Mailed JUN 12 1996

Decision 96-06-033 June 6, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of San Diego Gas & Electric Company for Authority to Increase its Rates and Charges for Electric, Gas, and Steam Service, Effective January 1, 1993.	Application 91-11-024 (Filed November 20, 1991)
Application of San Diego Gas & Electric Company (1) for authority to decrease its electric rates effective June 1, 1996 and (2) for a Commission Order Finding SDG&E's Nuclear and Certain Natural Gas Operations and Expenses Reasonable for the Applicable Record Period (U 902 E)	Application 95-10-006 (Filed October 16, 1995)

(See Appendix B for List of Appearances.)

O P I N I O N

San Diego Gas & Electric Company (SDG&E) filed Application (A.) 95-10-006, its Energy Cost Adjustment Clause (ECAC) application seeking authority to decrease its electric revenues on June 1, 1996, by approximately $18.0 million. The application also recommended the following changes to the various components used in calculating short-run avoided cost (SRAC) energy prices for qualifying facilities (QFs). Specifically, SDG&E proposed to set: 1) the Incremental Energy Rate (IER) at 8,820 Btu/kilowatt hour (kWh); 2) the Operations & Maintenance (O&M) Adder at 0.00 mill/kWh; 3) the Incremental Heat Rate (IHR) at 10,319 Btu/kWh; and 4) the Shortage Cost Value (SCV) at $70.34/kWyr.

SDG&E, on November 1, 1995, filed its Rate Design Window (RDW) update in A.91-11-024, which recommended various revenue allocation/rate design proposals for concurrent implementation with its ECAC filing, A.95-10-006.

Division of Ratepayer Advocates (DRA) issued its report on January 16, 1996 in A.95-10-006. The DRA report recommended that SDG&E decrease its revenues by $105 million. DRA also proposed SRAC pricing components of: 1) 9,362 Btu/kWh for the IER; 2) 0.00 mill/kWh for the O&M Adder; 3) an IHR of 9,989 Btu/kWh; and 4) an SCV of $70.34/kWyr. DRA's report in A.91-11-024 was issued December 1995.

On February 14, 1996, prior to hearing, SDG&E, on its own behalf and on behalf of the parties listed below, moved the Commission to adopt the Settlement Agreement (the Settlement (attached hereto as Attachment A)) reached between the parties for the forecast period May 1996-April 1997 in A.95-10-006. The parties assert that the Settlement presents a just, reasonable, and fair resolution of the issues surrounding the forecast phase of SDG&E's 1996 ECAC proceeding. The parties to the Settlement are SDG&E, the California Cogeneration Council (CCC), DRA, Kelco, a unit of Monsanto Company (Kelco), and Utility Consumers' Action Network (UCAN).

On March 13, 1996, SDG&E and all the active parties in A.91-11-024, the RDW portion of this consolidated proceeding, filed a proposed RDW Settlement, admitted in evidence as Exhibit 111. This Settlement proposes resolutions to all rate design, marginal cost, and revenue allocation issues raised in both the RDW and ECAC portions of this joint proceeding.

Public hearing on the proposed Settlements was held on March 20, 1996 before Commissioner J. L. Neeper and Administrative Law Judge (ALJ) Robert Barnett.

I. Summary of the Settlement in A.95-10-006

This Settlement recommends a total revenue requirement decrease for SDG&E of approximately $21.9 million. The significant difference between this and DRA's originally proposed reduction of $105 million primarily reflects 1) SDG&E's implementation of the San Onofre Nuclear Generating Station (SONGS) 2&3 Incremental Cost Incentive Pricing (ICIP) mechanism resulting from Decision (D.) 96-01-011, (which was issued by the Commission after DRA's report was issued), and 2) the parties' proposed direct refund to SDG&E's customers of approximately $35 million.

The Settlement also recommends adoption of specific QF payment components. The parties achieved an agreement on those values with the understanding that should the Commission adopt a revised methodology for calculating SRAC payments prior to May 1997, the Commission's new methodology would govern.

After reviewing the proposed Settlement, the presiding ALJ requested from the settling parties further clarification of the Settlement, especially in regard to the ICIP. On March 15, the parties responded. The response was admitted as Exhibit 13.

Table 1-1 of the Settlement shows removal of $65,600,000 from base rate revenues and an increase of $122,700,000 to ICIP revenue. The ALJ requested an explanation of the apparent $57.1 million increase. The parties responded that the increase resulted from shifting some expenses from other accounts to the ICIP account and incorporating the ICIP formula authorized in the Southern California Edison Company (Edison) general rate case, A.93-12-025, in which SDG&E participated. (D.96-01-011 and D.96-04-059 set forth the formula.)

The SONGS 2&3 ICIP methodology eliminates many of the individual components of recovering the incremental costs associated with SONGS and creates an ICIP rate that is used to develop a revenue stream for SONGS. The ICIP rates of 3.8 cents/kWh for May 1996 through December 1996 and 3.85 cents/kWh for January 1997 through April 1997, are multiplied by the forecasted SONGS generation, resulting in $122.7 million revenue requirement. The major cost differences between the $65.6 million and $122.7 million are set forth below. These estimates are affected by the fact that as a result of the SONGS Settlement negotiations, the ICIP rate was effectively levelized over an 8-year recovery period.

Revenue Increase Due to Implementation of ICIP Rev. Req.	$ in Millions
1. Nuclear Fuel Expenses removed from ECAC	18
2. Levelized recovery of SONGS operating costs and capital additions*	29
3. Higher capacity factor adopted in the ECAC Settlement as compared to the SONGS proceeding (83.5% vs. 78%)	7
4. The $65.6 million removed from base rates does not reflect 1997 inflation	2
5. Increase due to ICIP rate rising to 3.85 cents/kWh in January 1997	1
TOTAL	57

*The ICIP pricing reflects a positive cash flow in the early years and a negative cash flow in the latter years compared to cost-based forecasts. The revenue stream allows capital additions to be expensed rather than capitalized. (Exhibit 450, A.93-12-025, p. 3-8.)

The ECAC overcollection, as of April 30, 1996, is estimated at $77.4 million. The ERAM undercollection is estimated at $35 million. The Settlement proposes a $35 million refund. Refunding almost half of the overcollection allows SDG&E to provide ratepayers an overall decrease to the system average rate as well as providing an immediate credit to their bills. Further, it continues moving SDG&E's prices towards the equal percent of marginal cost (EPMC) goal while keeping rates relatively stable.

If the total overcollection of $77.4 million was refunded in one month, similar to the order for Edison in D.96-02-071, SDG&E's system average rate would jump to 9.92 cents/kWh from the currently authorized system average rate of 9.87 cents/kWh. The Settlement's refund plan results in a system average rate of 9.64 cents/kWh, a reduction from the currently authorized level. Furthermore, the Settlement results in a revenue requirement <u>decrease</u> of $21.9 million. A one-time refund of the full amount of the ECAC overcollection would cause a revenue requirement <u>increase</u> of $21.4 million. The parties firmly believe it is not in the public interest to raise rates to customers at the same time a refund is provided. This results in significant customer confusion and is counter to the commitment of SDG&E to reduce rates.

Although we prefer a one-time refund of an overcollection, under the circumstances where there is an ERAM offset of $35 million, we are reluctant to disturb an otherwise reasonable Settlement.

II. <u>Summary of the Settlement in A.91-11-024</u>

This RDW Settlement proposes that the revenue requirement decrease recommended in the ECAC Settlement be allocated to customer classes using a capped EPMC methodology. The parties have settled upon the technical details and capping parameters necessary to accomplish this. The parties agree that the marginal costs set forth in this RDW Settlement be used to allocate revenue in this proceeding only. The RDW Settlement also proposes two flexible contracting options as tools to obtain or attract new customers, and retain or prevent customer flight from SDG&E's service territory.

We will adopt the RDW Settlement. Set forth below is a summary of the principal issues settled. Refer to Exhibit 111 for the entire RDW Settlement.

A. <u>Revenue Allocation</u>

The parties propose allocating revenue to customer classes based on the Commission adopted capped EPMC methodology. The parties recommend that the allocation determinants proposed by SDG&E be adopted for revenue allocation in this proceeding only, since no party disputed the values; that the revenue requirement proposed in the ECAC Settlement be used as the recommended authorized revenue for revenue allocation purposes; and that a compromise methodology be adopted for the technical method of applying caps since different methods have been proposed by the parties.

The parties recommend for adoption, in this proceeding only, the following: (1) UCAN's proposed technical EPMC capping methodology, a cap, or upper constraint, of a 1% decrease for all classes, and a floor, or lower constraint, of two times the SAPC less the 1%. The 1% is applied after the full EPMC is applied; (2) DRA's proposed constraints of no change (0%) and minus two times SAPC (2.82% decrease based on ECAC Settlement revenue requirement of 1.41% decrease); (3) SDG&E's proposed Schedule AD and AL-TOU allocation equalization adjustment; (4) SDG&E's marginal costs updated in accordance with this settlement document; (5) the revenue requirement recommended in the ECAC Settlement.

This recommended revenue allocation recognizes that the parties recommend deferring litigation of marginal customer costs, specifically the new customer only (NCO) or "Hookup," versus "Rental," issue. The parties recommend that the Commission adopt SDG&E's marginal customer costs applying the rental method, as adjusted by UCAN's recommendations, in the revenue allocation calculation for this proceeding only. The parties' recommended revenue allocation is therefore based on marginal costs with appropriate caps.

B. <u>Marginal Customer Cost</u>

1. <u>Rental vs. New Customer Only (NCO)</u>

In the Rental method, one marginal customer cost, including an investment component, is applied to all customers during the forecast period. In the NCO method, two marginal customer costs are calculated. The first is an investment marginal cost that is only applied to new customers during the forecast period. The second is a customer maintenance and accounting/collection cost that is applied to all customers during the forecast period.

The parties recommend that the NCO Vs. Rental issue be deferred until SDG&E's next RDW proceeding. The parties recommend that the following marginal customer cost revenue, based on the SDG&E proposed Rental method, with UCAN's modifications, be used solely for revenue allocation purposes in this proceeding:

<u>Customer Class</u>	<u>Marginal Revenue</u> (Millions of $)	<u>Customers</u>	<u>Marginal Cost</u> ($/Customer/Yr.)
Residential	80,150.3	1,032,465	77.63
Schedule A	30,014.5	104,293	287.79
Schedule AD	1,973.4	2,167	910.65
Schedule AL-TOU	12,424.9	11,738	1,058.52
Schedule A6-TOU	750.7	17	44,156.22
Agriculture	1,494.2	3,868	386.30
Lighting	1,316.0	6,913	190.37
System Total	128,123.9	1,161,461	109.41

2. Customer-Related Distribution O&M

The parties recommend an allocation based 50% on the number of customers in the class, and 50% on class TSM investment costs. The parties agree to the following allocation ($/Customer/yr):

Residential	$ 11.31
Schedule A	$ 31.76
Schedule AD	$104.80
Schedule AL-TOU	$133.30
Schedule A6-TOU	$306.33
Agriculture	$ 43.17

C. Marginal Distribution Costs

1. Distribution Demand

The parties agree to accept the SDG&E proposed distribution investment cost of $713.08/kW.

2. Distribution O&M

The parties agree, for purposes of this settlement only, to use DRA's and UCAN's proposed five years of historic data and the DRA O&M value of $5.75/kW/yr. The parties believe that using five years of recent data is more representative than the ten year or one year alternatives.

D. Marginal Energy Costs

The parties agree to use the marginal energy costs based on the avoided energy costs adopted in the ECAC proceeding. These marginal energy costs are based on incremental energy rates (IERs) by time of use (TOU) periods and an average gas fuel price. The average gas fuel price agreed to in the ECAC settlement is 2.4039 $/MMBtu. The IERs are listed below. The parties further recommend that the Commission use a variable O&M adder of 0.0005 $/kWh. The IERs and resulting marginal energy rates are as follows:

TOU Period		IER	Marginal Energy Cost
Summer:	On-Peak	9,654 Btu/kWh	2.37¢/kWh
	Semi-Peak	9,194	2.26
	Off-Peak	6,998	1.73
Winter:	On-Peak	11,722	2.87
	Semi-Peak	10,860	2.66
	Off-Peak	9,952	2.44
Annual Average		9,465	2.33

E. Other Marginal Cost Factors

1. Working Capital Loading Factor

The parties recommend that this issue be deferred until the next RDW proceeding. In order to calculate marginal costs, for use in revenue allocation for this proceeding only, the parties recommend that SDG&E's proposed value of 1.16% be used.

2. Real Economic Carrying Charge (RECC) Factors

Because the parties were able to reach agreement on revenue allocation using SDG&E's proposed RECC values, the parties recommend that this issue be deferred to the next RDW proceeding.

F. Residential Rate Design

1. Baseline to Nonbaseline Rate Relationship

SDG&E's currently approved baseline rate for Schedule DR, its standard domestic service tariff, is $0.10088 per kWh. SDG&E's nonbaseline rate is $0.12644 per kWh. The relationship between these is 1.25 to 1.00 ($0.12644/$0.10088). SDG&E proposed to decrease the baseline and nonbaseline rate relationship on a percentage basis. By applying a uniform percentage decrease to the baseline and nonbaseline rates, the nonbaseline rate will decrease by 1.25 cents per kWh for every cent per kWh that the baseline rate decreases. This methodology will maintain the current percentage difference between the baseline and the nonbaseline rates, but will decrease the cent-per-kWh differential.

DRA proposed reducing the ratio between nonbaseline and baseline rates to 1.15 to 1.00, noting that Edison's current differential is 1.15 to 1.00. If rates only decrease by 1.2% for the residential class, then the baseline rates could go up with bill increases by as much as 3% for some of SDG&E's smaller customers. If, however, the level of the decrease is close to 6% for the class, then the baseline rate could decrease by approximately 1% while the nonbaseline rate could decrease by 11%. In this scenario, all SDG&E customers would see bill reductions.

The parties agree as follows: Only the nonbaseline rates will be reduced in this proceeding. The baseline rates will remain unchanged. This will result in a reduction in the nonbaseline to baseline rate differential without increasing any customer's rates. The resulting nonbaseline to baseline rate differential is 1.19 to 1.

2. Customer Charge

SDG&E currently does not have a residential customer charge in its domestic service tariffs.

The parties agree as follows: SDG&E should be ordered to submit a customer charge proposal on October 1, 1996, along with any studies that it deems appropriate. Unless SDG&E submits studies indicating more appropriate values, the parties agree that in the next RDW the following factors will be uncontested.

a. Multi-family customers shall be assumed to have an 11% higher coincident demand factor than customers in single-family dwellings.

b. A multi-family customer shall be assumed to have a noncoincident load factor measured at the final line transformer which is three percentage points higher than for single-family residential customers. This difference results from two offsetting factors: a slightly lower load factor at the customer transformer for multi-family customers and a higher diversity factor from the multi-family customer at the transformer.

3. Seasonal Rates

The parties agree as follows: SDG&E should be ordered to submit a proposal for seasonal rate differentials for its domestic class of customers as a part of its November 1, 1996 RDW filing.

4. Commercial and Industrial Rate Design

The parties agree as follows: For this class of customers, the customer charges should be increased by 5%. The noncoincident demand charges should be increased by 5% except that the noncoincident demand charges for transmission level service should be increased by 30%. On-peak demand charges will not be increased.

The on-peak energy rates should not be decreased, except for changes resulting from reducing the CARE surcharge. The revenue reconciliation should occur in the semi- and off-peak energy rates.

5. Small and Medium Customer Rates

The parties agree as follows: SDG&E's proposals should be adopted for this proceeding. Specifically, the customer charge should remain at $7.50 per month for Schedule A and the energy rate should be reduced to reconcile with the allocated revenues. For Schedule AD, the customer charge should remain $20 per month, the demand charge be increased by 5%, and the energy rate reduced to reconcile with the allocated revenues.

G. Agricultural Rate Design

SDG&E proposed only minor rate design methodology changes for agricultural schedules.

The parties agree as follows: SDG&E's proposals should be adopted for this proceeding. The customer charge under Schedule PA-T-1, however, should be increased in the same manner as for Schedule AL-TOU.

H. Special Contracts

1. Pre-approved Contract Option

SDG&E requests authorization to enter into agreements with customers to obtain, retain, or attract new customers, to avoid the flight of a customer out of state, and to reduce the construction of self-generation.

The parties agree that such arrangements should reflect the following:

a. The contract term should not exceed ten years;

b. The contract must clearly state that customers will be responsible for any and all competition transition charges (CTCs). The contract must clearly state that CTCs will apply to customers in accordance with the Commission's ongoing[1] determination of the issue;

c. SDG&E shareholders will absorb 50% of any difference between what SDG&E collects from the customer as compared to what SDG&E would have collected had the customer been billed on SDG&E's otherwise-applicable rate;

d. Once the Commission implements restructuring, shareholders will absorb 100% of any discount in the existing and future contracts from the date that restructuring goes into effect;

e. SDG&E will be limited to not more than 50 different corporate entities with whom it may enter into these contracts;

f. SDG&E will be further limited to selling a maximum of 100 MW of load collectively under these contracts;

1 We have substituted "ongoing" for the Settlement's "final" to make clear that CTC will apply when ordered, not when the CTC issue is finally settled and all appeals exhausted.

g. SDG&E must apply for and obtain Commission approval of a contract before it becomes effective;

h. If SDG&E elects not to provide the proposed contract in its entirety, SDG&E must explain the need for confidentiality;

i. This contracting option as set forth herein is subject to review by the Commission and shall be discontinued effective December 31, 1999, unless specific Commission approval is granted to continue the option;

j. The contracts will be subject to a floor price of the customer-specific marginal cost;

k. The customer has the right to terminate the contract, and each contract will specify the amount of any liquidated damages owed by a customer electing to terminate the contract;

l. All contracts will specify that after the date on which the Commission has issued a final decision which deregulates that service, both the customer and the utility have the right to terminate the contract with one year's prior written notice, without liquidated or other damages, for any services covered by the contract;

m. SDG&E must obtain a signed affidavit from the customer explaining what the customer's alternatives were and their viability;

n. SDG&E must provide proof that the contract results in benefits to all other customers;

o. Each contract must provide for modification of the contract at any time if necessary to conform to Commission decisions;

p. SDG&E must submit an annual report to the Commission providing copies of ongoing contracts and monthly level details on each contract. SDG&E will provide the report to the Commission Advisory and Compliance

Division and may submit it under Public Utilities Code (PU) § 583;

q. SDG&E is required to issue an annual report to the public that provides the information in item "p" in an aggregated format;

r. When a specific contract or a form contract is filed, SDG&E shall set forth the specified reporting requirements contained in D.95-10-033, or the Commission's reporting requirements in effect at the time of filing;

s. No contract entered into under this provision may contain any term or condition that will in any way bind the customer to generation resources owned by SDG&E, its holding company, or any of its affiliates;

t. When SDG&E files its first proposed contract for pre-approval under this provision, SDG&E must clearly demonstrate how its proposal will interact with its base rate performance-based ratemaking (PBR) procedure, in order to show that SDG&E will be splitting all discounts 50/50 between shareholders and customers. If it cannot so demonstrate, SDG&E will either withdraw the contract or propose to modify its tariffs to guarantee that the final split is 50/50. SDG&E will assure that for purposes of determining the national rate comparison incentive under its Base Rate PBR, it will account for revenues from each customer under contract covered by this section as though each customer were billed pursuant to Commission approved tariffs;

u. Under this contract option, SDG&E shall not be allowed to offer a discount to a customer of another California utility for existing or expanding load of that customer; and

v. An exemplary form contract for this flexible contracting option is set forth in Appendix B to the RDW Settlement.

2. Total Flexibility in Contracts Option

The parties agree as follows: SDG&E should be allowed to enter into a contract with any customer so long as:

a. The contract term does not exceed ten years, except by specific Commission approval on a case-by-case basis;

b. SDG&E informs the customer of its rate options;

c. SDG&E informs the customer monthly of what its bill would have been on the customer's otherwise applicable rate option;

d. SDG&E shareholders absorb 100% of any difference between what SDG&E collects from the customer as compared to what SDG&E would have collected had the customer been billed on SDG&E's otherwise applicable rate;

e. SDG&E submits the contract to the Commission within 90 days of executing the contract. SDG&E will provide the contract to CACD and may submit it under PU Code § 583;

f. This contracts option as set forth herein is subject to review by the Commission and shall be discontinued effective December 31, 1999, unless the Commission grants specific approval to continue the option;

g. The contracts are subject to a floor price of the customer specific marginal cost;

h. The customer must have the right to terminate the contract, and each contract specify any liquidated damages owed by customers electing to terminate the contract prior to its original term;

i. All contracts specify that after the date on which the Commission has issued a final decision which deregulates that service, both the customer and the utility have the right to terminate the contract with one year's prior written notice without liquidated or other damages;

j. Any contract entered into under this provision may not contain any term or condition that will in any way bind the customer to generation resources owned by SDG&E, its holding company, or any of its affiliates; and

k. SDG&E must assure, for the purposes of determining the national rate comparison incentive under its Base Rate PBR, that it will input revenues from each customer covered under contract by this section as though each customer was billed on Commission approved tariffs.

III. Approval of Settlements

The parties to the Settlements represent the full range of affected interests in this consolidated ECAC and RDW proceeding. The parties believe that the Settlements as presented are reasonable in light of the whole record, consistent with the law, and in the public interest.

A. The Settlements are Reasonable in Light of the Whole Record

Although this matter has not been heard by the Commission, the parties believe that the prepared testimony served in this proceeding, coupled with the Settlements and the tables attached thereto, provide a sufficient record for the Commission to find the parties' recommendations reasonable.

The SRAC pricing components proposed in the ECAC Settlement are within the range of values proposed or expected to be proposed by the parties, and are consistent with the values adopted in SDG&E's last ECAC decision, D.95-04-076. They are supported by a broad-based coalition, including SDG&E, DRA, and CCC and Kelco, as representatives of the QF community.

B. The Settlements Do Not Contravene Statutory Provisions or Prior Commission Decisions

The terms of the Settlements comply with all statutes and decisions.

C. The Settlements are in the Public Interest

The parties to the Settlements have a long history of taking strong positions, often leading to different conclusions on various ECAC and rate design issues. The parties represent diverse interests and are experienced practitioners before the Commission. All parties were actively involved in the extensive negotiations leading to the Settlements.

In agreeing to the Settlements, the parties have used their collective experience to produce a reasonable outcome without the need for further commitments of time and resources that would otherwise be devoted to litigating this application. The parties also note that litigation concerning the QF issues in this ECAC would be of questionable value given the SRAC reform process currently before the Commission. In this regard, as noted above, the parties have agreed that should the Commission adopt a revised methodology for calculating SRAC payments prior to the expiration of this Settlement, the Commission's new methodology will govern.

IV. Findings of Fact - A.95-10-066

1. All active parties to this SDG&E ECAC (SDG&E, CCC, DRA, Kelco, and UCAN) participated in a duly noticed settlement conference to address issues in A.95-10-006.

2. SDG&E, CCC, DRA, Kelco, and UCAN (collectively, the settling parties) entered into a Settlement proposing resolution of all issues in the forecast phase of SDG&E's 1996 ECAC proceeding (the Settlement). The settling parties represent the diverse interests affected by this proceeding.

3. The settling parties filed a joint motion for adoption of the Settlement on February 14, 1996.

4. No party opposed the Settlement. All parties had the opportunity to cross-examine witnesses sponsoring the Settlement and review the terms and rationale behind the Settlement.

5. The Settlement does not contravene any statute, Commission rule, or decision.

6. The Settlement does not address the reasonableness of SDG&E's nuclear and gas operations. These issues will be addressed in a separate phase of this proceeding.

7. The settling parties' recommendation that the Commission adopt, on June 1, 1996, or as soon thereafter as feasible, a revenue decrease of approximately $21.9 million, is reasonable and should be adopted. This represents a 1.41% decrease from revenues collected from presently authorized rates. This change in revenue requirement reflects the combined effects of SDG&E's ECAC proceeding as well as changes authorized by the Commission in other proceedings.

8. The Settlement proposes a revision to the revenue requirement to reflect 1) the implementation of the ICIP balancing account revenue requirement, 2) the removal of SONGS 2&3 incremental costs from the base rate revenue, and 3) the removal of nuclear fuel expenses and nuclear lease interest costs from the total Fuel and Purchased Power budget.

9. SDG&E's Electric Department Preliminary Statement should be revised to indicate that nuclear fuel expenses will no longer be recovered in the ECAC balancing account.

10. The proposed revenue requirement reflects recorded balancing account data as of December 31, 1995.

11. The electric sales forecast set forth in Exhibit 2, SDG&E's Forecast of Energy Operations and Expenses for the period May 1, 1996 through April 30, 1997, is reasonable and should be adopted.

12. It is reasonable for SDG&E to refund to its customers approximately $35 million in June 1996, or as soon thereafter as feasible, to reduce the forecasted overcollection in the ECAC balancing account. The remainder of this overcollection will be amortized over a 12-month period.

13. DRA's San Juan basin gas price forecast of $1.49/MMBtu is reasonable for dispatch purposes.

14. The Settlement values of: 1) an IER of 9,465 Btu/kWh; 2) an O&M Adder of 1.0 mill/kWh; 3) an IHR of 10,600 Btu/kWh; 4) a shortage cost value of $70.34/kWyr.; and 5) an ERI of 1.0, are reasonable to use in determining QF payments by SDG&E for this ECAC period. If the Commission adopts a revised methodology for calculating SRAC at any time prior to May 1997, the Commission's new SRAC methodology will supersede the terms of the Settlement.

15. It is reasonable to assume that 1) the SONGS Unit 2 refueling outage will begin on December 15, 1996, and will last for 60 days; 2) the SONGS Unit 3 refueling will begin on April 23, 1997, and will extend beyond the current ECAC forecast period. A 92% production factor is a reasonable assumption for SONGS 2&3. Due to the recommended outage dates and production factors of the two remaining SONGS units, SDG&E's subsequent revisions to planned purchase four (PP4), from 19 megawatts (MW) to 95 MW, and planned purchase five (PP5), from 150 MW to 69 MW, are also reasonable and should be adopted.

16. It is reasonable for SDG&E to forecast economy energy purchases scaled to 113% of historical purchases.

17. It is reasonable to reduce by $496,000 the Portland General Electric (PGE) Boardman capital and O&M costs reflected in SDG&E's fuel and purchased power budget due to recent operating information.

18. It is reasonable to use historical data from January 1993 to December 1995 to forecast purchased quantities and floor prices of firm-displacement and economy energy.

19. DRA's proposed Southwest Power Link (SWPL) transmission line loss factor of 1.95% is reasonable and should be adopted.

20. It is reasonable to adjust heat rates for certain of SDG&E's steam generating units to encourage revised heat rate testing. The Settlement's recommendation that an additional 5% adjustment be made to all SDG&E steam generating units which do not have updated testing results by July 1, 1996, is reasonable and should be adopted.

21. It is reasonable to revise the Comision Federal de Electricidad (CFE) contract to reflect a more recent peso to dollar exchange rate.

22. SDG&E's plan to implement (with input from DRA) dynamic line loss calculations for evaluating transactions over SWPL by March 1, 1996, is reasonable and should be adopted.

23. SDG&E's gas rate schedules GCORE, GTCG, and GTCG-SD should be revised to reflect the results of the most recent ECAC proceeding.

V. Findings of Fact - A.91-11-024

1. All active parties - SDG&E, DRA, FEA, and UCAN (collectively, the settling parties) - participated in noticed settlement conferences to address issues in SDG&E's 1996 Rate Design Window (RDW) A.91-11-024.

2. The settling parties entered into a Settlement proposing resolution of all issues in this year's RDW proceeding. The settling parties represent the diverse interests affected by this RDW.

3. The settling parties filed a joint motion for adoption of the Settlement on March 13, 1996.

4. No party opposed the Settlement. All parties had the opportunity to cross-examine the witnesses sponsoring the

Settlement and review the terms and rationale behind the Settlement.

5. The Settlement does not contravene any statute, Commission rule, or decision.

6. The proposed rates and rule changes presented in Appendix A of the Settlement (Exhibit 111) and Appendix A of this decision are reasonable and should be adopted.

7. It is reasonable that SDG&E be ordered to file with the Commission, on or before October 1, 1996, a residential customer charge proposal, along with all such studies as SDG&E deems appropriate to support its proposal.

8. It is reasonable that SDG&E be ordered to submit in its next RDW filing 1) an analysis that compares the marginal generation capacity costs presented by SDG&E to those of Edison and Pacific Gas and Electric Company and 2) a proposal for seasonal rate differentials for residential customers.

9. The capped EPMC revenue allocation methodology presented by SDG&E is reasonable and should be adopted.

10. Notwithstanding any provisions adopted by this decision for the Contract Options for flexibility, the provisions of Section X.B of General Order 96-A are still available to the parties.

VI. Conclusions of Law - For the Joint Proceeding

1. The record in this proceeding demonstrates that the ECAC Settlement and the RDW Settlement are both reasonable in light of the whole record, consistent with law, and in the public interest.

2. Both Settlements should be adopted in their entirety without change.

3. SDG&E should be authorized to file new rates consistent with this decision.

4. The capped BPMC allocation methodology presented in Exhibit 111 should be used to allocate the revenue requirement to all customer classes.

5. SDG&E should discuss in its next RDW proceeding the comparability of its proposed marginal generating costs with those currently adopted by the Commission for other energy utilities.

6. The marginal costs of generation, distribution, transmission, and energy proposed in Exhibit 111 should be used for purposes of revenue allocation in this proceeding only.

7. The revenue and rate changes set forth in Appendix A to Exhibit 111 should become effective on June 1, 1996, or as soon thereafter as feasible. SDG&E should file an advice letter submitting these tariff changes.

8. For convenience, we have set forth the principal rate changes authorized by this decision in Appendix A to this decision, which shall prevail over the rates set forth in Appendix A to Exhibit 111, should there be a discrepancy.

9. The reference in Table VI-1 of the RDW settlement should be:

EXTENSION OF SCHEDULE NJ AND THE NEW JOB CONNECTION CREDIT

Schedule NJ

- o Change under the "APPLICABILITY" section:
  - December 31, 1996 to December 31, 1999
- o Change under the "RATES" section:
  - December 31, 1999 to December 31, 2002

Form 142-1059

- o Change Section 1, Paragraph 1, 2
  - December 31, 1997 to December 31, 1998
- o Change Section 5, Paragraph 5
  - December 31, 1997 to December 31, 1998

10. The reference in Table VII-3 of the RDW settlement should be "Change Section B.1.b." Delete "Change Section A.1.a.1."

11. SDG&E should be ordered to submit a proposal to introduce a residential customer charge on or before October 1, 1996, along with any information it deems appropriate.

12. SDG&E should be ordered to submit a proposal to institute seasonal rates for residential customers in its November 1, 1996 RDW filing.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) shall file on 3 days' notice to the Commission and to the public tariffs setting forth the adopted rates set forth in Appendix A to Exhibit 111, modified to the extent set forth in Appendix A to this decision.

2. The Settlement in Application (A.) 95-10-006 is approved; the Settlement in A.91-11-024 is approved.

3. SDG&E shall refund approximately $35 million to ratepayers in the manner provided in the Settlement set forth in Attachment A hereto.

This order is effective today.

Dated June 6, 1996, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

Commissioner Daniel Wm. Fessler, being necessarily absent, did not participate.

I will file a written concurring opinion.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

SETTLEMENT AGREEMENT BETWEEN SAN DIEGO GAS & ELECTRIC COMPANY, THE CALIFORNIA COGENERATION COUNCIL, THE DIVISION OF RATEPAYER ADVOCATES, KELCO, UNIT OF MONSANTO COMPANY, AND UTILITY CONSUMERS' ACTION NETWORK

This Settlement Agreement ("Settlement") is made by and among San Diego Gas & Electric Company ("SDG&E"), the California Cogeneration Council ("CCC"), the Division of Ratepayer Advocates ("DRA"), Kelco, Unit of Monsanto Company ("Kelco"), and Utility Consumers' Action Network ("UCAN"), collectively referred to as the "Parties", and is submitted pursuant to Rules 51 through 51.10 of the Commission's Rules of Practice and Procedure ("the Rules"). Specifically, the Settlement proposes a one year resolution of all revenue requirement issues raised in SDG&E's 1996 Energy Cost Adjustment Clause ("ECAC") proceeding (A. 95-10-006) for the Forecast Period of May 1996 through April 1997. The Settlement also establishes the Incremental Energy Rate ("IER"), the Operation and Maintenance Adder ("O&M Adder"), the Incremental Heat Rate ("IHR"), and the Shortage Cost Value ("SCV") SDG&E uses to calculate payments to Qualifying Facilities ("QFs"). While Kelco and CCC support the IER, O&M Adder, IHR and SCV set forth below in Section IX and the provisions of Sections XVIII through XX of this Settlement, they take no position on the other issues addressed in this Settlement.[1] References to "Parties" in all other sections of this Settlement should be construed accordingly. Further, any subsequent agreements reached concerning rate design and revenue allocation issues will be the subject of a separate agreement.

The attached appendices are included in, and are part of this Settlement. The Appendices are: A. Revenue Requirements; B. Fuel and Purchased Power Budget, IER, O&M Adder, and As-Available Capacity Payment Detail; and C. Comparison Exhibit.

BACKGROUND

Based upon the prepared testimony submitted in the Forecast Phase of this ECAC proceeding, the Parties perceived the potential to reach agreement on most, if not all contested issues. Accordingly, the Parties engaged in extensive discovery and held several discussions, both in person and by

[1] Upon the verbal approval of ALJ Barnett, Kelco and CCC did not file testimony given the progress of the settlement discussions.

Appendix B to ATTACHMENT A is omitted.

telephone, to determine if a Settlement could be reached. SDG&E scheduled a formal Settlement Conference for 10:00 AM on February 1, 1996. On January 15, 1996, SDG&E mailed to all Parties a Notice of Settlement Conference as required by Rule 51.1(b) of the Rules.

The Settlement Conference was held as scheduled at the Commission's offices in San Francisco, California. All active Parties attended. This Settlement sets forth the final agreement reached by the Parties.

SETTLEMENT

I. Total Revenue Requirement

The Parties recommend a total revenue requirement decrease of approximately $21.9 million. (See Appendix A: Revenue Requirement)

II. Balancing Accounts

The Parties adopt DRA's estimate of a $77.4 million overcollection in the ECAC Balancing Account and a $35.0 million undercollection in the ERAM Balancing Account. Having filed later, DRA's estimates reflect recorded data through December 1995, as required by D. 92-04-061 (the decision in SDG&E's 1992 ECAC). Additionally, the Parties' proposal to refund $35 million of the ECAC Balancing Account overcollection (discussed in Section V below) will leave approximately $43 million to be amortized over the traditional twelve month period.

III. SONGS 2 & 3 Revenue Requirement

Pursuant to the SONGS 2 & 3 Proposal filed by SDG&E and Edison in Edison's GRC, A.93-12-025, SDG&E has revised the revenue requirement in this ECAC to reflect: 1) the implementation of the Incremental Cost Incentive Pricing ("ICIP") Balancing Account revenue requirement (estimated $122.7 million); 2) the removal of SONGS 2 & 3 Incremental Costs from SDG&E's base rate revenue (estimated $65.6 million); and 3) the removal of Nuclear Fuel expenses and Nuclear Lease Interest Costs from the total Fuel and Purchased Power budget (estimated $17.0 million and $1.0 million, respectively).

On February 5, 1996, SDG&E and Edison submitted a proposed methodology for calculating the above revenue adjustments as part of the Joint SONGS 2 & 3 Proposal filed in A. 93-12-025. In that proceeding SDG&E and Edison are requesting final Commission approval for an effective date

Appendix B to ATTACHMENT A is omitted.

of May 1, 1996 or earlier. Therefore, the revised revenue requirement table in this proceeding reflects the proposed SONGS 2 & 3 adjustments subject to Commission review and approval in A.93-12-025. If the Commission subsequently denies or changes the SONGS 2 & 3 Proposal and /or tariffs, or if the Commission fails to adopt the Proposal by May 1, 1996, SDG&E will make the appropriate adjustment to its revenue requirement in this ECAC. SDG&E will remove the SONGS 2 & 3 revenue impacts from this proceeding altogether if the Commission has not approved the proposal by May 1, 1996.

IV. Preliminary Statement Changes

SDG&E proposes to revise Section II F of its Electric Department Preliminary Statement to indicate that Nuclear Fuel expenses will no longer be recovered in the ECAC Balancing Account.

In addition, upon Commission implementation of the SONGS 2 & 3 Ratemaking Procedure pursuant to A.93-12-025, SDG&E will further revise its Electric Department Preliminary Statement to remove the section concerning the SONGS 2 & 3 Nuclear Unit Incentive Procedure (NUIP).

V. ECAC Balancing Account Overcollection: Proposed Refund Plan

The Parties agree that SDG&E will reduce the projected $77.4 million overcollection in the ECAC balancing account (as of May 1, 1996) by making a one-time refund to electric customers of approximately $35 million in June, 1996. This one-time refund will achieve the same goal of returning the overcollection to the ratepayer as a "traditional" amortization plan, but it would do so in one month instead of over a 12 month period. The remaining overcollection of approximately $42.4 million, however, will be amortized over 12 months.

The Parties have developed a refund plan in line with the Equal Percent of Marginal Cost ("EPMC') methodology in order to allocate the refund equitably to all customer classes. Specifically, SDG&E will develop a refund rate based on the $35 million as a percent of the total on-system revenue for the period May 1995-April 1996. This rate will then be multiplied by the revenue billed each customer during the May 1995-April 1996 period. The total refund will be applied to customers' bills in the month of June 1996. All SDG&E electric customers as of June 1996, and all electric customers of record during the ECAC period, May 1995-April 1996, will be eligible for the refund. A refund desk will be set up to handle customer questions concerning the refund. The refund will be officially noticed in local newspapers before and after the refund month of June 1996.

SDG&E also commits to file a revenue allocation proposal in its next ECAC/RDW proceeding which will move the residential class towards EPMC. The Parties intend that this methodology will achieve a residential revenue allocation at EPMC, or $20 million closer to EPMC, which ever is less.

Finally, SDG&E agrees to keep records and submit a report to DRA 1) showing the total amount refunded to customers in June 1996, and 2) indicating that the total refunded amount will be reflected in the June 1996 ECAC Balancing Account calculation, thereby significantly reducing the overcollection.

VI. Heat Rate Testing

SDG&E has not completed heat rate testing on certain generation units as required by D.95-04-076. SDG&E agrees to test the heat rates of all nine South Bay and Encina Units and provide the results and analyses of heat rate tests to DRA by June 30, 1996. Because the units were not tested by December 31, 1995, as required by D.95-04-076, the Parties agree that certain adjustments to SDG&E's heat rate assumptions will be applied to the current ECAC forecast period model.

For the purposes of calculating the 1996 fuel and purchased power budget from the ELFIN model, the following adjustments will be made to South Bay Units 3 and 4 and Encina Units 4 and 5 in the described manner:

South Bay 3: reduce each heat rate block by 46 Btu/kWh

South Bay 4: reduce each heat rate block by 767 Btu/kWh

Encina 4: reduce each heat rate block by 374 Btu/kWh

Encina 5: reduce each heat rate block by 99 Btu/kWh

Furthermore, effective July 1, 1996, the Parties agree that an additional heat rate efficiency factor of 5% will be imputed to the theoretical heat rates of all South Bay or Encina Units which do not have updated testing results by June 30, 1996. For modeling purposes, the 5% adjustment to the heat rates of all South Bay and Encina Units has been included in ELFIN. For purposes of setting the G&D benchmark, the ELFIN model will be trued-up on the first day of the month following the month in which the test results became available. Should the testing of any unit not be completed by June 30, 1996, the 5% adjustment for such unit will remain in place for purposes of calculating any potential G&D reward or penalty until testing is completed for such unit.

VII. Fuel Oil Inventory Carrying Costs

In developing its carrying cost calculation for fuel oil inventory, SDG&E first estimates its average oil inventory. To determine the appropriate inventory levels for this ECAC period, SDG&E used a Utility Fuel Inventory Model (UFIM) in conducting its analysis. SDG&E proposed carrying costs of $730,500 based on a projected 19-day average inventory and a minimum amount of oil necessary as operational inventory.

DRA believes that a 14-day inventory is adequate for planning purposes, arguing that SDG&E should be able to recover from any natural gas supply disruption or replenish its fuel oil supply in two weeks or less. While SDG&E believes that utilizing the UFIM provides a more detailed and objective analysis of the appropriate inventory, SDG&E concedes that developing its carrying costs based on a 14-day inventory is, for purposes of this Settlement, reasonable. Accordingly, the Parties agree that fuel oil inventory carrying costs should be $561,359.

VIII. Gas Price Forecast

SDG&E developed its gas price forecast by analyzing historical cycles over the period of January 1990 through May 1995. Together with this analysis and current expectations of the gas market, SDG&E forecasted an average price of $1.73/MMBtu for the ECAC forecast period.

In its report, DRA utilized a more current methodology as adopted in PG&E's recent ECAC decision, D. 95-12-051, wherein the arithmetic average forecast is calculated using data from three outside forecasting companies: Cambridge Energy Research Associates (CERA); DRI/McGraw-Hill; and, WEFA Group. The Parties agree to use DRA's methodology which produces a gas price forecast in SDG&E's forecast period of $1.49/MMBtu.

IX. **Short Run Avoided Cost ("SRAC") Components for Variably-Priced QFs**

The initial positions taken by the Parties represented a wide range of values for the various SRAC components. The Parties acknowledge that there are considerable differences of opinion between them with regard to how to develop these SRAC components. The Parties recognize, however, that their resources are better allocated to the current SRAC reform proceedings instead of litigating these same issues in this ECAC. Therefore, the Parties ask the Commission to accept the recommendations presented below as reasonable compromises for calculating payments to variably-priced QFs for this ECAC period.

The Parties further agree that if the Commission adopts a revised methodology for calculating Short Run Avoided Costs at any time prior to May 1997, the Commission's new SRAC methodology will supersede the terms of this Settlement.

With that caveat, the Parties recommend that the Commission set:

The Operation and Maintenance (O&M) Adder at 1.0 mills/kWh.

The Incremental Energy Rate (IER) at an annual average of 9,465 Btu/kWh, with the seasonal time-of-use ("TOU") allocation set forth in Table 10, attached hereto in Appendix B.

The Shortage Cost Value at $70.34/kWyr, with the TOU allocation set forth in Table 13, attached hereto in Appendix B.

The Incremental Heat Rate (IHR) at 10,600 Btu/kWh.

The Energy Reliability Index (ERI) at 1.0.

X. **Nuclear Generation and Nuclear Fuel Forecast**

For purposes of forecasting fuel and purchased power costs, the Parties agree that San Onofre Nuclear Generation Station ("SONGS") Unit 2 refueling outage will begin on December 15, 1996, and last for 60 days. The SONGS Unit 3 outage is scheduled to begin on April 23, 1997, and will continue beyond the current ECAC forecast period. The Parties agree that a 92% production factor is a reasonable assumption for SONGS Units 2 and 3.

XI. <u>Generation: Planned Purchases</u>

The Parties agree with, and recommend adoption of SDG&E's forecast of short-term firm purchases with DRA's recommended modifications. DRA recommends adopting SDG&E's forecast of short-term firm contracts which reflect Planned Purchases 1 through 9 based on SDG&E's 1995 Request for Proposals (RFP) except that Planned Purchase 4 should be 93 MW, Planned Purchase 5 should be 69 MW and Planned Purchase 10 should be 0 MW as reflected in DRA's Report (Chapter 7, Section B). These adjustments to Planned Purchases 4 and 5 are intended to reflect the most cost-effective purchases based on DRA's recommended refueling schedule for SONGS. SDG&E agrees to adopt DRA's proposal that Planned Purchase 10 be reduced to 0 MW although SDG&E does not agree with DRA's basis for the recommendation that the capacity requirement for June 1997 is less than for July through September 1997. The peak demand shall include a 15% operating reserve margin net of scheduled maintenance.

XII. <u>Transmission: Line Losses</u>

SDG&E has not yet incorporated dynamic estimates of transmission line losses in its forecast as required by the Commission in D.94-03-041. The Parties agree that SDG&E will develop, with input from DRA, an acceptable internal line-loss mechanism in its Transaction Evaluation Program ("TEV"). This mechanism will be in place by March 1, 1996. The Parties also agree that SDG&E must complete and provide to DRA, an analysis of implementing such an automatic function as part of SDG&E's new EMS/2 (energy management system) by January 1, 1997. Finally, the Parties agree to use the line loss estimate of 1.95% for this ECAC forecast. This is the estimate adopted in last year's ECAC decision.

XIII. <u>Transmission: Wheeling Costs - Fixed and Variable</u>

The Parties agreed to reduce SDG&E's forecast of wheeling expenses by the following amounts: First, fixed wheeling charges shall be decreased by $3,464,960, the reduction recommended in DRA's Report (at pg. 7-10) since SDG&E did not sufficiently support its claim of a year-round transmission service requirement for those charges. Second, DRA agrees to add $252,930 for wheeling expenses to return energy to BPA in January through April 1997. Third, the

Parties agree to updates of four wheeling charges. The PGE Boardman Wheeling cost is increased by $13,342 based on new rates from PGE. The SCE/ NOB-SONGS 150MW wheeling is reduced by $59,000 and the SCE SONGS-Sylmar 50MW wheeling is decreased by $4,583 because of new rates of return. Variable wheeling is reduced by $58,053 because the Parties agree to use recorded data through December 1995 for this estimate. Finally, the Parties agree to include $36,000 for WSCC loop flow mitigation expenses as SDG&E's share of these WSCC costs.

XIV. Updates: Portland General Electric Boardman Capital/O&M Costs

The Parties recommend that the most current information available regarding capital costs charged to SDG&E under the PGE/Boardman contract should be included in SDG&E's forecast of purchases for the ECAC forecast period. This adjustment accounts for changed O&M costs at the Boardman plant, coal cars, capital additions, carrying costs, and property tax revisions. The total adjustment for the above items decreases SDG&E's revenue requirement by $496,392. The Parties also agree and recommend that this adjustment be made based on the information provided to SDG&E by Portland General Electric.

XV. Updates: Comision Federal de Electricidad/ Mexican Peso Devaluation

In last year's ECAC decision, D.95-04-076, the Commission ordered that the O&M costs charged to SDG&E through its contract with Comision Federal de Electricidad ("CFE") must be calculated using current exchange rates (peso to the dollar) each month and trued up in the ECAC balancing account. The Parties agree that this methodology will continue through the remainder of the CFE contract which expires August 31, 1996.

XVI: Economy Energy Scaler

The Parties agree to scale economy energy by 13% in accordance with DRA's filed position.

XVII. Economy Energy and Firm Displacement Energy Forecast

The Parties agree to revise the forecast to reflect a more recent 36 month historical data period. The period now used is January 1993 through December 1995. In addition, floor prices that make use of the historical forecast are also revised. The Southwest floor price shall be $11.00/MWh while the Northwest floor prices shall be $3.00/MWh for the run-off months of April, May and June, and $7.00/MWh for all other months.

XVIII. The Settlement is Reasonable and In the Public Interest

The Parties respectfully ask the Commission to adopt this Settlement in its entirety.

The Parties to this Settlement represent the full range of affected interests in the Forecast Phase of this ECAC proceeding. This Settlement represents compromises by all Parties, arrived at after a series of face to face meetings and telephone conferences which involved extensive negotiation and discussion of positions. The settled values are reasonable in light of the Parties positions. In addition to presenting a reasonable and equitable outcome, this Settlement serves the public interest by enabling the Parties and the Commission to conserve the considerable time and resources that would be necessary to litigate this phase of the ECAC.

XIX. General Terms

The Parties agree that the principles, assumptions, methodologies, positions, and arguments underlying the specific items addressed in the Settlement are recommended for purposes of this proceeding only and are not to be considered as precedent in any Commission proceeding or litigation, except as necessary to implement the recommendations contained herein. The Parties expressly reserve the right to advocate in other proceedings, principles, assumptions, methodologies, arguments, and positions different from those that may underlie or appear to be implied by this Settlement. Nothing in this Settlement is intended to limit the positions taken by the Parties or the possible outcome of discussions in any other proceeding.

The Parties intend and agree that this Settlement is subject to each and every condition set forth herein, including its acceptance by the Commission in its entirety and without change or condition. Additionally, if the Commission rejects this Settlement for any reason, Kelco and CCC reserve the right to file testimony in this ECAC on any issue of concern. The Parties also agree to cooperate to establish a procedural schedule should the Commission reject this Settlement. If the Commission does not adopt the Parties' recommendations as set forth in this Settlement without change or condition, the Parties shall convene a settlement conference within 15 days after

Commission action on this Settlement to discuss whether to resolve by settlement the unchanged portions.

The Parties agree to expend reasonable efforts to ensure the Commission's adoption of this Settlement.

The Parties agree that the California Public Utilities Commission shall have exclusive jurisdiction over any issues related to this Settlement, and that no other court, regulatory agency, or other governing body shall have jurisdiction over any issue related to the interpretation of this agreement, the enforcement of the agreement, or the rights of the Parties to this agreement (with the exception of the California Supreme Court in connection with review of any Commission decision). All rights and remedies are limited to those available before the California Public Utilities Commission. The Parties further agree that no party to this Settlement, nor any member of the staff of the Public Utilities Commission, assumes any personal liability as a result of this Settlement. The settling Parties agree that no legal action may be brought in any state or federal court, or in any other forum, against any individual signatory, party representative, or staff member related to this Settlement.

At any time after the Commission issues a decision adopting this Settlement, each Party hereby reserves any rights it may have under the Commission's Rules or decisions to petition the Commission for modification of such decision (or modification of the terms of such decision in any other related proceeding) provided, however, that prior to exercising such rights, the Party seeking such modification shall first provide all other Parties hereto with five (5) days' notice of its intent to request such modification. The other Parties reserve the right to oppose or protest any such modification in accordance with the Commission's Rules and decisions. Nothing in this Settlement is intended to limit or expand any Party's rights under the Commission's Rules or decisions to petition to modify a decision adopting this Settlement, or to oppose or protest such a petition.

XX. Execution

The undersigned, on behalf of the Parties they represent, hereby agree to abide by the conditions and recommendations set forth herein. This Settlement may be signed in counterparts.

Dated this 14th day of February 1996.

Respectfully submitted,

Vicki L. Thompson Attorney for San Diego Gas & Electric Company	Jerry R. Bloom/Marc D. Young Morrison & Foerster Attorneys for California Cogeneration Council
Catherine A. Johnson Attorney for Division of Ratepayer Advocates	James D. Squeri Attorney for Goodin, MacBride, Squeri, Scholtz & Ritchie/ Kelco, a Unit of Mansanto Co.
Michael Shames Attorney for Utility Consumers' Action Network	

1111 Ω

XX. Execution

The undersigned, on behalf of the Parties they represent, hereby agree to abide by the conditions and recommendations set forth herein. This Settlement may be signed in counterparts.

Dated this 14th day of February 1996.

Respectfully submitted,

Vicki L. Thompson
Attorney for
San Diego Gas & Electric Company

Jerry R. Bloom/Marc D. Young
Morrison & Foerster
Attorneys for
California Cogeneration Council

Catherine A. Johnson
Attorney for
Division of Ratepayer Advocates

James D. Squeri
Attorney for
Goodin, MacBride, Squeri, Scholtz & Ritchie/
Kelco, a Unit of Mansanto Co.

Michael Shames
Attorney for
Utility Consumers' Action Network

XX. Execution

The undersigned, on behalf of the Parties they represent, hereby agree to abide by the conditions and recommendations set forth herein. This Settlement may be signed in counterparts. Dated this 14th day of February 1996.

Respectfully submitted,

Vicki L. Thompson
Attorney for
San Diego Gas & Electric Company

Jerry R. Bloom/Marc D. Young
Morrison & Foerster
Attorneys for
California Cogeneration Council

Catherine A. Johnson
Attorney for
Division of Ratepayer Advocates

James D. Squeri
Attorney for
Goodin, MacBride, Squeri, Scholtz & Ritchie/
Kelco, a Unit of Mansanto Co.

Michael Shames
Attorney for
Utility Consumers' Action Network

XX. Execution

The undersigned, on behalf of the Parties they represent, hereby agree to abide by the conditions and recommendations set forth herein. This Settlement may be signed in counterparts.

Dated this 14th day of February 1996.

Respectfully submitted,

Vicki L. Thompson Attorney for San Diego Gas & Electric Company	Jerry R. Bloom/Marc D. Young Morrison & Foerster Attorneys for California Cogeneration Council
Catherine A. Johnson Attorney for Division of Ratepayer Advocates	James D. Squeri Attorney for Goodin, MacBride, Squeri, Scholtz & Ritchie/ Kelco, a Unit of Monsanto Co.
Michael Shames Attorney for Utility Consumers' Action Network	

XX. Execution

The undersigned, on behalf of the Parties they represent, hereby agree to abide by the conditions and recommendations set forth herein. This Settlement may be signed in counterparts. Dated this 14th day of February 1996.

Respectfully submitted,

Vicki L. Thompson
Attorney for
San Diego Gas & Electric Company

Jerry R. Bloom/Marc D. Young
Morrison & Foerster
Attorneys for
California Cogeneration Council

Catherine A. Johnson
Attorney for
Division of Ratepayer Advocates

James D. Squeri
James D. Squeri
Attorney for
Goodin, MacBride, Squeri, Scholtz & Ritchie/
Kelco, a Unit of Monsanto Co.

Michael Shames
Attorney for
Utility Consumers' Action Network

APPENDIX A

REVENUE REQUIREMENT

TABLE I-1
SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
REVENUE REQUIREMENT CHANGE
MAY 1996 THRU APRIL 1997
(THOUSANDS OF DOLLARS)

LINE NO.	REVENUE ELEMENT	PRESENT RATE REVENUE	REVENUE CHANGE	PROPOSED REVENUE	AUTHORITY OR REFERENCE
1	BASE RATE REVENUES:				
2	– CURRENT MARGIN	$1,030,446	$0	$1,030,446	ADVICE LETTER 862-E
3					
4	– SONGS 1 (eff. 9/1/95)	$0	($2,215)	($2,215)	ADVICE LETTER 853-E
5	– 1996 PBR (eff. 1/1/96)	$0	$14,666	$14,666	AL 900-E / RES. E-3434
6	– 1994 DSM REWARD (eff. 1/1/96)	$0	$2,190	$2,190	A.95-04-044 / D.95-12-054
7	– COST OF CAPITAL (eff. 1/1/96)	$0	($14,771)	($14,771)	A.95-06-022 / D.95-11-062
8	– 1996 PBR REVISION (eff. 1/1/96)	$0	$6,377	$6,377	ADVICE LETTER 979-E
9	– SALES ADJUSTMENT	$17,000	($17,000)	$0	
	–SONGS 2&3 ICIP REMOVAL	$0	($65,633)	($65,633)	A. 93-12-029
10	TOTAL BASE RATE REVENUES	$1,047,446.	($76,386)	$971,060	
11	ERAM:				
12					
13	– ERAM BALANCING	$3,220	$31,780	$35,000	TABLE I-1A & TABLE I-1B
14	TOTAL ERAM	$3,220	$31,780	$35,000	
15	CARE				
16	– CARE DISCOUNT	($8,468)	$313	($8,155)	TABLE I-1A & TABLE I-1B
17	– CARE SURCHARGE	$8,837	($1,701)	$7,136	TABLE I-1A & TABLE I-1B
18	TOTAL CARE	$369	($1,388)	($1,019)	
19	ECAC:				
20	– ECAC BALANCING	($38,284)	($5,047)	($43,331)	TABLE I-1A & TABLE I-1B
21	– FUEL AND PURCHASED POWER	$546,614	($93,583)	$453,031	TABLE I-1A & TABLE I-1B
22	TOTAL ECAC	$508,330	($98,630)	$409,700	
	TOTAL ICIP REVENUE	$0	$122,700	$122,700	A. 93-12-029
23	TOTAL REV. FROM RETAIL SALES	$1,559,365	($21,924)	$1,537,441	
24	PERCENT CHANGE			-1.41%	

TABLE 1-2
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ECAC RATE CHANGE
MAY 1996 THRU APRIL 1997

LINE	ITEM	GWH	CENTS/KWH	COST M$
1	NATURAL GAS	4,298	2.531	108,802.0
2	OIL	64	2.753	1,762.0
3	FIRM PURCHASES	6,351	3.155	200,381.0
4	ECONOMY PURCHASES	1,372	1.334	18,306.0
5	WHEELING	N/A	–	12,098.0
6	QF PURCHASES	1,765	5.823	102,780.0
7	NUCLEAR *	0	0.000	0.0
8				
9	SUBTOTAL LINES 1-7	13,850	3.207	444,129.0
10				
11	FUEL OIL INVENTORY CARRYING COSTS			561.4
12	NUCLEAR LEASE INTEREST COSTS *			0.0
13	EEDA REVENUES			(1,644.0)
14				
15	TOTAL FUEL AND PURCHASED POWER			
16	(SUM OF LINES 9, 11, 12, AND 13)			443,046.4
17				
18	ECAC BALANCE AS OF 4/30/96 **			(42,375.5)
19				
20	GRAND TOTAL (LINE 16 + LINE 18)			400,670.9
21				
22				CENTS/
23				KWHR
24	PROPOSED ECAC RATE (LINE 20 / 15,941.9 GWHR)			2.513
25				
26	ADJUSTED FOR FF&U (LINE 24 x 1.0137)			2.547
27				
28	CURRENT ECAC RATE			3.160
29				
30	CHANGE TO ECAC RATE (LINE 26 – LINE 28)			–0.613
	14-Feb-96	BALANCING RATE		–0.269
	10:38 AM	FUEL & PUR. POW. RATE		2.817

* No longer recovered in ECAC, now reflected in ICIP Rev. Req.
** Reflects $35 million refund

TABLE I-3
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ERAM RATE CHANGE
MAY 1996 THRU APRIL 1997

LINE	ITEM	AMOUNT
1	ESTIMATED BALANCE IN THE ERAM BALANCING ACCOUNT AS OF 4/30/96	$35,000.0 (THOUSANDS OF $)
2	REVENUE REQUIREMENT ADJUSTED BY SAN DIEGO FRANCHISE FEE DIFFERENTIAL (LINE 1 / 1.00857)	$34,702.6 (THOUSANDS OF $)
3	MAY 1996 THRU APRIL 1997 SALES ESTIMATE	15,941.90 (GWHR)
4	PROPOSED ERAM BALANCING RATE (LINE 2 / LINE 3)	0.218 (CENTS/KWHR)
5	PRESENT ERAM BALANCING RATE	0.020 (CENTS/KWHR)
6	ERAM BALANCING RATE CHANGE (LINE 4 – LINE 5)	0.198 (CENTS/KWHR)

14-Feb-96
10:39 AM

APPENDIX C

COMPARISON EXHIBIT

San Diego Gas & Electric
1996 ECAC Forecast Phase
A.95-10-006
SDG&E / DRA Comparison Exhibit

ISSUE	SDG&E Application	DRA Report	Proposed Settlement	Remarks
Nuclear Generation				
Production Factor	88%	92%	92%	Unit 2 outage scheduled to begin December 15, 1996
Outage Duration	70 days	60 days	60 days	Unit 3 outage scheduled to begin April 23, 1997
G&D Benchmark				
Planned Purchases #4 #5 #10	 19MW 150MW 100MW	 95MW 70MW 0MW	 95MW 70MW 0MW	Reflects impact of changes to gas prices/nuclear gen
Transmission: Fixed & Variable Wheeling ($000)	$15,382	$11,918	$12,098	
Economy Energy Scaler	10%	13%	13%	
Gas & Oil Price Fcst				
Gas Spot Price	$1.73 / MMBtu	$1.49 / MMBtu	$1.49 / MMBtu	DRA used a more current methodology, data from outside forecasting companies.
Gas Dispatch Price	$2.13 / MMBtu	$1.90 / MMBtu	$1.90 / MMBtu	
Fuel Oil Price	$16.39 / bbl	$16.39 / bbl	$16.39 / bbl	
Fuel Oil Inventory	19 days reserve	14 days reserve	14 days reserve	
Fuel Oil Carrying Cost	$730,500	$561,359	$561,359	
Balancing Accounts ECAC ERAM	 ($33,363) over $50,994 under	 ($77,376) over $ 35,000 under	 ($77,376) over $ 35,000 under	DRA estimates reflect recorded data through December 1995 per D.92-04-061

San Diego Gas & Electric
1996 ECAC Forecast Phase
A.95-10-006
SDG&E / DRA Comparison Exhibit

ISSUE	SDG&E Application	DRA Report	Proposed Settlement	Remarks
Heat Rate Testing		5% adjustment to all nine units through Forecast Period	Nine units tested by 6/30/96; Adjust 4 units; add'l 5% adj. if tests not completed	Heat rate adjustments to four units with negative deviation heat rates. Additional 5% adjustment to any unit not tested by 6/30/96.
Transmission Line Losses	1.99%	1.95%	1.95%	SDG&B will work with DRA to develop a program for measuring dynamic line losses.
ECAC Refund Plan			$35MM refund	SDG&B's proposal to refund approx. $35MM of overcollected ECAC balance through a one-time bill credit to customers; amortize remaining overcollection over 12 mos.

(END OF ATTACHMENT A)

TABLE OF CONTENTS

Raupd3

TABLE 1
SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
REVENUE REQUIREMENT CHANGE
MAY 1996 THRU APRIL 1997
(THOUSANDS OF DOLLARS)

LINE NO.	REVENUE ELEMENT	PRESENT RATE REVENUE	REVENUE CHANGE	ADOPTED REVENUE		AUTHORITY OR REFERENCE
1	<u>BASE RATE REVENUES:</u>					
2	- CURRENT MARGIN	$1,030,446	$0	$1,030,446		AL 862-E, Approved 10-17-96 by CACO Letter.
3						
4	- SONGS 1 (eff. 8/1/95)	$0	($2,215)	($2,215)		AL 853-E, Approved 8-28-96 by CACO Letter.
5	- 1996 PBR (eff. 1/1/96)	$0	$14,666	$14,666		AL 860-E / RES. E-3434
6	- 1994 DSM REWARD (eff. 1/1/96)	$0	$2,190	$2,190		A.96-06-018 / D.96-12-064
7	- COST OF CAPITAL (eff. 1/1/96)	$0	($14,771)	($14,771)		A.96-06-022 / D.96-11-062
8	- SALES ADJUSTMENT	$17,000	($17,000)	$0		Exhibit SDG&E-2, TABLE I-1A
9	- 1996 PBR REVISION (eff. 1/1/96)	$0	$6,377	$6,377		AL 870-E, Approved 6-4-96 by CACO Letter.
10	-SONGS 2&3 ICIP REMOVAL	$0	($65,633)	($65,633)		A.93-12-025
11	TOTAL BASE RATE REVENUES	$1,047,446	($76,386)	$971,060		
12	<u>ERAM:</u>					
13						
14	- ERAM BALANCING	$3,220	$31,780	$35,000		Exhibit SDG&E-2, TABLE I-1A
15	TOTAL ERAM	$3,220	$31,780	$35,000		
16	<u>CARE</u>					
17	- CARE DISCOUNT	($8,468)	$313	($8,155)		Exhibit SDG&E-2, TABLE I-1B
18	- CARE SURCHARGE	$8,837	($1,701)	$7,136		Exhibit SDG&E-2, TABLE I-1B
19	TOTAL CARE	$369	($1,388)	($1,019)		
20	<u>ECAC:</u>					
21	- ECAC BALANCING	($38,284)	($5,047)	($43,331)	**	Exhibit SDG&E-2, TABLE I-1A
22	- FUEL AND PURCHASED POWER	$546,614	($93,583)	$453,031	**	Exhibit SDG&E-2, TABLE I-1A
23	TOTAL ECAC	$508,330	($98,630)	$409,700	**	
24	TOTAL ICIP REVENUE	$0	$122,700	$122,700		A.93-12-025
25	<u>TOTAL REV. FROM RETAIL SALES</u>	<u>$1,559,365</u>	<u>($21,924)</u>	<u>$1,537,441</u>		
26	PERCENT CHANGE			-1.41%		
27	SALES - GWHR *	15,941.9		15,941.9		EXHIBIT SDG&E-2 TABLE II-1
28	SYSTEM AVERAGE RATE (CENTS/KWHR)	9.78		9.64		

* ON-SYSTEM SALES EXCLUDING RESALE
** ADJUSTED WITH AN FF&U FACTOR OF 1.022537

(continued)

TABLE 2
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ECAC RATE CHANGE
MAY 1996 THRU APRIL 1997

LINE	ITEM	GWH	CENTS/KWH	COST M$
1	NATURAL GAS	4,298	2.531	108,802.0
2	OIL	64	2.753	1,762.0
3	FIRM PURCHASES	6,351	3.155	200,381.0
4	ECONOMY PURCHASES	1,372	1.334	18,306.0
5	WHEELING	N/A	-	12,098.0
6	QF PURCHASES	1,765	5.823	102,780.0
7	NUCLEAR *	0	0.000	0.0
8				
9	SUBTOTAL LINES 1-7	13,850	3.207	444,129.0
10				
11	FUEL OIL INVENTORY CARRYING COSTS			561.4
12	NUCLEAR LEASE INTEREST COSTS *			0.0
13	EEDA REVENUES			(1,644.0)
14				
15	TOTAL FUEL AND PURCHASED POWER			
16	(SUM OF LINES 9, 11, 12, AND 13)			443,046.4
17				
18	ECAC BALANCE AS OF 4/30/96 **			(42,375.5)
19				
20	GRAND TOTAL (LINE 16 + LINE 18)			400,670.9
21				
22				CENTS/
23				KWHR
24	ADOPTED ECAC RATE (LINE 20 / 15,941.9 GWHR)			2.513
25				
26	ADJUSTED FOR FF&U (LINE 24 x 1.0137)			2.547
27				
28	CURRENT ECAC RATE			3.160
29				
30	CHANGE TO ECAC RATE (LINE 26 - LINE 28)			-0.613
	BALANCING RATE			-0.269
	FUEL & PUR. POW. RATE			2.817

* No longer recovered in ECAC, now reflected in ICIP Rev. Req.
** Reflects $35 million refund

(continued)

TABLE 3
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ERAM RATE CHANGE
MAY 1996 THRU APRIL 1997

LINE	ITEM	AMOUNT
1	BALANCE IN THE ERAM BALANCING ACCOUNT AS OF 4/30/96	$35,000.0 (THOUSANDS OF $)
2	REVENUE REQUIREMENT ADJUSTED BY SAN DIEGO FRANCHISE FEE DIFFERENTIAL (LINE 1 / 1.00857)	$34,702.6 (THOUSANDS OF $)
3	MAY 1996 THRU APRIL 1997 SALES FORECAST	15,941.90 (GWHR)
4	ADOPTED ERAM BALANCING RATE (LINE 2 / LINE 3)	0.218 (CENTS/KWHR)
5	PRESENT ERAM BALANCING RATE	0.020 (CENTS/KWHR)
6	ERAM BALANCING RATE CHANGE (LINE 4 - LINE 5)	0.198 (CENTS/KWHR)

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 4

Comparison Table
Present and Adopted Revenue Allocation

Line No.		(A) Adopted Sales (GWhrs)	(B) Present Revenue ($000's)	(C) Present Avg Rate (¢/KWhr)	(D) Marginal Cost Revenue ($000's)	(E) EPMC Allocator (Percentage)	Line No.
1	Residential	5,854.76	652,049	11.14	541,034	41.69%	1
	Commercial/Industrial:						
2	Schedule A	1,918.95	222,102	11.57	189,005	14.57%	2
3	Schedule AD	579.73	67,924	11.72	51,378	3.96%	3
4	Schedule AL-TOU	6,698.65	550,705	8.22	462,223	35.62%	4
5	Schedule A6-TOU	665.34	41,943	6.30	35,490	2.73%	5
6	Subtotal	9,862.66	882,674	8.95	738,097	56.88%	6
7	Agriculture	144.79	15,889	10.97	14,320	1.10%	7
8	Lighting	79.76	8,753	10.97	4,191	0.32%	8
9	System Total	15,941.97	1,559,365	9.78	1,297,641	100.00%	9

		Adopted Revenue ($000's)	Adopted Avg Rate (¢/KWhr)	Change in Revenue ($000's)	Change in Avg Rate (¢/KWhr)	Percentage Change (Percentage)	
10	Residential	635,686	10.86	(16,363)	(0.28)	-2.51%	10
	Commercial/Industrial:						
11	Schedule A	219,881	11.46	(2,221)	(0.12)	-1.00%	11
12	Schedule AD	67,618	11.66	(306)	(0.05)	-0.45%	12
13	Schedule AL-TOU	548,221	8.18	(2,483)	(0.04)	-0.45%	13
14	Schedule A6-TOU	41,726	6.27	(217)	(0.03)	-0.52%	14
15	Subtotal	877,446	8.90	(5,228)	(0.05)	-0.59%	15
16	Agriculture	15,802	10.91	(87)	(0.06)	-0.55%	16
17	Lighting	8,507	10.67	(246)	(0.31)	-2.81%	17
18	System Total	1,537,441	9.64	(21,924)	(0.14)	-1.41%	18

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 6

(Sheet 1 of 2)

Comparison Table
Non-Marginal Cost Allocated Revenue

Present and Adopted Non-EPMC CARE Revenue

Line No.		(A) Sales (GWhrs)	(B) Present Discount ($000's)	(C) Present Surcharge ($000's)	(D) Present Total ($000's)	(E) Present CARE Avg Rate (¢/KWhr)	Line No.
1	Residential	5,854.76	(8,356)	3,075	(5,281)	(0.090)	1
	Commercial/Industrial:						
2	Schedule A	1,918.95	(36)	1,104	1,068	0.056	2
3	Schedule AD	579.73	(14)	333	319	0.055	3
4	Schedule AL-TOU	6,698.65	(56)	3,860	3,803	0.057	4
5	Schedule A6-TOU	665.34	(6)	383	378	0.057	5
6	Subtotal	9,862.66	(112)	5,680	5,568	0.056	6
7	Agriculture	144.79	0	82	82	0.057	7
8	Lighting	79.76	0	0	0	0.000	8
9	System Total	15,941.97	(8,468)	8,837	369	0.002	9

Line No.		Adopted Discount ($000's)	Adopted Surcharge ($000's)	Adopted Total ($000's)	Adopted CARE Avg Rate (¢/KWhr)	Line No.
10	Residential	(8,086)	2,477	(5,609)	(0.096)	10
	Commercial/Industrial:					
11	Schedule A	(36)	890	854	0.045	11
12	Schedule AD	(14)	258	244	0.042	12
13	Schedule AL-TOU	(56)	3,026	2,970	0.044	13
14	Schedule A6-TOU	(6)	301	295	0.044	14
15	Subtotal	(112)	4,475	4,363	0.044	15
16	Agriculture	0	67	67	0.046	16
17	Lighting	0	0	0	0.000	17
18	System Total	(8,198)	7,019	(1,179)	(0.007)	18

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 ROW Proceeding (A.91-11-024)

Table 5

(Sheet 2 of 2)

Non-Marginal Cost Allocated Revenue

Adopted Other NonEPMC Allocated NonCARE Revenue

		StreetLighting Facilities ($000's)	TOU Meter Charges ($000's)	Adopted Total ($000's)	Adopted Other Avg Rate (¢/KWhr)	
19	Residential	0	130	130	0.00	19
	Commercial/Industrial:					
20	Schedule A	0	0	0	0.00	20
21	Schedule AD	0	0	0	0.00	21
22	Schedule AL-TOU	0	0	0	0.00	22
23	Schedule A6-TOU	0	0	0	0.00	23
24	Subtotal	0	0	0	0.00	24
25	Agriculture	0	4	4	0.00	25
26	Lighting	3,251	0	3,251	4.08	26
27	System Total	3,251	134	3,385	0.02	27

Adopted Total NonEPMC Allocated Revenue

		Adopted CARE Revenue ($000's)	Adopted Non-CARE Revenue ($000's)	Adopted Total ($000's)	Non-EPMC Avg Rate (¢/KWhr)	
28	Residential	(5,609)	130	(5,479)	(0.09)	28
	Commercial/Industrial:					
29	Schedule A	854	0	854	0.04	29
30	Schedule AD	244	0	244	0.04	30
31	Schedule AL-TOU	2,970	0	2,970	0.04	31
32	Schedule A6-TOU	295	0	295	0.04	32
33	Subtotal	4,363	0	4,363	0.04	33
34	Agriculture	67	4	71	0.05	34
35	Lighting	0	3,251	3,251	4.08	35
36	System Total	(1,179)	3,385	2,206	0.01	36

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 6

Marginal Cost Revenue

Summary Marginal Cost Revenue by Customer Classes ($000's)

Line No.		(A) Customer	(B) Demand	(C) Energy	(D) Total	(E)	(F)	(G)	Line No.
1	Residential	80,150.3	317,601.73	143,281.8	541,033.8				1
	Commercial/Industrial:								
2	Schedule A	30,014.5	111,675.29	47,315.3	189,005.1				2
3	Schedule AD	1,973.4	35,164.71	14,239.7	51,377.8				3
4	Schedule AL-TOU	12,424.9	286,466.90	163,331.4	462,223.2				4
5	Schedule A6-TOU	750.7	18,968.65	15,771.1	35,490.4				5
6	Subtotal	45,163.4	452,275.5	240,657.6	738,096.6				6
7	Agriculture	1,494.2	9,379.81	3,445.7	14,319.7				7
8	Lighting	1,316.0	968.71	1,886.1	4,190.9				8
9	System Total	128,123.9	780,245.8	389,271.3	1,297,641.0				9

Summary Marginal Demand Costs by Customer Classes ($000's)

		Distribution	Transmission	Ancillary	Generation	Total	
10	Residential	157,642.2	51,483.4	0.0	108,476.1	317,601.7	10
	Commercial/Industrial:						
11	Schedule A	43,385.4	19,402.1	0.0	48,887.8	111,675.3	11
12	Schedule AD	13,967.2	6,076.4	0.0	15,121.2	35,164.7	12
13	Schedule AL-TOU	104,674.9	50,855.0	0.0	130,937.0	286,466.9	13
14	Schedule A6-TOU	3,717.8	4,353.6	0.0	10,897.2	18,968.6	14
15	Subtotal	165,745.4	80,687.0	0.0	205,843.1	452,275.5	15
16	Agriculture	4,779.9	1,507.1	0.0	3,092.8	9,379.8	16
17	Lighting	832.4	123.4	0.0	32.9	968.7	17
18	System Total	328,999.9	133,800.9	0.0	317,444.9	780,245.8	18

Summary Marginal Energy Costs by TOU Periods and Customer Classes ($000's)

		Summer			Winter			Annual	
		Peak	Semi-Peak	Off-Peak	Peak	Semi-Peak	Off-Peak		
19	Residential	12,642.3	16,676.3	21,289.2	13,228.3	35,847.3	43,598.4	143,281.8	19
	Commercial/Industrial:								
20	Schedule A	6,433.2	5,424.6	6,149.3	3,337.6	14,430.4	11,540.2	47,315.3	20
21	Schedule AD	2,155.4	2,009.0	1,848.6	866.9	4,437.2	2,922.6	14,239.7	21
22	Schedule AL-TOU	17,865.2	19,904.7	23,092.3	12,194.5	47,014.6	43,260.1	163,331.4	22
23	Schedule A6-TOU	1,470.2	1,780.3	2,455.3	922.6	4,415.3	4,727.5	15,771.1	23
24	Subtotal	27,924.0	29,118.6	33,545.5	17,321.6	70,297.5	62,450.4	240,657.6	24
25	Agriculture	435.8	521.1	660.3	183.0	777.5	868.1	3,445.7	25
26	Lighting	0.0	116.3	425.7	191.4	187.3	965.5	1,886.1	26
27	System Total	41,002.1	46,432.2	55,920.6	30,924.3	107,109.7	107,882.5	389,271.3	27

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 7

Customer Revenue Allocation Determinants
(Average Number of Monthly Customers)

Line No.	Class	Customers
1	Residential	1,032,465
2	Schedule A	104,293
3	Schedule AD	2,167
4	Schedule AL-TOU	11,738
5	Schedule A6-TOU	17
6	Agriculture	3,868
7	Lighting	6,913
8	System Total	1,161,461

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 8

Demand Revenue Allocation Determinants

(Peak MWs)

Line No.		(A) Secondary	(B) Primary	(C) Transmission	(D) Sub-Total	Line No.
	Generation					
1	Residential	1154.87	0.16	0.00	1155.03	1
2	Schedule A	520.14	0.42	0.00	520.55	2
3	Schedule AD	155.34	5.75	0.00	161.09	3
4	Schedule AL-TOU	948.94	406.42	46.19	1401.55	4
5	Schedule A6-TOU	0.00	44.27	75.23	119.50	5
6	Agriculture	32.93	0.00	0.00	32.93	6
7	Lighting	0.35	0.00	0.00	0.35	7
8	System Total	2812.57	457.01	121.42	3391.00	8
	Transmission					
9	Residential	1309.13	0.18	0.00	1309.31	9
10	Schedule A	493.04	0.39	0.00	493.43	10
11	Schedule AD	149.09	5.52	0.00	154.61	11
12	Schedule AL-TOU	880.29	377.01	42.85	1300.16	12
13	Schedule A6-TOU	0.00	42.24	71.78	114.03	13
14	Agriculture	38.33	0.00	0.00	38.33	14
15	Lighting	3.14	0.00	0.00	3.14	15
16	System Total	2873.01	425.35	114.63	3413.00	16
	Distribution					
17	Residential	1806.02	0.25	0.00	1806.27	17
18	Schedule A	496.72	0.40	0.00	497.12	18
19	Schedule AD	154.40	5.72	0.00	160.11	19
20	Schedule AL-TOU	843.22	361.13	41.05	1245.40	20
21	Schedule A6-TOU	0.00	43.20	73.40	116.59	21
22	Agriculture	54.77	0.00	0.00	54.77	22
23	Lighting	9.54	0.00	0.00	9.54	23
24	System Total	3364.66	410.70	114.45	3889.80	24

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 9

(Sheet 1 of 3)

Energy Revenue Allocation Determinants by Voltage Level, TOU, and Customer Class

(MWhrs)

Line No.	Customer Class	(A) Secondary	(B) Primary	(C) Transmission	(D) Sub-Total	Line No.
	Residential					
1	Summer Peak	511,257	69	0	511,326	1
2	Summer Semi-Peak	708,212	96	0	708,308	2
3	Summer Off-Peak	1,182,099	159	0	1,182,258	3
4	Winter Peak	441,889	63	0	441,952	4
5	Winter Semi-Peak	1,293,595	184	0	1,293,779	5
6	Winter Off-Peak	1,716,892	245	0	1,717,137	6
7	Annual Total	5,853,944	816	0	5,854,760	7
	Schedule A					
8	Summer Peak	259,990	208	0	260,198	8
9	Summer Semi-Peak	230,224	184	0	230,408	9
10	Summer Off-Peak	341,221	274	0	341,495	10
11	Winter Peak	111,421	89	0	111,510	11
12	Winter Semi-Peak	520,401	416	0	520,817	12
13	Winter Off-Peak	454,156	364	0	454,520	13
14	Annual Total	1,917,413	1,535	0	1,918,948	14
	Schedule AD					
15	Summer Peak	84,110	3,114	0	87,224	15
16	Summer Semi-Peak	82,331	3,048	0	85,379	16
17	Summer Off-Peak	99,058	3,667	0	102,725	17
18	Winter Peak	27,944	1,035	0	28,979	18
19	Winter Semi-Peak	154,516	5,720	0	160,236	19
20	Winter Off-Peak	111,073	4,112	0	115,185	20
21	Annual Total	559,032	20,696	0	579,728	21
	Schedule AL-TOU					
22	Summer Peak	508,644	196,404	21,217	726,265	22
23	Summer Semi-Peak	580,611	242,280	27,239	850,130	23
24	Summer Off-Peak	867,618	381,913	41,288	1,290,819	24
25	Winter Peak	282,377	112,645	14,559	409,581	25
26	Winter Semi-Peak	1,154,028	496,171	56,322	1,706,521	26
27	Winter Off-Peak	1,142,149	513,029	60,154	1,715,332	27
28	Annual Total	4,535,427	1,942,442	220,779	6,698,648	28

Raupd3

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 9 (Sheet 2 of 3)

Energy Revenue Allocation Determinants by Voltage Level, TOU, and Customer Class
(MWhrs)

Line No	Customer Class	(A) Secondary	(B) Primary	(C) Transmission	(D) Sub-Total	Line No.
	Schedule A6-TOU					
29	Summer Peak	0	22,304	38,752	61,056	29
30	Summer Semi-Peak	0	29,050	48,566	77,616	30
31	Summer Off-Peak	0	50,685	89,437	140,122	31
32	Winter Peak	0	11,171	20,487	31,658	32
33	Winter Semi-Peak	0	62,620	100,926	163,546	33
34	Winter Off-Peak	0	70,660	120,678	191,338	34
35	Annual Total	0	246,490	418,846	665,336	35
	Agriculture					
36	Summer Peak	17,625	0	0	17,625	36
37	Summer Semi-Peak	22,132	0	0	22,132	37
38	Summer Off-Peak	36,666	0	0	36,666	38
39	Winter Peak	6,115	0	0	6,115	39
40	Winter Semi-Peak	28,060	0	0	28,060	40
41	Winter Off-Peak	34,189	0	0	34,189	41
42	Annual Total	144,787	0	0	144,787	42
	Lighting					
43	Summer Peak	0	0	0	0	43
44	Summer Semi-Peak	4,938	0	0	4,938	44
45	Summer Off-Peak	23,639	0	0	23,639	45
46	Winter Peak	6,393	0	0	6,393	46
47	Winter Semi-Peak	6,761	0	0	6,761	47
48	Winter Off-Peak	38,027	0	0	38,027	48
49	Annual Total	79,758	0	0	79,758	49
	System Total					
50	Summer Peak	1,381,626	222,099	59,969	1,663,694	50
51	Summer Semi-Peak	1,628,448	274,658	75,805	1,978,911	51
52	Summer Off-Peak	2,550,301	436,698	130,725	3,117,724	52
53	Winter Peak	876,139	125,003	35,046	1,036,188	53
54	Winter Semi-Peak	3,157,361	565,111	157,248	3,879,720	54
55	Winter Off-Peak	3,496,486	588,410	180,832	4,265,728	55
56	Annual Total	13,090,361	2,211,979	639,625	15,941,965	56

Raupd3

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 9 (Sheet 3 of 3)

Energy Revenue Allocation Determinants by Voltage Level, TOU, and Customer Class
(MWhrs)

Ine No	Customer Class	(A) Secondary	(B) Primary	(C) Transmission	(D) Sub-Total	Ine No
1	Residential	5,853,944	816	0	5,854,760	1
2	Schedule A	1,917,413	1,535	0	1,918,948	2
3	Schedule AD	559,032	20,696	0	579,728	3
4	Schedule AL-TOU	4,535,427	1,942,442	220,779	6,698,648	4
5	Schedule A6-TOU	0	246,490	418,846	665,336	5
6	Agriculture	144,787	0	0	144,787	6
7	Lighting	79,758	0	0	79,758	7
8	System Total	13,090,361	2,211,979	639,625	15,941,965	8

Raupd3

San Diego Gas & Electric Company - Electric Department
Forecast Period May 1, 1996 Through April 30, 1997
1996 RDW Proceeding (A.91-11-024)

Table 10

Summary of Unit Marginal Costs

Line No.	Description	Value	Units	Line No.
	Customer Costs:			
1	Residential	77.63	$/Customer/Yr	1
	Commercial/Industrial			
2	Schedule A	287.79	$/Customer/Yr	2
3	Schedule AD	910.65	$/Customer/Yr	3
4	Schedule AL-TOU	1,058.52	$/Customer/Yr	4
5	Schedule A6-TOU	44,156.22	$/Customer/Yr	5
6	Agricultural	386.30	$/Customer/Yr	6
7	System Average	109.41	$/Customer/Yr	7
	Demand Costs:			
8	Distribution Demand	82.83	$/kW/Yr	8
9	Substation Demand	20.79	$/kW/Yr	9
10	Network Transmission Demand	37.32	$/kW/Yr	10
11	Intertie Transmission Demand	-	$/kW/Yr	11
12	Generation Demand Cost	89.14	$/kW/Yr	12
13	Ancillary Services Cost	-	$/kW/Yr	13
14	Demand Sub-Total	209.29	$/kW/Yr	14
	Energy Costs:			
	Summer			
15	On-Peak	2.37	¢/KWHR	15
16	Semi-Peak	2.26	¢/KWHR	16
17	Off-Peak	1.73	¢/KWHR	17
	Winter			
18	On-Peak	2.87	¢/KWHR	18
19	Semi-Peak	2.66	¢/KWHR	19
20	Off-Peak	2.44	¢/KWHR	20
21	Annual Average	2.33	¢/KWHR	21

NOTE:
These Customer and Demand Marginal Cost Values are used for Revenue Allocation in this proceeding only.

Raup03

TABLE 11 (Sheet 1 of 2)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

RESIDENTIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE DR						1
2	Baseline Energy	$/kWh	$0.10088	$0.10077	($0.00011)	(0.11)	2
3	Non-Baseline Energy	$/kWh	0.12644	0.12039	(0.00605)	(4.78)	3
4	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	4
5							5
6	SCHEDULE DR-LI						6
7	Baseline Energy	$/kWh	0.08526	0.08526	0.00000	0.00	7
8	Non-Baseline Energy	$/kWh	0.10699	0.10194	(0.00505)	(4.72)	8
9	Minimum Bill	$/Day	0.139	0.139	0.000	0.00	9
10							10
11	SCHEDULE DM						11
12	Baseline Energy	$/kWh	0.10088	0.10077	(0.00011)	(0.11)	12
13	Non-Baseline Energy	$/kWh	0.12644	0.12039	(0.00605)	(4.78)	13
14	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	14
15							15
16	SCHEDULE DS						16
17	Baseline Energy	$/kWh	0.10088	0.10077	(0.00011)	(0.11)	17
18	Non-Baseline Energy	$/kWh	0.12644	0.12039	(0.00605)	(4.78)	18
19	Baseline Energy L/I	$/kWh	0.08526	0.08526	0.00000	0.00	19
20	Non-Baseline Energy L/I	$/kWh	0.10699	0.10194	(0.00505)	(4.72)	20
21	Unit Discount	$/Day	0.110	0.113	0.003	2.73	21
22	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	22
23							23
24	SCHEDULE DT						24
25	Baseline Energy	$/kWh	0.10088	0.10077	(0.00011)	(0.11)	25
26	Non-Baseline Energy	$/kWh	0.12644	0.12039	(0.00605)	(4.78)	26
27	Baseline Energy L/I	$/kWh	0.08526	0.08526	0.00000	0.00	27
28	Non-Baseline Energy L/I	$/kWh	0.10699	0.10194	(0.00505)	(4.72)	28
29	Space Discount	$/Day	0.232	0.238	0.006	2.59	29
30	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	30
31							31
32	SCHEDULE DT-RV						32
33	Energy						33
34	Regular - Baseline	$/kWh	0.10088	0.10077	(0.00011)	(0.11)	34
35	Regular - Non-Baseline	$/kWh	0.12644	0.12039	(0.00605)	(4.78)	35
36	Low-Income - Baseline	$/kWh	0.08526	0.08526	0.00000	0.00	36
37	Low-Income - Non-Baseline	$/kWh	0.10699	0.10194	(0.00505)	(4.72)	37
38	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	38

Notes (applicable to all Present & ADOPTED Rates tables in this Appendix):

- Column C: Includes rate adjustments ordered in D.95-04-076 (SDG&E's 1995 ECAC proceeding), effective 5/1/95.
- Column D: From rate design workpapers.
- Column E: Column D - Column C
- Column F: (Column E / Column C) * 100
- L/I represents Low-Income

TABLE 11

(Sheet 2 of 2)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

RESIDENTIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE DR-VTOU						1
2	Metering Charge	$/Month	3.28	$3.28	$0.00	0.00	2
3	Contract Demand	$/kW/Month	6.99	7.86	0.87	12.45	3
4	Energy						4
5	On-Peak	$/kWh	3.12366	3.83177	0.70811	22.67	5
6	Semi-Peak	$/kWh	0.07163	0.05693	(0.01470)	(20.52)	6
7	Off-Peak	$/kWh	0.05693	0.04968	(0.00725)	(12.73)	7
8							8
9	SCHEDULE D-SMF						9
10	Basic Service Fee	$/Month	40.00	42.00	2.00	5.00	10
11	On-Peak Demand	$/KW	10.94	10.94	0.00	0.00	11
12	Baseline Energy	$/kWh	0.08199	0.08158	(0.00041)	(0.50)	12
13	Non-Baseline Energy	$/kWh	0.10274	0.09745	(0.00529)	(5.15)	13
14	Baseline Energy L/I	$/kWh	0.06921	0.06896	(0.00025)	(0.36)	14
15	Non-Baseline Energy L/I	$/kWh	0.08684	0.08244	(0.00440)	(5.07)	15
16	Unit Discount	$/kWh	0.110	0.110	0.000	0.00	16
17	Space Discount	$/Day	0.312	0.312	0.000	0.00	17
18							18
19	SCHEDULE DR-TOU						19
20	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	20
21	Metering Charge	$/Month	3.28	3.28	0.00	0.00	21
22	On-Peak Energy: Summer	$/Kwh	0.35266	0.34416	(0.00850)	(2.41)	22
23	Off-Peak Energy: Summer	$/kWh	0.08099	0.07674	(0.00425)	(5.25)	23
24	On-Peak Energy: Winter	$/kWh	0.12016	0.10803	(0.01213)	(10.09)	24
25	Off-Peak Energy: Winter	$/kWh	0.08099	0.07674	(0.00425)	(5.25)	25
26	Baseline Adjustment	$/kWh	0.02556	0.01962	(0.00594)	(23.24)	26
27							27
28	SCHEDULE DR-TOU-2						28
29	Minimum Bill	$/Day	0.164	0.164	0.000	0.00	29
30	Metering Charge	$/Month	3.28	3.28	0.00	0.00	30
31	On-Peak Energy: Summer	$/kWh	0.31100	0.31187	0.00087	0.28	31
32	Off-Peak Energy: Summer	$/kWh	0.07152	0.06960	(0.00192)	(2.68)	32
33	On-Peak Energy: Winter	$/kWh	0.10605	0.09796	(0.00809)	(7.63)	33
34	Off-Peak Energy: Winter	$/kWh	0.07152	0.06960	(0.00192)	(2.68)	34

TABLE 12
CARE SURCHARGE
1996 RDW PROCEEDING (A.91-11-024)
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997

CARE PROGRAM COSTS

Line No.	(A) Description	(B) Baseline	(C) Non-Baseline	(D) Minimum Bill	(E) Total	Line No.
1	**Residential CARE Discount:**					1
2	Residential Rate Before Surcharge (est)	$0.10031	$0.12254	$0.164		2
3	CARE Rate (Line 3 * 85%)	0.08526	0.10416	0.139		3
4	Low Income Discount	0.01505	0.01838	0.025		4
5						5
6	Low Income Discount Sales (kWh or Bills)	349,549,497	148,934,503	527,000	498,484,000	6
7	Low Income Discount	$5,259,497	$2,737,565	$13,175	$8,010,237	7
8						8
9				Discount		9
10				Revenue		10
11	**Commercial CARE Discount:**			($000's)		11
12	General Service (A)			$36		12
13	GS-Demand Metered 20kW (AD)			$14		13
14	Large TOU			$62		14
15	Total Commercial Industrial				$112,000	15
16						16
17	**Administrative Budget**				$303,896	17
18	FF&U Costs				1.01365	18
19	Total Administrative Costs				$310,071	19
20						20
21	**Forecasted CARE Account Balance on 4/30/96**				($1,439,474)	21
22						22
23	**Total CARE Program Costs**				$6,992,834	23
24						24
25	**SALES SUBJECT TO CARE SURCHARGE**					25
26						26
27	**Total Forecast Period Sales (000's kWh)**				15,941,964	27
28						28
29	**Adjustments:**					29
30	Residential Low Income Sales (000's kWh)				498,484	30
31	Residential Low Income Minimum Bill Sales (000's kWh)				320	31
32	Total Residential				498,804	32
33						33
34	Commercial Low Income Sales (000's kWh)		Total	CARE		34
35		CARE Sales	Sales	Sales		35
36		Factor	(000's kWh)	(000's kWh)		36
37	General Service (A)	1.28310%	1,918,948	24,622		37
38	GS-Demand Metered 20kW (AD)	0.08722%	579,728	506		38
39	Large TOU	0.05512%	7,272,643	4,009		39
40	Total Commercial Industrial				29,136	40
41						41
42	Exempt Streetlight Sales (000's kWh)				79,758	42
43	Special Contract Sales (000's kWh)				0	43
44						44
45	Total Adjustments (000's kWh)				607,698	45
46						46
47	**Total Sales Subject to CARE Surcharge**				15,334,266	47
48						48
49	**CALCULATION OF THE CARE SURCHARGE**					49
50						50
51	Total CARE Program Costs				$6,992,834	51
52	Total Sales Subject to Surcharge (000's kWh)				15,334,266	52
53						53
54	CARE Surcharge ($/kWh):				$0.00046	54

Fa.pd3

TABLE 13 (Sheet 1 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A						1
2	Basic Service Fee	$/Month	$7.50	$7.50	$0.00	0.00	2
3	Energy Charge						3
4	Secondary	$/kWh	0.11100	0.10985	(0.00115)	(1.04)	4
5	Primary	$/kWh	0.10782	0.10647	(0.00135)	(1.25)	5
6							6
7	SCHEDULE A-TC						7
8	Basic Service Fee	$/Month	7.50	7.50	0.00	0.00	8
9	Energy Charge	$/kWh	0.06618	0.06558	(0.00060)	(0.91)	9
10							10
11	SCHEDULE A-TOU						11
12	Basic Service Fee						12
13	Basic	$/Month	7.50	7.50	0.00	0.00	13
14	Metering	$/Month	3.28	3.28	0.00	0.00	14
15	Energy						15
16	Summer On-Peak	$/kWh	0.30132	0.32121	0.01989	6.60	16
17	Winter On-Peak	$/kWh	0.18580	0.18639	0.00059	0.32	17
18	Semi-Peak	$/kWh	0.06487	0.05523	(0.00964)	(14.86)	18
19	Off-Peak	$/kWh	0.05529	0.04969	(0.00560)	(10.13)	19
20							20
21	SCHEDULE AD						21
22	Basic Service Fee	$/Month	20.00	20.00	0.00	0.00	22
23	Demand Charge						23
24	Secondary	$/KW	8.77	9.21	0.44	5.00	24
25	Primary	$/KW	8.42	8.84	0.42	4.99	25
26	Energy Charge						26
27	Secondary	$/kWh	0.08408	0.08187	(0.00221)	(2.63)	27
28	Primary	$/kWh	0.08198	0.07961	(0.00237)	(2.89)	28
29	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	29
30	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	30

Note: Current rates for Schedules A and AD incorporate voltage discounts.

TABLE 13 (Sheet 2 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT – (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE AL-TOU						1
2	Basic Service Fee						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Non-Coincident Demand						15
16	Secondary	$/kW	4.30	4.52	0.22	5.12	16
17	Primary	$/kW	3.91	4.11	0.20	5.12	17
18	Primary Substation	$/kW	0.31	0.40	0.09	29.03	18
19	Transmission	$/kW	0.31	0.40	0.09	29.03	19
20	Maximum On-Peak Demand: Summer						20
21	Secondary	$/kW	19.81	19.81	0.00	0.00	21
22	Primary	$/kW	19.31	19.31	0.00	0.00	22
23	Primary Substation	$/kW	14.16	14.16	0.00	0.00	23
24	Transmission	$/kW	14.07	14.07	0.00	0.00	24
25	Maximum On-Peak Demand: Winter						25
26	Secondary	$/kW	4.60	4.60	0.00	0.00	26
27	Primary	$/kW	4.48	4.48	0.00	0.00	27
28	Primary Substation	$/kW	2.89	2.89	0.00	0.00	28
29	Transmission	$/kW	2.87	2.87	0.00	0.00	29
30	Power Factor						30
31	Secondary	$/kvar	0.21	0.21	0.00	0.00	31
32	Primary	$/kvar	0.21	0.21	0.00	0.00	32
33	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	33
34	Transmission	$/kvar	0.21	0.21	0.00	0.00	34
35	Contract Minimum Demand	$/kW					35
36	Secondary	$/kW	0.50	0.50	0.00	0.00	36
37	Primary	$/kW	0.50	0.50	0.00	0.00	37
38	Primary Substation	$/kW	0.50	0.50	0.00	0.00	38
39	Transmission	$/kW	0.50	0.50	0.00	0.00	39
40	Signaled Period 1G Energy						40
41	Secondary	$/kWh	0.10158	0.10147	(0.00011)	(0.11)	41
42	Primary	$/kWh	0.09964	0.09953	(0.00011)	(0.11)	42
43	Primary Substation	$/kWh	0.09715	0.09704	(0.00011)	(0.11)	43
44	Transmission	$/kWh	0.09668	0.09657	(0.00011)	(0.11)	44
45	On-Peak Energy: Summer						45
46	Secondary	$/kWh	0.07658	0.07647	(0.00011)	(0.14)	46
47	Primary	$/kWh	0.07464	0.07453	(0.00011)	(0.15)	47
48	Primary Substation	$/kWh	0.07215	0.07204	(0.00011)	(0.15)	48
49	Transmission	$/kWh	0.07168	0.07157	(0.00011)	(0.15)	49
50	Semi-Peak Energy: Summer						50
51	Secondary	$/kWh	0.04615	0.04467	(0.00148)	(3.21)	51
52	Primary	$/kWh	0.04512	0.04367	(0.00145)	(3.21)	52
53	Primary Substation	$/kWh	0.04384	0.04242	(0.00142)	(3.24)	53
54	Transmission	$/kWh	0.04355	0.04214	(0.00141)	(3.24)	54
55	Off-Peak Energy: Summer						55
56	Secondary	$/kWh	0.03630	0.03511	(0.00119)	(3.28)	56
57	Primary	$/kWh	0.03573	0.03456	(0.00117)	(3.27)	57
58	Primary Substation	$/kWh	0.03507	0.03392	(0.00115)	(3.28)	58
59	Transmission	$/kWh	0.03484	0.03370	(0.00114)	(3.27)	59
60	On-Peak Energy: Winter						60
61	Secondary	$/kWh	0.06413	0.06402	(0.00011)	(0.17)	61
62	Primary	$/kWh	0.06251	0.06240	(0.00011)	(0.18)	62
63	Primary Substation	$/kWh	0.06043	0.06032	(0.00011)	(0.18)	63
64	Transmission	$/kWh	0.06003	0.05992	(0.00011)	(0.18)	64
65	Semi-Peak Energy: Winter						65
66	Secondary	$/kWh	0.04636	0.04487	(0.00149)	(3.21)	66
67	Primary	$/kWh	0.04533	0.04387	(0.00146)	(3.22)	67
68	Primary Substation	$/kWh	0.04406	0.04264	(0.00142)	(3.22)	68
69	Transmission	$/kWh	0.04377	0.04236	(0.00141)	(3.22)	69
70	Off-Peak Energy: Winter						70
71	Secondary	$/kWh	0.03669	0.03549	(0.00120)	(3.27)	71
72	Primary	$/kWh	0.03611	0.03493	(0.00118)	(3.27)	72
73	Primary Substation	$/kWh	0.03545	0.03429	(0.00116)	(3.27)	73
74	Transmission	$/kWh	0.03522	0.03407	(0.00115)	(3.27)	74
75	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	75
76	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	76
77	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	77

TABLE 11 (Sheet 3 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE AL-TOU-2						1
2	Basic Service Fee						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Non-Coincident Demand						15
16	Secondary	$/kW	4.30	4.52	0.22	5.12	16
17	Primary	$/kW	3.91	4.11	0.20	5.12	17
18	Primary Substation	$/kW	0.31	0.40	0.09	29.03	18
19	Transmission	$/kW	0.31	0.40	0.09	29.03	19
20	Maximum On-Peak Demand: Summer						20
21	Secondary	$/kW	22.25	22.25	0.00	0.00	21
22	Primary	$/kW	21.69	21.69	0.00	0.00	22
23	Primary Substation	$/kW	15.91	15.91	0.00	0.00	23
24	Transmission	$/kW	15.81	15.81	0.00	0.00	24
25	Maximum On-Peak Demand: Winter						25
26	Secondary	$/kW	4.60	4.60	0.00	0.00	26
27	Primary	$/kW	4.48	4.48	0.00	0.00	27
28	Primary Substation	$/kW	2.89	2.89	0.00	0.00	28
29	Transmission	$/kW	2.87	2.87	0.00	0.00	29
30	Power Factor						30
31	Secondary	$/kvar	0.21	0.21	0.00	0.00	31
32	Primary	$/kvar	0.21	0.21	0.00	0.00	32
33	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	33
34	Transmission	$/kvar	0.21	0.21	0.00	0.00	34
35	On-Peak Energy: Summer						35
36	Secondary	$/kWh	0.08594	0.08583	(0.00011)	(0.13)	36
37	Primary	$/kWh	0.08375	0.08365	(0.00010)	(0.12)	37
38	Primary Substation	$/kWh	0.08097	0.08085	(0.00012)	(0.15)	38
39	Transmission	$/kWh	0.08044	0.08032	(0.00012)	(0.15)	39
40	Semi-Peak Energy: Summer						40
41	Secondary	$/kWh	0.05176	0.05011	(0.00165)	(3.19)	41
42	Primary	$/kWh	0.05060	0.04898	(0.00162)	(3.20)	42
43	Primary Substation	$/kWh	0.04916	0.04758	(0.00158)	(3.21)	43
44	Transmission	$/kWh	0.04884	0.04727	(0.00157)	(3.21)	44
45	Off-Peak Energy: Summer						45
46	Secondary	$/kWh	0.03630	0.03511	(0.00119)	(3.28)	46
47	Primary	$/kWh	0.03573	0.03456	(0.00117)	(3.27)	47
48	Primary Substation	$/kWh	0.03507	0.03392	(0.00115)	(3.28)	48
49	Transmission	$/kWh	0.03484	0.03370	(0.00114)	(3.27)	49
50	On-Peak Energy: Winter						50
51	Secondary	$/kWh	0.06413	0.06402	(0.00011)	(0.17)	51
52	Primary	$/kWh	0.06251	0.06240	(0.00011)	(0.18)	52
53	Primary Substation	$/kWh	0.06043	0.06032	(0.00011)	(0.18)	53
54	Transmission	$/kWh	0.06003	0.05992	(0.00011)	(0.18)	54
55	Semi-Peak Energy: Winter						55
56	Secondary	$/kWh	0.04636	0.04487	(0.00149)	(3.21)	56
57	Primary	$/kWh	0.04533	0.04387	(0.00146)	(3.22)	57
58	Primary Substation	$/kWh	0.04406	0.04264	(0.00142)	(3.22)	58
59	Transmission	$/kWh	0.04377	0.04236	(0.00141)	(3.22)	59
60	Off-Peak Energy: Winter						60
61	Secondary	$/kWh	0.03669	0.03549	(0.00120)	(3.27)	61
62	Primary	$/kWh	0.03611	0.03493	(0.00118)	(3.27)	62
63	Primary Substation	$/kWh	0.03545	0.03429	(0.00116)	(3.27)	63
64	Transmission	$/kWh	0.03522	0.03407	(0.00115)	(3.27)	64
65	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	65
66	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	66
67	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	67

TABLE 13

(Sheet 4 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A6-TOU						1
2	Greater than 500 kW						2
3	Primary	$/Month	$160.00	$168.00	$8.00	5.00	3
4	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	4
5	Transmission	$/Month	600.00	630.00	30.00	5.00	5
6	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	6
7	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	7
8	Non-Coincident Demand						8
9	Primary	$/KW	3.91	4.11	0.20	5.12	9
10	Primary Substation	$/kW	0.31	0.40	0.09	29.03	10
11	Transmission	$/KW	0.31	0.40	0.09	29.03	11
12	Maximum On-Peak Demand: Summer						12
13	Primary	$/KW	21.66	21.66	0.00	0.00	13
14	Primary Substation	$/kW	16.59	16.59	0.00	0.00	14
15	Transmission	$/KW	16.48	16.48	0.00	0.00	15
16	Maximum On-Peak Demand: Winter						16
17	Primary	$/KW	5.20	5.20	0.00	0.00	17
18	Primary Substation	$/kW	3.21	3.21	0.00	0.00	18
19	Transmission	$/KW	3.19	3.19	0.00	0.00	19
20	Power Factor						20
21	Primary	$/kvar	0.21	0.21	0.00	0.00	21
22	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	22
23	Transmission	$/kvar	0.21	0.21	0.00	0.00	23
24	On-Peak Energy: Summer						24
25	Primary	$/kWh	0.07464	0.07453	(0.00011)	(0.15)	25
26	Primary Substation	$/kWh	0.07215	0.07204	(0.00011)	(0.15)	26
27	Transmission	$/kWh	0.07168	0.07157	(0.00011)	(0.15)	27
28	Semi-Peak Energy: Summer						28
29	Primary	$/kWh	0.04512	0.04398	(0.00114)	(2.53)	29
30	Primary Substation	$/kWh	0.04384	0.04273	(0.00111)	(2.53)	30
31	Transmission	$/kWh	0.04355	0.04245	(0.00110)	(2.53)	31
32	Off-Peak Energy: Summer						32
33	Primary	$/kWh	0.03573	0.03481	(0.00092)	(2.57)	33
34	Primary Substation	$/kWh	0.03507	0.03416	(0.00091)	(2.59)	34
35	Transmission	$/kWh	0.03484	0.03394	(0.00090)	(2.58)	35
36	On-Peak Energy: Winter						36
37	Primary	$/kWh	0.06251	0.06240	(0.00011)	(0.18)	37
38	Primary Substation	$/kWh	0.06043	0.06032	(0.00011)	(0.18)	38
39	Transmission	$/kWh	0.06003	0.05992	(0.00011)	(0.18)	39
40	Semi-Peak Energy: Winter						40
41	Primary	$/kWh	0.04533	0.04418	(0.00115)	(2.54)	41
42	Primary Substation	$/kWh	0.04406	0.04294	(0.00112)	(2.54)	42
43	Transmission	$/kWh	0.04377	0.04266	(0.00111)	(2.54)	43
44	Off-Peak Energy: Winter						44
45	Primary	$/kWh	0.03611	0.03518	(0.00093)	(2.58)	45
46	Primary Substation	$/kWh	0.03545	0.03454	(0.00091)	(2.57)	46
47	Transmission	$/kWh	0.03522	0.03431	(0.00091)	(2.58)	47
48	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	48
49	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	49
50	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	50

TABLE 13

(Sheet 5 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT – (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE AO-TOU						1
2	Basic Service Fee						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Non-Coincident Demand						15
16	Secondary	$/kW	4.55	4.78	0.23	5.05	16
17	Primary	$/kW	4.43	4.65	0.22	4.97	17
18	Primary Substation	$/kW	0.31	0.40	0.09	29.03	18
19	Transmission	$/kW	0.31	0.40	0.09	29.03	19
20	Maximum On-Peak Demand: Summer						20
21	Secondary	$/kW	22.41	22.41	0.00	0.00	21
22	Primary	$/kW	21.84	21.84	0.00	0.00	22
23	Primary Substation	$/kW	18.46	18.46	0.00	0.00	23
24	Transmission	$/kW	18.34	18.34	0.00	0.00	24
25	Maximum On-Peak Demand: Winter						25
26	Secondary	$/kW	4.78	4.78	0.00	0.00	26
27	Primary	$/kW	4.66	4.66	0.00	0.00	27
28	Primary Substation	$/kW	3.94	3.94	0.00	0.00	28
29	Transmission	$/kW	3.91	3.91	0.00	0.00	29
30	Power Factor						30
31	Secondary	$/kvar	0.21	0.21	0.00	0.00	31
32	Primary	$/kvar	0.21	0.21	0.00	0.00	32
33	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	33
34	Transmission	$/kvar	0.21	0.21	0.00	0.00	34
35	On-Peak Energy: Summer						35
36	Secondary	$/kWh	0.05139	0.05128	(0.00011)	(0.21)	36
37	Primary	$/kWh	0.05008	0.04997	(0.00011)	(0.22)	37
38	Primary Substation	$/kWh	0.04843	0.04832	(0.00011)	(0.23)	38
39	Transmission	$/kWh	0.04811	0.04800	(0.00011)	(0.23)	39
40	Semi-Peak Energy: Summer						40
41	Secondary	$/kWh	0.04526	0.04405	(0.00121)	(2.67)	41
42	Primary	$/kWh	0.04425	0.04306	(0.00119)	(2.69)	42
43	Primary Substation	$/kWh	0.04299	0.04183	(0.00116)	(2.70)	43
44	Transmission	$/kWh	0.04271	0.04156	(0.00115)	(2.69)	44
45	Off-Peak Energy: Summer						45
46	Secondary	$/kWh	0.03560	0.03463	(0.00097)	(2.72)	46
47	Primary	$/kWh	0.03504	0.03408	(0.00096)	(2.74)	47
48	Primary Substation	$/kWh	0.03440	0.03345	(0.00095)	(2.76)	48
49	Transmission	$/kWh	0.03417	0.03323	(0.00094)	(2.75)	49
50	On-Peak Energy: Winter						50
51	Secondary	$/kWh	0.05917	0.05906	(0.00011)	(0.19)	51
52	Primary	$/kWh	0.05767	0.05756	(0.00011)	(0.19)	52
53	Primary Substation	$/kWh	0.05576	0.05564	(0.00012)	(0.22)	53
54	Transmission	$/kWh	0.05539	0.05528	(0.00011)	(0.20)	54
55	Semi-Peak Energy: Winter						55
56	Secondary	$/kWh	0.04546	0.04424	(0.00122)	(2.68)	56
57	Primary	$/kWh	0.04445	0.04326	(0.00119)	(2.68)	57
58	Primary Substation	$/kWh	0.04320	0.04205	(0.00115)	(2.66)	58
59	Transmission	$/kWh	0.04292	0.04177	(0.00115)	(2.68)	59
60	Off-Peak Energy: Winter						60
61	Secondary	$/kWh	0.03598	0.03500	(0.00098)	(2.72)	61
62	Primary	$/kWh	0.03541	0.03444	(0.00097)	(2.74)	62
63	Primary Substation	$/kWh	0.03477	0.03381	(0.00096)	(2.76)	63
64	Transmission	$/kWh	0.03454	0.03359	(0.00095)	(2.75)	64
65	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	65
66	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	66
67	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	67

TABLE 13 (Sheet 8 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE NJ						1
2	Basic Service Fee						2
3	Secondary	$/Month	$160.00	$168.00	$8.00	5.00	3
4	Primary	$/Month	160.00	168.00	8.00	5.00	4
5	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	5
6	Transmission	$/Month	160.00	168.00	8.00	5.00	6
7	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	7
8	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	8
9	Non-Coincident Demand						9
10	Secondary	$/kW	4.55	4.78	0.23	5.05	10
11	Primary	$/kW	4.43	4.65	0.22	4.97	11
12	Primary Substation	$/kW	0.31	0.40	0.09	29.03	12
13	Transmission	$/kW	0.31	0.40	0.09	29.03	13
14	Maximum On-Peak Demand: Summer						14
15	Secondary	$/kW	22.41	22.41	0.00	0.00	15
16	Primary	$/kW	21.84	21.84	0.00	0.00	16
17	Primary Substation	$/kW	18.46	18.46	0.00	0.00	17
18	Transmission	$/kW	18.34	18.34	0.00	0.00	18
19	Maximum On-Peak Demand: Winter						19
20	Secondary	$/kW	4.78	4.78	0.00	0.00	20
21	Primary	$/kW	4.66	4.66	0.00	0.00	21
22	Primary Substation	$/kW	3.94	3.94	0.00	0.00	22
23	Transmission	$/kW	3.91	3.91	0.00	0.00	23
24	Power Factor						24
25	Secondary	$/kvar	0.21	0.21	0.00	0.00	25
26	Primary	$/kvar	0.21	0.21	0.00	0.00	26
27	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	27
28	Transmission	$/kvar	0.21	0.21	0.00	0.00	28
29	On-Peak Energy: Summer						29
30	Secondary	$/kWh	0.05139	0.05128	(0.00011)	(0.21)	30
31	Primary	$/kWh	0.05008	0.04997	(0.00011)	(0.22)	31
32	Primary Substation	$/kWh	0.04843	0.04832	(0.00011)	(0.23)	32
33	Transmission	$/kWh	0.04811	0.04800	(0.00011)	(0.23)	33
34	Semi-Peak Energy: Summer						34
35	Secondary	$/kWh	0.04526	0.04405	(0.00121)	(2.67)	35
36	Primary	$/kWh	0.04425	0.04306	(0.00119)	(2.69)	36
37	Primary Substation	$/kWh	0.04299	0.04183	(0.00116)	(2.70)	37
38	Transmission	$/kWh	0.04271	0.04156	(0.00115)	(2.69)	38
39	Off-Peak Energy: Summer						39
40	Secondary	$/kWh	0.03560	0.03463	(0.00097)	(2.72)	40
41	Primary	$/kWh	0.03504	0.03408	(0.00096)	(2.74)	41
42	Primary Substation	$/kWh	0.03440	0.03345	(0.00095)	(2.76)	42
43	Transmission	$/kWh	0.03417	0.03323	(0.00094)	(2.75)	43
44	On-Peak Energy: Winter						44
45	Secondary	$/kWh	0.05917	0.05906	(0.00011)	(0.19)	45
46	Primary	$/kWh	0.05767	0.05756	(0.00011)	(0.19)	46
47	Primary Substation	$/kWh	0.05576	0.05564	(0.00012)	(0.22)	47
48	Transmission	$/kWh	0.05539	0.05528	(0.00011)	(0.20)	48
49	Semi-Peak Energy: Winter						49
50	Secondary	$/kWh	0.04546	0.04424	(0.00122)	(2.68)	50
51	Primary	$/kWh	0.04445	0.04326	(0.00119)	(2.68)	51
52	Primary Substation	$/kWh	0.04320	0.04205	(0.00115)	(2.66)	52
53	Transmission	$/kWh	0.04292	0.04177	(0.00115)	(2.68)	53
54	Off-Peak Energy: Winter						54
55	Secondary	$/kWh	0.03598	0.03500	(0.00098)	(2.72)	55
56	Primary	$/kWh	0.03541	0.03444	(0.00097)	(2.74)	56
57	Primary Substation	$/kWh	0.03477	0.03381	(0.00096)	(2.76)	57
58	Transmission	$/kWh	0.03454	0.03359	(0.00095)	(2.75)	58
59	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	59
60	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	60
61	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	61

Notes:
- The rates contained in Schedule NJ are the same as those of Schedule AO-TOU.
- A three-year declining discount (15%, 10% and 5%) will be applied as specified in the Schedule NJ tariff.

TABLE 11 (Sheet 7 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE AY-TOU						1
2	Basic Service Fee						2
3	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	3
4	Primary	$/Month	40.00	42.00	2.00	5.00	4
5	Transmission	$/Month	40.00	42.00	2.00	5.00	5
6	Non-Coincident Demand						6
7	Secondary	$/kW	4.30	4.52	0.22	5.12	7
8	Primary	$/kW	3.91	4.11	0.20	5.12	8
9	Transmission	$/kW	0.31	0.40	0.09	29.03	9
10	Maximum On-Peak Demand						10
11	Secondary	$/kW	11.32	11.24	(0.08)	(0.68)	11
12	Primary	$/kW	11.13	11.02	(0.11)	(0.99)	12
13	Transmission	$/kW	7.71	7.64	(0.07)	(0.91)	13
14	Power Factor						14
15	Secondary	$/kvar	0.21	0.21	0.00	0.00	15
16	Primary	$/kvar	0.21	0.21	0.00	0.00	16
17	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	17
18	Transmission	$/kvar	0.21	0.21	0.00	0.00	18
19	On-Peak Energy						19
20	Secondary	$/kWh	0.07401	0.07354	(0.00047)	(0.64)	20
21	Primary	$/kWh	0.07189	0.07158	(0.00031)	(0.43)	21
22	Transmission	$/kWh	0.06837	0.06823	(0.00014)	(0.20)	22
23	Semi-Peak Energy						23
24	Secondary	$/kWh	0.04754	0.04574	(0.00180)	(3.79)	24
25	Primary	$/kWh	0.04648	0.04472	(0.00176)	(3.79)	25
26	Transmission	$/kWh	0.04487	0.04317	(0.00170)	(3.79)	26
27	Off-Peak Energy						27
28	Secondary	$/kWh	0.03750	0.03606	(0.00144)	(3.84)	28
29	Primary	$/kWh	0.03691	0.03550	(0.00141)	(3.82)	29
30	Transmission	$/kWh	0.03601	0.03462	(0.00139)	(3.86)	30
31	On-Peak Rate Limiter	$/kWh	0.51	0.51	0.00	0.00	31
32	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	32

TABLE 11

(Sheet 8 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A-V1						1
2	Basic Service Fee						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	600.00	630.00	30.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	600.00	630.00	30.00	5.00	12
13	Greater than 10 MW -- Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	--	2.70	--	--	14
15	Contact Closure	$/Month	75.00	75.00	0.00	0.00	15
16	Demand Charge						16
17	Non-Coincident Demand						17
18	Secondary	$/kW	4.30	4.52	0.22	5.12	18
19	Primary	$/kW	3.91	4.11	0.20	5.12	19
20	Primary Substation	$/kW	0.31	0.40	0.09	29.88	20
21	Transmission	$/kW	0.31	0.40	0.09	29.03	21
22	Power Factor						22
23	Secondary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary	$/kvar	0.21	0.21	0.00	0.00	24
25	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	25
26	Transmission	$/kvar	0.21	0.21	0.00	0.00	26
27	Energy						27
28	Signaled Period 1G						28
29	Secondary	$/kWh	4.15986	4.46958	0.30972	7.45	29
30	Primary	$/kWh	3.39929	3.79175	0.39246	11.55	30
31	Primary Substation	$/kWh	2.24512	3.02522	0.78010	34.75	31
32	Transmission	$/kWh	2.23040	3.00539	0.77499	34.75	32
33	Semi-Peak						33
34	Secondary	$/kWh	0.06480	0.06327	(0.00153)	(2.36)	34
35	Primary	$/kWh	0.06185	0.05959	(0.00226)	(3.66)	35
36	Primary Substation	$/kWh	0.05538	0.05255	(0.00283)	(5.11)	36
37	Transmission	$/kWh	0.05502	0.05220	(0.00282)	(5.12)	37
38	Off-Peak						38
39	Secondary	$/kWh	0.03621	0.03802	0.00181	5.00	39
40	Primary	$/kWh	0.03608	0.03670	0.00062	1.71	40
41	Primary Substation	$/kWh	0.03481	0.03316	(0.00165)	(4.74)	41
42	Transmission	$/kWh	0.03459	0.03294	(0.00165)	(4.76)	42
43	Contract Minimum Demand						43
44	Secondary	$/kW/Month	8.46	8.47	0.01	0.06	44
45	Primary	$/kW/Month	8.25	8.34	0.09	1.03	45
46	Primary Substation	$/kW/Month	6.97	6.71	(0.26)	(3.76)	46
47	Transmission	$/kW/Month	6.93	6.66	(0.27)	(3.84)	47

TABLE 11

(Sheet 9 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A-V2						1
2	Basic Service Fee						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	600.00	630.00	30.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	600.00	630.00	30.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Contact Closure	$/Month	75.00	75.00	0.00	0.00	15
16	Demand Charge						16
17	Non-Coincident Demand						17
18	Secondary	$/kW	4.30	4.52	0.22	5.12	18
19	Primary	$/kW	3.91	4.11	0.20	5.12	19
20	Primary Substation	$/kW	0.31	0.40	0.09	29.88	20
21	Transmission	$/kW	0.31	0.40	0.09	29.03	21
22	Power Factor						22
23	Secondary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary	$/kvar	0.21	0.21	0.00	0.00	24
25	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	25
26	Transmission	$/kvar	0.21	0.21	0.00	0.00	26
27	Contract Minimum Demand						27
28	Secondary	$/kW/Month	10.96	11.69	0.73	6.71	28
29	Primary	$/kW/Month	10.68	11.52	0.84	7.82	29
30	Primary Substation	$/kW/Month	9.03	9.27	0.24	2.63	30
31	Transmission	$/kW/Month	8.97	9.21	0.24	2.64	31
32	Energy						32
33	Signaled Period 1G						33
34	Secondary	$/kWh	4.15984	4.46958	0.30974	7.45	34
35	Primary	$/kWh	3.39926	3.79174	0.39248	11.55	35
36	Primary Substation	$/kWh	2.24509	3.02522	0.78013	34.75	36
37	Transmission	$/kWh	2.23037	3.00539	0.77502	34.75	37
38	Signaled Period 2G						38
39	Secondary	$/kWh	0.61308	0.56465	(0.04843)	(7.90)	39
40	Primary	$/kWh	0.50903	0.48391	(0.02512)	(4.94)	40
41	Primary Substation	$/kWh	0.34975	0.39006	0.04031	11.53	41
42	Transmission	$/kWh	0.34746	0.38750	0.04004	11.52	42
43	Semi-Peak						43
44	Secondary	$/kWh	0.05364	0.04980	(0.00384)	(7.17)	44
45	Primary	$/kWh	0.05233	0.04772	(0.00461)	(8.81)	45
46	Primary Substation	$/kWh	0.04873	0.04267	(0.00606)	(12.44)	46
47	Transmission	$/kWh	0.04841	0.04239	(0.00602)	(12.43)	47
48	Off-Peak						48
49	Secondary	$/kWh	0.03619	0.03802	0.00183	5.06	49
50	Primary	$/kWh	0.03607	0.03670	0.00063	1.74	50
51	Primary Substation	$/kWh	0.03480	0.03316	(0.00164)	(4.71)	51
52	Transmission	$/kWh	0.03457	0.03294	(0.00163)	(4.71)	52

TABLE 13

(Sheet 10 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A-V3						1
2	Basic Service Fees						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	600.00	630.00	30.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	600.00	630.00	30.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Contact Closure	$/Month	75.00	75.00	0.00	0.00	15
16	Demand Charge						16
17	Non-Coincident Demand						17
18	Secondary	$/kW	4.30	4.52	0.22	5.12	18
19	Primary	$/kW	3.91	4.11	0.20	5.12	19
20	Primary Substation	$/kW	0.31	0.40	0.09	29.88	20
21	Transmission	$/kW	0.31	0.40	0.09	29.03	21
22	Power Factor						22
23	Secondary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary	$/kvar	0.21	0.21	0.00	0.00	24
25	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	25
26	Transmission	$/kvar	0.21	0.21	0.00	0.00	26
27	Contract Minimum Demand						27
28	Secondary	$/kW/Month	11.94	12.42	0.48	4.02	28
29	Primary	$/kW/Month	11.63	12.23	0.60	5.16	29
30	Primary Substation	$/kW/Month	9.83	9.84	0.01	0.12	30
31	Transmission	$/kW/Month	9.77	9.78	0.01	0.08	31
32	Energy						32
33	Signaled Period 1G						33
34	Secondary	$/kWh	4.15977	4.46958	0.30981	7.45	34
35	Primary	$/kWh	3.39919	3.79174	0.39255	11.55	35
36	Primary Substation	$/kWh	2.24501	3.02522	0.78021	34.75	36
37	Transmission	$/kWh	2.23029	3.00539	0.77510	34.75	37
38	Signaled Period 2G						38
39	Secondary	$/kWh	0.61302	0.56465	(0.04837)	(7.89)	39
40	Primary	$/kWh	0.50896	0.48390	(0.02506)	(4.92)	40
41	Primary Substation	$/kWh	0.34967	0.39006	0.04039	11.55	41
42	Transmission	$/kWh	0.34738	0.38750	0.04012	11.55	42
43	Signaled Period 3G						43
44	Secondary	$/kWh	0.12419	0.10077	(0.02342)	(18.86)	44
45	Primary	$/kWh	0.11062	0.09095	(0.01967)	(17.78)	45
46	Primary Substation	$/kWh	0.08844	0.07701	(0.01143)	(12.92)	46
47	Transmission	$/kWh	0.08786	0.07651	(0.01135)	(12.92)	47
48	Semi-Peak						48
49	Secondary	$/kWh	0.04887	0.04673	(0.00214)	(4.38)	49
50	Primary	$/kWh	0.04821	0.04501	(0.00320)	(6.65)	50
51	Primary Substation	$/kWh	0.04576	0.04041	(0.00535)	(11.69)	51
52	Transmission	$/kWh	0.04546	0.04015	(0.00531)	(11.68)	52
53	Off-Peak						53
54	Secondary	$/kWh	0.03615	0.03802	0.00187	5.18	54
55	Primary	$/kWh	0.03602	0.03670	0.00068	1.88	55
56	Primary Substation	$/kWh	0.03474	0.03316	(0.00158)	(4.55)	56
57	Transmission	$/kWh	0.03452	0.03294	(0.00158)	(4.58)	57

TABLE 13 (Sheet 11 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A-V6-C						1
2	Basic Service Fees						2
3	Zero to 10 kW						3
4	Secondary	$/Month	$35.00	$25.00	($10.00)	(28.57)	4
5	Primary	$/Month	250.00	200.00	(50.00)	(20.00)	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	7
8	10.1 to 25 kW						8
9	Secondary	$/Month	50.00	50.00	0.00	0.00	9
10	Primary	$/Month	250.00	200.00	(50.00)	(20.00)	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	12
13	25.1 to 250 kW						13
14	Secondary	$/Month	75.00	75.00	0.00	0.00	14
15	Primary	$/Month	250.00	200.00	(50.00)	(20.00)	15
16	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	16
17	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	17
18	250.1 to 450 kW						18
19	Secondary	$/Month	150.00	150.00	0.00	0.00	19
20	Primary	$/Month	250.00	250.00	0.00	0.00	20
21	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	21
22	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	22
23	450.1 to 650 kW						23
24	Secondary	$/Month	300.00	300.00	0.00	0.00	24
25	Primary	$/Month	300.00	250.00	(50.00)	(16.67)	25
26	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	26
27	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	27
28	650.1 to 1,250 kW						28
29	Secondary	$/Month	500.00	500.00	0.00	0.00	29
30	Primary	$/Month	300.00	300.00	0.00	0.00	30
31	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	31
32	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	32
33	1,250 to 10,000 kW						33
34	Secondary	$/Month	750.00	750.00	0.00	0.00	34
35	Primary	$/Month	350.00	300.00	(50.00)	(14.29)	35
36	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	36
37	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	37
38	Greater than 10,000 kW						38
39	Secondary	$/Month	750.00	750.00	0.00	0.00	39
40	Primary	$/Month	350.00	350.00	0.00	0.00	40
41	Primary Substation	$/Month	30,000.00	30,000.00	0.00	0.00	41
42	Transmission	$/Month	6,500.00	6,500.00	0.00	0.00	42
43	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	43
44	Demand Charge						44
45	Non-Coincident Demand						45
46	Secondary	$/kW	7.11	8.60	1.49	20.96	46
47	Primary	$/kW	6.93	8.16	1.23	17.75	47
48	Primary Substation	$/kW	0.71	0.83	0.12	16.90	48
49	Transmission	$/kW	0.71	0.83	0.12	16.90	49
50	Power Factor						50
51	Secondary	$/kvar	0.21	0.21	0.00	0.00	51
52	Primary	$/kvar	0.21	0.21	0.00	0.00	52
53	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	53
54	Transmission	$/kvar	0.21	0.21	0.00	0.00	54
55	Contract Minimum Demand						55
56	Signaled Period 1T						56
57	Secondary	$/kW	2.06	0.00	(2.06)	(100.00)	57
58	Primary	$/kW	2.01	0.00	(2.01)	(100.00)	58
59	Primary Substation	$/kW	1.94	0.00	(1.94)	(100.00)	59
60	Transmission	$/kW	1.93	0.00	(1.93)	(100.00)	60
61	Signaled Period 2T						61
62	Secondary	$/kW	0.52	0.00	(0.52)	(100.00)	62
63	Primary	$/kW	0.51	0.00	(0.51)	(100.00)	63
64	Primary Substation	$/kW	0.49	0.00	(0.49)	(100.00)	64
65	Transmission	$/kW	0.43	0.00	(0.43)	(100.00)	65
66	Signaled Period 1G, 2G and 3G						66
67	Secondary	$/kW	7.45	8.49	1.04	13.96	67
68	Primary	$/kW	7.15	7.82	0.67	9.37	68
69	Primary Substation	$/kW	3.77	4.11	0.34	9.02	69
70	Transmission	$/kW	3.72	4.03	0.31	8.33	70
71	Generation	$/kW	4.39	7.27	2.88	65.60	71

Note: Schedule A-V6-C rates are continued on next page.

TABLE 13

(Sheet 12 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A 91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
64	SCHEDULE A-V6-C (Continued)						64
65	Energy						65
66	Signaled Period 1T						66
67	Secondary	$/kWh	$24.70	$0.00	($24.70)	(100.00)	67
68	Primary	$/kWh	24.07	0.00	(24.07)	(100.00)	68
69	Primary Substation	$/kWh	23.26	0.00	(23.26)	(100.00)	69
70	Transmission	$/kWh	23.11	0.00	(23.11)	(100.00)	70
71	Signaled Period 2T						71
72	Secondary	$/kWh	6.29	0.00	(6.29)	(100.00)	72
73	Primary	$/kWh	6.13	0.00	(6.13)	(100.00)	73
74	Primary Substation	$/kWh	5.93	0.00	(5.93)	(100.00)	74
75	Transmission	$/kWh	5.89	0.00	(5.89)	(100.00)	75
76	Signaled Period 1G						76
77	Secondary	$/kWh	2.19196	2.77250	0.58054	26.48	77
78	Primary	$/kWh	2.10192	2.55960	0.45768	21.77	78
79	Primary Substation	$/kWh	1.11179	1.34394	0.23215	20.88	79
80	Transmission	$/kWh	1.09583	1.31938	0.22355	20.40	80
81	Generation	$/kWh	1.32258	2.40358	1.08100	81.73	81
82	Signaled Period 2G						82
83	Secondary	$/kWh	0.30637	0.31336	0.00699	2.28	83
84	Primary	$/kWh	0.29308	0.28847	(0.00461)	(1.57)	84
85	Primary Substation	$/kWh	0.15521	0.15158	(0.00363)	(2.34)	85
86	Transmission	$/kWh	0.15279	0.14867	(0.00412)	(2.70)	86
87	Generation	$/kWh	0.21356	0.29241	0.07885	36.92	87
88	Signaled Period 3G						88
89	Secondary	$/kWh	0.03960	0.03376	(0.00584)	(14.75)	89
90	Primary	$/kWh	0.03716	0.03024	(0.00692)	(18.62)	90
91	Primary Substation	$/kWh	0.01988	0.01602	(0.00386)	(19.42)	91
92	Transmission	$/kWh	0.01937	0.01558	(0.00379)	(19.57)	92
93	Generation	$/kWh	0.05666	0.05238	(0.00428)	(7.55)	93
94	Signaled Period 4G						94
95	Secondary	$/kWh	0.00194	0.00179	(0.00015)	(7.73)	95
96	Primary	$/kWh	0.00156	0.00098	(0.00058)	(37.18)	96
97	Primary Substation	$/kWh	0.00114	0.00072	(0.00042)	(36.84)	97
98	Transmission	$/kWh	0.00099	0.00059	(0.00040)	(40.40)	98
99	Generation	$/kWh	0.02181	0.01973	(0.00208)	(9.54)	99
100	On-Peak						100
101	Secondary	$/kWh	0.00540	0.00506	(0.00034)	(6.30)	101
102	Primary	$/kWh	0.00434	0.00372	(0.00062)	(14.29)	102
103	Primary Substation	$/kWh	0.00252	0.00208	(0.00044)	(17.46)	103
104	Transmission	$/kWh	0.00226	0.00190	(0.00036)	(15.93)	104
105	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	105
106	Semi-Peak						106
107	Secondary	$/kWh	0.00327	0.00239	(0.00088)	(26.91)	107
108	Primary	$/kWh	0.00253	0.00131	(0.00122)	(48.22)	108
109	Primary Substation	$/kWh	0.00159	0.00085	(0.00074)	(46.54)	109
110	Transmission	$/kWh	0.00138	0.00068	(0.00070)	(50.72)	110
111	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	111
112	Off-Peak						112
113	Secondary	$/kWh	0.00220	0.00198	(0.00022)	(10.00)	113
114	Primary	$/kWh	0.00175	0.00106	(0.00069)	(39.43)	114
115	Primary Substation	$/kWh	0.00125	0.00077	(0.00048)	(38.40)	115
116	Transmission	$/kWh	0.00107	0.00061	(0.00046)	(42.99)	116
117	Generation	$/kWh	0.02609	0.02256	(0.00353)	(13.53)	117

TABLE 13 (Sheet 13 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A-V2-O						1
2	Basic Service Fees						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	600.00	600.00	0.00	0.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	600.00	600.00	0.00	0.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Demand Charge						15
16	Non-Coincident Demand						16
17	Secondary	$/kW	4.30	4.52	0.22	5.12	17
18	Primary	$/kW	3.91	4.11	0.20	5.12	18
19	Primary Substation	$/kW	0.31	0.40	0.09	29.88	19
20	Transmission	$/kW	0.31	0.40	0.09	29.03	20
21	Power Factor						21
22	Secondary	$/kvar	0.21	0.21	0.00	0.00	22
23	Primary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	24
25	Transmission	$/kvar	0.21	0.21	0.00	0.00	25
26	Contract Minimum Demand						26
27	Signaled Period 1G, 2G and 4G						27
28	Secondary	$/kW	10.96	11.69	0.73	6.67	28
29	Primary	$/kW	10.68	11.52	0.83	7.79	29
30	Primary Substation	$/kW	9.03	9.27	0.24	2.63	30
31	Transmission	$/kW	8.97	9.21	0.23	2.60	31
32	Energy						32
33	Signaled Period 1G						33
34	Secondary	$/kWh	4.15984	4.46958	0.30974	7.45	34
35	Primary	$/kWh	3.39926	3.79174	0.39248	11.55	35
36	Primary Substation	$/kWh	2.24509	3.02522	0.78013	34.75	36
37	Transmission	$/kWh	2.23037	3.00539	0.77502	34.75	37
38	Signaled Period 2G						38
39	Secondary	$/kWh	0.61308	0.56465	(0.04843)	(7.90)	39
40	Primary	$/kWh	0.50903	0.48391	(0.02512)	(4.94)	40
41	Primary Substation	$/kWh	0.34975	0.39006	0.04031	11.53	41
42	Transmission	$/kWh	0.34746	0.38750	0.04004	11.52	42
43	Signaled Period 4G						43
44	Secondary	$/kWh	0.02375	0.02078	(0.00297)	(12.51)	44
45	Primary	$/kWh	0.02337	0.02000	(0.00337)	(14.42)	45
46	Primary Substation	$/kWh	0.02295	0.01975	(0.00320)	(13.94)	46
47	Transmission	$/kWh	0.02280	0.01962	(0.00318)	(13.95)	47
48	Semi-Peak						48
49	Secondary	$/kWh	0.05364	0.04980	(0.00384)	(7.17)	49
50	Primary	$/kWh	0.05233	0.04772	(0.00461)	(8.81)	50
51	Primary Substation	$/kWh	0.04873	0.04267	(0.00606)	(12.44)	51
52	Transmission	$/kWh	0.04841	0.04239	(0.00602)	(12.43)	52
53	Off-Peak						53
54	Secondary	$/kWh	0.04448	0.04782	0.00334	7.51	54
55	Primary	$/kWh	0.04433	0.04623	0.00190	4.29	55
56	Primary Substation	$/kWh	0.04277	0.04196	(0.00081)	(1.89)	56
57	Transmission	$/kWh	0.04249	0.04168	(0.00081)	(1.91)	57

TABLE 13 (Sheet 14 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE RTP-1						1
2	Basic Service Fees						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Demand Charge						15
16	Non-Coincident Demand						16
17	Secondary	$/kW	4.30	4.52	0.22	5.12	17
18	Primary	$/kW	3.91	4.11	0.20	5.12	18
19	Primary Substation	$/kW	0.31	0.40	0.09	29.03	19
20	Transmission	$/kW	0.31	0.40	0.09	29.03	20
21	Power Factor						21
22	Secondary	$/kvar	0.21	0.21	0.00	0.00	22
23	Primary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	24
25	Transmission	$/kvar	0.21	0.21	0.00	0.00	25
26	Contract Minimum Demand						26
27	Secondary	$/kW	9.43	11.69	2.26	24.02	27
28	Primary	$/kW	8.93	11.52	2.59	28.95	28
29	Primary Substation	$/kW	7.29	9.27	1.98	27.12	29
30	Transmission	$/kW	7.24	9.21	1.97	27.16	30
31	Energy						31
32	RTP Period A						32
33	Secondary	$/kWh	2.93932	3.12666	0.18734	6.37	33
34	Primary	$/kWh	2.40464	2.65415	0.24951	10.38	34
35	Primary Substation	$/kWh	1.59281	2.11897	0.52616	33.03	35
36	Transmission	$/kWh	1.58237	2.10508	0.52271	33.03	36
37	RTP Period B						37
38	Secondary	$/kWh	0.74104	0.72544	(0.01560)	(2.11)	38
39	Primary	$/kWh	0.61328	0.62010	0.00682	1.11	39
40	Primary Substation	$/kWh	0.41808	0.49855	0.08047	19.25	40
41	Transmission	$/kWh	0.41534	0.49528	0.07994	19.25	41
42	On-Peak Summer						42
43	Secondary	$/kWh	0.06424	0.05846	(0.00578)	(8.99)	43
44	Primary	$/kWh	0.06261	0.05757	(0.00504)	(8.05)	44
45	Primary Substation	$/kWh	0.06053	0.05659	(0.00394)	(6.50)	45
46	Transmission	$/kWh	0.06014	0.05659	(0.00355)	(5.89)	46
47	Semi-Peak Summer						47
48	Secondary	$/kWh	0.04672	0.04513	(0.00159)	(3.40)	48
49	Primary	$/kWh	0.04569	0.04413	(0.00156)	(3.41)	49
50	Primary Substation	$/kWh	0.04441	0.04288	(0.00153)	(3.45)	50
51	Transmission	$/kWh	0.04412	0.04260	(0.00152)	(3.45)	51
52	Off-Peak Summer						52
53	Secondary	$/kWh	0.03687	0.03557	(0.00130)	(3.53)	53
54	Primary	$/kWh	0.03630	0.03502	(0.00128)	(3.53)	54
55	Primary Substation	$/kWh	0.03564	0.03438	(0.00126)	(3.54)	55
56	Transmission	$/kWh	0.03541	0.03416	(0.00125)	(3.53)	56
57	On-Peak Winter						57
58	Secondary	$/kWh	0.07398	0.07643	0.00245	3.31	58
59	Primary	$/kWh	0.07210	0.07325	0.00115	1.59	59
60	Primary Substation	$/kWh	0.06969	0.07173	0.00204	2.93	60
61	Transmission	$/kWh	0.06924	0.07127	0.00203	2.93	61
62	Semi-Peak Winter						62
63	Secondary	$/kWh	0.04693	0.04533	(0.00160)	(3.41)	63
64	Primary	$/kWh	0.04590	0.04433	(0.00157)	(3.42)	64
65	Primary Substation	$/kWh	0.04463	0.04310	(0.00153)	(3.43)	65
66	Transmission	$/kWh	0.04434	0.04282	(0.00152)	(3.43)	66
67	Off-Peak Winter						67
68	Secondary	$/kWh	0.03726	0.03595	(0.00131)	(3.52)	68
69	Primary	$/kWh	0.03668	0.03539	(0.00129)	(3.52)	69
70	Primary Substation	$/kWh	0.03602	0.03475	(0.00127)	(3.53)	70
71	Transmission	$/kWh	0.03579	0.03453	(0.00126)	(3.52)	71

TABLE 11 (Sheet 15 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE RTP-2						1
2	Basic Service Fees						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot Month	–	2.70	–	–	14
15	Demand Charge						15
16	Non-Coincident Demand						16
17	Secondary	$/kW	4.30	4.52	0.22	5.12	17
18	Primary	$/kW	3.91	4.11	0.20	5.12	18
19	Primary Substation	$/kW	0.31	0.40	0.09	29.03	19
20	Transmission	$/kW	0.31	0.40	0.09	29.03	20
21	Power Factor						21
22	Secondary	$/kvar	0.21	0.21	0.00	0.00	22
23	Primary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	24
25	Transmission	$/kvar	0.21	0.21	0.00	0.00	25
26	Contract Minimum Demand						26
27	Secondary	$/kW	9.43	11.69	2.26	24.02	27
28	Primary	$/kW	8.93	11.52	2.59	28.95	28
29	Primary Substation	$/kW	7.29	9.27	1.98	27.12	29
30	Transmission	$/kW	7.24	9.21	1.97	27.16	30
31	Energy						31
32	RTP Period						32
33	Secondary	$/kWh	1.25257	1.28398	0.03141	2.51	33
34	Primary	$/kWh	1.03013	1.09325	0.06312	6.13	34
35	Primary Substation	$/kWh	0.69143	0.87548	0.18405	26.62	35
36	Transmission	$/kWh	0.68690	0.86974	0.18284	26.62	36
37	On-Peak Summer						37
38	Secondary	$/kWh	0.09343	0.08806	(0.00537)	(5.74)	38
39	Primary	$/kWh	0.09105	0.08672	(0.00433)	(4.76)	39
40	Primary Substation	$/kWh	0.08802	0.08524	(0.00278)	(3.15)	40
41	Transmission	$/kWh	0.08745	0.08524	(0.00221)	(2.52)	41
42	Semi-Peak Summer						42
43	Secondary	$/kWh	0.04672	0.04513	(0.00159)	(3.40)	43
44	Primary	$/kWh	0.04569	0.04413	(0.00156)	(3.41)	44
45	Primary Substation	$/kWh	0.04441	0.04288	(0.00153)	(3.45)	45
46	Transmission	$/kWh	0.04412	0.04260	(0.00152)	(3.45)	46
47	Off-Peak Summer						47
48	Secondary	$/kWh	0.03687	0.03557	(0.00130)	(3.53)	48
49	Primary	$/kWh	0.03630	0.03502	(0.00128)	(3.53)	49
50	Primary Substation	$/kWh	0.03564	0.03438	(0.00126)	(3.54)	50
51	Transmission	$/kWh	0.03541	0.03416	(0.00125)	(3.53)	51
52	On-Peak Winter						52
53	Secondary	$/kWh	0.10763	0.11520	0.00757	7.04	53
54	Primary	$/kWh	0.10489	0.11040	0.00551	5.25	54
55	Primary Substation	$/kWh	0.10138	0.10811	0.00673	6.64	55
56	Transmission	$/kWh	0.10072	0.10740	0.00668	6.64	56
57	Semi-Peak Winter						57
58	Secondary	$/kWh	0.04693	0.04533	(0.00160)	(3.41)	58
59	Primary	$/kWh	0.04590	0.04433	(0.00157)	(3.42)	59
60	Primary Substation	$/kWh	0.04463	0.04310	(0.00153)	(3.43)	60
61	Transmission	$/kWh	0.04434	0.04282	(0.00152)	(3.43)	61
62	Off-Peak Winter						62
63	Secondary	$/kWh	0.03726	0.03595	(0.00131)	(3.52)	63
64	Primary	$/kWh	0.03668	0.03539	(0.00129)	(3.52)	64
65	Primary Substation	$/kWh	0.03602	0.03475	(0.00127)	(3.53)	65
66	Transmission	$/kWh	0.03579	0.03453	(0.00126)	(3.52)	66

TABLE 11

(Sheet 16 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL - PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE AO-TOU-C						1
2	Basic Service Fees						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Demand Charge						15
16	Non-Coincident Demand						16
17	Secondary	$/kW	4.55	4.78	0.23	5.06	17
18	Primary	$/kW	4.43	4.65	0.22	4.97	18
19	Primary Substation	$/kW	0.31	0.40	0.09	29.03	19
20	Transmission	$/kW	0.31	0.40	0.09	29.03	20
21	Maximum On-Peak Demand: Summer						21
22	Secondary	$/kW	14.30	9.90	(4.40)	(30.77)	22
23	Primary	$/kW	13.73	9.33	(4.40)	(32.05)	23
24	Primary Substation	$/kW	10.35	5.95	(4.40)	(42.51)	24
25	Transmission	$/kW	10.23	5.83	(4.40)	(43.01)	25
26	Maximum On-Peak Demand: Winter						26
27	Secondary	$/kW	3.05	2.12	(0.93)	(30.49)	27
28	Primary	$/kW	2.93	2.00	(0.93)	(31.74)	28
29	Primary Substation	$/kW	2.21	1.28	(0.93)	(42.08)	29
30	Transmission	$/kW	2.18	1.25	(0.93)	(42.66)	30
31	Power Factor						31
32	Secondary	$/kvar	0.21	0.21	0.00	0.00	32
33	Primary	$/kvar	0.21	0.21	0.00	0.00	33
34	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	34
35	Transmission	$/kvar	0.21	0.21	0.00	0.00	35
36	Contract Minimum Demand						36
37	Generation Level	$/kW	4.39	7.27	2.88	65.60	37
38	Energy Charge						38
39	Generation Level						39
40	Signaled Period 1G	$/kWh	1.32258	2.40358	1.08100	81.73	40
41	Signaled Period 2G	$/kWh	0.21356	0.29241	0.07885	36.92	41
42	Signaled Period 3G	$/kWh	0.05666	0.05238	(0.00428)	(7.55)	42
43	Signaled Period 4G	$/kWh	0.02181	0.01973	(0.00208)	(9.54)	43
44	On-Peak Energy: Summer						44
45	Secondary	$/kWh	0.01485	0.02354	0.00869	58.52	45
46	Primary	$/kWh	0.01354	0.02223	0.00869	64.18	46
47	Primary Substation	$/kWh	0.01189	0.02058	0.00869	73.09	47
48	Transmission	$/kWh	0.01157	0.02026	0.00869	75.11	48
49	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	49
50	Semi-Peak Energy: Summer						50
51	Secondary	$/kWh	0.01499	0.01878	0.00379	25.28	51
52	Primary	$/kWh	0.01398	0.01779	0.00381	27.25	52
53	Primary Substation	$/kWh	0.01272	0.01656	0.00384	30.19	53
54	Transmission	$/kWh	0.01244	0.01629	0.00385	30.95	54
55	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	55
56	Off-Peak Energy: Summer						56
57	Secondary	$/kWh	0.01121	0.01207	0.00086	7.67	57
58	Primary	$/kWh	0.01065	0.01152	0.00087	8.17	58
59	Primary Substation	$/kWh	0.01001	0.01089	0.00088	8.79	59
60	Transmission	$/kWh	0.00978	0.01067	0.00089	9.10	60
61	Generation	$/kWh	0.02439	0.02435	(0.00004)	(0.16)	61

TABLE 13

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
59	SCHEDULE AO-TOU-C (Continued)						59
60	On-Peak Energy: Winter						60
61	Secondary	$/kWh	$0.02263	$0.03132	$0.00869	38.40	61
62	Primary	$/kWh	0.02113	0.02982	0.00869	41.13	62
63	Primary Substation	$/kWh	0.01922	0.02790	0.00868	45.16	63
64	Transmission	$/kWh	0.01885	0.02754	0.00869	46.10	64
65	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	65
66	Semi-Peak Energy: Winter						66
67	Secondary	$/kWh	0.01519	0.01897	0.00378	24.88	67
68	Primary	$/kWh	0.01418	0.01799	0.00381	26.87	68
69	Primary Substation	$/kWh	0.01293	0.01678	0.00385	29.78	69
70	Transmission	$/kWh	0.01265	0.01650	0.00385	30.43	70
71	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	71
72	Off-Peak Energy: Winter						72
73	Secondary	$/kWh	0.01159	0.01244	0.00085	7.33	73
74	Primary	$/kWh	0.01102	0.01188	0.00086	7.80	74
75	Primary Substation	$/kWh	0.01038	0.01125	0.00087	8.38	75
76	Transmission	$/kWh	0.01015	0.01103	0.00088	8.67	76
77	Generation	$/kWh	0.02439	0.02435	(0.00004)	(0.16)	77

TABLE 13

(Sheet 18 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE AL-TOU-0						1
2	Basic Service Fees						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW -- Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Non-Coincident Demand						15
16	Secondary	$/kW	4.30	4.52	0.22	5.12	16
17	Primary	$/kW	3.91	4.11	0.20	5.12	17
18	Primary Substation	$/kW	0.31	0.40	0.09	29.03	18
19	Transmission	$/kW	0.31	0.40	0.09	29.03	19
20	Maximum On-Peak Demand: Summer						20
21	Secondary	$/kW	11.61	7.53	(4.08)	(35.14)	21
22	Primary	$/kW	11.11	7.03	(4.08)	(36.72)	22
23	Primary Substation	$/kW	5.96	1.88	(4.08)	(68.45)	23
24	Transmission	$/kW	5.87	1.79	(4.08)	(69.51)	24
25	Maximum On-Peak Demand: Winter						25
26	Secondary	$/kW	2.93	1.76	(1.17)	(39.93)	26
27	Primary	$/kW	2.81	1.64	(1.17)	(41.64)	27
28	Primary Substation	$/kW	1.22	0.05	(1.17)	(95.90)	28
29	Transmission	$/kW	1.20	0.03	(1.17)	(97.50)	29
30	Power Factor						30
31	Secondary	$/kvar	0.21	0.21	0.00	0.00	31
32	Primary	$/kvar	0.21	0.21	0.00	0.00	32
33	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	33
34	Transmission	$/kvar	0.21	0.21	0.00	0.00	34
35	Contract Minimum Demand						35
36	Generation Level	$/kW	4.39	7.27	2.88	65.60	36
37	Energy Charge						37
38	Generation Level						38
39	Signaled Period 1G	$/kWh	1.32258	2.40358	1.08100	81.73	39
40	Signaled Period 2G	$/kWh	0.21356	0.29241	0.07885	36.92	40
41	Signaled Period 3G	$/kWh	0.05666	0.05238	(0.00428)	(7.55)	41
42	Signaled Period 4G	$/kWh	0.02181	0.01973	(0.00208)	(9.54)	42
43	On-Peak Energy: Summer						43
44	Secondary	$/kWh	0.04004	0.04873	0.00869	21.70	44
45	Primary	$/kWh	0.03810	0.04679	0.00869	22.81	45
46	Primary Substation	$/kWh	0.03561	0.04430	0.00869	24.40	46
47	Transmission	$/kWh	0.03514	0.04383	0.00869	24.73	47
48	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	48
49	Semi-Peak Energy: Summer						49
50	Secondary	$/kWh	0.01588	0.0194	0.00352	22.17	50
51	Primary	$/kWh	0.01485	0.0184	0.00355	23.91	51
52	Primary Substation	$/kWh	0.01357	0.01715	0.00358	26.38	52
53	Transmission	$/kWh	0.01328	0.01687	0.00359	27.03	53
54	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	54
55	Off-Peak Energy: Summer						55
56	Secondary	$/kWh	0.01191	0.01255	0.00064	5.37	56
57	Primary	$/kWh	0.01134	0.01200	0.00066	5.82	57
58	Primary Substation	$/kWh	0.01068	0.01136	0.00068	6.37	58
59	Transmission	$/kWh	0.01045	0.01114	0.00069	6.60	59
60	Generation	$/kWh	0.02439	0.02435	(0.00004)	(0.16)	60

TABLE 13 (Sheet 19 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
59	SCHEDULE AL-TOU-O (Continued)						59
60	On-Peak Energy: Winter						60
61	Secondary	$/kWh	$0.02759	$0.03628	$0.00869	31.50	61
62	Primary	$/kWh	0.02597	0.03466	0.00869	33.46	62
63	Primary Substation	$/kWh	0.02389	0.03258	0.00869	36.38	63
64	Transmission	$/kWh	0.02349	0.03218	0.00869	36.99	64
65	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	65
66	Semi-Peak Energy: Winter						66
67	Secondary	$/kWh	0.01609	0.01960	0.00351	21.81	67
68	Primary	$/kWh	0.01506	0.01860	0.00354	23.51	68
69	Primary Substation	$/kWh	0.01379	0.01737	0.00358	25.96	69
70	Transmission	$/kWh	0.01350	0.01709	0.00359	26.59	70
71	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	71
72	Off-Peak Energy: Winter						72
73	Secondary	$/kWh	0.01230	0.01293	0.00063	5.12	73
74	Primary	$/kWh	0.01172	0.01237	0.00065	5.55	74
75	Primary Substation	$/kWh	0.01106	0.01173	0.00067	6.06	75
76	Transmission	$/kWh	0.01083	0.01151	0.00068	6.28	76
77	Generation	$/kWh	0.02439	0.02435	(0.00004)	(0.16)	77

TABLE 11

(Sheet 20 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A 91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE A6-TOU-C						1
2	Basic Service Fee						2
3	Primary	$/Month	$160.00	$168.00	8.00	5.00	3
4	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	4
5	Transimssion	$/Month	600.00	630.00	30.00	5.00	5
6	Greater than 10 MW -- Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	6
7	Distance Adjustment Fee	$/foot/Month	--	2.70	--	--	7
8	Non-Coincident Demand						8
9	Primary	$/kW	3.91	4.11	0.20	5.12	9
10	Primary Substation	$/kW	0.31	0.40	0.09	29.03	10
11	Transmission	$/kW	0.31	0.40	0.09	29.03	11
12	Maximum On-Peak Demand: Summer						12
13	Primary	$/kW	13.37	7.93	(5.44)	(40.69)	13
14	Primary Substation	$/kW	8.30	2.86	(5.44)	(65.54)	14
15	Transmission	$/kW	8.19	2.75	(5.44)	(66.42)	15
16	Generation	$/kW	8.29	13.73	5.44	65.62	16
17	Maximum On-Peak Demand: Winter						17
18	Primary	$/kW	3.60	2.54	(1.06)	(29.44)	18
19	Primary Substation	$/kW	1.61	0.55	(1.06)	(65.84)	19
20	Transmission	$/kW	1.59	0.53	(1.06)	(66.67)	20
21	Generation	$/kW	1.60	2.66	1.06	66.25	21
22	Power Factor						22
23	Primary	$/kvar	0.21	0.21	0.00	0.00	23
24	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	24
25	Transmission	$/kvar	0.21	0.21	0.00	0.00	25
26	On-Peak Energy: Summer						26
27	Primary	$/kWh	0.03810	0.04679	0.00869	22.81	27
28	Primary Substation	$/kWh	0.03561	0.04430	0.00869	24.40	28
29	Transmission	$/kWh	0.03514	0.04383	0.00869	24.73	29
30	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	30
31	Semi-Peak Energy: Summer						31
32	Primary	$/kWh	0.01485	0.01871	0.00386	25.99	32
33	Primary Substation	$/kWh	0.01357	0.01746	0.00389	28.67	33
34	Transmission	$/kWh	0.01328	0.01718	0.00390	29.37	34
35	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	35
36	Off-Peak Energy: Summer						36
37	Primary	$/kWh	0.01134	0.01225	0.00091	8.02	37
38	Primary Substation	$/kWh	0.01068	0.01160	0.00092	8.61	38
39	Transmission	$/kWh	0.01045	0.01138	0.00093	8.90	39
40	Generation	$/kWh	0.02439	0.02256	(0.00183)	(7.50)	40
41	On-Peak Energy: Winter						41
42	Primary	$/kWh	0.02597	0.03466	0.00869	33.46	42
43	Primary Substation	$/kWh	0.02389	0.03258	0.00869	36.38	43
44	Transmission	$/kWh	0.02349	0.03218	0.00869	36.99	44
45	Generation	$/kWh	0.03654	0.02774	(0.00880)	(24.08)	45
46	Semi-Peak Energy: Winter						46
47	Primary	$/kWh	0.01506	0.01891	0.00385	25.56	47
48	Primary Substation	$/kWh	0.01379	0.01767	0.00388	28.14	48
49	Transmission	$/kWh	0.01350	0.01739	0.00389	28.81	49
50	Generation	$/kWh	0.03027	0.02527	(0.00500)	(16.52)	50
51	Off-Peak Energy: Winter						51
52	Primary	$/kWh	0.01172	0.01262	0.00090	7.68	52
53	Primary Substation	$/kWh	0.01106	0.01198	0.00092	8.32	53
54	Transmission	$/kWh	0.01083	0.01266	0.00183	16.90	54
55	Generation	$/kWh	0.02439	0.02256	(0.00183)	(7.50)	55

TABLE 11 (Sheet 21 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE S						1
2	Contracted Demand						2
3	Secondary	$/kW	$3.44	$3.62	$0.18	5.12	3
4	Primary	$/kW	3.13	3.29	0.16	5.12	4
5	Primary Substation	$/kW	0.25	0.32	0.07	29.03	5
6	Transmission	$/kW	0.25	0.32	0.07	29.03	6
7							7
8	SCHEDULE I-2						8
9	Rate A: 1 YR Cancellation						9
10	Guaranteed Load Credit	$/kW	5.45	5.45	0.00	0.00	10
11	Rate A: 5 YR Cancellation						11
12	Guaranteed Load Credit	$/kW	6.81	6.81	0.00	0.00	12
13	Rate B: 1 YR Cancellation						13
14	Guaranteed Load Credit	$/kW	5.01	5.01	0.00	0.00	14
15	Rate B: 5 YR Cancellation						15
16	Guaranteed Load Credit	$/kW	6.27	6.27	0.00	0.00	16
17	Rate C: 1 YR Cancellation						17
18	Guaranteed Load Credit	$/kW	4.09	4.09	0.00	0.00	18
19	Rate C: 5 YR Cancellation						19
20	Guaranteed Load Credit	$/kW	5.11	5.11	0.00	0.00	20
21	Rate D: 1 YR Cancellation						21
22	Guaranteed Load Credit	$/kW	3.76	3.76	0.00	0.00	22
23	Rate D: YR Cancellation						23
24	Guaranteed Load Credit	$/kW	4.70	4.70	0.00	0.00	24
25	Rates A-D:						25
26	Credit for Each Interruption	$/kW	0.28	0.28	0.00	0.00	26
27							27
28	SCHEDULE I-3						28
29	Rate A: 1 YR Cancellation						29
30	Guaranteed Load Credit	$/kW	5.47	5.47	0.00	0.00	30
31	Rate A: 5 YR Cancellation						31
32	Guaranteed Load Credit	$/kW	6.84	6.84	0.00	0.00	32
33	Rate B: 1 YR Cancellation						33
34	Guaranteed Load Credit	$/kW	5.03	5.03	0.00	0.00	34
35	Rate B: 5 YR Cancellation						35
36	Guaranteed Load Credit	$/kW	6.29	6.29	0.00	0.00	36
37	Rate C: 1 YR Cancellation						37
38	Guaranteed Load Credit	$/kW	4.10	4.10	0.00	0.00	38
39	Rate C: 5 YR Cancellation						39
40	Guaranteed Load Credit	$/kW	5.13	5.13	0.00	0.00	40
41	Rate D: 1 YR Cancellation						41
42	Guaranteed Load Credit	$/kW	3.77	3.77	0.00	0.00	42
43	Rate D: YR Cancellation						43
44	Guaranteed Load Credit	$/kW	4.72	4.72	0.00	0.00	44
45	Rates A-D:						45
46	Credit for Each Interruption	$/kW	0.28	0.28	0.00	0.00	46

Note: Schedule I-3 rates are continued on next page.

TABLE 13

(Sheet 22 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
43	SCHEDULE I-3 (continued)						43
44	Basic Service Fee						44
45	Less than or equal to 500 kW						45
46	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	46
47	Primary	$/Month	40.00	42.00	2.00	5.00	47
48	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	48
49	Transmission	$/Month	40.00	42.00	2.00	5.00	49
50	Greater than 500 kW						50
51	Secondary	$/Month	160.00	168.00	8.00	5.00	51
52	Primary	$/Month	160.00	168.00	8.00	5.00	52
53	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	53
54	Transmission	$/Month	160.00	168.00	8.00	5.00	54
55	Greater than 10 MW -- Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	55
56	Distance Adjustment Fee	$/foot/Month	--	2.70	--	--	56
57	Non-Coincident Demand						57
58	Secondary	$/kW	4.30	4.52	0.22	5.12	58
59	Primary	$/kW	3.91	4.11	0.20	5.12	59
60	Primary Substation	$/kW	0.31	0.40	0.09	29.03	60
61	Transmission	$/kW	0.31	0.40	0.09	29.03	61
62	Maximum On-Peak Demand: Summer						62
63	Secondary	$/kW	19.81	19.81	0.00	0.00	63
64	Primary	$/kW	19.31	19.31	0.00	0.00	64
65	Primary Substation	$/kW	14.16	14.16	0.00	0.00	65
66	Transmission	$/kW	14.07	14.07	0.00	0.00	66
67	Maximum On-Peak Demand: Winter						67
68	Secondary	$/kW	4.60	4.60	0.00	0.00	68
69	Primary	$/kW	4.48	4.48	0.00	0.00	69
70	Primary Substation	$/kW	2.89	2.89	0.00	0.00	70
71	Transmission	$/kW	2.87	2.87	0.00	0.00	71
72	Power Factor						72
73	Secondary	$/kvar	0.21	0.21	0.00	0.00	73
74	Primary	$/kvar	0.21	0.21	0.00	0.00	74
75	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	75
76	Transmission	$/kvar	0.21	0.21	0.00	0.00	76
77	On-Peak Energy: Summer						77
78	Secondary	$/kWh	0.07658	0.07647	(0.00011)	(0.14)	78
79	Primary	$/kWh	0.07464	0.07453	(0.00011)	(0.15)	79
80	Primary Substation	$/kWh	0.07215	0.07204	(0.00011)	(0.15)	80
81	Transmission	$/kWh	0.07168	0.07157	(0.00011)	(0.15)	81
82	Semi-Peak Energy: Summer						82
83	Secondary	$/kWh	0.04615	0.04467	(0.00148)	(3.21)	83
84	Primary	$/kWh	0.04512	0.04367	(0.00145)	(3.21)	84
85	Primary Substation	$/kWh	0.04384	0.04242	(0.00142)	(3.24)	85
86	Transmission	$/kWh	0.04355	0.04214	(0.00141)	(3.24)	86
87	Off-Peak Energy: Summer						87
88	Secondary	$/kWh	0.03630	0.03511	(0.00119)	(3.28)	88
89	Primary	$/kWh	0.03573	0.03456	(0.00117)	(3.27)	89
90	Primary Substation	$/kWh	0.03507	0.03392	(0.00115)	(3.28)	90
91	Transmission	$/kWh	0.03484	0.03370	(0.00114)	(3.27)	91
92	On-Peak Energy: Winter						92
93	Secondary	$/kWh	0.06413	0.06402	(0.00011)	(0.17)	93
94	Primary	$/kWh	0.06251	0.06240	(0.00011)	(0.18)	94
95	Primary Substation	$/kWh	0.06043	0.06032	(0.00011)	(0.18)	95
96	Transmission	$/kWh	0.06003	0.05992	(0.00011)	(0.18)	96
97	Semi-Peak Energy: Winter						97
98	Secondary	$/kWh	0.04636	0.04487	(0.00149)	(3.21)	98
99	Primary	$/kWh	0.04533	0.04387	(0.00146)	(3.22)	99
100	Primary Substation	$/kWh	0.04406	0.04264	(0.00142)	(3.22)	100
101	Transmission	$/kWh	0.04377	0.04236	(0.00141)	(3.22)	101
102	Off-Peak Energy: Winter						102
103	Secondary	$/kWh	0.03669	0.03549	(0.00120)	(3.27)	103
104	Primary	$/kWh	0.03611	0.03493	(0.00118)	(3.27)	104
105	Primary Substation	$/kWh	0.03545	0.03429	(0.00116)	(3.27)	105
106	Transmission	$/kWh	0.03522	0.03407	(0.00115)	(3.27)	106
107	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	107
108	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	108
109	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	109

TABLE 13 (Sheet 23 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE LR						1
2	Basic Service Fee						2
3	Less than or equal to 500 kW						3
4	Secondary	$/Month	$40.00	$42.00	$2.00	5.00	4
5	Primary	$/Month	40.00	42.00	2.00	5.00	5
6	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	6
7	Transmission	$/Month	40.00	42.00	2.00	5.00	7
8	Greater than 500 kW						8
9	Secondary	$/Month	160.00	168.00	8.00	5.00	9
10	Primary	$/Month	160.00	168.00	8.00	5.00	10
11	Primary Substation	$/Month	20,000.00	20,000.00	0.00	0.00	11
12	Transmission	$/Month	160.00	168.00	8.00	5.00	12
13	Greater than 10 MW – Pri. Sub.	$/Month	30,000.00	30,000.00	0.00	0.00	13
14	Distance Adjustment Fee	$/foot/Month	–	2.70	–	–	14
15	Metering Charge	$/Month	150.00	150.00	0.00	0.00	15
16	Non-Coincident Demand						16
17	Secondary	$/kW	4.30	4.52	0.22	5.12	17
18	Primary	$/kW	3.91	4.11	0.20	5.12	18
19	Primary Substation	$/kW	0.31	0.40	0.09	29.03	19
20	Transmission	$/kW	0.31	0.40	0.09	29.03	20
21	Maximum On-Peak Demand: Summer						21
22	Secondary	$/kW	19.81	19.81	0.00	0.00	22
23	Primary	$/kW	19.31	19.31	0.00	0.00	23
24	Primary Substation	$/kW	14.16	14.16	0.00	0.00	24
25	Transmission	$/kW	14.07	14.07	0.00	0.00	25
26	Maximum On-Peak Demand: Winter						26
27	Secondary	$/kW	4.60	4.60	0.00	0.00	27
28	Primary	$/kW	4.48	4.48	0.00	0.00	28
29	Primary Substation	$/kW	2.89	2.89	0.00	0.00	29
30	Transmission	$/kW	2.87	2.87	0.00	0.00	30
31	Power Factor						31
32	Secondary	$/kvar	0.21	0.21	0.00	0.00	32
33	Primary	$/kvar	0.21	0.21	0.00	0.00	33
34	Primary Substation	$/kvar	0.21	0.21	0.00	0.00	34
35	Transmission	$/kvar	0.21	0.21	0.00	0.00	35
36	On-Peak Energy: Summer						36
37	Secondary	$/kWh	0.07658	0.07647	(0.00011)	(0.14)	37
38	Primary	$/kWh	0.07464	0.07453	(0.00011)	(0.15)	38
39	Primary Substation	$/kWh	0.07215	0.07204	(0.00011)	(0.15)	39
40	Transmission	$/kWh	0.07168	0.07157	(0.00011)	(0.15)	40
41	Semi-Peak Energy: Summer						41
42	Secondary	$/kWh	0.04615	0.04467	(0.00148)	(3.21)	42
43	Primary	$/kWh	0.04512	0.04367	(0.00145)	(3.21)	43
44	Primary Substation	$/kWh	0.04384	0.04242	(0.00142)	(3.24)	44
45	Transmission	$/kWh	0.04355	0.04214	(0.00141)	(3.24)	45
46	Off-Peak Energy: Summer						46
47	Secondary	$/kWh	0.03630	0.03511	(0.00119)	(3.28)	47
48	Primary	$/kWh	0.03573	0.03456	(0.00117)	(3.27)	48
49	Primary Substation	$/kWh	0.03507	0.03392	(0.00115)	(3.28)	49
50	Transmission	$/kWh	0.03484	0.03370	(0.00114)	(3.27)	50
51	On-Peak Energy: Winter						51
52	Secondary	$/kWh	0.06413	0.06402	(0.00011)	(0.17)	52
53	Primary	$/kWh	0.06251	0.06240	(0.00011)	(0.18)	53
54	Primary Substation	$/kWh	0.06043	0.06032	(0.00011)	(0.18)	54
55	Transmission	$/kWh	0.06003	0.05992	(0.00011)	(0.18)	55
56	Semi-Peak Energy: Winter						56
57	Secondary	$/kWh	0.04636	0.04487	(0.00149)	(3.21)	57
58	Primary	$/kWh	0.04533	0.04387	(0.00146)	(3.22)	58
59	Primary Substation	$/kWh	0.04406	0.04264	(0.00142)	(3.22)	59
60	Transmission	$/kWh	0.04377	0.04236	(0.00141)	(3.22)	60
61	Off-Peak Energy: Winter						61
62	Secondary	$/kWh	0.03669	0.03549	(0.00120)	(3.27)	62
63	Primary	$/kWh	0.03611	0.03493	(0.00118)	(3.27)	63
64	Primary Substation	$/kWh	0.03545	0.03429	(0.00116)	(3.27)	64
65	Transmission	$/kWh	0.03522	0.03407	(0.00115)	(3.27)	65
66	On-Peak Rate Limiter: Summer	$/kWh	0.80	0.80	0.00	0.00	66
67	On-Peak Rate Limiter: Winter	$/kWh	0.31	0.31	0.00	0.00	67
68	Average Rate Limiter	$/kWh	5.00	5.00	0.00	0.00	68

Note: Schedule LR rates are continued on next page.

TABLE 13 (Sheet 24 of 24)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

COMMERCIAL AND INDUSTRIAL -- PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
54	SCHEDULE LR (Continued)						54
55	Contract Min Load Reduction						55
56	Demand Credit:						56
57	Option 1	$/kW	$5.87	$8.32	$1.45	21.11	57
58	Option 2	$/kW	5.15	6.24	1.09	21.17	58
59	Energy Credit for Output						59
60	Over Contract						60
61	Option 1	$/kWh	1.44516	2.03211	0.58595	40.52	61
62	Option 2	$/kWh	1.08476	1.52420	0.43944	40.51	62
63	Energy Charge for Output						63
64	Under Contract						64
65	Option 1	$/kWh	4.33735	6.09542	1.75807	40.53	65
66	Option 2	$/kWh	3.25316	4.57168	1.31852	40.53	66
67	5-Year Option:						67
68	Contract Min Load Reduction						68
69	Demand Credit:						69
70	Option 1	$/kW	8.59	10.40	1.81	21.11	70
71	Option 2	$/kW	6.44	7.80	1.36	21.17	71
72	Energy Credit for Output						72
73	Over Contract						73
74	Option 1	$/kWh	1.80770	2.54014	0.73244	40.52	74
75	Option 2	$/kWh	1.35595	1.90525	0.54930	40.51	75
76	Energy Charge for Output						76
77	Under Contract						77
78	Option 1	$/kWh	5.42169	7.61928	2.19759	40.53	78
79	Option 2	$/kWh	4.06645	5.71460	1.64815	40.53	79

TABLE 14

(Sheet 1 of 1)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)

AGRICULTURAL – PRESENT & ADOPTED RATES

LINE NO.	DESCRIPTION (A)	UNITS (B)	PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)	LINE NO.
1	SCHEDULE PA						1
2	Basic Service Fee	$/Month	$10.00	$10.00	0.00	0.00	2
3	Energy	$/kWh	0.10607	0.10545	(0.00)	(0.58)	3
4							4
5	SCHEDULE PA-TOU						5
6	Metering Charge	$/Month	10.00	10.00	0.00	0.00	6
7	Basic Service Fee	$/Month	8.00	8.00	0.00	0.00	7
8	Energy: On-Peak	$/kWh	0.21144	0.21718	0.00574	2.71	8
9	Energy: Off-Peak	$/kWh	0.08460	0.08186	(0.00274)	(3.24)	9
10							10
11	SCHEDULE PA-T-1						11
12	Basic Service Fee	$/Month	40.00	42.00	2.00	5.00	12
13	Demand: On-Peak						13
14	Option A						14
15	Secondary	$/kW	13.02	13.02	0.00	0.00	15
16	Primary	$/kW	12.50	12.50	0.00	0.00	16
17	Transmission	$/kW	12.11	12.11	0.00	0.00	17
18	Option B						18
19	Secondary	$/kW	11.44	11.44	0.00	0.00	19
20	Primary	$/kW	10.98	10.98	0.00	0.00	20
21	Transmission	$/kW	10.64	10.64	0.00	0.00	21
22	Option C						22
23	Secondary	$/kW	11.19	11.19	0.00	0.00	23
24	Primary	$/kW	10.74	10.74	0.00	0.00	24
25	Transmission	$/kW	10.41	10.41	0.00	0.00	25
26	Option D						26
27	Secondary	$/kW	11.67	11.67	0.00	0.00	27
28	Primary	$/kW	11.20	11.20	0.00	0.00	28
29	Transmission	$/kW	10.85	10.85	0.00	0.00	29
30	Option E						30
31	Secondary	$/kW	11.43	11.43	0.00	0.00	31
32	Primary	$/kW	10.97	10.97	0.00	0.00	32
33	Transmission	$/kW	10.63	10.63	0.00	0.00	33
34	Option F						34
35	Secondary	$/kW	10.94	10.94	0.00	0.00	35
36	Primary	$/kW	10.50	10.50	0.00	0.00	36
37	Transmission	$/kW	10.17	10.17	0.00	0.00	37
38	Demand: Semi-Peak						38
39	Secondary	$/kW	0.50	0.50	0.00	0.00	39
40	Primary	$/kW	0.48	0.48	0.00	0.00	40
41	Transmission	$/kW	0.47	0.47	0.00	0.00	41
42	Energy: On-Peak						42
43	Secondary	$/kWh	0.08500	0.09085	0.00585	6.89	43
44	Primary	$/kWh	0.08287	0.08824	0.00537	6.48	44
45	Transmission	$/kWh	0.08126	0.08628	0.00502	6.18	45
46	Energy: Semi-Peak						46
47	Secondary	$/kWh	0.06489	0.06571	0.00082	1.27	47
48	Primary	$/kWh	0.06356	0.06410	0.00054	0.85	48
49	Transmission	$/kWh	0.06256	0.06290	0.00034	0.54	49
50	Energy: Off-Peak						50
51	Secondary	$/kWh	0.04490	0.04072	(0.00418)	(9.30)	51
52	Primary	$/kWh	0.04437	0.04011	(0.00426)	(9.60)	52
53	Transmission	$/kWh	0.04397	0.03966	(0.00431)	(9.80)	53

TABLE 15

(Sheet 1 of 5)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)
STREET LIGHT – PRESENT AND ADOPTED RATES

LINE NO.	DESCRIPTION WATTS (A)	LUMENS (B)	PRESENT RATE ($/Lamp) (C)	ADOPTED RATE ($/Lamp) (D)	CHANGE ($/Lamp) (E)	CHANGE % (F)	LINE NO.
1	LS-1, Mercury Vapor, Class A						1
2	175	7000	9.97	9.75	(0.22)	(2.21)	2
3	400	20000	18.04	17.53	(0.51)	(2.83)	3
4	LS-1, Mercury Vapor, Class C, 1-Lamp						4
5	400	20000	30.30	29.87	(0.43)	(1.42)	5
6	LS-1, HPSV, Class A						6
7	70	5800	6.27	6.18	(0.09)	(1.44)	7
8	100	9500	7.33	7.19	(0.14)	(1.91)	8
9	150	16000	8.56	8.35	(0.21)	(2.45)	9
10	200	22000	10.88	10.62	(0.26)	(2.39)	10
11	250	30000	12.43	12.09	(0.34)	(2.74)	11
12	400	50000	16.55	16.02	(0.53)	(3.20)	12
13	LS-1, HPSV, Class B, 1-Lamp						13
14	70	5800	6.62	6.53	(0.09)	(1.36)	14
15	100	9500	7.68	7.54	(0.14)	(1.82)	15
16	150	16000	8.91	8.71	(0.20)	(2.24)	16
17	200	22000	11.33	11.08	(0.25)	(2.21)	17
18	250	30000	12.88	12.54	(0.34)	(2.64)	18
19	400	50000	17.19	16.66	(0.53)	(3.08)	19
20	LS-1, HPSV, Class B, 2-Lamp						20
21	70	5800	11.95	11.75	(0.20)	(1.67)	21
22	100	9500	14.06	13.76	(0.30)	(2.13)	22
23	150	16000	16.51	16.09	(0.42)	(2.54)	23
24	200	22000	21.37	20.84	(0.53)	(2.48)	24
25	250	30000	24.47	23.77	(0.70)	(2.86)	25
26	400	50000	32.93	31.85	(1.08)	(3.28)	26
27	LS-1, HPSV, Class C, 1-Lamp						27
28	70	5800	15.13	15.09	(0.04)	(0.26)	28
29	100	9500	16.19	16.10	(0.09)	(0.56)	29
30	150	16000	17.44	17.28	(0.16)	(0.92)	30
31	200	22000	21.12	20.92	(0.20)	(0.95)	31
32	250	30000	22.67	22.39	(0.28)	(1.24)	32
33	400	50000	29.42	28.96	(0.46)	(1.56)	33
34	LS-1, HPSV, Class C, 2-Lamp						34
35	70	5800	20.65	20.49	(0.16)	(0.77)	35
36	100	9500	22.76	22.51	(0.25)	(1.10)	36
37	150	16000	25.23	24.86	(0.37)	(1.47)	37
38	200	22000	32.77	32.29	(0.48)	(1.46)	38
39	250	30000	35.87	35.23	(0.64)	(1.78)	39
40	400	50000	47.35	46.34	(1.01)	(2.13)	40

TABLE 15 (Sheet 2 of 5)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)
STREET LIGHT – PRESENT AND ADOPTED RATES

LINE NO.	DESCRIPTION WATTS (A)	LUMENS (B)	PRESENT RATE ($/Lamp) (C)	ADOPTED RATE ($/Lamp) (D)	CHANGE ($/Lamp) (E)	CHANGE % (F)	LINE NO.
1	LS-1, LPSV, Class A						1
2	55	8000	10.06	10.01	(0.06)	(0.60)	2
3	90	13500	11.84	11.72	(0.12)	(1.01)	3
4	135	22500	14.36	14.17	(0.19)	(1.32)	4
5	180	33000	15.68	15.46	(0.22)	(1.40)	5
6	LS-1, LPSV, Class B, 1-Lamp						6
7	55	8000	10.44	10.39	(0.05)	(0.48)	7
8	90	13500	12.22	12.11	(0.11)	(0.90)	8
9	135	22500	14.84	14.65	(0.19)	(1.28)	9
10	180	33000	16.16	15.94	(0.22)	(1.36)	10
11	LS-1, LPSV, Class B, 2-Lamp						11
12	55	8000	19.57	19.44	(0.13)	(0.66)	12
13	90	13500	23.13	22.88	(0.25)	(1.08)	13
14	135	22500	28.36	27.97	(0.39)	(1.38)	14
15	180	33000	31.00	30.55	(0.45)	(1.45)	15
16	LS-1, LPSV, Class C, 1-Lamp						16
17	55	8000	19.04	19.03	(0.01)	(0.05)	17
18	90	13500	20.84	20.77	(0.07)	(0.34)	18
19	135	22500	24.71	24.59	(0.12)	(0.49)	19
20	180	33000	26.04	25.87	(0.17)	(0.65)	20
21	LS-1, LPSV, Class C, 2-Lamp						21
22	55	8000	28.45	28.37	(0.08)	(0.28)	22
23	90	13500	32.03	31.82	(0.21)	(0.66)	23
24	135	22500	39.94	39.61	(0.33)	(0.83)	24
25	180	33000	42.58	42.18	(0.40)	(0.94)	25
26	LS-1, Metal Halide, Class A						26
27	175	12000	13.52	13.26	(0.26)	(1.92)	27
28	250	18000	14.28	14.03	(0.25)	(1.75)	28
29	400	32000	17.00	16.43	(0.57)	(3.35)	29
30	LS-1, Metal Halide, Class B						30
31	175	12000	13.88	13.62	(0.26)	(1.87)	31
32	250	18000	14.62	14.38	(0.24)	(1.64)	32
33	400	32000	17.35	16.78	(0.57)	(3.29)	33
34	LS-1, Metal Halide, Class C						34
35	175	12000	22.38	22.16	(0.22)	(0.98)	35
36	250	18000	23.03	22.83	(0.20)	(0.87)	36
37	400	32000	25.76	25.24	(0.52)	(2.02)	37

TABLE 18 (Sheet 3 of 5)
SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)
STREET LIGHT – PRESENT AND ADOPTED RATES

LINE NO.	DESCRIPTION WATTS (A)	LUMENS (B)	PRESENT RATE ($/Lamp) (C)	ADOPTED RATE ($/Lamp) (D)	CHANGE ($/Lamp) (E)	CHANGE % (F)	LINE NO.
1	LS-1, Facilities and Rates, Class A						1
2	Center Suspension		4.78	4.56	(0.22)	(4.60)	2
3	Non-Standard Wood Pole						3
4	30-foot		2.40	2.29	(0.11)	(4.58)	4
5	35-foot		2.69	2.57	(0.12)	(4.46)	5
6	Reactor Ballast Discount						6
7	175		(0.98)	(0.93)	0.05	5.10	7
8	LS-2, Mercury Vapor, Rate A						8
9	175	7000	4.91	4.66	(0.25)	(5.09)	9
10	250	10000	6.83	6.48	(0.35)	(5.12)	10
11	400	20000	10.75	10.21	(0.54)	(5.02)	11
12	700	35000	18.24	17.32	(0.92)	(5.04)	12
13	1000	55000	25.76	24.47	(1.29)	(5.01)	13
14	LS-2, Mercury Vapor, Rate B, Energy & Limited Maintenance						14
15	175	7000	5.79	5.55	(0.24)	(4.15)	15
16	250	10000	7.71	7.37	(0.34)	(4.41)	16
17	400	20000	11.65	11.11	(0.54)	(4.64)	17
18	LS-2, Mercury Vapor, Surcharge for series service						18
19	175	7000	0.40	0.38	(0.02)	(5.00)	19
20	250	10000	0.50	0.48	(0.02)	(4.00)	20
21	400	20000	0.72	0.69	(0.03)	(4.17)	21
22	700	35000	1.32	1.26	(0.06)	(4.55)	22
23	LS-2, HPSV, Rate A						23
24	50	4000	1.36	1.29	(0.07)	(5.15)	24
25	70	5800	2.36	2.24	(0.12)	(5.08)	25
26	100	9500	3.30	3.13	(0.17)	(5.15)	26
27	150	16000	4.51	4.29	(0.22)	(4.88)	27
28	200	22000	5.75	5.46	(0.29)	(5.04)	28
29	250	30000	7.32	6.95	(0.37)	(5.05)	29
30	310	37000	8.95	8.50	(0.45)	(5.03)	30
31	400	50000	11.13	10.57	(0.56)	(5.03)	31
32	1000	140000	25.76	24.47	(1.29)	(5.01)	32
33	LS-2, HPSV, Rate B, Energy & Limited Maintenance						33
34	50	4000	2.18	2.12	(0.06)	(2.75)	34
35	70	5800	3.18	3.07	(0.11)	(3.46)	35
36	100	9500	4.11	3.95	(0.16)	(3.89)	36
37	150	16000	5.33	5.11	(0.22)	(4.13)	37
38	200	22000	6.58	6.29	(0.29)	(4.41)	38
39	250	30000	8.14	7.78	(0.36)	(4.42)	39
40	310	37000	9.81	9.37	(0.44)	(4.49)	40
41	400	50000	11.96	11.41	(0.55)	(4.60)	41
42	1000	140000	26.79	25.51	(1.28)	(4.78)	42

TABLE 16 (Sheet 4 of 5)

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)
STREET LIGHT -- PRESENT AND ADOPTED RATES

LINE NO.	DESCRIPTION WATTS (A)	DESCRIPTION LUMENS (B)	PRESENT RATE ($/Lamp) (C)	ADOPTED RATE ($/Lamp) (D)	CHANGE ($/Lamp) (E)	CHANGE % (F)	LINE NO.
1	LS-2, HPSV, Reduction for 120-volt Reactor Ballast						1
2	70	5800	(0.40)	(0.38)	0.02	5.00	2
3	100	9500	(0.53)	(0.51)	0.02	3.77	3
4	150	16000	(0.49)	(0.47)	0.02	4.08	4
5	LS-2, HPSV, Surcharge for Series Service						5
6	50	4000	0.45	0.43	(0.02)	(4.44)	6
7	70	5800	(0.22)	(0.21)	0.01	4.55	7
8	100	9500	(0.23)	(0.22)	0.01	4.35	8
9	150	16000	0.02	0.02	0.00	0.00	9
10	200	22000	0.48	0.45	(0.03)	(6.25)	10
11	LS-2, LPSV, Rate A						11
12	35	4800	1.57	1.49	(0.08)	(5.10)	12
13	55	8000	2.06	1.95	(0.11)	(5.34)	13
14	90	13500	3.39	3.22	(0.17)	(5.01)	14
15	135	22500	4.82	4.57	(0.25)	(5.19)	15
16	180	33000	5.49	5.22	(0.27)	(4.92)	16
17	LS-2, LPSV, Surcharge for series service						17
18	35	4800	(0.23)	(0.22)	0.01	(4.35)	18
19	55	8000	(0.13)	(0.13)	0.00	0.00	19
20	90	13500	0.45	0.43	(0.02)	(4.44)	20
21	135	22500	0.80	0.76	(0.04)	(5.00)	21
22	180	33000	0.51	0.49	(0.02)	(3.92)	22
23	LS-2, Incandescent Lamps, Rate A, Energy Only						23
24		1000	1.71	1.62	(0.09)	(5.26)	24
25		2500	3.79	3.60	(0.19)	(5.01)	25
26		4000	5.70	5.42	(0.28)	(4.91)	26
27		6000	8.37	7.95	(0.42)	(5.02)	27
28		10000	14.21	13.50	(0.71)	(5.00)	28
29	LS-2, Incdsnt Lamps, Rate B, Energy and Limited Maintenance						29
30		6000	9.54	9.13	(0.41)	(4.30)	30
31	LS-2, Metal Halide, Rate A						31
32	175	12000	4.84	4.60	(0.24)	(4.96)	32
33	250	18000	6.62	6.40	(0.22)	(3.32)	33
34	400	32000	10.38	9.86	(0.52)	(5.01)	34
35	LS-2, Metal Halide, Rate B						35
36	175	12000	10.62	10.61	(0.01)	(0.09)	36
37	250	18000	10.93	10.87	(0.06)	(0.55)	37
38	400	32000	12.61	12.17	(0.44)	(3.49)	38

TABLE 15 (Sheet 5 of 5)
SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
FORECAST PERIOD: MAY 1, 1996 THROUGH APRIL 30, 1997
1996 RDW PROCEEDING (A.91-11-024)
STREET LIGHT -- PRESENT AND ADOPTED RATES

LINE NO.	DESCRIPTION WATTS (A)	LUMENS (B)	PRESENT RATE ($/Lamp) (C)	ADOPTED RATE ($/Lamp) (D)	CHANGE ($/Lamp) (E)	CHANGE % (F)	LINE NO.
1	LS-3						1
2	Energy Charge ($/kwh)		0.08719	0.08641	-0.00078	(0.89)	2
3	Min Charge	($/month)	5.81	5.81	0.00	0.00	3
4							4
5	OL-1, HPSV, Rate A, Street Light Luminaire						5
6	100	9500	8.19	8.06	(0.13)	(1.59)	6
7	150	16000	9.41	9.21	(0.20)	(2.13)	7
8	250	30000	13.70	13.37	(0.33)	(2.41)	8
9	400	50000	17.91	17.38	(0.53)	(2.95)	9
10	1000	140000	36.78	35.65	(1.13)	(3.07)	10
11	OL-1, HPSV, Rate B, Directional Luminaire						11
12	250	30000	18.79	18.71	(0.08)	(0.43)	12
13	400	50000	23.50	24.18	0.68	2.89	13
14	1000	140000	42.20	46.42	4.22	10.00	14
15	OL-1, LPSV, Rate A, Street Light Luminaire						15
16	55	8000	10.19	10.13	(0.06)	(0.59)	16
17	90	13000	11.99	11.87	(0.12)	(1.00)	17
18	135	22500	14.54	14.35	(0.19)	(1.31)	18
19	180	33000	15.87	15.65	(0.22)	(1.39)	19
20	OL-1, Pole						20
21	30 ft wood pole		3.16	3.02	(0.14)	(4.43)	21
22	35 ft wood pole		3.55	3.39	(0.16)	(4.51)	22
23	DWL, facilities Charges						23
24	$ of Util invst.		0.0186	0.0186	0.00	0.00	24
25	DWL, Energy and Lamp Maintance Charge						25
26	50 Watt HPSV		3.44	3.39	(0.05)	(1.45)	26
27	DWL, Min. Charge		151.54	144.67	(6.87)	(4.53)	27

(END OF APPENDIX A)

APPENDIX B

List of Appearances

Applicant: Vicki Thompson, Roberta Detata, and Vince Bartolomucci, Attorneys at Law, for San Diego Gas & Electric Company.

Intervenor: McCracken, Byers & Bergeron, by David J. Byers, Attorney at Law, for California City-County Street Light Association.

Interested Parties: Morrison & Foerster, by Jerry Bloom and Joseph M. Karp, Attorneys at Law, for California Cogeneration Council; Maurice Brubaker, for Brubaker & Associates; Sam De Frawi, for the Department of the Navy; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Karen Johanson, for California Alliance for Utility Safety & Education; William Marcus, for JBS Energy; Judy Pau and Phil Endom, Attorneys at Law, for El Paso Natural Gas; Michael Shames, Attorney at Law, for Utility Consumers' Action Network; Goodin, MacBride, Squeri, Schlotz & Ritchie, by James Squeri, Attorney at Law, for Kelco; and Kevin Woodruff, for Independent Energy Producers.

Division of Ratepayer Advocates: Catherine A. Johnson, Attorney at Law, Raymond Charvez, and Sean Casey.

(END OF APPENDIX B)

Commissioner Knight, Concurring:

I concur with the majority in adopting this settlement. There are two aspects, however, that I would like to give special attention.

First, this decision does not refund the entire over-collection of $77.4 million dollars to customers as I would have preferred. The settlement refunds only $35 million dollars and uses the remaining $42.4 million dollars to offset a cost increase of $21.4 million. This still allows a rate decrease of $21 million dollars. While I support taking steps to reduce rates to captive consumers, as a matter of policy I do not think that the use of over-collections is the appropriate means of doing so. In this case, rates will only decrease because last year's rates were set too high. It is important for parties to note that SDG&B's revenue requirement would have increased by over $20 million dollars had it not been for the over-collection. Generally, I do not support using over-collections to mask the real costs for the utility to provide power.

I concur with the decision, although as I have articulated in other cases, I prefer a one-time refund of an over-collection, particularly under the circumstances where we are refunding $35 million, which is nearly half of the over-collection. However, I am a strong proponent of settlements, so I am restraining from dissenting on what otherwise seems to be a reasonable settlement.

Second, I wish to commend SDG&E and the other parties for devising a contracting approach which does not have the anti-competitive problems as those adopted in the PG&E rate design window (D.95-10-033). In particular, I support the settlement in the instant case because of the ability for customers to terminate the partially ratepayer funded Pre-approved Contract Option, one year after the service is deregulated. Thus, SDG&B is prevented from locking customers into long-term contracts that would have the effect of denying these customers choice in a future market. In addition, the full shareholder funding of the Total Flexibility Contract option prevents SDG&E from gaining a competitive advantage using ratepayer dollars. Both these approaches allow SDG&B to meet the competitive challenges of today, without unreasonably advantaging it in the future competitive marketplace.

For these reasons, I concur with the majority.

Dated this 6th day of June, 1996, at San Francisco, California

/s/ Jessie J. Knight, Jr.
Jessie J. Knight, Jr.
Commissioner

A.91-11-024/A.95-10-006
D.96-06-033

Commissioner Knight, concurring:

I concur with the majority in adopting this settlement. There are two aspects, however, that I would like to give special attention.

First, this decision does not refund the entire over-collection of $77.4 million dollars to customers as I would have preferred. The settlement refunds only $35 million dollars and uses the remaining $42.4 million dollars to offset a cost increase of $21.4 million. This still allows a rate decrease of $21 million dollars. While I support taking steps to reduce rates to captive consumers, as a matter of policy I do not think that the use of over-collections is the appropriate means of doing so. In this case, rates will only decrease because last year's rates were set too high. It is important for parties to note that SDG&E's revenue requirement would have increased by over $20 million dollars had it not been for the over-collection. Generally, I do not support using over-collections to mask the real costs for the utility to provide power.

I concur with the decision, although as I have articulated in other cases, I prefer a one-time refund of an over-collection, particularly under the circumstances where we are refunding $35 million, which is nearly half of the over-collection. However, I am a strong proponent of settlements, so I am restraining from dissenting on what otherwise seems to be a reasonable settlement.

Second, I wish to commend SDG&E and the other parties for devising a contracting approach which does not have the anti-competitive problems as those adopted in the PG&E rate design window (D.95-10-033). In particular, I support the settlement in the instant case because of the ability for customers to terminate the partially ratepayer funded Pre-approved Contract Option, one year after the service is deregulated. Thus, SDG&E is prevented from locking customers into long-term contracts that would have the effect of denying these customers choice in a future market. In addition, the full shareholder funding of the Total Flexibility Contract option prevents SDG&E from gaining a competitive advantage using ratepayer dollars. Both these approaches allow SDG&E to meet the competitive challenges of today, without unreasonably advantaging it in the future competitive marketplace.

For these reasons, I concur with the majority.

Dated this 6th day of June, 1996, at San Francisco, California

Jessie J. Knight, Jr.
Commissioner