~~EXH. 317 #14~~
5.C.

CALIFORNIA PUBLIC UTILITIES COMMISSION
Revenue Requirements Division

REPORT ON THE

RESULTS OF OPERATION

OF

SAN DIEGO GAS & ELECTRIC COMPANY

ELECTRIC DEPARTMENT

TEST YEAR 1981

Application No. 59788

J-1490

San Francisco, California
September 8, 1980

8103110760

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MEMORANDUM

This report was prepared by the Revenue Requirements Division staff under the direction of Project Manager Francis S. Ferraro. Individual chapters were prepared by the following members of the staff:

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2 and 3	History and Present Operations	See Company Report
4, 5 and 6	Balance Sheet, Statements of Income and Retained Earnings and Clearing Accounts	Gilbert Infante
7	Operating Revenues	Sandy Miller
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CHAPTER 1

INTRODUCTION

A - PURPOSE OF REPORT

1. The purpose of this report is to provide information for the Commission and interested parties on the operations and earnings of San Diego Gas & Electric Company (SDG&E). This report is prepared in response to the utility's Application No. 59788, filed July 1, 1980, for a general rate increase for the Electric Department of $126.6 million or 13.2%. The application requests an 11.44% rate or return and a 14.5% return on common equity in the test year.

2. In Decision No. 90405, dated June 5, 1979, in Application No. 58067 (applicant's last general rate proceeding), the utility was granted a rate of return of 10.59% and a return on equity of 14.50% for test year 1979.

B - SCOPE OF REPORT

3. The report includes a summary of the utility's system electric operations for the test year 1981. Also included are chapters and analyses of operating revenues, expenses, taxes, utility plant and depreciation. Chapter 4, Chapter 5, and Chapter 6 on Balance Sheet, Income Statement, and Clearing Accounts will be covered separately in the Report on the Results of Examination of San Diego Gas & Electric Company. Chapter 18, Summary of Earnings, contains a comparison of the staff's and utility's estimates at present rates and at utility proposed rates, of net revenues, rate base, and the rate of return for the test year 1981.

4. Differences between the staff and the utility's estimates for test year 1981 are indicated in succeeding chapters of this report. The report also explains the reasons for these differences.

5. A comparison of the staff's and utility's estimated rates of return based on respective results of operation is as follows:

Rate of Return

Item	Present Rates 1981	Proposed Rates 1981
Utility	3.48%	11.44%
Staff	8.51%	14.86%

6. In connection with the staff's presentation in this proceeding, the Utilities Division will present reports covering electric rate design and conservation. The Financial Analysis staff of the Revenue Requirements Division will also present reports on results of examination and rate of return.

7. Both the utility and the staff have developed estimates assuming a 9.5% wage increase for the year 1980 and 13.5% for test year 1981. For expenses other than labor, the staff and utility have used a 10% inflation rate for 1980 and 1981. Explanation of the staff's wage adjustment is contained in the general report.

8. Consistent with the Commission's recent decisions in general rate proceedings, staff's revenues and expenses exclude all direct ECAC energy costs. Also excluded are the variable portions of wheeling expenses and Department of Water Resources expenses which, in the OII-56 hearings, the staff has recommended be included in ECAC. The company's exhibit shows results both with and without ECAC revenues and expenses.

9. Consistent with the Commission's treatment of PG&E's Diablo Canyon nuclear facility,[1/] this report has excluded all expenses and rate base associated with the company's construction of San Onofre Units Nos. 2 and 3 (SONGS 2 and 3). It is anticipated that when these facilities are ready for operation, a separate proceeding will be instituted for the purpose of establishing rates.

10. All of the accounting adjustments contained in the Financial Analysis staff's "Report on the Results of Examination of San Diego Gas & Electric Company" have been utilized in developing the estimates contained in this report.

1/ Decision No. 91107, dated December 19, 1979, in Application No. 58545.

CHAPTER 2

HISTORY

1. The last previous detailed study of the Electric Department of the San Diego Gas & Electric Company was prepared by the staff in connection with Application No. 58067. This study covered results of operations for the test year 1979.

CHAPTER 3

PRESENT OPERATIONS

1. In the company's application is contained a description of corporate information. To the extent that the material in the utility's application is adequate for the purpose, it has not been duplicated in this report.

CHAPTER 4 - BALANCE SHEET ACCOUNTS
CHAPTER 5 - INCOME STATEMENT ACCOUNTS
CHAPTER 6 - CLEARING ACCOUNTS

FINANCIAL ANALYSIS AUDIT

1. An independent audit by the professional staff accountants of the Revenue Requirements Division, Financial Analysis Group, was conducted in conjunction with this rate proceeding. The staff accountants prepared a separate report on the results of this independent analysis of San Diego Gas & Electric Company and its subsidiary operations.

2. The staff accountants coordinated the audit recommendations discussed below with the staff engineers for consideration in the preparation of their test year estimates.

3. The "Report on the Results of Examination of San Diego Gas & Electric Company" contains the following recommendations made by the staff accountants.

   A. Exclude $9,250,970 from Account 105, Utility Plant Held for Future Use, relating to the two South Bay gas turbines for rate-making purposes.

   B. Exclude $151,179 of excessive Allowance for Funds Used During Construction (AFUDC) charged to Work Order No. 5071000 during the period October 1976 through August 1978 on SDG&E's books of account in Account 107, Construction Work in Progress.

   C. Gains or losses resulting from the future sale of property in the amount of $5,364,372 now recorded in Account 121, Non-Utility Property, which was previously recorded in Account 105, Utility Plant Held for Future Use, should be recorded "above the line" in Account 411.6, Gains From Disposition of Utility Plant, or Account 411.7, Losses From Disposition of Utility Plant.

   D. SDG&E should not be allowed to recover through base rates $596,755 representing the base rate component of lifeline refunds required due to the overcharging of lifeline customers in prior years.

E. Recognition should be given to the effects the Gas Meter Antitrust Litigation Refund of $193,688 will have on the 1981 test year accumulated provision for depreciation of Gas Utility Plant.

F. Goodwill and Educational Tours' recorded amounts of $1,602 for 1978 and $715 for 1979 should be excluded from operating expense for rate-making purposes.

G. Dues, Donations and Contributions of $5,691 (gas) and $68,083 (electric) for 1978 and $20,452 (gas) and $106,748 (electric) for 1979 should be excluded from operating expense for rate-making purposes.

H. Any effect on base rates resulting from the staff's investigation into the fuel oil exchange between SDG&E and United Petroleum Distributors should be deferred until SDG&E's 1982 test year filing.

I. Electric Credits given to Applied Energy, Inc. for fuel should be calculated at the average system cost per megawatt-hour for steam generation only.

J. The Kaiparawits coal reserve of $4,009,920 on New Albion Resources Company's (NARCO) books should be amortized through EEDA to ECAC. NARCO began amortizing the Kaiparawits coal reserve project costs July 1, 1980.

CHAPTER 7

REVENUES

1. The Electric Department revenues are derived primarily from the sales of electricity to its residential, nonresidential, and resale customers. Minor amounts of revenue are generated from service connection fees, rents, and other miscellaneous categories.

2. The following table compares staff and utility base revenue estimates[1/] for test year 1981 at present rates and utility proposed rates.

Estimated Total Revenues

Item	Staff	Utility	Utility Exceeds Staff: Amount	Utility Exceeds Staff: Percent
		(Dollars in Thousands)		
Present Rates	$296,647.3	$282,943.0	$(13,704.3)	(4.6)%
Proposed Rates	431,135.6	409,573.0	(21,562.6)	(5.0)
Increase in Revenues	134,488.3	126,630.0	(7,858.3)	(5.8)

(Red Figure)

3. A detail of these revenue estimates is provided in Tables 7-A and 7-B.

4. Underlying the differences in estimates are the sales forecasts for the individual sales categories. Table 7-C presents sales estimates by class of customer. Charts 7-A through 7-E are included at the rear of this chapter to illustrate the recorded sales and projected sales estimates by staff and utility for the residential, commercial, industrial, and agricultural and street lighting customers.

1/ Revenues are shown on a zero fuel basis, i.e., ECAC-related revenues are excluded.

Residential

5. The staff's estimate of residential sales in test year 1981 is 326.3 gigawatt-hours (GWh) higher than the company's estimate of 3,968.28 GWh. Both forecasts utilize econometric models which estimate historical statistical relationships between sales and economic and noneconomic variables. After these relationships have been developed, sales are estimated into the test year based on assumptions about what the economic and noneconomic variables are going to do.

6. The staff has accepted as reasonable the utility's assumptions about the "independent" variables that were used by the staff in its forecasts.

7. A major difference between staff and utility exists in the structures of the models. The staff utilizes quarterly data on total residential sales from 1966:1 through 1980:1 to develop its forecasting equation. The utility relies on quarterly data on residential sales per customer from 1960:1 through 1980:1 to develop its forecasting equation. The staff decided to use total sales instead of sales per customer, because it is felt that total sales is a little less volatile than sales per customer and, therefore, could be predicted with more certainty.

Commercial (General Service; General Power)
Industrial
Other (Agricultural Pumping; Street Lighting)

8. The staff estimates higher sales (and therefore higher revenues) in all of these categories compared to the company's estimates. Both forecasts use econometric models which attempt to estimate sales as a function of a variety of economic and noneconomic variables. The types of variables each forecast is built on are different, however, in each model. An important difference between models is the estimated effect on sales caused by the price of electricity. Contrary to the findings of the utility, the staff has not found that the price of electricity has yet significantly affected sales trends. Certainly, it can be stated that sales is determined by many factors including price, the general economic climate of a region, and the

ability by customers to pass on their increased energy costs in the prices of their final products (e.g., the California energy utilities directly pass on their increased energy costs without risk to their rates of return). Unless the competitive characteristics of these customers can be demonstrated to be a function of the price of electricity, it is not a foregone conclusion that an increase in electricity prices will result in a drop in electricity demand. Therefore, the staff believes its estimates are more realistic than the utility's estimates.

Customers

9. The staff and utility forecasts of customers are presented in Table 7-D. The differences between staff and utility estimates are due to differing methodologies. The staff bases its estimates on the recorded relationship between customers and county population and the county population projections by the State Department of Finance. The company ties its estimates to building permits which, in turn, rely on interest rate forecasts.

Miscellaneous Revenues

10. Staff and utility estimates of these revenues are presented in Table 7-E. Staff estimates for Accounts 451 and 454 are $53,000 and $92,000, respectively, higher than the utility estimates. Account 451 revenues are higher because the staff uses a higher growth rate (which is the staff's growth rate in customers) than the growth rate the utility uses. Revenues from Account 454 are higher than utility revenues because the staff combines all revenues except Sundesert rent revenues and escalates these based on the average growth from 1975-1979. The company uses a five-year average. The staff accepts as reasonable the company's estimate of rental income ($367,000) from its Sundesert properties.

11. The staff excludes the company's estimate of non-ECAC lifeline refunds from miscellaneous revenues as recommended by the Finance Division.

TABLE 7-A

SDGE--ELECTRIC DEPT

REVENUES AT PRESENT RATES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
			(THOUSANDS OF DOLLARS)			
1		RESIDENTIAL	$ 124497.3	$ 115374.0	$-9123.3	-7.3
2		GENERAL SERVICE	104272.6	101936.0	-2336.6	-2.2
3		GENERAL POWER	6496.7	6312.0	-184.7	-2.8
4		INDUSTRIAL	44838.8	43917.0	-921.8	-2.1
5		AGRICULTURAL POWER	4379.5	3986.0	-393.5	-9.0
6		STREET LIGHTING	4033.4	3644.0	-389.4	-9.7
7		RESALE	682.0	682.0	0.0	0.0
8		OTHER SALES TO PUB AUTH	17.0	17.0	0.0	0.0
9		BASE REV FROM CUST	289217.3	275868.0	-13349.3	-4.6
10		MISCELLANEOUS	7430.0	7075.0	-355.0	-4.8
11		REVENUES	296647.3	282943.0	-13704.3	-4.6

TABLE 7-B

SDGE--ELECTRIC DEPT

REVENUES AT PROPOSED RATES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1		RESIDENTIAL	$ 179150.4	$ 165421.0	$-13729.4	-7.7
2		GENERAL SERVICE	147677.4	144243.0	-3434.4	-2.3
3		GENERAL POWER	9207.4	8938.0	-269.4	-2.9
4		INDUSTRIAL	75527.8	72827.0	-2700.8	-3.6
5		AGRICULTURAL POWER	6457.2	5865.0	-592.2	-9.2
6		STREET LIGHTING	4986.4	4505.0	-481.4	-9.7
7		RESALE	682.0	682.0	0.0	0.0
8		OTHER SALES TO PUB AUTH	17.0	17.0	0.0	0.0
9		TOTAL BASE REVENUE FROM CUS	423705.6	402498.0	-21207.6	-5.0
10		MISCELLANEOUS	7430.0	7075.0	-355.0	-4.8
11		REVENUES	431135.6	409573.0	-21562.6	-5.0

TABLE 7-C

San Diego Gas & Electric Company
Total Sales - Electric Department

(Millions of Kilowatt-hours)

Test Year 1981

Class of Service	Staff	Utility	Utility Exceeds Staff: Amount	Utility Exceeds Staff: Percent
Residential	4,294.60	3,968.28	(326.32)	(7.6)
General Service	3,400.00	3,313.80	(86.20)	(2.5)
General Power	213.00	206.34	(6.66)	(3.1)
Industrial	2,440.75	2,299.77	(140.98)	(5.8)
Agricultural Power	164.31	148.60	(15.71)	(9.6)
Street Lighting	74.86	67.63	(7.23)	(9.7)
Resale	54.29	54.29	0	0
Other Sales to Public Authority	275.57	275.57	0	0
Total	10,917.38	10,334.28	(583.10)	(5.3)

TABLE 7-D

San Diego Gas & Electric Company
Electric Department

AVERAGE CUSTOMERS

Test Year 1981

Class of Service	Staff	Utility	Utility Exceeds Staff Amount	Utility Exceeds Staff Percent
Residential	714,344	715,736	1,392	0.2%
General Service	70,702	71,107	405	.6
General Power	3,532	3,532	0	0
Industrial	275	275	0	0
Agricultural Power	3,275	3,275	0	0
Street Lighting	916	916	0	0
Resale	5	5	0	0
Other Sales to Public Authority	1	1	0	0
Total	793,050	794,847	1,797	.2

TABLE 7-E

San Diego Gas & Electric Company
Electric Department

MISCELLANEOUS REVENUE

Test Year 1981
(000)

Line No.	Account	Description	Staff	Utility	Utility Exceeds Staff Amount	Utility Exceeds Staff Percent
1	411.6	Gain on Disp. of Plant	-	-	-	-
2	451	Misc. Service Revenues	$3,052	$2,999	(53)	(1.7)
3	454	Rent	1,239	1,140	(99)	(8.0)
4	456	Other Electric Revenues	3,139	3,139	0	0
5		Non-ECAC Lifeline Refund	0	(203)	(203)	(>100.0)
6		TOTAL	$7,430	$7,075	(355)	(4.8)

Chart 7-A
San Diego Gas and Electric Company

Quarterly Total Residential Electric Sales
Recorded and Estimated

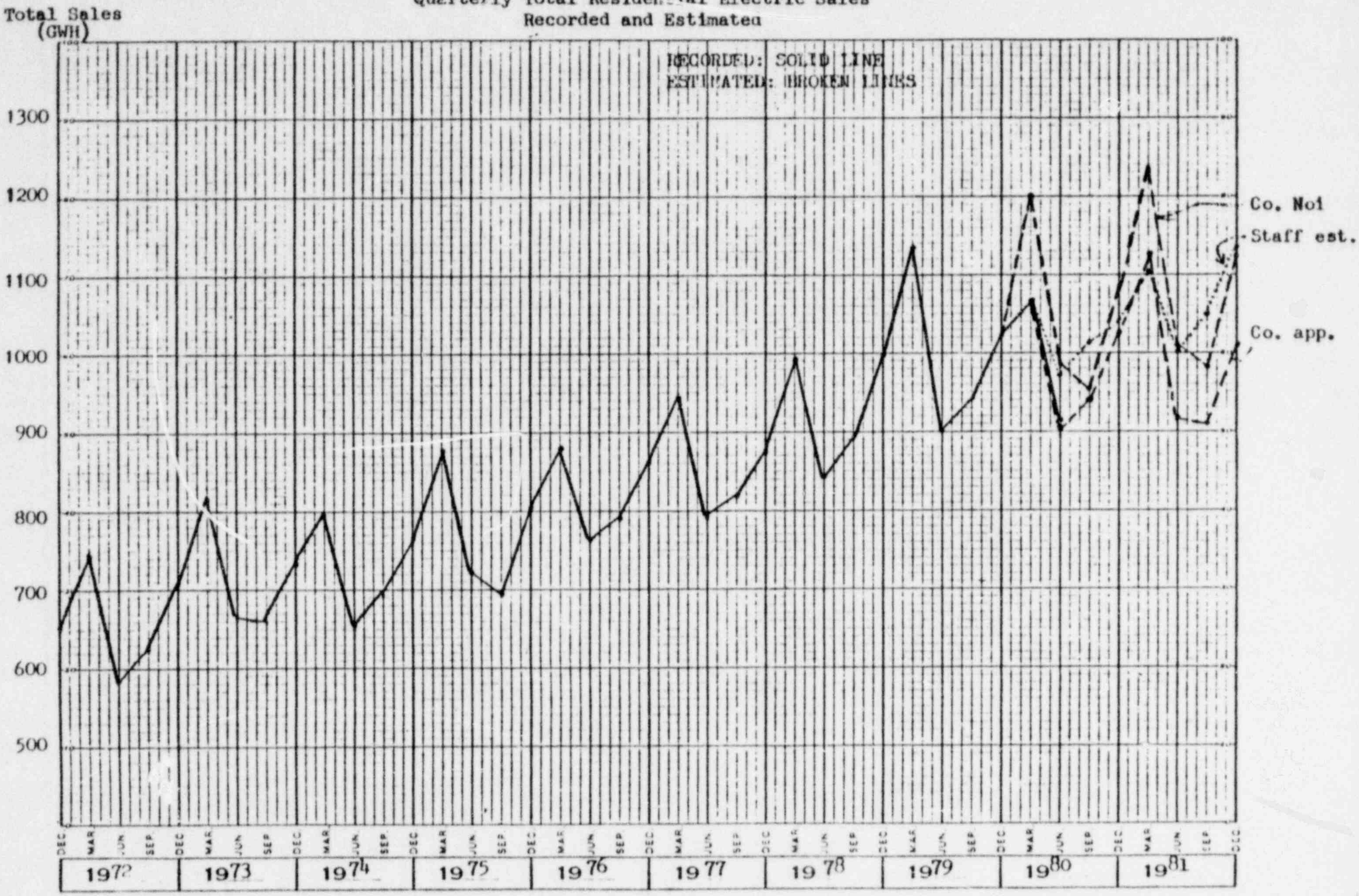

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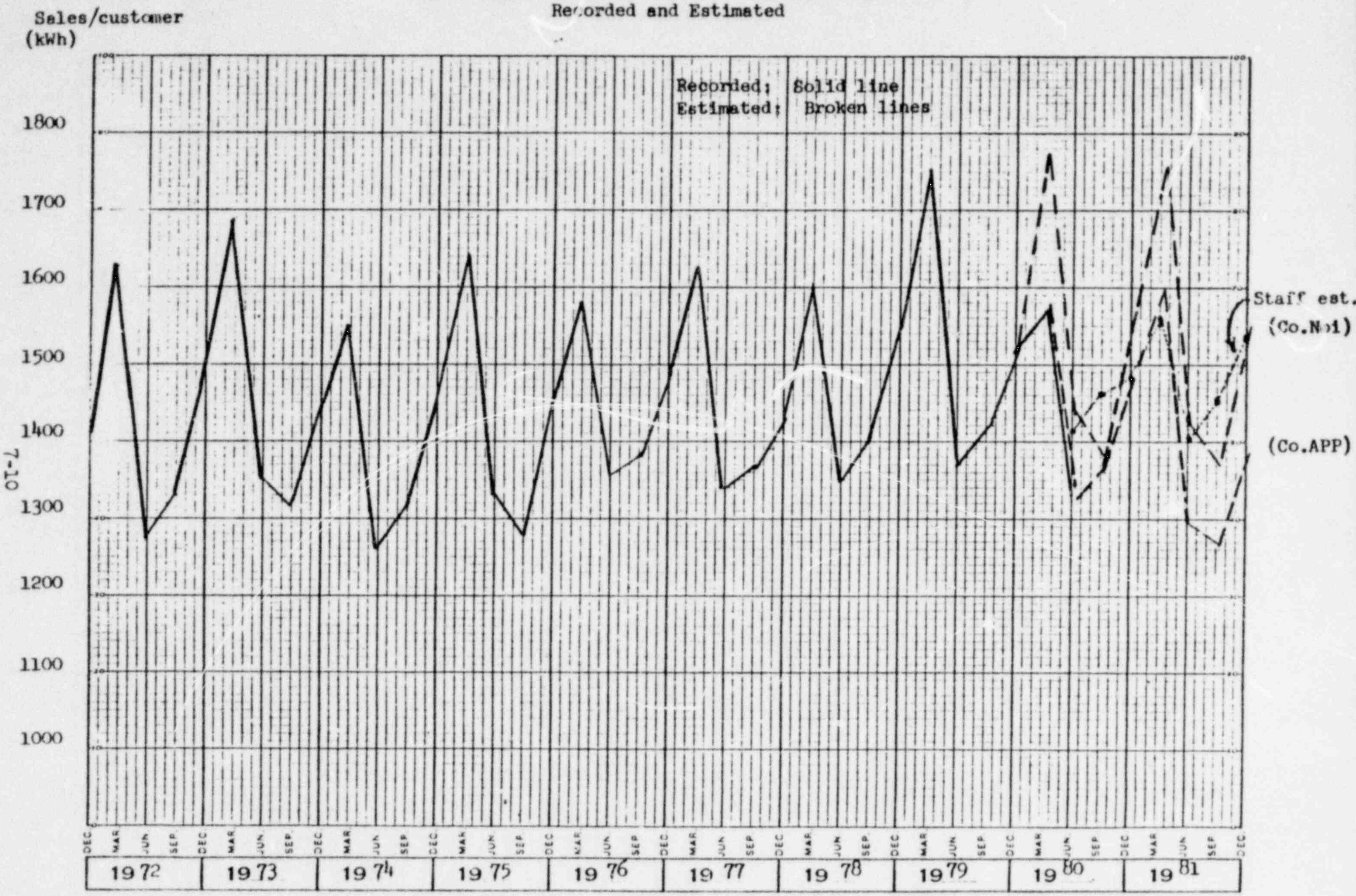
Chart 7-B
San Diego Gas and Electric Company

Quarterly Residential Electric Sales/Customer
Recorded and Estimated



7-10

Chart 7-C
San Diego Gas and Electric Company

Quarterly Electric Sales to Commercial Customers
Recorded and Estimated

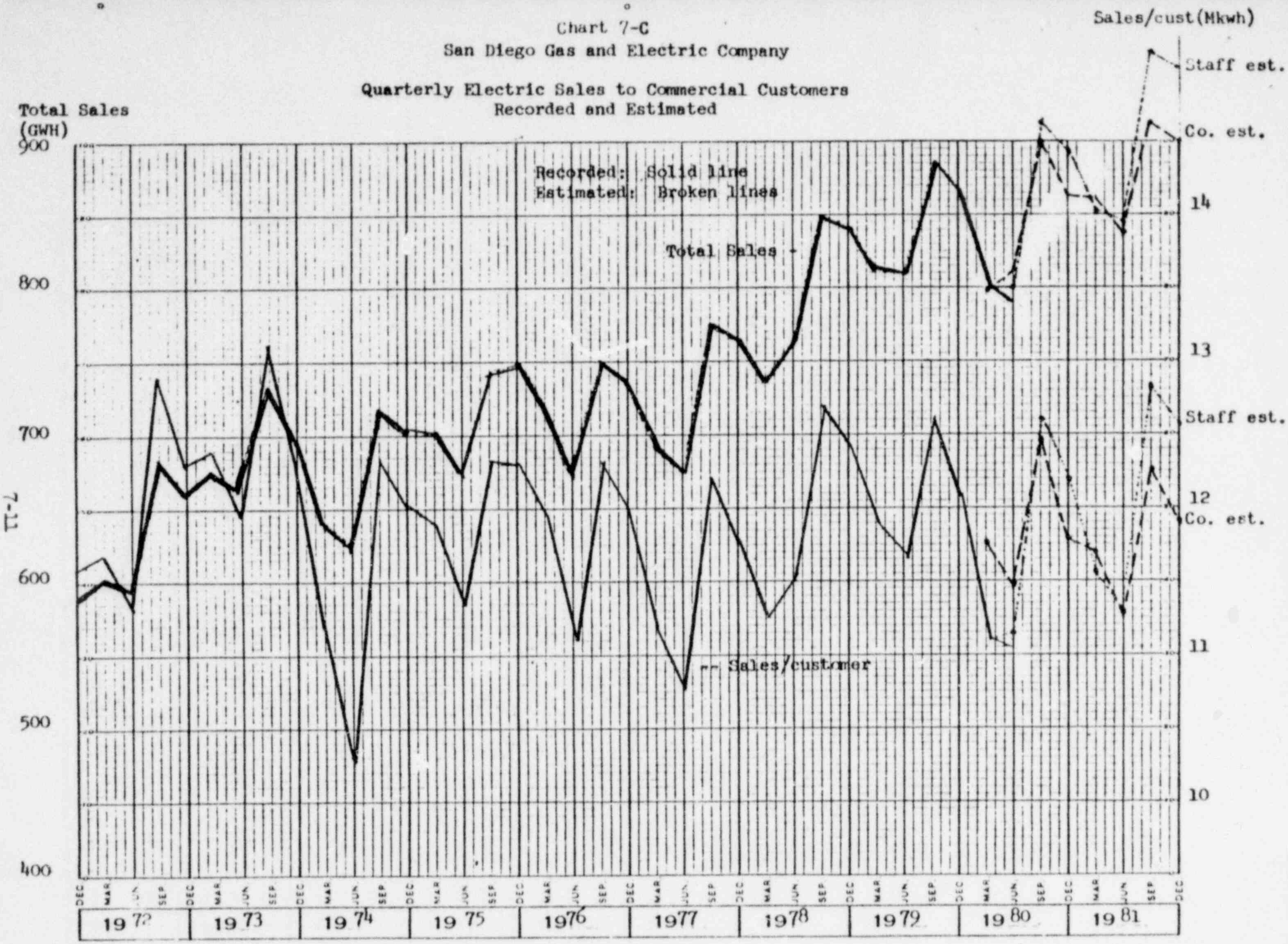


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Chart 7-D
San Diego Gas and Electric Company

Quarterly Electric Sales to Industrial Customers
Recorded and Estimated

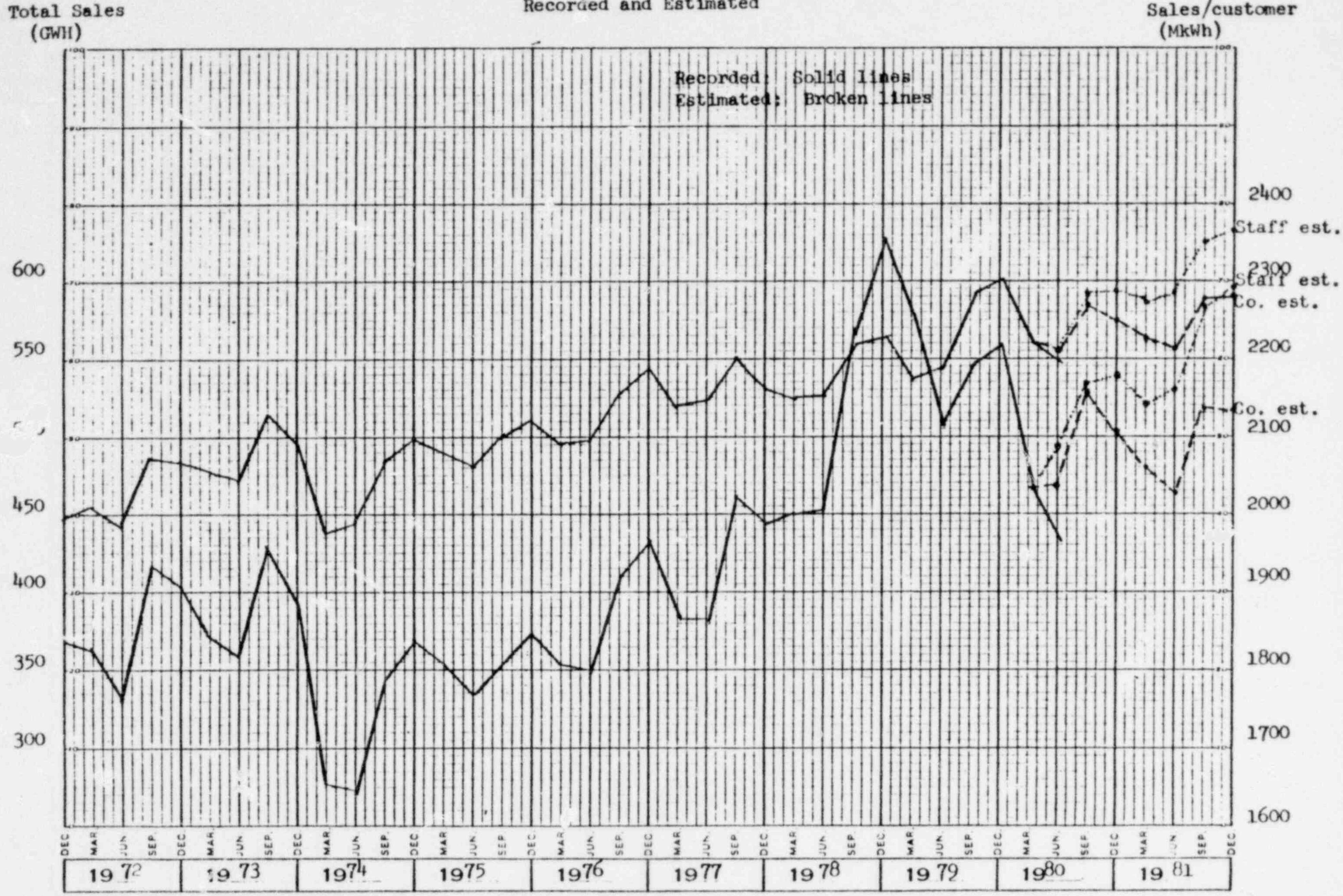
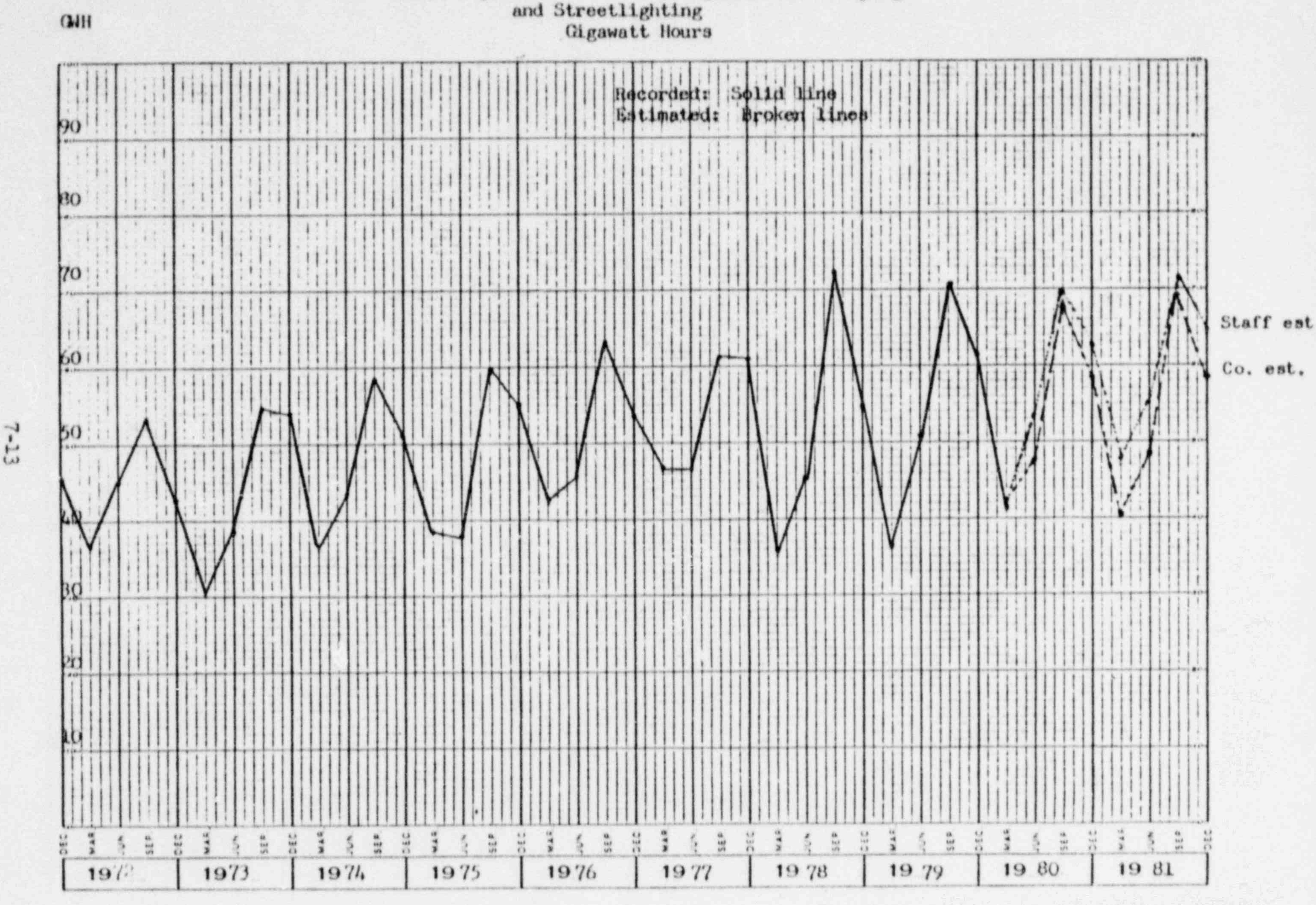


Chart 7-E
San Diego Gas & Electric Company

Quarterly Electric Sales to Agricultural Pumping
and Streetlighting
Gigawatt Hours



CHAPTER 8

PRODUCTION EXPENSES

1. Electric production expenses include expenses incurred in the operation and maintenance of the utility's steam-electric, nuclear, and combustion turbine generating facilities, including such items as system control and load dispatching, and purchased power.

2. The staff's estimates were made using information gathered through discussions with the utility, field trips, and analysis of recorded data. Tables 8-A through 8-E compare the staff's and the utility's estimated expenses for the 1981 test year. Both showings have excluded expenses associated with the Energy Cost Adjustment Clause (ECAC). A summary of the staff's and utility's estimates is shown below:

Production Expense Estimates

Item	Staff	Utility	Utility Exceeds Staff
	(Dollars in Thousands)		
Non-fuel Related	$49,159.0	$49,733.0	$ 574.0
Fuel Related	3,131.7	14,031.7	10,900.0
Totals:	52,290.7	63,764.7	11,474.0

3. San Diego's generating system, as of December 1979, consisted of four steam-electric generating plants (13 units - generating capacity of 2,039 MW), a 20% share of Southern California Edison's San Onofre Nuclear Plant (90 MW), and 20 combustion turbines, for a total generating capacity of 2,492 MW. The utility also receives and exchanges energy and capacity with other utilities.

4. Sixteen of the combustion turbines are used for peaking purposes and the remaining four are base loaded for cogeneration: Naval Station, Naval Training Center (NTC), North Island Unit 2, and Rohr Industries. North Island Unit 2 went into cogeneration service in October 1978, Naval Station became operational in December 1978, and Rohr Industries began commercial operation in February 1979.

5. The majority of the utility's estimates were based upon nine-year trends, 1971 through 1979 (11 months recorded, 1 month estimated), of historic costs, adjusted to remove unusual or non-reocurring expenses. These forcasted figures

were then escalated to 1981 dollars - the labor portion by 9.5% (effective February 1980) and 13.5% (effective March 1981), and the non-labor portion by 10% per year for 1980 and 1981. Future years' non-trendable expenses were added to these projected costs. Exceptions were as follows: the overhaul subaccounts, the load dispatching account, and the rent expense account were zero base estimated; the nuclear expense estimates were based upon information provided by SCE; and the fuel-related non-ECAC expenses were estimated based upon anticipated expenditures in 1981.

Steam-Electric (Accounts 500-514)

6. The staff reviewed the reasonableness of the utility's trends of the recorded/adjusted costs and found the estimates, excluding unusual expenses, for all steam-electric non-fuel operation and maintenance accounts to be reasonable (Accounts 500, 502, 504, 505, 510, 511, 512.1, 513.1, and 514). This was based upon analysis of recent charges since Encina Unit 5 became operational in November of 1978.

7. Non-trendable future year's additions to the various accounts were also analyzed. Differences between the staff's and the utility's estimates are discussed in the following paragraphs.

Account 500 (Air Environmental Expenses)

8. The utility has included $75,000 in its 1981 as-expected year estimate for ambient air quality monitoring in the South County area. This expense is associated with the siting of gas turbines in the South Bay area. The staff has removed this cost from the 1981 as-expected year estimate, to be consistent with the staff's treatment of the gas turbines in plant held for future use. (Refer to Chapter 15 - Electric Plant.)

9. The staff's test year adjustment reflects a five-year amortization of the expected air environmental expenses for 1980 and 1981, consistent with the treatment given these expenses in Decision No. 90405 for SDG&E's 1979 test year Application No. 58067. The staff's adjustment results in a test year estimate of $141,000, which is $184,500 lower than the utility's estimate.

Account 505 (Water Environmental Expenses)

10. The staff's test year treatment of water environmental expenses is identical to the treatment given to air environmental expenses. The 1980 and 1981 as-expected year estimates were amortized over five years. This results in a test year estimate of $387,600, which is $331,700 lower than the utility's test year estimate.

Accounts 510, 551 (Materials and Maintenance Management Systems)

11. Increased expenditures to these accounts, beginning in 1980, are attributable to a new computerized system that will be used to manage the materials and labor involved in power plant maintenance.

12. The Materials Management System will allow better control of materials. This will result in decreased delay time in acquiring the materials necessary to perform maintenance, thereby minimizing equipment down time. Other benefits will be increased worker productivity and increased generating unit availability.

13. The maintenance management program will also increase worker productivity, reduce overtime, and increase availability of the units. This will be accomplished by better planning, organization, and reporting of maintenance activities. Ideally, less time will be spent on corrective maintenance and more time will be spent on preventive maintenance.

14. The staff reviewed the utility's estimates for the costs associated with these systems and found them to be reasonable.

Account 510 (Maintenance Training Expenses)

15. The staff's estimate for maintenance training expenses reflects the utility's change in maintenance training practice. Beginning in 1981, the utility will only be training to replace people lost due to attrition. The impact of the staff's adjustment results in a test year estimate which is $42,800 lower than the utility's estimate.

Nuclear Power Expenses

16. San Diego Gas & Electric's nuclear expenses are for a 20% share of the operation and maintenance costs for San Onofre Nuclear Generating Station. Only expenses related to SONGS Unit 1 are included in the rate case estimates.

17. SDG&E's estimates for the non-fuel related nuclear accounts, excepting Account 525, were based on forecasts provided by Southern California Edison, with an adjustment to Account 517, Operation Supervision and Engineering. This adjustment was made to include expenses for the time spent by SDG&E's On Site Review Committee and Nuclear Audit Committee members on San Onofre related matters. The staff evaluated the utility's estimates and found them to be reasonable.

18. SDG&E made an independent estimate of the expenses for Account 525, Rents. The staff's test year estimate removes $15,000 worth of expenses associated with the SONGS Units 2 and 3 circulating water conduits. This adjustment is consistent with the staff's treatment of expenses for SONGS Units 2 and 3. The staff's test year estimate for the nuclear power accounts is $15,000 lower than the utility's, as shown in Table 8-C.

Fuel Related Expenses (DWR)

19. In OII-56, Investigation into Electric Utility Energy Cost Adjustment Clause, the staff recommended that the ECAC procedure be revised to include all sales and fuel expenses related to the California Department of Water Resources (DWR) contracts, including DWR sales in excess of purchases.

20. SDG&E also proposed that the ECAC proceeding be modified to include fuel expenses related to DWR sales.

21. In accordance with the positions taken by the staff and utility, the staff recommends that all costs associated with DWR sales be removed from the general rate case. The impact of the staff's adjustment is a test year estimate which is $10,900,000 lower than the utility's estimate. (Refer to Table 8-E.)

TABLE 8-A

SDGE--ELECTRIC DEPT

SUMMARY OF PRODUCTION EXPENSES

EXCLUDING ECAC

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1		OPERATION	$ 30416.6	$ 30947.8	$ 531.2	1.7
2		MAINTENANCE	17915.5	17958.3	42.8	0.2
3		MISCELLANEOUS	826.9	826.9	0.0	0.0
4		SUBTOTAL	49159.0	49733.0	574.0	1.2
5		FUEL UNDISTRIBUTED	3131.7	3131.7	0.0	0.0
6		FUEL COST-NON ECAC	0.0	10900.0	10900.0	0.0
7		TOTAL PRODUCTION EXPENSE	52290.7	63764.7	11474.0	21.9
8		WAGE ADJ.	-334.8	0.0	334.8	-100.0
9		TOTAL AFTER WAGE ADJ	51955.9	63764.7	11808.8	22.7

TABLE 8-B

SDGE--ELECTRIC DEPT

PRODUCTION EXPENSES EXCLUDING ECAC

STEAM POWER PRODUCTION

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
		OPERATION				
1	500.00	SUPERVISION & ENGINEERING	$1525.0	$1525.0	$ 0.0	0.0
2	500.00	AIR ENVIRONMENTAL EXPENSES	141.0	325.5	184.5	130.9
3	502.00	STEAM EXPENSES	3104.7	3104.7	0.0	0.0
4	504.00	STEAM TRANSFERRED	-31.1	-31.1	0.0	0.0
5	505.00	ELECTRIC EXPENSES	2952.0	2952.0	0.0	0.0
6	505.00	WATER ENVIRONMENTAL STUDIES	387.6	719.3	331.7	85.6
7	506.00	PART FALLOUT PROG AMORT	906.0	906.0	0.0	0.0
8	506.00	MEGMA GEOTHERMAL O&M	260.0	260.0	0.0	0.0
9	506.00	NILAND GEOTHERMAL AMORT	600.0	600.0	0.0	0.0
10	506.00	HEBER GEOTHERM PROG	6626.0	6626.0	0.0	0.0
11	506.00	EXPAND GEOTHERM PROG AMORT	471.6	471.6	0.0	0.0
12	506.00	MISC (NON-R&D EXPENSES)	1125.9	1125.9	0.0	0.0
13	507.00	RENTS-ENCINA 5 LEASE PMT	9302.0	9302.0	0.0	0.0
14	507.00	RENTS (OTHER THAN ENCINA 5)	90.4	90.4	0.0	0.0
15		SUBTOTAL	27461.1	27977.3	516.2	1.9
		MAINTENANCE				
16	510.00	SUPERVISION & ENGINEERING	1657.7	1700.5	42.8	2.6
17	511.00	STRUCTURES	2768.8	2768.8	0.0	0.0
18	512.00	BOILER PLANT	4864.7	4864.7	0.0	0.0
19	513.00	ELECTRIC PLANT	4225.4	4225.4	0.0	0.0
20	514.00	MISCELLANEOUS EQUIPMENT	355.6	355.6	0.0	0.0
21		SUBTOTAL	13872.2	13915.0	42.8	0.3
22		TOTAL EXPENSES	41333.3	41892.3	559.0	1.4
23		WAGE ADJ.	-245.0	0.0	245.0	-100.0
24		TOTAL AFTER WAGE ADJ	41088.3	41892.3	804.0	2.0

T A B L E 8-C

SDGE--ELECTRIC DEPT

PRODUCTION EXPENSES EXCLUDING ECAC

NUCLEAR POWER PRODUCTION

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
		OPERATION				
1	517.00	SUPERVISION & ENGINEERING	$ 748.1	$ 748.1	$ 0.0	0.0
2	519.00	COOLANTS & WATER	135.6	135.6	0.0	0.0
3	520.00	OPERATION OF REACTOR	536.2	536.2	0.0	0.0
4	523.00	ELECTRIC EXPENSES	58.4	58.4	0.0	0.0
5	524.00	MISCELLANEOUS EXPENSES	1076.2	1076.2	0.0	0.0
6	525.00	RENTS	22.2	37.2	15.0	67.6
7		SUBTOTAL	2576.7	2591.7	15.0	0.6
		MAINTENANCE				
8	528.00	SUPERVISION & ENGINEERING	471.2	471.2	0.0	0.0
9	529.00	STRUCTURES	97.5	97.5	0.0	0.0
10	530.00	REACTOR PLANT EQUIPMENT	573.9	573.9	0.0	0.0
11	531.00	ELECTRIC PLANT	319.0	319.0	0.0	0.0
12	532.00	MISC NUCLEAR PLANT	68.9	68.9	0.0	0.0
13		SUBTOTAL	1530.5	1530.5	0.0	0.0
14		TOTAL EXPENSES	4107.2	4122.2	15.0	0.4
15		WAGE ADJ.	-55.4	0.0	55.4	-100.0
16		TOTAL AFTER WAGE ADJ	4051.8	4122.2	70.4	1.7

TABLE 8-D

SDGE--ELECTRIC DEPT

PRODUCTION EXPENSES EXCLUDING ECAC

GAS TURBINE POWER PRODUCTION AND OTHER POWER SUPPLY EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
		OPERATION				
1	546.00	SUPERVISION & ENGINEERING	$ 65.1	$ 65.1	$ 0.0	0.0
2	548.00	GENERATION	198.9	198.9	0.0	0.0
3	549.00	MISCELLANEOUS EXPENSES	114.8	114.8	0.0	0.0
4	550.00	RENTS	0.0	0.0	0.0	0.0
5		SUBTOTAL	378.8	378.8	0.0	0.0
		MAINTENANCE				
6	551.00	SUPERVISION & ENGINEERING	256.3	256.3	0.0	0.0
7	552.00	STRUCTURES	58.6	58.6	0.0	0.0
8	553.00	GENERATING EQUIP	2197.4	2197.4	0.0	0.0
9	554.00	MISC PLANT EQUIPMENT	0.5	0.5	0.0	0.0
10		SUBTOTAL	2512.8	2512.8	0.0	0.0
		OTHER				
11	556.00	SYSTEM AND LOAD CONTROL	824.2	824.2	0.0	0.0
12	557.00	MISC OTHER EXPENSES	2.7	2.7	0.0	0.0
13		SUBTOTAL	826.9	826.9	0.0	0.0
14		TOTAL EXPENSES	3718.5	3718.5	0.0	0.0
15		WAGE ADJ.	-34.4	0.0	34.4	-100.0
16		TOTAL AFTER WAGE ADJ	3684.1	3718.5	34.4	0.9

TABLE 8-E

SDGE--ELECTRIC DEPT

NON-ECAC FUEL EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
		NON-ECAC FUEL HANDLING				
1	501.20	FUEL OIL-STEAM BOILER	$ 2847.5	$ 2847.5	$ 0.0	0.0
2	501.40	FUEL GAS-STEAM BOILER	8.6	8.6	0.0	0.0
3	547.20	DIESEL FUEL-COMBUSTION TURB	275.6	275.6	0.0	0.0
4	547.40	FUEL GAS-COMBUSTION TURBINE	0.0	0.0	0.0	0.0
5		SUBTOTAL	3131.7	3131.7	0.0	0.0
		NON-ECAC FUEL COST				
6	501.10	FUEL OIL	0.0	7967.8	7967.8	0.0
7	501.30	FUEL GAS	0.0	1201.9	1201.9	0.0
8	518.00	NUCLEAR FUEL	0.0	438.0	438.0	0.0
9	547.10	DIESEL FUEL FOR GAS TURBINE	0.0	93.0	93.0	0.0
10	547.30	FUEL GAS-COMBUSTION TURBINE	0.0	274.5	274.5	0.0
11	555.00	PURCHASED POWER CAPACITY	0.0	458.3	458.3	0.0
12	555.00	PURCHASED POWER	0.0	428.5	428.5	0.0
13	557.30	NARCO FUEL SERVICE AGREE.	0.0	38.0	38.0	0.0
14		SUBTOTAL	0.0	10900.0	10900.0	0.0
15		TOTAL	3131.7	14031.7	10900.0	348.1
16		WAGE ADJ.	0.0	0.0	0.0	0.0
17		TOTAL AFTER WAGE ADJ	3131.7	14031.7	10900.0	348.1

CHAPTER 9

TRANSMISSION EXPENSES

1. Electric transmission expenses include the expenses incurred in the operation and maintenance of the utility's overhead and underground transmission lines with voltage levels of 69 kV and above, for such items as: supervision and engineering, load dispatching, rights-of-way, wheeling, and station equipment and structures operation and maintenance.

2. San Diego Gas & Electric Company's service territory, 4,108 square miles, includes the majority of San Diego County and parts of Imperial and Orange Counties. Within this region the utility had, as of December 1979, 1,077 miles of transmission lines, including 118 miles of 230-kV line, 232 miles of 138-kV line, 727 miles of 69-kV line, and 24 major substations with a total capacity of 5,982 MVA.

3. **The staff's estimates were made using information gathered through discussions** with the utility, data requests, field trips, and analysis of recorded data. The following is a summary of the staff's and utility's transmission expense estimates for the 1981 test year:

<u>Expense Estimates</u>

Staff	Utility	Utility Exceeds Staff
	(Dollars in Thousands)	
$6,793.2	$8,648.7	$1,855.5

Table 9-A compares the staff's and utility's estimates by account for the 1981 test year.

4. The majority of the utility's estimates were made by applying a nine-year historic growth rate to projected 1979 costs. The labor portion was then escalated to 1981 dollars by 9.5% and 13.5% for 1980 and 1981, respectively. The non-labor portion was escalated by 10% per year for 1980 and 1981. The growth rates resulted from a least squares trend of 1971 through 1979 expenses, after adjusting for unusual or non-reoccurring expenses. One of three types of rates was applied to each account, either growth of the individual account, the sum of transmission accounts, or a combination of two or more related accounts.

5. The staff reviewed the reasonableness of the use of 1979 expenses as a base for estimating future costs and found these levels to be reasonable for the accounts where no new projects, reorganizations, or unusual expenses were anticipated (Accounts 560, 562, 563, 564, 569, 570 and 572).

6. For Account 571, Overhead Line Maintenance, the 1979 recorded level of expenses was adjusted upward to reflect a normalized insulator greasing year.

7. The staff's base level estimates for Account 566, Miscellaneous Operation, and Account 573, Miscellaneous Plant Maintenance, were made by averaging normalized historic costs. This method was chosen because of the erratic behavior of historic charges.

8. The base levels for these 10 accounts were then escalated to 1981 dollars by wage and material inflation factors. Analysis by individial accounts yielded no non-inflationary growth. This procedure resulted in differences between the staff's and utility's estimates for Accounts 560, 562, 563, 570, 571, and 572, as shown in Table 9-A. Accounts 561, 565, 567, and 568 will be discussed individually.

Account 567 (Rents)

9. The staff reviewed the utility's estimate for this account and found it to be reasonable.

Account 561 (Load Dispatching)

10. The increased level of expenditures to this account, beginning in 1981, is due to implementation of the utility's Energy Management System (EMS). This digital dispatching system will update the currently outdated system. It will provide system security and economic dispatch of both on- and off-system energy. The system is expected to be operational in mid-1981. (Charges for 1981 test year case also appear in Electric Production Account 556.)

11. Charges applicable to this account include costs for increased system operation's personnel to handle energy transactions between utilities, and for additional personnel to maintain the new computer's hardware and software systems.

12. Analysis of the utility's estimates led to an adjustment for the existing personnel's labor charges. The 1979 labor charges were adjusted upward to reflect the full-year equivalent charge for personnel hired during 1979. The staff did not include $30,000 worth of labor increases, resulting from a redistribution of scheduling personnel's time, in the base labor figure for existing personnel's time. The effect of this accounting change was to increase charges to Account 561 and to decrease charges to other transmission and distribution accounts. These costs, although additional charges to Account 561, are not additional costs to be incurred by the utility. Since these costs have not been specifically removed from the other accounts by the utility, they are included in the historical costs and are, therefore, considered in the estimates for those accounts. The utility's estimates for the non-EMS, non-labor portion and for the EMS portion appear reasonable. The staff's adjustment results in a test year estimate which is $76,000 lower than the utility's.

Account 568 (Maintenance Supervision and Engineering)

13. Charges to this account in 1980 and 1981 will be significantly increased due to the formation of a new transmission maintenance section. This section will supervise the utility's plans for increased maintenance on energized lines. It will also provide input on the design and routing of new transmission lines, including SDG&E's proposed 500-kV eastern interconnection tie line with Arizona, so that "hot-line" maintenance can be performed. Increases to Account 568 for the 1981 test year are for related supervisory charges.

14. The staff's estimate is based upon recent information provided by the utility in response to a staff data request. The staff's adjustment removes $100,000 from the utility's estimate, including $11,100 worth of temporary labor costs. This labor will be borrowed on an "as needed" basis from people currently working in the operating districts. These charges are included in the historical charges to other operation and maintenance accounts and, therefore, should not be included in the test year estimate to Account 568. These adjustments result in a test year estimate of $66,800, which is $100,000 lower than the utility's estimate.

Account 565 (Transmission by Others)

15. This account contains the charges payable to others for the transmission of electricity to SDG&E over transmission facilities owned by others, known as wheeling charges.

16. The staff's estimate for this account reflects the staff's position in OII-56, Investigation into Electric Utility Energy Cost Adjustment Clause. The staff recommended that the ECAC procedure be revised to include wheeling charges that are:

A. Variable-based on a dollar per kilowatt-hour basis.

B. Directly associated with purchased power recorded in Account 555.

C. Not recovered in general rates.

Fixed costs based on contract payments for fixed blocks of energy would be included in the general rate increase.

17. According to these criteria, only Pacific Intertie costs would be included in the test year estimate for the general rate case. The impact of the staff's adjustment is a test year estimate of $1,950,900, which is $1,512,800 lower than the utility's estimate.

18. However, if the $1,512,800 amount is not allowed in the ECAC proceeding, it should be adjusted for the general rate case. The staff's adjustment removes the California Power Pool wheeling charges from the 1981 test year estimate. The utility's estimate was based upon a five-year average of past energy receipts from the California Power Pool. SDG&E, however, does not expect to receive any energy from the Power Pool in future years. Under the agreement, no charges are incurred when no energy is wheeled. The staff's adjustment results in a test year estimate of $1,435,600, which is $77,200 lower than the utility's estimate.

T A B L E 9-A

SDGE--ELECTRIC DEPT

TRANSMISSION EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
			(THOUSANDS OF DOLLARS)			
1		OPERATION				
2	560.00	SUPERVISION & ENGINEERING	$ 436.8	$ 429.7	$ -7.1	-1.6
3	561.00	LOAD DISPATCHING	1101.4	1177.4	76.0	6.9
4	562.00	STATION EXPENSES	340.1	365.3	25.2	7.4
5	563.00	OVERHEAD LINE EXPENSES	138.7	146.9	8.2	5.9
6	564.00	UNDERGROUND LINE EXPENSES	2.6	2.6	0.0	0.0
7	565.00	TRANSMISSION BY OTHERS	1950.9	3463.7	1512.8	77.5
8	566.00	MISCELLANEOUS EXPENSES	133.3	133.3	0.0	0.0
9	567.00	RENTS	149.6	149.6	0.0	0.0
10		TOTAL OPERATION EXPENSES	4253.4	5868.5	1615.1	38.0
11		MAINTENANCE				
12	568.00	SUPERVISION & ENGINEERING	66.8	166.8	100.0	149.7
13	569.00	STRUCTURES	5.3	5.3	0.0	0.0
14	570.00	STATION EQUIPMENT	805.4	907.3	101.9	12.7
15	571.00	OVERHEAD LINES	1645.7	1677.8	32.1	2.0
16	572.00	UNDERGROUND LINES	16.1	22.5	6.4	39.8
17	573.00	MISC. TRANSMISSION PLANT	0.5	0.5	0.0	0.0
18		TOTAL MAINTENANCE EXPENSE	2539.8	2780.2	240.4	9.5
19		TOTAL TRANSMISSION EXPENSES	6793.2	8648.7	1855.5	27.3
20		WAGE ADJ.	-60.8	0.0	60.8	-100.0
21		ADJ.TRANSMISSION EXPENSES	6732.4	8648.7	1916.3	28.5

CHAPTER 10

DISTRIBUTION EXPENSES

1. A summary of distribution expenses is shown below:

Staff	Utility	Utility Exceeds Staff Amount	Utility Exceeds Staff Percent
	(Dollars in Thousands)		
$22,597.4	$25,101.3	$2,503.9	11.1%

2. Distribution expenses consist of the costs of operating and maintaining the utility's distribution system and include such items as supervision and engineering, station expenses, overhead and underground lines, street lights and signal systems, meters and customer services. The staff conducted an engineering operational audit of the electric distribution system and evaluated the reasonableness of the company estimated operational and maintenance distribution expenses. The staff's estimates are based on data gathered on field trips, special studies and an analysis of recorded data from 1975 to 1979, by account, after adjustments for unusual and nonrecurring expenses. The utility's estimates are based primarily on nine-year trends of recorded data. Table 10-A compares the staff's and utility's estimates of the distribution system expenses for test year 1981.

3. The staff's estimates were different than those of the utility in several accounts. An analysis of these differences is provided in the following paragraphs.

4. In Ac. 584, Operational Underground Line Expenses, the utility's estimate was derived by using a 19.76% historic annual growth rate of the sum of the charges to Acs. 584 and 594, excluding the underground preventive maintenance program. The expected growth was converted into a $39,000 per year growth excluding inflation. The staff's estimate consists of five-year (1975-1979) trends of labor and non-labor charges to Acs. 584 and 594. The staff reviewed the cost per underground customer and found the utility's estimates for 1980 and 1981 are increasing. The following is a summary of the staff study.

10 - DISTRIBUTION EXPENSES

Summary of Costs Per Underground Customer Study

Year	Account 584 Recorded Expenses	Account 584 Expenses (1979$)	Underground Customers	Cost per Underground Customer (1979$)
1975	$ 88,409	$120,500	163,200	$0.74
1976	152,616	193,200	186,300	1.04
1977	165,383	195,200	216,600	0.90
1978	221,843	241,100	246,000	0.98
1979	340,937	340,900	275,200	1.24
Staff Estimate				
1980	399,400	364,800	301,500	1.21
1981	480,500	390,500	327,800	1.19
Utility Estimate				
1980	426,400	389,000	300,700	1.29
1981	523,500	424,100	326,700	1.30

5. The staff's estimate considers the improvements in productivity in operation. For future cost savings, the costs per customer should be held near the level of previous years. The impact of the staff's adjustment is a test year estimate of $480,500, which is $43,000 lower than the utility's estimate.

6. Ac. 588 (Miscellansous Distribution Expenses) consists of general system records expenses, maps and records - overhead line expenses, maps and records - underground lines expenses and other small expense items. The utility believes that the present electric mapping system is inadequate and proposes a five-year (1981-1984) program to convert it into a Distribution Facilities Information System (DFIS). Based on a recent revision, the utility now estimates the cost of this program to be approximately $91,000 in 1980 and $1,159,000 in 1981. The utility originally requested $469,000 and $1,741,000 for the DFIS for 1980 and 1981, respectively. An amount of $172,000 for additional automatic drafting equipment and three draftsmen is also included in the utility's estimate. Based on the implementation schedule of the DFIS program and the cost savings that should be realized, the staff has not included the additional expense of $172,000.

The staff's estimate is based on a five-year trend of labor and non-labor expenses charged to Account 588, adjusted for labor cost escalation and material cost inflation. The impact of the staff's adjustment is a test year estimate of $2,858,500, which is $1,162,200 lower than the utility's estimate. Among the $1,162,200, $582,000 is due to the revised estimate for the DFIS program, $172,000 for the disallowance of additional automatic drafting equipment and draftsmen, and $408,200 due to different trending methods between the staff and the utility.

7. In Ac. 593, Maintenance of Overhead Lines, the staff considered the effects of the utility's overhead to underground conversion programs and the increase in new customers with underground service. The utility used a trend which included tree trimming expenses. The staff reviewed the utility's analysis of the historic tree trimming activities and tree related outages. The staff concluded that the historic tree trimming expenses did not correlate to system growth. The following is a summary of the staff's study.

Study of Cost of Tree Trimming per Customer to Tree Related Outages

Year	per Customer (1979$)	Tree related Outages
1975	$2.72	99
1976	2.52	116
1977	3.02	150
1978	3.19	306
1979	3.86	184
Staff's estimate 1981	2.95	-
Utility's estimate 1981	4.01	-

8. The staff used a five-year average of tree trimming cost as a basis for 1981 tree trimming expenses, adjusted for inflation. The utility estimated tree trimming cost to be approximately 30% of total Account 593. The utility's estimate for tree trimming cost is $2,297,900 including $400,000 for additional tree trimming. The staff's tree trimming cost estimate is $1,688,500, excluding the requested $400,000 for additional tree trimming.

9. In Ac. 594, Maintenance of Underground Lines, the staff's estimate reflects the utility's recorded experience with underground maintenance. The utility's estimate was derived by using a 19.76% historic annual growth rate of the sum of the charges to Acs. 584 and 594, excluding the underground preventive maintenance program. The expected growth was converted into a $184,000 per year growth excluding inflation. The staff found no indication that the underground distribution system was growing at a rapid rate. On the contrary, the percentage of increased underground customers is declining. The following is a summary of the staff's study.

Study of Underground Customer Growth

Year	Number of Underground Customers	Number Increase	Percent Increase
1977	216,600	30,300	16.3%
1978	246,000	29,400	13.6
1979	275,200	29,200	11.9
1980	301,500	26,300	9.6
1981	327,800	26,300	8.7

10. The staff also reviewed the cost per underground customer and found this cost to be decreasing. The implementation of the underground preventive maintenance program in 1979 improved the cost savings of underground maintenance. The staff expects this trend to continue and has reflected it in its estimate. The following is a summary of the staff study:

Summary of Costs Per Underground Customer Study

(Excluding Underground Preventive Maintenance Program)

Year	Account 594 (1979$)	Underground Customers	Cost per Underground Customer (1979$)
1975	$1,307,100	163,200	$8.01
1976	1,246,100	186,300	6.69
1977	1,369,900	216,600	6.33
1978	1,629,900	246,000	6.63
1979	1,542,300	275,200	5.60
(Staff Estimate)			
1980	1,641,500	301,500	5.44
1981	1,748,300	327,800	5.33
(Utility Estimate)			
1980	1,820,300	300,700	6.05
1981	2,067,600	326,700	6.33

11. The utility estimated the underground preventive maintenance program for 1980 to 1982 at $792,000 per year, excluding inflation. The staff has found this estimate reasonable and included $972,200 for the program in 1981. The impact of the staff's adjustment is a test year estimate of $3,119,100, which is $401,900 lower than the utility's estimate.

12. Ac. 597, Maintenance of Meters Expenses, includes the cost of labor, material used and expenses incurred in the maintenance of meters and meter testing equipment. The staff observed an improvement in productivity since 1975 and anticipated further cost savings. The impact of the staff adjustment is a test year estimate of $486,500, which is $14,200 lower than the utility's estimate.

T A B L E 10-A

SDGE--ELECTRIC DEPT

DISTRIBUTION EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
			(THOUSANDS OF DOLLARS)			
1		OPERATION				
2	580.00	SUPV. & ENGINEERING	$ 1252.8	$ 1252.8	$ 0.0	0.0
3	582.00	STATION EXPENSES	960.6	960.6	0.0	0.0
4	583.00	OVERHEAD LINE EXPENSES	1147.9	1147.9	0.0	0.0
5	584.00	UNDERGROUND LINE EXPENSES	480.5	523.5	43.0	8.9
6	585.00	STREET LIGHT EXPENSES	341.1	341.1	0.0	0.0
7	586.00	METER EXPENSES	1813.0	1813.0	0.0	0.0
8	587.00	CUSTOMER INST. EXPENSES	1616.9	1616.9	0.0	0.0
9	588.00	MISC DISTR EXPENSES	2858.5	4020.7	1162.2	40.7
10	589.00	RENTS	19.6	19.6	0.0	0.0
11		TOTAL DISTR. OPER. EXPENSE	10490.9	11696.1	1205.2	11.5
12		MAINTENANCE				
13	590.00	SUPV. & ENGINEERING	322.3	322.3	0.0	0.0
14	591.00	STRUCTURES	28.6	28.6	0.0	0.0
15	592.00	STATION EQUIP.	785.5	785.5	0.0	0.0
16	593.00	OVERHEAD LINES	7050.2	7659.6	609.4	8.6
17	594.00	UNDERGROUND LINES	3119.1	3521.0	401.9	12.9
18	595.00	LINE TRANSFORMERS	389.4	389.4	0.0	0.0
19	596.00	ST. LIGHT.& SIGNAL SYS.	145.1	145.1	0.0	0.0
20	597.00	METERS	486.5	500.7	14.2	2.9
21	598.00	MISC DIST PLANT	53.0	53.0	0.0	0.0
22		TOTAL DIST MAINT EXPENSE	12379.7	13405.2	1025.5	8.3
23		TOTAL DISTRIBUTION EXPENSE	22870.6	25101.3	2230.7	9.8
24		WAGE ADJ.	-273.2	0.0	273.2	-100.0
25		TOTAL DISTRI. EXP. ADJ.	22597.4	25101.3	2503.9	11.1

CHAPTER 11

CUSTOMER ACCOUNTS EXPENSES

1. A summary of customer accounts expenses is shown below:

Staff	Utility	Utility Exceeds Staff Amount	Utility Exceeds Staff Percent
(Dollars in Thousands)			
$10,469.4	$11,259.6	$790.2	7.5%

General

2. The costs of customer accounts include the handling of customer inquiries, credit, collections, billing and bookkeeping data processing charges, postage, uncollectibles and supervision of these activities.

Cost History and Estimates

3. Costs per customer for the total of customer accounts, gas and electric are:

(1979$) Customer Accounts	Year 1975	1976	1977	1978	1979	1981
Staff Estimate	$13.33	$13.46	$12.78	$12.13	$11.91	$11.72
Utility Estimate	13.33	13.46	12.78	12.13	11.91	12.04

The decline in cost per customer is generally due to greater utilization of existing capacity.

Estimating Methods

4. All company estimates, with the exception of Postage and Uncollectibles, are based on the 12-month recorded cost as of December 31, 1979, increased by the ratio of average customers' forecasts for 1981 to those recorded for 1979. These amounts were then adjusted for a wage increase of 9.5% for 1980 and 13.5% for 1981. No increase was taken into consideration for non-labor costs, other than the growth in number of customers.

5. The staff analyzed the history of cost per customer from 1975 through 1979. The trend of adjusted costs per customer of most accounts is generally downward, due mostly to the spreading of fixed costs over the greater number of customers.

11 - CUSTOMER ACCOUNTS EXPENSES

Staff Analysis

6. In Ac. 901 (Supervision Expenses) the staff estimate is based on the history of the costs per customer. The decline in adjusted cost in the labor portion shows improvement in productivity. The staff expects the trend to continue and the 1981 test year estimate is adjusted for a wage increase.

7. Ac. 903.2 (Credit Management Expenses) includes the cost of establishing the company credit policy and collection of all monies owed the company. The promotion of better labor management has caused the decrease in cost.

8. Ac. 903.3 (Collections Expenses) includes investigation of customer's credit, originating requests for refunding, preparation of delinquent notices, final meter reading of delinquent accounts, disconnection of services because of unpaid bills and collection on past-due accounts. The staff observed a decline in labor cost per customer from 1975 to 1979 and based its estimate on this trend. The staff used a five-year average of costs per customer as a basis for its non-labor estimate.

9. Ac. 903.5 (Billing and Bookkeeping Expenses) includes file maintenance, manual review and calculation of certain bills, meter deposits, taxes and microfilming. The company failed to consider the importance of cost savings. The staff anticipated further savings as the costs per customer continue to decrease.

10. In Ac. 903.7 (Postage Expenses) the company's estimate allows for an increase from 13¢ to 18¢ for presort and from 15¢ to 20¢ for first class. The staff recommends that the increase in postal rate not be included until the general rate increase is approved by the Postal Rate Commission and the U.S. Congress. The impact of the staff's adjustment is a test year estimate of $961,400, which is $354,200 lower than the utility's estimate. The following is a schedule of postage increases and their impacts.

Presort Postage	Percent Increase	Total Account 903.7
13¢	0.00%	$ 961,400
14	7.69	1,035,400
15	15.38	1,109,300
16	23.08	1,183,300
17	30.08	1,257,200
18	38.46	1,331,200
19	46.15	1,405,100
20	53.85	1,479,100

11. Ac. 904 (Uncollectible Accounts Expenses) is an account charged with amounts sufficient to provide for losses from uncollectible utility revenues. The staff adopts the utility's percentage of loss of 0.150% for test year 1981. However, the staff disagreed with the utility's approach in calculating the uncollectible expenses. In the Electric Department, the staff removed miscellaneous and off-system sales revenues from total revenues in its calculation. In the Gas Department, interdepartmental and miscellaneous revenues were taken out.

12. Based on staff reviews of the history of the costs and expected operations of all other accounts, the company's estimate appears to be reasonable and is adopted for purposes of this proceeding.

TABLE 11-A

SDGE--ELECTRIC DEPT

CUSTOMER ACCOUNTS EXPENSES

ELECTRIC DEPARTMENT

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1	901.00	SUPERVISION	$ 190.2	$ 196.0	$ 5.8	3.0
2	902.00	METER READING	2061.5	2061.5	0.0	0.0
3		CUSTOMER RECORDS AND COL.				
4	903.10	CUSTOMER SERVICE	3073.0	3073.0	0.0	0.0
5	903.20	CREDIT MANAGEMENT	132.1	144.5	12.4	9.4
6	903.30	COLLECTIONS	974.2	1056.0	81.8	8.4
7	903.40	CUSTOMER PAYMENTS	628.0	628.0	0.0	0.0
8	903.50	BILLING & BOOKKEEPING	785.1	878.3	93.2	11.9
9	903.60	DATA PROCESSING	1330.3	1330.3	0.0	0.0
10	903.70	POSTAGE	961.4	1315.6	354.2	36.8
11		TOTAL CUSTOMER REC. AND COL	7884.1	8425.7	541.6	6.9
12	904.00	UNCOLLECTIBLE ACCT.	432.8	546.8	114.0	26.3
13	905.00	MISC. CUST. ACCT. EXP.	29.6	29.6	0.0	0.0
14		SUBTOTAL CUSTOMER ACCT	10598.2	11259.6	661.4	6.2
15		WAGE ADJ.	-128.8	0.0	128.8	-100.0
16		TOTAL CUSTOMER ACCT. EXP.	10469.4	11259.6	790.2	7.5

***** AT PROPOSED RATES *****

17	904.00	UNCOLLECTIBLE ACCT.	634.6	737.2	102.6	16.2
18		SUBTOTAL CUSTOMER ACCT	10800.0	11450.0	650.0	6.0

CHAPTER 12

MARKET SERVICE EXPENSES - ELECTRIC DEPARTMENT (CONSERVATION)

1. These expenses include activities which encourage conservation and load reduction. They are the supervision, labor and administrative (ancillary) expenses of central staff and field personnel. They plan to implement and monitor monitor the various programs. Also included are the expenses for advertising and related collateral material, such as bill stuffers, printing of pamphlets and publication and dissemination of various conservation related material.

2. The staff's Conservation Branch evaluated the reasonableness of SDG&E's programs. A separate report published the staff's conclusions, recommendations and adjustments.

3. Table 12-A is a comparison of the utility's and staff's test year 1981 expense estimates, by the uniform system standard account number.

4. A comparison of total expenses is:

Item	Test Year 1981 Staff	Test Year 1981 Utility
	(Dollar in Thousands)	
Total Expenses	$9,268.1	$14,802.0

5. In order that the Commission and interested parties can have a better understanding of how SDG&E's conservation estimates relate to other California utilities, the staff has prepared the following table.

COMPARISON OF 1981 TEST YEAR CONSERVATION
EXPENSES INCLUDING LOAD MANAGEMENT[1/]

	Gas			Electric		
	$/cust.	¢/therm	¢/therm over life-line	$/cust.	¢/kWh	¢/kWh over lifeline
So. Cal. Gas						
Staff	8.16	.34	.43			
Utility	10.08	.42	.53			
So. Cal Ed.						
Staff & Utility				12.12	.60	.71
SDG&E						
Staff	7.26	.47	.72	11.69	.85	1.08
Utility	8.70	.57	.86	18.66	1.36	1.73
PG&E[2/]	5.99	.23	.29	14.22	.78	.94

1/ All estimates are from the staff Results of Operation reports. To be on a comparative basis, staff customers and sales estimates were used.

2/ Test Year 1980 per Decision No. 91107.

6. The following table lists the utility's estimated advertising expenses which are included in the 1981 test year. In order to allocate between departments, both the staff and utility have assigned approximately 75% of the conservation expenses to electric and the remainder to gas. All load management expenses are assigned to the Electric Department.

1981 ESTIMATED ADVERTISING EXPENSE

		Conservation	Load Management	Total
(1)	Radio	367,000	13,000	380,000
(2)	Television	330,000	47,000	377,000
(3)	Newspaper	504,000	130,000	634,000
(4)	Pamphlets	1,780,500	15,000	1,795,500
(5)	Miscellaneous (includes marketing, response envelopes. trade journals, magazine, transit, outdoor billboards, agency fee, development, etc.)	517,000	26,000	543,000
(6)	Total	3,498,500	231,000	3,729,500

TABLE 12-A

SDGE--ELECTRIC DEPT

MARKETING EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1	907.00	SUPERVISION	$ 159.2	$ 186.8	$ 27.6	17.3
2	908.00	CUSTOMER ASSISTANCE	7952.1	12726.4	4774.3	60.0
3	909.00	INFO.INSTRU. EXP.	752.2	1484.2	732.0	97.3
4	910.00	MISC.CUST. SERV.	404.6	404.6	0.0	0.0
5		MARKETING EXPENSES	9268.1	14802.0	5533.9	59.7
6		WAGE ADJ.	0.0	0.0	0.0	0.0
7		TOTAL CUSTOMER SERV.EXP.ADJ	9268.1	14802.0	5533.9	59.7

CHAPTER 13

ADMINISTRATIVE AND GENERAL EXPENSES - ELECTRIC

1. The staff's estimate of the Electric Department's administrative and general expenses is the result of evaluation of many general office departments in the San Diego Gas & Electric Company. This evaluation included analysis of the trends of current departmental expenses and the engineering economics of customers and growth on administrative and general expenses.

2. The comparable figures for total electric administrative and general expenses excluding franchise for test year 1981 are as follows:

Item	Staff	Utility
	(Dollars in Thousands)	
Total A&G Expense	$36,369	$38,336

3. Table 13-A compares the total direct and indirect, as estimated by staff and utility, administrative and general expenses for the Electric Department. Both the staff and the utility have included wage increases in their estimates relative to the administrative and general expense labor items. Staff's treatment of the 1981 estimated wage increase is stated in Chapter 1 of this report. Specific areas of differences between the staff and the utility regarding the indirect allocated amounts to the Electric Department are covered in the staff's General Report, Chapter 2. Differences between the staff and the utility estimates of direct electric expenses are due to different estimating methods and specific adjustments as explained in the General Report, Chapter 2.

TABLE 13-A

SDGE--ELECTRIC DEPT

ADMINISTRATIVE AND GENERAL EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1		AT PRESENT RATES				
2	920.00	ADMIN. AND GEN. SALARIES	$ 12729.1	$ 12732.6	$ 3.5	0.0
3	921.00	OFFICE SUPPLIES & EXPENSES	7482.5	7482.8	0.3	0.0
4	922.00	A & G TRANS.- CREDIT	-9189.5	-8406.0	783.5	-8.5
5	923.00	OUTSIDE SERVICES EMPLOYED	1068.9	1068.9	0.0	0.0
6	924.00	PROPERTY INSURANCE	2172.4	2350.5	178.1	8.2
7	925.00	INJURIES & DAMAGES	1268.4	1273.0	4.6	0.4
8	926.00	EMPLOY. PENSION & BENEFITS	13574.0	13850.0	276.0	2.0
9	927.00	FRANCHISE REQUIREMENTS	5676.0	5414.0	-262.0	-4.6
10	928.00	REG. COMM. EXPENSES	324.2	324.2	0.0	0.0
11	929.00	DUPLICATE CHARGES-CREDIT	-1310.3	-1310.3	0.0	0.0
12	930.00	MISCELL GENERAL EXP	6501.2	6852.9	351.7	5.4
13	931.00	RENTS	827.2	890.1	62.9	7.6
14	932.00	MAINT. GEN. PLANT	1190.0	1227.3	37.3	3.1
15		SUB-TOTAL A&G EXP.	42314.1	43750.0	1435.9	3.4
16		WAGE ADJ.	-442.6	0.0	442.6	-100.0
17		A & G TOTAL AFTER WAGE ADJ.	41871.5	43750.0	1878.5	4.5
		***** AT PROPOSED RATES *****				
18	927.00	FRANCHISE REQUIREMENTS	8298.0	7883.0	-415.0	-5.0
19		SUB-TOTAL A&G EXP.	44936.1	46219.0	1282.9	2.9

CHAPTER 14

INCOME TAXES

Introduction

1. This section presents the staff's computation of income tax expense for rate-making purposes based upon the test year results of operations for San Diego Gas & Electric Company's Electric Department.

2. In OII-24, this Commission has under investigation the methods to be utilized in establishing the proper level of income tax expense for rate-making purposes; many of the tax issues inherent in this proceeding will be addressed in OII-24. To the extent such issues have been deferred to OII-24 in prior rate cases, they have not been included in this staff presentation.

3. The following paragraphs describe the various line items which constitute the adjustments used for determining taxable income and explain the differences between the company's and staff's estimates.

Interest on Long-Term Debt

4. In Decision No. 77975, dated November 24, 1970, in response to Southern California Gas Company's General Rate Application No. 51567, this Commission stated:

> "The staff's use of a year-end composite interest rate for combined short-term and long-term debt to determine test year interest deductions for the calculation of taxes based on income is consistent with rate of return studies which involve in effect applying year-end capital cost rates with weighted average capital during the test year, in view of the relationship of such capital to rate base and the fact that the revenue requirement on which rates are to be based is, in part, the product of a rate of return and a weighted average rate base. In concept, the staff approach tends to bring income taxes and rate of return, as elements of the total cost of service or revenue requirement, into synchronization."

5. In the current rate case, the staff's rate of return witness is recommending the usage of an average of the beginning and end-of-year capital structure and embedded debt costs. In conformity with the rationale stated in Decision No. 77975 of bringing income taxes and rate of return into

synchronization, the average embedded debt cost as recommended by the rate of return witness has been multiplied by the average debt outstanding to arrive at the interest deduction for income tax purposes.

6. The computed amount of interest expense has been apportioned by the staff between departments on the basis of each department's net plant balance to the total. The apportioned interest expense has then been reduced by the amount expected to be charged as AFUDC on construction work in progress in the test year.

Tax Basis Depreciation

7. The tax depreciation has been computed using the shortest lives and fastest methods allowed by the Internal Revenue Code and California Corporation Franchise Tax Law.

Removal Cost

8. Removal cost represents the current deduction of the costs of dismantling, demolishing or removing certain assets in the process of retirement. There is no difference between the staff and utility estimates.

Administrative and General Costs, Payroll Taxes, Pension and Benefits Capitalized

9. For income tax purposes, certain pension and benefit, and administrative and general costs, which are capitalized for rate-making purposes as a part of constructed plant, can be deducted currently. This adjustment recognizes the amount estimated to be capitalized in the test year. The staff figure is a summation of the staff payroll tax and pension and benefit witness' estimates of the amount of these expenses which will be capitalized for rate-making purposes.

The staff estimate is computed thusly:

Administrative and General	$3,486,900
Pension and Benefits	5,702,600
Capitalized Payroll Taxes	439,000
Total (Rounded)	9,629,000

Ad Valorem Tax Capitalized

10. That portion of ad valorem tax which is capitalized for rate-making purposes is claimed as a current year deduction for income tax purposes. This adjustment reflects the staff's ad valorem witness estimate of that amount exclusive of that related to SONGS II and III.

11. The staff recommends that the ad valorem tax on SONGS II and III, of $4,857,000, not be flowed through currently but capitalized net of the income tax benefit, as is presently done with the interest portion of AFUDC. This proposed treatment is consistant with that adopted in D-89316, issued September 6, 1978, in response to PG&E's general rate case A-57284.

Use Tax Capitalized

12. This adjustment recognizes the estimated amount of used tax to be incurred which will be capitalized for rate-fixing purposes but expensed for income tax purposes. There is no difference between staff and company estimates.

Contributions for Service Fees (Service Connection Fees)

13. Internal Revenue Code Section 118, as revised by the Revenue Act of 1978, excludes from taxable income all contributions in aid of construction, except service connection fees; the staff and company estimates of the amount taxable in the test year are the same.

Repair Allowance

14. The repair allowance is an annual election available to the taxpayer under Internal Revenue Service regulations. Under this election, certain expenditures for the repair, maintenance, rehabilitation or improvement of property that have been capitalized for book purposes may be treated as currently deductible repairs to the extent they do not exceed the repair allowance prescribed by the regulations. There is no difference between the staff and utility estimates.

Preferred Dividend Deduction

15. This is a special deduction for utilities and is deductible for federal tax purposes only. It is based on a certain percentage of preferred dividends paid on preferred stock issued prior to 1943. The company will be able to claim $594,000 in 1981, which the staff apportioned on the same basis as it did interest expense.

Fiscal/Calendar Adjustment of Ad Valorem Taxes

16. A utility may, for income tax purposes, deduct in the current year the full amount of ad valorem taxes due on property held as of March 1, despite the fact that one-half of the amount is not payable until the following year. For book and rate-making purposes, utilities record ad valorem taxes on a calendar year basis. The staff figure was developed from information provided by the staff ad valorem tax witness.

Research and Development Costs

17. Decision No. 91271, issued January 29, 1980, in response to Application No. 59280, authorized San Diego to treat as research, development and demonstration costs its share of the costs of the Heber geothermal project. It addressed possible income tax consequences of the decision thusly:

> "The additional income tax liability of SDG&E, due to the project, is estimated at $3 million based on capitalizing $24 million of construction cost for income tax purposes and utilizing 90 percent ITC. Neither the staff nor SDG&E has made a full analysis of the proper treatment of such tax expense and the record is inadequate to decide the issue at this time. We, therefore, direct this matter to be fully explored in SDG&E's next general rate case. At this time, SDG&E will be permitted to recover no more than actual construction and demonstration expenses on a dollar-for-follar basis with no additional allowance for potential tax liability related to the Heber project."

18. It is the staff's opinion that were the company to take an aggressive position with the IRS that most, if not all, of the Heber expenses could be deducted as incurred.

19. If the company does not pursue an aggressive position, or if the IRS is adamant that the plant costs must be capitalized, the company will recognize only a very slight increase in its test year income tax expense for the following reasons:

A. Under IRS regulation 1.174-2(b)(4), the company will capitalize only: "... the costs of the component materials of the depreciable property, the costs of labor or other elements involved in its construction and installation, or costs attributable to the acquisition or improvement of the property."

B. The company at the end of 1979 had a $14.7 million operating loss carry-over which can be used to offset future taxable income and $39.7 million of unused investment tax credits which can be used to offset 80% of the computed income tax for 1980 and 1981 and 90% for 1982.

20. For the foregoing reasons, the staff opposes any reimbursement for possible test year income tax liabilities related to the Heber geothermal project.

Investment Tax Credit (ITC)

21. The Commission, in D-90405, issued in response to A-58067, et al. on June 5, 1979, adopted the same treatment as it did in D-89857, wherein it said:

> "By Decision No. 89048 dated June 27, 1978, the Commission granted limited rehearing as to the issue of proper treatment of income taxes in Decision No. 88697 in Applications Nos. 55627, 55628, and 55629 to be consolidated with the hearings in Application No. 58067. Both the staff and SDG&E offered testimony and exhibits as to the appropriate method for calculating investment tax credits to be used for rate-making purposes. SDG&E's tax witness Miller testified that flow-through of Investment Tax Credit (ITC) earned under the 1971 Revenue Act at a rate greater than 50 percent violates IRS Code Sections 46f(2) and (8) and Temporary Regulation Section 9.1 thereby jeopardizing the additional investment tax credits available under the Tax Reduction Act of 1975.
>
> "The staff witness examined the IRS code provisions upon which SDG&E relied to support its position and did not agree that the language therein clearly and convincingly demonstrated the interpretation of law that SDG&E set forth. Accordingly, for the purposes of this decision, ITC will be limited to 50 percent of the tax liability plus the rateable flow-through of the excess ITC generated by the 1975 Tax Reduction Act. Income tax expense computed with this limitation will be made subject to refund pending final resolution of this issue."

22. On September 18, 1978, the company requested a ruling from the IRS, wherein it asked (among other things):

> "Whether the additional credit allowed by reason of the Tax Reduction Act of 1975 includes any additional credit allowable because of the increase in the limitation based on tax under Section 46(a)(7) (from 50% to, among other rates, 100% for 1976 and 70% for 1979). To avoid possible misunderstanding, your ruling is also requested on the increase in the amount of the credit under Section 46(a)(2)."1/

1/ Section 46(a)(2) increased the amount of credit from 7% to 10% (4% to 10% for public utilities); Section 46(a)(7) increased the amount of federal income tax which could be offset by the ITC from 50% to percentages which varied by year but which were greater than 50%.

23. On January 17, 1980, the IRS responded thusly:

> "The additional ITC allowed by reason of the 1975 Act (which under the Company's 1975 election of ratable flow-through must be accounted for in the manner described in Section 46(f)(2) of the Code) includes an amount of additional ITC earned for limited property, allowed by reason of the increase in the amount of ITC under Section 46(a)(2) and the increase in the limitation based on tax under Section 46(a)(7), that results from the computation described in Section 9.1(a)(3)(i) of the temporary regulations."

<u>ITC Currently Flowed Through</u>

24. The staff recommends flowing through the lesser of:

A. fifty percent of the estimated test year tax liability; or

B. the average amount of ITC not covered by San Diego's option II election which is expected to be generated in the test year and the year preceding, plus that portion of previous years' credit not covered by the company's option II election, but not flowed through, because of the previously discussed 50% limitation. (The staff's analysis of D-87639 and D-90405 indicates that all previous years' ITC not covered by the company's option II election has been previously flowed through in lower rates.)

<u>ITC Ratably Flowed Through</u>

25. IRS regulation 1.46-6(g)(2) explains how to compute the amount of ITC which is to be flowed through under the company's option II (ratable flow through) election. It says, in part:

> "What is 'ratable' is determined by considering the period of time actually used in computing the taxpayer's regulated depreciation expense for the property for which a credit is allowed. 'Regulated depreciation expense' is the depreciation expense for the property used by a regulatory body for purposes of establishing the taxpayer's cost of service for rate-making pruposes. Such period of time shall be expressed in units of years (or shorter periods), units of production, or machine hours and shall be determined in accordance with the individual useful life system or composite (or other group asset) account system actually used in computing the taxpayer's regulated depreciation expense."

The staff's interpretation of the phrase, ". . . actually used in computing the taxpayer's regulated depreciation expense", is that the company's option II ITC is to be flowed through over the rate-making service lines of every asset class which actually generates the credit. For example, if the company generates $1 million of credit from the installation of new gas distribution mains, which has a rate-making service life of 43 years, the company should flow through 1/43 of the credit in each of the 43 years.

26. The company contends that it does not generate the accounting information required to use this methodology. It proposes, instead, to flow through the credit over the average rate-making service lines of all properties put in service in each year.

27. The staff finds two faults with the company methodology:

A. Because of the lack of strict adherence to the IRS regulations, San Diego is, to a limited degree, risking its eligibility to claim the ITC covered by its option II election.

B. Because different classes of property have different rate-making service lines, the staff's (and IRS's) methodology achieves a balance between the ratepayers paying for the property (through depreciation expense) and the company's flowing through the related ITC. The company's methodology, however, flows through a levelized amount of ITC over the properties' average service lines.

28. The staff recommends that the Commission order the company to implement accounting proceedings which permit flowing through the company's option II ITC in accordance with the staff's, and IRS's methodology for plant placed in service in 1981 and years thereafter, and that the company's methodology be used for the option II ITC generated in years prior to 1981.

Graduated Rate Benefit

29. The "Graduated Rate Benefit" recognizes the fact that the first $100,000 of corporate taxable income is taxed at various step rates which are less than the 46% rate which is applicable to taxable income in excess of $100,000. The staff apportioned the "benefit" on the same basis as interest expense.

TABLE 14-A

SDGE--ELECTRIC DEPT

SUMMARY OF TAX EXPENSES

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1		AD VALOREM TAXES	$ 10893.0	$ 11709.0	$ 816.0	7.5
		OTHER TAXES				
2		FEDERAL INSURANCE ACT (FICA	2821.0	2821.0	0.0	0.0
3		FEDERAL UNEMPLOYMENT (FUI)	85.0	85.0	0.0	0.0
4		CALIF UNEMPLOYMENT (SUI)	340.0	340.0	0.0	0.0
5		MISCELLANEOUS	2.0	2.0	0.0	0.0
6		WAGE ADJ	0.0	0.0	0.0	0.0
7		SUBTOTAL	3248.0	3248.0	0.0	0.0
8		TOTAL NON-INCOME TAXES	14141.0	14957.0	816.0	5.8
		AT PRESENT RATES				
9		CALIF CORP FRANCHISE TAX	532.4	2180.0	1647.6	309.5
10		FEDERAL CORP INCOME TAX	-633.2	9055.0	9688.2	-1530.0
11		SUBTOTAL-INCOME TAXES	-100.8	11235.0	11335.8	*******
12		TOTAL TAXES AT PRES RATES	14040.2	26192.0	12151.8	86.6
		AT PROPOSED RATES				
13		CALIF CORP FRANCHISE TAX	13172.2	9386.0	-3786.2	-28.7
14		FEDERAL CORP INCOME TAX	51354.2	35941.0	-15413.2	-30.0
15		SUBTOTAL-INCOME TAXES	64526.4	45327.0	-19199.4	-29.8
16		TOTAL TAXES AT PROP. RATES	78667.4	60284.0	-18383.4	-23.4

TABLE 14-B

SDGE--ELECTRIC DEPT

TAXES BASED ON INCOME

TEST YEAR 1981

LN NO.	ITEM	PRESENT RATES CCFT (A)	PRESENT RATES FIT (B)	UTILITY PROPOSED RATES CCFT (C)	UTILITY PROPOSED RATES FIT (D)
		(THOUSANDS OF DOLLARS)			
1	OPERATING REVENUES	$ 296647.3	$ 296647.3	$ 431135.6	431135.6
2	O + M EXPENSES	142894.7	142894.7	145718.5	145718.5
3	TAXES OTHER THAN INCOME	14141.0	14141.0	14141.0	14141.0
4	CCFT	0.0	532.4	0.0	13172.2
5	SUBTOTAL	157035.7	157568.1	159859.5	173031.7
6	DEDUCTIONS FROM TAXABLE INCOME				
7	TAX DEPRECIATION	51712.0	55700.0	51712.0	55700.0
8	INTEREST CHARGES	55977.0	55977.0	55977.0	55977.0
9	BENEFITS CAPITALIZED	9629.0	9629.0	9629.0	9629.0
10	AD-VALOREM TAXES	329.0	329.0	329.0	329.0
11	REMOVAL COST	3951.0	3951.0	3951.0	3951.0
12	REPAIR ALLOWANCE	6097.0	6097.0	6097.0	6097.0
13	PREFERRED DIV CREDIT	0.0	530.0	0.0	530.0
14	USE TAX	1125.0	1125.0	1125.0	1125.0
15	NUCLEAR FUEL	4655.0	4655.0	4655.0	4655.0
16	TAXABLE CIAC	-480.0	-480.0	-480.0	-480.0
17	RESEARCH & DEV COST	0.0	0.0	0.0	0.0
18	FISCAL/CALENDAR ADJ.	703.0	703.0	703.0	703.0
19	OTHER DEDUCTIONS	368.0	368.0	368.0	368.0
20	SUBTOTAL DEDUCTIONS	134066.0	138584.0	134066.0	138584.0
21	NET TAXABLE INCOME FOR CCFT	5545.6		137210.1	
22	CCFT	532.4		13172.2	
23	TOTAL CCFT	532.4		13172.2	
24	NET TAXABLE INCOME FOR FIT		495.2		119519.9
25	FEDERAL INCOME TAX		227.8		54979.2
26	DEFERRED TAXES-DEPR.		-58.0		-58.0
27	GRADUATED RATE BENEFIT		-17.0		-17.0
28	ITC NORMALIZED		-786.0		-786.0
29	FED INCOME TAX BEFORE ADJ.		-633.2		54118.2
30	ITC FLOWTHROUGH		0.0		-2764.0
31	TOTAL FIT		-633.2		51354.2

TABLE 14-C

SDGE--ELECTRIC DEPT

DEDUCTIONS FOR TAX CALCULATIONS

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
			(THOUSANDS OF DOLLARS)			
		TAX DEPRECIATION				
1		STATE	$ 51712.0	$ 52217.0	$ 505.0	1.0
2		FEDERAL	55700.0	55807.0	107.0	0.2
3		INTEREST CHARGES	55977.0	54547.0	-1430.0	-2.6
4		BENEFITS CAPITALIZED	9629.0	7448.0	-2181.0	-22.7
5		AD-VALOREM TAXES	329.0	3703.0	3374.0	1025.5
6		REMOVAL COST	3951.0	3951.0	0.0	0.0
7		REPAIR ALLOWANCE	6097.0	6097.0	0.0	0.0
8		PREFERRED DIV CREDIT	530.0	319.0	-211.0	-39.8
9		USE TAX	1125.0	1125.0	0.0	0.0
10		NUCLEAR FUEL	4655.0	4655.0	0.0	0.0
11		TAXABLE CIAC	-480.0	-480.0	0.0	0.0
12		RESEARCH & DEVELOPMENT	0.0	-6777.0	-6777.0	0.0
13		FISCAL/CALENDAR ADJ.	703.0	0.0	-703.0	-100.0
14		OTHER DEDUCTIONS	368.0	368.0	0.0	0.0
		INVESTMENT TAX CREDIT				
15		FLOWTHROUGH	-2764.0	-2764.0	0.0	0.0
16		NORMALIZED	-786.0	-98.0	688.0	-87.5
17		DEFERRED TAXES-DEPR.	-58.0	-58.0	0.0	0.0
18		GRADUATED RATE BENEFIT	-17.0	0.0	17.0	-100.0

CHAPTER 15

ELECTRIC PLANT

1. This chapter contains the development of the staff estimates of total weighted average electric plant for San Diego Gas and Electric Company for test year 1981. Tables 15-A and 15-B compare the staff and utility electric plant estimates for test year 1981. A summarization of the total weighted average plant as estimated by the staff and utility is as follows:

Test Year 1981

Table 15-B

(Dollars in Thousands)

	Staff	Utility
Electric Plant	$1,255,381	$1,260,082

2. The staff estimates are based on the results of field inspections of the utility's facilities, discussions with utility personnel responsible for construction budgets for the year 1980 and 1981.

3. The staff's estimates of plant in service reflect the recorded plant in service at the beginning of year 1980, the staff's estimated plant additions for year 1980, and the staff's weighted average plant additions for test year 1981.

4. Utility's electric plant includes: electric production, electric transmission and electric distribution facilities. The major additions were in the area of transmission and distribution.

5. Much of the expenditures are due to, compliance with regulations for safe operation, additions to existing facilities to accommodate growth, and promote efficient operation. Other significant additions are due to blanket projects.

6. Staff reviewed the additions and gave consideration to past expenditure levels and future requirements and concluded that the utility's estimates, except for the following differences, are reasonable.

7. Staff excluded $1,000,000 for estimated year 1980, which was intended for San Onofre I seismic study, but was rescheduled to a completion date of December 30, 1982 (Table 15-A).

8. Staff is lower than the utility by $3,965,000 (Table 15-B), for estimated year 1981 and is the result of the weighted average net plant additions in rate base.

9. Retirement differences are the result of the adoption of different plant additions by the staff and the utility.

Overhead to Underground Conversion

10. Rule 20.A and the franchise of the City of San Diego requires, systematically, the undergrounding of overhead electric facilities. Through the years the utility has accumulated unspent amounts due to underspending the Commission in rates authorized amounts. The primary causes for the utility's failure to expend the authorized amounts for the projects were delays by the City of San Diego in converting street lights, attached to power poles, to free standing units and delays for approval in related street improvements projects, which receive funding from the State and the Federal Government.

11. The utility's budgeted estimates, as filed with the Commission, for 1980 and 1981 reflect amounts based on a previous adopted formula, which is a requirement of the franchise with the City of San Diego. This formula is causing a rapid growth in the allocation of funds for undergrounding. As a result, the utility has approached the City of San Diego for another formula. Pending approval, the 1980 allocation was set at about the 1979 authorized level and the 1981 submitted budget is set at $11,548,000, which is based on city plans as known by the utility.

12. Included in both years' estimates are $1,600,000 per year for conversion of city-owned street lights from mercury vapor to more efficient high pressure sodium.

Table 15-A

SAN DIEGO GAS & ELECTRIC COMPANY

Electric Plant 1980

1981 Test Year

Line No.	Item	Staff	Utility	Utility Exceeds Staff Amount	Utility Exceeds Staff Percent
		(a)	(b)	(c)	(d)
		(Dollars in Thousands)			
1	January 1, 1980	$1,023,666	$1,023,666	$ -	- %
2	Additions	108,467	109,467	1,000	0.9 %
3	Retirements	6,480	6,540	(60)	-
4	Adjustments (R.F.S. Auto's, P.O.E. Transfers, etc.)	5,299	5,299	-	-
5	December 31, 1980	$1,130,952	$1,131,892	$ 940	0.1 %
6	Common Plant Allocation	$ 21,423	$ 21,423	$ -	- %
7	Total 1980 Plant	$1,152,375	$1,153,315	$ 940	0.1 %

Table 15-B

SAN DIEGO GAS & ELECTRIC COMPANY

Electric Plant (1981)

1981 Test Year

Line No.	Item	Staff	Utility	Utility Exceeds Staff Amount	Utility Exceeds Staff Percent
		(a)	(b)	(c)	(d)
		(Dollars in Thousands)			
1	January 1, 1981	$1,130,961	$1,131,901	$ 940	0.1%
2	Additions	106,475	110,440	3,965	3.7
3	Retirements	5,463	5,667	204	3.7
4	Adjustments (R.F.S. Auto's, P.O.E. Transfers, etc.)	53	53	-	-
5	December 31, 1981	$1,232,026	$1,236,727	$4,701	0.4%
6	Common Plant Allocation	$ 23,355	$ 23,355	$ -	- %
7	Total 1981 Plant	$1,255,381	$1,260,082	$4,701	0.4%

CHAPTER 16

DEPRECIATION EXPENSE AND RESERVE

1. The staff offers no objection to the depreciation rates used by San Diego Gas & Electric Company for its Electric Department. The differences between staff and utility for the estimates of depreciation expense and reserve for electric plant are explained by the lower plant estimates made by the staff in Chapter 15.

2. The staff has reviewed the utility's estimate for decommisioning its share of San Onofre Nuclear Generating Station No. 1. The staff addressed the issue of whether the recovery of decommissioning costs should be retained by the utility in Southern California Edison's rate case (A-59351).

3. No additional information has been forthcoming to dissuade the staff from its conclusion in the Edison rate case that estimated decommissioning costs should be recovered in the depreciation expense.

4. The staff, therefore, has the following recommendations:

1. The accumulation of the estimated net decommissioning costs should be recovered through the depreciation rates and retained by the utility, and should not be held in a separate escrow account.

2. SDG&E should file, with its next general rate application, an exhibit assessing any changes in the cost of decommissioning and its impact on the financial integrity of the company. Such an exhibit should also be filed for any rate base offset procedure for San Onofre Nuclear Generating Station Units 2 and 3.

TABLE 16-A

SDGE--ELECTRIC DEPT

DEPRECIATION AND AMORTIZATION EXPENSE

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
			(THOUSANDS OF DOLLARS)			
1		DEPRECIATION EXPENSE	$ 49950.0	$ 50076.0	$ 126.0	0.3
2		TOTAL DEPRECIATION EXPENSE	49950.0	50076.0	126.0	0.3

CHAPTER 17

RATE BASE

1. This chapter contains the development of the staff's estimate of the total weighted average rate base of SDG&E's for test year 1981. The following tabulation compares the staff and utility test year 1981 rate base as shown in Table 17-A.

Test Year 1981

Item	Staff	Utility
	(Dollars in Thousands)	
Electric Rate Base	$1,055,401	$1,129,302

Weighted Average Utility Plant

2. Weighted average utility plant is developed in Chapter 15 and carried forward.

Nuclear Fuel

3. The nuclear fuel represents the nuclear fuel owned by the utility. The utility switched from direct ownership to lease arrangement; therefore, no addition to nuclear fuel is anticipated.

Plant in Service

4. Staff is lower than the utility by $1,126,000 of which $940,000 is discussed in Chapter 15 and $186,000 reflects the difference in amounts of the application and the utility's submitted workpapers.

Plant Held for Future Use

5. Staff is lower than the utility by $9,618,900. Part of the amount above is due to the difference of Commission authorized cancelled Sundesert site related costs as reflected in Decision No. 90405, and the utility's submitted amount in plant held for future use, which differenced to $367,900.

6. The other part of the amount which totalled $9,251,000 is due to the staff's deletion of the two South Bay gas turbines originally purchased to be installed in 1974 at the utility's South Bay facility to provide 128 MW of peaking capacity. For various reasons, this initial project was cancelled and for the test year 1976 rate case the company had deferred the project to the year 1979. The staff learned that during 1979, the company attempted to sell the gas turbines, but withdrew apparently when the sale price was too low.

Presently, there is no definite and specific engineering plans available for the application of the gas turbines. The company has attempted to identify possible uses for the two gas turbines in 11 uncertain future projects. Since the gas turbines do not provide useful service to customers and presently no definite and specific engineering application with a target date is available, the staff has excluded them from rate base. The staff auditors have likewise taken exception to this item. An explanation of how this relates to Account 105 is contained in the staff's Results of Examination report.

New Plant Additions

7. Staff's estimate is lower than the utility's by $1,902,000. The staff's weighted average net plant additions for the test year was arrived at by applying a weighting factor of 4.43% to the plant-in-service amount. This weighting factor is based on the 5 years average of the annual recorded, 13 months, weighted average additions. This is in accordance to procedures adopted in Decision No. 83746 (dated November 26, 1974). The utility also used 13 months weighting method based on uncertain future estimated dates of plant additions to go on line in a particular month.

Customer Advances for Construction

8. The customer advances for construction is an advance of construction fund pursuant to the rules set forth in tariff schedules. The amount advanced is deducted from rate base for it represents funds provided from the customers. The staff's estimate of customers advances for construction is higher than the utility's by $919,000 and is arrived at by the same methodology as applied by the utility, except the staff had access to 1979 recorded data as opposed to the utility's 1979 estimated data.

Fuel in Storage

9. Staff's estimate is lower than the utility's estimate by $33,424,000 for test year 1981. Both the staff and utility used the same 13-month weighted average methodology in arriving at the estimated amount. Both staff's and utility's number include $11,185,000 for Nuclear Fuel. The staff adopted the following utility's estimated quantities in its computation for fuel in storage for test year 1981; Monthly Residual and Distillate fuel quantity purchases from Hawaiian Independent Refinery Incorporated (HIRI), Tesora Alaska Petroleum Company (TESORO) and Chevron U.S.A., Inc. (CHEVRON), including Exchanges, Displacement Oil and Payback, Monthly total burn requirements for residual oil for Encino and South Bay plants and distillate fuel for Silver Gate , Station B , Gas Turbine plants and steam heat department; Monthly Residual Oil and Distillate fuel handling costs; Method of computing the moving average costs; Monthly estimate of fuel costs.

10. Staff reviewed the adopted quantities above for the estimated and test year, compared them with past recorded amounts and future projected requirements from currently available information, and concluded that these amounts are reasonable.

11. The staff adopted as being reasonable, after review of past recorded fuel deliveries, fuel burns, fuel in storage, supplier's contractual obligations, the utility's 1979 recorded monthly Day Burn average of 65 as the amount of fuel in storage for residual fuel, and which was arrived at in the following manner.

$$\frac{\text{1979 Recorded Annual Fuel in Storage}}{\text{1979 Recorded Annual Fuel Burned}} \times \frac{365}{12} = \text{Day Burn}$$

$$\frac{22,478,000}{10,571,000} \times \frac{365}{12} = 64.7 \text{ Day Burn}$$ (Utility's 1979 recorded)

12. The staff adopted as being reasonable, after review of past recorded day burns for distillate fuel, a monthly average Day Burn of 200, as the amount of fuel in storage and which was arrived at in a similar manner as residual fuel. Distillate fuel is used in part by the utility for standby units at Silver Gate and Station B, and for peaking gas turbine units at Kearney and other. Since the amount of distillate fuel burned by these units, for the 1981 test year is of smaller magnitude as compared to some recorded amounts in the past, a prolonged peaking requirement as longer than anticipated standby unit operation, may well exceed the required amount of 65 Day Burn as recommended for residual fuel. The utility has requested the following estimated residual fuel monthly average Day Burn:

$$\frac{\text{1981 Estimated Annual Fuel in Storage}}{\text{1981 Estimated Annual Fuel Burned}} \times \frac{365}{12} = \text{Day Burn}$$

$$\frac{32,412,000}{11,729,000} \times \frac{365}{12} = 84 \text{ Day Burn}$$

and for distillate fuel the following estimated monthly average Day Burn:

$$\frac{5,689,500}{265,200} \times \frac{365}{12} = 652.5 \text{ Day Burn}$$

13. The utility has current contracts with oil suppliers running well through the year 1982. Oil deliveries are scheduled monthly with SDG&E to specify the oil quantity and date of delivery. SDG&E's oil suppliers indicated favorable oil availability through 1982. Recorded monthly oil deliveries have indicated a steady pattern.

14. Applicant states that Decision No. 90405 authorized a 45-day fuel oil inventory in rate base. Staff found that fuel in storage for test year 1979, of the previous rate case, was not an issue. The staff witness for test year 1979, adopted the utility's amount.

15. Applicant also states that the average inventory level for 1981 is projected at 3,000,000 barrels, which represents a 70-day inventory or burn. Staff observed that if 3,000,000 barrels reflect a 70-day burn, then the following average monthly burn will apply:

$$\frac{3{,}000{,}000}{\text{Average Monthly Burn}} \times \frac{365}{12} = \text{70-day burn}$$

$$\text{Average Monthly Burn:} \quad \frac{3{,}000{,}000 \times 365}{12 \times 70} = 1{,}303{,}571 \text{ Bbls}$$

Annually this corresponds to: 12 x 1,303,571 = 15,642,857 Bbls

Applicant's request reflects the following annual burn for test year 1981.

Residual Oil:	11,729,000 Bbls Burn/Annual
Distillate Fuel:	265,200 Bbls Burn/Annual
	11,994,200 Bbls Burn/Annual
Gas Equiv. Burn :	3,668,000 Bbls Burn/Annual
Total Burn: (Resid. + Distil. + Gas)	15,662,200 Bbls Burn/Annual

16. From the foregoing it is apparent that applicant in its computation of the fuel in inventory day burn, has completely disregarded the availability of gas as a partial source of energy.

17. Exhibit No. 3, in Application No. 55780, SDG&E's witness, Gregory L. Nesbitt, prepared direct testimony, dated February 27, 1978, states the following regarding SDG&E's minimum inventory requirement on page 9, question 15, answer 15.

> "SDG&E's minimum inventory requirements must be maintained at between 0.8 and 1.2 mmbbls, depending upon the time of year. Historically, high fuel oil burn rates occur during the summer and winter months. It is at these times that minimum inventory requirement is highest. Independent of the time of year, the company must maintain this range as a 30-day minimum fuel oil supply to protect against delays in deliveries, refinery strikes or other supply disruption."

18. The following table shows the weighted costs for Fuel in Inventory and other pertinent specifics for the recorded years 1977 through 1979 and Test Year 1981.

Fuel in thousands of Barrels
Dollars in thousands

	1977	1978	1979	1981 Test Year Staff	1981 Test Year Utility
Average Monthly Fuel in Inventory					
Residual	2,436.3	2,923.5	1,873.3	2,088.9	2,701.0
Distillate	479.5	393.0	415.9	145.3	474.1
Total	2,915.8	3,316.5	2,289.2	2,234.2	3,175.1
Weighted Average Cost of Fuels in Inventory	$59,257.5	$71,659.4	$58,665.0	$108,105.0	$141,529.0
Average Monthly Fuel Burned					
Residual	973.5	823.4	880.9	977.5	977.5
Distillate	78.9	77.6	23.8	22.1	22.1
Total	1,052.4	901.0	904.7	999.6	9[illegible].6

Working Cash Allowance

19. An allowance for working cash is included in rate base in order that the investors may be compensated for monies they have supplied over and above the investments in properties. The allowance is based on the average lag in collection of revenues and payment of expenses, as well as maintaining minimum bank balances, working funds, and certain deferred debits and credits.

20. The main difference between the staff and utility is due to differences in various lag days. The staff has increased the lag days for fuel oil, federal income tax, state corporate franchise tax, and reduced lag days for revenues and benefits.

21. The utility used zero lag days for fuel oil. This is not proper because there are 22.06 days of lag between the delivery of fuel oil and actual payment for the delivery of fuel oil. The staff used a lag of 22.06 days for fuel oil.

22. The utility arrived at the revenue lag days based on average daily accounts receivables by the amount of average daily collections. Since the average daily accounts receivables include potential uncollectible accounts receivables, it, therefore, overstates revenue lag days. In order to offset such overstated revenue lag, the staff reduced the accounts receivables by the amount of average uncollectible accounts receivables included in the accounts receivables resulting in a reduction of 0.21 days. Uncollectible expenses are excluded from lead-lag study. Uncollectibles is an accounting entry for unrealized revenues and it is not a cash expense item. The staff also increased the federal and state income tax lag days to 103.65 compared to the utility's lag days of 81.60 days, giving the effect of paying 80% of tax liabilities by the end of the year and an IRS revenue ruling allowing the utility to deduct 100% of property tax from the first quarterly tax liability.

23. The staff also increased the lag days of benefits to -2.60 days based on detailed expense lag-day study. The utility arbitrarily used zero lag days. Remaining differences are due to different staff's expense estimates and income taxes and franchise requirements are computed on a 10.59% rate of return.

TABLE 17-A

SDGE--ELECTRIC DEPT

WEIGHTED AVERAGE DEPRECIATED RATE BASE

TEST YEAR 1981

LN NO	ACCT. NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	PCT (D)
			(THOUSANDS OF DOLLARS)			
1		BEG.BALANCE-FIXED CAPITAL				
2		PLANT IN SERVICE	$ 1152375	$ 1153501	$ 1126	0.1
3		PLANT HELD FOR FUT USE	49478	59097	9619	19.4
4		RESEARCH AND DEV.	2060	4121	2061	100.0
5		SUBTOTAL	1203913	1216719	12806	1.1
6		NET PLANT ADDITIONS	51050	52952	1902	3.7
7		TOTAL FIXED CAPITAL	1254963	1269671	14708	1.2
8		CUST ADVANCE FOR CONST	-20620	-19701	919	-4.5
9		WORKING CAPITAL				
10		FUEL STORAGE	108105	141529	33424	30.9
11		MATERIALS & SUPPLIES	19392	19392	0	0.0
12		WORKING CASH	37078	61904	24826	67.0
13		TOTAL WORKING CAPITAL	164575	222825	58250	35.4
14		TOTAL BEFORE RESERVES	1398918	1472795	73877	5.3
15		RESERVES				
16		DEFERRED INCOME TAXES	401	401	0	0.0
17		DEPRECIATION	330065	330041	-24	0.0
18		AMORIZATION & OTHER	13051	13051	0	0.0
19		TOTAL RESERVES	343517	343493	-24	0.0
20		TOTAL RATE BASE	1055401	1129302	73901	7.0

TABLE 17-B
(Sheet 1 of 2)

San Diego Gas & Electric Company
Electric Department

WORKING CASH ALLOWANCE STUDY

Year 1981 Estimated

Line No.	Item	Electric Department (A) (Dollars in Thousands)
	Operational Cash Requirements	
1	Compensating Minimum Bank Balances	$ 5,086
2	Special Deposits and Working Funds	70
3	Miscellaneous Receivables	2,260
4	Prepayments	1,315
5	Deferred Debits	3,794
6	Total Operational Cash Requirements	12,525
	Deductions for the Amounts Not Supplied by Investors	
7	Accrued Vacations, Sick Leave and Withholdings	4,430
8	Accounts Payables	5,890
9	User Taxes	216
10	Customer Deposits	4,110
11	Total Deductions	14,646
12	Average Amount Needed as a Result of Paying Expenses, Taxes and Depreciation in Advance of Collecting Revenues	39,885
13	Total Working Cash Allowance	37,764

TABLE 17-B
(Sheet 2 of 2)
SDGE--ELECTRIC DEPT

DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES

	$ 1000 A	AVG DAY LAG B	$ 1000 C=A X B
FEDERAL INCOME TAX	$ 12635.20	103.65	$ 1309638.00
STATE INCOME TAX	4233.60	103.65	438812.70
FRANCHISE REQUIREMENTS	6460.40	159.81	1032437.00
FUEL OIL	504088.00	22.06	11120180.00
PURCHASED GAS	101233.00	37.82	3828632.00
NUCLEAR FUEL	4020.00	0.00	0.00
COMPANY LABOR	48802.00	12.77	623201.50
PURCHASED POWER	60864.00	31.34	1907478.00
GOODS & SERVICES	62865.00	29.91	1880292.00
EMPLOYEE BENEFITS	8416.00	-2.60	-21881.60
MISC. TAX	2.00	0.00	0.00
FEDERAL UNEMPLOYMENT TAX	85.00	72.04	6123.40
FICA TAX	2821.00	7.59	21411.39
AD VAL	10893.00	43.01	468507.90
DEPRECIATION	49950.00	0.00	0.00
MATERIALS FROM STOREROOM	1563.00	0.00	0.00
STATE UNEMPLOYMENT TAX	340.00	72.04	24493.60
ENCINA 5 LEASE EXPENSES	9302.00	92.[illegible]	860435.00
MISC. RES.	3441.00	0.00	0.00
TOTAL	892014.20		23499770.00

EXP LAG DAYS= C/A = 26.34

REVENUE LAG DAYS = 42.38

ADJUSTMENT TO RATE BASE 39199.74

NEW RATE BASE= 1012202.0 + 39199.7= 1051402.0

CHAPTER 18

SUMMARY OF EARNINGS

1. The revenues, expenses, taxes and depreciation expenses developed in the preceding chapters of this report for San Diego Gas & Electric Company, Electric Department, are brought together here in order to develop the net revenues and to determine the rate of return based on present rates and also at proposed rates.

2. In Tables 18-A and 18-B are shown comparisons of staff and utility summary of earnings for the 1981 test year estimated at present and utility proposed base rates, respectively. The utility showing is from its original application filed July 1, 1980.

3. A summary of the principal assumptions and rate-fixing adjustments reflected in the staff estimates is as follows:

A. The staff's revenues are based on higher estimated sales resulted in a $21,563,000 difference at proposed rates.

B. The major differences in production expenses are due to environmental expenses and fuel related expenses associated with Department of Water Resources sales (DWR). The staff's environmental expense estimates reflect five-year amortizations of expected expenses, and are lower than the utility by $516,200. The staff's exclusion of $10,900,000 for DWR expenses reflects the staff's position in OII-56.

C. The major difference in transmission expenses is due to the exclusion by the staff of $1,512,800 for wheeling charges. This is based upon the staff's recommendations in OII-56.

D. ACC. 588 (Miscellaneous Distribution Expenses) - Due to more recent data on the DFIS program and different estimating methods, the staff's estimate was $1,162,200 lower than the utility's.

E. ACC. 593 (Overhead Lines Expenses) - Staff disallowed $400,000 requested for additional tree trimming.

F. ACC 594 (Underground Lines Expenses) - The staff's estimated rate of growth for this account was lower than the utility's and resulted in a $401,900 adjustment.

G. ACC. 903.7 (Postage Expenses) - Staff did not include postal rate increase for 1981. Staff's estimate is $961,400, $354,200 lower than utility's.

H. The staff has made a $5,533,900 adjustment in SDG&E's conservation estimates. Details of this adjustment are shown in the conservation report.

I. Staff's ad valorem taxes are approximately $816,000 lower than the utility's. This difference is primarily due to the method used to allocate total company ad valorem taxes between operative plant and CWIP.

J. The staff's estimate of income taxes follows the Commission's policy as expressed in previous decisions. Major differences result from the deductions for capitalized benefits and R&D as it relates to Heber.

K. The staff adjusted rate base by $33,424,000 as a result of using a 65-day burn for fuel storage as compared to the Utility's 84-day burn.

L. A wage adjustment of $1,240,400 was made by the staff. This amount reflects the difference between a 13.5% and 11.0% wage increase.

Net-to-Gross Multiplier

4. The net-to-gross multiplier for the test year 1981, which is the ratio of the gross revenue required to produce a unit change in net revenue,

is 2.092 for sales to electric customers. This means that an increase of $2,092 in gross revenue is required to produce an increase of $1,000 in net revenue. The net-to-gross multiplier is developed as follows:

Gross Operating Revenue	100.0000
Less: Uncollectibles at 0.15%	0.15
Subtotal	99.8500
Less: Franchise Requirements at 1.95%	1.947
Subtotal	97.9030
State Income Tax at 9.6%	9.3987
Subtotal	88.5043
Federal Income Tax at 46%	40.7120
Remainder	47.7923
Net-to-Gross Multiplier (Gross Revenue Divided by Remainder)	2.0924

T A B L E 18-A

SDGE--ELECTRIC DEPT

SUMMARY OF EARNINGS

TEST YEAR 1981 AT PRESENT RATES

LN NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
		(THOUSANDS OF DOLLARS)			
1	OPERATING REVENUES				
2	REVENUES	$ 296647.3	$ 282943.0	$ -13704.3	-4.6
3	TOTAL OPERATING REVENUES	296647.3	282943.0	-13704.3	-4.6
4	OPERATING EXPENSES				
5	PRODUCTION EXPENSE	52290.7	63764.7	11474.0	21.9
6	TRANSMISSION EXP.	6793.2	8648.7	1855.5	27.3
7	DISTRIBUTION EXPENSES	22870.6	25101.3	2230.7	9.8
8	CUSTOMER ACCT.	10598.2	11259.6	661.4	6.2
9	MARKETING EXPENSES	9268.1	14802.0	5533.9	59.7
10	ADMIN. & GENER. EXP	42314.1	43750.0	1435.9	3.4
11	SUBTOTAL	144134.9	167326.3	23191.4	16.1
12	WAGE ADJ.	-1240.2	0.0	1240.2	-100.0
13	SUBTOTAL AFTER WAGE ADJ.	142894.7	167326.3	24431.6	17.1
14	DEP AND AMORT	49950.0	50076.0	126.0	0.3
15	TAXES OTHER THAN INCOME	14141.0	14957.0	816.0	5.8
16	CALIF CORP FRANCHISE TAX	532.4	2180.0	1647.6	309.5
17	FED CORP INCOME TAX	-633.2	9055.0	9688.2	-1530.0
18	TOTAL OPERATING EXPENSES	206884.9	243594.3	36709.4	17.7
19	NET OPERATING REVENUES ADJUSTD	89762.4	39348.7	-50413.7	-56.2
20	RATE BASE	1055401.0	1129302.0	73901.0	7.0
21	RATE OF RETURN	8.51%	3.48%	-5.03%	

TABLE 18-B

SDGE--ELECTRIC DEPT

SUMMARY OF EARNINGS

PROPOSED RATES-TEST YEAR 1981

LN NO	ITEM	STAFF (A)	UTILITY (B)	UTIL. EXCEEDS STAFF AMOUNT (C)	UTIL. EXCEEDS STAFF PCT (D)
		(THOUSANDS OF DOLLARS)			
1	OPERATING REVENUES				
2	REVENUES	$ 431135.6	$ 409573.0	$ -21562.6	-5.0
3	TOTAL OPERATING REVENUES	431135.6	409573.0	-21562.6	-5.0
4	OPERATING EXPENSES				
5	PRODUCTION EXPENSE	52290.7	63764.7	11474.0	21.9
6	TRANSMISSION EXP.	6793.2	8648.7	1855.5	27.3
7	DISTRIBUTION EXPENSES	22870.6	25101.3	2230.7	9.8
8	CUSTOMER ACCT.	10800.0	11450.0	650.0	6.0
9	MARKETING EXPENSES	9268.1	14802.0	5533.9	59.7
10	ADMIN. & GENER. EXP	44936.1	46219.0	1282.9	2.9
11	SUBTOTAL	146958.7	169985.7	23027.0	15.7
12	WAGE ADJ.	-1240.2	0.0	1240.2	-100.0
13	SUBTOTAL AFTER WAGE ADJ.	145718.5	169985.7	24267.2	16.7
14	DEP AND AMORT	49950.0	50076.0	126.0	0.3
15	TAXES OTHER THAN INCOME	14141.0	14957.0	816.0	5.8
16	CALIF CORP FRANCHISE TAX	13172.2	9386.0	-3786.2	-28.7
17	FED CORP INCOME TAX	51354.2	35941.0	-15413.2	-30.0
18	TOTAL OPERATING EXPENSES	274335.9	280345.7	6009.8	2.2
19	NET OPERATING REVENUES ADJUSTD	156799.7	129227.3	-27572.4	-17.6
20	RATE BASE	1055401.0	1129302.0	73901.0	7.0
21	RATE OF RETURN	14.86%	11.44%	-3.42%	

CHAPTER 19

JURISDICTIONAL COST ALLOCATION

1. The purpose of this chapter is to segregate San Diego Gas & Electric Company's electric revenues and to allocate electric expenses and rate base items between those subject to the jurisdiction of the California Public Utilities Commission and those subject to the jurisdiction of other regulatory agencies.

2. The United States Supreme Court, by unanimous decision of March 2, 1964, reported in 376 US 205, held that the Federal Power Commission had jurisdiction over all sales of electric energy at wholesale in interstate commerce not expressly exempted by the Federal Power Act itself. This decision necessitated the jurisdictional cost allocation analysis.

3. Costs associated with the operation of the Pacific Intertie are allocated on the basis of a special study which has been used in other proceedings before this Commission.

4. All energy costs and related revenues have been excluded. These costs and revenues are treated separately in a special ECAC proceeding before this Commission and the Federal Energy Regulatory Commission.

5. The staff has examined the various allocation factor calculation methods used by the utility and is of the opinion that they are reasonable. They have been utilized by the staff for the purpose of this report, and they are consistent with the previous decisions.

6. Tables 19-A and 19-B summarize the results of the jurisdictional cost separation at present and company proposed rates for 1981 test year. The separation distinguishes between the California Public Utilities Commission (CPUC) regulatory jurisdiction and that of the Federal Energy Regulatory Commission (FERC).

7. Column (A) reflects systems total figures as set forth in Chapter 18 of the staff's results of operations report for the Electric Department. Column (C) consists of revenue and expenses subject to FERC jurisdiction and Column (E) consists of revenue and expenses subject to the jurisdiction of the lifornia Public Utilities Commission as calculated by the staff. Columns (B), (D, and (F) represent equivalent utility figures in Tables 19-A and 19-B.

TABLE 19 - A
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COST ALLOCATION SUMMARY
TEST YEAR 1981 - SDG&E PRESENT RATES

LINE NO.	ITEM	TOTAL SYSTEM		FERC JURISDICTIONAL		CPUC JURISDICTIONAL	
		STAFF	UTILITY	STAFF	UTILITY	STAFF	UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
		(DOLLARS IN THOUSANDS)					
1	REVENUE	$ 296647	$ 282943	$ 890	$ 849	$ 295757	$ 282094
	OPERATING EXPENSES						
2	PRODUCTION	52291	63765	21	26	52270	63739
3	TRANSMISSION	6793	8649	172	219	6621	8430
4	DISTRIBUTION	22871	25101	0	0	22871	25101
5	CUSTOMER ACCOUNTS	10598	11260	0	0	10598	11260
6	MARKETING EXPENSE	9268	14802	0	0	9268	14802
7	A&G	42314	43750	121	125	42193	43642
8	WAGE ADJUSTMENT	-1240	0	-3	0	-1237	0
9	SUBTOTAL	142895	167327	311	370	142584	166974
10	DEPRECIATION	49950	50076	164	164	49786	49912
11	TAXES OTHER THAN INCOME	14141	14957	46	49	14095	14908
12	INCOME TAXES	-101	11235	109	59	-210	11176
13	TOTAL OPER. EXPENSES	206885	243595	630	642	206255	242970
14	NET REVENUE	89762	39348	260	207	89502	39124
15	RATE BASE	1055401	1129302	2247	2404	1053154	1126898
16	RATE OF RETURN (PERCENT)	8.51	3.48	11.57	8.61	8.50	3.47

TABLE 19 - B
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COST ALLOCATION SUMMARY
TEST YEAR 1981 - SDG&E PROPOSED RATES

LINE NO.	ITEM	TOTAL SYSTEM STAFF	TOTAL SYSTEM UTILITY	FERC JURISDICTIONAL STAFF	FERC JURISDICTIONAL UTILITY	CPUC JURISDICTIONAL STAFF	CPUC JURISDICTIONAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
				(DOLLARS IN THOUSANDS)			
1	REVENUE	$ 431136	$ 409573	$ 890	$ 849	$ 430246	$ 408724
	OPERATING EXPENSES						
2	PRODUCTION	52291	63765	21	26	52270	63739
3	TRANSMISSION	6793	8649	172	219	6621	8430
4	DISTRIBUTION	22871	25101	0	0	22871	25101
5	CUSTOMER ACCOUNTS	10800	11450	0	0	10800	11450
6	MARKETING EXPENSE	9268	14802	0	0	9268	14802
7	A&G	44936	46219	121	125	44815	46094
8	WAGE ADJUSTMENT	-1240	0	-3	0	-1237	0
9	SUBTOTAL	145719	169986	311	370	145408	169616
10	DEPRECIATION	49950	50076	164	164	49786	49912
11	TAXES OTHER THAN INCOME	14141	14957	46	49	14095	14908
12	INCOME TAXES	64526	45327	109	59	64417	45268
13	TOTAL OPER. EXPENSES	274336	280346	630	642	273706	279704
14	NET REVENUE	156800	129227	260	207	156540	129020
15	RATE BASE	1055401	1129302	2247	2404	1053154	1126898
16	RATE OF RETURN (PERCENT)	14.86	11.44	11.57	8.61	14.86	11.45

TABLE 19 - C
SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STAFF TAX CALCULATIONS AT PRESENT
AND PROPOSED RATES

LINE NO.	ITEM	TOTAL SYSTEM PRESENT	TOTAL SYSTEM PROPOSED	FERC JURISDICTIONAL PRESENT	FERC JURISDICTIONAL PROPOSED	CPUC JURISDICTIONAL PRESENT	CPUC JURISDICTIONAL PROPOSED
		(A)	(B)	(C)	(D)	(E)	(F)
		(DOLLARS IN THOUSANDS)					
1	OPERATING REVENUES	$ 296647	$ 431136	$ 890	$ 890	$ 295757	$ 430246
2	O + M EXPENSES	142895	145719	311	311	142584	145408
3	TAXES (OTHER THAN INCOME)	14141	14141	46	46	14095	14095
4	SUBTOTAL	157036	159860	357	357	156679	159503
5	CCFT DEDUCTIONS	134066	134066	295	295	133771	133771
6	TOTAL DEDUCTIONS (4+5)	291102	293926	652	652	290450	293274
7	NET TAXABLE INCOME (STATE)	5545	137210	238	238	5307	136972
8	C C F T	532	13172	23	23	509	13149
9	ADJUSTMENTS	0	0	0	0	0	0
10	TOTAL STATE TAX	532	13172	23	23	509	13149
11	SUBTOTAL EXPENSES (4+8)	157568	173032	380	380	157188	172652
12	FIT DEDUCTIONS	138584	138584	305	305	138279	138279
13	TOTAL DEDUCTIONS (11+12)	296152	311616	685	685	295467	310931
14	NET TAXABLE INCOME (FEDERAL)	495	119520	205	205	290	119315
15	F I T	228	54979	94	94	133	54885
16	JDIC, DEFERRED TAX + SURTAX	-861	-3625	-8	-8	-853	-3617
17	TOTAL FIT	-633	51354	86	86	-720	51268
18	TOTAL INCOME TAX (10+17)	$ -101	$ 64526	$ 109	$ 109	$ -210	$ 64417

TAXES AT PRESENT RATES ROUNDED OFF

CHAPTER 20

RECOMMENDATIONS

The Commission staff recommends that:

1. Department of Water Resources expenses should be included in ECAC.
2. Variable wheeling expenses be included in ECAC.
3. The wage increase expenses be adjusted prior to the Commission's decision to reflect the latest consumer price index available.
4. Until the postal increase receives final approval, no postal increase should be included in the test year expenses.
5. If SDG&E sells the Niland facility prior to the Commission's decision, the sale should be reflected in the test year estimates.
6. Without prior approval, SDG&E should not be allowed to cut major R&D program expenditures.
7. SDG&E be allowed to recover construction and demonstration expenses for the Heber Geothermal Project on a dollar-for-dollar basis with no allowance for potential tax liability.
8. The accumulation of the estimated net decommissioning costs should be recovered through the depreciation rates and retained by the utility.
9. The actual lag between the date of delivery and payment for fuel oil be included in the working cash allowance calculation.