.0308	0.0277	0.0251	0.0349	0.0338	0.0297	0.0254	0.03000
			0.0267				0.0280		
TAX FACTOR	1.0093	1.0093	1.0093		1.0093	1.0093	1.0093		
Energy Loss Factors									
Trans	1.0306	1.027	1.019		1.0306	1.0268	1.0189		
Primary	1.0415	1.0366	1.0258		1.0416	1.0362	1.0256		
Second	1.0263	1.0232	1.0163		1.0263	1.023	1.0163		
Unit Marginal Energy Cost									
Trans	0.0325	0.0319	0.0274		0.0363	0.0350	0.0288		
Primary	0.0338	0.0331	0.0281		0.0378	0.0363	0.0295		
Second	0.0347	0.0339	0.0286		0.0388	0.0371	0.0300		

UNIT MARGINAL CUSTOMER COSTS
($/CUSTOMER/YEAR)

CUSTOMER GROUP	
Residential	108.37
Commercial/Industrial	
General Service (A)	175.04
GS-Demand Metered 20kW (AD)	578.38
Large TOU	2,741.72
Total Commercial/Industrial	
Agriculture	620.22
Lighting	0.008946 ($/KWHR)

UNIT MARGINAL DEMAND COSTS
($/KW/YEAR)

DEMAND COMPONENT	TRANSMISSION	PRIMARY	SECONDARY
Generation	87.51	91.14	93.54
Transmission	26.21	27.29	28.02
Distribution	0.00	103.11	105.82

APPENDIX A
TABLE 4
SHEET 1 OF 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL DEMAND COST REVENUE
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	GENERATION ($000'S) (A)	TRANSMISSION ($000'S) (B)	DISTRIBUTION ($000'S) (C)	TOTAL ($000'S) (D)	LINE NO.
1	Residential	96,717	41,895	259,393	393,006	1
2						2
3	Commercial/Industrial					3
4	General Service (A)	39,947	14,483	74,394	128,823	4
5	GS-Demand Metered 20kW (AD)	33,225	12,165	63,263	108,652	5
6	Large TOU	100,360	33,105	149,010	282,474	6
7	Total Commercial/Industrial	173,531	59,752	286,666	519,950	7
8						8
9	Agriculture	2,157	958	6,059	9,174	9
10						10
11	Lighting	624	263	1,588	2,474	11
12	-------------------	------------	------------	------------	------------	12
13	Total	273,029	102,866	553,706	929,603	13

Column Calculations:

(D) col A + col B + col C

Notes:
1. Presents the functionalization of the demand cost component of marginal cost revenue by customer group.

APPENDIX A
TABLE 4
SHEET 3 OF 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
TRANSMISSION DEMAND COST REVENUE ($000's)
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	TRANSM (A)	PRIM (B)	SEC (C)	TOTAL (D)	LINE NO.
1	Residential	0	163	41,732	41,895	1
2						2
3	Commercial/Industrial					3
4	General Service (A)	0	10	14,472	14,483	4
5	GS-Demand Metered 20kW (AD)	0	341	11,824	12,165	5
6	Large TOU	535	15,545	17,025	33,105	6
7	Total Commercial/Industrial	535	15,896	43,322	59,7[illegible]2	7
8						8
9	Agriculture	0	4	954	958	9
10						10
11	Lighting	0	0	263	263	11
12						12
13	Total	535	16,063	86,270	102,8[illegible]8	13

LINE NO.		TRANSM (E)	PRIM (F)	SEC (G)	LINE NO.
14					14
15					15
18					18
19	UNIT MARGINAL TRANSMISSION	26.21	27.29	28.02	19
20	DEMAND COST ($/KW/YR)				20
21					21

LINE NO.	CUSTOMER GROUP	ALLOCATION DETERMINANTS (MWS/YR) TRANSM (H)	PRIM (I)	SEC (J)	LINE NO.
26					26
27	Residential	0.000	5.978	1,457.376	27
28					28
29	Commercial/Industrial				29
30	General Service (A)	0.000	0.370	516.509	30
31	GS-Demand Metered 20kW (AD)	0.000	12.482	421.996	31
32	AL-TOU	0.000	423.514	593.215	32
33	A6-TOU	20.403	146.075	14.392	33
34	Total Commercial/Industrial	20.403	582.441	1,545.111	34
35					35
36	Agriculture	0.000	0.149	34.041	36
37					37
38	Lighting	0.000	0.000	9.380	38
39					39
	Total	20.403	583.558	3,078.908	

Column Calculations:
(A) col H x col E
(B) col I x col F
(C) col J x col G
(D) col A + col B + col C

Notes:
1. Presents the calculation of the transmission demand cost component of marginal cost revenue by customer group

CORRECTION

THIS DOCUMENT HAS
BEEN REPHOTOGRAPHED
TO ASSURE
LEGIBILITY

APPENDIX A
TABLE 4
SHEET 1 OF 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL DEMAND COST REVENUE
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	GENERATION ($000'S) (A)	TRANSMISSION ($000'S) (B)	DISTRIBUTION ($000'S) (C)	TOTAL ($000'S) (D)	LINE NO.
1	Residential	96,717	41,895	259,393	398,006	1
2						2
3	Commercial/Industrial					3
4	General Service (A)	39,947	14,483	74,394	128,823	4
5	GS-Demand Metered 20kW (AD)	33,225	12,165	63,263	108,652	5
6	Large TOU	100,360	33,105	149,010	282,474	6
7	Total Commercial/Industrial	173,531	59,752	286,666	519,950	7
8						8
9	Agriculture	2,157	958	6,059	9,174	9
10						10
11	Lighting	624	263	1,588	2,474	11
12						12
13	Total	273,029	102,868	553,706	929,603	13

Column Calculations:

(D) Col A + Col B + Col C

Notes:
1. Presents the functionalization of the demand cost component of marginal cost revenue by customer group.

SDGEBORDER BLOCK: CA60..CJ62 PRINT BLOCK: CA1..CJ59

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
GENERATION DEMAND COST REVENUE ($000's)
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	TRANSM (A)	PRIM (B)	SEC (C)	TOTAL (D)	LINE NO.
1	Residential	0	377	96,341	96,717	1
2						2
3	Commercial/Industrial					3
4	General Service (A)	0	28	39,919	39,947	4
5	GS-Demand Metered 20kW (AD)	0	931	32,294	33,225	5
6	Large TOU	1,563	46,921	51,875	100,360	6
7	Total Commercial/Industrial	1,563	47,880	124,088	173,531	7
8						8
9	Agriculture	0	9	2,147	2,157	9
10						10
11	Lighting	0	0	624	624	11
12						12
13	Total	1,563	48,266	223,200	273,029	13
14						14
15						15
16		TRANSM	PRIM	SEC		16
17		(E)	(F)	(G)		17
18						18
19	UNIT MARGINAL GENERATION	87.51	91.14	93.54		19
20	DEMAND COST ($/KW/YR)					20
21						21
22			ALLOCATION DETERMINANTS			22
23			(MWS/YR)			23
24		TRANSM	PRIM	SEC		24
25	CUSTOMER GROUP	(H)	(I)	(J)		25
26						26
27	Residential	0.000	4.134	1,029.952		27
28						28
29	Commercial/Industrial					29
30	General Service (A)	0.000	0.306	426.766		30
31	GS-Demand Metered 20kW (AD)	0.000	10.212	345.244		31
32	AL-TOU	0.000	386.938	541.982		32
33	A6-TOU	17.862	127.887	12.600		33
34	Total Commercial/Industrial	17.862	525.342	1,326.593		34
35	Agriculture	0.000	0.101	22.958		35
36						36
37	Lighting	0.000	0.000	6.666		37
38						38
39	Total	17.862	529.577	2,386.168		39

Column Calculations:
(A) col H x col E
(B) col I x col F
(C) col J x col G
(D) col A + col B + col C

Notes:
1. Presents the calculation of the generation demand cost component of marginal cost revenue by customer group

APPENDIX A
TABLE 4
SHEET 3 OF 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
TRANSMISSION DEMAND COST REVENUE ($000's)
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	TRANSM (A)	PRIM (B)	SEC (C)	TOTAL (D)	LINE NO.
1	Residential	0	163	41,732	41,895	1
3	Commercial/Industrial					3
4	General Service (A)	0	10	14,472	14,483	4
5	GS-Demand Metered 20kW (AD)	0	341	11,824	12,165	5
6	Large TOU	535	15,545	17,025	33,105	6
7	Total Commercial/Industrial	535	15,896	43,322	59,752	7
9	Agriculture	0	4	954	958	9
11	Lighting	0	0	263	263	11
13	Total	535	16,063	86,270	102,868	13

LINE NO.		TRANSM (E)	PRIM (F)	SEC (G)	LINE NO.
19	UNIT MARGINAL TRANSMISSION	26.21	27.29	28.02	19
20	DEMAND COST ($/KW/YR)				20

ALLOCATION DETERMINANTS (MWS/YR)

LINE NO.	CUSTOMER GROUP	TRANSM (H)	PRIM (I)	SEC (J)	LINE NO.
27	Residential	0.000	5.978	1,489.376	27
29	Commercial/Industrial				29
30	General Service (A)	0.000	0.370	516.509	30
31	GS-Demand Metered 20kW (AD)	0.000	12.482	421.996	31
32	AL-TOU	0.000	423.514	593.215	32
33	A6-TOU	20.403	146.075	14.392	33
34	Total Commercial/Industrial	20.403	582.441	1,546.111	34
36	Agriculture	0.000	0.149	34.041	36
38	Lighting	0.000	0.000	9.380	38
	Total	20.403	588.568	3,078.908	

Column Calculations:
(A) col H x col E
(B) col I x col F
(C) col J x col G
(D) col A + col B + col C

Notes:
1. Presents the calculation of the transmission demand cost component of marginal cost revenue by customer group

APPENDIX A
TABLE 4
SHEET 4 OF 4
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
DISTRIBUTION DEMAND COST REVENUE ($000's)
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	PRIM (A)	SEC (B)	TOTAL (C)	LINE NO.
1	Residential	1,011	258,383	259,393	1
2					2
3	Commercial/Industrial				3
4	General Service (A)	52	74,342	74,394	4
5	GS-Demand Metered 20kW (AD)	1,772	61,491	63,263	5
6	Large TOU	73,084	75,926	149,010	6
7	Total Commercial/Industrial	74,908	211,758	286,666	7
8					8
9	Agriculture	26	6,033	6,059	9
10					10
11	Lighting	0	1,588	1,588	11
12	-------------------	----------	----------	----------	12
13	Total	75,944	477,762	553,706	13
14					14
15					15
16		PRIM	SEC		16
17		(D)	(E)		17
18		----------	----------		18
19	UNIT MARGINAL DISTRIBUTION	103.11	105.82		19
20	DEMAND COST ($/KW/YR)				20
21					21
22		ALLOCATION DETERMINANTS			22
23			(MWS/YR)		23
24		PRIM	SEC		24
25	CUSTOMER GROUP	(F)	(G)		25
26	-------------------	----------	----------		26
27	Residential	9.801	2,441.825		27
28	Commercial/Industrial				28
29	General Service (A)	0.504	702.560		29
30	GS-Demand Metered 20kW (AD)	17.188	581.111		30
31	AL-TOU	499.342	699.427		31
32	A6-TOU	209.449	18.106		32
33	Total Commercial/Industrial	726.483	2,001.204		33
34					34
35	Agriculture	0.250	57.018		35
36					36
37	Lighting	0.000	15.007		37
38	-------------------	----------	----------		38
39	Total	736.534	4,515.054		39

Column Calculations:
(A) col D x col F
(B) col E x col G
(C) col A + col B
Notes:
1. Presents the calculation of the distribution demand cost component of marginal cost revenue by customer group

TABLE 5
SHEET 1 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL ENERGY COST REVENUE
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	MARGINAL ENERGY COST REVENUE ($000'S) (A)	LINE NO.
1	Residential	180,905	1
2			2
3	Commercial/Industrial		3
4	General Service (A)	57,973	4
5	GS-Demand Metered 20kW (AD)	53,600	5
6	Large TOU	176,919	6
7	Total Commercial/Industrial	288,493	7
8			8
9	Agriculture	5,112	9
10			10
11	Lighting	2,326	11
12	--------------------	------------	12
13	Total	476,836	13

Notes:
1. Presents the energy cost component of marginal cost revenue by customer group

APPENDIX A
TABLE 5
SHEET 2 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
MARGINAL ENERGY COST REVENUE
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

RESIDENTIAL

	SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	ANNUAL (G)	LINE NO.
Unit Marginal Energy Costs ($/kWH)								1
Transmission	0.0325	0.0319	0.0274	0.0363	0.0350	0.0288		2
Primary	0.0338	0.0331	0.0281	0.0378	0.0363	0.0295		3
Secondary	0.0347	0.0339	0.0286	0.0388	0.0371	0.0300		4
								5
SDG&E 92 ECAC Sales (gWH)		RATIO	1.0000					6
Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7
Primary	1.768	2.542	4.235	1.594	4.700	6.438	21.278	8
Secondary	456.427	656.210	1,093.524	411.590	1,213.544	1,662.249	5,493.543	9
---------	----------	----------	----------	----------	----------	----------	----------	10
Total	458.195	658.752	1,097.759	413.184	1,218.244	1,668.687	5,514.821	11
							5,514.821	12
Adjusted Sales (gWH)								13
Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	14
Primary	1.768	2.542	4.235	1.594	4.700	6.438	21.278	15
Secondary	456.427	656.210	1093.524	411.590	1213.544	1662.249	5,493.543	16
----------	----------	----------	----------	----------	----------	----------	----------	17
Total	458.195	658.752	1,097.759	413.184	1,218.244	1,668.687	5,514.821	18
								19
Marginal Energy Cost Revenue($000's)								20
Transmission	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21
Primary	59.8	84.1	119.2	60.3	170.6	190.1	684.0	22
Secondary	15,833.2	22,220.6	31,265.5	15,972.6	45,060.6	49,868.4	180,221.0	23
---------	----------	----------	----------	----------	----------	----------	----------	24
Total	15,893.0	22,304.7	31,384.6	16,032.9	45,231.3	50,058.4	180,904.9	25

Line Calculations:
(6) line 12 col G / line 11 col G
(11) line 7 + line 8 + line 9
(14) line 6 x line 7
(15) line 6 x line 8
(16) line 6 x line 9
(18) line 14 + line 15 + line 16
(21) line 2 x line 14
(22) line 3 x line 15
(23) line 4 x line 16
(25) line 21 + line 22 + line 23

Column Calculations:
(G) sum of columns (A) through (F)

Notes:
1. Presents the calculation of the energy cost component of marginal cost revenue for the Residential Customer Group

APPENDIX A
TABLE 5
SHEET 3 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
MARGINAL ENERGY COST REVENUE

GENERAL SERVICE (A) FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.		SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	ANNUAL (G)	LINE NO.
1	Unit Marginal Energy Costs ($/kWH)								1
2	Transmission	0.0325	0.0319	0.0274	0.0363	0.0350	0.0288		2
3	Primary	0.0338	0.0331	0.0281	0.0378	0.0363	0.0295		3
4	Secondary	0.0347	0.0339	0.0286	0.0388	0.0371	0.0300		4
5									5
6	SDG&E 92 ECAC Sales (gWH) RATIO			1.0000					6
7	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7
8	Primary	0.188	0.166	0.235	0.079	0.368	0.312	1.348	8
9	Secondary	242.427	213.985	302.418	101.446	474.714	402.106	1,737.096	9
10	---------	---------	---------	---------	---------	---------	---------	---------	10
11	Total	242.615	214.151	302.652	101.524	475.083	402.418	1,738.444	11
12								1,738.444	12
13	Adjusted Sales (gWH)								13
14	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	14
15	Primary	0.188	0.166	0.235	0.079	0.368	0.312	1.348	15
16	Secondary	242.427	213.985	302.418	101.446	474.714	402.106	1,737.096	16
17	---------	---------	---------	---------	---------	---------	---------	---------	17
18	Total	242.615	214.151	302.652	101.524	475.083	402.418	1,738.444	18
19									19
20	Marginal Energy Cost Revenue($000's)								20
21	Transmission	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21
22	Primary	6.4	5.5	6.6	3.0	13.4	9.2	44.0	22
23	Secondary	8,409.7	7,246.0	8,646.6	3,936.8	17,626.8	12,063.4	57,929.3	23
24	---------	---------	---------	---------	---------	---------	---------	---------	24
25	Total	8,416.0	7,251.5	8,653.2	3,939.8	17,640.2	12,072.6	57,973.3	25

Line Calculations:
(6) line 12 col G / line 11 col G
(11) line 7 + line 8 + line 9
(14) line 6 x line 7
(15) line 6 x line 8
(16) line 6 x line 9
(18) line 14 + line 15 + line 16
(21) line 2 x line 14
(22) line 3 x line 15
(23) line 4 x line 16
(25) line 21 + line 22 + line 23

Column Calculations:
(G) sum of columns (A) through (F)

Notes:
1. Presents the calculation of the energy cost component of marginal cost revenue for the General Service (A) Customer Group

APPENDIX A
TABLE 5
SHEET 4 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
MARGINAL ENERGY COST REVENUE

GS-DEMAND METERED (AD) FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.		SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	ANNUAL (G)	LINE NO.
1	Unit Marginal Energy Costs ($/kWH)								1
2	Transmission	0.0325	0.0319	0.0274	0.0363	0.0350	0.0288		2
3	Primary	0.0338	0.0331	0.0281	0.0378	0.0363	0.0295		3
4	Secondary	0.0347	0.0339	0.0286	0.0388	0.0371	0.0300		4
5									5
6	SDG&E 92 ECAC Sales (gWH) ratio			1.0000					6
7	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7
8	Primary	6.548	6.437	8.161	2.622	13.743	10.373	47.885	8
9	Secondary	212.715	209.105	265.123	85.176	446.448	336.975	1,555.542	9
10	--------	-------	-------	-------	-------	-------	-------	-------	10
11	Total	219.263	215.542	273.285	87.798	460.191	347.348	1,603.427	11
12								1,603.427	12
13	Adjusted Sales (gWH)								13
14	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	14
15	Primary	6.548	6.437	8.161	2.622	13.743	10.373	47.885	15
16	Secondary	212.715	209.105	265.123	85.176	446.448	336.975	1,555.542	16
17	--------	-------	-------	-------	-------	-------	-------	-------	17
18	Total	219.263	215.542	273.285	87.798	460.191	347.348	1,603.427	18
19									19
20	Marginal Energy Cost Revenue($000's)								20
21	Transmission	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21
22	Primary	221.3	213.0	229.6	99.1	498.8	306.2	1,568.1	22
23	Secondary	7,379.0	7,080.7	7,580.3	3,305.4	16,577.3	10,109.4	52,032.1	23
24	--------	-------	-------	-------	-------	-------	-------	-------	24
25	Total	7,600.3	7,293.7	7,809.9	3,404.6	17,076.1	10,415.6	53,600.3	25

Line Calculations:
(6) line 12 col G / line 11 col G
(11) line 7 + line 8 + line 9
(12) Table 1-1
(14) line 6 x line 7
(15) line 6 x line 8
(16) line 6 x line 9
(18) line 14 + line 15 + line 16
(21) line 2 x line 14
(22) line 3 x line 15
(23) line 4 x line 16
(25) line 21 + line 22 + line 23

Column Calculations:
(G) sum of columns (A) through (F)

Notes:
1. Presents the calculation of the energy cost component of marginal cost revenue for the GS-Demand Metered 20KW (AD) Customer Group

APPENDIX A
TABLE 5
SHEET 5 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
MARGINAL ENERGY COST REVENUE

LARGE TOU — FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.		SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	ANNUAL (G)	LINE NO.
1	Unit Marginal Energy Costs ($/kWH)								1
2	Transmission	0.0325	0.0319	0.0274	0.0363	0.0350	0.0288		2
3	Primary	0.0338	0.0331	0.0281	0.0378	0.0363	0.0295		3
4	Secondary	0.0347	0.0339	0.0286	0.0388	0.0371	0.0300		4
5									5
6	SDG&E 92 ECAC Sales (gWH)		RATIO	1.0000					6
7	Transmission	9.816	12.019	20.821	4.931	24.932	28.451	100.969	7
8	Primary	306.835	344.878	539.874	146.003	705.316	722.422	2,765.328	8
9	Secondary	296.249	323.492	487.096	138.465	658.200	646.123	2,549.625	9
10	---------								10
11	Total	612.900	680.389	1,047.791	289.399	1,388.448	1,396.997	5,415.923	11
12								5,415.923	12
13	Adjusted Sales (gWH)								13
14	Transmission	9.816	12.019	20.821	4.931	24.932	28.451	100.969	14
15	Primary	306.835	344.878	539.874	146.003	705.316	722.422	2,765.328	15
16	Secondary	296.249	323.492	487.096	138.465	658.200	646.123	2,549.625	16
17	---------								17
18	Total	612.900	680.389	1,047.791	289.399	1,388.448	1,396.997	5,415.923	18
19									19
20	Marginal Energy Cost Revenue($000's)								20
21	Transmission	318.6	383.7	571.0	179.0	873.3	818.9	3,144.5	21
22	Primary	10,371.2	11,413.5	15,188.2	5,520.8	25,600.6	21,325.4	89,419.7	22
23	Secondary	10,276.7	10,954.1	13,926.8	5,373.4	24,439.9	19,384.0	84,355.1	23
24	---------								24
25	Total	20,966.5	22,751.3	29,686.0	11,073.2	50,913.8	41,528.4	176,919.3	25

Line Calculations:
(6) line 12 col G / line 11 col G
(11) line 7 + line 8 + line 9
(12) Table I-1
(14) line 6 x line 7
(15) line 6 x line 8
(16) line 6 x line 9
(18) line 14 + line 15 + line 16
(21) line 2 x line 14
(22) line 3 x line 15
(23) line 4 x line 16
(25) line 21 + line 22 + line 23

Column Calculations:
(G) sum of columns (A) through (F)

Notes:
1. Presents the calculation of the energy cost component of marginal cost revenue for the Large TOU Customer Group

APPENDIX A
TABLE 5
SHEET 6 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
MARGINAL ENERGY COST REVENUE
AGRICULTURE FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.		SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	ANNUAL (G)	LINE NO.
1	Unit Marginal Energy Costs ($/kWH)								1
2	Transmission	0.0325	0.0319	0.0274	0.0363	0.0350	0.0288		2
3	Primary	0.0338	0.0331	0.0281	0.0378	0.0363	0.0295		3
4	Secondary	0.0347	0.0339	0.0286	0.0388	0.0371	0.0300		4
5									5
6	SDG&E 92 ECAC Sales (gWH)		RATIO	1.0000					6
7	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7
8	Primary	0.116	0.147	0.281	0.048	0.211	0.278	1.080	8
9	Secondary	16.885	21.249	40.702	6.888	30.528	40.274	156.526	9
10	---------	---------	---------	---------	---------	---------	---------	---------	10
11	Total	17.001	21.396	40.983	6.935	30.738	40.552	157.606	11
12								157.606	12
13	Adjusted Sales (gWH)								13
14	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	14
15	Primary	0.116	0.147	0.281	0.048	0.211	0.278	1.080	15
16	Secondary	16.885	21.249	40.702	6.888	30.528	40.274	156.526	16
17	---------	---------	---------	---------	---------	---------	---------	---------	17
18	Total	17.001	21.396	40.983	6.935	30.738	40.552	157.606	18
19									19
20	Marginal Energy Cost Revenue($000's)								20
21	Transmission	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21
22	Primary	3.9	4.9	7.9	1.8	7.6	8.2	34.3	22
23	Secondary	585.7	719.5	1,163.7	267.3	1,133.5	1,208.3	5,078.1	23
24	---------	---------	---------	---------	---------	---------	---------	---------	24
25	Total	589.7	724.4	1,171.6	269.1	1,141.2	1,216.5	5,112.4	25

Line Calculations:
(6) line 12 col G / line 11 col G
(11) line 7 + line 8 + line 9
(14) line 6 x line 7
(15) line 6 x line 8
(16) line 6 x line 9
(18) line 14 + line 15 + line 16
(21) line 2 x line 14
(22) line 3 x line 15
(23) line 4 x line 16
(25) line 21 + line 22 + line 23

Column Calculations:
(G) sum of columns (A) through (F)

Notes:
1. Presents the calculation of the energy cost component of marginal cost revenue for the Agriculture Customer Group

APPENDIX A
TABLE 5
SHEET 7 OF 7
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
MARGINAL ENERGY COST REVENUE

LIGHTING
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.		SUMMER ON-PEAK (A)	SUMMER SEMI-PEAK (B)	SUMMER OFF-PEAK (C)	WINTER ON-PEAK (D)	WINTER SEMI-PEAK (E)	WINTER OFF-PEAK (F)	ANNUAL (G)	LINE NO.
1	Unit Marginal Energy Costs ($/kWH)								1
2	Transmission	0.0325	0.0319	0.0274	0.0363	0.0350	0.0288		2
3	Primary	0.0338	0.0331	0.0281	0.0378	0.0363	0.0295		3
4	Secondary	0.0347	0.0339	0.0286	0.0388	0.0371	0.0300		4
5									5
6	SDG&E 92 ECAC Sales (gWH)		RATIO	1.0000					6
7	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7
8	Primary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	8
9	Secondary	0.000	4.568	21.748	5.971	6.342	36.062	74.692	9
10	---------	----------	----------	----------	----------	----------	----------	----------	10
11	Total	0.000	4.568	21.748	5.971	6.342	36.062	74.692	11
12								74.692	12
13	Adjusted Sales (gWH)								13
14	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	14
15	Primary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	15
16	Secondary	0.000	4.568	21.748	5.971	6.342	36.062	74.692	16
17	---------	----------	----------	----------	----------	----------	----------	----------	17
18	Total	0.000	4.568	21.748	5.971	6.342	36.062	74.692	18
19									19
20	Marginal Energy Cost Revenue($000's)								20
21	Transmission	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21
22	Primary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22
23	Secondary	0.0	154.7	621.8	231.7	235.5	1,081.9	2,325.6	23
24	---------	----------	----------	----------	----------	----------	----------	----------	24
25	Total	0.0	154.7	621.8	231.7	235.5	1,081.9	2,325.6	25

Line Calculations:
(6) line 12 col G / line 11 col G
(11) line 7 + line 8 + line 9
(14) line 6 x line 7
(15) line 6 x line 8
(16) line 6 x line 9
(18) line 14 + line 15 + line 16
(21) line 2 x line 14
(22) line 3 x line 15
(23) line 4 x line 16
(25) line 21 + line 22 + line 23

Column Calculations:
(G) sum of columns (A) through (F)

Notes:
1. Presents the calculation of the energy cost component of marginal cost revenue for the Lighting Customer Group

APPENDIX A
TABLE 6
SHEET 1 OF 1
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL CUSTOMER COST REVENUE
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	UNIT MARGINAL CUSTOMER COST ($/CUSTOMER) (A)	NUMBER OF CUSTOMERS (B)	MARGINAL CUSTOMER COST REVENUE ($000'S) (C)	LINE NO.
1	Residential	108.37	1,006,718	109,101	1
2					2
3	Commercial/Industrial				3
4	General Service (A)	175.04	98,238	17,196	4
5	GS-Demand Metered 20kW (AD)	578.38	5,627	3,255	5
6	Large TOU	2,741.72	7,168	19,653	6
7	Total Commercial/Industrial		111,033	40,103	7
8					8
9	Agriculture	620.22	3,645	2,261	9
10					10
11					11
12		($/KWHR)	GWHR	($000'S)	12
13	Lighting	0.00895	74,692	668	13
14					14
15	Total			152,133	15

Column Calculations:
(C) col A x col B / 1,000 except for totals (lines 7 and 15)

Notes:
1. Presents the calculation of the customer cost component of marginal cost revenue by customer group

APPENDIX A

TABLE 7
SHEET 1 OF 1
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL COST REVENUE
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	CUSTOMER ($000's) (A)	DEMAND ($000's) (B)	MARGINAL COST REVENUE ENERGY ($000's) (C)	TOTAL ($000's) (D)	LINE NO.
1	Residential	109,101	398,006	180,905	688,012	1
2						2
3	Commercial/Industrial					3
4	General Service (A)	17,196	128,823	57,973	203,992	4
5	GS-Demand Metered 20kW (AD)	3,255	108,652	53,600	165,507	5
6	Large TOU	19,653	282,474	176,919	479,046	6
7	Total Commercial/Industrial	40,103	519,950	288,493	848,545	7
8						8
9	Agriculture	2,261	9,174	5,112	16,547	9
10						10
11	Lighting	668	2,474	2,326	5,468	11
12	-------------------	-----------	-----------	-----------	-----------	12
13	Total	152,133	929,603	476,836	1,558,572	13
14						14
15						15
16						16

LINE NO.	FACILITY CHARGES	STREET-LIGHTG CHARGES ($000'S) (E)	TOU METER CHARGES ($000'S) (F)	FACILITY CHARGES ($000'S) (G)	LINE NO.
17	FACILITY CHARGES				17
18	===================				18
19					19
20					20
21					21
22	CUSTOMER GROUP	(E)	(F)	(G)	22
23	-------------------	-----------	-----------	-----------	23
24	Residential	0	1	1	24
25					25
26	Commercial/Industrial				26
27	General Service (A)	0	0	0	27
28	GS-Demand Metered 20kW (AD)	0	0	0	28
29	Large TOU	0	0	0	29
30	Total Commercial/Industrial	0	0	0	30
31					31
32	Agriculture	0	20	20	32
33					33
34	Lighting	3,072	0	3,072	34
35	-------------------	-----------	-----------	-----------	35
36	Total	3,072	21	3,093	36

Column Calculations:
(D) col A + col B + col C
(G) col E + col F

Notes:
1. Presents the classifications of marginal cost revenue and disaggregation of facility charges by customer group

APPENDIX A
TABLE 8
SHEET 1 OF 2
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED 1992 ECAC REVENUE ALLOCATION
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	UNADJUSTED MARGINAL COST REVENUE			ADJUSTMENTS			LINE NO.
		MARG COST REVENUE ($000's) (A)	EPMC ALLOCATION FACTOR (B)	EPMC REVENUE ALLOCATION ($000's) (C)	FACILITY CHGS ($000's) (D)	LIRA ADJSTMT ($000's) (E)	ADOPTED REVENUE ($000's) (F)	
1	Residential	688,012	44.14%	594,454	1	(3,738)	590,927	1
2								2
3	Commercial/Industrial							3
4	General Service (A)	203,992	13.09%	176,253	0	53	176,368	4
5	GS-Demand Metered 20kW (AD)	165,507	10.62%	143,001	0	49	143,100	5
6	Large TOU	479,046	30.74%	413,904	0	165	414,216	6
7	Total Commercial/Industrial	848,545	54.44%	733,157	0	267	733,684	7
8								8
9	Agriculture	16,547	1.06%	14,297	20	5	13,849	9
10								10
11	Lighting	5,468	0.35%	4,725	3,072	0	7,798	11
12	********************	********	********	********	********	********	********	12
13	Total	1,558,572	100.00%	1,346,632	3,093	(3,466)	1,346,259	13

CAPPED ALLOCATION DETAIL

LINE NO.	CUSTOMER GROUP	CAPPED VALUE BEFORE ADJUSTMENTS (% CHANGE) (G)	MARGINAL COST ALLOCATOR (H)	CAPPED ALLOCATION REVENUE ($000's) (I)	MARGINAL COST ALLOCATION REVENUE ($000's) (J)	TOTAL CAPPED EPMC ALLOCATION ($000's) (K)	LINE NO.
1	Residential	N/A	594,454	0	594,664	594,664	1
2							2
3	Commercial/Industrial						3
4	General Service (A)	N/A	176,253	0	176,315	176,315	4
5	GS-Demand Metered 20kW (AD)	N/A	143,001	0	143,051	143,051	5
6	Large TOU	N/A	413,904	0	414,051	414,051	6
7	Total Commercial/Industrial						7
8							8
9	Agriculture	0.00%	0	13,824	0	13,824	9
10							10
11	Lighting	N/A	4,725	0	4,726	4,726	11
12	********************	********	********	********	********	********	12
13	Total		1,332,335	13,824	1,332,808	1,346,632	13

Column Calculations:
(B) % = marginal cost for group per col A/ total marginal cost per col A line 13.
(C) EPMC revenue allocation for each group = total EPMC revenue allocation x col B % for that group
(E) LIRA (Low Income Ratepayer Assistance) Adjustment from Rate Design Chapter
(F) col K + col D + col E. Adopted revenue includes Facility Charges and LIRA adjustment.
(G) Capped Percentage based on Present Revenue before Adjustments.
(H) Either zero or from col C.
(I) Either zero or capped class allocation.
(J) Allocation of remaining revenue to classes using col H allocators.
(K) Sum of col I and col J.

Notes:
1. Presents the adopted revenue requirement allocated among the customer groups based on the customer group marginal costs and EPMC revenue allocation method.

APPENDIX A
TABLE 8
SHEET 2 OF 2

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED 1992 ECAC REVENUE ALLOCATION
FORECAST PERIOD: MAY 1, 1992 THROUGH APRIL 30, 1993

LINE NO.	CUSTOMER GROUP	ADOPTED SALES (GWHR) (A)	PRESENT REVENUE ($000's) (B)	PRESENT AVG RATE ($/KWH) (C)	ADOPTED REVENUE ($000's) (D)	ADOPTED AVG RATE ($/KWH) (E)	CHANGE IN REVENUE ($000's) (F)	CHANGE IN REVENUE % (G)	LINE NO.
1	Residential	5,514.821	615,392	0.11159	590,927	0.10715	(24,465)	-4.0%	1
2									2
3	Commercial/Industrial								3
4	General Service (A)	1,738.444	187,205	0.10769	176,368	0.10145	(10,837)	-5.8%	4
5	GS-Demand Metered 20kW (AD)	1,603.427	149,033	0.09295	143,100	0.08925	(5,933)	-4.0%	5
6	Large TOU	5,415.923	443,002	0.08180	414,216	0.07648	(28,786)	-6.5%	6
7	Total Commercial/Industrial	8,757.794	779,240	0.08898	733,684	0.08378	(45,556)	-5.8%	7
8									8
9	Agriculture	157.606	13,844	0.08784	13,849	0.08787	5	0.0%	9
10									10
11	Lighting	74.692	8,218	0.11003	7,798	0.10440	(420)	-5.1%	11
12									12
13	Total	14,504.913	1,416,694	0.09767	1,346,259	0.09281	(70,435)	-5.0%	13

Column calculations:
(C) col B/col A/1,000
(E) (col D)/col A/1,000
(F) col D-col B
(G) (col D-col B)/col B

Notes:
1. Presents the results of the Capped Equal Percentage of Marginal Cost (EPMC) revenue allocation based on adopted sales

TABLE 9-1
RESIDENTIAL RATE DESIGN, PAGE 1

LN.	DESCRIPTION (A)	BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	TIER ADJUSTED RATES ($/UNIT) (C)	TIER ADJUSTED REVENUE ($) (D)	EMPLOYEE DISCOUNT FACTOR (%) (E)	SOFFD (%) (F)	CURRENT REVENUE ($) (G)	ADOPTED RATES ($/KWH) (H)	ADOPTED REVENUES ($) (I)	ECAC/AER REVENUES AT ADOPTED ECAC ($) (J)	ADJUSTED SALES (KWH) (K)
1	SCHEDULE DR											
2												
3	Minimum Bill	8,273,000	0.164	0.164	1,356,772	0.1543%	0.690%	1,364,026	0.164	1,364,026		8,317,230
4	Baseline Base	2,875,268,000	0.06447	0.06197	178,182,871	0.1543%	0.690%	179,135,500	0.06764	195,525,405		2,890,640,199
5	Nonbaseline Base	2,380,165,000	0.09446	0.08753	208,333,561	0.1543%	0.690%	209,447,385	0.09320	223,015,052		2,392,890,203
6	Baseline ECAC/AER	2,875,268,000	0.03441	0.03441	98,937,972	0.1543%	0.690%	99,466,929	0.02874	83,076,999	83,076,999	2,890,640,199
7	Nonbaseline ECAC/AER	2,380,165,000	0.03441	0.03441	81,901,478	0.1543%	0.690%	82,339,352	0.02874	68,771,664	68,771,664	2,392,890,203
8												
9	Base	5,255,433,000			387,873,204			389,946,911		419,904,483		5,283,530,402
10	ECAC/AER	5,255,433,000			180,839,450			181,806,281	0.02172	151,848,664		5,283,530,402
11	Total	5,255,433,000			568,712,653			571,753,192		571,753,147		5,283,530,402
12												
13	SCHEDULE DM											
14												
15	Baseline Base	58,411,000	0.06447	0.06197	3,619,781		0.843%	3,650,295	0.06764	3,984,277		58,903,405
16	Nonbaseline Base	44,789,000	0.09446	0.08753	3,920,338		0.843%	3,953,387	0.09320	4,209,481		45,166,571
17	Baseline ECAC/AER	58,411,000	0.03441	0.03441	2,009,923		0.843%	2,026,866	0.02874	1,692,884	1,692,884	58,903,405
18	Nonbaseline ECAC/AER	44,789,000	0.03441	0.03441	1,541,189		0.843%	1,554,182	0.02874	1,298,087	1,298,087	45,166,571
19												
20	Base	103,200,000			7,540,119			7,603,682		8,193,758		104,069,976
21	ECAC/AER	103,200,000			3,551,112			3,581,048		2,990,971		104,069,976
22	Total	103,200,000			11,091,231			11,184,730		11,184,729		104,069,976
23												
24	SCHEDULE DS											
25												
26	Unit Discounts	2,068,000	(0.110)	(0.110)	(227,480)		0.893%	(229,511)	(0.110)	(229,511)		2,086,467
27	Baseline Base	15,829,000	0.06447	0.06197	980,937		0.893%	989,697	0.06764	1,080,248		15,970,353
28	Nonbaseline Base	2,386,000	0.09446	0.08753	208,844		0.893%	210,709	0.09320	224,359		2,407,307
29	Baseline ECAC/AER	15,829,000	0.03441	0.03441	544,676		0.893%	549,540	0.02874	458,988	458,988	15,970,353
30	Nonbaseline ECAC/AER	2,386,000	0.03441	0.03441	82,102		0.893%	82,835	0.02874	69,186	69,186	2,407,307
31												
32	Base	18,215,000			962,301			970,895		1,075,096		18,377,660
33	ECAC/AER	18,215,000			626,778			632,375		528,174		18,377,660
34	Total	18,215,000			1,589,079			1,603,270		1,603,270		18,377,660
35												
36	SCHEDULE DT											
37												
38	Space Discounts	13,087,000	(0.312)	(0.312)	(4,083,144)		0.202%	(4,091,392)	(0.312)	(4,091,392)		13,113,436
39	Baseline Base	103,204,000	0.06447	0.06197	6,395,642		0.202%	6,408,561	0.06764	6,994,909		103,412,472
40	Nonbaseline Base	34,769,000	0.09446	0.08753	3,043,297		0.202%	3,049,445	0.09320	3,246,983		34,839,233
41	Baseline ECAC/AER	103,204,000	0.03441	0.03441	3,551,250		0.202%	3,558,423	0.02874	2,972,074	2,972,074	103,412,472
42	Nonbaseline ECAC/AER	34,769,000	0.03441	0.03441	1,196,401		0.202%	1,198,818	0.02874	1,001,280	1,001,280	34,839,233
43												
44	Base	137,973,000			5,355,795			5,366,614		6,150,500		138,251,705
45	ECAC/AER	137,973,000			4,747,651			4,757,241		3,973,354		138,251,705
46	Total	137,973,000			10,103,446			10,123,855		10,123,854		138,251,705
47												
48	TOTAL RESIDENTIAL											
49												
50	Base	5,514,821,000			401,731,419			403,888,102		435,323,837		5,544,229,743
51	ECAC/AER	5,514,821,000			189,764,991			190,776,945		159,341,163	159,341,163	5,544,229,743
52	Total	5,514,821,000			591,496,410			594,665,047		594,665,000		5,544,229,743
53												

TABLE 9-2
RESIDENTIAL DESIGN, PAGE 2

LINE NO.	DESCRIPTION (A)	BILLING UNITS (B)	ADOPTED RATE ($/UNIT) (C)	SUB-TOTAL REVENUE ($) (D)	EMPLOYEE DISCOUNT FACTOR (%) (E)	SOFFD (%) (F)	TOTAL REVENUE ($) (G)	LINE NO.
1								1
2	SCHEDULE DR							2
3	Baseline Energy	2,711,219,000	0.09641	261,388,624	0.1543	0.690	262,786,100	3
4	Non-Baseline Energy	2,318,872,000	0.12197	282,832,818	0.1543	0.690	284,344,942	4
5	Minimum Bill	8,074,000	0.164	1,324,136	0.1543	0.690	1,331,215	5
6								6
7	Subtotal						548,462,257	7
8								8
9	SCHEDULE DR-LI							9
10	Baseline Energy	164,049,000	0.08192	13,438,894	0.1543	0.690	13,510,743	10
11	Non-Baseline Energy	61,293,000	0.10365	6,353,019	0.1543	0.690	6,386,985	11
12	Minimum Bill	199,000	0.139	27,661	0.1543	0.690	27,809	12
13								13
14	Subtotal						19,925,537	14
15								15
16	SCHEDULE DM							16
17	Baseline Energy	58,411,000	0.09641	5,631,405		0.843	5,678,877	17
18	Non-Baseline Energy	44,789,000	0.12197	5,462,914		0.843	5,508,967	18
19	Minimum Bill	0	0.164	0		0.843	0	19
20								20
21	Subtotal						11,187,844	21
22								22
23	SCHEDULE DS							23
24	Baseline Energy	12,975,000	0.09641	1,250,920		0.893	1,262,090	24
25	Non-Baseline Energy	1,956,000	0.12197	238,573		0.893	240,704	25
26	Baseline Energy L/I	2,854,000	0.08192	233,800		0.893	235,888	26
27	Non-Baseline Energy L/I	430,000	0.10365	44,570		0.893	44,968	27
28	Unit Discount	2,068,000	(0.11000)	(227,480)		0.893	(229,511)	28
29	Minimum Bill	0	0.164	0		0.893	0	29
30								30
31	Subtotal						1,554,138	31
32								32
33	SCHEDULE DT							33
34	Baseline Energy	87,228,000	0.09641	8,409,651		0.202	8,426,639	34
35	Non-Baseline Energy	29,387,000	0.12197	3,584,332		0.202	3,591,573	35
36	Baseline Energy L/I	15,976,000	0.08192	1,308,754		0.202	1,311,398	36
37	Non-Baseline Energy L/I	5,382,000	0.10365	557,844		0.202	558,971	37
38	Space Discount	13,087,000	(0.31200)	(4,083,144)		0.202	(4,091,392)	38
39	Minimum Bill	0	0.164	0		0.202	0	39
40								40
41	Subtotal						9,797,189	41
42								42
43	TOTAL RESIDENTIAL	5,514,821,000					590,926,964	43
44								44

TABLE 9-3
RESIDENTIAL DESIGN, PAGE 3

Row	B	C	D	E	F	G	H	Row
1	A.89-09-031		Calculation of New Residential Rates					1
2	12-01-89		Under 15% Tier Closure Scenario					2
3								3
4	B	C	D	E	F	G	H	4
5		Current Baseline Rate:		0.09888			Residential	5
6		Current Nonbaseline Rate:		0.12887		n*nkwh:	318,992,338	6
7		Current Composite Baseline Rate:		0.09932		n*bkwh:	395,492,549	7
8						nkwh+bkwh:	5,544,229,743	8
9		Current Tier Differential:		0.02955		rev:	598,985,903	9
10		Current Tier Ratio:		1.297		newdiff*bkwh:	77,072,156	10
11		Tier Closure Factor:		0.85		H6+H7:	714,484,887	11
12						H9+H10:	676,058,060	12
13		New Tier Differential:		0.02511		(H12-H11)/H8 = dn:	(0.00693)	13
14						n+dn:	0.12194	14
15		Baseline Adjusted KWH:		3,068,926,428		H14-newdiff-c = dc:	(0.00250)	15
16		Nonbaseline Adjusted KWH:		2,475,303,315		c+dc:	0.09683	16
17						H14-H16 = newdiff:	0.02511	17
18		Total Adjusted KWH:		5,544,229,743		H14/H16:	1.25937	18
19								19
20		Minimum Bill Revenues:		$1,356,772		H14*nkwh	301,836,113	20
21		Baseline KWH:		3,052,712,000		H16*bkwh	297,149,790	21
22						H28+H29 = rev	598,985,903	22
23		Normalized Revenue Requirement:		$598,985,903				23
24								24
25	***							25
26	*			*				26
27	*	New Baseline Rate:		0.09638 *		0.09638		27
28	*	New Nonbaseline Rate:		0.12194 *		0.12194		28
29	*	New Composite Baseline Rate:		0.09683 *		0.09683		29
30	*	Verify Tier Differential:		0.02511 *		0.02511		30
31	*	Verify Revenue Requirement:		$598,985,903 *				31
32	*	New Tier Ratio:		1.259 *				32
33	*			*				33
34	***							34

This routine calculates the new Tier 1 and Tier 2 rates by forcing the new rates to produce the required revenue given the new tier differential.

TABLE 10
LOW INCOME DISCOUNT RATES

CALCULATION OF THE LOW INCOME RATEPAYER SURCHARGE

LINE NO.	DESCRIPTION (A)	BASELINE (B)	NON-BASELINE (C)	MINIMUM BILL (D)	TOTAL (E)	LINE NO.
1	LIRA PROGRAM COSTS (5/1/91 - 4/30/92)					1
2						2
3	LIRA Discount ($/kWh):					3
4	Residential Rate Before Surcharge	0.09638	0.12194	0.164		4
5	LIRA Rate (Line 1 * 85%)	0.08192	0.10365	0.139		5
6	Low Income Discount	0.01446	0.01829	0.025		6
7						7
8	Low Income Discount Sales (kWh or Bills)	182,879,000	67,105,000	199,000	249,984,000	8
9						9
10	Low Income Discount	$2,644,430	$1,227,350	$4,975	$3,876,756	10
11						11
12	Administrative Budget				$337,460	12
13	FF&U Costs (Factor of 1.013)				$4,387	13
14						14
15	Total Administrative Budget w/FF&U				$341,847	15
16						16
17	Forecasted LIRA Account Balance on 4/30/91				($3,838,609)	17
18						18
19	Total LIRA Program Costs				$379,993	19
20						20
21						21
22	SALES SUBJECT TO LIRA SURCHARGE					22
23						23
24	Total Forecast Period Sales (kWh)				14,504,913,000	24
25						25
26	Adjustments:					26
27	Low Income Sales (Kwh)				249,984,000	27
28	Low Income Minimum Bill Sales (Kwh)				245,554	28
29	Exempt Streetlight Sales (Kwh)				69,537,000	29
30	Special Contract Sales (Kwh)				0	30
31						31
32	Total Adjustments				319,766,554	32
33						33
34	Total Sales Subject to LIRA Surcharge				14,185,146,446	34
35						35
36						36
37	CALCULATION OF THE LIRA SURCHARGE					37
38						38
39	Total LIRA Program Costs				$379,993	39
40	Total Sales Subject to LIS (kWh)				14,185,146,446	40
41						41
42	LIRA Surcharge ($/kWh)				0.00003	42

TABLE 11-1
OPTIONAL RESIDENTIAL RATE DESIGN, PAGE 1
SCHEDULE D-SMF

LN.		(A)	
1	Residential Baseline-ECAC/AER Rate	0.02874	
2	Residential Baseline-Total Rate	0.09641	
3	Residential Non-Baseline-ECAC/AER Rate	0.02874	
4	Residential Non-Baseline-Total Rate	0.12197	
5			
6	Average AL-TOU On-Peak Demand Charge as On-Peak	9.69	AL-TOU On-peak kW Charge
7	Adopted D-SMF Customer Charge	20.00	
8			
9	Schedule DS Baseline Energy (Kwh)	15,829,000	Schedule DS Baseline
10	Schedule DS Non-Baseline Energy (Kwh)	2,386,000	Schedule DS Non-Baseline
11	Schedule DT Baseline Energy (Kwh)	103,204,000	Schedule DT Baseline
12	Schedule DT Non-Baseline Energy (Kwh)	34,769,000	Schedule DT Non-Baseline
13			
14	Schedule DS SDFFD	0.893%	
15	Schedule DT SDFFD	0.202%	
16			
17	On-Peak Energy/Total Energy Factor	16.17%	
18			
19	Calculated On-Peak Energy (Kwh)	25,326,968	
20	On-Peak Demand Charge by $/Kwh	0.09829	
21			
22	Schedule DS Total Revenue @ Adopted Rates	$1,554,138	
23	Schedule DT Total Revenue @ Adopted Rates	$9,797,189	
24	DS and DT Total Revenue @ Adopted Rates	$11,351,326	
25	Schedule D-SMF Demand Charge Revenues	$2,489,450	
26	DS and DT Revenues Less Demand Charge Revenues	$8,861,876	
27	Schedule DS Unit Discounts	$229,511	
28	Schedule DT Space Discounts	$4,091,392	
29	Total DS and DT Discounts	$4,320,903	
30	Balance for Energy Rate Derivation	$13,182,779	
31			
32	Non-Base to Base Rates Ratio	1.2651	
33			
34	Schedules DS & DT Adjusted Baseline Energy (Kwh)	119,382,825	
35	Schedules DS & DT Adjusted Non-Baseline Energy (Kwh)	37,246,540	
36			
37	Schedules DS & DT Rate Adjusted Energy (Kwh)	166,504,084	
38			
39			
40			
41	SCHEDULE D-SMF DESIGNED RATE SUMMARY		
42			
43	Customer Charge ($/Month)	20.00	
44	On-Peak Demand Charge ($/kW)	9.69	
45	Baseline Energy ($/kWh)	0.07917	
46	Non-Baseline Energy ($/kWh)	0.10016	
47	Baseline Energy L/I ($/kWh)	0.06730	
48	Non-Baseline Energy L/I ($/kWh)	0.08514	
49	Unit Discount ($/kWh)	0.110	
50	Space Discount ($/kWh)	0.312	

TABLE 11-2
OPTIONAL RESIDENTIAL RATE DESIGN, PAGE 2
DR-TOU

LN. (A)	USAGE DATA (%) (C)	Peak: 12-6 (D)	HOLIDAYS OFF (E)	LINE (F)
7	ANNUAL USAGE ON-PEAK		16.9%	7
8	SUMMER USAGE ON-PEAK		17.7%	8
9	WINTER USAGE ON-PEAK		16.2%	9
10	ON-PEAK SUMMER AS % OF YEAR		8.5%	10
11	ON-PEAK WINTER AS % OF YEAR		8.4%	11
12				12
13	HOURS DATA (%)			13
14				14
15	ANNUAL HOURS ON-PEAK		17.32877%	15
16	SUMMER HOURS ON-PEAK		17.52717%	16
17	WINTER HOURS ON-PEAK		17.12707%	17
18				18
19	MARGINAL ENERGY COSTS			19
20				20
21	ANNUAL ON-PEAK		0.0362	21
22	ANNUAL OFF-PEAK AND SEMI-PEAK		0.0316	22
23	SUMMER ON-PEAK		0.0347	23
24	WINTER ON-PEAK		0.0388	24
25				25
26	MARGINAL CAPACITY COSTS ($/KW PER MONTH)			26
27				27
28	ANNUAL COINCIDENT		11.09	28
29	SUMMER COINCIDENT		20.36	29
30	WINTER COINCIDENT		4.47	30
31	ANNUAL NCD		7.27	31
32	SUMMER NCD		8.09	32
33	WINTER NCD		6.68	33
34				
35	CUSTOMER COSTS ($/CUSTOMER PER MONTH)			
36				
37	MONTHLY CUSTOMER COST		7.95	
38				
39	AVERAGE USAGE (KWH/MONTH)			
40				
41	AVERAGE MONTHLY USAGE		432	
42				
43	AVERAGE PEAK DEMAND (KW)			
44				
45	CUSTOMER DEMAND AT SYSTEM PEAK		1.0	
46				
47	AVERAGE NON-COINCIDENT DEMAND (KW)			
48				
49	NONCOINCIDENT DEMAND		1.4	
50				
51	BASELINE DISCOUNT (BASELINE - NON-BASELINE C/KWH)			
52				
53	CURRENT DISCOUNT		(0.02999)	
54				
55	LOSS OF LOAD PROBABILITY WEIGHTING FACTORS			
56				
57	SUMMER ON-PEAK		88%	
58	SUMMER OFF-PEAK		12%	
59				

LN.		(F)
60	RESIDENTIAL TOU REVENUE REQUIREMENT	(F)
61		
62	SDG&E RESIDENTIAL REVENUE REQUIREMENT	594,665,000
63	PG&E GRC D.89-12-057 E-7 Adopted Revenue ($000s)	60,377
64	PG&E GRC E-7 Sales (MkWh)	669,286
65	PG&E GRC E-1 Adopted Revenue ($000s)	2,432,039
66	PG&E GRC E-1 Sales (MkWh)	22,679,833
67	PG&E SCHEDULE E-7/E-1 GRC RATE RATIO	0.84126
68	SDG&E RESIDENTIAL TOU REVENUE REQUIREMENT	500,266,573
69		
70	GROSS-UP RATE ADJUSTMENTS	
71		
72	EPMC ADJUSTMENT FACTOR FOR DR-TOU-2	1.01733
73	EPMC ADJUSTMENT FACTOR FOR DR-TOU	1.19329
74		

TABLE II-3
OPTIONAL RESIDENTIAL RATE DESIGN, PAGE 3
EXPERIMENTAL SCHEDULE DR-TOU-2

DESCRIPTION (C)	SCHEDULE DR SALES (KWH) (D)	UNADJUSTED RATES ($/KWH) (E)	UNADJUSTED REVENUE ($) (F)	EMP DISC FACTOR (%) (G)	SOFFD (%) (H)	ADJUSTED REVENUE ($) (I)	TARIFF RATE ($/KWH) (J)	COLLECTED REVENUES ($) (K)
SUMMER ON-PEAK	468,759,785	0.27552	129,154,842	0.1543%	0.6900%	129,845,349	0.28030	132,095,983
WINTER ON-PEAK	463,244,964	0.10847	50,249,085	0.1543%	0.6900%	50,517,735	0.11035	51,393,368
ANNUAL OFF-PEAK	4,582,816,251	0.06758	309,724,118	0.1543%	0.6900%	311,380,012	0.06876	316,777,221
TOTAL	5,514,821,000		489,128,045			491,743,096		500,266,573

EXPERIMENTAL SCHEDULE DR-TOU DESIGN

DESCRIPTION (C)	SCHEDULE DR SALES (KWH) (D)	UNADJUSTED RATES ($/KWH) (E)	UNADJUSTED REVENUE ($) (F)	EMP DISC FACTOR (%) (G)	SOFFD (%) (H)	ADJUSTED REVENUE ($) (I)	TARIFF RATE ($/KWH) (J)	COLLECTED REVENUES ($) (K)
BASELINE DISCOUNT	2,869,833,000	(0.02999)	(86,066,292)	0.1543%	0.6900%	(86,526,432)	(0.02999)	(86,526,432)
SUMMER ON-PEAK	468,759,785	0.27552	129,154,842	0.1543%	0.6900%	129,845,349	0.32878	154,943,391
WINTER ON-PEAK	463,244,964	0.10847	50,249,085	0.1543%	0.6900%	50,517,735	0.12944	60,282,399
ANNUAL OFF-PEAK	4,582,816,251	0.06758	309,724,118	0.1543%	0.6900%	311,380,012	0.08065	371,567,216
TOTAL	5,514,821,000		403,061,753			405,216,664		500,266,573

TARIFF RATES	UNITS	DR-TOU	DR-TOU-2	LIS
METER CHARGE /1	$/MONTH	3.28	3.28	0.00003
ON-PEAK (SUMMER) /2	$/KWH	0.32881	0.28033	
ON-PEAK (WINTER) /2	$/KWH	0.12947	0.11038	
OFF-PEAK (ANNUAL)	$/KWH	0.08068	0.06879	
BASELINE CREDIT	$/KWH	0.02999	N/A	

/1 Meter Charge will not apply to qualifying low-income customers
/2 On-peak is defined as 12 Noon to 6 p.m. Monday through Friday, excluding holidays

TABLE 12-1
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 1

LN.	DESCRIPTION (A)	CURRENT BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	(E)	VOLTAGE DISCOUNT FACTOR (%) (F)	SDFFD (%) (G)	REVENUE ($) (H)	ADOPTED RATE ($/UNIT) (I)	ADOPTED TOTAL RATE ($/UNIT) (J)	ADOPTED REVENUE ($) (K)
1	SCHEDULE A										
3	CUSTOMER CHARGE	1,178,855	5.00	5,894,275		0.0000%	0.857%	5,944,789	5.00	5.00	5,944,789
4	ENERGY BASE	1,738,444,000	0.06897	119,900,483		0.0000%	0.857%	120,928,030	0.06877	0.09751	120,581,149
5	ENERGY ECAC/AER	1,738,444,000	0.03441	59,819,858		0.0000%	0.857%	60,332,514	0.02874		50,391,062
7	TOTAL	1,738,444,000		185,614,616				187,205,333			176,917,000
10	ADOPTED ECAC/AER RATE:			0.02874							
11	SCHEDULE A REVENUE ALLOCATION:			176,917,000							

LN.	DESCRIPTION (A)	CURRENT BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	STANDBY ADJUSTMENT FACTOR (%) (E)	VOLTAGE DISCOUNT FACTOR (%) (F)	SDFFD (%) (G)	REVENUE ($) (H)	ADOPTED RATE ($/UNIT) (I)	ADOPTED TOTAL RATE ($/UNIT) (J)	ADOPTED REVENUE ($) (K)
24	SCHEDULE AD										
26	CUSTOMER CHARGE	67,518	15.00	1,012,770	0.0148%	-0.1100%	0.990%	1,021,822	15.00	15.00	1,021,822
27	DEMAND CHARGE	5,211,000	6.74	35,122,140	0.0148%	-0.1100%	0.990%	35,436,064	6.74	6.74	35,436,064
28	ENERGY BASE	1,603,427,000	0.03514	56,344,425	0.0148%	-0.1100%	0.990%	56,848,036	0.03742	0.06616	60,541,532
29	ENERGY ECAC/AER	1,603,427,000	0.03441	55,173,923	0.0148%	0.0000%	0.990%	55,728,373	0.02874		46,545,581
31	TOTAL	1,603,427,000		147,653,258				149,034,296			143,545,000
34	ADOPTED ECAC/AER RATE:			0.02874							
35	SCHEDULE AD REVENUE ALLOCATION:			143,545,000							
36	INDEX FOR EQUAL % ADJUSTMENT TO DEMAND & ENERGY			0.96291329							

TABLE 12-2
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 2

DESCRIPTION (A)	CURRENT BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	(E)	VOLTAGE DISCOUNT FACTOR (%) (F)	SOFFD (%) (G)	REVENUE ($) (H)	ADOPTED RATE ($/UNIT) (I)	ADOPTED TOTAL RATE ($/UNIT) (J)	ADOPTED REVENUE ($) (K)
SCHEDULE PA										
CUSTOMER CHARGE	43,080	8.00	344,640		0.0000%	0.344%	345,826	8.00	8.00	345,826
ENERGY BASE	156,439,000	0.05085	7,954,923		0.0000%	0.344%	7,982,288	0.05656	0.08530	8,878,158
ENERGY ECAC/AER	156,439,000	0.03441	5,383,066		0.0000%	0.344%	5,401,584	0.02874		4,511,523
TOTAL	156,439,000		13,682,629				13,729,697			13,735,507

AGRICULTURAL REVENUE ALLOCATION: 13,849,000
ADOPTED ECAC/AER RATE: 0.02874
SCHEDULE PA REVENUE ALLOCATION: 13,735,507

DESCRIPTION (A)	CURRENT BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	(E)	VOLTAGE DISCOUNT FACTOR (%) (F)	SOFFD (%) (G)	REVENUE ($) (H)	ADOPTED RATE ($/UNIT) (I)	ADOPTED TOTAL RATE ($/UNIT) (J)	ADOPTED REVENUE ($) (K)
SCHEDULE PA-TOU										
CUSTOMER CHARGE	655	8.00	5,240		0.0000%	0.000%	5,240	8.00	8.00	5,240
METERING CHARGE	655	10.00	6,550		0.0000%	0.000%	6,550	10.00	10.00	6,550
ON-PEAK ENERGY BASE	245,000	0.11915	29,192		0.0000%	0.000%	29,192	0.13206	0.16080	32,355
OFF-PEAK ENERGY BASE	922,000	0.03504	32,307		0.0000%	0.000%	32,307	0.03884	0.06758	35,808
ENERGY ECAC/AER	1,167,000	0.03441	40,156		0.0000%	0.000%	40,156	0.02874		33,540
TOTAL	1,167,000		113,445				113,445			113,493

ADOPTED ECAC/AER RATE: 0.02874
PA-TOU REVENUE ALLOCATION: 113,493
INDEX FOR EQUAL % INCREASE TO BASE ENERGY: 1.108374651

TABLE 12-3
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 3

LN.	SCHEDULE A-E2 RATE SUMMARY	
1	Customer Charge	$600.00
2	Contract Demand	$10.38
3	Non-Coincident Demand	
4	Secondary	$3.71
5	Primary	$2.95
6	Transmission	$1.24
7	Energy: On-Peak	$4.41297
8	Energy: Semi-Peak	$0.06637
9	Energy: Off-Peak	$0.03232
10		
11		
12		
13		
14	SCHEDULE R-TOU-3 RATE SUMMARY	
15		
16	Customer Charge	$600.00
17	Contract Demand	$10.38
18	Non-Coincident Demand	
19	Secondary	$3.71
20	Primary	$2.95
21	Transmission	$1.24
22	Energy: Super-Peak	$1.25246
23	Energy: On-Peak	$0.10130
24	Energy: Semi-Peak	$0.04845
25	Energy: Off-Peak	$0.03232
26		
27		
28		
29	SCHEDULE R-TOU-4 RATE SUMMARY	
30		
31	Customer Charge	$600.00
32	Contract Demand	$10.38
33	Non-Coincident Demand	
34	Secondary	$3.71
35	Primary	$2.95
36	Transmission	$1.24
37	Energy: Super-Peak	$0.48994
38	Energy: On-Peak	$0.08097
39	Energy: Semi-Peak	$0.04370
40	Energy: Off-Peak	$0.03232

TABLE 12-4
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 4

LN.	DESCRIPTION (A)	CURRENT BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	CURRENT UNADJUSTED REVENUE ($) (D)	STANDBY FACTOR (%) (E)	ADOPTED RATE LIMITER FACTOR (%) (F)	SOFFD (%) (G)	CURRENT REVENUE ($) (H)	ADOPTED RATE ($/UNIT) (I)	ADOPTED REVENUE ($) (J)	ADOPTED TOTAL RATE ($/UNIT) (K)	ADOPTED OPTIONAL RATE ($/UNIT) (L)	ADOPTED OPTIONAL TOTAL RATE ($/UNIT) (M)
1	SCHEDULE AL-TOU												
2													
3	SERVICE CHARGE	85,394	30.00	2,561,820	0.153%	0.006%	1.166%	2,595,501	30.00	2,595,501	30.00	30.00	30.00
4	NON-COINCIDENT DEMAND												
5	SECONDARY	7,238,000	3.71	26,852,980	0.153%	0.006%	1.166%	27,206,024	3.71	27,206,024	3.71	3.71	3.71
6	PRIMARY	4,271,000	2.95	12,599,450	0.153%	0.006%	1.166%	12,765,099	2.95	12,765,099	2.95	2.95	2.95
7	TRANSMISSION	0	1.24	0	0.153%	0.006%	1.166%	0	1.24	0	1.24	1.24	1.24
8	ON-PEAK DEMAND: SUMMER												
9	SECONDARY	2,942,000	17.54	51,602,680	0.153%	0.006%	1.166%	52,281,115	17.54	52,281,115	17.54	19.70	19.70
10	PRIMARY	1,731,000	17.54	30,361,740	0.153%	0.006%	1.166%	30,760,914	17.54	30,760,914	17.54	19.70	19.70
11	TRANSMISSION	0	11.03	0	0.153%	0.006%	1.166%	0	11.03	0	11.03	12.39	12.39
12	ON-PEAK DEMAND: WINTER												
13	SECONDARY	3,499,000	4.08	14,275,920	0.153%	0.006%	1.166%	14,463,610	4.08	14,463,610	4.08	4.08	4.08
14	PRIMARY	2,084,000	4.08	8,502,720	0.153%	0.006%	1.166%	8,614,508	4.08	8,614,508	4.08	4.08	4.08
15	TRANSMISSION	0	1.64	0	0.153%	0.006%	1.166%	0	1.64	0	1.64	1.64	1.64
16	ON-PEAK ENERGY: SUMMER												
17	SECONDARY	307,502,000	0.05056	15,547,301	0.153%	0.006%	1.166%	15,751,706	0.04753	14,806,802	0.07627	0.05691	0.08565
18	PRIMARY	185,194,000	0.04509	8,350,397	0.153%	0.006%	1.166%	8,460,183	0.04262	7,996,232	0.07136	0.05140	0.08014
19	TRANSMISSION	0	0.04271	0	0.153%	0.006%	1.166%	0	0.04048	0	0.06922	0.04900	0.07774
20	ECAC/AER	492,696,000	0.03441	16,953,669	0.153%	0.006%	1.166%	17,176,564	0.02874	14,346,250		0.02874	
21	SEMI-PEAK ENERGY: SUMMER												
22	SECONDARY	354,041,000	0.02054	7,272,002	0.153%	0.006%	1.166%	7,367,609	0.02058	7,382,604	0.04932	0.02665	0.05539
23	PRIMARY	235,771,000	0.01793	4,227,374	0.153%	0.006%	1.166%	4,282,953	0.01824	4,356,795	0.04698	0.02402	0.05276
24	TRANSMISSION	0	0.01636	0	0.153%	0.006%	1.166%	0	0.01683	0	0.04557	0.02244	0.05118
25	ECAC/AER	589,812,000	0.03441	20,295,431	0.153%	0.006%	1.166%	20,562,261	0.02874	17,174,059		0.02874	
26	OFF-PEAK ENERGY: SUMMER												
27	SECONDARY	493,657,000	0.00715	3,529,648	0.153%	0.006%	1.166%	3,576,053	0.00856	4,282,891	0.03730	0.00856	0.03730
28	PRIMARY	346,925,000	0.00449	1,557,693	0.153%	0.006%	1.166%	1,578,173	0.00618	2,170,676	0.03492	0.00618	0.03492
29	TRANSMISSION	0	0.00332	0	0.153%	0.006%	1.166%	0	0.00513	0	0.03387	0.00513	0.03387
30	ECAC/AER	840,582,000	0.03441	28,924,427	0.153%	0.006%	1.166%	29,304,704	0.02874	24,475,943		0.02874	
31	ON-PEAK ENERGY: WINTER												
32	SECONDARY	170,321,000	0.04179	7,117,715	0.153%	0.006%	1.166%	7,211,293	0.03966	6,842,928	0.06840	0.03966	0.06840
33	PRIMARY	113,462,000	0.03685	4,181,075	0.153%	0.006%	1.166%	4,236,044	0.03522	4,048,816	0.06396	0.03522	0.06396
34	TRANSMISSION	0	0.03471	0	0.153%	0.006%	1.166%	0	0.03330	0	0.06204	0.03330	0.06204
35	ECAC/AER	283,783,000	0.03441	9,764,973	0.153%	0.006%	1.166%	9,893,356	0.02874	8,263,152		0.02874	
36	SEMI-PEAK ENERGY: WINTER												
37	SECONDARY	682,313,000	0.01365	9,313,572	0.153%	0.006%	1.166%	9,436,021	0.01440	9,952,759	0.04314	0.01440	0.04314
38	PRIMARY	463,880,000	0.01021	4,736,215	0.153%	0.006%	1.166%	4,798,483	0.01131	5,315,386	0.04005	0.01131	0.04005
39	TRANSMISSION	0	0.00887	0	0.153%	0.006%	1.166%	0	0.01011	0	0.03885	0.01011	0.03885
40	ECAC/AER	1,146,193,000	0.03441	39,440,501	0.153%	0.006%	1.166%	39,959,037	0.02874	33,374,679		0.02874	
41	OFF-PEAK ENERGY: WINTER												
42	SECONDARY	657,099,000	0.00603	3,962,307	0.153%	0.006%	1.166%	4,014,401	0.00756	5,031,632	0.03630	0.00756	0.03630
43	PRIMARY	486,006,000	0.00238	1,156,694	0.153%	0.006%	1.166%	1,171,902	0.00428	2,108,351	0.03302	0.00428	0.03302
44	TRANSMISSION	0	0.00127	0	0.153%	0.006%	1.166%	0	0.00329	0	0.03203	0.00329	0.03203
45	ECAC/AER	1,143,105,000	0.03441	39,334,243	0.153%	0.006%	1.166%	39,851,382	0.02874	33,284,763		0.02874	
46													
47	TOTAL	4,496,171,000						377,318,893		353,901,490			
48													

TABLE 12-5
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 5

LN.	DESCRIPTION (A)	CURRENT BILLING UNITS (B)	CURRENT RATES ($/UNIT) (C)	CURRENT UNADJUSTED REVENUE ($) (D)	STANDBY FACTOR (%) (E)	ADOPTED RATE LIMITER FACTOR (%) (F)	SOFFD (%) (G)	CURRENT REVENUE ($) (H)	ADOPTED RATE ($/UNIT) (I)	ADOPTED REVENUE ($) (J)	ADOPTED TOTAL RATE ($/UNIT) (K)	ADOPTED OPTIONAL RATE ($/UNIT) (L)	ADOPTED OPTIONAL TOTAL RATE ($/UNIT) (M)
1	SCHEDULE A-6 TOU												
2													
3	SERVICE CHARGE	624	600.00	374,400	0.474%	0.021%	1.358%	381,203	600.00	381,203	600.00	600.00	600.00
4	NON-COINCIDENT DEMAND												
5	PRIMARY	1,831,000	2.95	5,401,450	0.474%	0.021%	1.358%	5,499,594	2.95	5,499,594	2.95	2.95	2.95
6	TRANSMISSION	267,000	1.24	331,080	0.474%	0.021%	1.358%	337,096	1.24	337,096	1.24	1.24	1.24
7	ON-PEAK DEMAND: SUMMER												
8	PRIMARY	554,000	20.89	11,573,060	0.474%	0.021%	1.358%	11,783,343	20.89	11,783,343	20.89	23.46	23.46
9	TRANSMISSION	75,000	13.39	1,004,250	0.474%	0.021%	1.358%	1,022,497	13.39	1,022,497	13.39	15.04	15.04
10	ON-PEAK DEMAND: WINTER												
11	PRIMARY	640,000	4.88	3,123,200	0.474%	0.021%	1.358%	3,179,949	4.88	3,179,949	4.88	4.88	4.88
12	TRANSMISSION	68,000	2.17	147,560	0.474%	0.021%	1.358%	150,241	2.17	150,241	2.17	2.17	2.17
13	ON-PEAK ENERGY: SUMMER												
14	PRIMARY	72,624,000	0.04509	3,274,616	0.474%	0.021%	1.358%	3,334,116	0.04262	3,151,275	0.07136	0.05140	0.08014
15	TRANSMISSION	9,775,000	0.04271	417,490	0.474%	0.021%	1.358%	425,076	0.04048	402,892	0.06922	0.04900	0.07774
16	ECAC/AER	82,399,000	0.03441	2,835,350	0.474%	0.021%	1.358%	2,886,868	0.02874	2,411,177		0.02874	
17	SEMI-PEAK ENERGY: SUMMER												
18	PRIMARY	104,879,000	0.01793	1,880,480	0.474%	0.021%	1.358%	1,914,649	0.01824	1,947,659	0.04698	0.02402	0.05276
19	TRANSMISSION	14,841,000	0.01636	242,799	0.474%	0.021%	1.358%	247,210	0.01683	254,311	0.04557	0.02244	0.05118
20	ECAC/AER	119,720,000	0.03441	4,119,565	0.474%	0.021%	1.358%	4,194,418	0.02874	3,503,271		0.02874	
21	OFF-PEAK ENERGY: SUMMER												
22	PRIMARY	165,946,000	0.00449	745,098	0.474%	0.021%	1.358%	758,636	0.00618	1,043,455	0.03492	0.00618	0.03492
23	TRANSMISSION	27,743,000	0.00332	92,107	0.474%	0.021%	1.358%	93,780	0.00513	144,782	0.03387	0.00513	0.03387
24	ECAC/AER	193,689,000	0.03441	6,664,838	0.474%	0.021%	1.358%	6,785,939	0.02874	5,667,768		0.02874	
25	ON-PEAK ENERGY: WINTER												
26	PRIMARY	47,182,000	0.03685	1,738,657	0.474%	0.021%	1.358%	1,770,248	0.03522	1,692,005	0.06396	0.03522	0.06396
27	TRANSMISSION	5,347,000	0.03471	185,594	0.474%	0.021%	1.358%	188,967	0.03330	181,293	0.06204	0.03330	0.06204
28	ECAC/AER	52,529,000	0.03441	1,807,523	0.474%	0.021%	1.358%	1,840,366	0.02874	1,537,114		0.02874	
29	SEMI-PEAK ENERGY: WINTER												
30	PRIMARY	190,981,000	0.01021	1,949,916	0.474%	0.021%	1.358%	1,985,346	0.01131	2,199,212	0.04005	0.01131	0.04005
31	TRANSMISSION	19,187,000	0.00887	170,189	0.474%	0.021%	1.358%	173,281	0.01011	197,448	0.03885	0.01011	0.03885
32	ECAC/AER	210,168,000	0.03441	7,231,881	0.474%	0.021%	1.358%	7,363,284	0.02874	6,149,979		0.02874	
33	OFF-PEAK ENERGY: WINTER												
34	PRIMARY	233,339,000	0.00238	555,347	0.474%	0.021%	1.358%	565,437	0.00428	1,017,270	0.03302	0.00428	0.03302
35	TRANSMISSION	28,204,000	0.00127	35,819	0.474%	0.021%	1.358%	36,470	0.00329	94,348	0.03203	0.00329	0.03203
36	ECAC/AER	261,543,000	0.03441	8,999,695	0.474%	0.021%	1.358%	9,163,219	0.02874	7,653,325		0.02874	
37													
38	TOTAL	920,048,000						66,081,234		61,602,510			
39													
40	TOTAL AL-TOU AND A-6 TOU	5,416,219,000						443,400,126		415,504,000			
41													
42													
43	CURRENT ECAC/AER RATE:			0.03441									
44	ADOPTED ECAC/AER RATE:			0.02874									
45	TOTAL AL-TOU AND A-6 TOU REVENUE ALLOCATION:			415,504,000									
46	DEMAND/ENERGY INCREASE FACTOR:			0.89758									

TABLE 12-6
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 6

LN.	DESCRIPTION (A)	CURRENT BILLING UNITS (B)	RATES ($/UNIT) (C)	CURRENT UNADJUSTED REVENUE ($) (D)	VOLTAGE DISCOUNT FACTOR (%) (E)	SDFFD (%) (F)	CURRENT REVENUE ($) (G)	ADOPTED RATE ($/UNIT) (H)	ADOPTED TOTAL RATE ($/UNIT) (I)	ADOPTED REVENUE ($) (J)
1	SCHEDULE PA-T-1 (AL-TOU DETERMINANTS)									
2										
3	CUSTOMER CHARGE	85,394	30.00	2,561,820	-2.7160%	1.166%	2,521,300	30.00	30.00	2,521,300
4	DEMAND CHARGE ON-PEAK	10,256,000	7.31	74,971,360	-2.7160%	1.166%	73,785,562	9.69	9.69	97,791,945
5	DEMAND CHARGE SEMI-PEAK	0	0.50	0	-2.7160%	1.166%	0			0
6										
7	ON-PEAK ENERGY BASE	776,479,000	0.09399	72,981,261	-2.7160%	1.166%	71,826,940	0.05902	0.08776	45,100,691
8	SEMI-PEAK ENERGY BASE	1,736,005,000	0.05380	93,397,069	-2.7160%	1.166%	91,919,837	0.03378	0.06252	57,717,177
9	OFF-PEAK ENERGY BASE	1,983,687,000	0.01385	27,474,065	-2.7160%	1.166%	27,039,516	0.00870	0.03744	16,978,321
10	ECAC/AER	4,496,171,000	0.03441	154,713,244	0.0000%	1.166%	156,517,201	0.02874		130,726,659
11										
12	TOTAL	4,496,171,000		426,098,819			423,610,355			350,836,094
13										
14	SCHEDULE PA-T-1 (A-6 TOU DETERMINANTS)									
15										
16	CUSTOMER CHARGE	624	600.00	374,400	-3.9210%	1.358%	364,605	600.00	600.00	364,605
17	DEMAND CHARGE ON-PEAK	1,337,000	8.71	11,645,270	-3.9210%	1.358%	11,340,601	11.55	11.55	15,039,425
18	DEMAND CHARGE SEMI-PEAK	0	0.50	0	-3.9210%	1.358%	0			0
19										
20	ON-PEAK ENERGY BASE	134,928,000	0.09399	12,681,883	-3.9210%	1.358%	12,350,093	0.05902	0.08776	7,754,719
21	SEMI-PEAK ENERGY BASE	329,888,000	0.05380	17,747,974	-3.9210%	1.358%	17,283,644	0.03378	0.06252	10,852,533
22	OFF-PEAK ENERGY BASE	455,232,000	0.01385	6,304,963	-3.9210%	1.358%	6,140,010	0.00870	0.03744	3,855,360
23	ECAC/AER	920,048,000	0.03441	31,658,852	0.0000%	1.358%	32,088,779	0.02874		26,801,264
24										
25	TOTAL	920,048,000		80,413,342			79,567,731			64,667,906
26										
27	TOTAL PA-T-1 (AL-TOU AND A-6 TOU DETERMINANTS)						503,178,087			415,504,000
28										
29										
30	REVENUE REQUIREMENT:			415,504,000						
31	INDEX FOR ENERGY RATES:			0.627907737						
32	ADOPTED ECAC/AER:			0.02874						
33										

TABLE 12-7
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 7

LN.	FINAL SCHEDULE PA-T-1 RATES	CURRENT AL-TOU AVG PEAK DMD RATE	CURRENT PA-T-1 PEAK DMD RATE	RATIO OF AL-TOU TO PA-T-1 RATES	ADOPTED AL-TOU AVG PEAK DMD RATE	ADOPTED RATE
1	DEMAND CHARGES ($/KW)					
2	OPTION A (CONTRIBUTION TO PEAK)	$9.69	$11.53	1.1899	$9.69	$11.53
3	OPTION B (ON-PEAK)	$9.69	$10.13	1.0456	$9.69	$10.13
4	OPTION C (ON-PEAK)	$9.69	$9.92	1.0237	$9.69	$9.92
5	OPTION D (ON-PEAK)	$9.69	$10.33	1.0660	$9.69	$10.33
6	OPTION E (ON-PEAK)	$9.69	$10.12	1.0444	$9.69	$10.12
7	OPTION F (ON-PEAK)	$9.69	$9.69	1.0000	$9.69	$9.69
8	SEMI-PEAK DEMAND		$0.50			$0.50
9	ENERGY RATES ($/KWH)					
10	PEAK	---	0.09179	---	---	0.08776
11	SEMI-PEAK	---	0.06725	---	---	0.06252
12	OFF-PEAK	---	0.04287	---	---	0.03744
13						

TABLE 12-8
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 8

LN.	DESCRIPTION	CURRENT BILLING UNITS	CURRENT RATES ($/UNIT)	CURRENT UNADJUSTED REVENUE ($)	VOLTAGE DISCOUNT FACTOR (%)	SOFFD (%)	CURRENT REVENUE ($)	ADOPTED RATE ($/UNIT)	ADOPTED TOTAL RATE ($/UNIT)	ADOPTED REVENUE ($)
1	SCHEDULE AO-TOU									
2										
2	CUSTOMER CHARGE	85,394	50.00	4,269,700	-2.7160%	1.130%	4,200,672	50.00	50.00	4,200,672
3	NON-COINCIDENT DEMAND CHARGE	11,509,000	8.82	101,509,380	-2.7160%	1.130%	99,868,287	8.31	8.31	94,143,625
4	SUMMER ON-PEAK DEMAND CHARGE	4,673,000	15.67	73,225,910	-2.7160%	1.130%	72,042,073	14.77	14.77	67,912,469
5	WINTER ON-PEAK DEMAND CHARGE	5,583,000	4.22	23,560,260	-2.7160%	1.130%	23,179,363	3.98	3.98	21,850,673
6										
7	ON-PEAK ENERGY BASE	776,479,000	0.01217	9,449,749	-2.7160%	1.130%	9,296,976	0.01517	0.04391	11,588,704
8	ON-PEAK ENERGY ECAC/AER	776,479,000	0.03441	26,718,642	0.0000%	1.130%	27,020,563	0.02874		22,568,177
9	SEMI-PEAK ENERGY BASE	1,736,005,000	0.00456	7,916,183	-2.7160%	1.130%	7,788,203	0.00800	0.03674	13,656,950
10	SEMI-PEAK ENERGY ECAC/AER	1,736,005,000	0.03441	59,735,932	0.0000%	1.130%	60,410,948	0.02874		50,456,572
11	OFF-PEAK ENERGY BASE	1,983,687,000	0.00041	813,312	-2.7160%	1.130%	800,163	0.00408	0.03282	7,970,489
12	OFF-PEAK ENERGY ECAC/AER	1,983,687,000	0.03441	68,258,670	0.0000%	1.130%	69,029,993	0.02874		57,655,391
13										
14	TOTAL	4,496,171,000		375,457,738			373,637,242			352,003,722
15										
16	SCHEDULE A06-TOU									
17										
18	CUSTOMER CHARGE	624	250.00	156,000	-3.9210%	0.000%	149,883	250.00	250.00	149,883
19	NON-COINCIDENT DEMAND CHARGE	2,098,000	8.82	18,504,360	-3.9210%	0.000%	17,778,804	8.31	8.31	16,759,685
20	SUMMER ON-PEAK DEMAND CHARGE	629,000	18.67	11,743,430	-3.9210%	0.000%	11,282,970	17.60	17.60	10,635,772
21	WINTER ON-PEAK DEMAND CHARGE	708,000	5.03	3,561,240	-3.9210%	0.000%	3,421,604	4.74	4.74	3,225,470
22										
23	ON-PEAK ENERGY BASE	134,928,000	0.01217	1,642,074	-3.9210%	0.000%	1,577,688	0.01517	0.04391	1,966,592
24	ON-PEAK ENERGY ECAC/AER	134,928,000	0.03441	4,642,872	0.0000%	0.000%	4,642,872	0.02874		3,877,831
25	SEMI-PEAK ENERGY BASE	329,888,000	0.00456	1,504,289	-3.9210%	0.000%	1,445,306	0.00800	0.03674	2,534,407
26	SEMI-PEAK ENERGY ECAC/AER	329,888,000	0.03441	11,351,446	0.0000%	0.000%	11,351,446	0.02874		9,480,981
27	OFF-PEAK ENERGY BASE	455,232,000	0.00041	186,645	-3.9210%	0.000%	179,327	0.00408	0.03282	1,786,289
28	OFF-PEAK ENERGY ECAC/AER	455,232,000	0.03441	15,664,533	0.0000%	0.000%	15,664,533	0.02874		13,083,368
29										
30	TOTAL	920,048,000		68,956,890			67,494,434			63,500,278
31										
32	TOTAL REVENUE COLLECTION	5,416,219,000					441,131,676			415,504,000
33										
34										
35	REVENUE REQUIREMENT:			415,504,000						
36	INDEX FOR ENERGY RATES:			0.94267788						
37				0.001351834						
38	ADOPTED ECAC/AER RATE:			0.02874						

TABLE 12-9
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 9

LINE NO.	DESCRIPTION (A)	BILLING UNITS (B)	ADOPTED AL-TOU RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	SEASONAL ADJUSTMENT FACTOR (E)	STANDBY FACTOR (%) (F)	ADOPTED RATE LIMITER FACTOR (%) (G)	SOFFD (%) (H)	TOTAL REVENUE ($) (I)	NEW RATE ($/UNIT) (J)	TOTAL NEW RATE ($/UNIT) (K)	REVENUE COLLECTED ($) (L)
1	SCHEDULE AL-TOU											
2												
3	CUSTOMER CHARGE	85,394	30.00	2,561,820	0.765%	0.153%	0.006%	1.166%	2,575,675			
4	NON-COINCIDENT DEMAND											
5	SECONDARY	7,238,000	3.71	26,852,980	0.765%	0.153%	0.006%	1.166%	26,998,203			
6	PRIMARY	4,271,000	2.95	12,599,450	0.765%	0.153%	0.006%	1.166%	12,667,589			
7	SUMMER PEAK DEMAND											
8	SECONDARY	2,942,000	17.54	51,602,680	0.765%	0.153%	0.006%	1.166%	51,881,752			
9	PRIMARY	1,731,000	17.54	30,361,740	0.765%	0.153%	0.006%	1.166%	30,525,939			
10	WINTER PEAK DEMAND											
11	SECONDARY	3,499,000	4.08	14,275,920	0.765%	0.153%	0.006%	1.166%	14,353,125			
12	PRIMARY	2,084,000	4.08	8,502,720	0.765%	0.153%	0.006%	1.166%	8,548,703			
13	SUMMER PEAK ENERGY											
14	SECONDARY	307,502,000	0.04753	14,614,659	0.765%	0.153%	0.006%	1.166%	14,693,696			
15	PRIMARY	185,194,000	0.04262	7,892,468	0.765%	0.153%	0.006%	1.166%	7,935,151			
16	ECAC/AER	492,696,000	0.02874	14,160,083	0.765%	0.153%	0.006%	1.166%	14,236,662			
17	SUMMER SEMI-PEAK ENERGY											
18	SECONDARY	354,041,000	0.02058	7,286,803	0.765%	0.153%	0.006%	1.166%	7,326,210			
19	PRIMARY	235,771,000	0.01824	4,300,258	0.765%	0.153%	0.006%	1.166%	4,323,514			
20	ECAC/AER	589,812,000	0.02874	16,951,197	0.765%	0.153%	0.006%	1.166%	17,042,870			
21	SUMMER OFF-PEAK ENERGY											
22	SECONDARY	493,657,000	0.00856	4,227,314	0.765%	0.153%	0.006%	1.166%	4,250,175			
23	PRIMARY	346,925,000	0.00618	2,142,508	0.765%	0.153%	0.006%	1.166%	2,154,095			
24	ECAC/AER	840,582,000	0.02874	24,158,327	0.765%	0.153%	0.006%	1.166%	24,288,977			
25	WINTER PEAK ENERGY											
26	SECONDARY	170,321,000	0.03966	6,754,130	0.765%	0.153%	0.006%	1.166%	6,790,657			
27	PRIMARY	113,462,000	0.03522	3,996,276	0.765%	0.153%	0.006%	1.166%	4,017,888			
28	ECAC/AER	283,783,000	0.02874	8,155,923	0.765%	0.153%	0.006%	1.166%	8,200,031			
29	WINTER SEMI-PEAK ENERGY											
30	SECONDARY	682,313,000	0.01440	9,823,605	0.765%	0.153%	0.006%	1.166%	9,876,732			
31	PRIMARY	463,880,000	0.01131	5,246,410	0.765%	0.153%	0.006%	1.166%	5,274,783			
32	ECAC/AER	1,146,193,000	0.02874	32,941,587	0.765%	0.153%	0.006%	1.166%	33,119,738			
33	WINTER OFF-PEAK ENERGY											
34	SECONDARY	657,099,000	0.00756	4,966,338	0.765%	0.153%	0.006%	1.166%	4,993,197			
35	PRIMARY	486,006,000	0.00428	2,080,992	0.765%	0.153%	0.006%	1.166%	2,092,246			
36	ECAC/AER	1,143,105,000	0.02874	32,852,838	0.765%	0.153%	0.006%	1.166%	33,030,509			
37												
	SUBTOTAL	4,496,171,000		349,309,025					351,198,118			

TABLE 12-10
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 10

LINE NO.	DESCRIPTION (A)	BILLING UNITS (B)	ADOPTED AL-TOU RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	SEASONAL ADJUSTMENT FACTOR (E)	STANDBY FACTOR (%) (F)	ADOPTED RATE LIMITER FACTOR (%) (G)	SDFFD (%) (H)	TOTAL REVENUE ($) (I)	NEW RATE ($/UNIT) (J)	TOTAL NEW RATE ($/UNIT) (K)	REVENUE COLLECTED ($) (L)
38	AY-TOU (AL-TOU DETERMINANTS)											
39												
40	CUSTOMER CHARGE	85,394	30.00	2,561,820	0.765%	0.153%	0.006%	1.166%	2,575,675	30.00	30.00	2,575,675
41	NON-COINCIDENT DEMAND											
42	SECONDARY	7,238,000	3.71	26,852,980	0.765%	0.153%	0.006%	1.166%	26,998,203	3.71	3.71	26,998,203
43	PRIMARY	4,271,000	2.95	12,599,450	0.765%	0.153%	0.006%	1.166%	12,667,589	2.95	2.95	12,667,589
44	YEAR PEAK DEMAND											
45	SECONDARY	6,441,000	10.21	65,781,011	0.765%	0.153%	0.006%	1.166%	66,136,760	10.21	10.21	66,136,760
46	PRIMARY	3,815,000	10.21	38,962,049	0.765%	0.153%	0.006%	1.166%	39,172,759	10.21	10.21	39,172,759
47	YEAR PEAK ENERGY											
48	SECONDARY	477,823,000	0.04472	21,368,789	0.765%	0.153%	0.006%	1.166%	21,484,353	(0.08014)	-0.05140	(38,498,697)
49	PRIMARY	298,656,000	0.03978	11,879,946	0.765%	0.153%	0.006%	1.166%	11,944,194	(0.07668)	-0.04794	(23,024,541)
50	ECAC/AER	776,479,000	0.02874	22,316,006	0.765%	0.153%	0.006%	1.166%	22,436,693	0.02874		22,436,693
51	YEAR SEMI-PEAK ENERGY											
52	SECONDARY	1,036,354,000	0.01651	17,110,408	0.765%	0.153%	0.006%	1.166%	17,202,942	(0.06040)	-0.03166	(62,933,937)
53	PRIMARY	699,651,000	0.01368	9,571,890	0.765%	0.153%	0.006%	1.166%	9,623,655	(0.05842)	-0.02968	(41,094,760)
54	ECAC/AER	1,736,005,000	0.02874	49,892,784	0.765%	0.153%	0.006%	1.166%	50,162,608	0.02874		50,162,608
55	YEAR OFF-PEAK ENERGY											
56	SECONDARY	1,150,756,000	0.00799	9,193,652	0.765%	0.153%	0.006%	1.166%	9,243,372	(0.05444)	-0.02570	(62,983,512)
57	PRIMARY	832,931,000	0.00507	4,223,038	0.765%	0.153%	0.006%	1.166%	4,245,876	(0.05240)	-0.02366	(43,877,848)
58	ECAC/AER	1,983,687,000	0.02874	57,011,164	0.765%	0.153%	0.006%	1.166%	57,319,486	0.02874		57,319,486
59												
60	SUBTOTAL	4,496,171,000		349,324,987					351,214,166			5,056,478
61												

TABLE 12-11
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 11

LINE NO.	DESCRIPTION (A)	BILLING UNITS (B)	ADOPTED AL-TOU RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	SEASONAL ADJUSTMENT FACTOR (E)	STANDBY FACTOR (%) (F)	ADOPTED RATE LIMITER FACTOR (%) (G)	SOFFD (%) (H)	TOTAL REVENUE ($) (I)	NEW RATE ($/UNIT) (J)	TOTAL NEW RATE ($/UNIT) (K)	REVENUE COLLECTED ($) (L)
62	SCHEDULE A6-TOU											
63												
64	CUSTOMER CHARGE	624	600.00	374,400	0.765%	0.474%	0.021%	1.358%	378,300			
65	NON-COINCIDENT DEMAND											
66	PRIMARY	1,831,000	2.95	5,401,450	0.765%	0.474%	0.021%	1.358%	5,457,712			
67	TRANSMISSION	267,000	1.24	331,080	0.765%	0.474%	0.021%	1.358%	334,529			
68	SUMMER PEAK DEMAND											
69	PRIMARY	554,000	20.89	11,573,060	0.765%	0.474%	0.021%	1.358%	11,693,607			
70	TRANSMISSION	75,000	13.39	1,004,250	0.765%	0.474%	0.021%	1.358%	1,014,710			
71	WINTER PEAK DEMAND											
72	PRIMARY	640,000	4.88	3,123,200	0.765%	0.474%	0.021%	1.358%	3,155,732			
73	TRANSMISSION	68,000	2.17	147,560	0.765%	0.474%	0.021%	1.358%	149,097			
74	SUMMER PEAK ENERGY											
75	PRIMARY	72,624,000	0.04262	3,095,039	0.765%	0.474%	0.021%	1.358%	3,127,277			
76	TRANSMISSION	9,775,000	0.04048	395,702	0.765%	0.474%	0.021%	1.358%	399,824			
77	ECAC/AER	82,399,000	0.02874	2,368,147	0.765%	0.474%	0.021%	1.358%	2,392,814			
78	SUMMER SEMI-PEAK ENERGY											
79	PRIMARY	104,879,000	0.01824	1,912,902	0.765%	0.474%	0.021%	1.358%	1,932,827			
80	TRANSMISSION	14,841,000	0.01683	249,773	0.765%	0.474%	0.021%	1.358%	252,375			
81	ECAC/AER	119,720,000	0.02874	3,440,753	0.765%	0.474%	0.021%	1.358%	3,476,592			
82	SUMMER OFF-PEAK ENERGY											
83	PRIMARY	165,946,000	0.00618	1,024,834	0.765%	0.474%	0.021%	1.358%	1,035,509			
84	TRANSMISSION	27,743,000	0.00513	142,198	0.765%	0.474%	0.021%	1.358%	143,679			
85	ECAC/AER	193,689,000	0.02874	5,566,622	0.765%	0.474%	0.021%	1.358%	5,624,605			
86	WINTER PEAK ENERGY											
87	PRIMARY	47,182,000	0.03522	1,661,810	0.765%	0.474%	0.021%	1.358%	1,679,120			
88	TRANSMISSION	5,347,000	0.03330	178,058	0.765%	0.474%	0.021%	1.358%	179,912			
89	ECAC/AER	52,529,000	0.02874	1,509,683	0.765%	0.474%	0.021%	1.358%	1,525,409			
90	WINTER SEMI-PEAK ENERGY											
91	PRIMARY	190,981,000	0.01131	2,159,965	0.765%	0.474%	0.021%	1.358%	2,182,464			
92	TRANSMISSION	19,187,000	0.01011	193,925	0.765%	0.474%	0.021%	1.358%	195,945			
93	ECAC/AER	210,168,000	0.02874	6,040,228	0.765%	0.474%	0.021%	1.358%	6,103,144			
94	WINTER OFF-PEAK ENERGY											
95	PRIMARY	233,339,000	0.00428	999,116	0.765%	0.474%	0.021%	1.358%	1,009,523			
96	TRANSMISSION	28,204,000	0.00329	92,665	0.765%	0.474%	0.021%	1.358%	93,630			
97	ECAC/AER	261,543,000	0.02874	7,516,746	0.765%	0.474%	0.021%	1.358%	7,595,041			
98												
	SUBTOTAL	920,048,000		60,503,166					61,133,375			

TABLE 12-12
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 12

LINE NO.	DESCRIPTION (A)	BILLING UNITS (B)	ADOPTED AL-TOU RATES ($/UNIT) (C)	UNADJUSTED REVENUE ($) (D)	SEASONAL ADJUSTMENT FACTOR (E)	STANDBY FACTOR (%) (F)	ADOPTED RATE LIMITER FACTOR (%) (G)	SOFFD (%) (H)	TOTAL REVENUE ($) (I)	NEW RATE ($/UNIT) (J)	TOTAL NEW RATE ($/UNIT) (K)	REVENUE COLLECTED ($) (L)
99	AY-TOU (A-6 DETERMINANTS)											
100												
101	CUSTOMER CHARGE	624	600.00	374,400	0.765%	0.474%	0.021%	1.358%	378,300	600.00	600.00	378,300
102	NON-COINCIDENT DEMAND											
103	PRIMARY	1,831,000	2.95	5,401,450	0.765%	0.474%	0.021%	1.358%	5,457,712	2.95	2.95	5,457,712
104	TRANSMISSION	267,000	1.24	331,080	0.765%	0.474%	0.021%	1.358%	334,529	1.24	1.24	334,529
105	YEAR PEAK DEMAND											
106	PRIMARY	1,194,000	12.31	14,696,260	0.765%	0.474%	0.021%	1.358%	14,849,338	12.31	12.31	14,849,338
107	TRANSMISSION	143,000	8.05	1,151,810	0.765%	0.474%	0.021%	1.358%	1,163,807	8.05	8.05	1,163,807
108	YEAR PEAK ENERGY											
109	PRIMARY	119,806,000	0.03978	4,765,646	0.765%	0.474%	0.021%	1.358%	4,815,286	(0.07668)	-0.04794	(9,282,313)
110	TRANSMISSION	15,122,000	0.03794	573,760	0.765%	0.474%	0.021%	1.358%	579,736	(0.07539)	-0.04665	(1,151,993)
111	ECAC/AER	134,928,000	0.02874	3,877,831	0.765%	0.474%	0.021%	1.358%	3,918,223	0.02874		3,918,223
112	YEAR SEMI-PEAK ENERGY											
113	PRIMARY	295,860,000	0.01368	4,047,646	0.765%	0.474%	0.021%	1.358%	4,089,807	(0.05842)	-0.02968	(17,464,218)
114	TRANSMISSION	34,028,000	0.01304	443,698	0.765%	0.474%	0.021%	1.358%	448,319	(0.05797)	-0.02923	(1,993,189)
115	ECAC/AER	329,888,000	0.02874	9,480,981	0.765%	0.474%	0.021%	1.358%	9,579,736	0.02874		9,579,736
116	YEAR OFF-PEAK ENERGY											
117	PRIMARY	399,285,000	0.00507	2,024,412	0.765%	0.474%	0.021%	1.358%	2,045,499	(0.05240)	-0.02366	(21,138,647)
118	TRANSMISSION	55,947,000	0.00420	234,863	0.765%	0.474%	0.021%	1.358%	237,309	(0.05179)	-0.02305	(2,927,410)
119	ECAC/AER	455,232,000	0.02874	13,083,368	0.765%	0.474%	0.021%	1.358%	13,219,646	0.02874		13,219,646
120												
121	SUBTOTAL	920,048,000							61,117,247			(5,056,478)
122												
123	TOTAL AL & A6 (SEASONAL)	5,416,219,000							412,331,493			
124	TOTAL FOR AY (ANNUAL)	5,416,219,000							412,331,413			0
125												
126												
127	AL-TOU ON-PEAK TRANSMISSION: SUMMER		11.03									
128	AL-TOU ON-PEAK TRANSMISSION: WINTER		1.64									
129	SCHEDULE AY-TOU ON-PEAK TRANSMISSION		5.85									

TABLE 12-13
COMMERCIAL AND AGRICULTURAL RATE DESIGN, PAGE 13

SCHEDULE I-3

METHODOLOGY: 1986 GRC adopted disaggregation methodology, current marginal capacity costs. No change to per interruption credit. Original allocation of transmission costs. Maintain relationship of I-1 and I-2.

LN.	DESCRIPTION (A)	(B)	(C)	(D)	(E)
1	MARGINAL CAPACITY VALUE ($/kW/yr)				75.30
2	(from report on cost of service)				
3					
4	MARGINAL TRANSMISSION COSTS		25.05	x 50% =	12.525
5					----------
6					87.825
7					
8					
9					
10	WEIGHTING ADJUSTMENTS:				
11	(5-year contract = 100%, 1-year contract = 80%)				
12	(30 minute notice = 75% of 10 minute notice)				
13	(customer-controlled = 92% of utility controlled)				
14					
15					
16	PER OCCURANCE CREDIT:				
17	10-YR AVG NO. OF AE-TYPE INTERRUPTION (annual)				6.5
18	PER OCCURANCE CREDIT ($/kW/interruption)				0.28
19	PERFORMANCE CREDIT ($/kW/yr, annual)				1.82
20					
21					
22	MONTHLY CREDIT:	RATE A	RATE B	RATE C	RATE D
23		--------	--------	--------	--------
24	SCHEDULE I-1	$3.49	$2.37	N/A	N/A
25					
26	SCHEDULES I-2, I-3				
27	1-YEAR CONTRACT	$5.73	$5.27	$4.30	$3.96
28	5-YEAR CONTRACT	$7.17	$6.59	$5.38	$4.95

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TABLE 13-1
LIGHTING RATE DESIGN, PAGE 1

STREET LIGHT -- REVENUE AT ADOPTED RATES

LINE NO.	DESCRIPTION # LAMPS (A)	WATTS (B)	LUMENS (C)	ADOPTED RATE ($/Lamp) (D)	SUB-TOTAL REVENUE ($) (E)	SOFFD FACTOR (%) (F)	TOTAL REVENUE ($) (G)	LINE NO.
----	---------	------	---------	-------	-----------	-------	-----------	----
1	LS-1, Mercury Vapor, Class A							1
2	7,858	175	7,000	$9.81	$77,079	0.054%	$77,121	2
3	123	250	10,000	$12.97	$1,595	0.054%	$1,596	3
4	2,074	400	20,000	$17.67	$36,647	0.054%	$36,667	4
5	56	700	35,000	$33.44	$1,872	0.054%	$1,873	5
6	LS-1, Mercury Vapor, Class C, 1-Lamp							6
7	448	175	7,000	$18.46	$8,268	0.054%	$8,273	7
8	1	250	10,000	$24.48	$24	0.054%	$24	8
9	314	400	20,000	$29.18	$9,162	0.054%	$9,167	9
10	LS-1, Mercury Vapor, Class C, 2-Lamp							10
11	34	175	7,000	$28.00	$952	0.054%	$952	11
12	1	400	20,000	$47.44	$47	0.054%	$47	12
13	LS-1, HPSV, Class A							13
14	19,280	70	5,800	$6.44	$124,162	0.054%	$124,229	14
15	146,977	100	9,500	$7.42	$1,091,081	0.054%	$1,091,670	15
16	5,593	150	16,000	$8.76	$49,023	0.054%	$49,049	16
17	146	200	22,000	$10.53	$1,537	0.054%	$1,538	17
18	19,269	250	30,000	$13.27	$255,676	0.054%	$255,815	18
19	168	400	50,000	$16.48	$2,769	0.054%	$2,770	19
20	1	1000	140,000	$34.19	$34	0.054%	$34	20
21	LS-1, HPSV, Class B, 1-Lamp							21
22	7,656	70	5,800	$7.12	$54,545	0.054%	$54,574	22
23	17,969	100	9,500	$8.11	$145,693	0.054%	$145,771	23
24	1,995	150	16,000	$9.45	$18,855	0.054%	$18,865	24
25	527	200	22,000	$11.40	$6,009	0.054%	$6,012	25
26	4,192	250	30,000	$14.15	$59,329	0.054%	$59,361	26
27	90	400	50,000	$17.46	$1,571	0.054%	$1,572	27
28	1	1000	140,000	$35.24	$35	0.054%	$35	28
29	LS-1, HPSV, Class B, 2-Lamp							29
30	179	70	5,800	$12.37	$2,214	0.054%	$2,215	30
31	1,121	100	9,500	$14.34	$16,070	0.054%	$16,079	31
32	1,199	150	16,000	$17.02	$20,407	0.054%	$20,419	32
33	1	200	22,000	$20.79	$21	0.054%	$21	33
34	34	250	30,000	$26.29	$894	0.054%	$894	34
35	1	400	50,000	$32.63	$33	0.054%	$33	35
36	1	1000	140,000	$68.17	$68	0.054%	$68	36
37	LS-1, HPSV, Class C, 1-Lamp							37
38	13,877	70	5,800	$15.08	$209,293	0.054%	$209,406	38
39	52,326	100	9,500	$16.07	$840,645	0.054%	$841,099	39
40	4,147	150	16,000	$17.42	$72,261	0.054%	$72,300	40
41	1	200	22,000	$22.02	$22	0.054%	$22	41
42	5,268	250	30,000	$24.77	$130,509	0.054%	$130,579	42
43	1,569	400	50,000	$29.44	$46,194	0.054%	$46,219	43
44	1	1000	140,000	$48.12	$48	0.054%	$48	44

TABLE 13-2
LIGHTING RATE DESIGN, PAGE 2

STREET LIGHT -- REVENUE AT ADOPTED RATES

LINE NO.	# LAMPS (A)	DESCRIPTION WATTS (B)	LUMENS (C)	ADOPTED RATE ($/Lamp) (D)	SUB-TOTAL REVENUE ($) (E)	SOFFD FACTOR (%) (F)	TOTAL REVENUE ($) (G)	LINE NO.
1	LS-1, HPSV, Class C, 2-Lamp							1
2	448	70	5,800	$21.25	$9,519	0.054%	$9,525	2
3	919	100	9,500	$23.22	$21,335	0.054%	$21,347	3
4	235	150	16,000	$25.92	$6,090	0.054%	$6,094	4
5	1	200	22,000	$33.13	$33	0.054%	$33	5
6	504	250	30,000	$38.63	$19,469	0.054%	$19,480	6
7	1	400	50,000	$43.97	$44	0.054%	$44	7
8	1	1000	140,000	$80.81	$81	0.054%	$81	8
9	LS-1, LPSV, Class A							9
10	1	35	4,800	$7.93	$8	0.054%	$8	10
11	560	55	8,000	$8.56	$4,793	0.054%	$4,795	11
12	370	90	13,500	$10.52	$3,891	0.054%	$3,893	12
13	112	135	22,500	$12.96	$1,451	0.054%	$1,452	13
14	1,928	180	33,000	$14.06	$27,112	0.054%	$27,126	14
15	LS-1, LPSV, Class B, 1-Lamp							15
16	1	35	4,800	$8.63	$9	0.054%	$9	16
17	276	55	8,000	$9.36	$2,582	0.054%	$2,584	17
18	242	90	13,500	$11.32	$2,739	0.054%	$2,741	18
19	241	135	22,500	$13.95	$3,363	0.054%	$3,364	19
20	241	180	33,000	$15.06	$3,630	0.054%	$3,631	20
21	LS-1, LPSV, Class B, 2-Lamp							21
22	1	35	4,800	$15.37	$15	0.054%	$15	22
23	1	55	8,000	$16.73	$17	0.054%	$17	23
24	1	90	13,500	$20.65	$21	0.054%	$21	24
25	1	135	22,500	$25.79	$26	0.054%	$26	25
26	1	180	33,000	$28.00	$28	0.054%	$28	26
27	LS-1, LPSV, Class C, 1-Lamp							27
28	1	35	4,800	$16.58	$17	0.054%	$17	28
29	359	55	8,000	$17.32	$6,217	0.054%	$6,220	29
30	280	90	13,500	$19.30	$5,403	0.054%	$5,406	30
31	247	135	22,500	$24.58	$6,070	0.054%	$6,073	31
32	269	180	33,000	$25.68	$6,909	0.054%	$6,913	32
33	LS-1, LPSV, Class C, 2-Lamp							33
34	1	35	4,800	$24.25	$24	0.054%	$24	34
35	1	55	8,000	$25.61	$26	0.054%	$26	35
36	1	90	13,500	$29.55	$30	0.054%	$30	36
37	1	135	22,500	$38.13	$38	0.054%	$38	37
38	1	180	33,000	$40.34	$40	0.054%	$40	38

TABLE 13-3
LIGHTING RATE DESIGN, PAGE 3

STREET LIGHT -- REVENUE AT ADOPTED RATES

LINE NO.	# LAMPS (A)	DESCRIPTION WATTS (B)	LUMENS (C)	ADOPTED RATE ($/Lamp) (D)	SUB-TOTAL REVENUE ($) (E)	SOFFD FACTOR (%) (F)	TOTAL REVENUE ($) (G)	LINE NO.
1	LS-1, Facilities and Rates, Class A							1
2	12	Center Suspension		$4.77	$57	0.054%	$57	2
3		Non-Standard Wood Pole						3
4	9,264	30-foot		$2.39	$22,134	0.054%	$22,146	4
5	1,680	35-foot		$2.69	$4,512	0.054%	$4,514	5
6		Recator Ballast Discount						6
7	3,139	175		($0.97)	($3,060)	0.054%	($3,062)	7
8	11	250		($0.38)	($4)	0.054%	($4)	8
9	Subtotal Revenue LS-1				$3,439,312		$3,441,169	9
10	----------							10
11								11
12	LS-2, Mercury Vapor, Rate A							12
13	22,621	175	7,000	$5.04	$113,926	0.751%	$114,781	13
14	471	250	10,000	$7.00	$3,298	0.751%	$3,323	14
15	11,546	400	20,000	$11.03	$127,374	0.751%	$128,330	15
16	482	700	35,000	$18.71	$9,016	0.751%	$9,084	16
17	45	1000	55,000	$26.43	$1,189	0.751%	$1,198	17
18	LS-2, Mercury Vapor, Rate B, Energy & Limited Maintenance							18
19	6,401	175	7,000	$5.64	$36,097	0.751%	$36,368	19
20	22	250	10,000	$7.61	$167	0.751%	$169	20
21	1,625	400	20,000	$11.64	$18,918	0.751%	$19,060	21
22	LS-2, Mercury Vapor, Surcharge for series service							22
23	804	175	7,000	$0.40	$320	0.751%	$323	23
24	1	250	10,000	$0.50	$1	0.751%	$1	24
25	3,900	400	20,000	$0.72	$2,813	0.751%	$2,834	25
26	312	700	35,000	$1.32	$412	0.751%	$415	26
27	LS-2, HPSV, Rate A							27
28	1,334	50	3,300	$1.39	$1,856	0.751%	$1,869	28
29	46,452	70	5,800	$2.42	$112,516	0.751%	$113,361	29
30	85,808	100	9,500	$3.38	$290,160	0.751%	$292,339	30
31	23,697	150	16,000	$4.63	$109,683	0.751%	$110,507	31
32	26,622	200	22,000	$5.90	$157,060	0.751%	$158,240	32
33	48,010	250	30,000	$7.51	$360,384	0.751%	$363,091	33
34	3,441	310	37,000	$9.19	$31,606	0.751%	$31,844	34
35	3,654	400	50,000	$11.42	$41,712	0.751%	$42,026	35
36	1	1000	140,000	$26.43	$26	0.751%	$27	36

TABLE 13-4
LIGHTING RATE DESIGN, PAGE 4

STREET LIGHT -- REVENUE AT ADOPTED RATES

LINE NO.	# LAMPS (A)	DESCRIPTION WATTS (B)	LUMENS (C)	ADOPTED RATE ($/Lamp) (D)	SUB-TOTAL REVENUE ($) (E)	SOFFD FACTOR (%) (F)	TOTAL REVENUE ($) (G)	LINE NO.
1	LS-2, HPSV, Rate B, Energy & Limited Maintenance							1
2	1	50	3,300	$2.07	$2	0.751%	$2	2
3	796	70	5,800	$3.10	$2,465	0.751%	$2,483	3
4	1,087	100	9,500	$4.06	$4,408	0.751%	$4,442	4
5	2,376	150	16,000	$5.32	$12,651	0.751%	$12,746	5
6	1	200	22,000	$6.59	$7	0.751%	$7	6
7	572	250	30,000	$8.20	$4,689	0.751%	$4,724	7
8	1	310	37,000	$9.89	$10	0.751%	$10	8
9	1	400	50,000	$12.12	$12	0.751%	$12	9
10	1	1000	140,000	$27.29	$27	0.751%	$27	10
11	LS-2, HPSV, Reduction for 120-volt Reactor Ballast							11
12	20,782	70	5,800	($0.40)	($8,305)	0.751%	($8,368)	12
13	18,888	100	9,500	($0.53)	($10,064)	0.751%	($10,140)	13
14	8,048	150	16,000	($0.49)	($3,931)	0.751%	($3,961)	14
15	LS-2, HPSV, Surcharge for Series Service							15
16	1	50	3,300	$0.45	$0	0.751%	$0	16
17	1	70	5,800	($0.22)	($0)	0.751%	($0)	17
18	336	100	9,500	($0.23)	($77)	0.751%	($77)	18
19	156	150	16,000	$0.02	$3	0.751%	$3	19
20	132	200	22,000	$0.47	$63	0.751%	$63	20
21	LS-2, LPSV, Rate A							21
22	22,183	35	4,800	$1.56	$34,606	0.751%	$34,866	22
23	259,621	55	8,000	$2.05	$531,955	0.751%	$535,950	23
24	70,832	90	13,500	$3.38	$239,139	0.751%	$240,935	24
25	57,796	135	22,500	$4.80	$277,216	0.751%	$279,298	25
26	16,680	180	33,000	$5.47	$91,268	0.751%	$91,953	26
27	LS-2, LPSV, Surcharge for series service							27
28	15,108	35	4,800	($0.23)	($3,441)	0.751%	($3,467)	28
29	13,788	55	8,000	($0.13)	($1,832)	0.751%	($1,846)	29
30	1,596	90	13,500	$0.45	$712	0.751%	$717	30
31	16,572	135	22,500	$0.80	$13,212	0.751%	$13,311	31
32	120	180	33,000	$0.51	$62	0.751%	$62	32
33	LS-2, Incandescent Lamps, Rate A, Energy Only							33
34	493		1,000	$1.70	$838	0.751%	$844	34
35	22		2,500	$3.77	$83	0.751%	$84	35
36	1		4,000	$5.68	$6	0.751%	$6	36
37	168		6,000	$8.34	$1,400	0.751%	$1,411	37
38	34		10,000	$14.16	$481	0.751%	$485	38
39	LS-2, Incdsnt Lamps, Rate B, Energy and Limited Maintenance							39
40	1		4,000	$7.64	$8	0.751%	$8	40
41	67		6,000	$10.34	$693	0.751%	$698	41
42								42
43	Subtotal Revenue LS-2				$2,606,898	0.751%	$2,626,476	43
44	------------	------------	------------	------------	------------	------------	------------	44

TABLE 13-5
LIGHTING RATE DESIGN, PAGE 5

STREET LIGHT -- REVENUE AT ADOPTED RATES

LINE NO.	# LAMPS (A)	DESCRIPTION WATTS (B)	LUMENS (C)	ADOPTED RATE ($/Lamp) (D)	SUB-TOTAL REVENUE ($) (E)	SOFFD FACTOR (%) (F)	TOTAL REVENUE ($) (G)	LINE NO.
1								1
2	LS-3							2
3	5,532,000	Energy Charge		$0.07338	$405,962	1.155%	$410,651	3
4	1	Minimum Charge		$5.81	$6	1.155%	$6	4
5								5
6	Subtotal Revenue LS-3				$405,968	1.1550%	$410,657	6
7	------------------------							7
8								8
9	OL-1, Mercury Vapor, Rate A, St Light Luminaire							9
10	1	175	7,000	$9.69	$10	0.689%	$10	10
11	1	400	20,000	$19.52	$20	0.689%	$20	11
12	OL-1, HPSV, Rate A, Street Light Luminaire							12
13	54,926	100	9,500	$8.21	$451,136	0.689%	$454,244	13
14	3,531	150	16,000	$9.57	$33,787	0.689%	$34,019	14
15	31,386	250	30,000	$14.56	$457,089	0.689%	$460,238	15
16	1,569	400	50,000	$17.51	$27,466	0.689%	$27,655	16
17	1	1000	140,000	$35.89	$36	0.689%	$36	17
18	OL-1, HPSV, Rate B, Directional Luminaire							18
19	1,681	250	30,000	$17.20	$28,920	0.689%	$29,119	19
20	560	400	50,000	$21.07	$11,798	0.689%	$11,879	20
21	168	1000	140,000	$36.66	$6,159	0.689%	$6,202	21
22	OL-1, LPSV, Rate A, Street Light Luminaire							22
23	0	55	8,000	$8.67	$0	0.689%	$0	23
24	0	90	13,000	$10.65	$0	0.689%	$0	24
25	0	135	22,500	$13.12	$0	0.689%	$0	25
26	0	180	33,000	$14.24	$0	0.689%	$0	26
27	OL-1, Pole							27
28	14,040	30 ft wood pole		$3.15	$44,267	0.689%	$44,572	28
29	18,000	35 ft wood pole		$3.54	$63,761	0.689%	$64,200	29
30								30
31	SUBTOTAL REVENUE OL-1				$1,124,447	0.689%	$1,132,194	31
32	------------------------							32
33								33
34	DWL, Facilities Charges							34
35	8,500,000	$ of Util Invst.		$0.0186	$158,100	0.465%	$158,835	35
36	DWL, Energy and Lamp Maintance Charge							36
37	13,732	50 Watt HPSV		$3.15	$43,316	0.465%	$43,517	37
38	1	DWL, Min. Charge		$151.16	$151	0.465%	$152	38
39								39
40	SUBTOTAL REVENUE DWL				$201,567	0.465%	$202,504	40
41	------------------------							41
42	TOTAL STREET LIGHT REVENUES				$7,778,192		$7,813,000	42
43	========================							43
44								44

TABLE 13-6
LIGHTING RATE DESIGN, PAGE 6

SCHEDULE LR

LN.		OPTION 1 (A)	OPTION 2 (B)
1			
2	Current Yearly Capacity Value ($/kW/year) /1	70.94	
3			
4	Minimum number of trigger hours	5.0	
5	Maximum number of trigger hours	80.0	
6			
7	LOLP (ELFIN): /2		
8	February	2.87%	
9	March	0.24%	
10	Weekends	0.00%	
11			
12	LOLE (ELFIN):		
13	February	1.70%	
14	March	0.00%	
15	Weekends	0.00%	
16			
17			
18			
19	Customer Charge ($/month) /3	150.00	150.00
20			
21	LOLP: /2		
22	Monthly Credit ($/kW/month)	5.73	4.30
23	Energy Credit: kWh output over contract ($/kWh)	0.85917	0.64438
24	Energy Charge: kWh output under contract ($/kWh)	13.74675	10.31006
25			
26	LOLE:		
27	Monthly Credit ($/kW/month)	5.81	4.36
28	Energy Credit: kWh output over contract ($/kWh)	0.87168	0.65376
29	Energy Charge: kWh output under contract ($/kWh)	13.94680	10.46010
30			
31			
32	NOTES:		
33	/1 From SDG&E Avoided Energy & Capacity Prices for the period 11/1/91		
34	through 1/31/92.		
35	/2 LOLP data calculated as part of 1991 ECAC application (A.91-09-059).		
36	/3 Adjusted A-E2 telemetering differential.		
37			

(END OF APPENDIX A)

APPENDIX B

Applicant: E. Gregory Barnes, Michael C. Tierney, Attorneys at Law, and Lynn G. Van Wagenen, for San Diego Gas & Electric Company.

Interested Parties: Deborah L. Berger and Peter Allen, Attorneys at Law, for City of San Diego; Messrs. Morrison & Foerster, by Jerry R. Bloom and Kevin D. Debre, Attorneys at Law, for California Cogeneration Council; Thomas R. Brill, Attorney at Law, for Southern California Gas Company; Maurice Brubaker, for Drazen-Brubaker & Associates; John M. Edwards, for Sithe Energies, U.S.A., Inc.; Phillip D. Endom, Attorney at Law, and Phyllis Huckabee, for El Paso Natural Gas Company; Norman Furuta, for Federal Executive Agencies; Messrs. Morrison & Foerster, by Joseph M. Karp, Attorney at Law, and Barry Lovell, for University Cogeneration; Bruce A. Reed, and Janet Lohmann, Attorneys at Law, and David R. Hinman, for Southern Calfiornia Edison Company; Michael Shames, Attorney at Law, for Utility Consumers' Action Network (UCAN); Messrs. Armour, Goodin, Schlotz & MacBride, by James D. Squeri, Attorney at Law, for Kelco Division of Merck & Company, Inc.; and Mark Younger, for California Cogeneration Company.

Division of Ratepayer Advocates: Alberto Guerrero, Attorney at Law, and Linda Gustafson.

(END OF APPENDIX B)